OFFICE OF ATMOSPHERIC PROTECTION
WASHINGTON, D.C. 20460

April 9, 2025

Mr. Jimmy Oxford
Targa Midstream Services, LLC
11194 W State Highway 302
Kermit, Texas 79745

Re: Monitoring, Reporting and Verification (MRV) Plan for Bull Moose Gas Plant

Dear Mr. Oxford:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Bull Moose Gas Plant, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Bull Moose Gas Plant on November 14, 2024, as the final MRV plan. The MRV Plan Approval Number is 1015124-1. This decision is effective April 14, 2025 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 Digitally signed by JULIUS BANKS
Date: 2025.04.09 15:09:51 -04'00'

Julius Banks
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the Bull Moose Gas Plant

January 2025

Contents

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 Targa Midstream Services, LLC (Targa) for the Bull Moose Gas Plant (BMGP) located in Winkler County, Texas. Note that this evaluation pertains only to the subpart RR MRV plan for the BMGP, 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 BMGP is currently authorized to inject treated acid gas (TAG) through the Bull Moose AGI #1 well (BM AGI #1) (American Petroleum Institute (API) No. 42-495-34978) located approximately 15 miles west of Kermit in Winkler County, Texas (Texas Railroad Commission (TRRC) District 08). The TRRC issued a permit (number 17541) to inject non-hazardous oil and gas waste under its Statewide Rule 9 (Appendix 2) for the Bull Moose AGI lease. All oil- and gas-related wells around the BM AGI #1 well, including both injection and production wells, are regulated by the TRRC, which has primacy to implement the UIC Class II program. The MRV plan states that the UIC permit number is 000126603. The BMGP is within the eastern part of the Delaware Basin region of the Permian Basin. BM AGI #1 was drilled for the purpose of disposing of the treated acid gas (TAG) that is a byproduct of natural gas processing operations at the BMGP. The project, with a design life of 30 years, plans to inject TAG through BM AGI #1 into the deep subsurface in the Siluro-Devonian, Fusselman, and Montoya formations.

According to the MRV plan, the source of carbon dioxide (CO_2) that is supplied to the facility is the BMGP. The plant gathers and processes produced natural gas. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. TAG from the plant's sweeteners will be routed to a central compressor facility. Compressed TAG is then routed to the well via high-pressure rated lines. The project allows the BMGP to run at full capacity without discharging large amounts of CO_2 to the atmosphere.

The MRV plan states that the BMGP is currently authorized to inject a total of up to 20 million standard cubic feet (ft) per day (MMSCFD) of TAG through the approved BM AGI #1 in accordance with Statewide Rule 9 of the TRRC. The BMGP received authorization to inject hydrogen sulfide (H_2S) under the TRRC Rule 36. The TAG stream is anticipated to consist of approximately 70% CO_2 and 30% H_2S with trace components of hydrocarbons (C1(methane) – C7(heptane)) and nitrogen. The permitted injection interval for BM AGI #1 is between 17,889 ft and 19,488 ft. The MRV plan also states that the BMGP intends to inject CO_2 through BM AGI #1 for 30 years. Following the operational period, the BMGP proposes a post-injection monitoring and site closure period of 15 years.

Section 3 of the MRV plan provides the project description and general geologic setting. The MRV plan states that the BMGP and the BM AGI #1 well are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The BMGP site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

For the BM AGI #1, the MRV plan states that the designated injection targets encompass the Siluro-Devonian formations, specifically the Devonian, Wristen, Fusselman and Montoya strata. The total thickness of the injection interval is estimated to be 1,594 ft. The deposits of the Simpson Group represent a regional transgression after the unconformity at the end of Ellenburger deposition. This group is a thick sequence of carbonates, sandstones, and shales (~1,000 ft thick) which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. Within the sandstones (particularly the McKee Sandstone member), well logs indicate porosity averages around 15%. Permeability averages 45 millidarcy (mD), though cementation and compaction may decrease that in the area. The Montoya deposits (~250 ft thick) are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin. Like the Ellenburger Group, the porosity within the Montoya Group is dependent on depositional environment and diagenesis. Based on well logs, the average porosity is approximately 3%, with scattered zones over 5%. The probable average permeability is probably less than 1 mD, but fracturing may enhance it. The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Bull Moose area, the Fusselman thickens to around 1,000 ft of high-energy packstones to grainstones. Based on well logs, the porosity averages around 2%, but there are zones, like in well API No. 42-495-31047, with over 70 ft of greater than 5% porosity. Reported permeability for shallower sections range from 0.001 to 10 mD. Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section (~275 ft thick). Porosity and permeability in the Wristen Group are limited in the main body of the unit (porosity is 1-2%), although exposure events and carbonate dissolution can improve the porosity up to~5%. Within the Thirtyone deposits, the chert-rich hemipelagic deposits maintain the best porosity, up to 40%, and have permeability values of up to 80 mD, while the limestones have less than 7% porosity and less than 1 mD of permeability.

According to the MRV plan, the Woodford Shale and the Mississippian Limestone serve as the upper confining zone (UCZ). Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 ft thick in the Bull Moose area and is regionally extensive. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is ~750 ft thick. Overall, the Mississippian units are good seals in preventing upward fluid movement through the section. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units. In combination with the Mississippian section, it makes an excellent seal. The Woodford Shale is ~620 ft thick in the BMGP area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. Porosity in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). The

MRV plan also states that the Ellenburger Group and Cambrian to Precambrian strata serve as the lower confining zone (LCZ). The lower sediments, approximately 150 to 200 ft, of the Ellenburger Group are normally less porous and have lower permeability (1 – 2% porosity and <2 mD) due to their original depositional environment and the depth of burial, making this zone a potential underlying seal. The oldest sediment in the area is Cambrian Bliss Sandstone (Broadhead, 2017) which overlies Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland. Within the BMGP area, no porosity and permeability data could be found for the Bliss Sandstones. Considering their depth, compactional history, and potential diagenetic alteration, the Bliss sandstones and associated granitic debris (from weathering of the basement rock) are probably relatively tight.

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 the 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 the 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, dynamic reservoir simulation was performed based on a high-resolution geological model. The modeling predicts well injectivity, pressure behaviors, and TAG plume migration. Schlumberger's Petrel® (Version 2023.3) software was used to construct the geological models used in this work. Computer Modelling Group (CMG) software was used to perform the reservoir simulations, which terminated in 2085. The software was used to perform pressure, volume, and temperature (PVT) calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling. A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling to define the extent of the plume. Simulations indicate BM AGI #1 can inject at the proposed rate throughout the 30-year period without any complications.

Section 4 of the MRV plan states that according to the reservoir modeling results, after 30 years of post-injection monitoring (year = 2085), the injected gas will remain in the reservoir and no expansion of the TAG footprint is observed after 2070. Therefore, the plume extent at year 2070 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA. The BMGP considered the identified faults surrounding the injection well to define the MMA. There was no need to extend the MMA to incorporate the faults plus a one-half-mile buffer around the faults because they are outside the initial AMA and MMA. Therefore, the MMA encompasses the union of two areas:

1. The area covered by the stabilized plume plus an all-around buffer zone of one-half mile.

- The area covered by the lateral extent of known potential leakage pathways (the trace faults in Figure 4.2 of the MRV plan) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 in the MRV plan shows the MMA as defined by Section 40 CFR 98.449 of subpart RR. The MMA is expected to contain the free phase CO_2 plume throughout the life of the project and the lateral extent of potential leakage pathway plus a one-half mile buffer. The AMA is set equal to the MMA.

Section 4 of the MRV plan also states that the AMA is shown in Figure 4.1-1 in the MRV plan and is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

1. to contain the free phase CO_2 plume for the duration of the project (year t, t = 2055), plus an all-around buffer zone of one-half mile.

2. to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2060).

The MRV plan states that the BMGP defines the AMA to be the same area as the MMA. The BMGP chose t = 2055, which corresponds to the end of the 30-year injection period, for the purpose of calculating the AMA. The AMA and MMA contain the CO_2 plume during the duration of the project and at the time the plume is stabilized.

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 duration of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). The BMGP identified the following as potential leakage pathways in Section 5 of their MRV plan that required consideration:

- Surface equipment
- Approved not yet drilled wells
- Existing wells
- Confining/seal system

- Lateral migration
- Fractures and faults
- Natural/induced seismicity

3.1 Potential Leakage from Surface Equipment

The MRV plan states that preventative risk mitigation for preventing the potential for leakage from surface equipment will include adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants.

The BMGP infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place, and the regular inspections and maintenances, the probability of such leakage is considered very unlikely. Furthermore, any leaks from surface equipment would result in immediate emissions of CO_2 into the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak. The MRV plan also states that surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage. Therefore, the BMGP concludes that the impact of such a leakage is considered to vary from insignificant to severe according to scenarios, and the timing is also variable.

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

3.2 Potential Leakage through Approved not yet Drilled Wells

The MRV plan states that the approval and construction of oil and gas-related wells, including injection wells, are regulated by TRRC rules, specifically Rule 13 for casing, cementing, drilling, well control, and completion, which require that wells be constructed in such a manner as to prevent vertical migration of fluids, including gases, behind the casing. Adherence to these requirements will mitigate the risk of potential CO_2 emissions to the surface. Additionally, these wells have strict requirements and will be actively monitored for integrity on a regular basis. Therefore, the BMGP states that leakage from approved but not yet drilled wells is considered very unlikely.

The MRV plan also states that based on worst-case scenario considerations, the following National Risk Assessment Partnership (NRAP) analysis and the very unlikely risk of leakage happening from approved wells that have not yet been drilled, the magnitude of potential gas leaks through these wells is insignificant. All the wells within the MMA are either injecting, producing, plugged and abandoned or inactive, as shown in Table 5.1-1 in the MRV plan. There are no approved and not yet drilled wells based on the available records. Timing evaluations indicate no imminent risk of gas leakage from approved wells that have not yet been drilled.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through approved not yet drilled wells.

3.3 Potential Leakage through Existing Wells

The MRV plan states that the BMGP considered all wells completed and approved within the MMA. Of the 29 wells identified within the MMA, 22 were active oil wells, two were injection wells, six were abandoned and plugged, and one was inactive. None of the wells in the MMA penetrate the confining zone nor the injection zone. All the productive zones lie at more than 5,300 ft above the BM AGI #1 injection zone. Therefore, the MRV plan concludes that the risk of CO_2 leakage through existing wells is very unlikely and of insignificant magnitude. The MRV plans states that the duration for CO_2 to get to the atmosphere via upward migration through the 5,300 ft of sealing and other geologic formations would be several thousands of years.

Wells Completed in the Injection Zone

The MRV plan states that the only well completed in the targeted injection zone is BM AGI #1. The MRV plan states that to minimize the likelihood of leaks from new wells, TRRC regulation regarding the casing and cementing of injection wells requires operators to case injection wells with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string. Additionally, the BMGP states that to minimize the magnitude and duration of CO_2 leakage to the surface, TRRC requires the use of blowout preventers in areas of high pressure at or above the projected depth of the well. These requirements apply to any other new well drilled within the MMA for this MRV plan. Therefore, the MRV plan states that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

Horizontal Wells

Appendix 3 and Figure 3.7-2 of the MRV plan show multiple horizontal wells in the area, many of which are producing. The MRV plan states that they are all 5,300 ft above the injection zone and the risk of leakage through these wells is considered very unlikely and insignificant.

Groundwater Wells

The MRV plan states that according to the Texas Water Development Board (TWDB) water database, there are no water wells within the MMA. There is only one North-East of the MMA and one South-West of the MMA. Therefore, the risk of leakage through these wells is considered very unlikely and insignificant.

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

3.4 Potential Leakage through the Confining/Seal System

The MRV plan states that the Barnett shale (440 ft thick), Mississippian limestone (440 ft thick) and Woodford Shale (660 ft thick) serve as the major seals or caprock layer to the injection zones. Their low porosity (1%) and permeability (<0.1 mD) provide high seal integrity. In addition, the MRV plan states that there is no evidence of faulting or natural fracturing. Therefore, the BMGP concludes that it is very unlikely that TAG injected into the injection formation will leak through this confining zone to the surface. The MRV states that the worst-case scenario is defined as leakage through the seal immediately above the injection well, where CO_2 saturation is highest.

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

3.5 Potential Leakage due to Lateral Migration

The BMGP believes that the BM AGI #1 injection zones have adequate storage capacity for the proposed injection amount. In addition, the MRV plan states that the simulation indicates that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA. Therefore, based on the geological discussion and analysis of the injection zone, the BMGP considers that the likelihood of CO_2 to migrate laterally is unlikely. Finally, the BMGP states that the sealing zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration occurs.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected due to lateral migration.

3.6 Potential Leakage through Fractures and Faults

The MRV plan states that no faults were identified in the injection zone or confining zone within the MMA. Considering faults that are going through the confining or injection zone, the closest identified fault lies approximately 1.5 miles east of the Bull Moose site and has approximately 1,000 ft of down-to-the-west structural relief. Additionally, the nearest fault going through the injection or confining zone is found approximately 7,276 ft east of the BM AGI #1 site. The MRV plan states that the risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume or lateral migration carries CO_2 to faults. Therefore, the BMGP concludes that the risk of CO_2 leakage through the faults is very unlikely and insignificant.

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

3.7 Potential Leakage due to Natural/Induced Seismicity

Natural Seismicity

The MRV plan states that due to the distance between the BM AGI #1 well and the location of the seismic events recorded since 2017, the magnitude of these events, and the fact that the BMGP injects at pressures below fracture opening pressure, the BMGP considers the likelihood of CO_2 emissions to the surface caused by seismicity to be very unlikely. The MRV plan also states that the magnitude and timing of a seismic event can vary greatly. In the region, the earthquakes ranged from magnitude 1.5 to 4. They are in clusters that are around 20 miles North-West, South, and South-West of the BMGP.

Induced Seismicity

The MRV plan states that the faults that might be affected by pressure changes have been analyzed to evaluate the risk of induced seismicity, and the risk of leakage due to induced seismicity. The BMGP states that they evaluated Fault Slip Potential (FSP) using the FSP software version 1.07. The results of the FSP analysis indicated that over a 30-year injection period, faults experienced only a small pressure drop in effective stress. Therefore, the MRV plan states that the risk of leakage due to induced is considered very low. Its likelihood, timing and magnitude are considered very unlikely and insignificant.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected due to natural/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 contains a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 6 of the MRV plan discusses the strategies that the BMGP will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(3). The MRV plan states that the BMGP considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage close to the plant equipment. A summary table of the BMGP's detection strategies can be found in Table 6-1 of the MRV plan and is reproduced below. Monitoring will occur over the duration of injection and the 15-year post-injection period.

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Wells that have not yet been drilled	• Monitor applications for permit to drill and permit to inject made to the TRRC • Communicate with operators/drillers that are active within the MMA so that they are aware that they are drilling in an area that has CO_2/H_2S injection activities
BM AGI #1 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well pressure/temperature (P/T) sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone/Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural/Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring station
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

4.1 Detection of Leakage from Surface Equipment

The BMGP states that they implement several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Leaks from surface equipment are detected by the BMGP field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events. The BMGP states that they also maintain in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Approved Not Yet Drilled Wells

The MRV plan states that special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. The MRV plan states that this applies to the BMGP and other operators drilling new wells through the BM AGI #1 injection zone within the MMA.

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through approved not yet drilled wells. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage through approved not yet drilled wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Existing Wells

The MRV plan states that the BMGP continuously monitors and collects flow, pressure, temperature, and gas composition data in its data collection system. These data are monitored continuously by qualified technicians who follow response and reporting protocols when the system delivers alerts that data is not within acceptable limits. To monitor leakage and wellbore integrity, the MRV plan states that pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) will be deployed in the BM AGI #1 well.

For other existing wells within the MMA, the MRV plan states that the CO_2 monitoring network and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. In addition, the MRV plan states that groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface.

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

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through existing wells. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage through existing wells as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through the Confining/Seal System

The MRV plan states that continuous operational monitoring of the BM AGI #1 well will provide an indicator if CO_2 leaks out of the injection zone. Additionally, the MRV plan states that groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. The BMGP states that if changes in operating parameters or other monitoring methods indicate leakage of CO_2 through the confining/seal system, they will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well.

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through the confining/seal system. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage through the confining/seal system as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage due to Lateral Migration

The MRV plan states that continuous operational monitoring of the BM AGI #1 well during and after the period of the injection will provide an indication of the movement of the CO_2 plume migration in the injection zones. The MRV plan states that the CO_2 monitoring network and routine well surveillance will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. The BMGP states that if monitoring of operational parameters or other monitoring methods indicate that the CO_2 plume extends beyond the area modeled, they will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 migration. As this scenario would be considered a material change per 40 CFR 98.448(d)(1), the MRV plan states that the BMGP will submit a revised MRV plan as required by 40 CFR 98.448(d).

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected due to lateral migration. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage due to lateral migration as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage through Fractures and Faults

The MRV plan states if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, the BMGP will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. The BMGP states that they will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface.

Table 6.1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through fractures and faults. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage through fractures and faults as required by 40 CFR 98.448(a)(3).

4.7 Detection of Leakage due to Natural/Induced Seismicity

To monitor the influence of natural and/or induced seismicity, the BMGP states that they will use the established TexNet seismic network. The network consists of seismic monitoring stations that detect and locate seismic events. Continuous monitoring helps differentiate between natural and induced seismicity. The MRV plan states that if the monitoring systems indicate surface leakage of CO_2 linked to seismic events, the BMGP will assess whether the CO_2 originated from the BM AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected.

Table 6-1 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected due to natural/induced seismicity. Thus, the MRV plan provides adequate characterization of the BMGP's approach to detect potential leakage due to natural/induced seismicity as required by 40 CFR 98.448(a)(3).

4.8 Quantifying CO_2 Leakage

Leakage From Surface Equipment

The MRV plan states that for normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in subpart W according to the requirements of 98.444(d) of subpart RR. Additionally, quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 of the MRV plan will be assessed by employing methods most appropriate for the site of the identified leak. The MRV plan states that quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. The BMGP states that they have standard operating procedures to report and quantify all pipeline leaks in accordance with the TRRC regulations. Additionally, the BMGP may employ available leakage models for characterizing and predicting gas leakage from gas pipelines.

The MRV plan lists the following example quantification strategies specifically designed for surface leakage:

- Direct measurement techniques: The BMGP will use mass flow meters in surface equipment. These meters can capture CO_2 mass flow rates in real-time, providing direct quantification of emissions as soon as a leak is detected.

- Leak rate models: The BMGP will use models that incorporate thermodynamic and fluid dynamics principles to estimate the mass of CO_2 escaping from leaks. For example: empirical leak rate models employ empirical equations that estimate leak rates based on equipment size, the differential pressure across the leak, and gas composition.

Subsurface Leakage

The MRV plan states that the selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method that identifies the leak. The MRV plan also states that quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the facility. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. The BMGP may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Surface Leakage

The MRV plan states that leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1 of the MRV plan, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8 of the MRV plan, will be employed to quantify the surface leaks.

4.9 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that the BMGP will use to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). The MRV plan states that the BMGP uses the existing automatic DCS to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. The MRV plan also states that the BMGP considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon the methodologies detailed in their H_2S Contingency Plan to establish baselines for monitoring CO_2 surface leakage.

Visual Inspection

The MRV plan states that the BMGP field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the BMGP.

Fixed In-Field, handheld, and Personal H_2S Monitors

The MRV plan states that the BMGP's H_2S Contingency Plan contains procedures for an organized response to an unplanned release of H_2S from the plant or the associated BM AGI #1 well, and documents of procedures that would be followed in the case of such an event.

Fixed In-Field H_2S Monitors

The BMGP states that they utilize numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS.

Handheld and Personal H_2S Monitors

The MRV plan states that handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. Additionally, all personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S.

CO_2 Detection

The BMGP states that they will set up a monitoring network for CO_2 leakage detection in the MMA as defined. In addition, there will be periodic groundwater and soil flux sampling within the MMA.

Continuous Parameter Monitoring

The MRV plan states that the DCS of the plant monitors injection rates, pressures, and composition on a continuous basis. High and low set points are programmed into the DCS, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.

Well Surveillance

The BMGP states that they adhere to the requirements of TRRC Rules governing the construction, operation and closing of an injection well under the Oil and Gas Act. Furthermore, the BMGP's Routine

Operations and Maintenance Procedures for BM AGI #1 ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

Seismic (Microseismic) Monitoring Stations

The BMGP states that they have installed a seismometer and a digital recorder to monitor and record data for any seismic event at the BMGP. The seismic station meets the requirements of the TRRC. Furthermore, data that is recorded by the TexNet network surrounding the BMGP will be analyzed by the BMGP.

Groundwater Monitoring

The BMGP will monitor groundwater wells for CO_2 leakage. The MRV plan states that water samples will be collected and analyzed monthly for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly.

Soil CO_2 Flux Monitoring

The MRV plan states that soil CO_2 flux will be collected monthly for 12 months to establish the baseline and understand seasonal and other variation at the BMGP. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Thus, the BMGP provides an acceptable approach for detecting and quantifying leakage and for establishing the 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

Section 8 of the MRV plan provides the equations that the BMGP will use to calculate the mass of CO_2 sequestered in subsurface geologic formations. The BMGP states that all the meters cited in the MRV plan are in accordance with 40 CFR 98.444(b)(1).

5.1 Calculation of Mass of CO_2 Received

Section 8.1 of the MRV plan states that the BMGP receives gas through a network of pipelines. The gas is processed to produce compressed TAG, which is then routed to the BM AGI #1 wellhead and pumped at the injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline. The BMGP will use Equation RR-2 to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. Receiving flow meter r in the following equations corresponds to flow meter FM in Figure 3.7-1 in the MRV plan.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

The MRV plan also states that the total annual mass of CO_2 received through all pipelines will be calculated using Equation RR-3.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

Although the BMGP does not currently receive CO_2 in containers, the facility states it wishes to include this flexibility in the MRV plan. When the BMGP begins to receive CO_2 in containers, the facility will use Equations RR-1 and RR-2 to calculate the mass of CO_2 received in containers. The BMGP will adhere to the requirements in 40 CFR 98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

BMGP provides an acceptable approach for calculating the mass of CO_2 received under subpart RR.

5.2 Calculation of Mass of CO_2 Injected

Section 8.2 of the MRV plan states that upon completion, the BMGP will commence injection into the BM AGI #1 well. Equation RR-5 will be used to calculate the CO_2 measured through volumetric flow meters before being injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meter FM in Figure 3.7-1 in the MRV plan.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

The MRV plan also states Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the well.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

BMGP provides an acceptable approach for calculating the mass of CO_2 injected under subpart RR.

5.3 Calculation of Mass of CO_2 Produced/Recycled

Section 8.3 of the MRV plan states the BMGP does not produce oil, gas, or any other liquid, so there is no CO_2 produced or recycled.

BMGP provides an acceptable approach for calculating the mass CO_2 produced under subpart RR.

5.4 Calculation of Mass of CO_2 Lost through Surface Leakage

Section 8.4 of the MRV plan states Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified in the plan. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12.

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

where:

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

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

x = Leakage pathway.

BMGP provides an acceptable approach for calculating the mass of CO_2 lost by surface leakage under subpart RR.

5.5 Calculation of Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Section 8.5 of the MRV plan states that as required by 98.444(d), the BMGP will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of subpart W. According to 98.233(r)(2) of subpart W, the emissions factor listed in Table W-1A of subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

5.6 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since the BMGP does not actively produce oil, natural gas, or any other fluid, the MRV plan states that Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

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

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 [refers to subpart W of the GHGRP rules].

BMGP provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations under subpart RR.

6 Summary of Findings

The subpart RR MRV plan for the Bull Moose Gas Plant 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 BMGP's MRV plan.

Subpart RR MRV Plan Requirement	Bull Moose Gas Plant MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan delineates the MMA and AMA. The MMA is defined by the most conservative extent of the TAG plume in the year 2070 plus a one-half mile buffer. The MRV plan defines the active monitoring area as the same area as the MMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude,	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: surface

and timing, of surface leakage of CO_2 through these pathways.	equipment, approved not yet drilled wells, existing wells, confining/seal system, lateral migration, fractures and faults, and natural/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 6 and 7 of the MRV plan describe the strategy that the BMGP will use to detect and quantify potential CO_2 leakage to the surface should it occur. The MRV plan states that leakage models including transport, geomechanical, or reactive transport model simulations will be used to quantify CO_2 leakage.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. The BMGP will use an existing automatic DCS to identify and investigate deviations from expected performance that could indicate CO_2 leakage. The BMGP's strategy for establishing baselines includes visual inspection; fixed in-infield, handheld, and personal H_2S monitors; CO_2 detection; continuous parameter monitoring; well surveillance; seismic (micro seismic) monitoring stations; groundwater monitoring, and soil CO_2 flux 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 8 of the MRV plan describes the BMGP's approach for determining the total amount of CO_2 sequestered using the subpart RR mass balance equations, including calculation of equipment leaks and vented emissions of CO_2.
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.	Sections 2 and 12 of the MRV plan identify the well identification number used for the UIC permit and the UIC class for the Bull Moose AGI #1 well. The well is permitted as Class II under the TRRC.
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 9 of the MRV plan states that the BMGP will begin collecting data for calculating the total amount sequestered according to equation RR-11 or RR-12 of this subpart as soon as it is approved by EPA.

Appendix A: Final MRV Plan

MONITORING, REPORTING, AND VERIFICATION PLAN

Bull Moose AGI #1

Targa Delaware, LLC (Targa)

Version 1.0

November, 2024

Table of Contents

1 Introduction

Targa Delaware, LLC (Targa) proposes an underground injection project at the Targa Bull Moose Gas Processing Plant (the Plant) located approximately 15 miles west of Kermit in Winkler County, district 08, Texas. The Plant is within the eastern part of the Delaware Basin region of the Permian Basin. (**Figure 1-1**).

Targa submitted a Class II Acid Gas Injection (AGI) permit application (Form W-14) for the Bull Moose AGI #1 well (BM AGI #1) to the Texas Railroad Commission (TRRC). Targa intends to drill BM AGI #1 in Q4 of 2024 for the purpose of disposing of the treated acid gas (TAG) that is a byproduct of natural gas processing operations at the Plant. The TAG stream is anticipated to consist of approximately 70% CO_2 (carbon dioxide) and 30% H_2S (hydrogen sulfide), with trace components of hydrocarbons (C1(methane) – C7(heptane)) and nitrogen. The project, with a design life of 30 years, plans to inject TAG through BM AGI #1 into the deep subsurface in the Siluro-Devonian, Fusselman, and Montoya formations.

The project allows Targa to run the Plant at full capacity without discharging large amounts of CO_2 to the atmosphere; replacing the flare with deep injection decreases the negative environmental footprint of the gas plant.

Targa has significant experience in the handling and disposal of TAG in this remotely populated area. Targa submitted forms and supporting documentation designed to meet the requirements of Texas Administrative Code Title 16 Chapter 3 Rule §3.9 and current best engineering practices to ensure that the USDW and the atmosphere are protected from any contamination from injection.

Targa is currently authorized to inject a total of up to 20 million standard cubic feet per day (MMSCFD) of TAG in the approved BM AGI #1 (API 42-495-34978) in accordance with Statewide Rule 9 of the TRRC. Targa received authorization to inject H_2S under the TRRC Rule 36. BM AGI #1 is located on the Plant property (**Figure 1-2**). The permitted injection interval is between 17,889 feet (ft) and 19,488 ft.

The BM AGI #1 well will be constructed with four strings of casing cemented to surface. Corrosion resistant alloys will be used in the bottom 300 ft of the long-string, in the confining zone. Acid resistant cements will also be used across the upper confining zone. Monitoring systems will be installed to ensure that bottomhole injection pressure does not exceed 90% of the determined fracture gradient of the injection interval. Targa is requesting a maximum allowable surface pressure of 0.5 psi/ft (pounds per square inch per foot), or 8,969 psi.

Targa submits this Monitoring, Reporting, and Verification (MRV) plan for the BM AGI #1 well to the United States Environmental Protection Agency (U.S. EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Targa intends to inject CO_2 in BM AGI #1 for 30 years. Following the operational period, Targa proposes a post-injection monitoring and site closure period of 15 years.

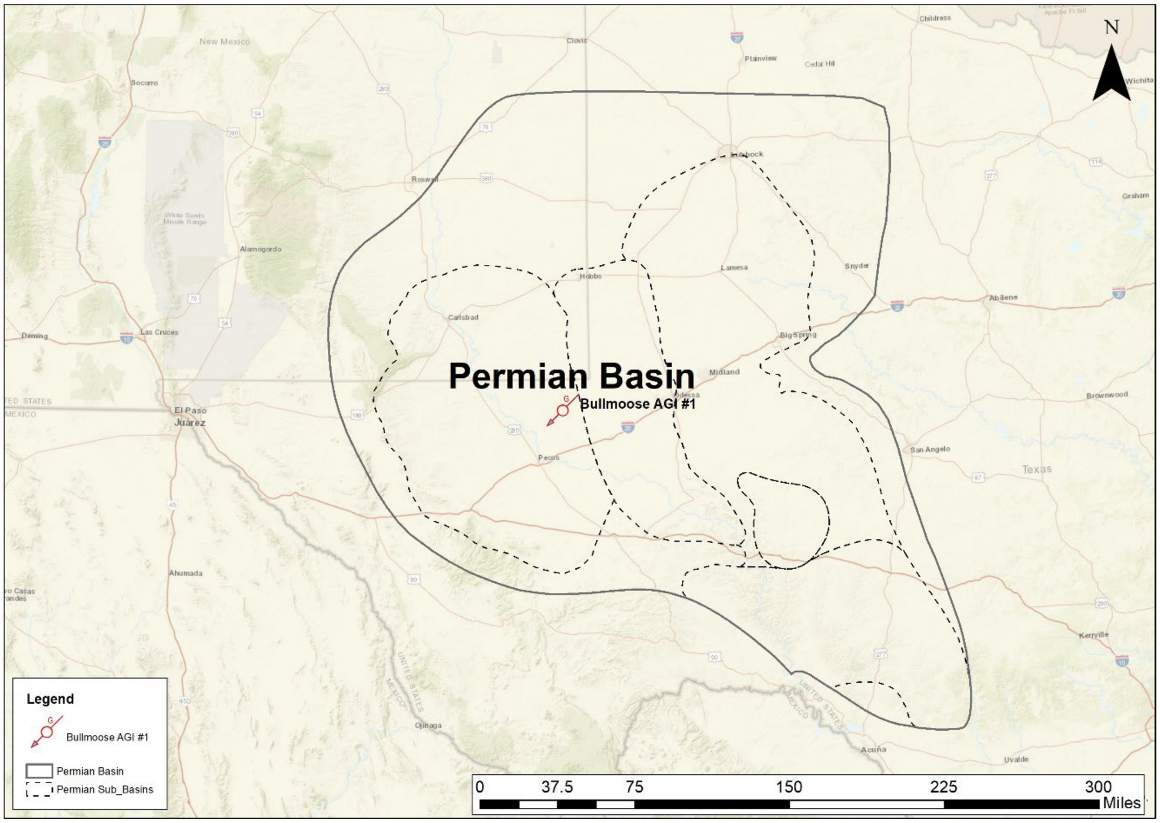


Figure 1-1: *Location of the Bull Moose Facility in the Permian Basin, Texas*

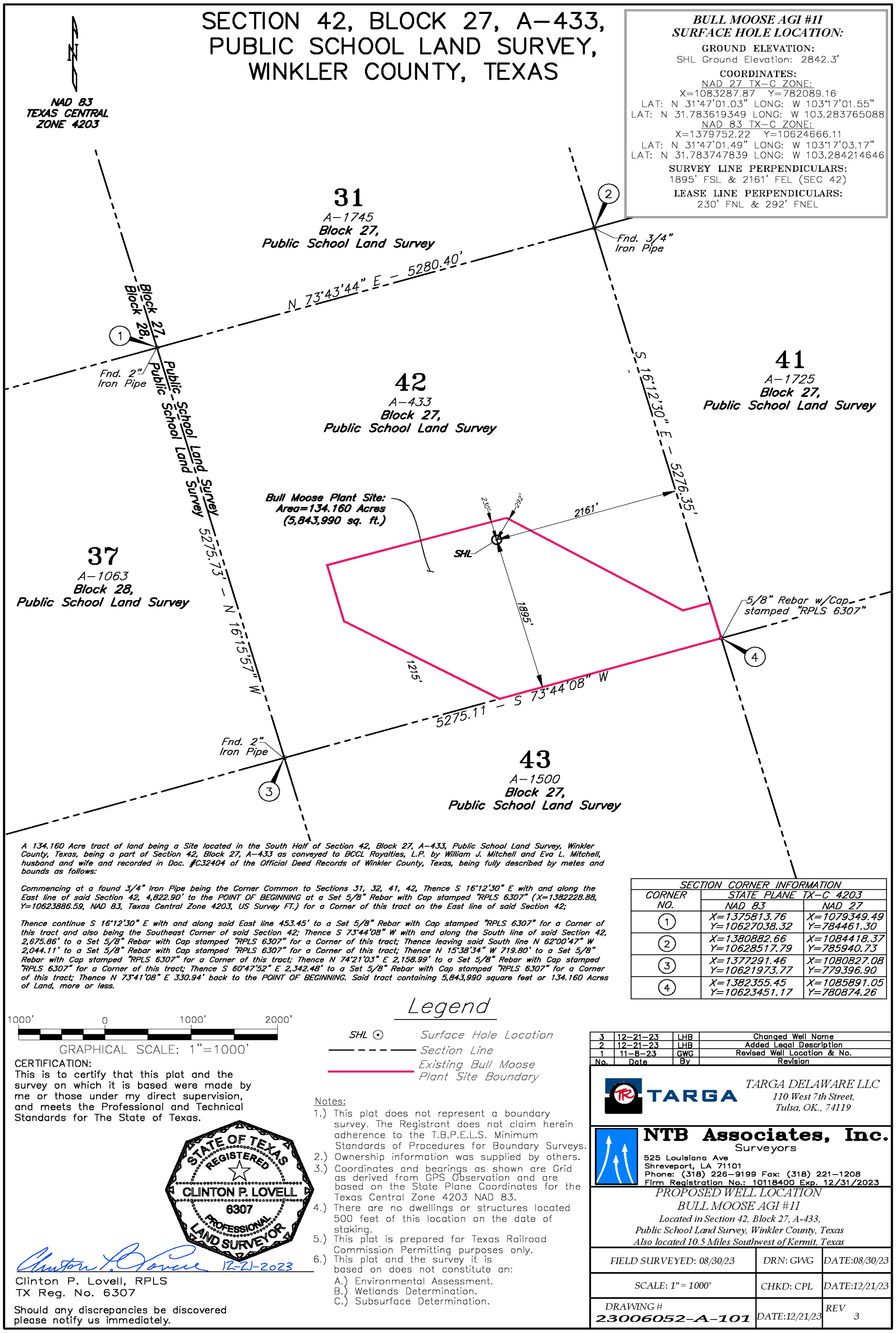


Figure 1-2: Location of the Bull Moose Gas Plant and BM AGI #1 Well

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 589241.

2.2 UIC injection well identification numbers

This MRV plan is for the BM AGI #1 well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The TRRC has issued a permit (number 17541) to inject non-hazardous oil and gas waste under its Statewide Rule 9 (**Appendix 2**) for the Bull Moose AGI lease. All oil- and gas-related wells around the BM AGI #1 well, including both injection and production wells, are regulated by the TRRC which has primacy to implement the UIC Class II program.

Well identification and permit parameters:

- BM AGI #1 API Number: 42-495-34978
- UIC Permit Number: 000126603

3 Project Description

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

3.1 General Geologic Setting / Surficial Geology

The Plant is located in Sec. 42, A-433, Blk 27, approximately 10.5 miles south-west of Kermit in Winkler County, Texas, immediately adjacent to the BM AGI #1 well **(Figs 1-1, 1-2)**. The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

3.2 Bedrock Geology

3.2.1 Basin Development

The Bull Moose Gas Plant and the BM AGI #1 well are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**).

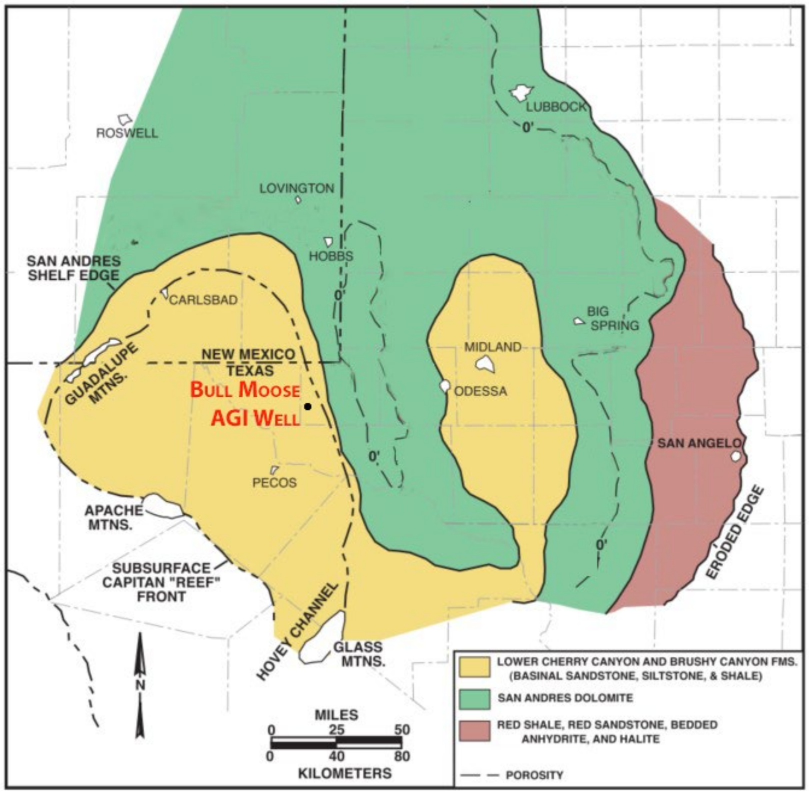


Figure 3.2-1: *Structural features of the Permian Basin during the Late Permian. Location of the Targa BM AGI well is shown by the black circle. (Modified from Ward, et al (1986))*

The BM AGI well is in the Delaware Basin portion of the broader Permian Basin. **Figure 3.2-2** is a generalized stratigraphic column showing the formations that underlie the Bull Moose Gas Plant and BM AGI #1 well site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below. Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit.

Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (with formation thickness varying from 0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit’s overall porosity and permeability.

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

Figure 3.2-2: *Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

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

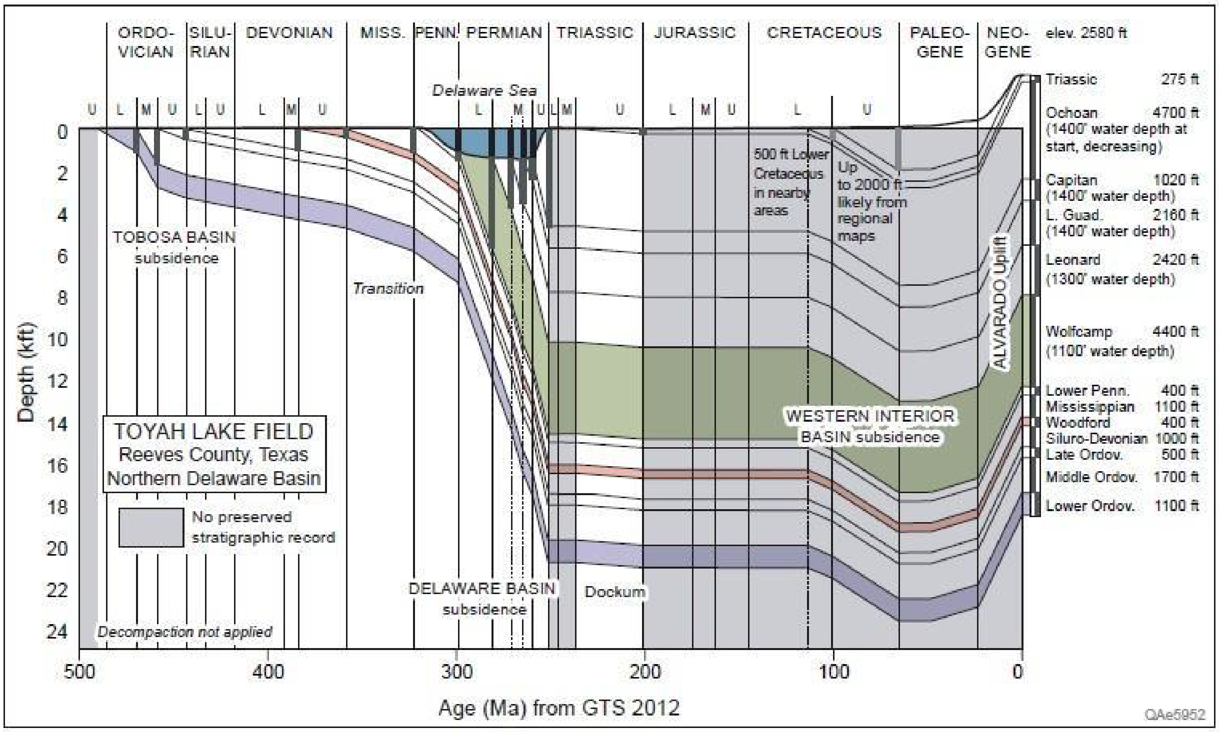
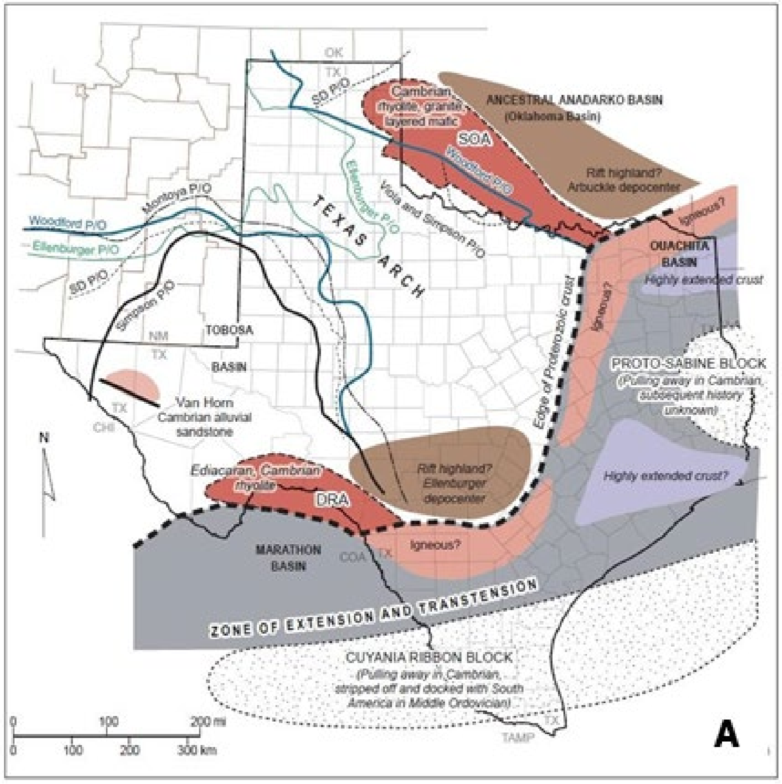


Figure 3.2-3: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)



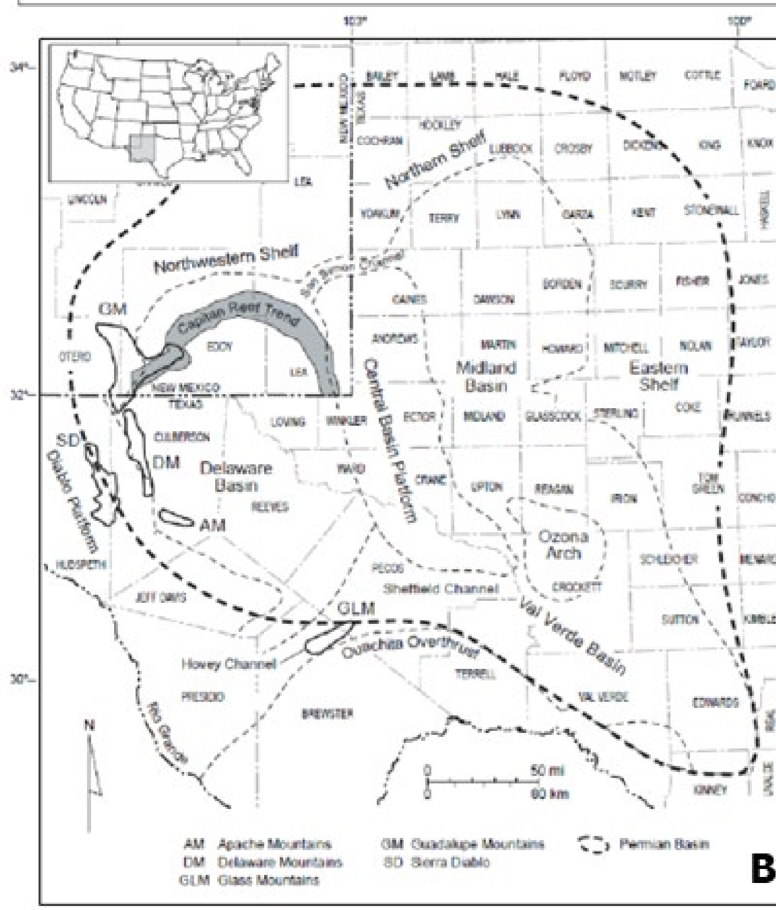


Figure 3.2-4: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).

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

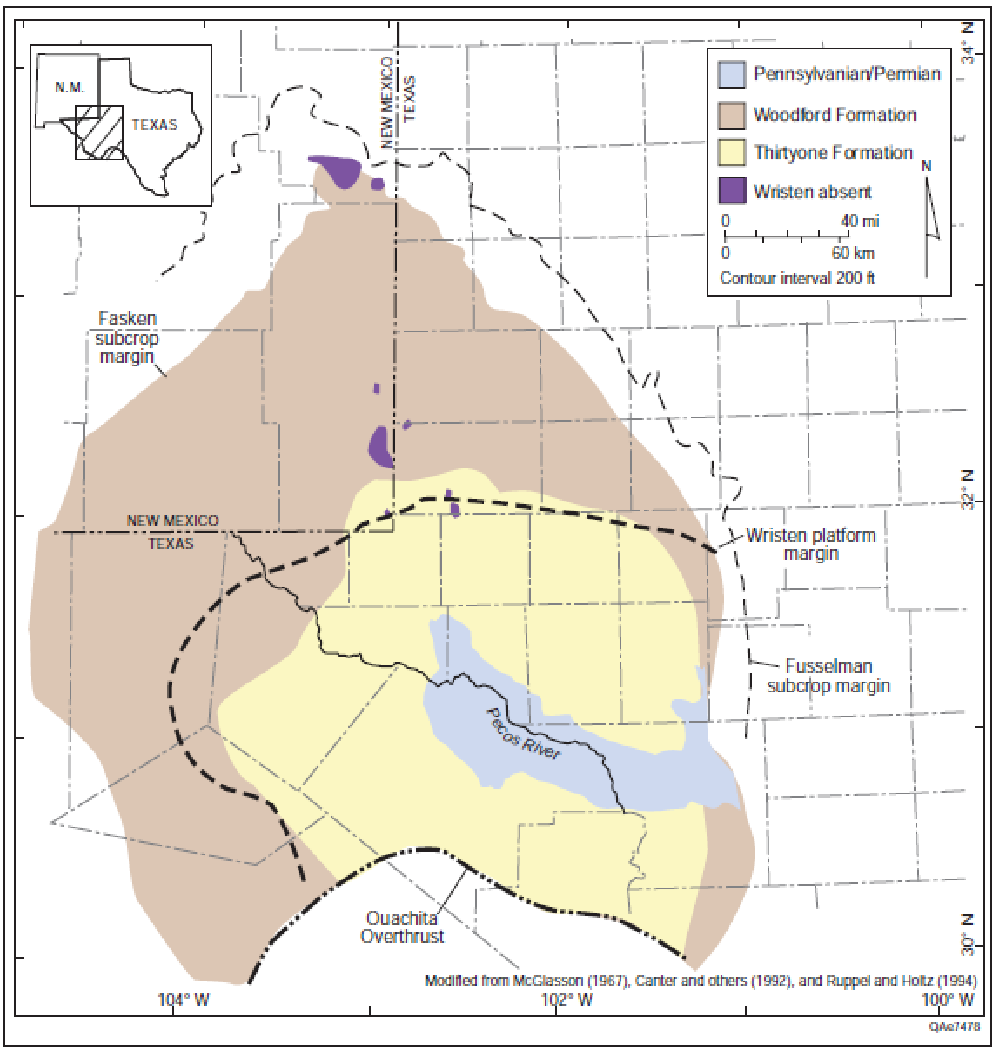


Figure 3.2-5: *A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial

exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

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

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian sediments include the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). In the area, the Atoka Formation (0-500 ft) was deposited during another sea-level transgression. is dominated by siliciclastic sediments, with depositional environments ranging from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

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

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4, 3.2-6, 3.2-7**). The Permian “Wolfcamp” or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued throughout

the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

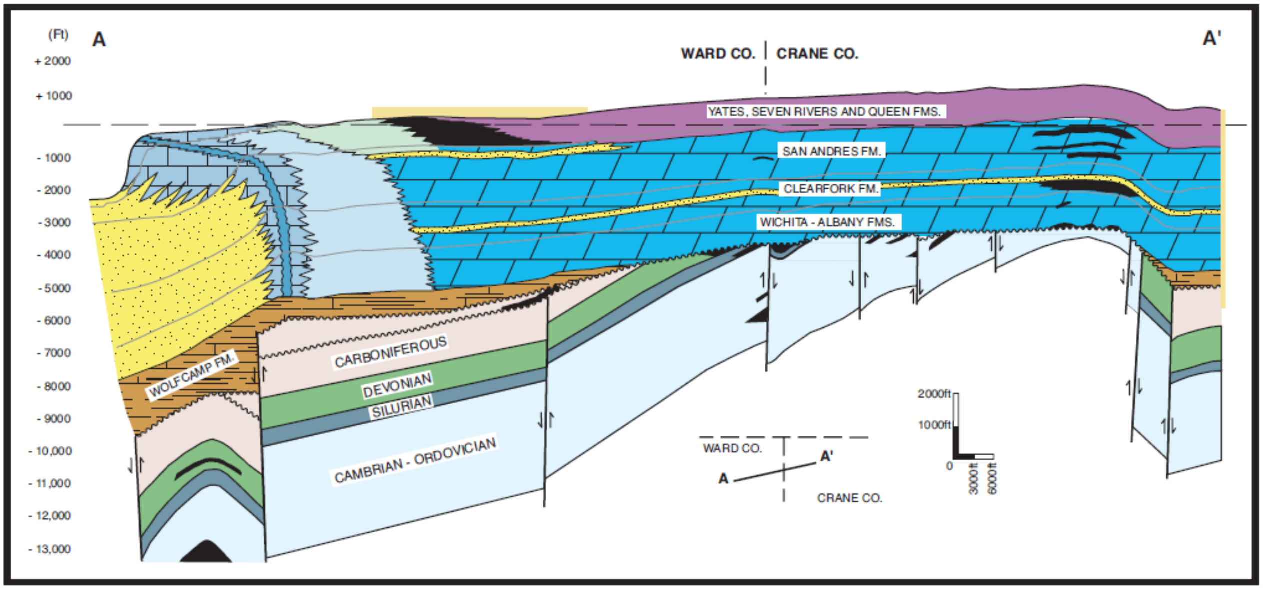


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

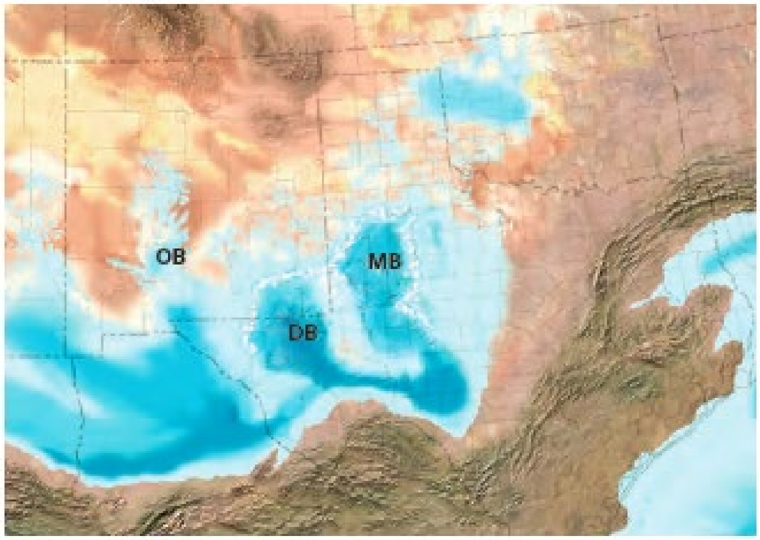


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shed off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s of feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso are the clean white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within

the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon formations.

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

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

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (Figure 3.2-2). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the Bull Moose AGI well, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Within the Bull

Moose area, there is no active production from the Permian Delaware Mountain Group, but there is production from the basinal Bone Spring and Wolfcamp formations. The injection and confining zones for BM AGI #1 are discussed below.

3.3 Injection Interval Properties

3.3.1 Siluro-Devonian to Ellenburger Group

In the context of BM AGI #1, the designated injection targets encompass the Siluro-Devonian formations, specifically the Devonian, Wristen, Fusselman and Montoya strata. The total thickness of the injection interval is estimated to be 1,594 ft (**Table 3.3-1**).

Table 3.3-1: *Estimated BM AGI #1 formation top depths, formation thicknesses, seal and reservoir thicknesses (total), and average porosity, and permeability.*

Formation	Measured Depth (ft)	Formation thickness (ft)	Unit Thickness (ft)	Porosity (%)	Permeability (mD)	Behaviour	Notes*
Rustler Fm.	934	255	4,165			Seal	450' base of useable groundwater
Salado Fm.	1,189	1,400		2.5	0.2	Seal	1200' base of USDW
Castile Fm.	2,589	2,510		1	0.01	Seal	
Lamar Ls.	5,099	45	3,990	15	100	Reservoir	
Bell Canyon Fm.	5,144	1,100		23	110	Reservoir	
Cherry Canyon Fm.	6,244	995		15	12	Reservoir	
Brushy Canyon Fm.	7,239	1,850		12	11	Reservoir	
Bone Spring Fm.	9,089	2,860	2,860	2	0.2	Seal	
Wolfcamp	11,979	1,600				Reservoir	Deepest nearby production wells
Strawn Fm.	13,579	760				Reservoir	
Atoka Fm.	14,339	215				Reservoir	
Morrow Fm.	14,554	1,795				Reservoir	
Barnett Sh.	16,349	440	1,540	1	0.1	3° Seal	
Mississippian Ls.	16,789	440		2	1	2° Seal	
Woodford Sh.	17,229	660		1	0.1	1° Seal	
Wristen Grp. And Thirtyone Fm.(Siluro Devonian)	17,889	289	1,594	5	1	Injection interval	
Fusselman Fm.	18,184	1,055		7	1	Injection interval	
Montoya Grp.	19,239	250		3	1	Injection interval	
Simpson Sands*	19,489	1,000		15	45	Not Drilled	
Ellenburger Grp.	20,489	550		6	15	Not Drilled	
Bliss/Precambrian	21,039					Lower seal	

*Simpson Sands consist of three discrete sand bodies (~300 ft of sands) within the over thousand-feet-thick unit.

ORDOVICIAN.

ELLENBURGER GROUP – The Ordovician Ellenburger Group is below the injection interval and is comprised of dolomites and limestones that are approximately 550 ft thick. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during later tectonic events (**Figure 3.3-1**).

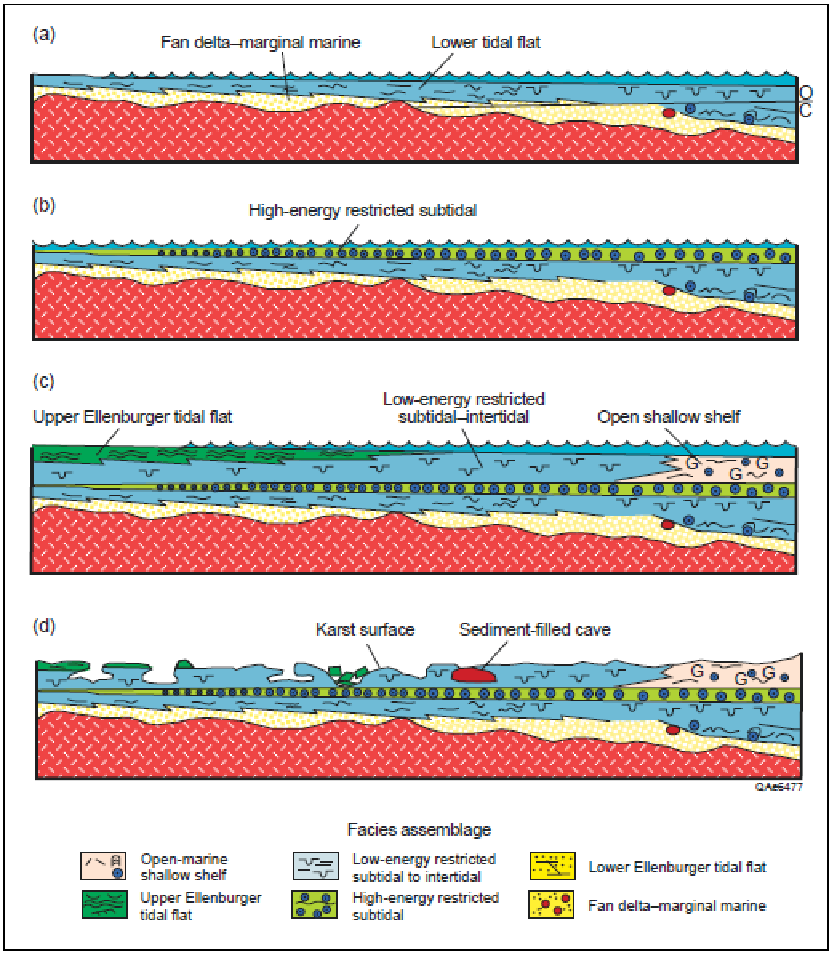


Figure 3.3-1: *Depositional model for Ellenburger Group deposits. The diagram shows a sequence of transgressive sandstones (Bliss Sandstone, yellow) to carbonates (Panels a through c followed by a regressive sequence (Panels c – d) with exposure and karstification in Panel d (from Loucks and Kerans, 2019).*

Within the Ellenburger Group strata, the upper and middle section typically has the highest porosity and permeability due to karsting and cave development as well as later faulting and fracturing (**Figure 3.3-2**). Late diagenesis plays an important role in porosity destruction and resurrection. Based on work by Loucks (2016, unpublished report), the best karst-related porosity is to the east of the Bull Moose area, whereas the Bull Moose area is in the zone of porosity due to tectonically controlled faulting and fracturing.

Porosity and permeability in the Ellenburger section can vary greatly due to the above considerations, but a realistic value for the porosity and permeability, at approximate 20,000 ft depth, is 5-6% and 15 mD (**Table 3.3-1**). Potentially the range of porosity and permeability can range up to 12% and greater than 100 mD (Loucks and Kerans, 2019).

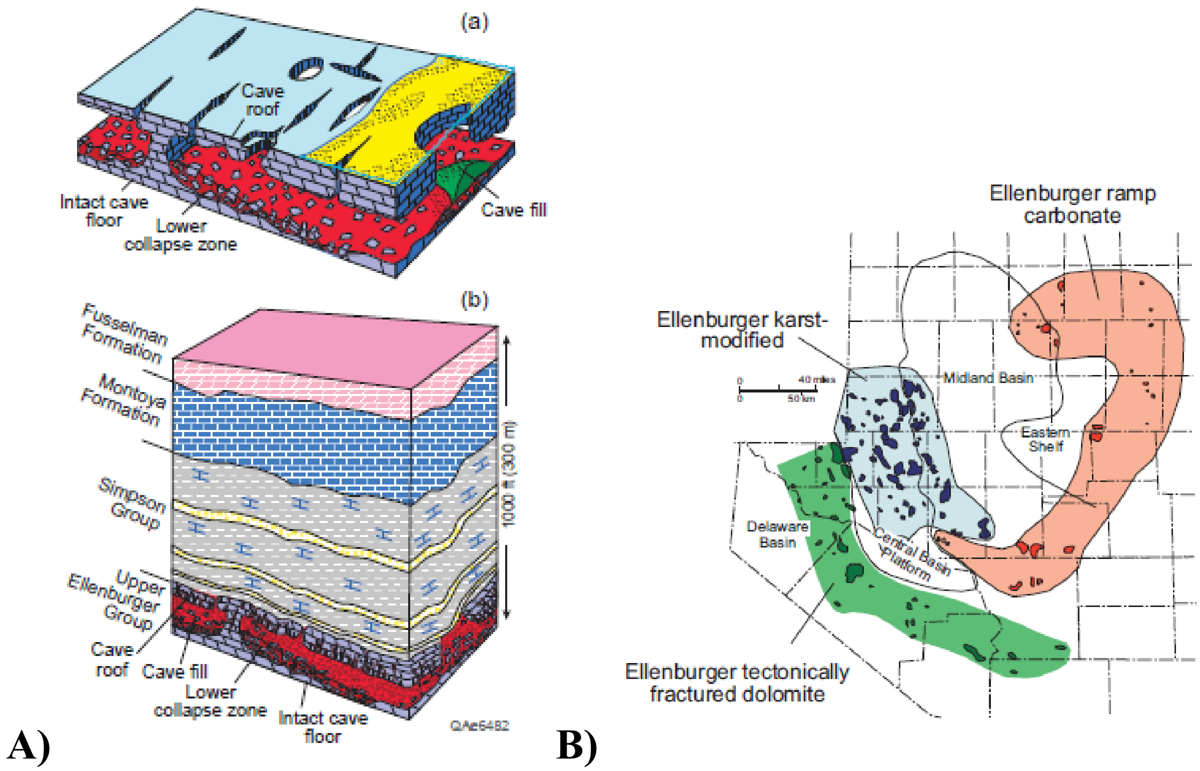


__Figure 3.3-2:__ Karst development. __A)__ Cave development in the upper Ellenburger rocks and their potential impact to produce porosity and permeability (from Loucks and Kerans, 2019). __B)__ Zones of potential porosity creation: karst related (blue), fault and fracture (green) and enhanced primary porosity (orange) (from unpublished manuscript by R. Loucks, 2016).

SIMPSON GROUP – The deposits of the Simpson Group represent a regional transgression after the unconformity at the end of Ellenburger deposition. This group is a thick sequence of carbonates, sandstones, and shales (~1,000 ft) which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. There are several transgressive/regressive cycles within the section, but only the transgressive sandstone sections have significant porosity. The rest of the section typically consists of mud-rich carbonates and shales. Within the sandstones (particularly the McKee Sandstone member), well logs indicate porosity averages around 15% (**Table 3.3-1**). Permeability averages 45 mD (Harrington, 2019), though cementation and compaction may decrease that in the area.

MONTOYA GROUP – The Montoya deposits (~250 feet) are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin (**Figure 3.3-3**). Like the Ellenburger Group, the porosity within the Montoya Group is dependent on depositional environment and diagenesis. Sediments deposited in higher energy environments tend to have better initial porosity than those of low-energy environments. Compaction destroys porosity, while dolomitization produces

secondary porosity and local interactions of these factors determine porosity and permeability in a given area. Based on well logs, the average porosity is approximately 3%, with scattered zones over 5% (**Table 3.3-1**). The probable average permeability is probably less than 1 mD, but fracturing may enhance it.

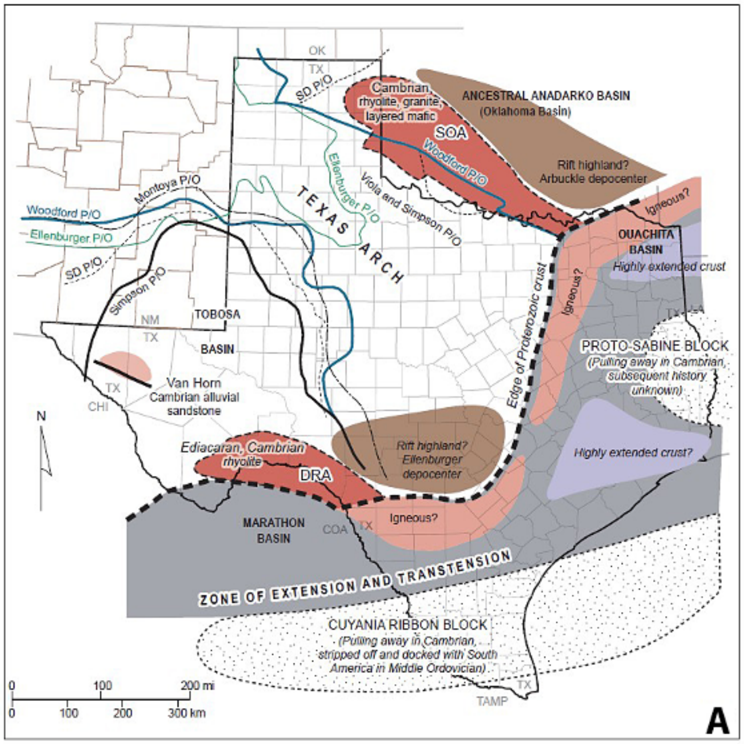


Figure 3.3-3: Tectonic features during development of the Tobosa and Permian Basins during Late Mississippian time (Ewing, 2019).

ORDOVICIAN – SILURIAN.

FUSSELMAN FORMATION – The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Bull Moose area, the Fusselman thickens to around 1,000 ft of high-energy packstones to grainstones. Like the Montoya Group, these high-energy sediments started out with the best primary porosity, but diagenesis usually has decreased both the porosity and permeability unless impacted by exposure and dissolution. Based on well logs, the porosity averages around 2%, but there are zones, like in well API No. 42-495-31047, with over 70 ft of greater than 5% porosity. Reported permeability for shallower sections range from 0.001 to 10 mD (Ruppel, 2019).

LOWER DEVONIAN – SILURIAN.

THIRTYONE AND WRISTEN FORMATIONS – Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section (~275 ft thick). Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Bull Moose area. These deposits range from deeper ramp mudstones and wackestones, to chert- and sponge/radiolarian-rich hemipelagic mudstones (Wristen/Thirtyone) to outer ramp packstones (**Figure 3.3-4**, Thirtyone; Ruppel, 2020; Ruppel et al., 2020a). Porosity and permeability in the Wristen are limited in the main body of the unit (1-2%), but exposure events and carbonate dissolution can improve the porosity (~5%). Within Thirtyone deposits, the chert-rich hemipelagic

deposits maintain the best porosity (up to 40%, up to 80 mD), while the limestones have less than 7% porosity and less than 1 mD of permeability (**Table 3.3-1**; Ruppel et al., 2020a).

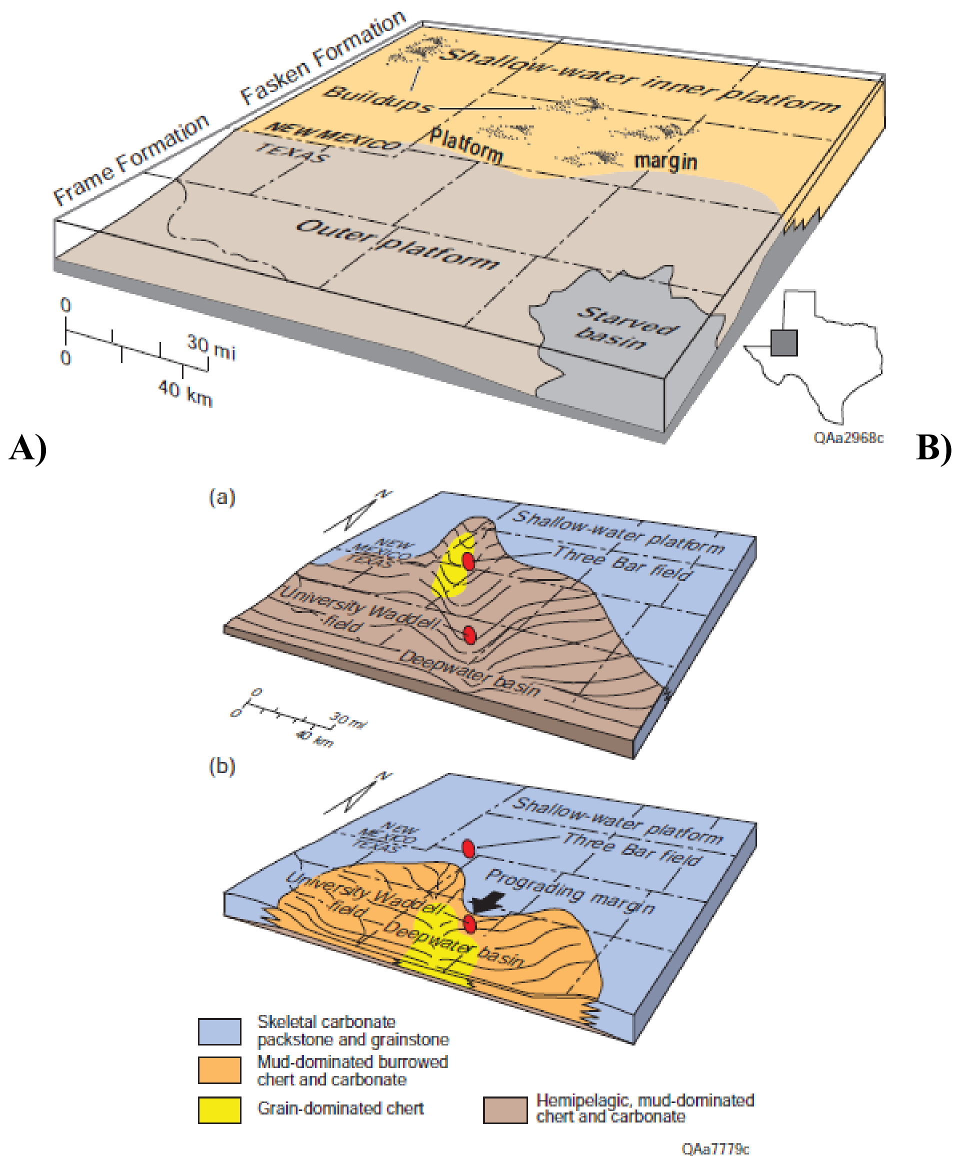


Figure 3.3-4: *Generalized Paleogeography.* ***A)*** *Generalized paleogeography for the Wristen Group (from Ruppel, 2020).* ***B)*** *Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Bull Moose area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

3.3.2 Upper Confining Zone Properties: Woodford Shale/Mississippian Limestone

Mississippian. Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 ft thick in the Bull Moose area and is regionally extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is ~555 ft thick. Known production from this limestone comes from small, one to two well fields that normally have poor porosity (4-9%) and permeability (Broadhead, 2017)

in New Mexico and a few isolated fields in the shallow water, high-energy limestones in Texas. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is ~750 ft thick. Overall, Mississippian units would be good seals in preventing upward fluid movement through the section (**Table 3.3-1**).

Upper Devonian. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units. In combination with the Mississippian section, it makes an excellent seal for potential injection. the Woodford Shale is ~620 ft thick in the Bull Moose area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. Porosity in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). Porosity can reach 10% (Jarvie et al., 2001), but it averages around 1% with very low permeabilities (**Table 3.3-1**).

3.3.3 Lower Confining Zone Properties: Ordovician to Precambrian

Ordovician. The lower approximately 150 to 200 ft of the Ellenburger Group sediments are normally less porous and have lower permeability (1 – 2% porosity and <2 mD) due their original depositional environment and the depth of burial (Loucks and Kerans, 2019), making this zone a potential underlying seal.

Cambrian to Precambrian. The oldest sediment in the area is Cambrian Bliss Sandstone (Broadhead, 2017) which overlies Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland. With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Bliss Sandstone and crystalline Precambrian rocks are potential lower seals. Within the Bull Moose area, no porosity and permeability data could be found. Considering their depth, compactional history, and potential diagenetic alteration, the Bliss sandstones and associated granitic debris (from weathering of the basement rock) are probably relatively tight.

3.4 Structure/Faulting

Structure maps and cross sections for the injection interval and confining zones are provided in **Figures 3.3-5** through **3.3-15**.

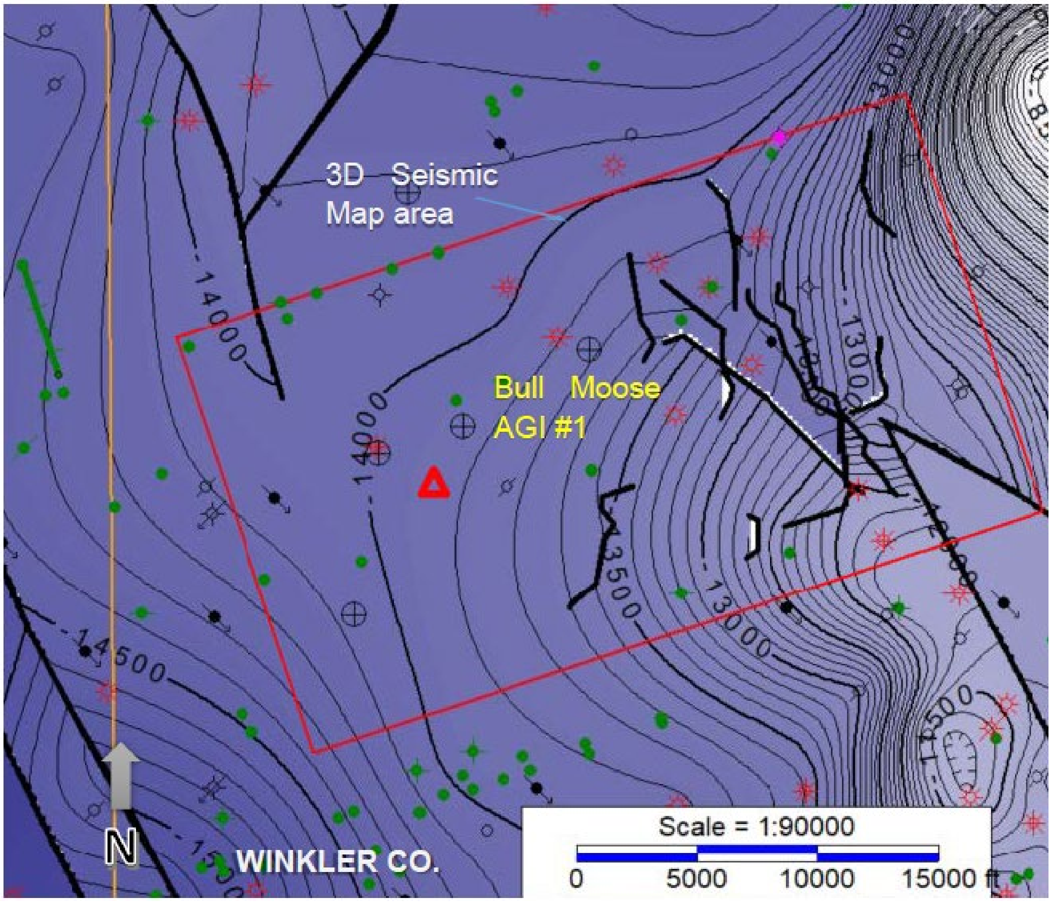


Figure 3.3-5: Mississippian Limestone Subsea Structure Map. CI = 100 ft.

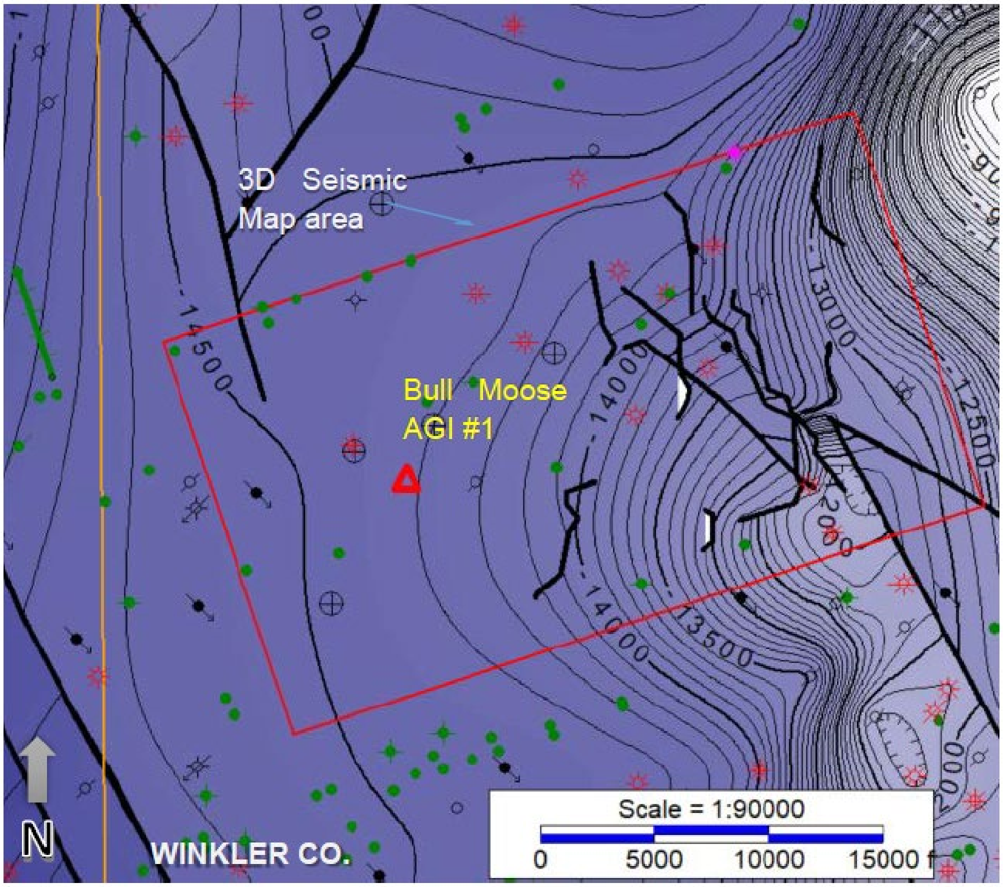


Figure 3.3-6: Woodford Shale Subsea Structure Map. CI = 100 ft.

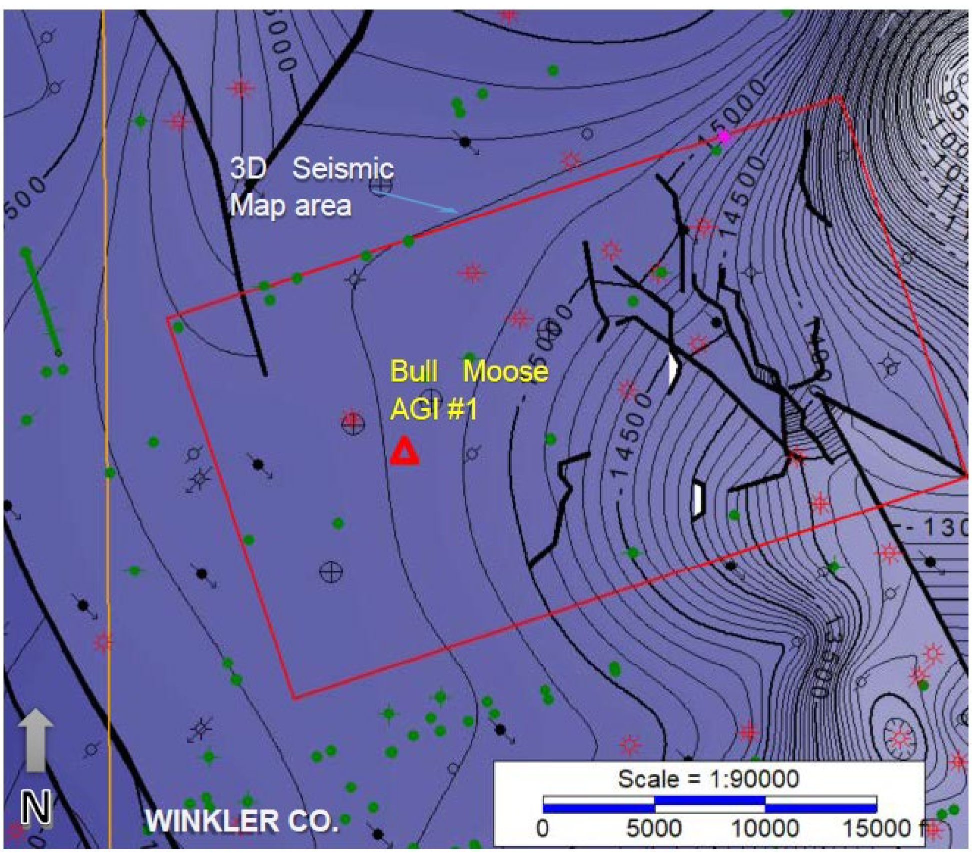


Figure 3.3-7: Siluro-Devonian Strata Subsea Structure Map. CI = 100 ft.

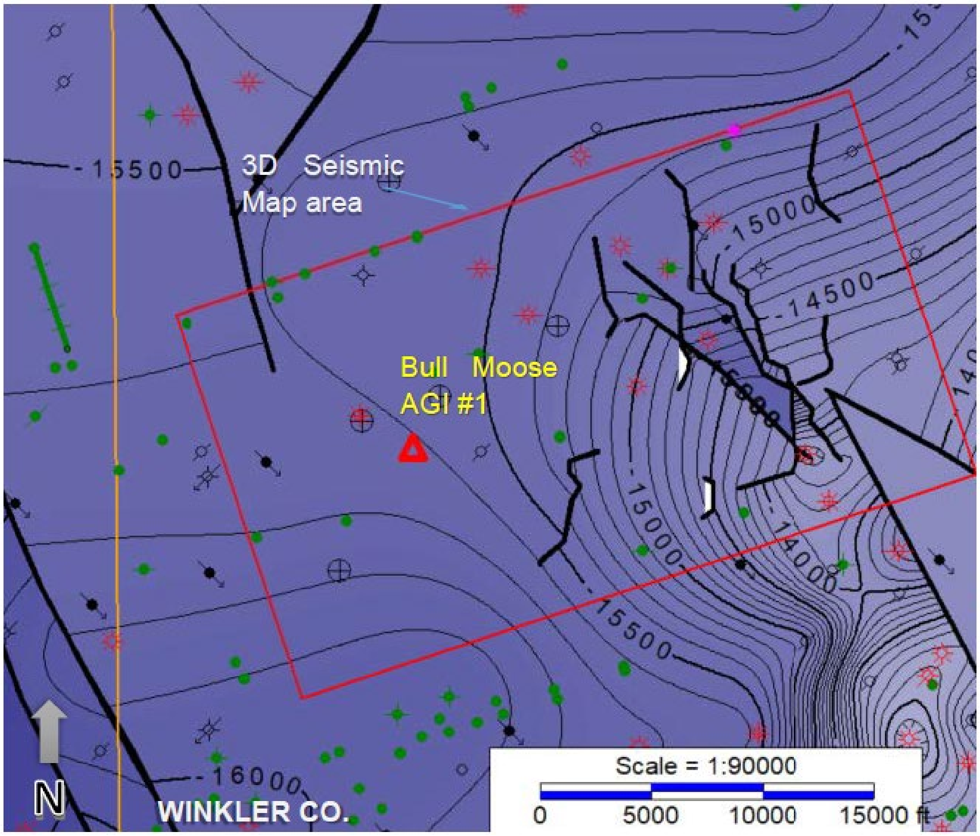


Figure 3.3-8: Fusselman Formation Subsea Structure Map. CI = 100 ft.

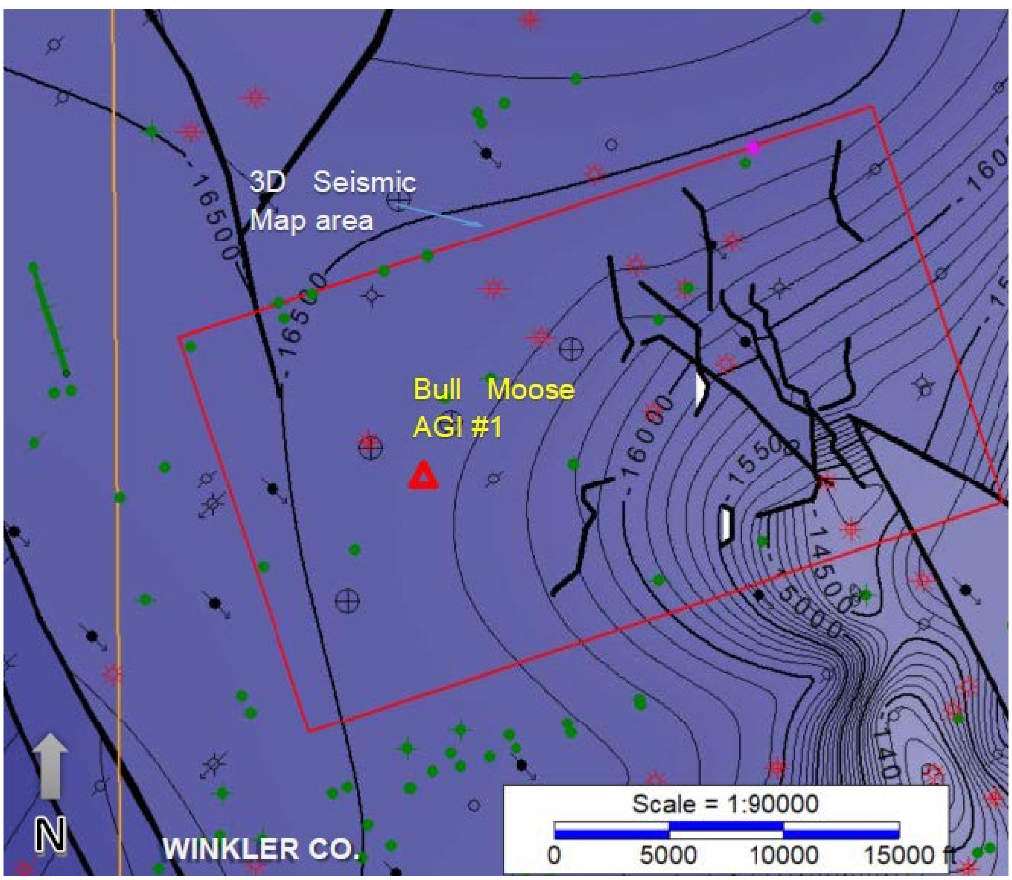


Figure 3.3-9: Montoya Group Subsea Structure Map. CI = 100 ft.

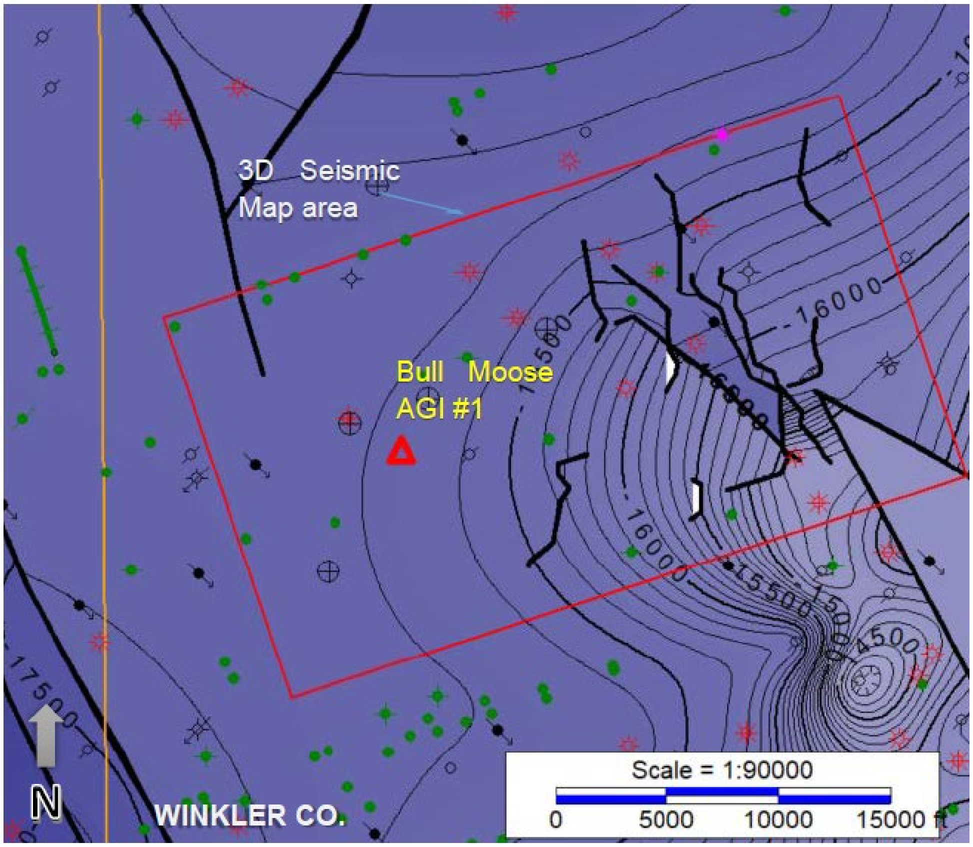


Figure 3.3-10: Simpson Group Subsea Structure Map. CI = 100 ft.

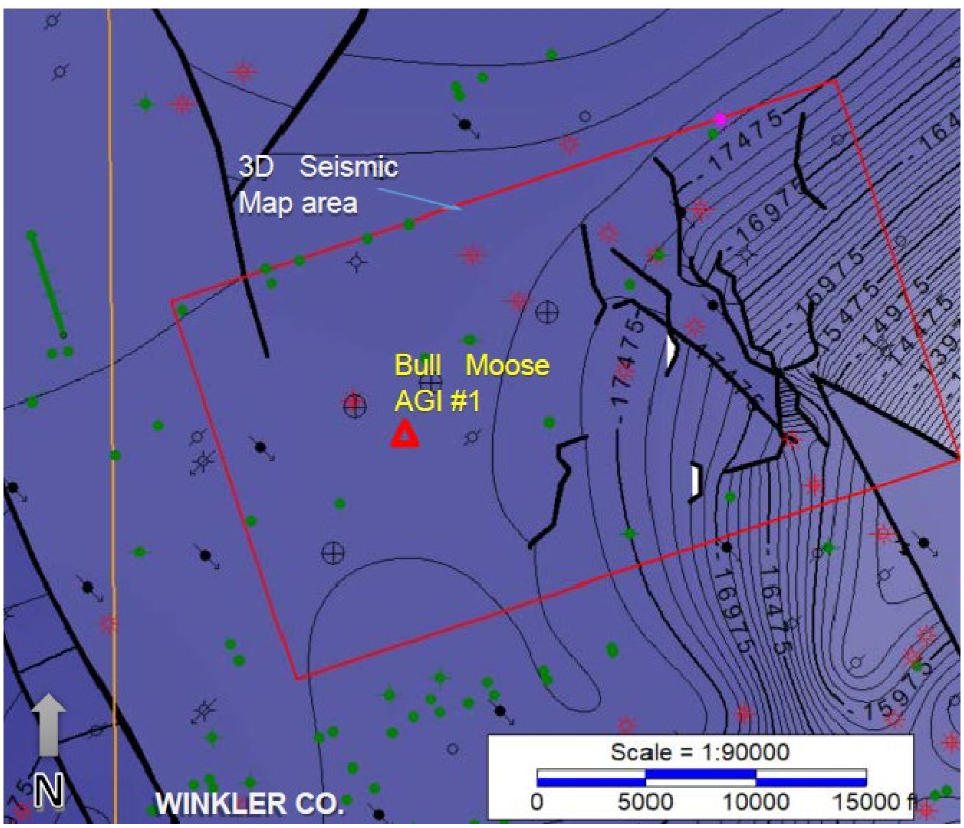


Figure 3.3-11: Ellenburger Group Subsea Structure Map. CI = 100 ft.

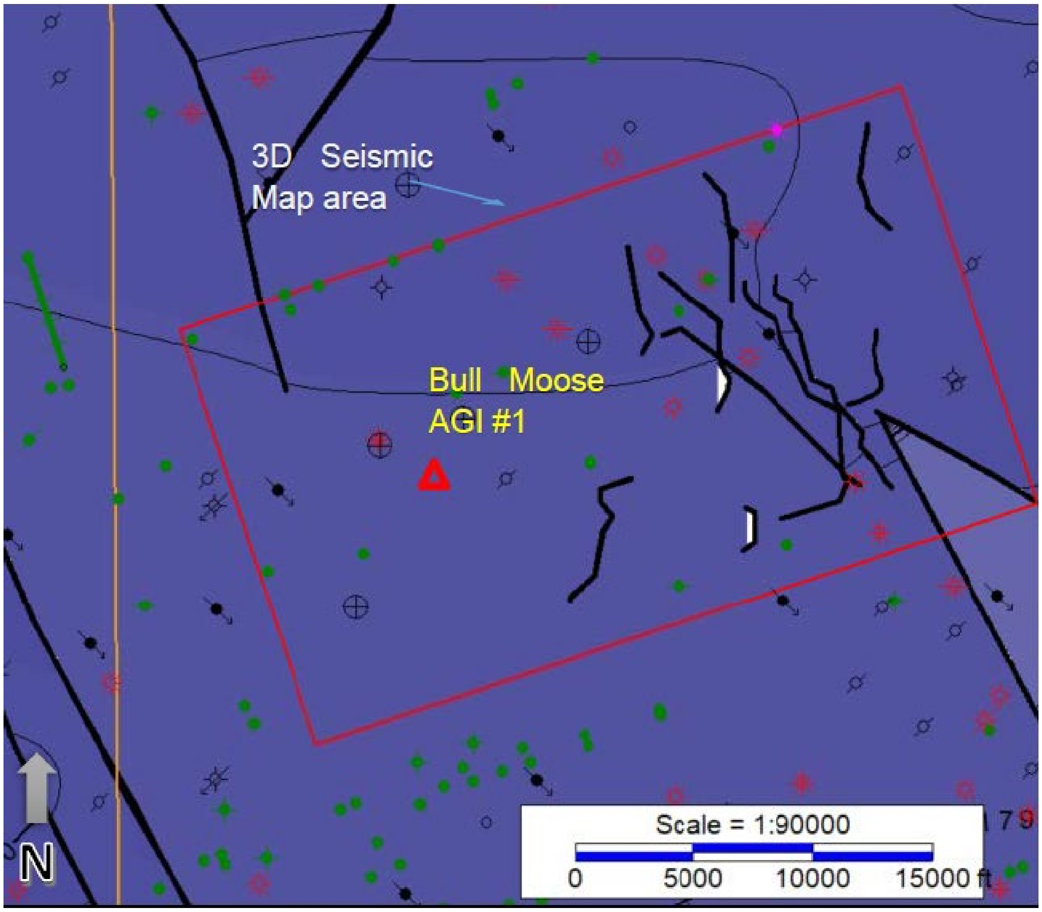


Figure 3.3-12: Precambrian Subsea Structure Map. CI = 100 ft.

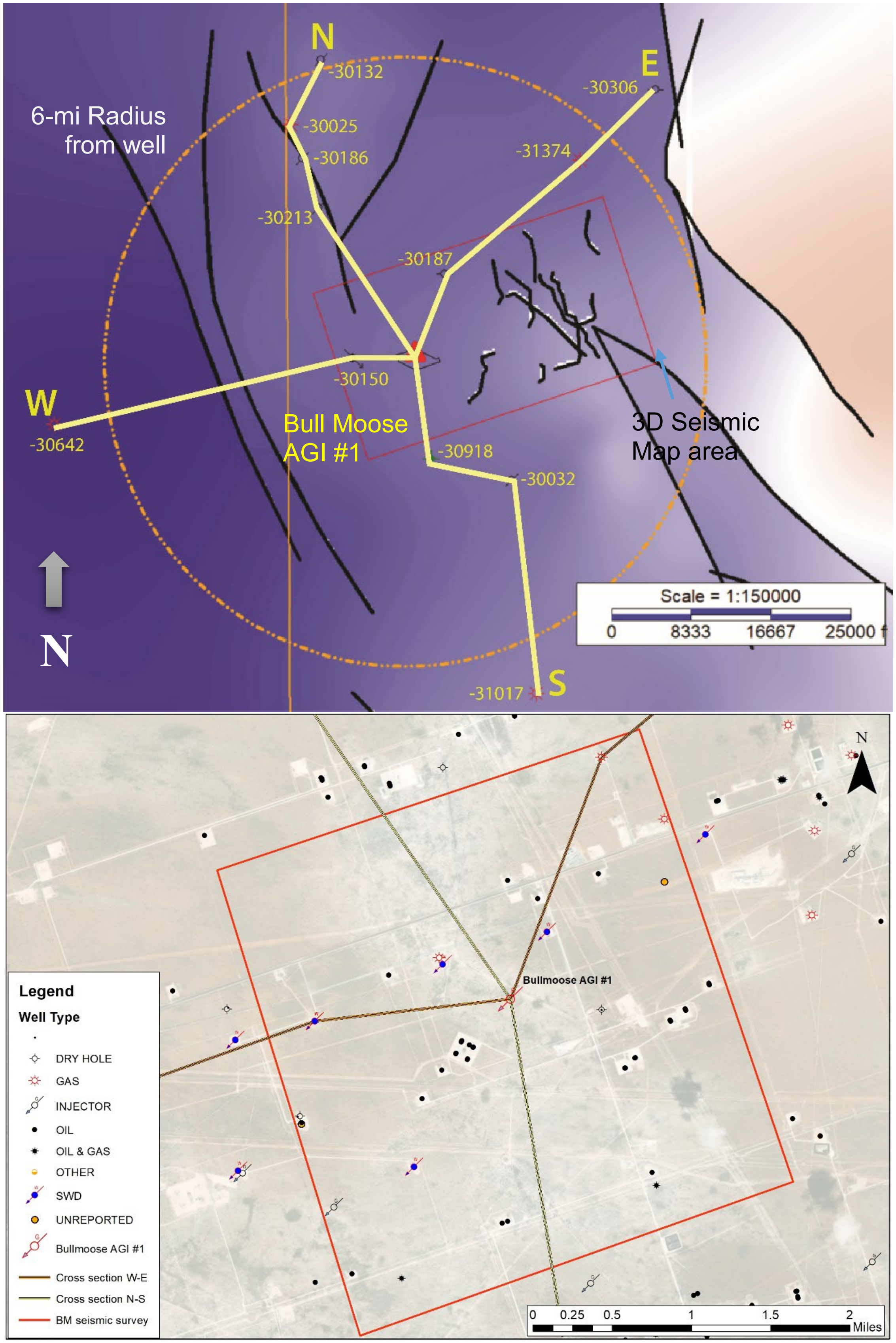


Figure 3.3-13: Base Map for Cross Sections

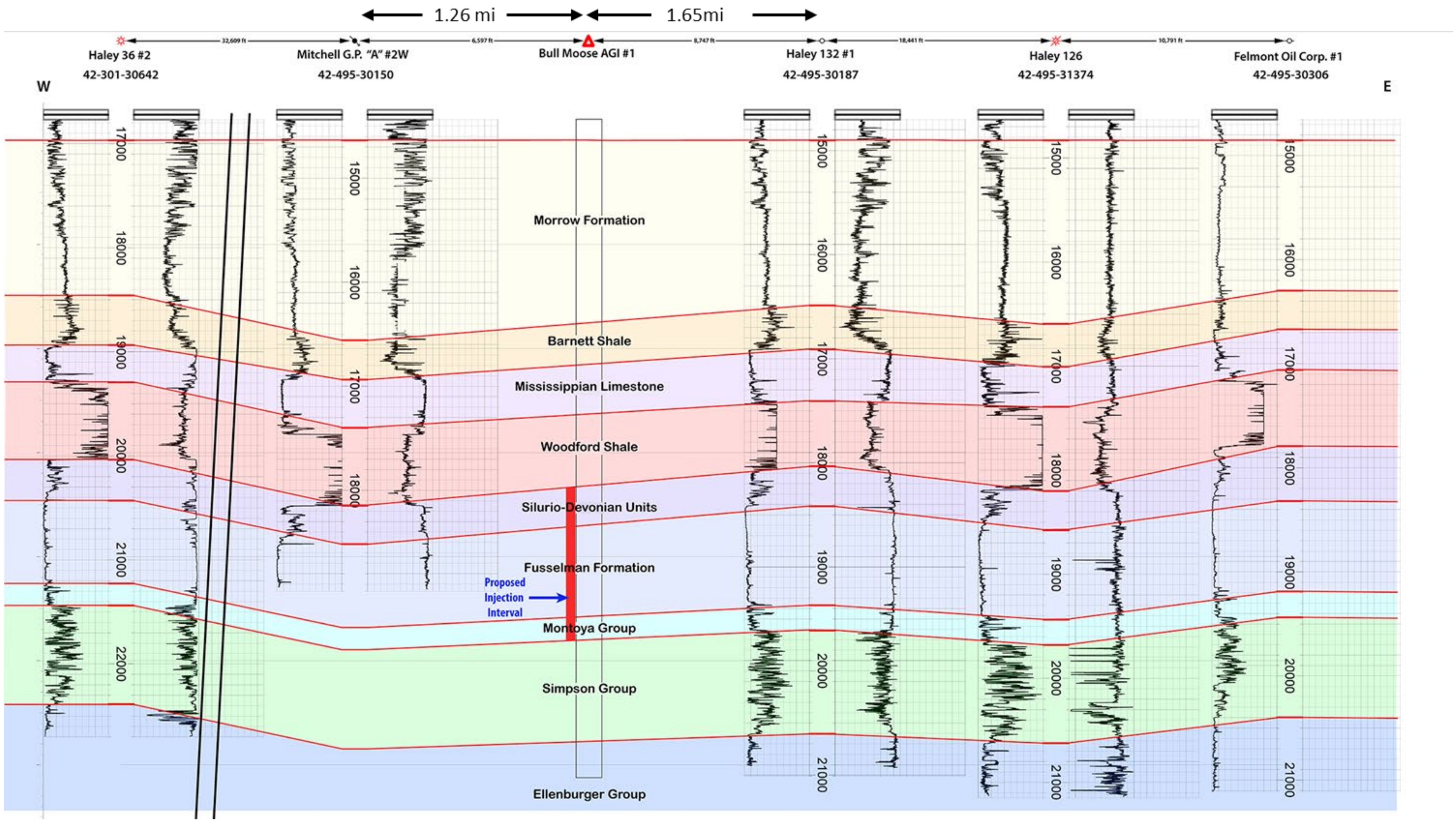


Figure 3.3-14: West to East Cross Section

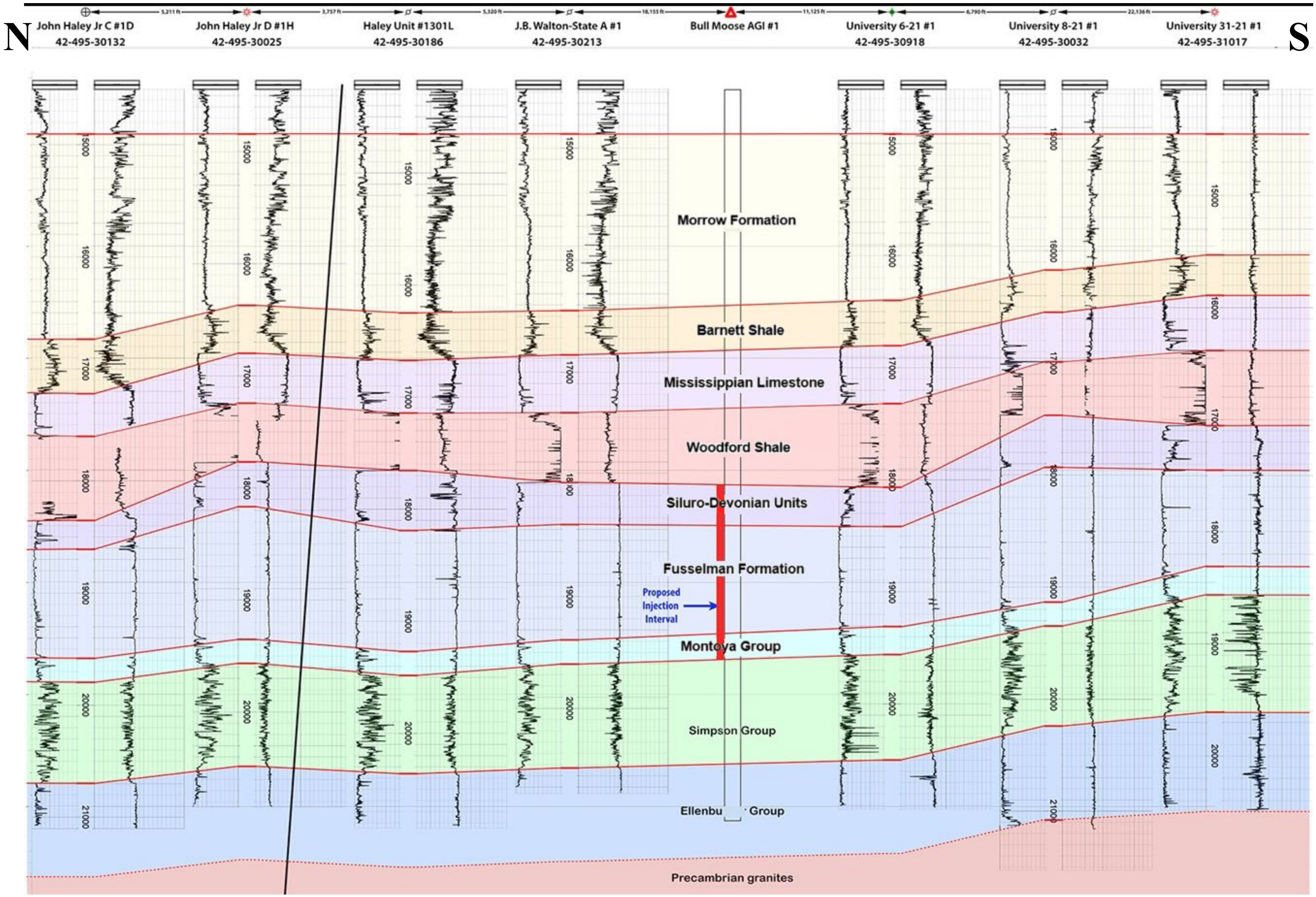


Figure 3.3-15: North to South Cross Section

3.5 Formation Fluid Chemistry

Water data was retrieved from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 (05/22/2019) to determine formation chemistry in the Siluro-Devonian, Fusselman, and Montoya injection intervals for BM AGI #1. Chemical data was plotted in a geographical interface and delineated to a 15-mile boundary around the Bull Moose site to fully constrain each formation's geochemical signature.

There are 12 wells with analyses collected from the Siluro-Devonian, Fusselman, Montoya, and Simpson formations within 15 miles of BM #1 (red squares **Figure 3.5-1).** Samples taken in these formations generally fall within a saline (NaCl) hydrofacies, and concentrations of total dissolved solids (TDS) range from 69,140 to 341,260 milligrams per liter (mg/L) with an average of 140,024 mg/L. High salinity in these formations indicate they are compatible with injection (**Table 3.5-1**).

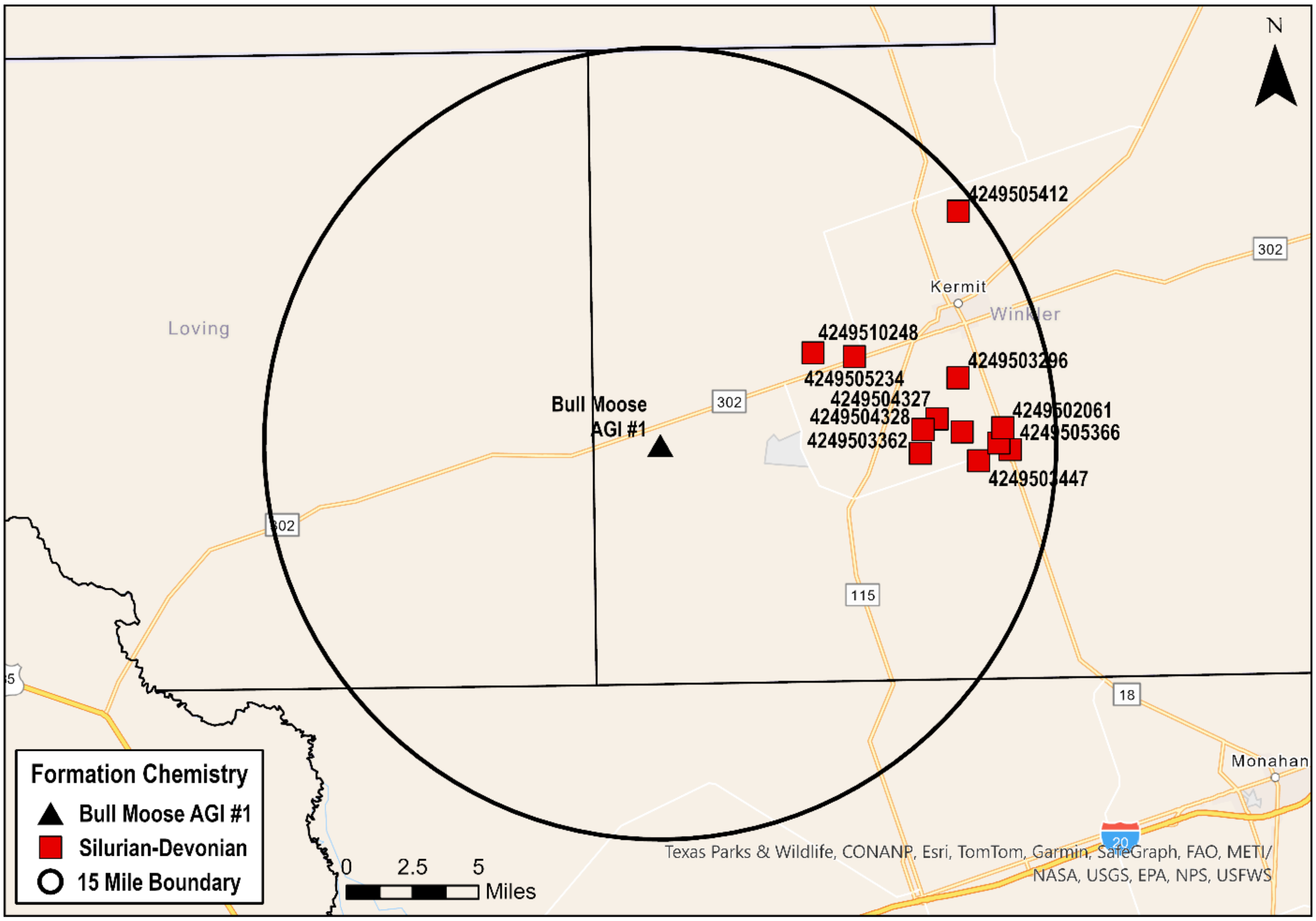


Figure 3.5-1: *Wells with water chemistry in the Silurian, Fusselman, or Devonian formations within 7 to 15 miles of the Bull Moose AGI well from the U.S. Geological Survey National Produced Waters Geochemical Database. Data show these formations are NaCl waters with average TDS of 140,024 mg/L.*

Table 3.5-1: *Water chemistry in mg/L for wells in the Silurian, Fusselman, or Devonian formations within ≈7 to 15 miles of BM AGI #1 from the USGS National Produced Waters Geochemical Database.*

API	Latitude	Longitude	Formation	HCO_3	Ca	Mg	KNa	Cl	SO_4	TDS
4249503296	31.8171	-103.0914	Devonian	1,347	12,410	1,799	10,290	40,390	2,904	69,140
4249503296	31.8171	-103.0914	Devonian	97	14,610	4,052	36,590	92,530	2,480	150,359
4249503296	31.8171	-103.0914	Devonian	145	14,510	4,163	36,590	92,830	2,520	150,758
4249503296	31.8171	-103.0914	Devonian	80	14,610	4,153	36,790	92,830	2,500	150,963
4249503296	31.8171	-103.0914	Devonian	122	14,600	4,028	37,050	92,940	2,437	151,177
4249503362	31.7759	-103.1165	Devonian	352	10,780	2,806	6,470	36,010	1,403	57,821
4249503447	31.7713	-103.0791	Devonian	635	2,900	300	35,500	60,000	475	99,810
4249505366	31.7771	-103.0587	Devonian	151	11,804	2,578	59,112	118,202	1,703	193,550
4249500556	31.7808	-103.0659	Fusselman	362	4,232	881	29,090	53,850	2,857	91,273
4249502061	31.7892	-103.0632	Fusselman	148	6,960	4,440	118,800	208,800	2,112	341,260
4249504327	31.7947	-103.1054	Fusselman	458	4,244	706	29,620	53,810	1,568	90,406
4249504328	31.789	-103.1145	Fusselman	427	4,236	1,016	45,650	78,800	2,420	132,549
4249505210	31.7873	-103.0894	Fusselman	849	10,640	945	24,780	59,440	460	97,114
4249505412	31.9086	-103.0894	Fusselman	202	1,733	536	48,589	73,421	4,400	128,881
4249510248	31.8322	-103.1845	Fusselman	706	499	386	91,284	139,300	4,317	236,491
4249505234	31.8297	-103.1579	Silurian	327	4,758	962	31,960	59,200	1,625	98,832

3.6 Groundwater Hydrology in the Vicinity of the Bull Moose Gas Plant

Regionally, groundwater near the BM AGI #1 site is drawn from one of five sources. From shallow to deep those are Quaternary-Late Tertiary Pecos Valley Deposits, Cretaceous sediments of the Edwards-Trinity Groups, Triassic deposits of the Dockum Group, the Permian (Oochan) aged Rustler Formation, and the Permian (Guadalupian) aged Capitan Reef Complex. Based on current water data with the Texas Water Development Board (TWDB), the primary groundwater sources at the site are the Pecos Valley Alluvium and the Dockum Group (**Figure 3.6-1**). Below we provide a general description of the groundwater sources and the wells within the MMA at the BM AGI #1 site.

3.6.1 Pecos Valley Aquifer

The Pecos Valley Aquifer lies unconformably on portions of the Edwards-Trinity Plateau, Dockum, Rustler, and Capitan Reef aquifers. It covers an area of 6,829 mi^2 and is comprised of sediments that range in size from clay to boulder which were deposited in a variety of continental settings including fluvial, valley-fill, eolian, lacustrine, and solution-collapse environments (Wise et al., 2012). Sediments of the Pecos Valley Aquifer fill several structural basins, the largest of which are Monument Draw Trough in the east and the Pecos Trough in the west. Maximum thickness of the alluvial fill reaches approximately 1,500 ft, and freshwater saturated thickness averages around 250 ft (George et al., 2011).

The water quality is highly variable, with the water typically being hard, and generally better in the Monument Draw Trough than in the Pecos Trough. Total dissolved solids have been found to range from 116 to over 15,000 mg/L depending on location and proximity to oil and gas or halite mining operations in the region (Wise et al., 2012). The aquifer is generally characterized by high levels of sulfate and chloride in excess of secondary drinking water standards which has been linked to previous oil field activities. Also, naturally occurring radionuclides and arsenic can be found in excess of primary drinking water standards (George et al., 2011). More than 80 percent of Pecos

Valley groundwater is used for irrigation, while the remainder is used for municipal supplies, power generation, and industrial use.

3.6.2 Dockum Aquifer

The Upper Triassic Dockum Group covers about 96,000 square miles in parts of Kansas, Oklahoma, Colorado, New Mexico, and Texas. From young to old the Dockum includes the Santa Rosa and Tecovas formations, the Trujillo Sandstone, and the Cooper Canyon Formation. These formations consist of conglomerate, gravel, sandstone, siltstone, mudstone, and shale with recoverable quantities of groundwater located in the sandstone and conglomerate. The largest yields are typically found in the coarsest deposits in the middle and base of the group. Locally any water-bearing sandstone of the Dockum Group is referred to as the Santa Rosa Aquifer (Bradley and Kalaswad, 2003; 2004; George et al., 2011).

Water quality in the Dockum Aquifer varies, ranging from fresh (TDS <1,000 mg/L) on outcrop to brine (TDS >10,000mg/L) where it is confined, typically deteriorating with depth. TDS concentrations have been found to be >60,000 mg/L in the deepest parts of the aquifer. Groundwater in the Dockum aquifer is typically hard, average of 470 mg/L, and radionuclides naturally derived from uranium can be found at concentrations a >5 pCi/L in many areas of the aquifer (Bradley and Kalaswad, 2003; 2004). Locally, the Dockum Aquifer can be vital for irrigation, public supply, livestock watering, manufacturing, and oil-field activity. However, a combination of deep pumping depths, low yields, poor water quality, and declining water levels have hindered a more widespread use (Bradley and Kalaswad, 2003).

3.6.3 Groundwater Wells Within the Bull Moose AGI Site MMA

Data collected from the Texas Water Development Board's (TWDB) Groundwater Database and Submitted Driller Report Database indicate there are 2 freshwater wells located within the MMA for BM AGI #1. Both wells are permitted for domestic use and are shallow, collecting water from 152 to 245 ft depth in Pecos Alluvium and Triassic redbeds of the Dockum Group (Garza and Wesselman, 1963; Ashworth, 1990; Bradley and Kalaswad, 2003; **Table 3.6-1**). General chemistry analysis of one well within the MMA indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L (**Table 3.6-2**). The shallow freshwater aquifers are protected by the surface and intermediate casings and cements in the BM AGI #1 well. While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

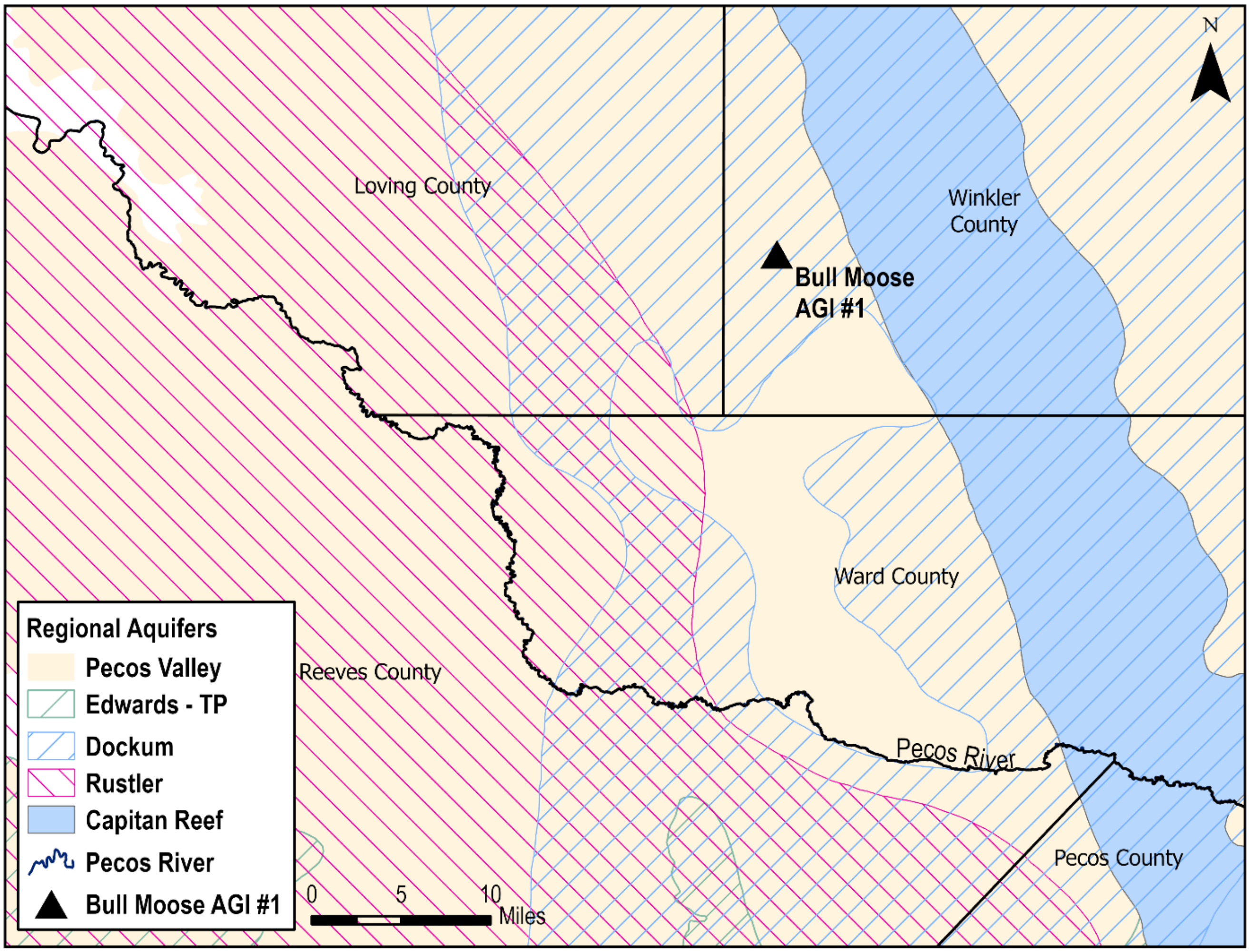


Figure 3.6-1: *Major and minor aquifers of the region. Groundwater at the proposed site is derived from the Pecos Valley Alluvium and Dockum Group.*

Table 3.6-1: *Groundwater wells within the MMA of the Bull Moose AGI site with from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database. Well depth is from 152 to 245 ft. and used for domestic purposes.*

Well ID/Report	Owner_Name	Use	County	Well_Depth	Latitude	Longitude
4614901	D P Anderson	Domestic	Winkler	152	31.76806	-103.285
409232	Frontier Energy	Domestic	Winkler	245	31.79591	-103.277

Table 3.6-2: *Groundwater chemistry for well 4614901 from Table 3.5-1 indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L.*

StateWellID	Aquifer_Code	Date	HCO_3	Ca	Mg	Na	Cl	SO4	TDS
4614901	100CPDG	8/23/1940	256	97	38	43	53	189	557

3.7 Historical Operations

3.7.1 Bull Moose Site

In response to increasing production and to meet the infrastructure needs of producers, Targa is constructing a new Bull Moose 275 MMSCFD cryogenic natural gas processing plant. **Figure 3.7-1** shows the simplified process block flow diagram, with the entry point for the CO_2, the flow meter location and the sampling point, before BM AGI #1 well.

3.7.2 Operations within the MMA for the BM AGI Well

TRRC records identify a total of 29 oil- and gas-related wells within the MMA (see **Appendix 3**). **Figure 3.7-2** shows the geometry of producing and injection wells within the MMA. **Appendix 3** summarizes the relevant information for those wells.

Among the 29 wells identified, 25 are horizontal oil wells completed in the Bone Spring (8 wells) or Wolfcamp (17 wells) formations, at depths between 11,564 and 12,545 ft. One is inactive and three are plugged and abandoned.

There are four other vertical wells. There are two vertical plugged and abandoned gas well in the Morrow Formation (16,000 ft). There are also two Saltwater Disposal (SWD) wells that are injecting in the Brushy Canyon (7,516 and 7,630 ft).

All of these productive zones are more than 5,300 ft above the BM AGI #1 injection zone.

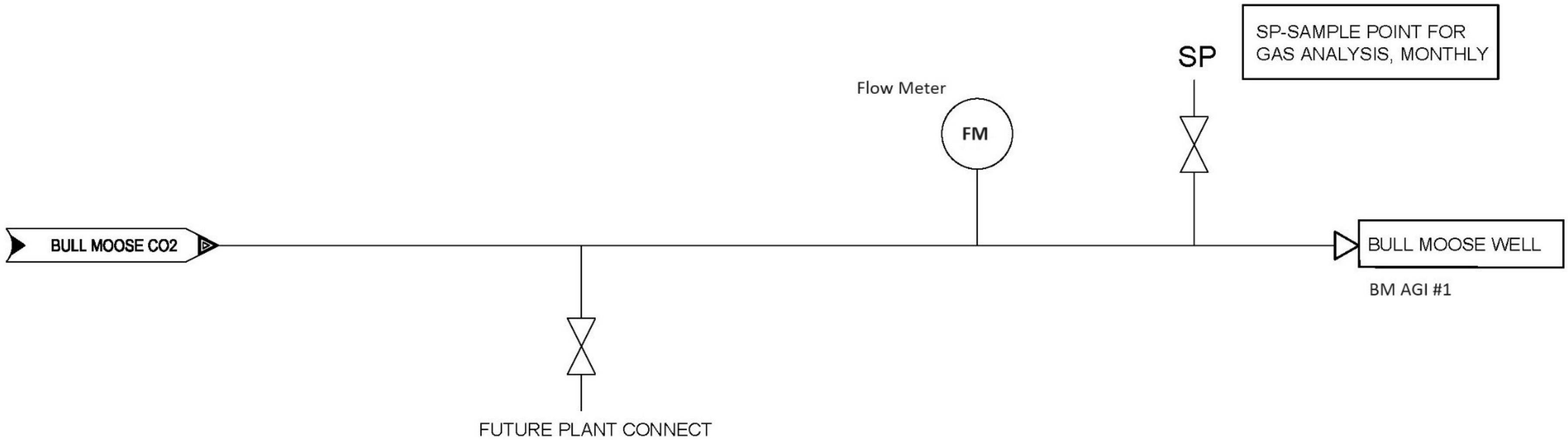


Figure 3.7-1: Process Block Flow Diagram with CO_2 entry, Flow meter (FM), Sampling point (SP) and BM AGI #1.

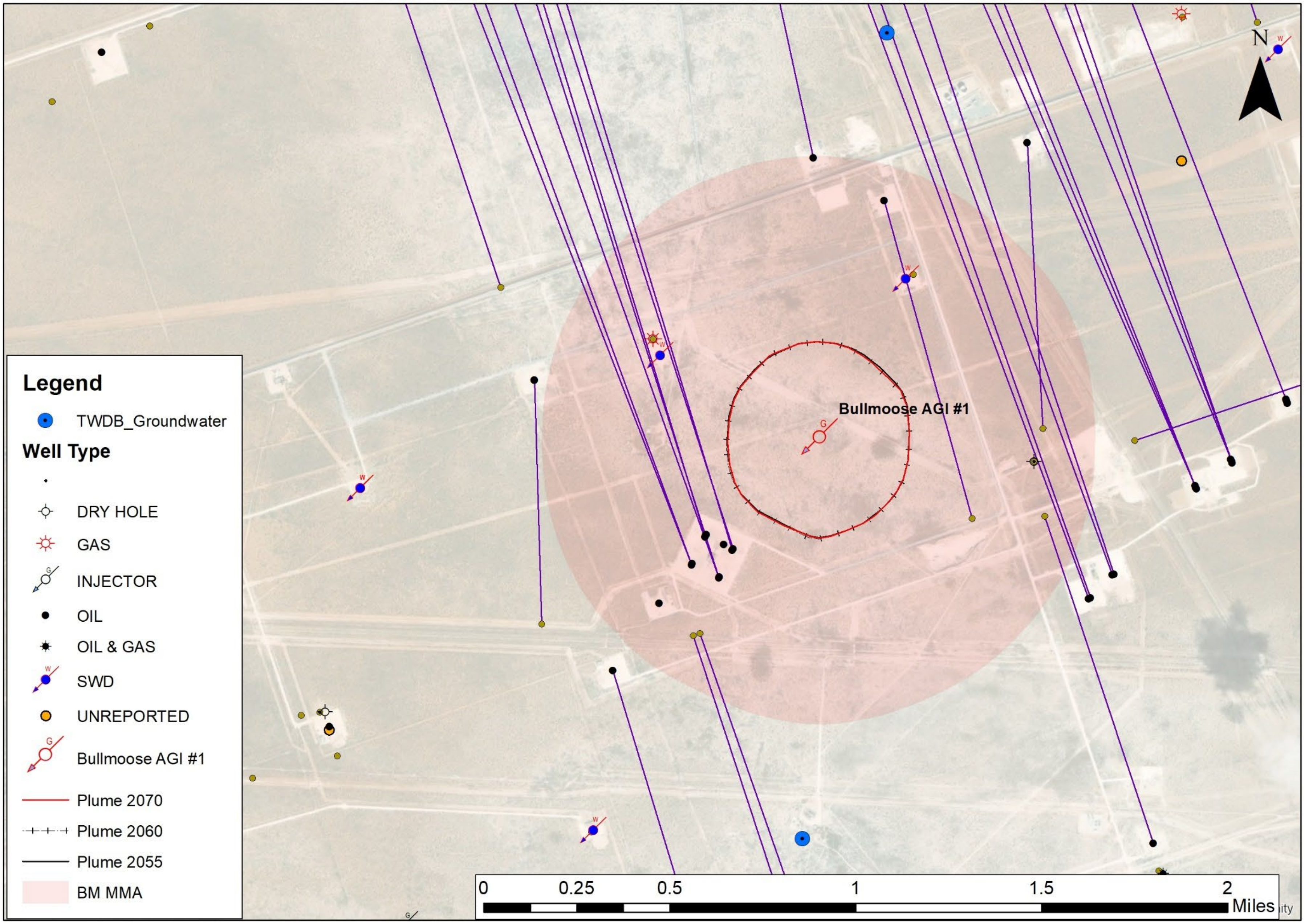


Figure 3.7-2: *Location of all oil- and gas-related wells within the MMA for the BM AGI #1 well. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure.*

3.8 Description of Injection Process

The Bull Moose Gas Plant, including the BM AGI #1 well, will be in operation and staffed 24-hours-a-day, 7-days-a week. The plant gathers and processes produced natural gas. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility. Compressed TAG is then routed to the well via high-pressure rated lines.

The natural gas to be treated at this facility is produced from oil and gas wells in the Permian Basin region, including Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward and Winkler counties, Texas plus Lea and Eddy counties in New Mexico. A sample from Targa 's nearby Wildcat facility (5 miles west) was taken on 11/10/2023 and is representative of the injection stream for the Bull Moose facility. The results of that analysis are provided in **Table 3.8-1**.

Table 3.8-1: Sample Gas Composition for Wildcat AGI #1

Component	Mol %
Carbon Dioxide	91.339
Methane	0.350
Ethane	0.054
Propane	0.061
Iso-Butane	0.003
N-Butane	0.022
Iso-Pentane	0.000
Hexanes Plus	0.099
Hydrogen Sulfide	8.072
Nitrogen	0.000
TOTAL	100.00

The composition may change over time based on the amount of H_2S in the natural gas processing inlet stream. For modeling purposes, an injectate composition of 30% H_2S and 70% CO_2 was assumed as a conservative approach.

3.9 Reservoir Characterization Modeling

3.9.1 Inputs and Assumptions

Dynamic reservoir simulation was performed based on a high resolution geological model. The modeling predicts the well injectivity, pressure behaviors, and TAG plume migration.

Schlumberger's Petrel® (Version 2023.3) software was used to construct the geological models used in this work. Computer Modelling Group (CMG) software was used to perform the reservoir simulations presented in this MRV plan. The software was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling. The hydrodynamical model considers aqueous, gaseous, and supercritical phases of the CO_2, simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in an aqueous phase or in a gaseous phase, in a supercritical state.

The static model is constructed using well tops picked from logs and interpretations from 3D seismic survey to interpret and delineate formations and structural features. The geologic model covers a 3.2-miles by 3.0-miles area (**Figure 3.9-1**). The model is divided into 745,200 cells. The average cell size of the active injection area is 150 square ft. **Figure 3.9-2** shows the simulation model in 3D view. The porosity and permeability of the model are evaluated using existing well logs and 3D seismic inversion. The range of the porosity is between 0.01 to 0.31. The initial permeability is interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy is 0.1. (**Figure 3.9-2**).

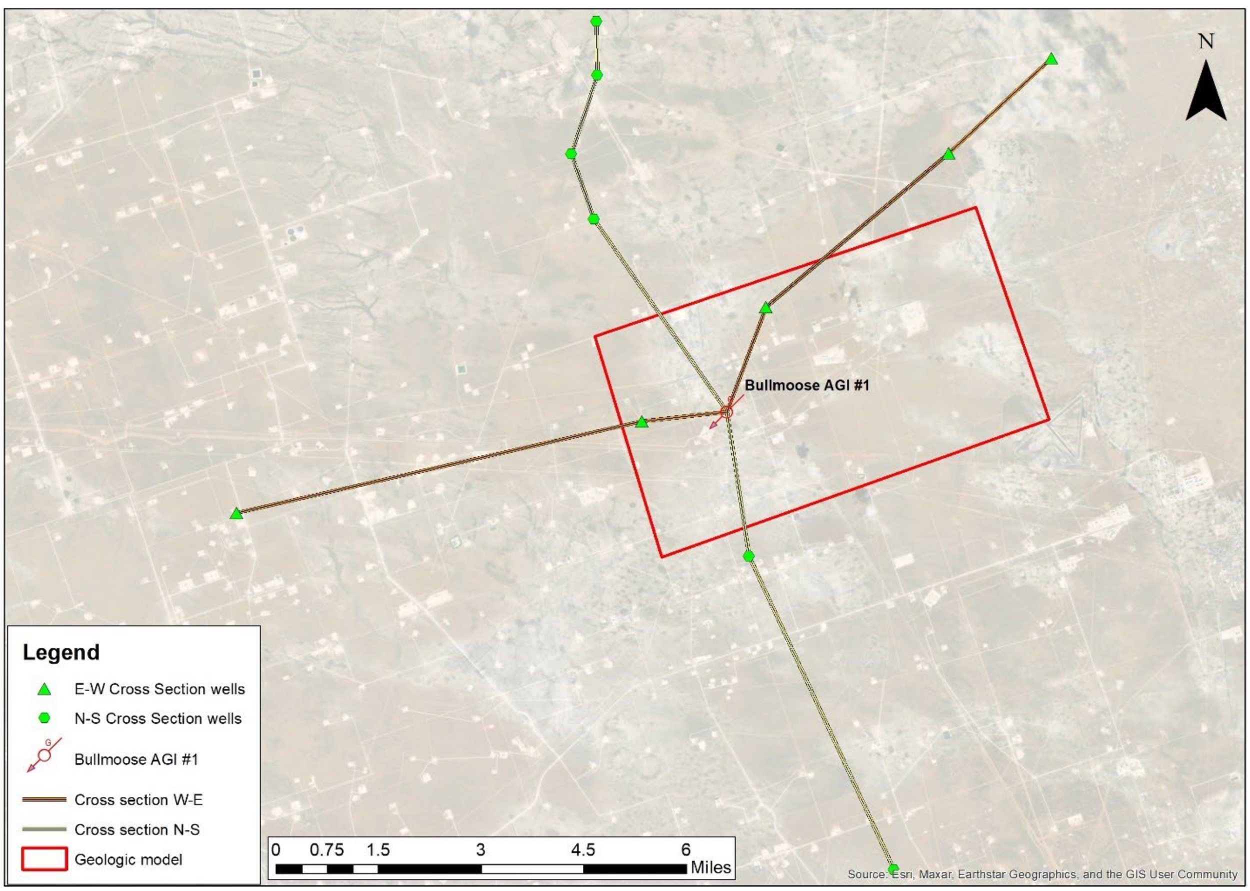


Figure 3.9-1: BM AGI #1 model boundaries

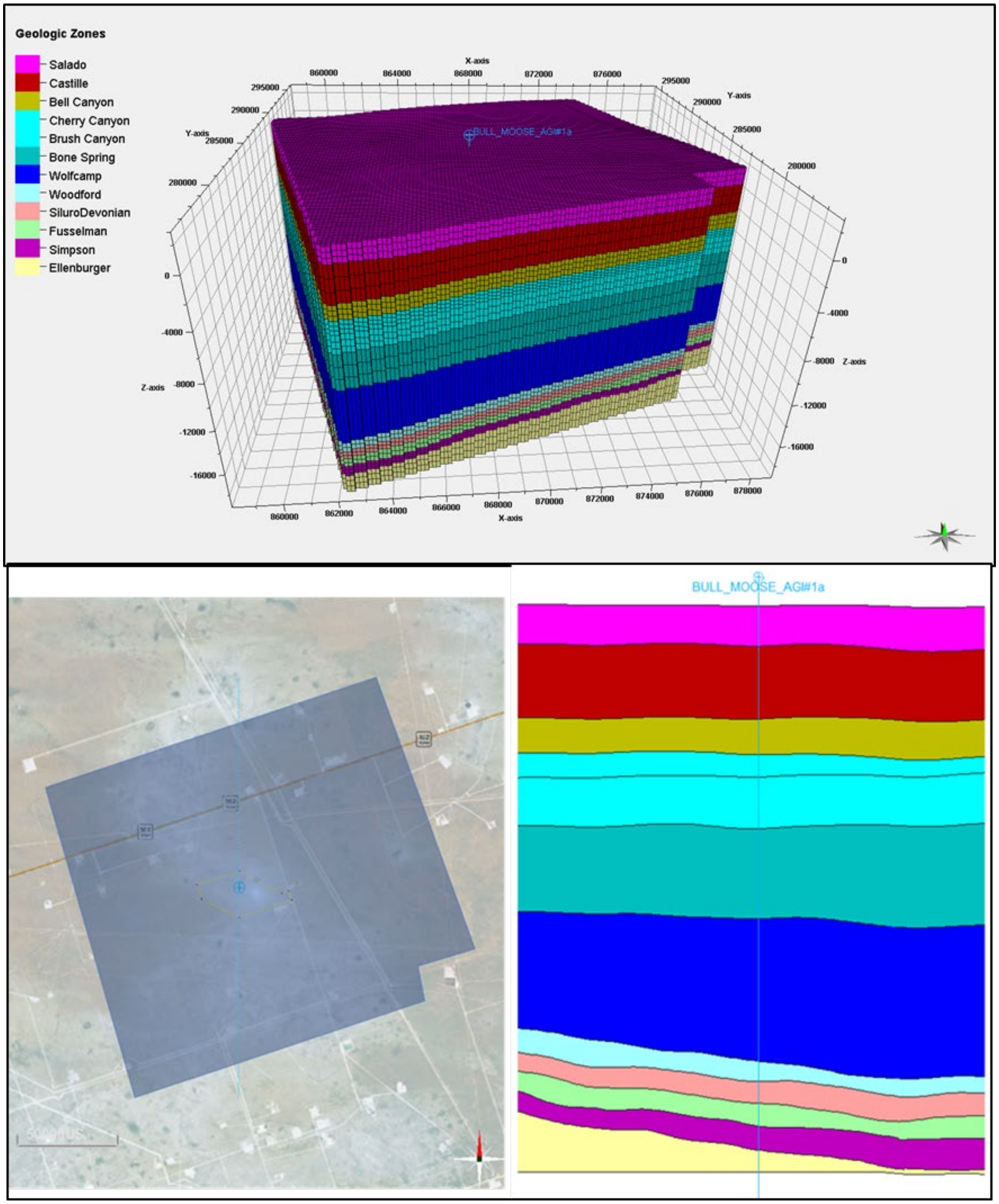


Figure 3.9-2: *3D view of the geological model for the BM AGI #1 well. The model displays the Salado-Castile Formation, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, Simpson and Ellenburger formations. Color legends represent the zones.*

At the initialization of the simulation, the water saturation in the storage reservoir is assumed to be 100%, with a residual water saturation of 20% (Krause, M. H., and Benson, S. M., 2015). The initial salinity is assumed to be 150,000 ppm (Nicot et al., 2020). A geothermal gradient of 1.25°F/100 ft was adopted (Ge, J. et al., 2022). Following standard industry practices, a pore pressure gradient of 0.43 psi/ft is used. Therefore, the reservoir pressure at the top of the Siluro-Devonian at the location is estimated to be 7,650 psi.

The fracture gradient (FG) for the injection interval is calculated using Eaton's equation.

$$FG = \frac{\nu}{1-\nu}\left(OBG - p_p\right) + p_p$$

Where,

ν is the Poisson's ratio,

OBG is the overburden gradient,

p_p is the pore pressure gradient.

An overburden gradient of 1.05 psi/ft is adopted in the calculation. This value is considered best practice when a site-specific number is not available. Poisson's ratio is inferred to be 0.3 in the injection interval. A minimum value of 0.29 and a maximum value of 0.31 are used to quantify uncertainty (Smye et al, 2021, Dvory and Zoback, 2021). The fracture gradient is estimated to be 0.62 to 0.68 psi/ft, therefore the formation fracture pressure calculated at the top of the injection interval is 12,350 psi. In addition, a safety factor of 10% is applied to the resulting fracture gradient. This safety factor ensures injecting pressure will not exceed the fracture gradient in the injection interval, where the maximum bottomhole pressure was set to 0.63 psi/ft during active injection in the simulation. The results are summarized in **Table 3.9-1 & Table 3.9-2**. As these values are calculated based on available legacy well logs and literature listed in the reference, the actual gradient will be measured upon completion of the proposed well, and the modeling and simulation efforts will be updated accordingly.

A review of the TRRC databases identified no saltwater disposal (SWDs) or other injection wells within the model boundaries in the proposed injection interval.

Table 3.9-1: Summary of reservoir simulation inputs.

Reservoir properties of injection zones	Wristen & Fusselman
Porosity	As shown in geologic model
Permeability	As shown in geologic model
Pore pressure gradient	0.43 – 0.45 psi/ft (estimated from DST data in Winkler county – Dvory and Zoback (2021); Luo et al. (1994)
Formation fracture gradient	0.65 $\pm$0.03 psi/ft

Reservoir properties of injection zones	Wristen & Fusselman
Formation temperature	0.014 F/ ft (45 wells BHT data in Winkler–Luo et al. 1994)
Water salinity	150,000 ppm (Nicot et al. 2020 based on P50 of TDS in Winkler County showing 150kppm)
Initial water saturation	100% (assumption made for conservative CO_2 plume)

Table 3.9-2: Summary of well simulation inputs.

Injection well setup	Wristen & Fusselman
Bottom hole pressure	90% of formation fracture pressure or 11,300 psi at bottom hole
Well head pressure	0.5 psi/ft to the top of injection interval (approximately 8,945 psi) – RRC Standards and Procedures for Class II Wells
Wellhead temperature	90-100 °F
Injection fluid	70% CO_2, 30% H_2S
Injection rate	20 MMSCFD over 30 years (2025 – 2055)

BM AGI #1 is simulated to inject at the injection rate of 20 MMSCFD. In accordance with the TRRC Injection Storage Manual; Chapter III - Standards and Procedures for Class II Wells, the maximum surface injection pressure may not ordinarily exceed 0.5 psi per foot of depth to the top of the authorized injection or disposal interval. Therefore, a maximum allowable surface injection pressure of 8,945 psi is used in the simulation. Additionally, a maximum bottomhole pressure of 11,300 is enforced and 90% of the estimated formation fracture gradient is set as a secondary

constraint in the simulation. The composition of the injection stream is estimated to be 30% H_2S and 70% CO_2. The simulated injection starts on 01/01/2025 and stops on 01/01/2055, after a 30-year active injection phase. The termination of the simulation is on 01/01/2085, with an additional 30 years of post-injection, to estimate the maximum plume extent and the stabilized plume.

3.9.2 Model Outputs

Simulations indicate BM AGI #1 can inject at the proposed rate throughout the 30-year period without any complications. Linear cumulative injection behavior (**Figure 3.9-3**) also indicates that the Siluro-Devonian, Fusselman and Montoya formations receive the TAG stream freely. **Figure 3.9-3** shows a constant injection rate of 20 MMSCFD of the TAG stream injected over 30 years under the proposed bottom-hole pressure constraint. The modeling results indicate that the formations are capable of safely receiving and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.9-4** shows the cumulative disposed H_2S and CO_2 separately in gas mass.

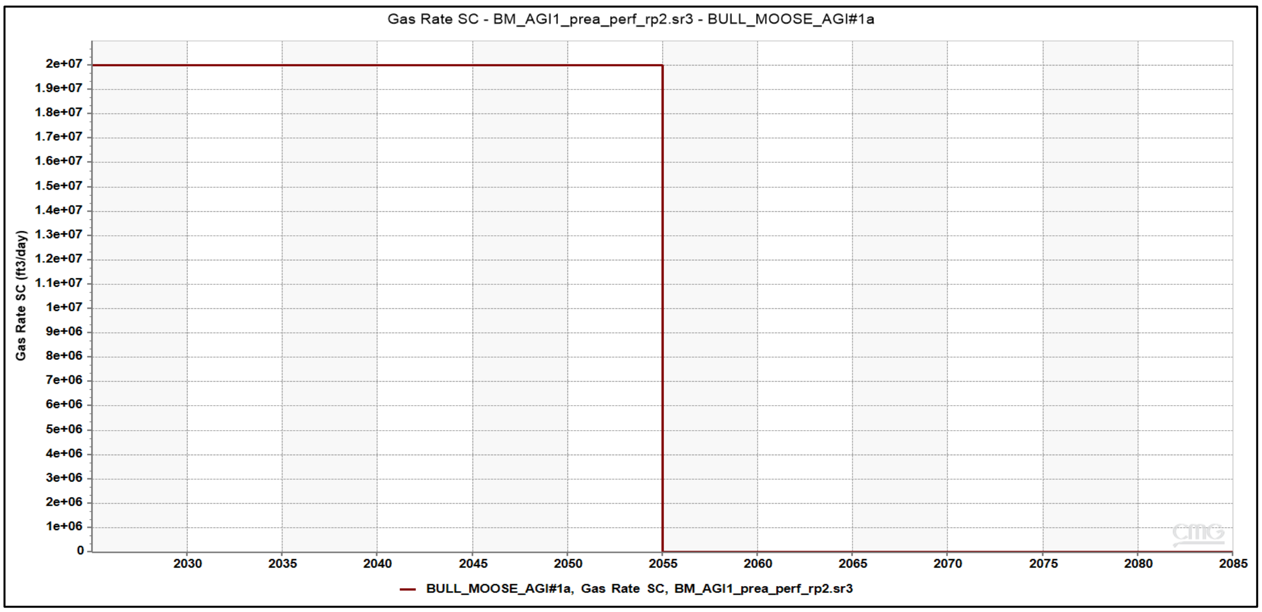


Figure 3.9-3: Average daily injection volume for Bull Moose AGI No. 1 (2025 to 2055, 20 MMSCFD).

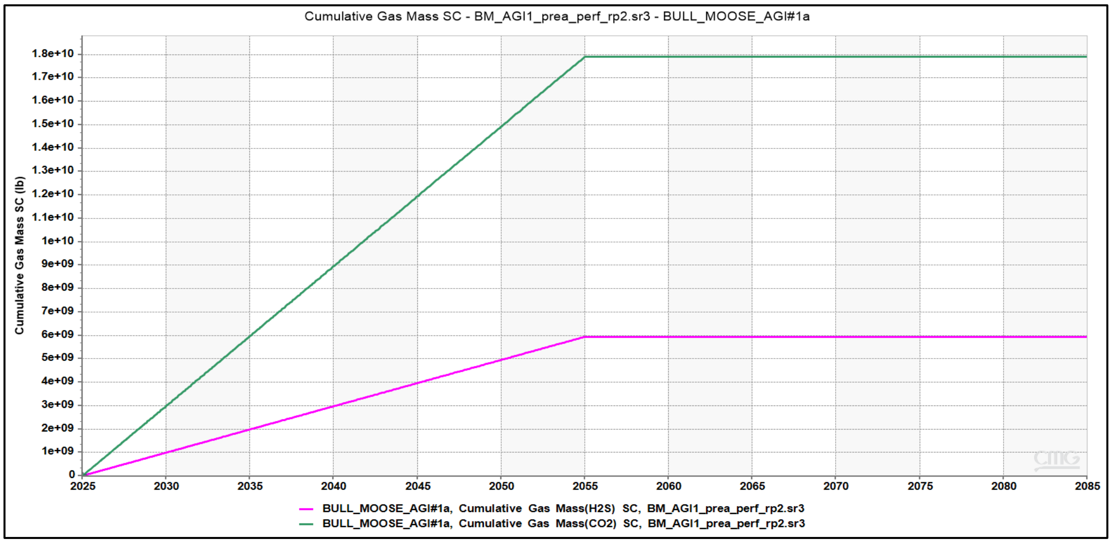


Figure 3.9-4: *Predicted cumulative mass of injected CO_2 and H_2S for BM AGI #1 well (injection operation from 2025 to 2055).*

3.9.3 Treated Acid Gas Plume

Figure 3.9-5 shows the TAG plume evolution for BM AGI #1 in the years 2030, 2035, 2040, 2045, 2050, 2055, marking 5-year increments from the beginning of the injection simulation in 2025. The diameter of the most extensive part of the TAG plume is estimated to be 7,500 ft (1.42 mi), with stabilization achieved in 2070

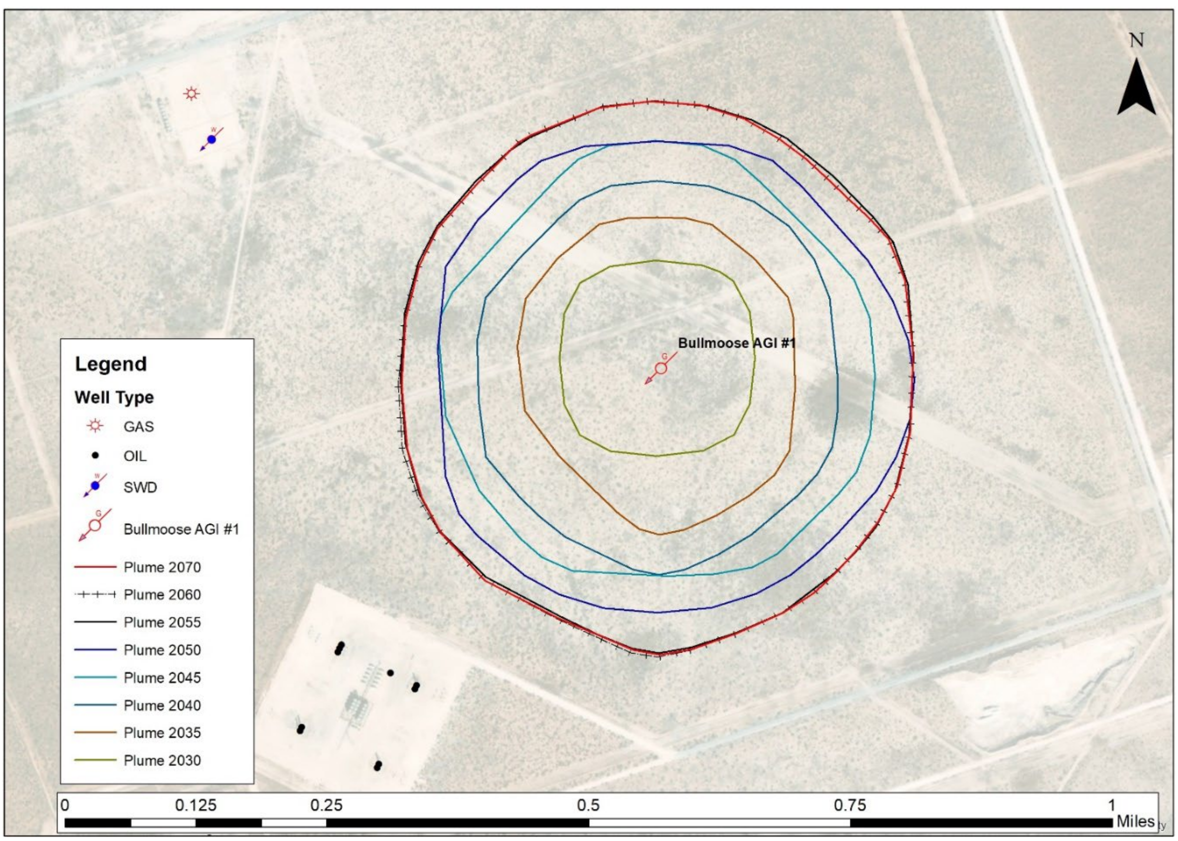


Figure 3.9-5: *Extent of TAG plume (represented by gas saturation with 1% threshold) at years 2030, 2035, 2040, 2045, 2050, 2055 (end of injection = t), 2060 (t+5) and stabilized plume in 2070.*

4 Delineation of the Monitoring Areas

The delineation of the active monitoring area (AMA) and the maximum monitoring area (MMA) are based on the simulation results from section 3.9.

4.1 AMA – Active Monitoring Area

The AMA is shown in **Figure 4-1** and is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

(1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2055), plus an all-around buffer zone of one-half mile **(Figure 4.1-1);**

(2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2060).

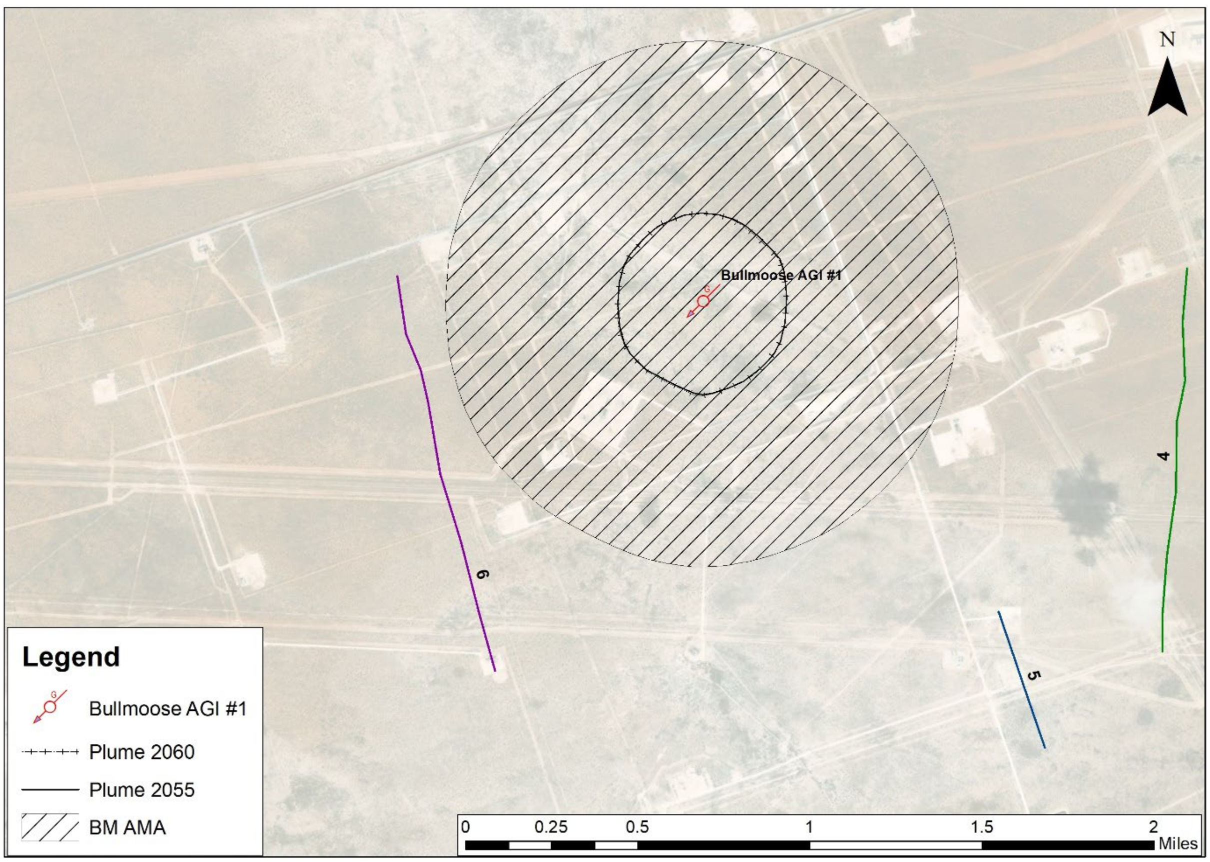


Figure 4.1-1: *Bull Moose AMA according to definition (1).*

Targa intends to define the AMA to be the same area as the MMA. The black polygon at year t=2055 is the BM AGI #1 well plume at the end of injection, and the black cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection plus 5 years. The red polygon in **Figure 4.1-2** is the stabilized plume extent 15 years after injection ceases, i.e. 2070. The AMA, which is the hatched area in **Figure 4.1-1** and the MMA shown as the red-filled polygon in **Figure 4.1-2** contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

4.2 MMA – Maximum Monitoring Area

As defined in Section 40 CFR 98.449 of Subpart RR, the MMA is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.9 to define the extent of the plume.

According to the reservoir modeling results, after 30 years of post-injection monitoring (year=2085), the injected gas will remain in the reservoir and no expansion of the TAG footprint is observed after 2070. Therefore, the plume extent at year 2070 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA: **Figure 4.1-2**.

In addition, according to EPA regulation: "The buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that a buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances."

Therefore, Targa considered the identified faults surrounding the injection well in order to define the MMA. There was no need to extend the MMA to incorporate the faults plus a one-half-mile buffer around the faults because they are outside the initial AMA and MMA. Therefore, the MMA encompasses the union of two areas:

- The area covered by the stabilized plume plus an all-around buffer zone of one-half mile
- The area covered by the lateral extent of known potential leakage pathways (the trace faults Figure 4.2) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 shows the MMA as defined by Section 40 CFR 98.449 of Subpart RR. The MMA is expected to contain the free phase CO_2 plume throughout the life of the project and the lateral extent of potential leakage pathway plus a one-half mile buffer. The AMA is set equal to the MMA.

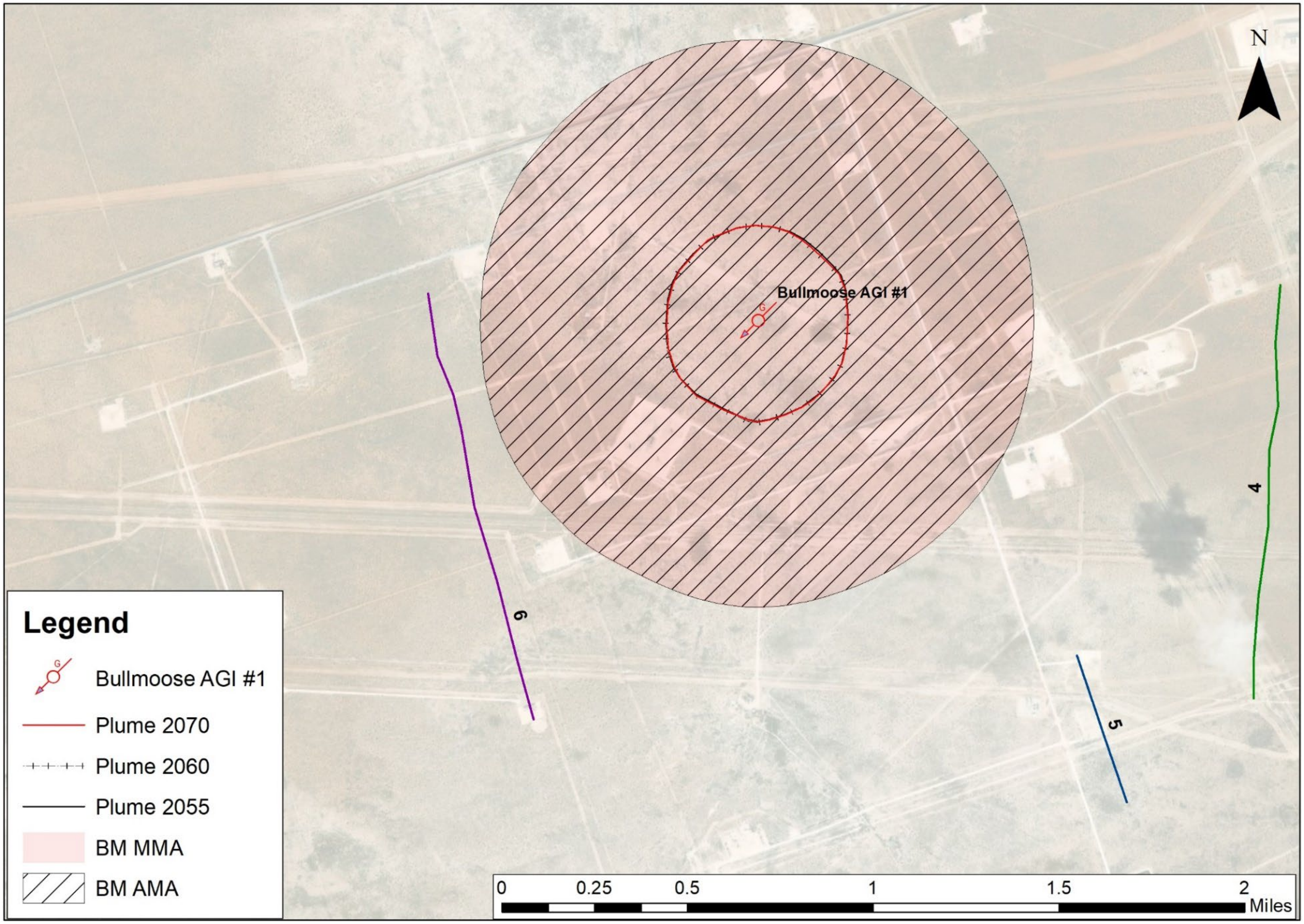


Figure 4.1-2: *Active monitoring area (AMA) and Maximum monitoring area (MMA) for Targa BM AGI #1; and plume at the end of injection (2055), 5 years after end of injection (2060) and stabilized plume (2070)*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

An evaluation of each of the potential leakage pathways is described in the following paragraphs, notably:

1. Potential leakage from surface equipment
2. Potential leakage from approved not yet drilled wells
3. Potential leakage from existing wells
4. Potential leakage through the confining / seal system
5. Potential leakage due to lateral migration
6. Potential leakage through fractures and faults
7. Potential leakage due to natural / induced seismicity

Risk estimates were made using a risk matrix (**Figure 5.1-1**) with a methodology to evaluate risk probability and impact. In addition, Targa used the National Risk Assessment Partnership (NRAP) tools, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage leakage risks at geologic carbon storage sites.

Magnitude →

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

Figure 5.1-1: *5x5 Risk Matrix used to evaluate leakage likelihood and magnitude.*

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills".

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

Likelihood:

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2.

Therefore, Targa infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place and the regular inspections and maintenances, the probability of such leakage is considered very unlikely.

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days.

Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

Therefore, the impact (i.e. magnitude) of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable.

5.2 Potential Leakage from Approved Not Yet Drilled Wells

Likelihood:

Approval and construction of oil and gas-related wells, including injection wells, are regulated by TRRC rules (Appendix 2), specifically Rule 13 for casing, cementing, drilling, well control, and completion, which require that wells be constructed in such a manner as to prevent vertical migration of fluids, including gases, behind the casing. Adherence to these requirements will mitigate the risk of potential CO_2 emissions to the surface. In addition, these wells have strict requirements and will be actively monitored for integrity on a regular basis. Therefore, the likelihood of leakage from approved and not yet drilled wells is considered very unlikely.

Magnitude:

Based on worst-case scenario considerations, the following NRAP analysis and the very unlikely risk of leakage happening from approved wells that have not yet been drilled, the magnitude of potential gas leaks through these wells is insignificant.

Timing:

All the wells within the MMA are either injecting, producing, plugged and abandoned or inactive, **Table 5.1-1**. There are no approved and not yet drilled wells based on the available records. Timing evaluations indicate no imminent risk of gas leakage from approved wells that have not yet been drilled.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA, as delineated in Section 4, are shown in **Figure 3.7-2** and detailed in **Appendix 3**.

Targa considered all wells completed and approved within the MMA in the NRAP risk assessment. None of the wells in the MMA penetrate the confining zone nor the injection zone. All of the productive zones lie at more than 5,300 ft above the BM AGI #1 injection zone.

Likelihood:

Even though the risk of CO_2 leakage through the wells that do not penetrate confining zones is very unlikely, (the CO_2 would have to leak through the sealing zone), Targa did not omit any potential source of leakage in the NRAP analysis.

Magnitude:

If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. A total of 29 wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage.

There were 22 active oil wells that were considered in the NRAP risk assessment section. The other wells that were considered for the risk leakage assessment include two injection wells, six abandoned and plugged wells, and one inactive well. Reservoir and seal confinement properties were incorporated into the model, together with CO_2 properties and injection rates and pressures. The injection period was set to 30 years. According to the NRAP results, no leakage mass of CO_2 was recorded throughout the injection period.

Timing: The duration for CO_2 to get to the atmosphere via upward migration through the 5,300 ft of sealing and other geologic formations would be several thousands of years.

The **Table 5.1-1** summarizes the oil and gas wells and their evaluated risk. Based on the previous comments, all the wells expect three have a very low risk of CO_2 leakage. The likelihood of CO_2 leakage is very unlikely and the magnitude insignificant. Three wells have a medium risk, they present an unlikely likelihood of CO_2 leakage but can have a significant magnitude.

Table 5.1-1: *Well within the MMA with their evaluated risk.*

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34978	AGI	INJECTING	VERTICAL	Siluro-Devonian	TBD	2	3	6
42-495-34038	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516	1	1	1
42-495-33871	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630	1	1	1
42-495-34331	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564	1	1	1
42-495-34324	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621	1	1	1
42-495-34488	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627	1	1	1
42-495-34489	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637	1	1	1
42-495-33759	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,811	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,814	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,816	1	1	1
42-495-34325	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858	1	1	1
42-495-33236	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868	1	1	1
42-495-34332	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897	1	1	1
42-495-34483	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972	1	1	1
42-495-34323	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106	1	1	1

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34485	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129	1	1	1
42-495-34481	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145	1	1	1
42-495-34482	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176	1	1	1
42-495-33840	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185	1	1	1
42-495-33726	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188	1	1	1
42-495-34329	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193	1	1	1
42-495-33763	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194	1	1	1
42-495-34326	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208	1	1	1
42-495-34484	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217	1	1	1
42-495-34328	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263	1	1	1
42-495-34330	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537	1	1	1
42-495-34327	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545	1	1	1
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6

5.3.1 Wells Completed in the Injection Zone

The only well completed in the BM AGI #1 well injection zone is the BM AGI #1 well.

Likelihood:

To minimize the likelihood of leaks from new wells, TRRC regulation regarding the casing and cementing of injection wells requires operators to case injection wells with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string.

Magnitude and Timing:

To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, TRRC requires the use of blowout preventers in areas of high pressure at or above the projected depth of the well. These requirements apply to any other new well drilled within the MMA for this MRV plan.

In addition, for safety purposes, Targa will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 flow to the surface by:

- Monitoring H_2S at surface at many locations (H_2S can be a proxy to detect CO_2);
- Employing a high level of caution and care while drilling, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the injection zone.

By drilling through producing zones, there is a possibility of gas emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent and/or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of BM AGI #1 operating parameters by the distributed control system (DCS), Targa considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.3.2 Horizontal Wells

The table in **Appendix 3** and **Figure 3.7-2** show a number of horizontal wells in the area, many of which are producing. As discussed in 5.3, they are all 5,300 ft above the injection zone and the risk of leakage through these wells is considered very unlikely and insignificant.

5.3.3 Groundwater Wells

According to the Texas Water Development Board water database, there are no water wells within the MMA. There are only one North-East of the MMA and South-West of the MMA. Therefore, the risk of leakage through these wells are considered very unlikely and insignificant TWDB

5.4 Potential Leakage through the Confining / Seal System

Although unlikely, Targa considered leakage through confining zones in the NRAP risk assessment.

Likelihood:

The Barnett shale (440 ft), Mississipian limestone (440 ft) and Woodford Shale (660 ft) serve as the major seals or caprock layer to the injection zones. Their low porosity (1%) and permeability (<0.1

mD) provide high seal integrity (Sections 3.2, 3.3) There is. no evidence of faulting or natural fracturing. It is very unlikely that TAG injected into the injection formation will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Magnitude and Timing:

The worst-case scenario is defined as leakage through the seal immediately above the injection well, where CO_2 saturation is highest.

To simulate this scenario, cell blocks were created to cover the MMA, serving as the most prone zone for CO_2 leakage. These cell block locations and CO_2 saturation at the seal and seal properties were incorporated into the NRAP model.

Figures 5.4-1 and 5.4-2 present the leakage rate and cumulative mass of leakage over 60 years. The total leakage mass recorded after 60 years is about 8,000 kg. According to the total mass of CO_2 injected per year alone, after 60 years, the percentage of leakage through confining zone is estimated to be 0.0021%. This is reliably minimal and considering other stratigraphic strata, Targa concludes that the risk of leakage through this pathway is highly unlikely and insignificant.

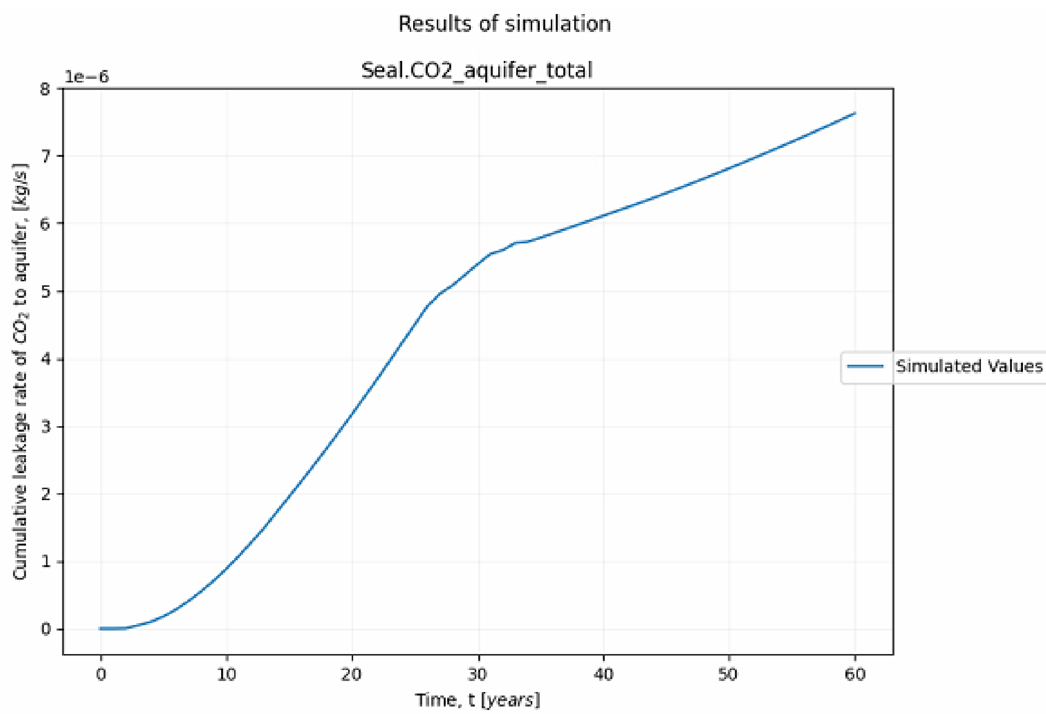


__Figure 5.4-1:__ Seal leakage rate

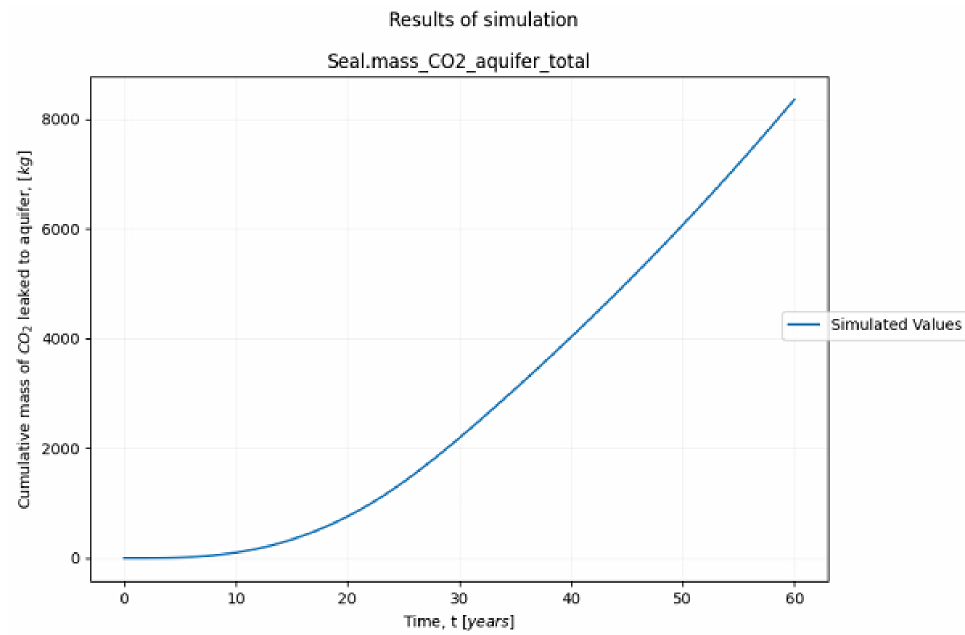


***Figure 5.4-1:** Cumulative mass of Seal leakage*

5.5 Potential Leakage due to Lateral Migration

Likelihood:

Regional consideration of the geology (Section 3.3) and the model built suggest that BM AGI #1 injection zones have adequate storage capacity for the proposed injection amount. In addition, simulation (Section 3.9) indicates that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA.

Based on the geological discussion and analysis of the injection zone, Targa considers that the likelihood of CO_2 to migrate laterally is unlikely.

Magnitude and Timing:

Based on simulation results, the TAG is projected to be contained within the injection zone close to the injection well. The sealing zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration occurs.

5.6 Potential Leakage through Fractures and Faults

Likelihood:

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces (numbered 4, 5 and 6) in the vicinity of the Bull Moose plant. The fault number 6 shown on **Figure 5.6-1** is above the injection zone for the BM AGI well. No faults were identified in the injection zone or confining zone within the MMA. Therefore, the likelihood of leakage through faults is considered very unlikely.

Magnitude and Timing:

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. Considering faults that are going through the confining or injection zone, the closest identified fault lies approximately 1.5 miles east of the Bull Moose site and has approximately 1,000 ft of down-to-the-west structural relief.

The nearest fault going through the injection or confining zone is found approximately 7,276 ft east of the BM AGI #1 site. The risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume or lateral migration carries CO_2 to faults. Other nearby faults are 12,031 ft (~2.3 mi)and ft (2.9 mi) east the site, placing them outside the MMA. Hence, leakage through faults will be an unlikely event. This is supported by NRAP simulation results (**Figure 5.6-1**) that consider fault location, geometry, and direction. For faults that do not directly connect with the CO_2 plume, CO_2 leakage rate and mass are estimated to be zero. The estimated cumulative leakage (**Figure 5.6-1**) shows no leakage throughout the period of simulation (60 years).

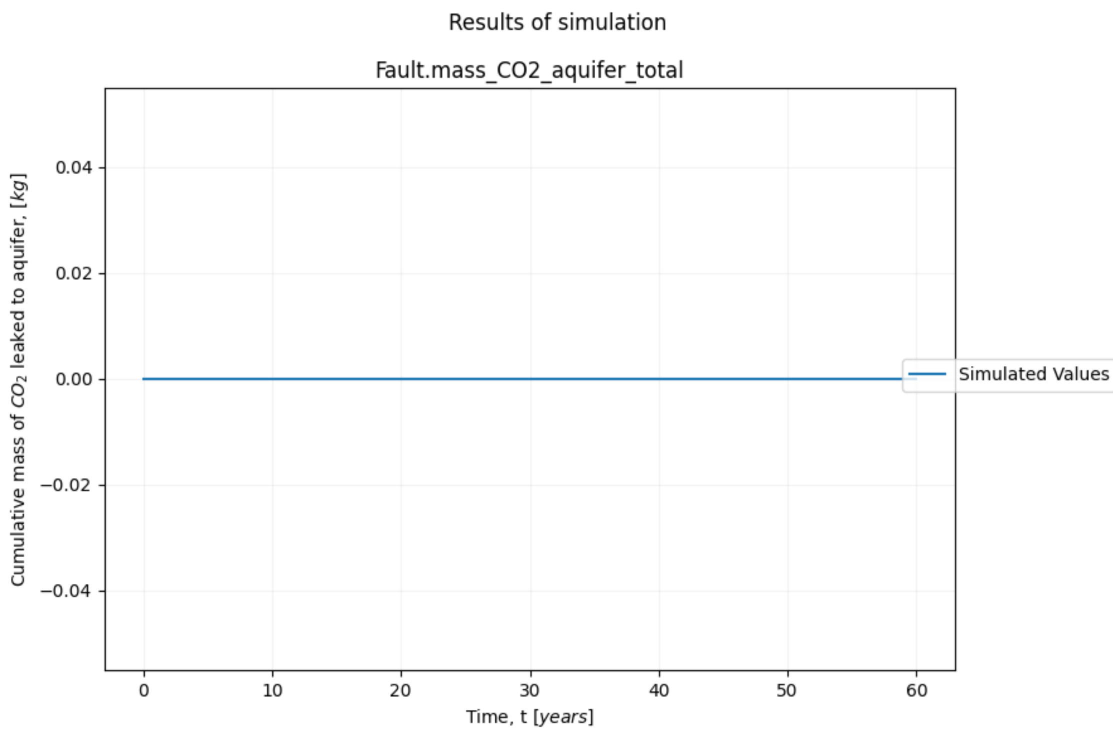


Figure 5.6-1: *Faults 7,276 ft*

Therefore, Targa concludes that the risk of CO_2 leakage through the faults are very unlikely and insignificant.

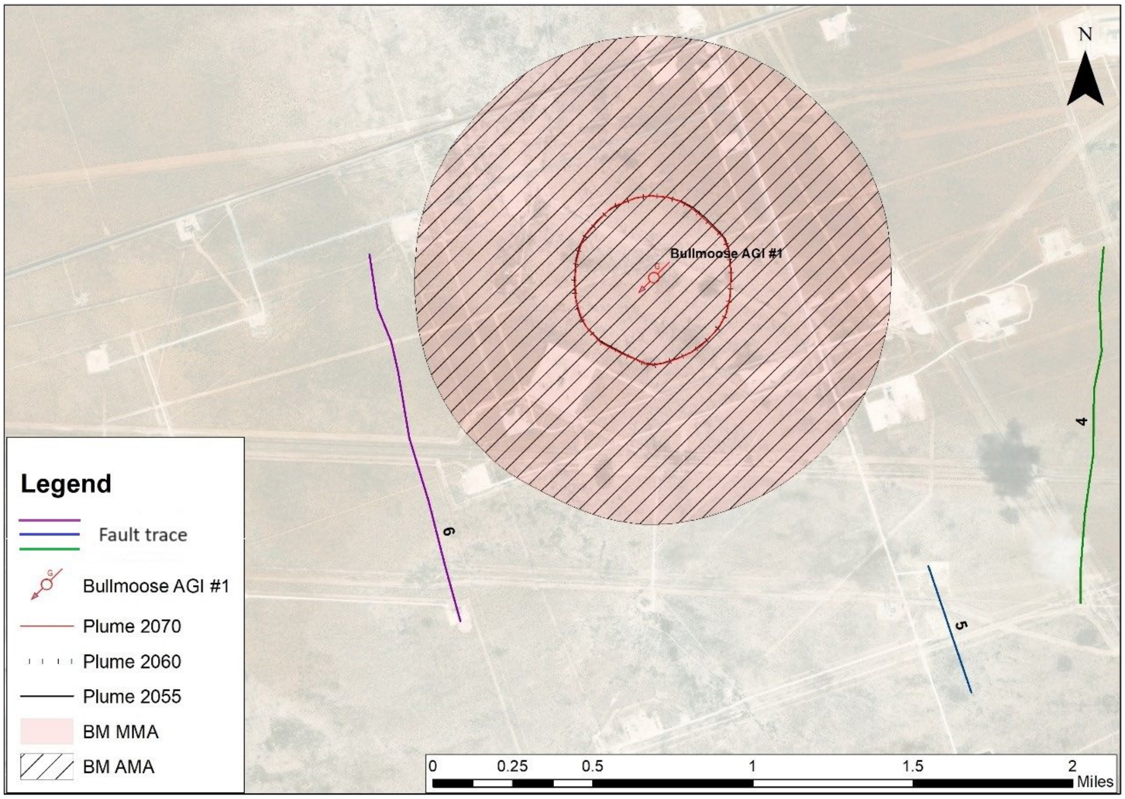


Figure 5.6-1: *Faults surrounding Bull Moose facility relative to the plume and the MMA.*

5.7 Potential Leakage due to Natural / Induced Seismicity

5.7.1 Natural Seismicity

Likelihood:

Due to the distance between the BM AGI #1 well and the location of the seismic events recorded since 2017, the magnitude of these events, and the fact that Targa injects at pressures below fracture opening pressure, Targa considers the likelihood of CO_2 emissions to the surface caused by seismicity to be very unlikely.

Magnitude and Timing:

The magnitude and timing of a seismic event can vary greatly. In the region, the earthquakes ranged from magnitude 1.5 to 4. They are located in clusters that are around 20 miles North-West and South, South-West of Bull Moose.

Based on historical data and the geology of the surroundings, the risk of CO_2 leakage due to seismicity is considered insignificant.

Monitoring of seismic events in the vicinity of the Bull Moose AGI well is discussed in Section 6.7.

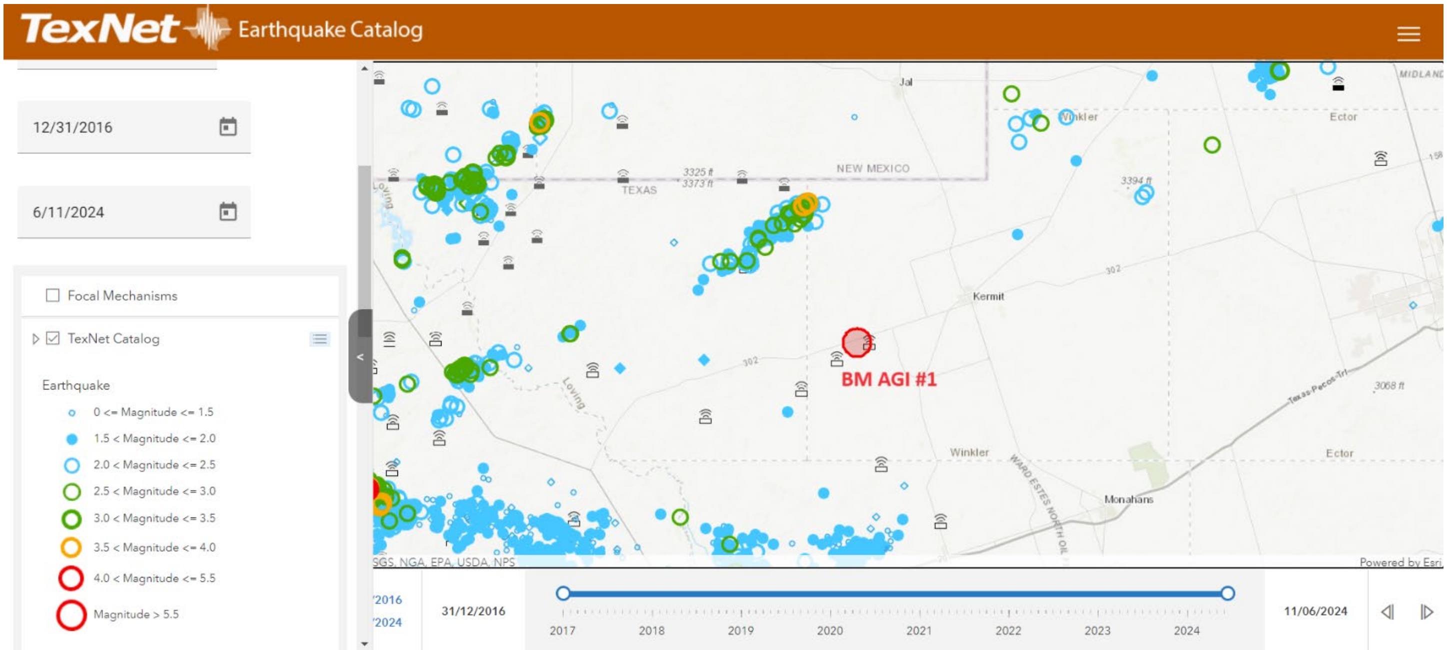


__Figure 5.7-1:__ TexNet seismic events since 2017 and seismic monitoring stations close to Bull Moose plant.

5.7.1 Induced Seismicity

The faults that might be affected by pressure changes have been analyzed to evaluate the risk of induced seismicity, and the risk of leakage due to induced seismicity. The examination of faults identified from the 3D seismic data, illustrated in **Figure 5.7-2**, discloses the presence of 6 major faults traversing the reservoir interval. These faults are far east from BM AGI #1 and they have been further subdivided into 41 sub-fault segments, allowing for a detailed analysis of their slip potentials.

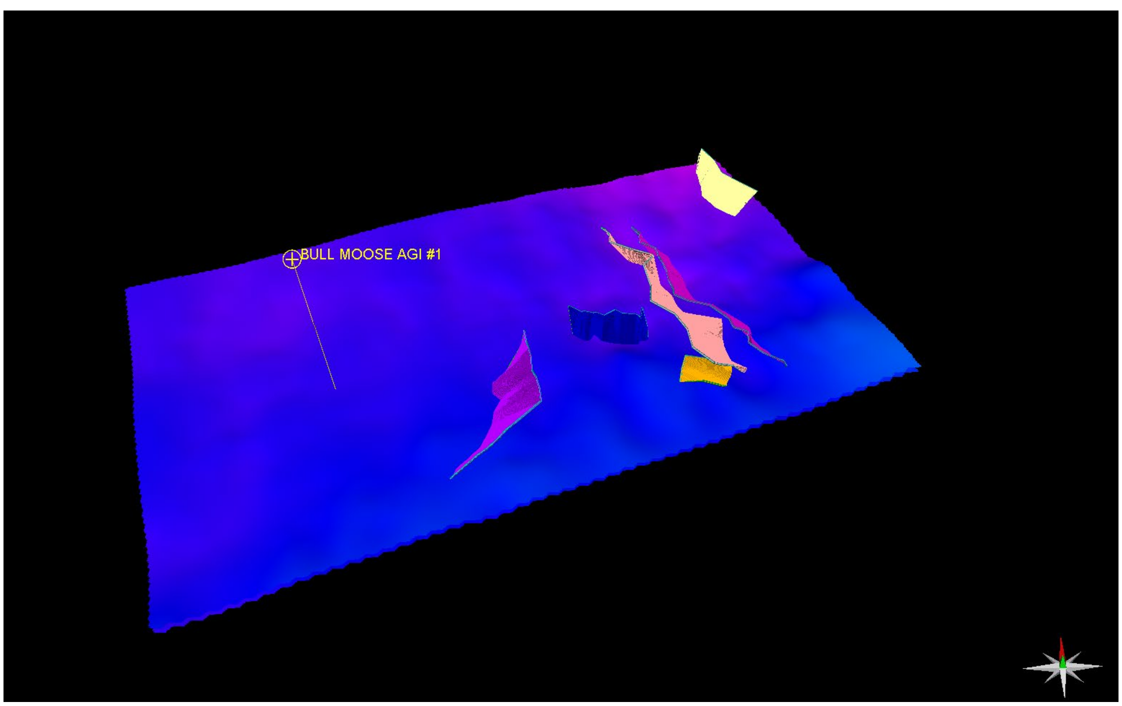


__Figure 5.7-2:__ Structure and fault system picked from 3D seismic data on Silu-Devonian to Ellenburger.

The evaluation of Fault Slip Potential (FSP) using the FSP software version 1.07 involved the utilization of specific parameters (**Table 5.7**). The software requires various inputs or parameters to assess the potential for fault slippage. These parameters are fundamental in assessing the likelihood of fault slippage. The FSP software incorporates and processes these inputs to generate an estimation or analysis of the potential for faults to slip under the given conditions. These parameters could include factors such as: Pressure Changes (the magnitude of pore pressure changes within the geological formations), fault geometry (details about the fault, including its orientation, size, and geometry), stress conditions (information on stress distribution within the rock formations, including the magnitudes and orientations of principal stresses), rock properties (data regarding the mechanical properties of the rocks, such as porosity, permeability, and strength), and seismic data (3D seismic data used to identify and characterize faults geometry). These parameters are from published papers and reports.

Table 5.7: *Fault Slip Potential simulation parameters.*

Fault Friction Coeff (mu)	0.58
Vertical Stress Gradient (psi/ft)	1.07+/-0.01
Maximum Horizontal Stress Direction (deg)	82.5 +/- 7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.465 +/- 0.05
Minimum Horizontal Stress Gradient (psi/ft)	0.5
Maximum Horizontal Stress Gradient (psi/ft)	1
A-Phi Parameter	0.8+/-0.1
Reference Friction Coefficient (mu)	0.58+/-.005
Porosity (%)	15
Permeability (mD)	7.2
Injection Years	2025 to 2055

It appears that the results of the FSP (Fault Slip Potential) analysis indicate that over a 30-year injection period, faults have experienced only a small pressure drop in effective stress. The slippage of fault walls is contingent on having sufficient pore pressure to raise the effective stress to a level that would induce slippage. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation. As shown in **Figure 5.7-3**, 97% of interpreted faults require more than 180 psi effective pressure to cause slip. The predicted value of effective pressure changes on **Figure 5.7-4** and **Figure 5.7-5** shows that the pore pressure will change less than 30 psi after 30 years. The probability of fault slip are shown in **Figure 5.7-5**. These values indicate negligible potential for fault slips for major faults. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation.

Therefore, the risk of leakage due to induced seismicity is considered very low. Its **likelihood, timing and magnitude** are considered very unlikely and insignificant.

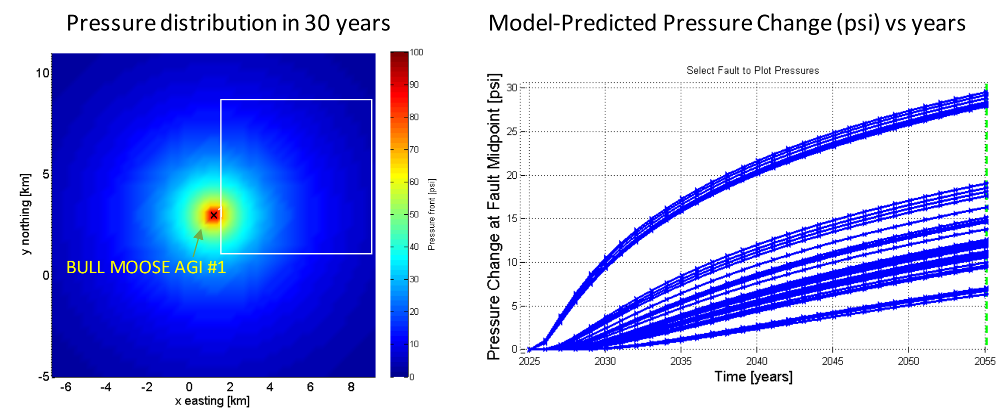


Figure 5.7-3: Visualization of pressure change after 30 years of injection

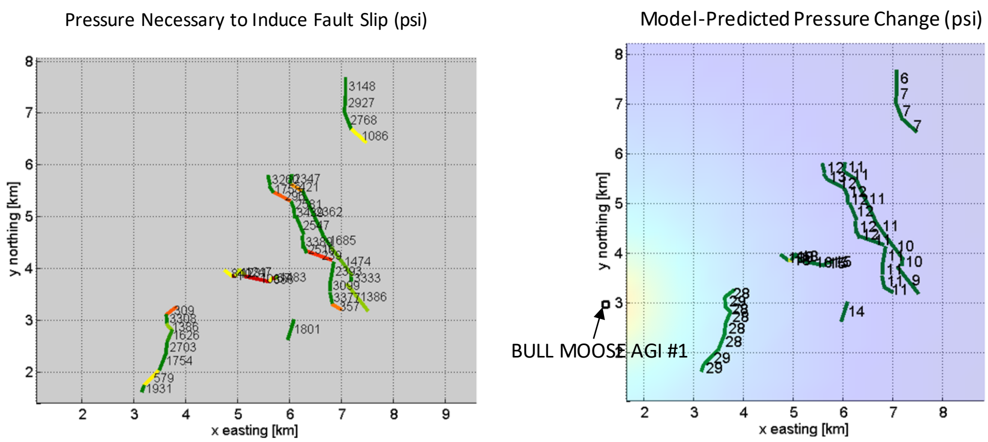


Figure 5.7-4: Visualization of pressure change required to cause fault slip and the predicted pressure after 30 years of injection

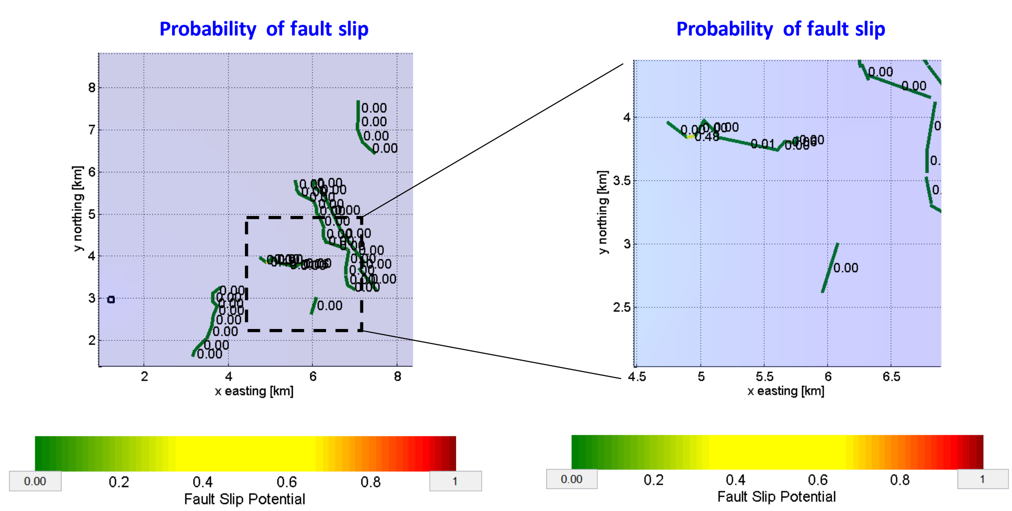


Figure 5.7-5: Fault slip probability after 30 years of injection. Fault color represent the fault slip potential value indicated by color bar and they show almost 0% of fault slip potential.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2.

Targa will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Targa considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage close to the plant equipment. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 15-year post-injection period.

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Wells that have not yet been drilled	• Monitor applications for permit to drill and permit to inject made to the TRRC • Communicate with operators/drillers that are active within the MMA so they are aware that they are drilling in an area that has CO_2/H_2S injection activities.
BM AGI #1 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well pressure/temperature (P/T) sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring

Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring station
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

Targa implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Leaks from surface equipment are detected by Targa field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Targa also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. This applies to Targa and other operators drilling new wells through the BM AGI #1 injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 BM AGI Well

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

To monitor leakage and wellbore integrity, pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) will be deployed in Targa's BM AGI #1 well.

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

Well Schematic for BM AGI #1 showing installation of pressure and temperature sensors are in **Appendix 1**.

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the BM AGI #1 well, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining / seal system, Targa will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well (see Section 6.8).

6.5 Leakage due to Lateral Migration

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

If monitoring of operational parameters or other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, Targa will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults.

However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, Targa will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. Targa will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

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

If the monitoring systems indicate surface leakage of CO_2 linked to seismic events, Targa will assess whether the CO_2 originated from the BM AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR.

Quantification of major leakage events from surface equipment as identified by the detection techniques listed in **Table 6-1** will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point.

Targa has standard operating procedures to report and quantify all pipeline leaks in accordance with the TRRC regulations. Targa will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by Targa or third parties. Additionally, Targa may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

Here are example quantification strategies specifically designed for surface leakage:

- Direct measurement techniques: Targa will use mass flow meters in surface equipment. These meters can capture CO_2 mass flow rates in real-time, providing direct quantification of emissions as soon as a leak is detected.
- Leak rate models: Targa will use models that incorporate thermodynamic and fluid dynamics principles to estimate the mass of CO_2 escaping from leaks. For example: empirical leak rate

models employ empirical equations that estimate leak rates based on equipment size, the differential pressure across the leak, and gas composition.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 6-1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. Targa may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

Targa field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Bull Moose Gas Plant.

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

Compositional analysis of Targa's gas injectate at the Bull Moose Gas Plant indicates an approximate H_2S concentration of 30% thus requiring Targa to develop and maintain an H_2S Contingency Plan (Plan) according to the TRRC Regulations. Targa considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated BM AGI #1 Well and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Bull Moose Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, Targa will set up a monitoring network for CO_2 leakage detection in the MMA as defined in Section 4.2. In addition, there will be periodic groundwater and soil flux sampling within the MMA. Once the network is set up, Targa will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

Targa adheres to the requirements of TRRC Rules governing the construction, operation and closing of an injection well under the Oil and Gas Act. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Targa's Routine Operations and Maintenance Procedures for the BM AGI #1 well ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

Targa has Installed a seismometer and a digital recorder to monitor for and record data for any seismic event at the Bull Moose Gas Plant. The seismic station meets the requirements of the TRRC.

In addition, data that is recorded by the TexNet network surrounding the Bull Moose Gas Plant will be analyzed by Targa. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

Targa will monitor groundwater wells for CO_2 leakage as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes TDS, conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Bull Moose Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

Parameters
pH
Alkalinity as HCO^{3-} (mg/L)
Chloride (mg/L)
Fluoride (F^-) (mg/L)
Bromide (mg/L)
Nitrate (NO^{3-}) (mg/L)
Phosphate (mg/L)
Sulfate ($SO4^{2-}$) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, Targa can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Bull Moose Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system’s flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

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

8.1 CO_2 Received

Currently, Targa receives gas to its Bull Moose Gas Plant through pipelines. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. Targa will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to the flow meter (FM) in **Figure 3.7-1**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

Although Targa does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When Targa begins to receive CO_2 in containers, Targa will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Targa will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Upon completion, Targa will commence injection into BM AGI #1. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to the flow meter (FM) in **Figure 3.7-1**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

Targa does not produce oil or gas or any other liquid at its Bull Moose Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Targa will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

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

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

(Equation RR-12)

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells 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 [refers to subpart W of the GHGRP rules].

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established by Targa for several years and continues to the present. Targa will begin implementing this MRV plan as soon as it is approved by EPA. After BM AGI #1 is drilled, Targa will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

Targa will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), Targa's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the BM AGI #1 well using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.4 CO_2 produced.

Targa does not produce CO_2 at the Bull Moose Gas Plant.

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

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

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

10.1.6 Measurement devices.

As required by 40CFR98.444(e), Targa will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

Targa will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

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

10.4 Revisions of the MRV Plan

Targa will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of Texas. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change. Targa intends to update the MRV plan after BM AGI #1 has been drilled and characterized.

11 Records Retention

Targa will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, Targa will retain the following documents:

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

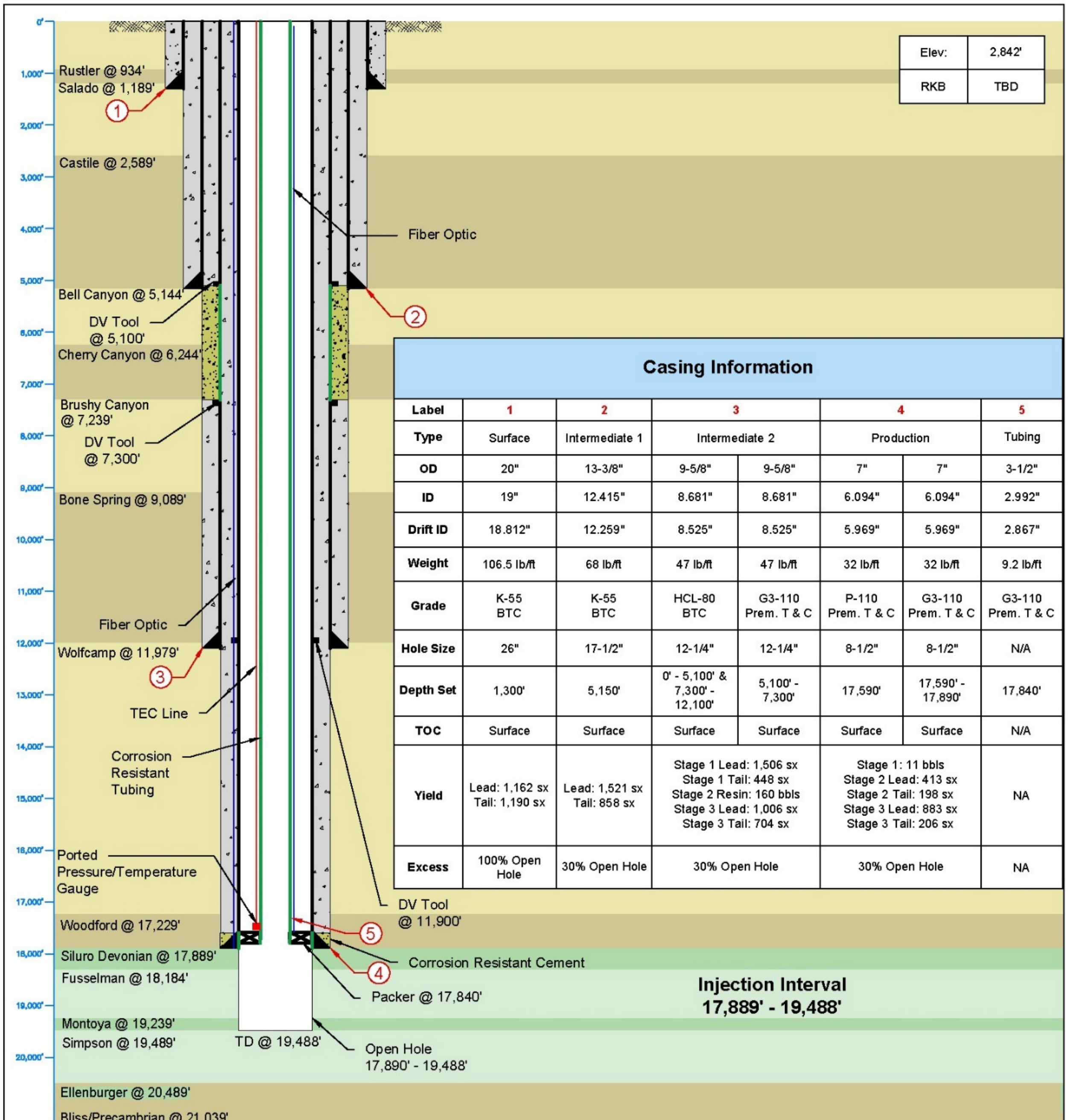
(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

12 Appendices

Appendix 1 Targa Well

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Bull Moose AGI #1 (BM AGI #1)	42-495-34978	1,895' FSL & 2,161' FEL, SEC 42, BLK 27, Public School Land Survey, A-433	KERMIT, TX	To be determined	19,488 ft	17,790 ft



Casing Information

Label	1	2	3		4		5
Type	Surface	Intermediate 1	Intermediate 2		Production		Tubing
OD	20"	13-3/8"	9-5/8"	9-5/8"	7"	7"	3-1/2"
ID	19"	12.415"	8.681"	8.681"	6.094"	6.094"	2.992"
Drift ID	18.812"	12.259"	8.525"	8.525"	5.969"	5.969"	2.867"
Weight	106.5 lb/ft	68 lb/ft	47 lb/ft	47 lb/ft	32 lb/ft	32 lb/ft	9.2 lb/ft
Grade	K-55 BTC	K-55 BTC	HCL-80 BTC	G3-110 Prem. T & C	P-110 Prem. T & C	G3-110 Prem. T & C	G3-110 Prem. T & C
Hole Size	26"	17-1/2"	12-1/4"	12-1/4"	8-1/2"	8-1/2"	N/A
Depth Set	1,300'	5,150'	0' - 5,100' & 7,300' - 12,100'	5,100' - 7,300'	17,590'	17,590' - 17,890'	17,840'
TOC	Surface	Surface	Surface	Surface	Surface	Surface	N/A
Yield	Lead: 1,162 sx Tail: 1,190 sx	Lead: 1,521 sx Tail: 858 sx	Stage 1 Lead: 1,506 sx Stage 1 Tail: 448 sx Stage 2 Resin: 160 bbls Stage 3 Lead: 1,006 sx Stage 3 Tail: 704 sx		Stage 1: 11 bbls Stage 2 Lead: 413 sx Stage 2 Tail: 198 sx Stage 3 Lead: 883 sx Stage 3 Tail: 206 sx		NA
Excess	100% Open Hole	30% Open Hole	30% Open Hole		30% Open Hole		NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS · ENERGY ADVISORS AUSTIN · HOUSTON · CALGARY · WICHITA DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON	Targa Delaware LLC	Bull Moose AGI No. 01	
	Country: USA	**State/Province:** Texas	**County/Parish:** Winkler
	Location: Sec. 42, A-433, Blk 27		**District:** 08
	API No: TBD	**Field:**	**Well Type/Status:** AGI Disposal
Texas License F-9147	**Survey:**	**Project No:** F2345	**Date:** 5/6/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** CJL	**Reviewed:** WHG	**Approved:**
	Rev No: 1	**Notes:** Intermediate 2 Revisions Requested by Targa	

Figure Appendix 1-1: Schematic of Targa BM AGI #1 Well

Appendix 2 Referenced Regulations

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

Texas Administrative Code > Title 16, Economic Regulation, > Part 1 Railroad Commissions of Texas > Chapter 3, Oil and Gas Division
CHAPTER 15 - OIL AND GAS

§3.1	Organization Report; Retention of Records; Notice Requirements
§3.2	Commission Access to Properties
§3.3	Identification of Properties, Wells, and Tanks
§3.4	Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
§3.5	Application To Drill, Deepen, Reenter, or Plug Back
§3.6	Application for Multiple Completion
§3.7	Strata To Be Sealed Off
§3.8	Water Protection
§3.9	Disposal Wells
§3.10	Restriction of Production of Oil and Gas from Different Strata
§3.11	Inclination and Directional Surveys Required
§3.12	Directional Survey Company Report
§3.13	Casing, Cementing, Drilling, Well Control, and Completion Requirements
§3.14	Plugging
§3.15	Surface Equipment Removal Requirements and Inactive Wells
§3.16	Log and Completion or Plugging Report
§3.17	Pressure on Bradenhead
§3.18	Mud Circulation Required
§3.19	Density of Mud-Fluid
§3.20	Notification of Fire Breaks, Leaks, or Blow-outs
§3.21	Fire Prevention and Swabbing
§3.22	Protection of Birds
§3.23	Vacuum Pumps
§3.24	Check Valves Required
§3.25	Use of Common Storage

§3.26	Separating Devices, Tanks, and Surface Commingling of Oil
§3.27	Gas to be Measured and Surface Commingling of Gas
§3.28	Potential and Deliverability of Gas Wells to be Ascertained and Reported
§3.29	Hydraulic Fracturing Chemical Disclosure Requirements
§3.30	Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)
§3.31	Gas Reservoirs and Gas Well Allowable
§3.32	Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes
§3.33	Geothermal Resource Production Test Forms Required
§3.34	Gas To Be Produced and Purchased Ratably
§3.35	Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned
§3.36	Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas
§3.37	Statewide Spacing Rule
§3.38	Well Densities
§3.39	Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40	Assignment of Acreage to Pooled Development and Proration Units
§3.41	Application for New Oil or Gas Field Designation and/or Allowable
§3.42	Oil Discovery Allowable
§3.43	Application for Temporary Field Rules
§3.45	Oil Allowables
§3.46	Fluid Injection into Productive Reservoirs
§3.47	Allowable Transfers for Saltwater Injection Wells
§3.48	Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

§3.49	Gas-Oil Ratio
§3.50	Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51	Oil Potential Test Forms Required
§3.52	Oil Well Allowable Production
§3.53	Annual Well Tests and Well Status Reports Required
§3.54	Gas Reports Required
§3.55	Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56	Scrubber Oil and Skim Hydrocarbons
§3.57	Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58	Certificate of Compliance and Transportation Authority; Operator Reports
§3.59	Oil and Gas Transporter's Reports
§3.60	Refinery Reports
§3.61	Refinery and Gasoline Plants
§3.62	Cycling Plant Control and Reports
§3.63	Carbon Black Plant Permits Required
§3.65	Critical Designation of Natural Gas Infrastructure
§3.66	Weather Emergency Preparedness Standards
§3.70	Pipeline Permits Required
§3.71	Pipeline Tariffs
§3.72	Obtaining Pipeline Connections
§3.73	Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76	Commission Approval of Plats for Mineral Development
§3.78	Fees and Financial Security Requirements
§3.79	Definitions
§3.80	Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81	Brine Mining Injection Wells
§3.83	Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84	Gas Shortage Emergency Response

§3.85	Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86	Horizontal Drainhole Wells
§3.91	Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93	Water Quality Certification Definitions
§3.95	Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96	Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97	Underground Storage of Gas in Salt Formations
§3.98	Standards for Management of Hazardous Oil and Gas Waste
§3.99	Cathodic Protection Wells
§3.100	Seismic Holes and Core Holes
§3.101	Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102	Tax Reduction for Incremental Production
§3.103	Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106	Sour Gas Pipeline Facility Construction Permit
§3.107	Penalty Guidelines for Oil and Gas Violations

Appendix 3 Oil and Gas Wells within MMA of the BM AGI Well Site

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34323	SILVER DOLLAR 4231-27 A 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,814
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,811
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,816
42-495-34481	BRIDAL VEIL STATE W 4132-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145
42-495-33759	VALLECITO 37-28 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718
42-495-34328	SILVER DOLLAR 4231-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263
42-495-34331	SILVER DOLLAR 4231-27 E 5H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564
42-495-34485	BRIDAL VEIL STATE W 4132-27 L 12H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129
42-495-33871	MITCHELL 42-27 1	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630
42-495-34488	BRIDAL VEIL STATE W 4132-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627
42-495-34482	BRIDAL VEIL STATE W 4132-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176
42-495-33840	SAINT VRAIN 48-28 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185
42-495-33763	AVALANCHE 42-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194
42-495-33726	SILVER DOLLAR 31-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188
42-495-34484	BRIDAL VEIL STATE W 4132-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217
42-495-34038	MITCHELL 42-27 2	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516
42-495-34489	BRIDAL VEIL STATE W 4132-27 K 11H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637
42-495-34332	SILVER DOLLAR 4231-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897
42-495-34329	SILVER DOLLAR 4231-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193
42-495-34327	SILVER DOLLAR 4231-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545
42-495-34325	SILVER DOLLAR 4231-27 D 4H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-34326	SILVER DOLLAR 4231-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34324	SILVER DOLLAR 4231-27 B 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621
42-495-34330	SILVER DOLLAR 4231-27 C 3H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537
42-495-34483	BRIDAL VEIL STATE W 4132-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972
42-495-33236	HARRISON STATE 41 1H	DEVON	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868

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Appendix 5 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
PPM – Parts Per Million
QA/QC – quality assurance/quality control
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 6 Targa Bull Moose AGI Well - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

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

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

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

Appendix 7 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

Appendix B: Submissions and Responses to Requests for Additional Information

MONITORING, REPORTING, AND VERIFICATION PLAN

Bull Moose AGI #1

Targa Delaware, LLC (Targa)

Version 1.0

November, 2024

Table of Contents

1 Introduction

Targa Delaware, LLC (Targa) proposes an underground injection project at the Targa Bull Moose Gas Processing Plant (the Plant) located approximately 15 miles west of Kermit in Winkler County, district 08, Texas. The Plant is within the eastern part of the Delaware Basin region of the Permian Basin. (**Figure 1-1**).

Targa submitted a Class II Acid Gas Injection (AGI) permit application (Form W-14) for the Bull Moose AGI #1 well (BM AGI #1) to the Texas Railroad Commission (TRRC). Targa intends to drill BM AGI #1 in Q4 of 2024 for the purpose of disposing of the treated acid gas (TAG) that is a byproduct of natural gas processing operations at the Plant. The TAG stream is anticipated to consist of approximately 70% CO_2 (carbon dioxide) and 30% H_2S (hydrogen sulfide), with trace components of hydrocarbons (C1(methane) – C7(heptane)) and nitrogen. The project, with a design life of 30 years, plans to inject TAG through BM AGI #1 into the deep subsurface in the Siluro-Devonian, Fusselman, and Montoya formations.

The project allows Targa to run the Plant at full capacity without discharging large amounts of CO_2 to the atmosphere; replacing the flare with deep injection decreases the negative environmental footprint of the gas plant.

Targa has significant experience in the handling and disposal of TAG in this remotely populated area. Targa submitted forms and supporting documentation designed to meet the requirements of Texas Administrative Code Title 16 Chapter 3 Rule §3.9 and current best engineering practices to ensure that the USDW and the atmosphere are protected from any contamination from injection.

Targa is currently authorized to inject a total of up to 20 million standard cubic feet per day (MMSCFD) of TAG in the approved BM AGI #1 (API 42-495-34978) in accordance with Statewide Rule 9 of the TRRC. Targa received authorization to inject H_2S under the TRRC Rule 36. BM AGI #1 is located on the Plant property (**Figure 1-2**). The permitted injection interval is between 17,889 feet (ft) and 19,488 ft.

The BM AGI #1 well will be constructed with four strings of casing cemented to surface. Corrosion resistant alloys will be used in the bottom 300 ft of the long-string, in the confining zone. Acid resistant cements will also be used across the upper confining zone. Monitoring systems will be installed to ensure that bottomhole injection pressure does not exceed 90% of the determined fracture gradient of the injection interval. Targa is requesting a maximum allowable surface pressure of 0.5 psi/ft (pounds per square inch per foot), or 8,969 psi.

Targa submits this Monitoring, Reporting, and Verification (MRV) plan for the BM AGI #1 well to the United States Environmental Protection Agency (U.S. EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. Targa intends to inject CO_2 in BM AGI #1 for 30 years. Following the operational period, Targa proposes a post-injection monitoring and site closure period of 15 years.

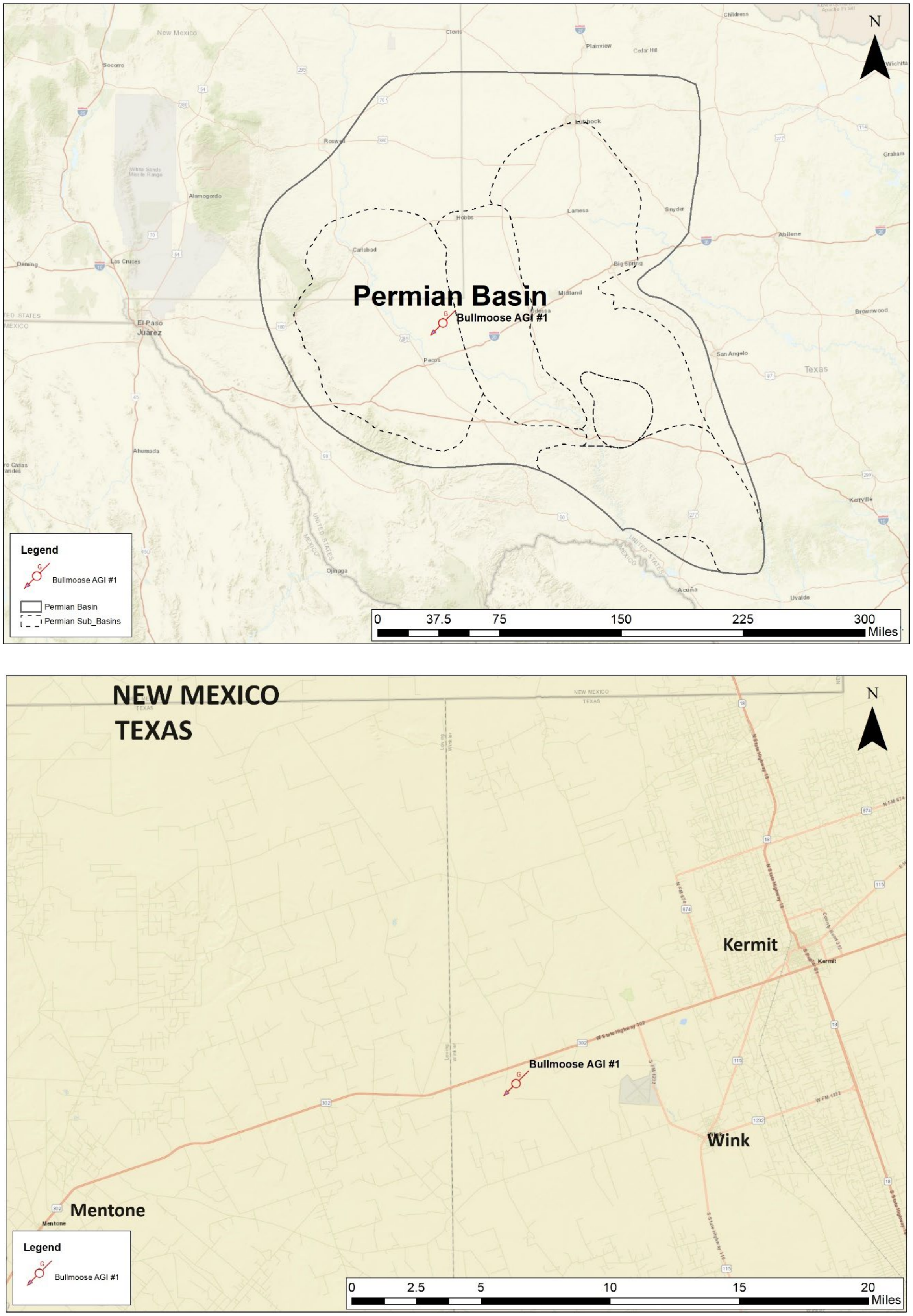
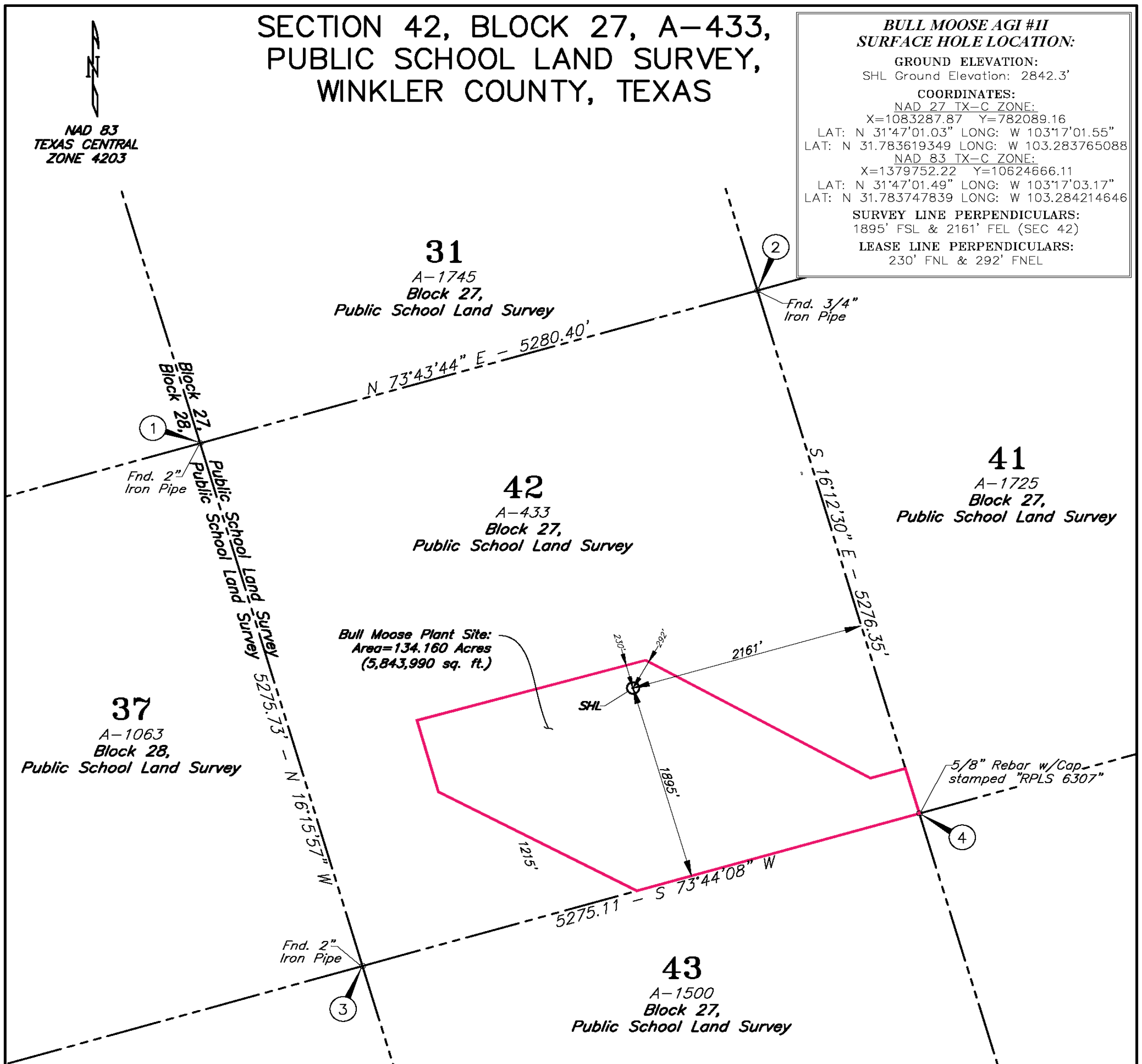


Figure 1-1: *Location of the Bull Moose Facility in the Permian Basin, Texas*



A 134.160 Acre tract of land being a Site located in the South Half of Section 42, Block 27, A-433, Public School Land Survey, Winkler County, Texas, being a part of Section 42, Block 27, A-433 as conveyed to BCCL Royalties, L.P. by William J. Mitchell and Eva L. Mitchell, husband and wife and recorded in Doc. #C32404 of the Official Deed Records of Winkler County, Texas, being fully described by metes and bounds as follows:

Commencing at a found 3/4" Iron Pipe being the Corner Common to Sections 31, 32, 41, 42, Thence S 16°12'30" E with and along the East line of said Section 42, 4,822.90' to the POINT OF BEGINNING at a Set 5/8" Rebar with Cap stamped "RPLS 6307" (X=1382228.88, Y=10623886.59, NAD 83, Texas Central Zone 4203, US Survey FT.) for a Corner of this tract on the East line of said Section 42;

Thence continue S 16°12'30" E with and along said East line 453.45' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract and also being the Southeast Corner of said Section 42; Thence S 73°44'08" W with and along the South line of said Section 42, 2,675.86' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract; Thence leaving said South line N 62°00'47" W 2,044.11' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract; Thence N 15°38'34" W 719.80' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract; Thence N 74°21'03" E 2,158.99' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract; Thence S 60°47'52" E 2,342.48' to a Set 5/8" Rebar with Cap stamped "RPLS 6307" for a Corner of this tract; Thence N 73°41'08" E 330.94' back to the POINT OF BEGINNING. Said tract containing 5,843,990 square feet or 134.160 Acres of Land, more or less.

SECTION CORNER INFORMATION		
CORNER NO.	STATE PLANE TX-C 4203	
	NAD 83	NAD 27
1	X=1375813.76 Y=10627038.32	X=1079349.49 Y=784461.30
2	X=1380882.66 Y=10628517.79	X=1084418.37 Y=785940.73
3	X=1377291.46 Y=10621973.77	X=1080827.08 Y=779396.90
4	X=1382355.45 Y=10623451.17	X=1085891.05 Y=780874.26

1000' 0 1000' 2000'

GRAPHICAL SCALE: 1"=1000'

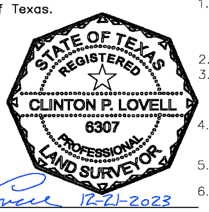
Legend

SHL ⊙ Surface Hole Location

Section Line

Existing Bull Moose Plant Site Boundary

CERTIFICATION:
This is to certify that this plat and the survey on which it is based were made by me or those under my direct supervision, and meets the Professional and Technical Standards for The State of Texas.



Clinton P. Lovell 12-21-2023

Clinton P. Lovell, RPLS
TX Reg. No. 6307

Should any discrepancies be discovered please notify us immediately.

Notes:
1.) This plat does not represent a boundary survey. The Registrant does not claim herein adherence to the T.B.P.E.L.S. Minimum Standards of Procedures for Boundary Surveys.
2.) Ownership information was supplied by others.
3.) Coordinates and bearings as shown are Grid as derived from GPS Observation and are based on the State Plane Coordinates for the Texas Central Zone 4203 NAD 83.
4.) There are no dwellings or structures located 500 feet of this location on the date of staking.
5.) This plat is prepared for Texas Railroad Commission Permitting purposes only.
6.) This plat and the survey it is based on does not constitute an:
A.) Environmental Assessment.
B.) Wetlands Determination.
C.) Subsurface Determination.

No.	Date	By	Revision
3	12-21-23	LHB	Changed Well Name
2	12-21-23	LHB	Added Legal Description
1	11-8-23	GWG	Revised Well Location & No.

TARGA

TARGA DELAWARE LLC
110 West 7th Street,
Tulsa, OK., 74119

NTB Associates, Inc.
Surveyors
525 Louisiana Ave
Shreveport, LA 71101
Phone: (318) 226-9199 Fax: (318) 221-1208
Firm Registration No.: 10118400 Exp. 12/31/2023

PROPOSED WELL LOCATION
BULL MOOSE AGI #1I
Located in Section 42, Block 27, A-433,
Public School Land Survey, Winkler County, Texas
Also located 10.5 Miles Southwest of Kermit, Texas

FIELD SURVEYED: 08/30/23	DRN: GWG	DATE:08/30/23
SCALE: 1" = 1000'	CHKD: CPL	DATE:12/21/23
DRAWING # 23006052-A-101	DATE:12/21/23	REV 3

Figure 1-2: *Location of the Bull Moose Gas Plant and BM AGI #1 Well*

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 589241.

2.2 UIC injection well identification numbers

This MRV plan is for the BM AGI #1 well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The TRRC has issued a permit (number 17541) to inject non-hazardous oil and gas waste under its Statewide Rule 9 (**Appendix 2**) for the Bull Moose AGI lease. All oil- and gas-related wells around the BM AGI #1 well, including both injection and production wells, are regulated by the TRRC which has primacy to implement the UIC Class II program.

Well identification and permit parameters:

- BM AGI #1 API Number: 42-495-34978
- UIC Permit Number: 000126603

3 Project Description

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

3.1 General Geologic Setting / Surficial Geology

The Plant is located in Sec. 42, A-433, Blk 27, approximately 10.5 miles south-west of Kermit in Winkler County, Texas, immediately adjacent to the BM AGI #1 well **(Figs 1-1, 1-2)**. The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

3.2 Bedrock Geology

3.2.1 Basin Development

The Bull Moose Gas Plant and the BM AGI #1 well are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**).

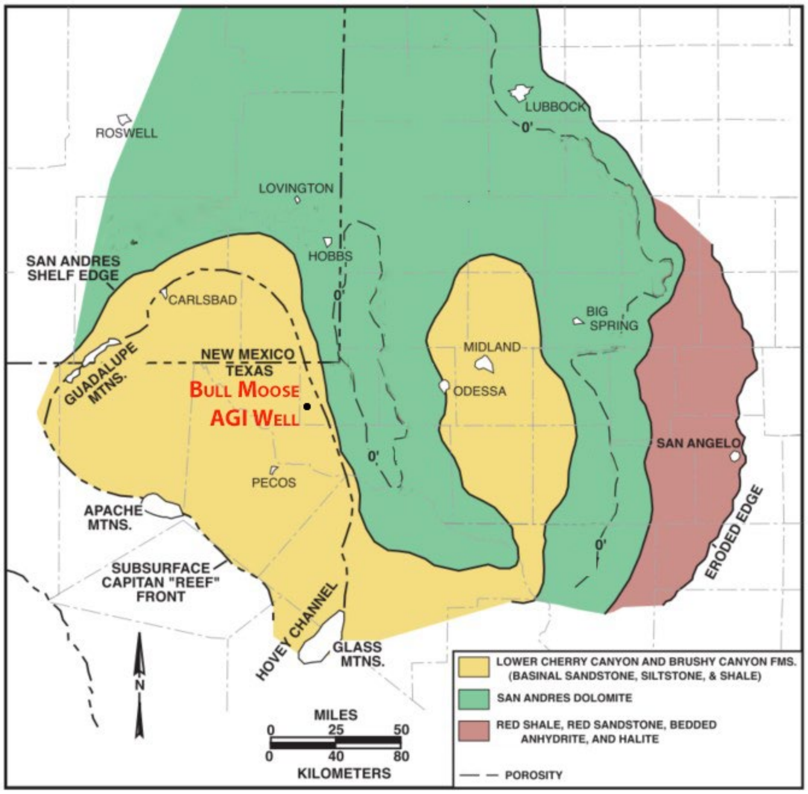


Figure 3.2-1: *Structural features of the Permian Basin during the Late Permian. Location of the Targa BM AGI well is shown by the black circle. (Modified from Ward, et al (1986))*

The BM AGI well is in the Delaware Basin portion of the broader Permian Basin. **Figure 3.2-2** is a generalized stratigraphic column showing the formations that underlie the Bull Moose Gas Plant and BM AGI #1 well site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below. Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit.

Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (with formation thickness varying from 0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit's overall porosity and permeability.

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

Figure 3.2-2: *Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

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

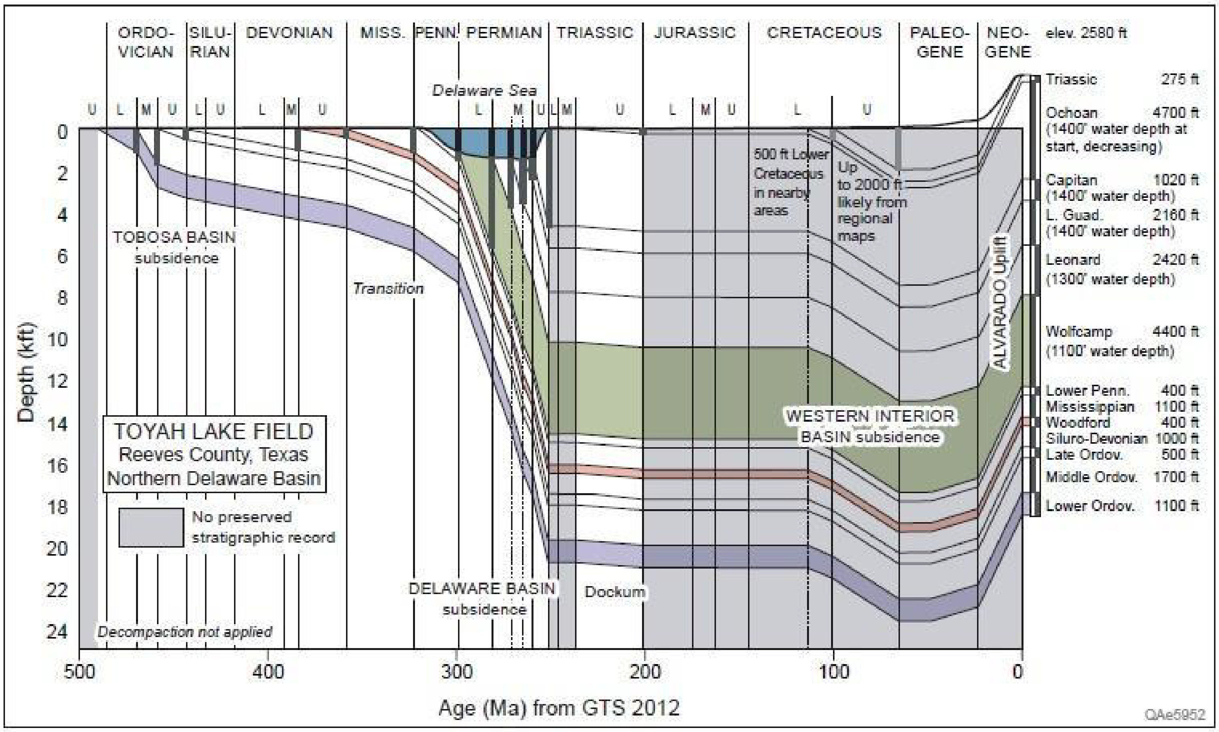


Figure 3.2-3: *A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

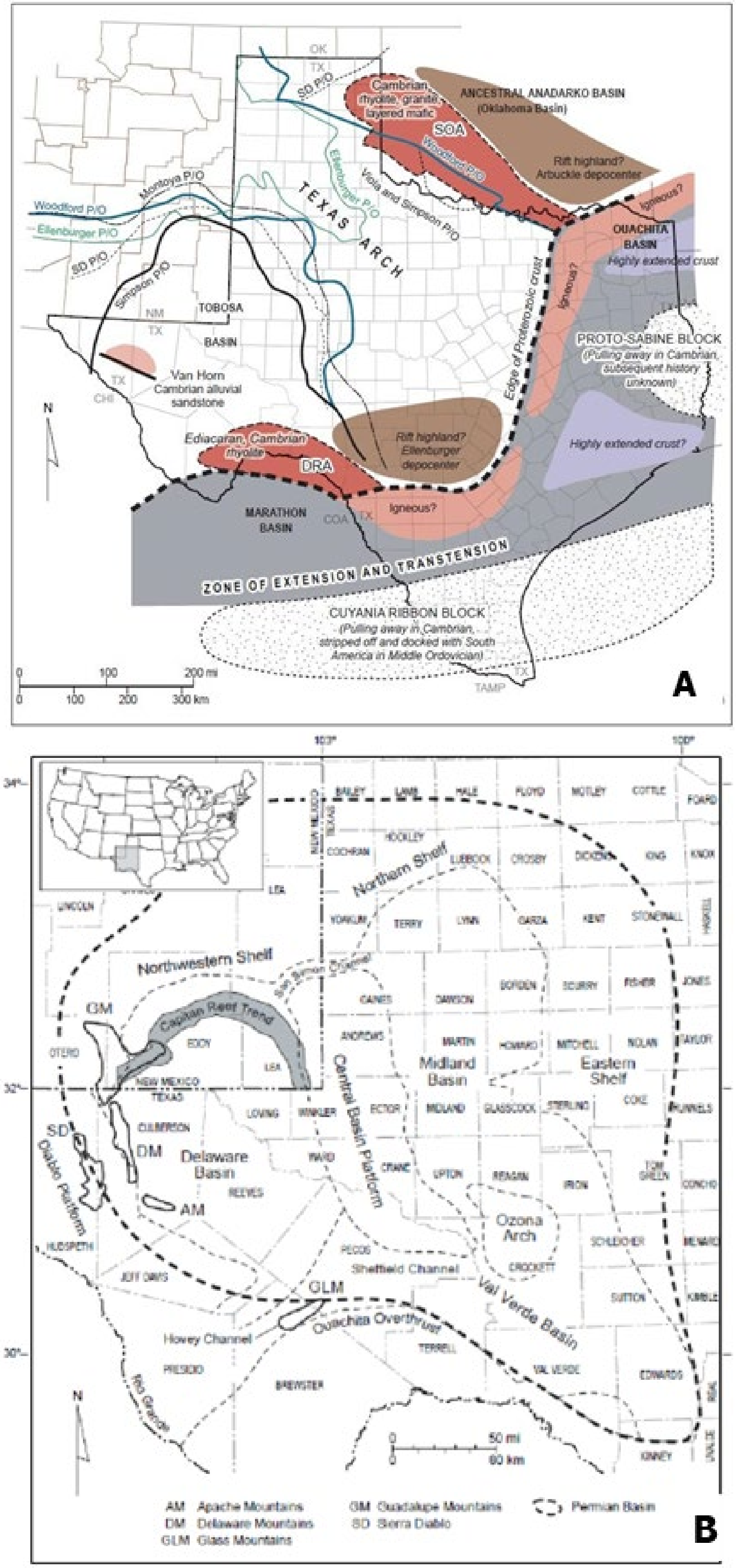


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

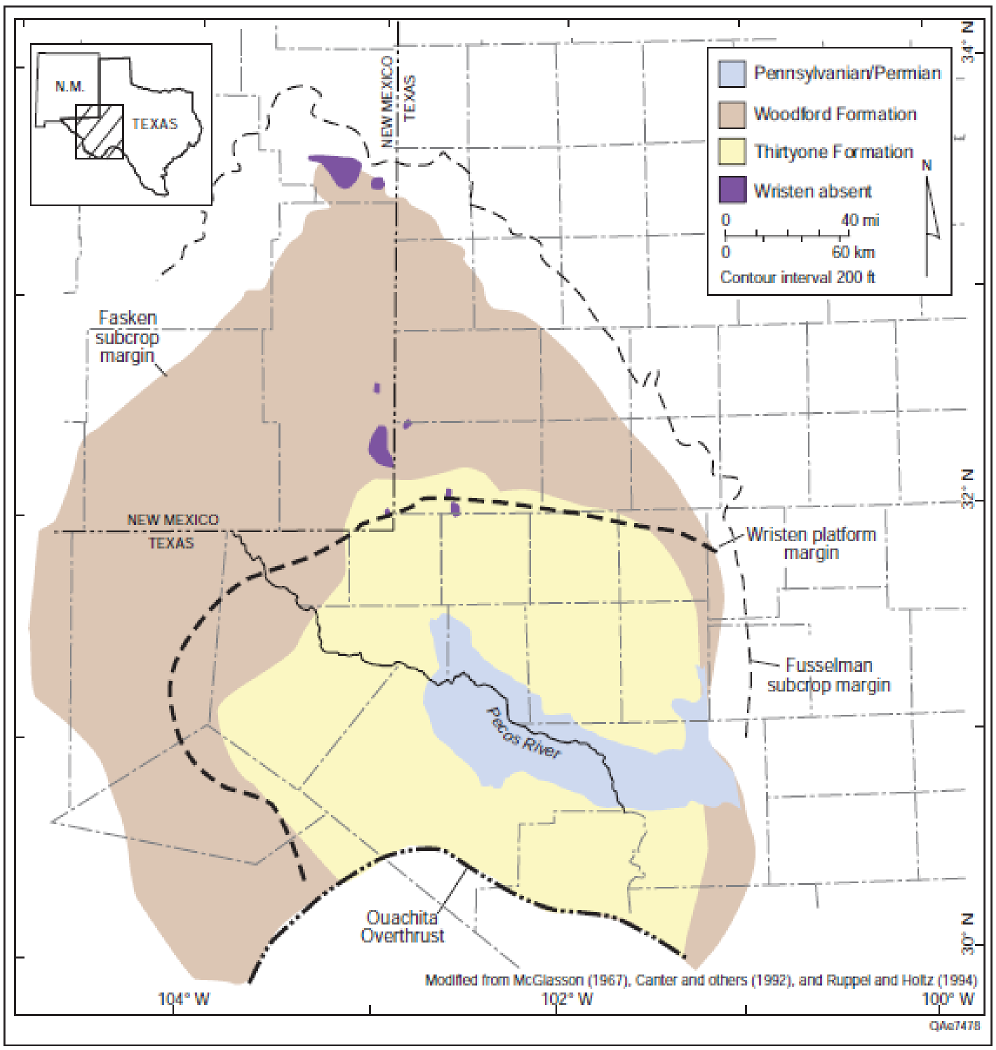


Figure 3.2-5: *A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial

exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

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

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian sediments include the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). In the area, the Atoka Formation (0-500 ft) was deposited during another sea-level transgression. is dominated by siliciclastic sediments, with depositional environments ranging from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

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

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued throughout

the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

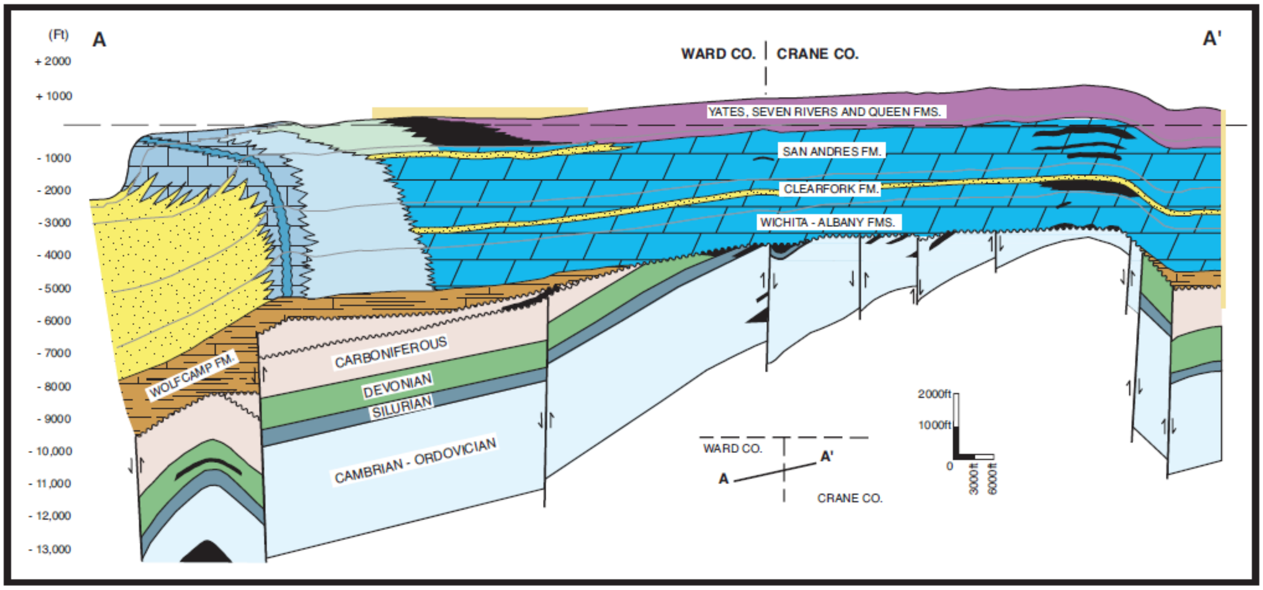


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

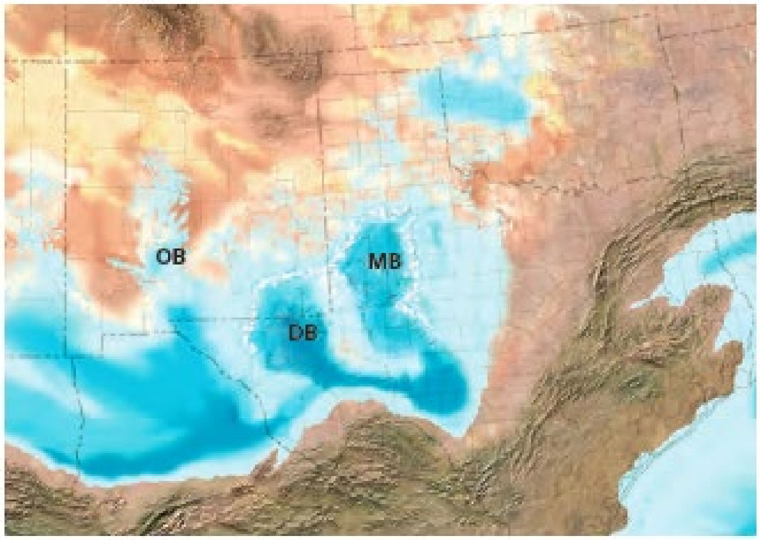


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a "carbonate factory" on the shelf and shelf edge. Carbonate debris beds shed off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s of feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso are the clean white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within

the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon formations.

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

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

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (Figure 3.2-2). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the Bull Moose AGI well, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Within the Bull

Moose area, there is no active production from the Permian Delaware Mountain Group, but there is production from the basinal Bone Spring and Wolfcamp formations. The injection and confining zones for BM AGI #1 are discussed below.

3.3 Injection Interval Properties

3.3.1 Siluro-Devonian to Ellenburger Group

In the context of BM AGI #1, the designated injection targets encompass the Siluro-Devonian formations, specifically the Devonian, Wristen, Fusselman and Montoya strata. The total thickness of the injection interval is estimated to be 1,594 ft (**Table 3.3-1**).

Table 3.3-1: *Estimated BM AGI #1 formation top depths, formation thicknesses, seal and reservoir thicknesses (total), and average porosity, and permeability.*

Formation	Measured Depth (ft)	Formation thickness (ft)	Unit Thickness (ft)	Porosity (%)	Permeability (mD)	Behaviour	Notes*
Rustler Fm.	934	255	4,165			Seal	450' base of useable groundwater
Salado Fm.	1,189	1,400		2.5	0.2	Seal	1200' base of USDW
Castile Fm.	2,589	2,510		1	0.01	Seal	
Lamar Ls.	5,099	45	3,990	15	100	Reservoir	
Bell Canyon Fm.	5,144	1,100		23	110	Reservoir	
Cherry Canyon Fm.	6,244	995		15	12	Reservoir	
Brushy Canyon Fm.	7,239	1,850		12	11	Reservoir	
Bone Spring Fm.	9,089	2,860	2,860	2	0.2	Seal	
Wolfcamp	11,979	1,600				Reservoir	Deepest nearby production wells
Strawn Fm.	13,579	760				Reservoir	
Atoka Fm.	14,339	215				Reservoir	
Morrow Fm.	14,554	1,795				Reservoir	
Barnett Sh.	16,349	440	1,540	1	0.1	3° Seal	
Mississippian Ls.	16,789	440		2	1	2° Seal	
Woodford Sh.	17,229	660		1	0.1	1° Seal	
Wristen Grp. And Thirtyone Fm.(Siluro Devonian)	17,889	289	1,594	5	1	Injection interval	
Fusselman Fm.	18,184	1,055		7	1	Injection interval	
Montoya Grp.	19,239	250		3	1	Injection interval	
Simpson Sands*	19,489	1,000		15	45	Not Drilled	
Ellenburger Grp.	20,489	550		6	15	Not Drilled	
Bliss/Precambrian	21,039					Lower seal	

*Simpson Sands consist of three discrete sand bodies (~300 ft of sands) within the over thousand-feet-thick unit.

ORDOVICIAN.

ELLENBURGER GROUP – The Ordovician Ellenburger Group is below the injection interval and is comprised of dolomites and limestones that are approximately 550 ft thick. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during later tectonic events (**Figure 3.3-1**).

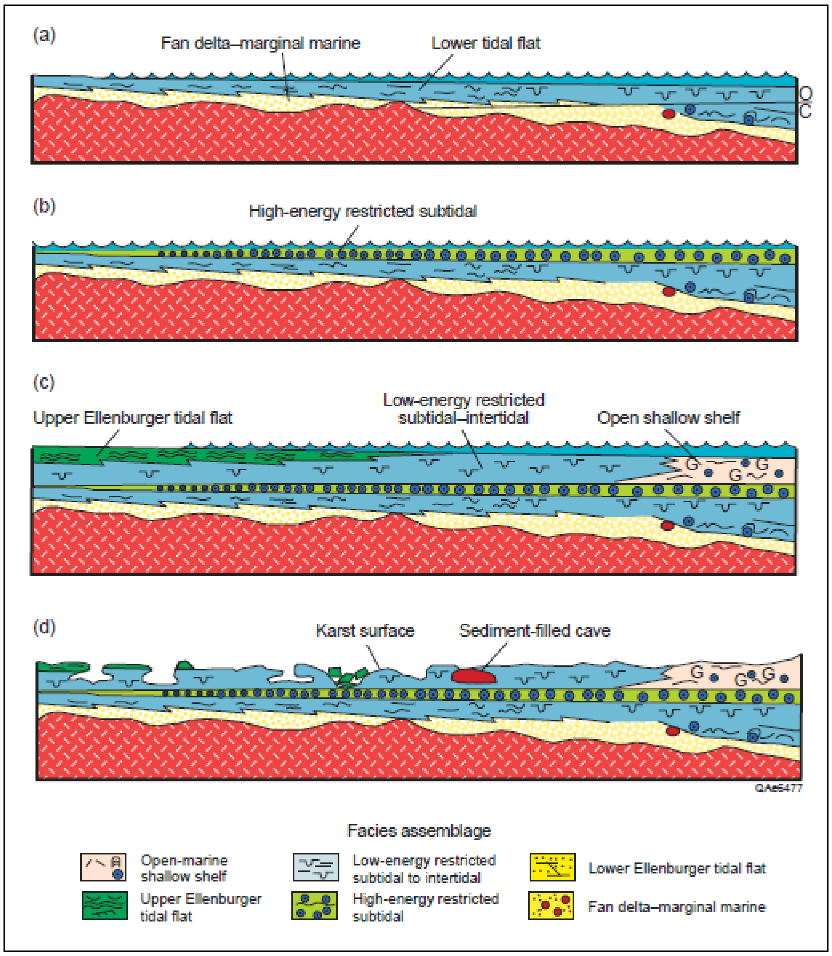


Figure 3.3-1: *Depositional model for Ellenburger Group deposits. The diagram shows a sequence of transgressive sandstones (Bliss Sandstone, yellow) to carbonates (Panels a through c followed by a regressive sequence (Panels c – d) with exposure and karstification in Panel d (from Loucks and Kerans, 2019).*

Within the Ellenburger Group strata, the upper and middle section typically has the highest porosity and permeability due to karsting and cave development as well as later faulting and fracturing (**Figure 3.3-2**). Late diagenesis plays an important role in porosity destruction and resurrection. Based on work by Loucks (2016, unpublished report), the best karst-related porosity is to the east of the Bull Moose area, whereas the Bull Moose area is in the zone of porosity due to tectonically controlled faulting and fracturing.

Porosity and permeability in the Ellenburger section can vary greatly due to the above considerations, but a realistic value for the porosity and permeability, at approximate 20,000 ft depth, is 5-6% and 15 mD (**Table 3.3-1**). Potentially the range of porosity and permeability can range up to 12% and greater than 100 mD (Loucks and Kerans, 2019).

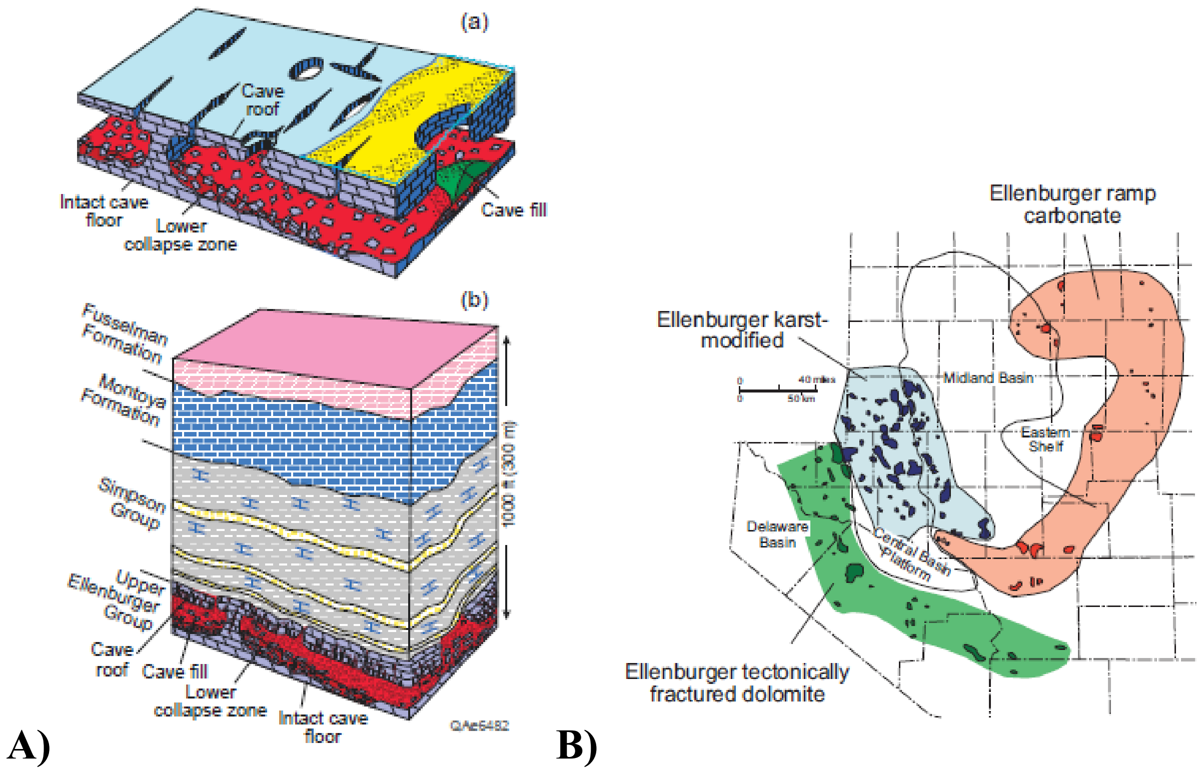


Figure 3.3-2: *Karst development.* ***A)*** *Cave development in the upper Ellenburger rocks and their potential impact to produce porosity and permeability (from Loucks and Kerans, 2019).* ***B)*** *Zones of potential porosity creation: karst related (blue), fault and fracture (green) and enhanced primary porosity (orange) (from unpublished manuscript by R. Loucks, 2016).*

SIMPSON GROUP – The deposits of the Simpson Group represent a regional transgression after the unconformity at the end of Ellenburger deposition. This group is a thick sequence of carbonates, sandstones, and shales (~1,000 ft) which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. There are several transgressive/regressive cycles within the section, but only the transgressive sandstone sections have significant porosity. The rest of the section typically consists of mud-rich carbonates and shales. Within the sandstones (particularly the McKee Sandstone member), well logs indicate porosity averages around 15% (**Table 3.3-1**). Permeability averages 45 mD (Harrington, 2019), though cementation and compaction may decrease that in the area.

MONTOYA GROUP – The Montoya deposits (~250 feet) are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin (**Figure 3.3-3**). Like the Ellenburger Group, the porosity within the Montoya Group is dependent on depositional environment and diagenesis. Sediments deposited in higher energy environments tend to have better initial porosity than those of low-energy environments. Compaction destroys porosity, while dolomitization produces

secondary porosity and local interactions of these factors determine porosity and permeability in a given area. Based on well logs, the average porosity is approximately 3%, with scattered zones over 5% (**Table 3.3-1**). The probable average permeability is probably less than 1 mD, but fracturing may enhance it.

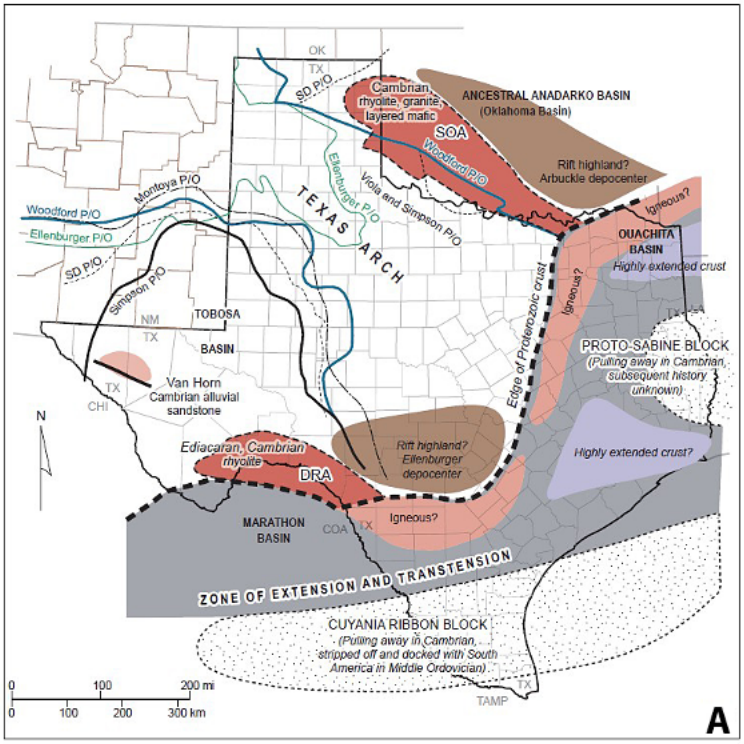


__Figure 3.3-3:__ Tectonic features during development of the Tobosa and Permian Basins during Late Mississippian time (Ewing, 2019).

ORDOVICIAN – SILURIAN.

FUSSELMAN FORMATION – The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Bull Moose area, the Fusselman thickens to around 1,000 ft of high-energy packstones to grainstones. Like the Montoya Group, these high-energy sediments started out with the best primary porosity, but diagenesis usually has decreased both the porosity and permeability unless impacted by exposure and dissolution. Based on well logs, the porosity averages around 2%, but there are zones, like in well API No. 42-495-31047, with over 70 ft of greater than 5% porosity. Reported permeability for shallower sections range from 0.001 to 10 mD (Ruppel, 2019).

LOWER DEVONIAN – SILURIAN.

THIRTYONE AND WRISTEN FORMATIONS – Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section (~275 ft thick). Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Bull Moose area. These deposits range from deeper ramp mudstones and wackestones, to chert- and sponge/radiolarian-rich hemipelagic mudstones (Wristen/Thirtyone) to outer ramp packstones (**Figure 3.3-4**, Thirtyone; Ruppel, 2020; Ruppel et al., 2020a). Porosity and permeability in the Wristen are limited in the main body of the unit (1-2%), but exposure events and carbonate dissolution can improve the porosity (~5%). Within Thirtyone deposits, the chert-rich hemipelagic

deposits maintain the best porosity (up to 40%, up to 80 mD), while the limestones have less than 7% porosity and less than 1 mD of permeability (**Table 3.3-1**; Ruppel et al., 2020a).

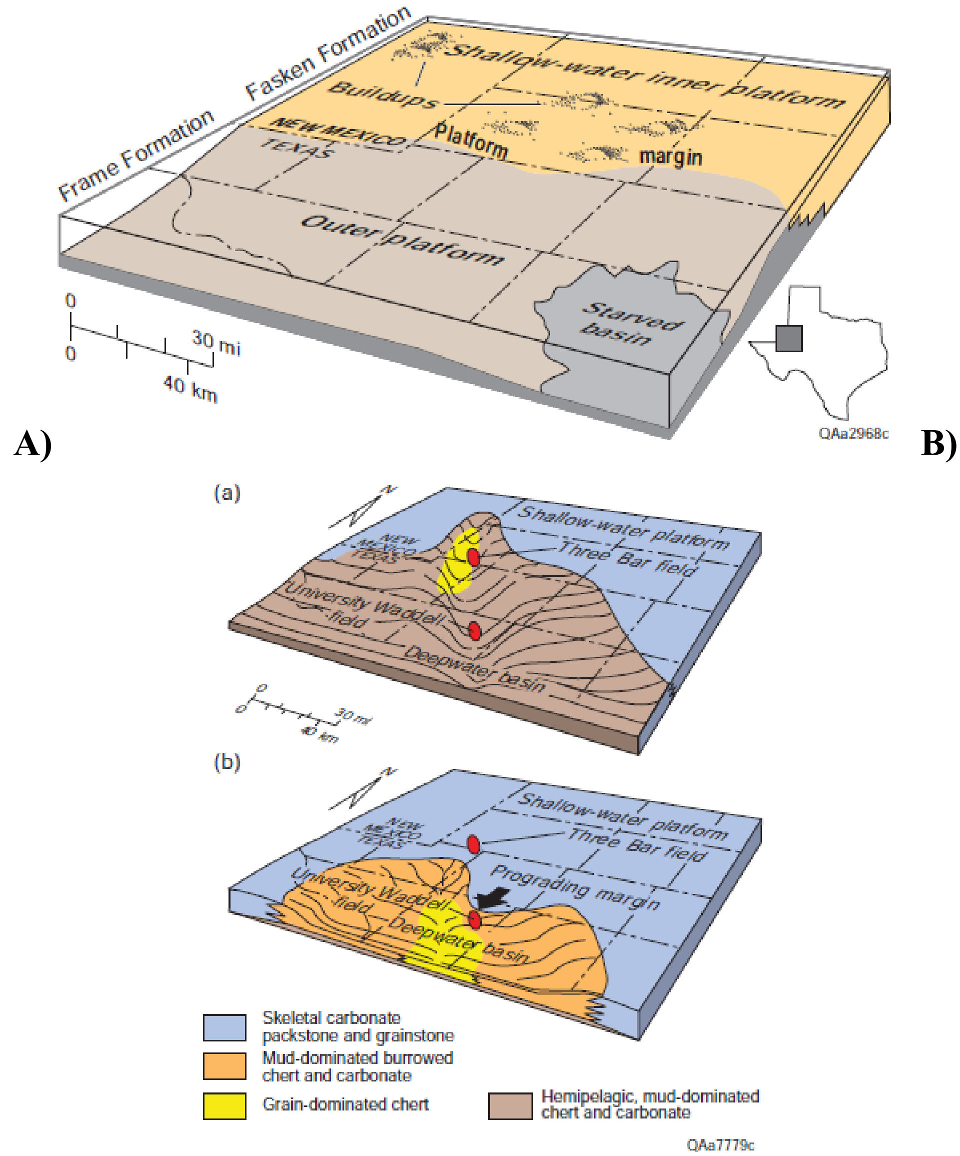


Figure 3.3-4: *Generalized Paleogeography.* ***A)*** *Generalized paleogeography for the Wristen Group (from Ruppel, 2020).* ***B)*** *Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Bull Moose area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

3.3.2 Upper Confining Zone Properties: Woodford Shale/Mississippian Limestone

Mississippian. Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 ft thick in the Bull Moose area and is regionally extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is ~555 ft thick. Known production from this limestone comes from small, one to two well fields that normally have poor porosity (4-9%) and permeability (Broadhead, 2017)

in New Mexico and a few isolated fields in the shallow water, high-energy limestones in Texas. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is ~750 ft thick. Overall, Mississippian units would be good seals in preventing upward fluid movement through the section (**Table 3.3-1**).

Upper Devonian. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units. In combination with the Mississippian section, it makes an excellent seal for potential injection. the Woodford Shale is ~620 ft thick in the Bull Moose area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. Porosity in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). Porosity can reach 10% (Jarvie et al., 2001), but it averages around 1% with very low permeabilities (**Table 3.3-1**).

3.3.3 Lower Confining Zone Properties: Ordovician to Precambrian

Ordovician. The lower approximately 150 to 200 ft of the Ellenburger Group sediments are normally less porous and have lower permeability (1 – 2% porosity and <2 mD) due their original depositional environment and the depth of burial (Loucks and Kerans, 2019), making this zone a potential underlying seal.

Cambrian to Precambrian. The oldest sediment in the area is Cambrian Bliss Sandstone (Broadhead, 2017) which overlies Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland. With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Bliss Sandstone and crystalline Precambrian rocks are potential lower seals. Within the Bull Moose area, no porosity and permeability data could be found. Considering their depth, compactional history, and potential diagenetic alteration, the Bliss sandstones and associated granitic debris (from weathering of the basement rock) are probably relatively tight.

3.4 Structure/Faulting

Structure maps and cross sections for the injection interval and confining zones are provided in **Figures 3.3-5** through **3.3-15**.

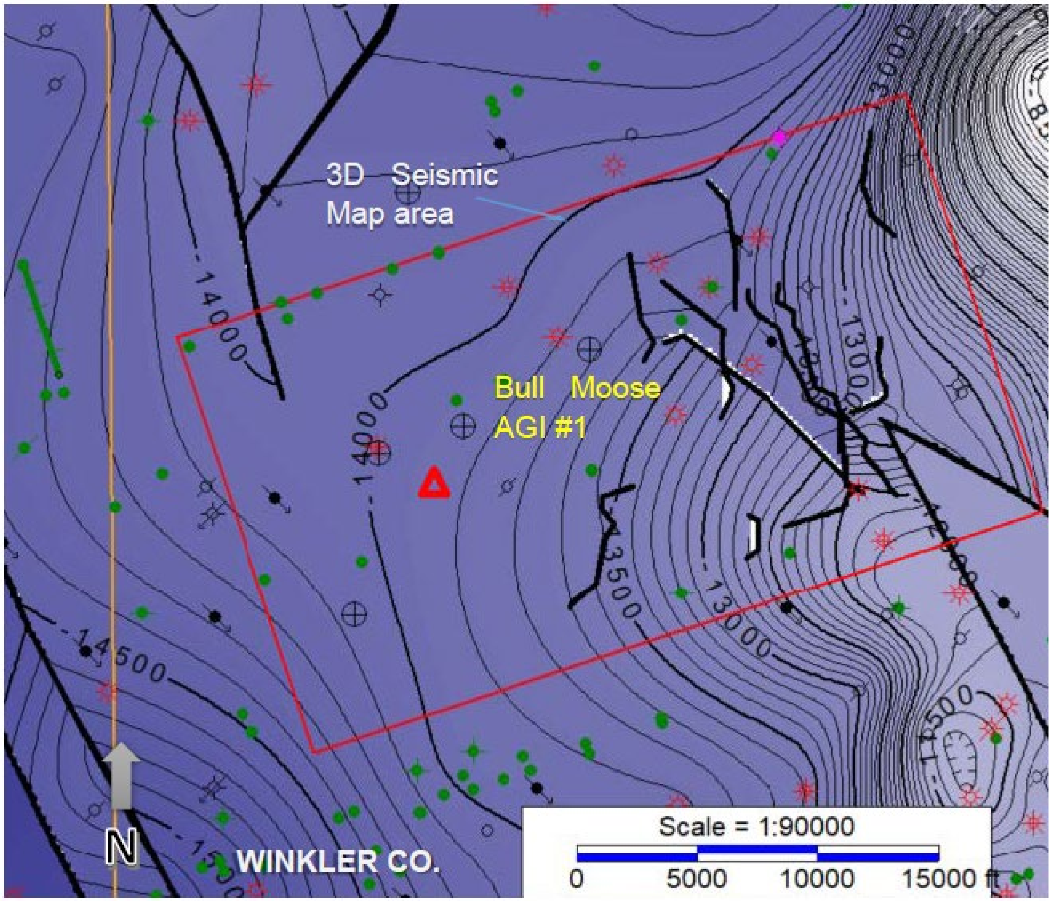


Figure 3.3-5: Mississippian Limestone Subsea Structure Map. CI = 100 ft.

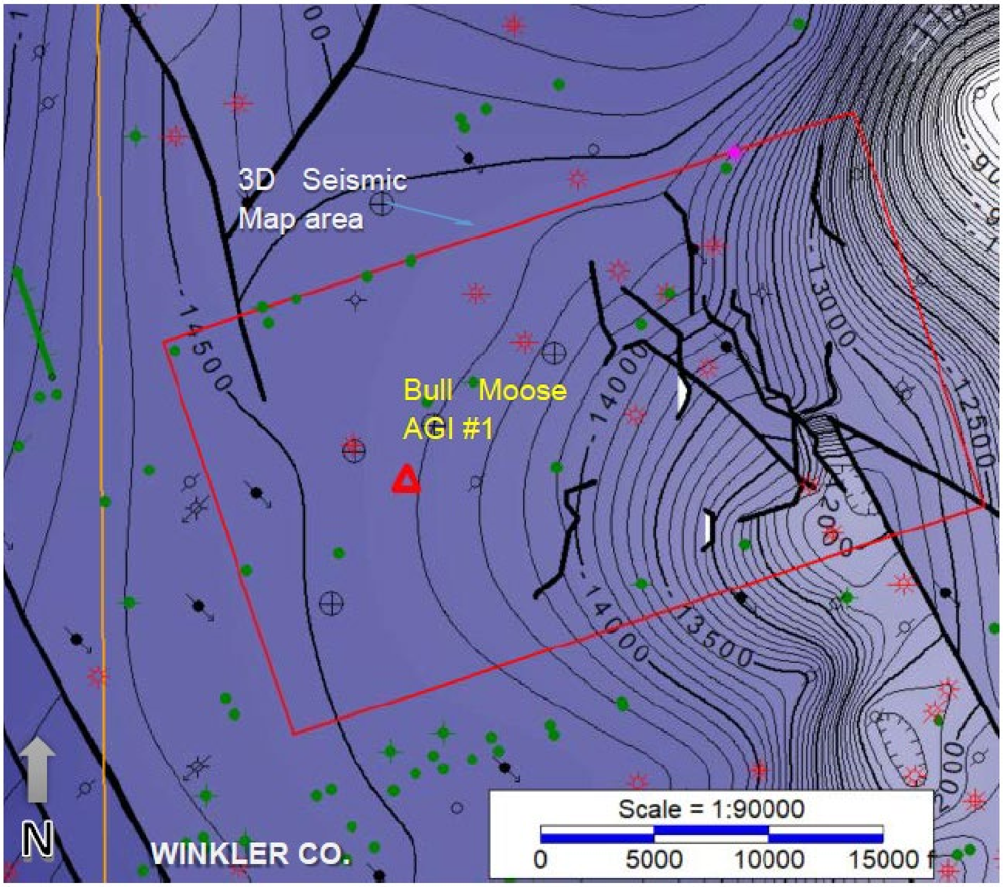


Figure 3.3-6: Woodford Shale Subsea Structure Map. CI = 100 ft.

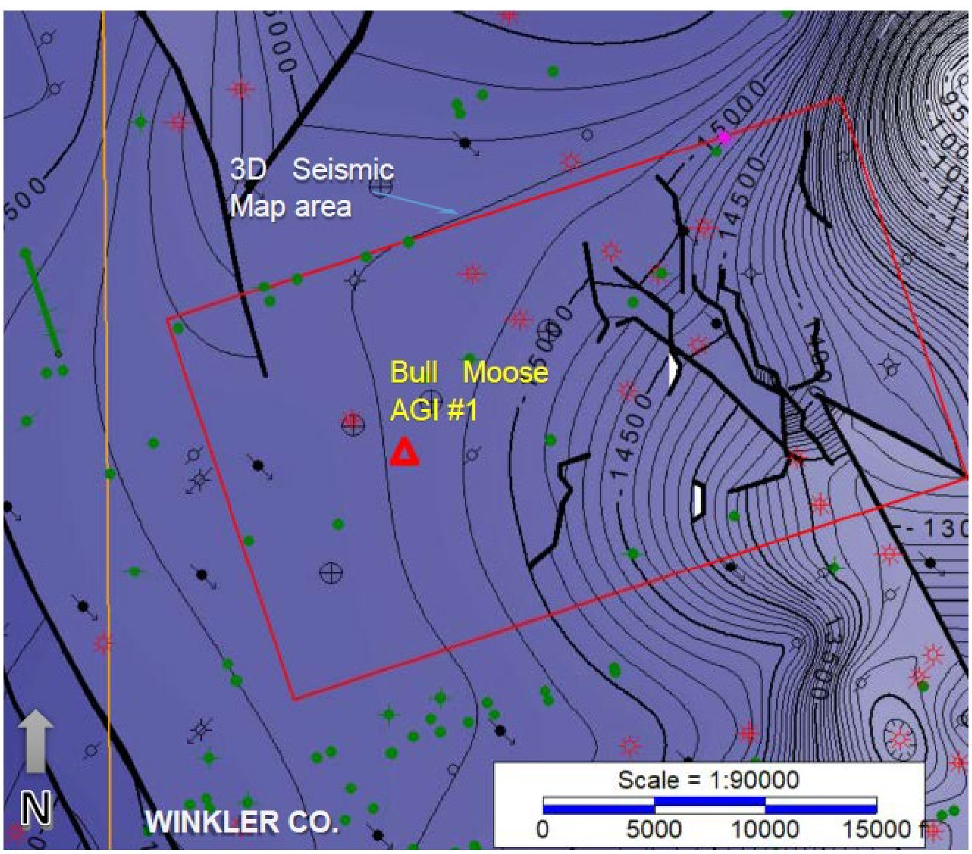


Figure 3.3-7: Siluro-Devonian Strata Subsea Structure Map. CI = 100 ft.

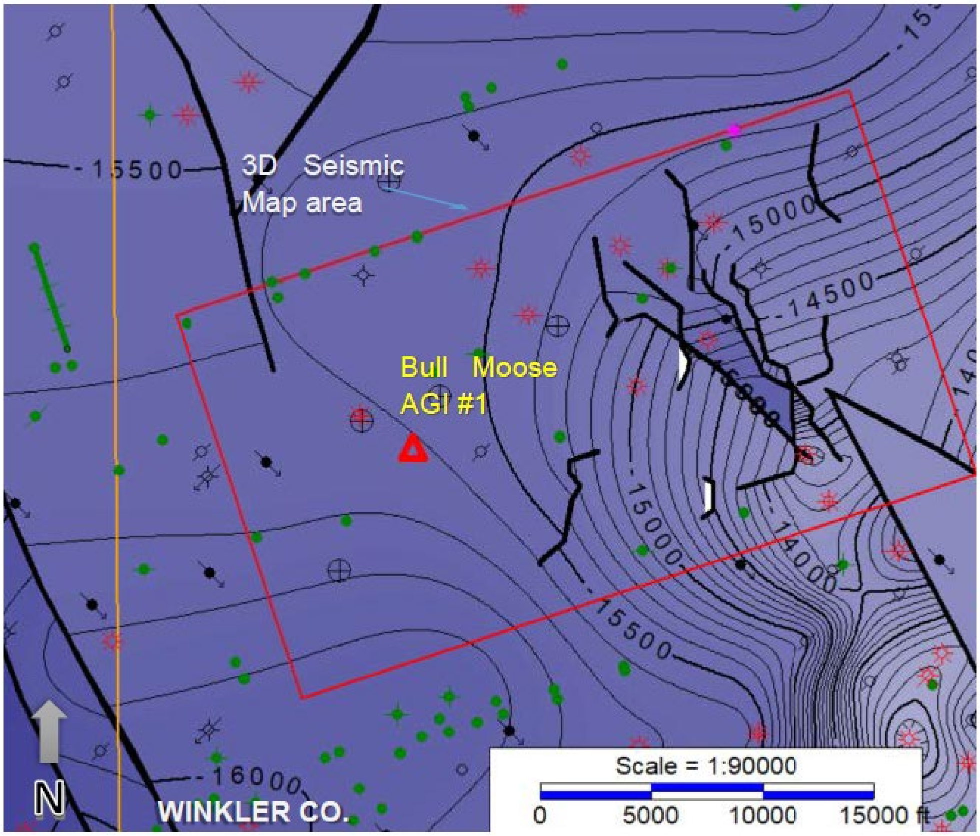


Figure 3.3-8: Fusselman Formation Subsea Structure Map. CI = 100 ft.

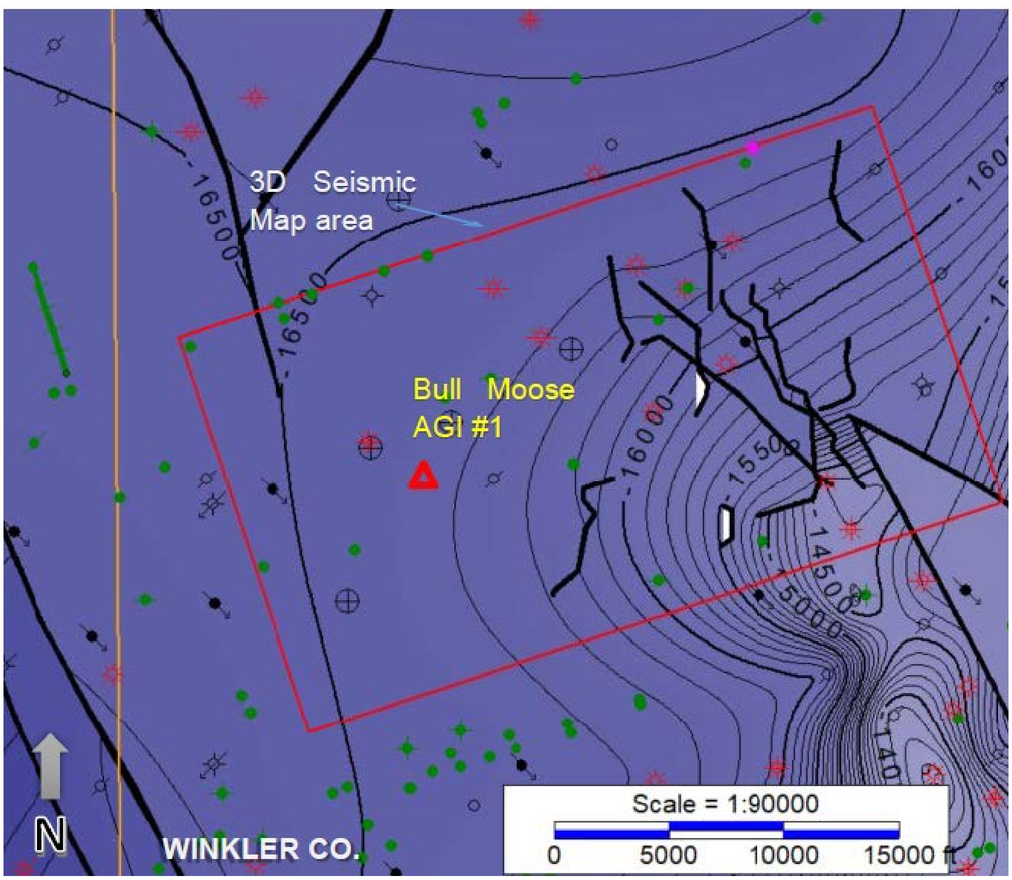


Figure 3.3-9: Montoya Group Subsea Structure Map. CI = 100 ft.

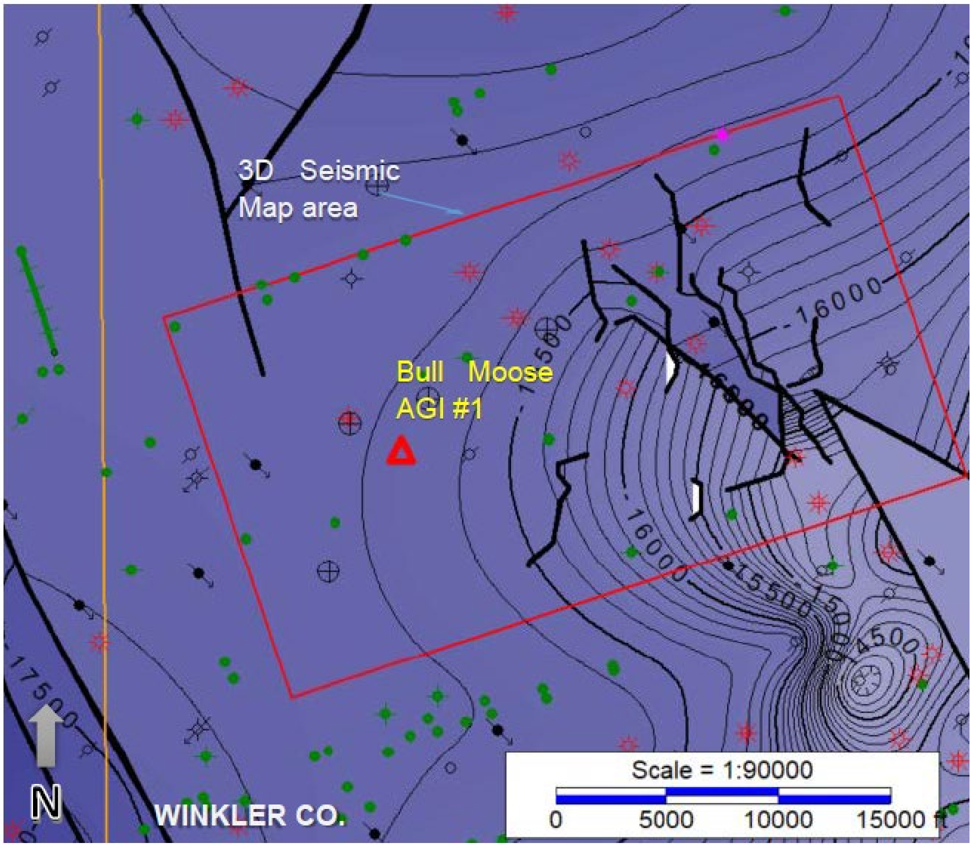


Figure 3.3-10: Simpson Group Subsea Structure Map. CI = 100 ft.

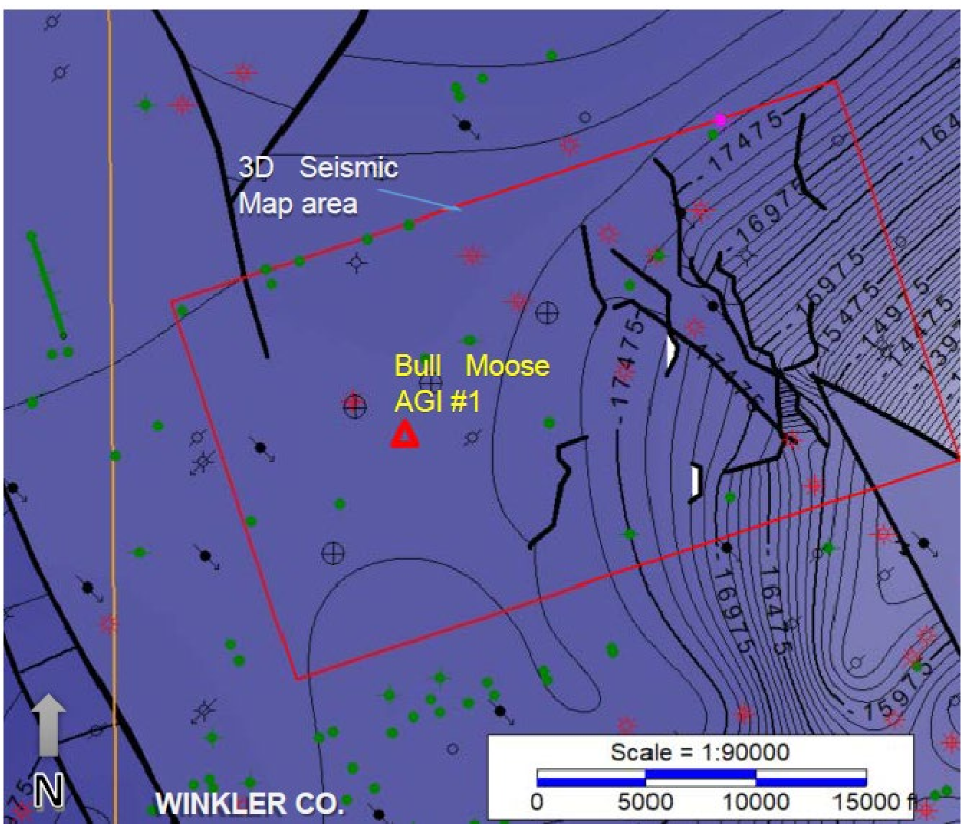


Figure 3.3-11: Ellenburger Group Subsea Structure Map. CI = 100 ft.

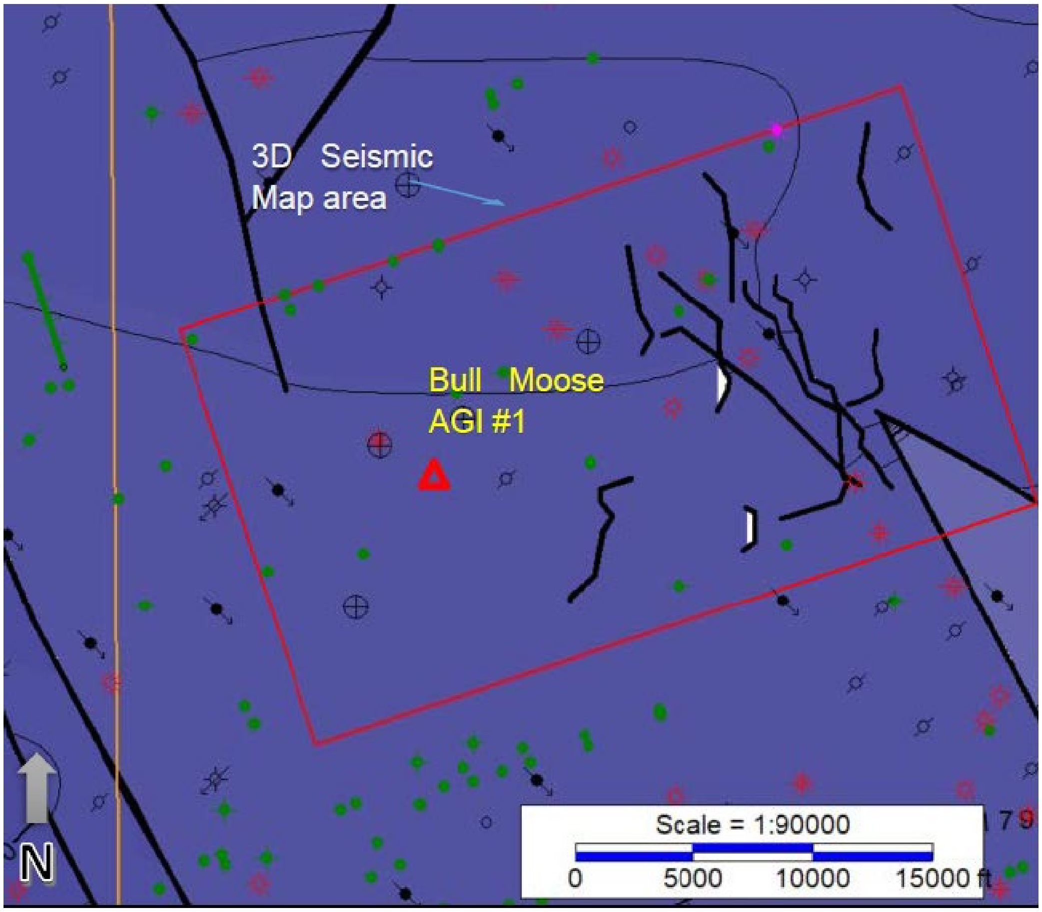


Figure 3.3-12: Precambrian Subsea Structure Map. CI = 100 ft.

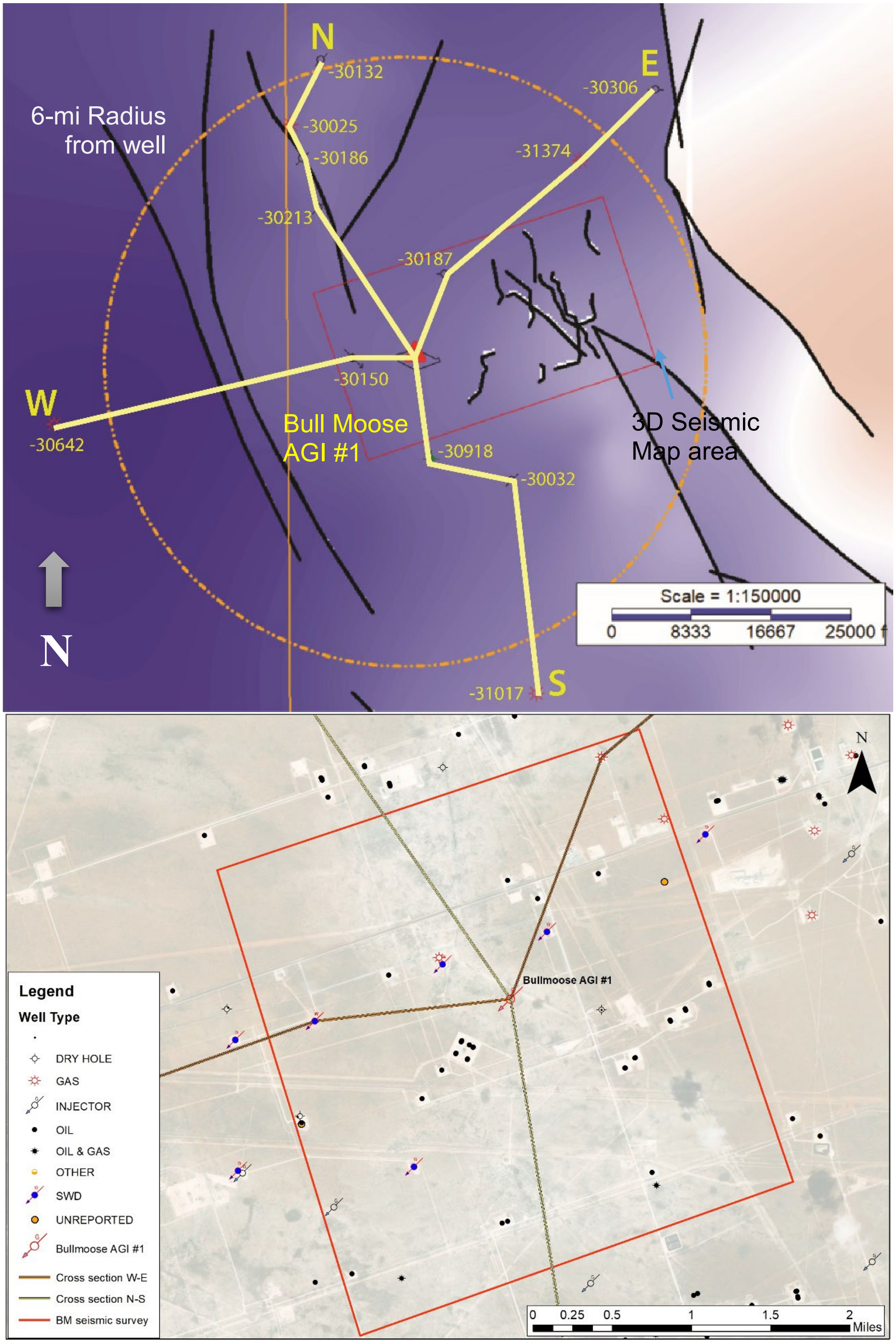


Figure 3.3-13: Base Map for Cross Sections

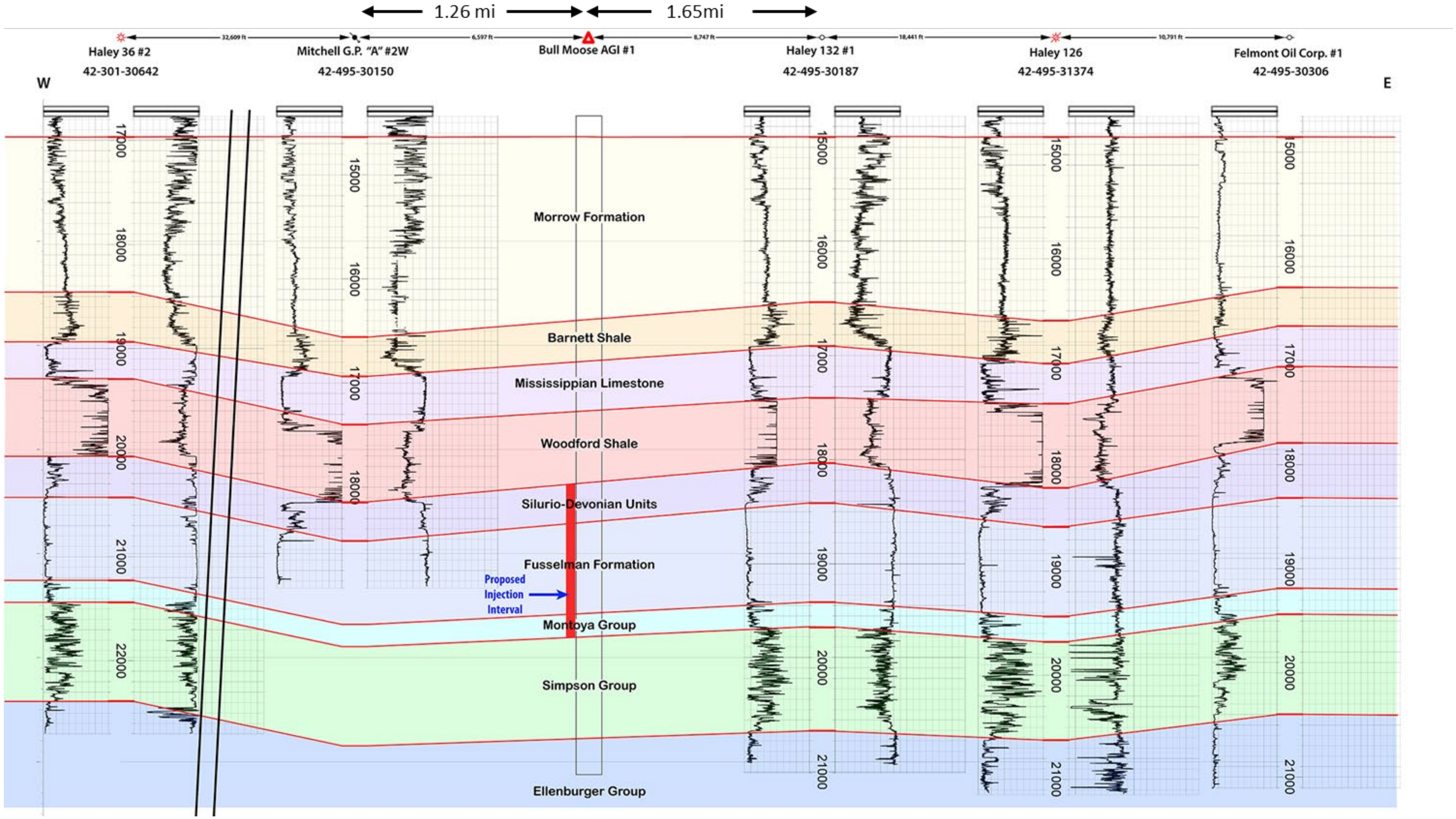


Figure 3.3-14: West to East Cross Section

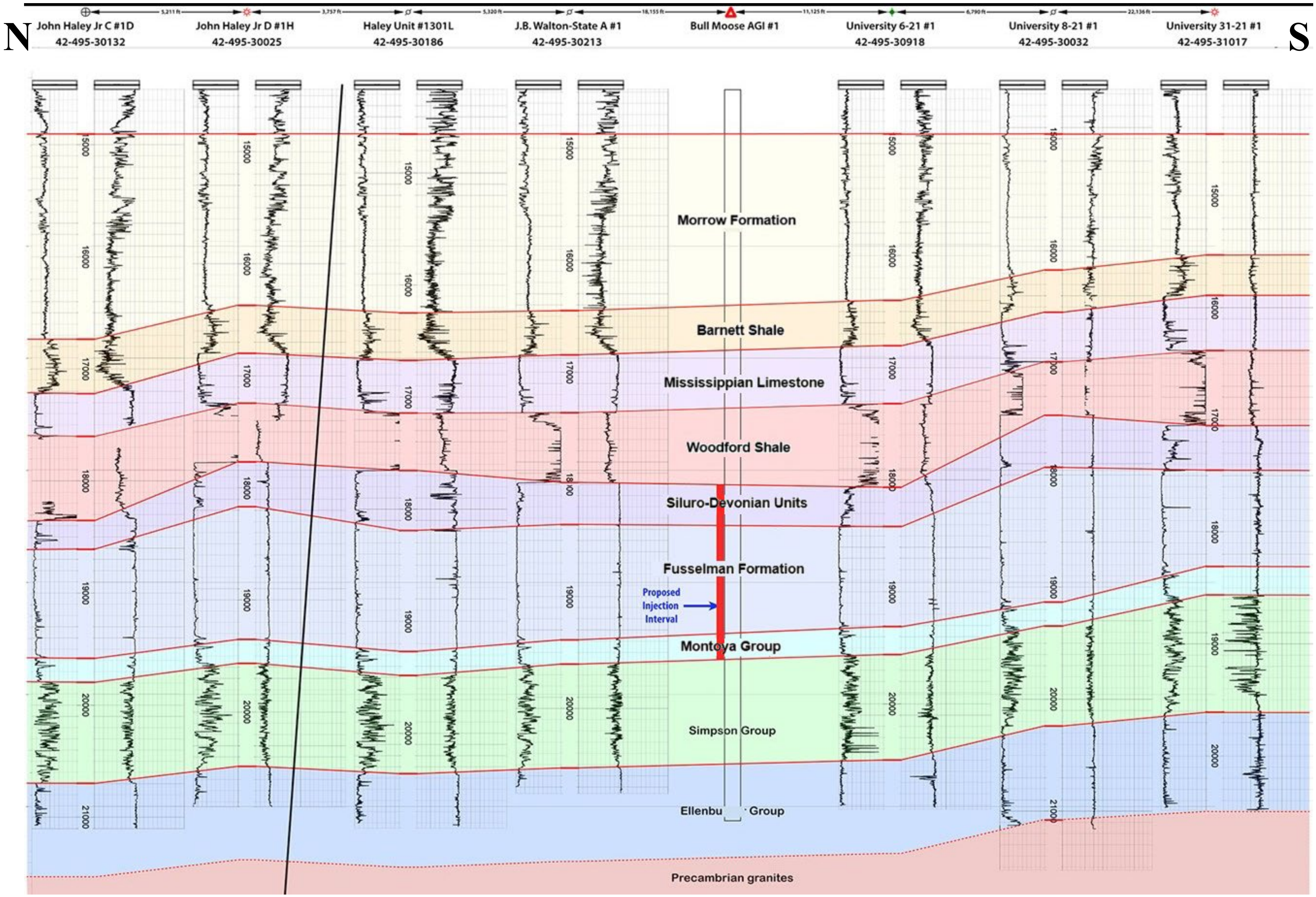


Figure 3.3-15: North to South Cross Section

3.5 Formation Fluid Chemistry

Water data was retrieved from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 (05/22/2019) to determine formation chemistry in the Siluro-Devonian, Fusselman, and Montoya injection intervals for BM AGI #1. Chemical data was plotted in a geographical interface and delineated to a 15-mile boundary around the Bull Moose site to fully constrain each formation's geochemical signature.

There are 12 wells with analyses collected from the Siluro-Devonian, Fusselman, Montoya, and Simpson formations within 15 miles of BM #1 (red squares **Figure 3.5-1).** Samples taken in these formations generally fall within a saline (NaCl) hydrofacies, and concentrations of total dissolved solids (TDS) range from 69,140 to 341,260 milligrams per liter (mg/L) with an average of 140,024 mg/L. High salinity in these formations indicate they are compatible with injection (**Table 3.5-1**).

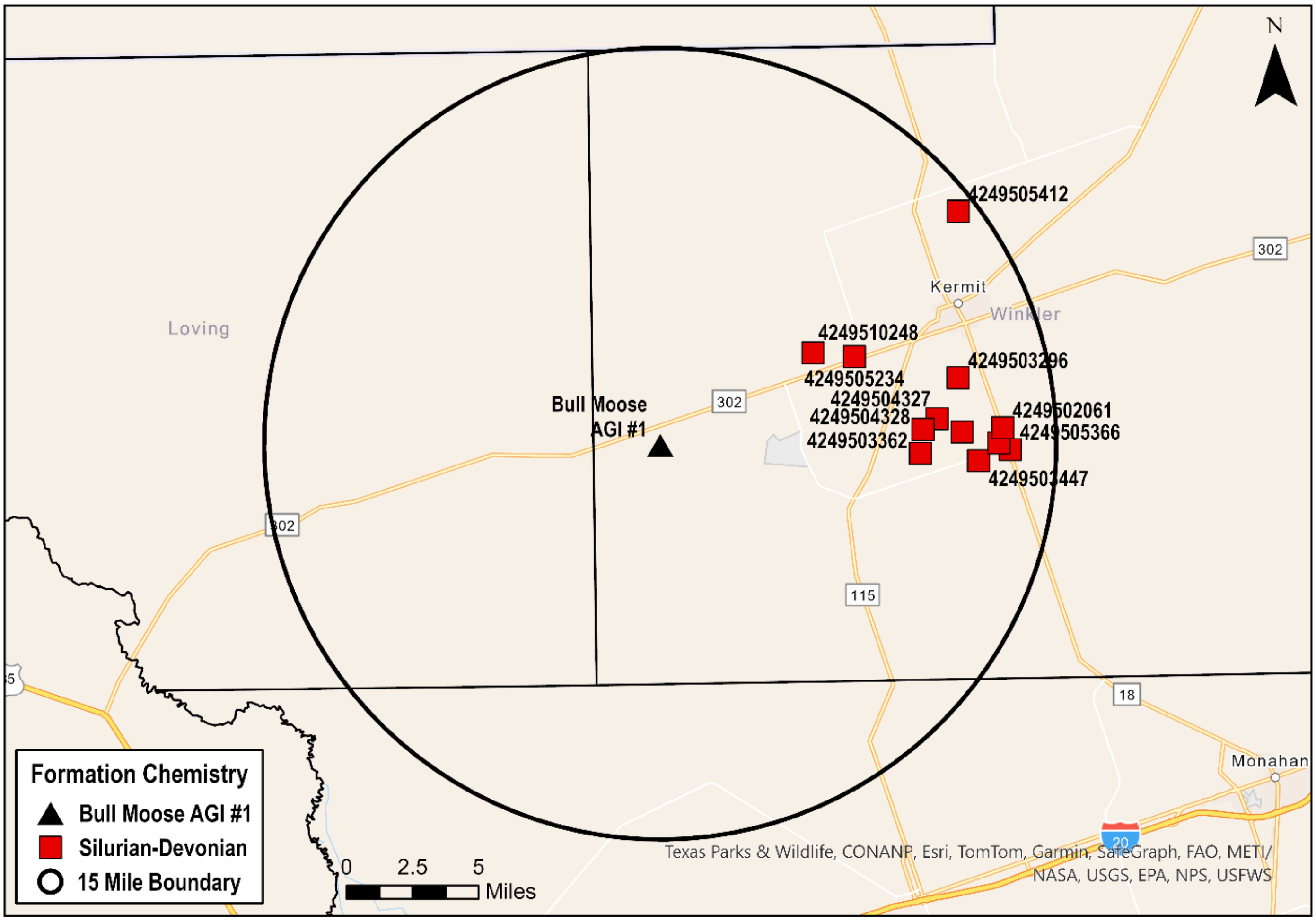


Figure 3.5-1: *Wells with water chemistry in the Silurian, Fusselman, or Devonian formations within 7 to 15 miles of the Bull Moose AGI well from the U.S. Geological Survey National Produced Waters Geochemical Database. Data show these formations are NaCl waters with average TDS of 140,024 mg/L.*

Table 3.5-1: *Water chemistry in mg/L for wells in the Silurian, Fusselman, or Devonian formations within ≈7 to 15 miles of BM AGI #1 from the USGS National Produced Waters Geochemical Database.*

API	Latitude	Longitude	Formation	HCO_3	Ca	Mg	KNa	Cl	SO_4	TDS
4249503296	31.8171	-103.0914	Devonian	1,347	12,410	1,799	10,290	40,390	2,904	69,140
4249503296	31.8171	-103.0914	Devonian	97	14,610	4,052	36,590	92,530	2,480	150,359
4249503296	31.8171	-103.0914	Devonian	145	14,510	4,163	36,590	92,830	2,520	150,758
4249503296	31.8171	-103.0914	Devonian	80	14,610	4,153	36,790	92,830	2,500	150,963
4249503296	31.8171	-103.0914	Devonian	122	14,600	4,028	37,050	92,940	2,437	151,177
4249503362	31.7759	-103.1165	Devonian	352	10,780	2,806	6,470	36,010	1,403	57,821
4249503447	31.7713	-103.0791	Devonian	635	2,900	300	35,500	60,000	475	99,810
4249505366	31.7771	-103.0587	Devonian	151	11,804	2,578	59,112	118,202	1,703	193,550
4249500556	31.7808	-103.0659	Fusselman	362	4,232	881	29,090	53,850	2,857	91,273
4249502061	31.7892	-103.0632	Fusselman	148	6,960	4,440	118,800	208,800	2,112	341,260
4249504327	31.7947	-103.1054	Fusselman	458	4,244	706	29,620	53,810	1,568	90,406
4249504328	31.789	-103.1145	Fusselman	427	4,236	1,016	45,650	78,800	2,420	132,549
4249505210	31.7873	-103.0894	Fusselman	849	10,640	945	24,780	59,440	460	97,114
4249505412	31.9086	-103.0894	Fusselman	202	1,733	536	48,589	73,421	4,400	128,881
4249510248	31.8322	-103.1845	Fusselman	706	499	386	91,284	139,300	4,317	236,491
4249505234	31.8297	-103.1579	Silurian	327	4,758	962	31,960	59,200	1,625	98,832

3.6 Groundwater Hydrology in the Vicinity of the Bull Moose Gas Plant

Regionally, groundwater near the BM AGI #1 site is drawn from one of five sources. From shallow to deep those are Quaternary-Late Tertiary Pecos Valley Deposits, Cretaceous sediments of the Edwards-Trinity Groups, Triassic deposits of the Dockum Group, the Permian (Oochan) aged Rustler Formation, and the Permian (Guadalupian) aged Capitan Reef Complex. Based on current water data with the Texas Water Development Board (TWDB), the primary groundwater sources at the site are the Pecos Valley Alluvium and the Dockum Group (**Figure 3.6-1**). Below we provide a general description of the groundwater sources and the wells within the MMA at the BM AGI #1 site.

3.6.1 Pecos Valley Aquifer

The Pecos Valley Aquifer lies unconformably on portions of the Edwards-Trinity Plateau, Dockum, Rustler, and Capitan Reef aquifers. It covers an area of 6,829 mi^2 and is comprised of sediments that range in size from clay to boulder which were deposited in a variety of continental settings including fluvial, valley-fill, eolian, lacustrine, and solution-collapse environments (Wise et al., 2012). Sediments of the Pecos Valley Aquifer fill several structural basins, the largest of which are Monument Draw Trough in the east and the Pecos Trough in the west. Maximum thickness of the alluvial fill reaches approximately 1,500 ft, and freshwater saturated thickness averages around 250 ft (George et al., 2011).

The water quality is highly variable, with the water typically being hard, and generally better in the Monument Draw Trough than in the Pecos Trough. Total dissolved solids have been found to range from 116 to over 15,000 mg/L depending on location and proximity to oil and gas or halite mining operations in the region (Wise et al., 2012). The aquifer is generally characterized by high levels of sulfate and chloride in excess of secondary drinking water standards which has been linked to previous oil field activities. Also, naturally occurring radionuclides and arsenic can be found in excess of primary drinking water standards (George et al., 2011). More than 80 percent of Pecos

Valley groundwater is used for irrigation, while the remainder is used for municipal supplies, power generation, and industrial use.

3.6.2 Dockum Aquifer

The Upper Triassic Dockum Group covers about 96,000 square miles in parts of Kansas, Oklahoma, Colorado, New Mexico, and Texas. From young to old the Dockum includes the Santa Rosa and Tecovas formations, the Trujillo Sandstone, and the Cooper Canyon Formation. These formations consist of conglomerate, gravel, sandstone, siltstone, mudstone, and shale with recoverable quantities of groundwater located in the sandstone and conglomerate. The largest yields are typically found in the coarsest deposits in the middle and base of the group. Locally any water-bearing sandstone of the Dockum Group is referred to as the Santa Rosa Aquifer (Bradley and Kalaswad, 2003; 2004; George et al., 2011).

Water quality in the Dockum Aquifer varies, ranging from fresh (TDS <1,000 mg/L) on outcrop to brine (TDS >10,000mg/L) where it is confined, typically deteriorating with depth. TDS concentrations have been found to be >60,000 mg/L in the deepest parts of the aquifer. Groundwater in the Dockum aquifer is typically hard, average of 470 mg/L, and radionuclides naturally derived from uranium can be found at concentrations a >5 pCi/L in many areas of the aquifer (Bradley and Kalaswad, 2003; 2004). Locally, the Dockum Aquifer can be vital for irrigation, public supply, livestock watering, manufacturing, and oil-field activity. However, a combination of deep pumping depths, low yields, poor water quality, and declining water levels have hindered a more widespread use (Bradley and Kalaswad, 2003).

3.6.3 Groundwater Wells Within the Bull Moose AGI Site MMA

Data collected from the Texas Water Development Board's (TWDB) Groundwater Database and Submitted Driller Report Database indicate there are 2 freshwater wells located within the MMA for BM AGI #1. Both wells are permitted for domestic use and are shallow, collecting water from 152 to 245 ft depth in Pecos Alluvium and Triassic redbeds of the Dockum Group (Garza and Wesselman, 1963; Ashworth, 1990; Bradley and Kalaswad, 2003; **Table 3.6-1**). General chemistry analysis of one well within the MMA indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L (**Table 3.6-2**). The shallow freshwater aquifers are protected by the surface and intermediate casings and cements in the BM AGI #1 well. While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

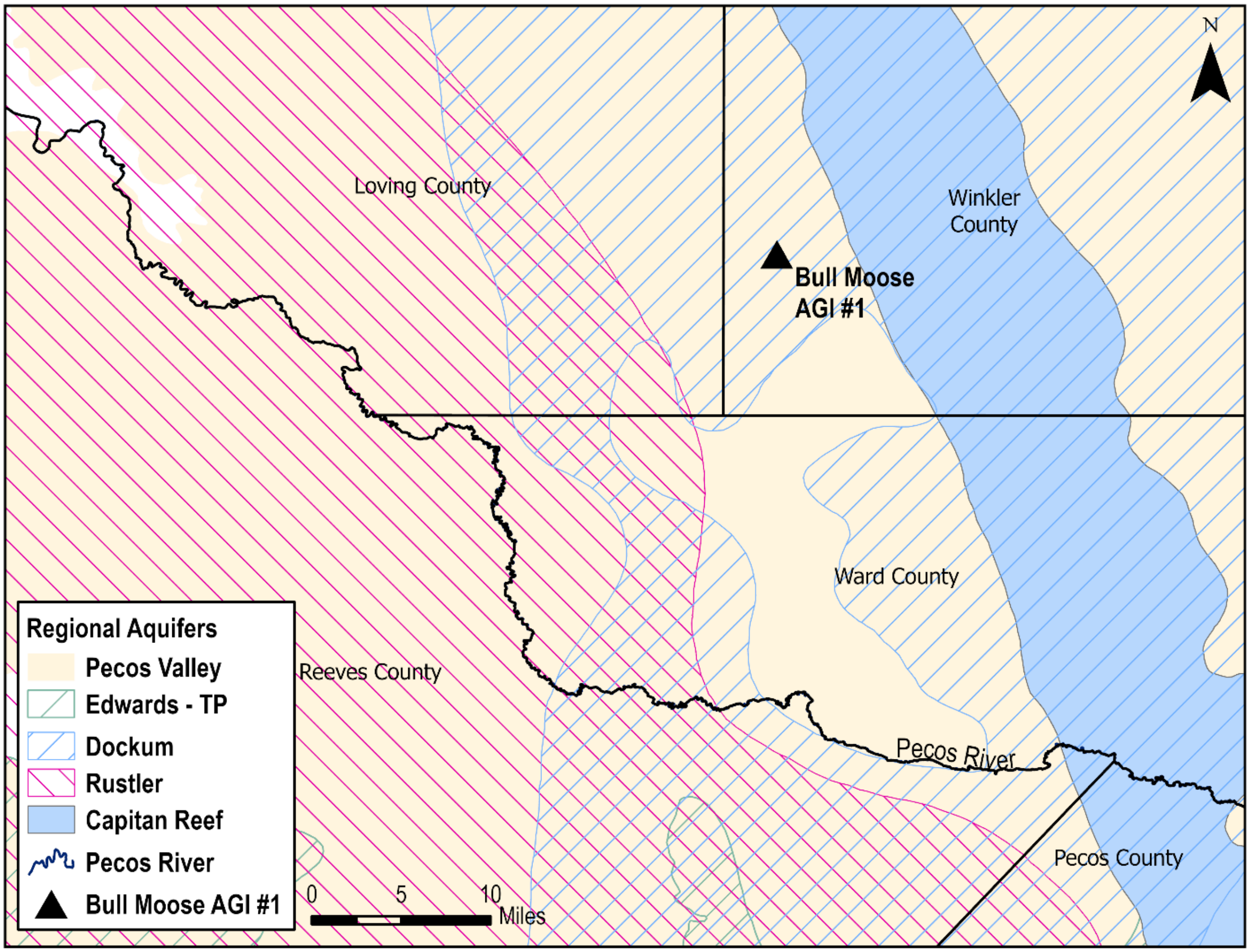


Figure 3.6-1: *Major and minor aquifers of the region. Groundwater at the proposed site is derived from the Pecos Valley Alluvium and Dockum Group.*

Table 3.6-1: *Groundwater wells within the MMA of the Bull Moose AGI site with from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database. Well depth is from 152 to 245 ft. and used for domestic purposes.*

Well ID/Report	Owner_Name	Use	County	Well_Depth	Latitude	Longitude
4614901	D P Anderson	Domestic	Winkler	152	31.76806	-103.285
409232	Frontier Energy	Domestic	Winkler	245	31.79591	-103.277

Table 3.6-2: *Groundwater chemistry for well 4614901 from Table 3.5-1 indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L.*

StateWellID	Aquifer_Code	Date	HCO_3	Ca	Mg	Na	Cl	SO4	TDS
4614901	100CPDG	8/23/1940	256	97	38	43	53	189	557

3.7 Historical Operations

3.7.1 Bull Moose Site

In response to increasing production and to meet the infrastructure needs of producers, Targa is constructing a new Bull Moose 275 MMSCFD cryogenic natural gas processing plant. **Figure 3.7-1** shows the simplified process block flow diagram, with the entry point for the CO_2, the flow meter location and the sampling point, before BM AGI #1 well.

3.7.2 Operations within the MMA for the BM AGI Well

TRRC records identify a total of 29 oil- and gas-related wells within the MMA (see **Appendix 3**). **Figure 3.7-2** shows the geometry of producing and injection wells within the MMA. **Appendix 3** summarizes the relevant information for those wells.

Among the 29 wells identified, 25 are horizontal oil wells completed in the Bone Spring (8 wells) or Wolfcamp (17 wells) formations, at depths between 11,564 and 12,545 ft. One is inactive and three are plugged and abandoned.

There are four other vertical wells. There are two vertical plugged and abandoned gas well in the Morrow Formation (16,000 ft). There are also two Saltwater Disposal (SWD) wells that are injecting in the Brushy Canyon (7,516 and 7,630 ft).

All of these productive zones are more than 5,300 ft above the BM AGI #1 injection zone.

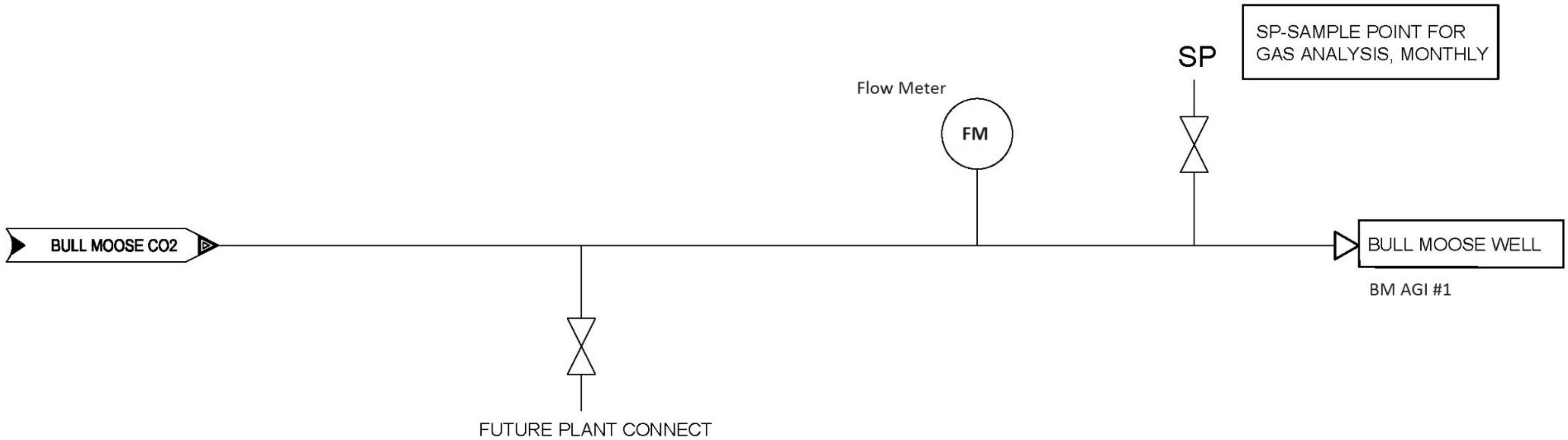


Figure 3.7-1: Process Block Flow Diagram with CO_2 entry, Flow meter (FM), Sampling point (SP) and BM AGI #1.

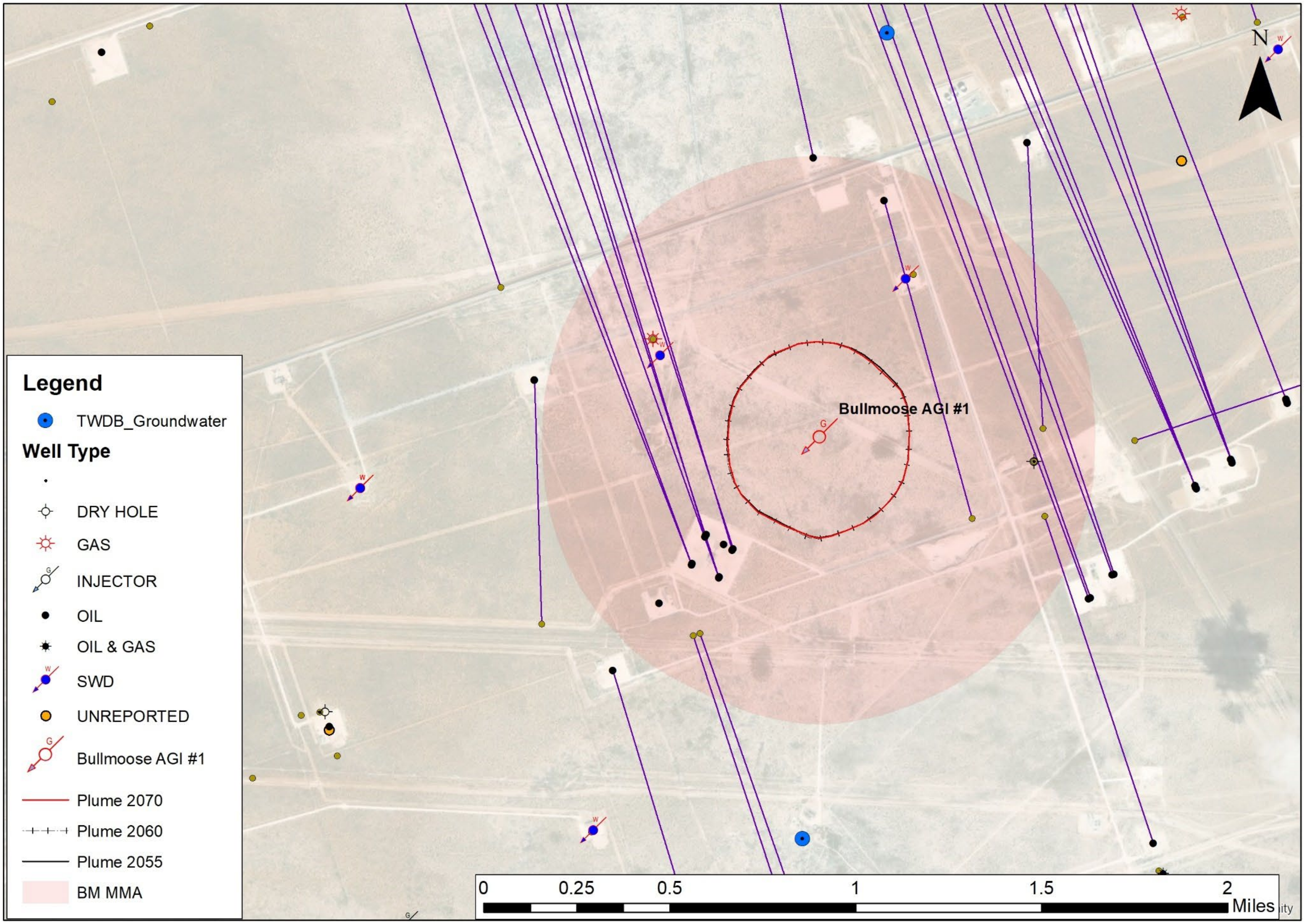


Figure 3.7-2: *Location of all oil- and gas-related wells within the MMA for the BM AGI #1 well. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure.*

3.8 Description of Injection Process

The Bull Moose Gas Plant, including the BM AGI #1 well, will be in operation and staffed 24-hours-a-day, 7-days-a week. The plant gathers and processes produced natural gas. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility. Compressed TAG is then routed to the well via high-pressure rated lines.

The natural gas to be treated at this facility is produced from oil and gas wells in the Permian Basin region, including Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward and Winkler counties, Texas plus Lea and Eddy counties in New Mexico. A sample from Targa 's nearby Wildcat facility (5 miles west) was taken on 11/10/2023 and is representative of the injection stream for the Bull Moose facility. The results of that analysis are provided in **Table 3.8-1**.

Table 3.8-1: Sample Gas Composition for Wildcat AGI #1

Component	Mol %
Carbon Dioxide	91.339
Methane	0.350
Ethane	0.054
Propane	0.061
Iso-Butane	0.003
N-Butane	0.022
Iso-Pentane	0.000
Hexanes Plus	0.099
Hydrogen Sulfide	8.072
Nitrogen	0.000
TOTAL	100.00

The composition may change over time based on the amount of H_2S in the natural gas processing inlet stream. For modeling purposes, an injectate composition of 30% H_2S and 70% CO_2 was assumed as a conservative approach.

3.9 Reservoir Characterization Modeling

3.9.1 Inputs and Assumptions

Dynamic reservoir simulation was performed based on a high resolution geological model. The modeling predicts the well injectivity, pressure behaviors, and TAG plume migration.

Schlumberger's Petrel® (Version 2023.3) software was used to construct the geological models used in this work. Computer Modelling Group (CMG) software was used to perform the reservoir simulations presented in this MRV plan. The software was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling. The hydrodynamical model considers aqueous, gaseous, and supercritical phases of the CO_2, simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in an aqueous phase or in a gaseous phase, in a supercritical state.

The static model is constructed using well tops picked from logs and interpretations from 3D seismic survey to interpret and delineate formations and structural features. The geologic model covers a 3.2-miles by 3.0-miles area (**Figure 3.9-1**). The model is divided into 745,200 cells. The average cell size of the active injection area is 150 square ft. **Figure 3.9-2** shows the simulation model in 3D view. The porosity and permeability of the model are evaluated using existing well logs and 3D seismic inversion. The range of the porosity is between 0.01 to 0.31. The initial permeability is interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy is 0.1. (**Figure 3.9-2**).

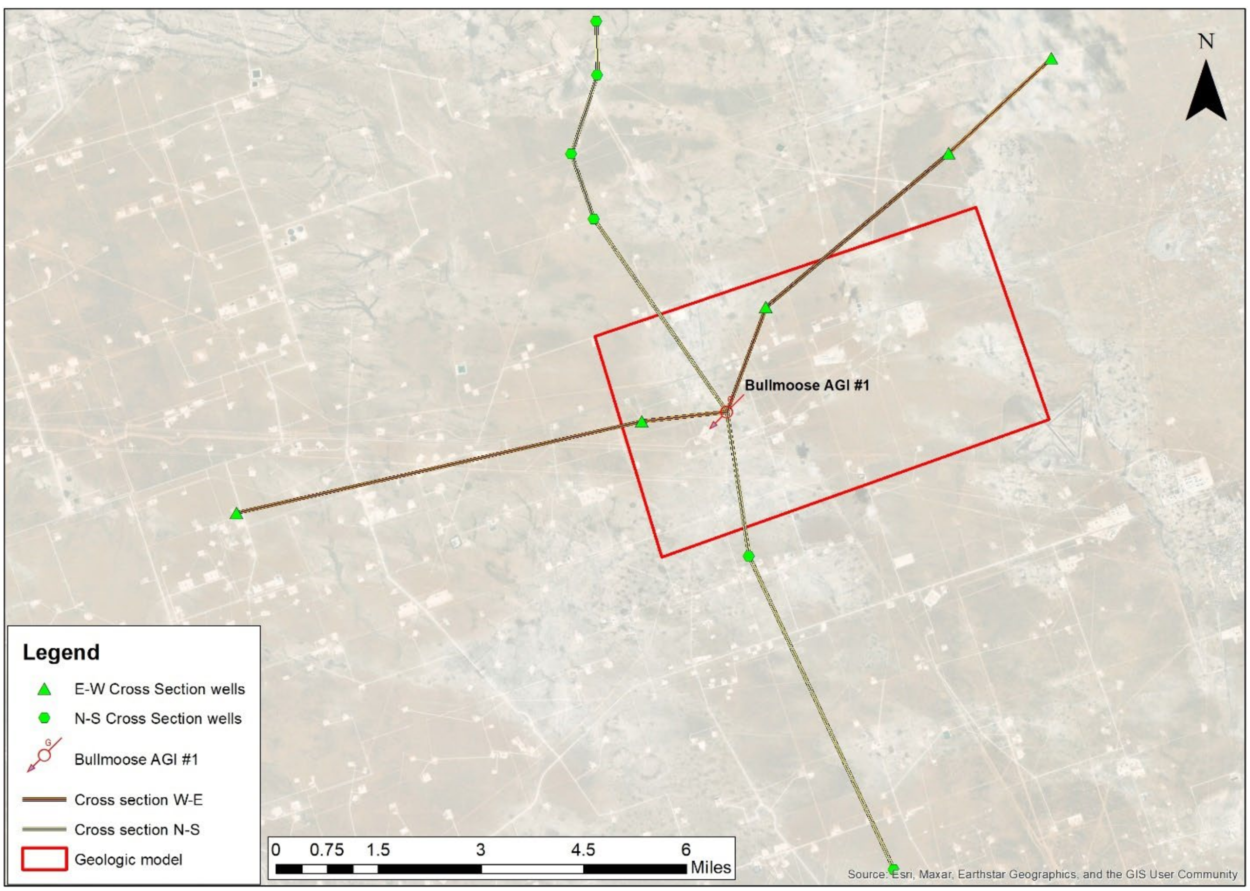


Figure 3.9-1: BM AGI #1 model boundaries

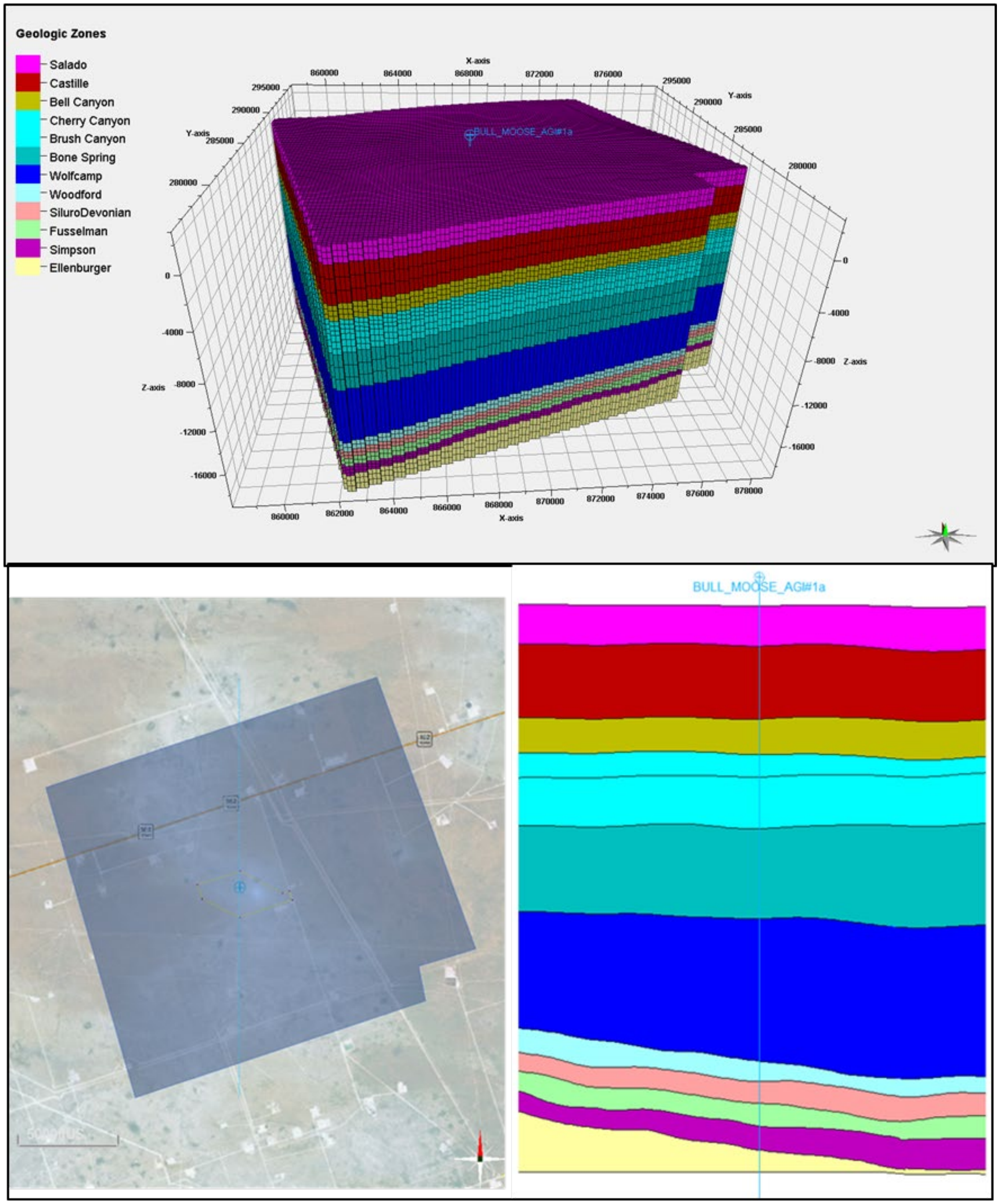


Figure 3.9-2: *3D view of the geological model for the BM AGI #1 well. The model displays the Salado-Castile Formation, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, Simpson and Ellenburger formations. Color legends represent the zones.*

At the initialization of the simulation, the water saturation in the storage reservoir is assumed to be 100%, with a residual water saturation of 20% (Krause, M. H., and Benson, S. M., 2015). The initial salinity is assumed to be 150,000 ppm (Nicot et al., 2020). A geothermal gradient of 1.25°F/100 ft was adopted (Ge, J. et al., 2022). Following standard industry practices, a pore pressure gradient of 0.43 psi/ft is used. Therefore, the reservoir pressure at the top of the Siluro-Devonian at the location is estimated to be 7,650 psi.

The fracture gradient (FG) for the injection interval is calculated using Eaton's equation.

$$FG = \frac{\nu}{1-\nu}\left(OBG - p_p\right) + p_p$$

Where,

ν is the Poisson's ratio,

OBG is the overburden gradient,

p_p is the pore pressure gradient.

An overburden gradient of 1.05 psi/ft is adopted in the calculation. This value is considered best practice when a site-specific number is not available. Poisson's ratio is inferred to be 0.3 in the injection interval. A minimum value of 0.29 and a maximum value of 0.31 are used to quantify uncertainty (Smye et al, 2021, Dvory and Zoback, 2021). The fracture gradient is estimated to be 0.62 to 0.68 psi/ft, therefore the formation fracture pressure calculated at the top of the injection interval is 12,350 psi. In addition, a safety factor of 10% is applied to the resulting fracture gradient. This safety factor ensures injecting pressure will not exceed the fracture gradient in the injection interval, where the maximum bottomhole pressure was set to 0.63 psi/ft during active injection in the simulation. The results are summarized in **Table 3.9-1 & Table 3.9-2**. As these values are calculated based on available legacy well logs and literature listed in the reference, the actual gradient will be measured upon completion of the proposed well, and the modeling and simulation efforts will be updated accordingly.

A review of the TRRC databases identified no saltwater disposal (SWDs) or other injection wells within the model boundaries in the proposed injection interval.

Table 3.9-1: Summary of reservoir simulation inputs.

Reservoir properties of injection zones	Wristen & Fusselman
Porosity	As shown in geologic model
Permeability	As shown in geologic model
Pore pressure gradient	0.43 – 0.45 psi/ft (estimated from DST data in Winkler county – Dvory and Zoback (2021); Luo et al. (1994)
Formation fracture gradient	0.65 $\pm$0.03 psi/ft

Reservoir properties of injection zones	Wristen & Fusselman
Formation temperature	0.014 F/ ft (45 wells BHT data in Winkler– Luo et al. 1994)
Water salinity	150,000 ppm (Nicot et al. 2020 based on P50 of TDS in Winkler County showing 150kppm)
Initial water saturation	100% (assumption made for conservative CO_2 plume)

Table 3.9-2: Summary of well simulation inputs.

Injection well setup	Wristen & Fusselman
Bottom hole pressure	90% of formation fracture pressure or 11,300 psi at bottom hole
Well head pressure	0.5 psi/ft to the top of injection interval (approximately 8,945 psi) – RRC Standards and Procedures for Class II Wells
Wellhead temperature	90-100 °F
Injection fluid	70% CO_2, 30% H_2S
Injection rate	20 MMSCFD over 30 years (2025 – 2055)

BM AGI #1 is simulated to inject at the injection rate of 20 MMSCFD. In accordance with the TRRC Injection Storage Manual; Chapter III - Standards and Procedures for Class II Wells, the maximum surface injection pressure may not ordinarily exceed 0.5 psi per foot of depth to the top of the authorized injection or disposal interval. Therefore, a maximum allowable surface injection pressure of 8,945 psi is used in the simulation. Additionally, a maximum bottomhole pressure of 11,300 is enforced and 90% of the estimated formation fracture gradient is set as a secondary

constraint in the simulation. The composition of the injection stream is estimated to be 30% H_2S and 70% CO_2. The simulated injection starts on 01/01/2025 and stops on 01/01/2055, after a 30-year active injection phase. The termination of the simulation is on 01/01/2085, with an additional 30 years of post-injection, to estimate the maximum plume extent and the stabilized plume.

3.9.2 Model Outputs

Simulations indicate BM AGI #1 can inject at the proposed rate throughout the 30-year period without any complications. Linear cumulative injection behavior (**Figure 3.9-3**) also indicates that the Siluro-Devonian, Fusselman and Montoya formations receive the TAG stream freely. **Figure 3.9-3** shows a constant injection rate of 20 MMSCFD of the TAG stream injected over 30 years under the proposed bottom-hole pressure constraint. The modeling results indicate that the formations are capable of safely receiving and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.9-4** shows the cumulative disposed H_2S and CO_2 separately in gas mass.

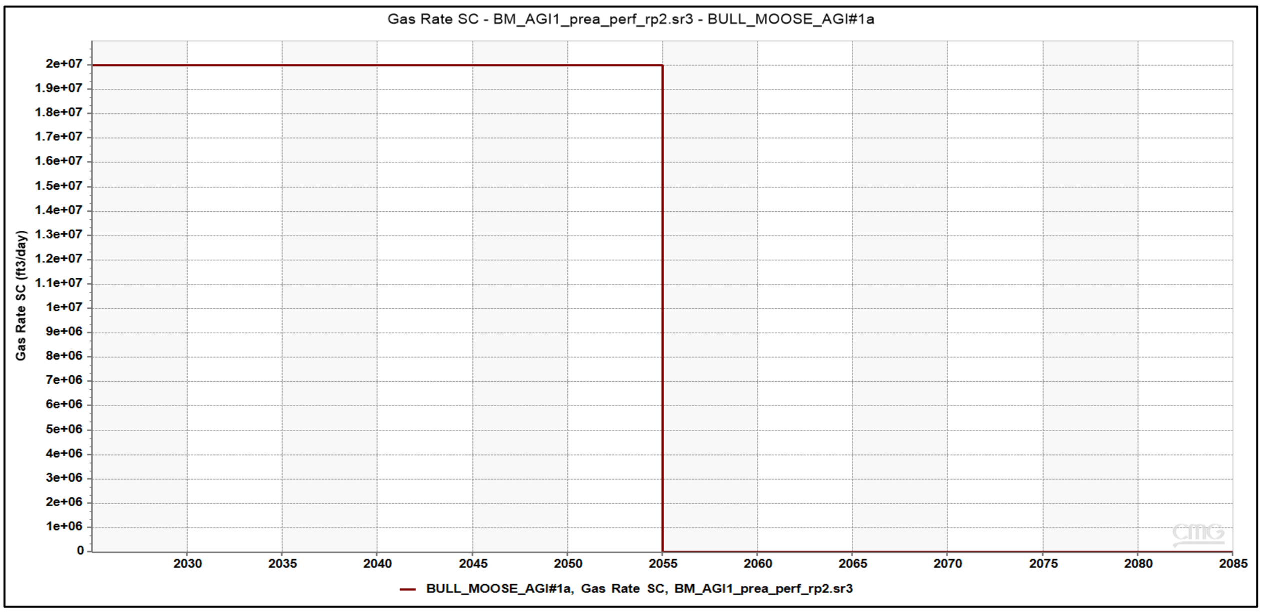


Figure 3.9-3: Average daily injection volume for Bull Moose AGI No. 1 (2025 to 2055, 20 MMSCFD).

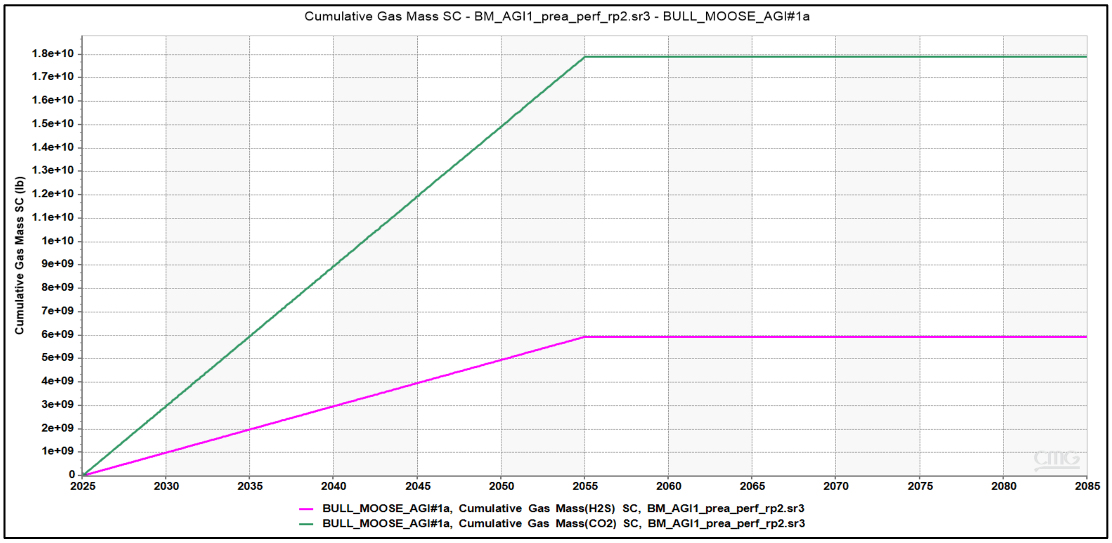


Figure 3.9-4: *Predicted cumulative mass of injected CO_2 and H_2S for BM AGI #1 well (injection operation from 2025 to 2055).*

3.9.3 Treated Acid Gas Plume

Figure 3.9-5 shows the TAG plume evolution for BM AGI #1 in the years 2030, 2035, 2040, 2045, 2050, 2055, marking 5-year increments from the beginning of the injection simulation in 2025. The diameter of the most extensive part of the TAG plume is estimated to be 7,500 ft (1.42 mi), with stabilization achieved in 2070

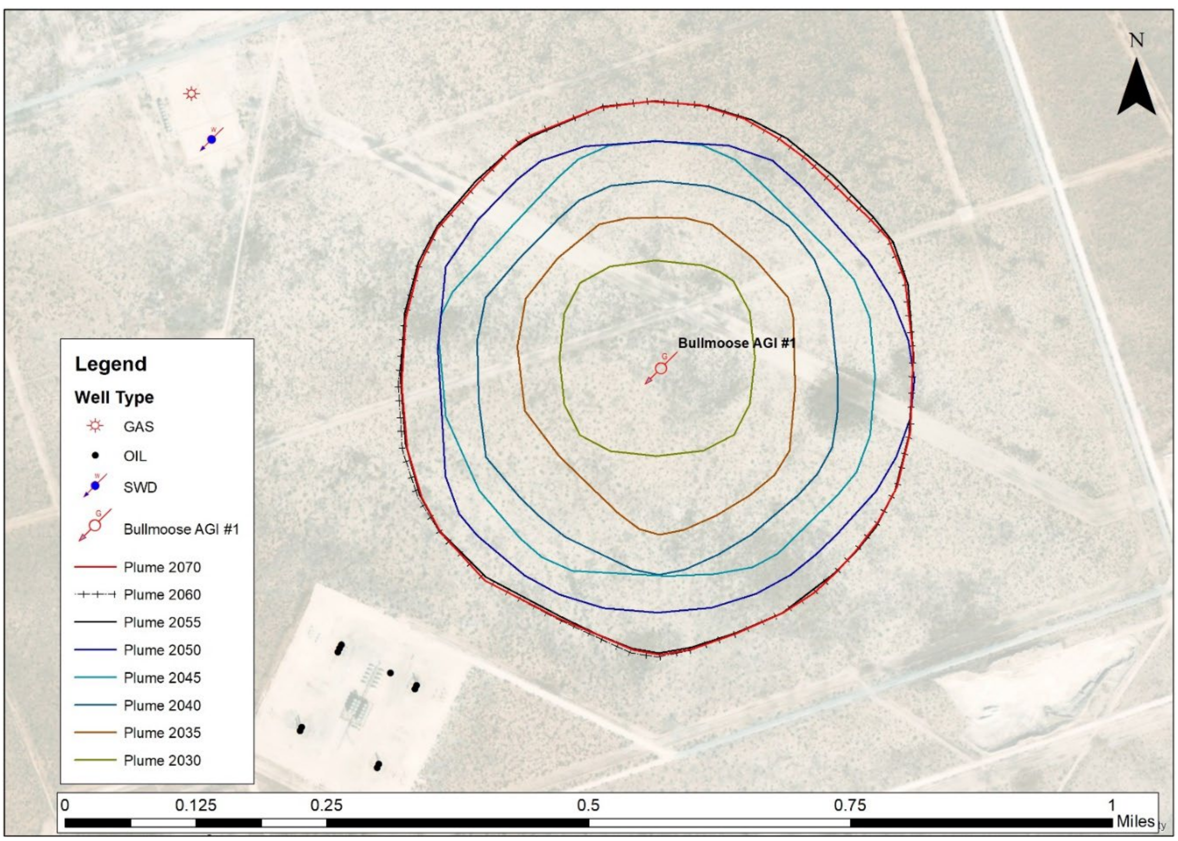


Figure 3.9-5: *Extent of TAG plume (represented by gas saturation with 1% threshold) at years 2030, 2035, 2040, 2045, 2050, 2055 (end of injection = t), 2060 (t+5) and stabilized plume in 2070.*

4 Delineation of the Monitoring Areas

The delineation of the active monitoring area (AMA) and the maximum monitoring area (MMA) are based on the simulation results from section 3.9.

4.1 AMA – Active Monitoring Area

The AMA is shown in **Figure 4-1** and is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

(1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2055), plus an all-around buffer zone of one-half mile **(Figure 4.1-1);**

(2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2060).

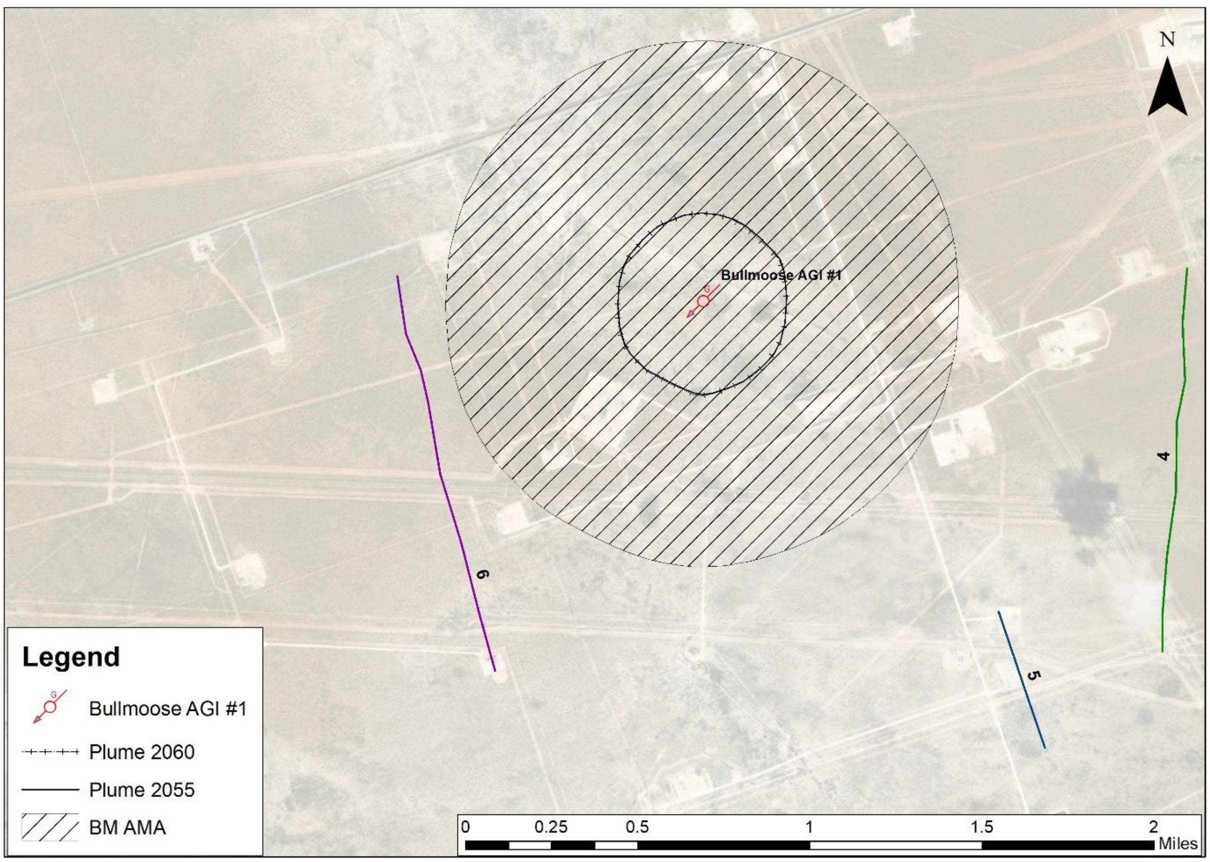


Figure 4.1-1: *Bull Moose AMA according to definition (1).*

Targa intends to define the AMA to be the same area as the MMA. The black polygon at year t=2055 is the BM AGI #1 well plume at the end of injection, and the black cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection plus 5 years. The red polygon in **Figure 4.1-2** is the stabilized plume extent 15 years after injection ceases, i.e. 2070. The AMA, which is the hatched area in **Figure 4.1-1** and the MMA shown as the red-filled polygon in **Figure 4.1-2** contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

4.2 MMA – Maximum Monitoring Area

As defined in Section 40 CFR 98.449 of Subpart RR, the MMA is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.9 to define the extent of the plume.

According to the reservoir modeling results, after 30 years of post-injection monitoring (year=2085), the injected gas will remain in the reservoir and no expansion of the TAG footprint is observed after 2070. Therefore, the plume extent at year 2070 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA: **Figure 4.1-2**.

In addition, according to EPA regulation: "The buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that a buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances."

Therefore, Targa considered the identified faults surrounding the injection well in order to define the MMA. There was no need to extend the MMA to incorporate the faults plus a one-half-mile buffer around the faults because they are outside the initial AMA and MMA. Therefore, the MMA encompasses the union of two areas:

- The area covered by the stabilized plume plus an all-around buffer zone of one-half mile
- The area covered by the lateral extent of known potential leakage pathways (the trace faults Figure 4.2) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 shows the MMA as defined by Section 40 CFR 98.449 of Subpart RR. The MMA is expected to contain the free phase CO_2 plume throughout the life of the project and the lateral extent of potential leakage pathway plus a one-half mile buffer. The AMA is set equal to the MMA.

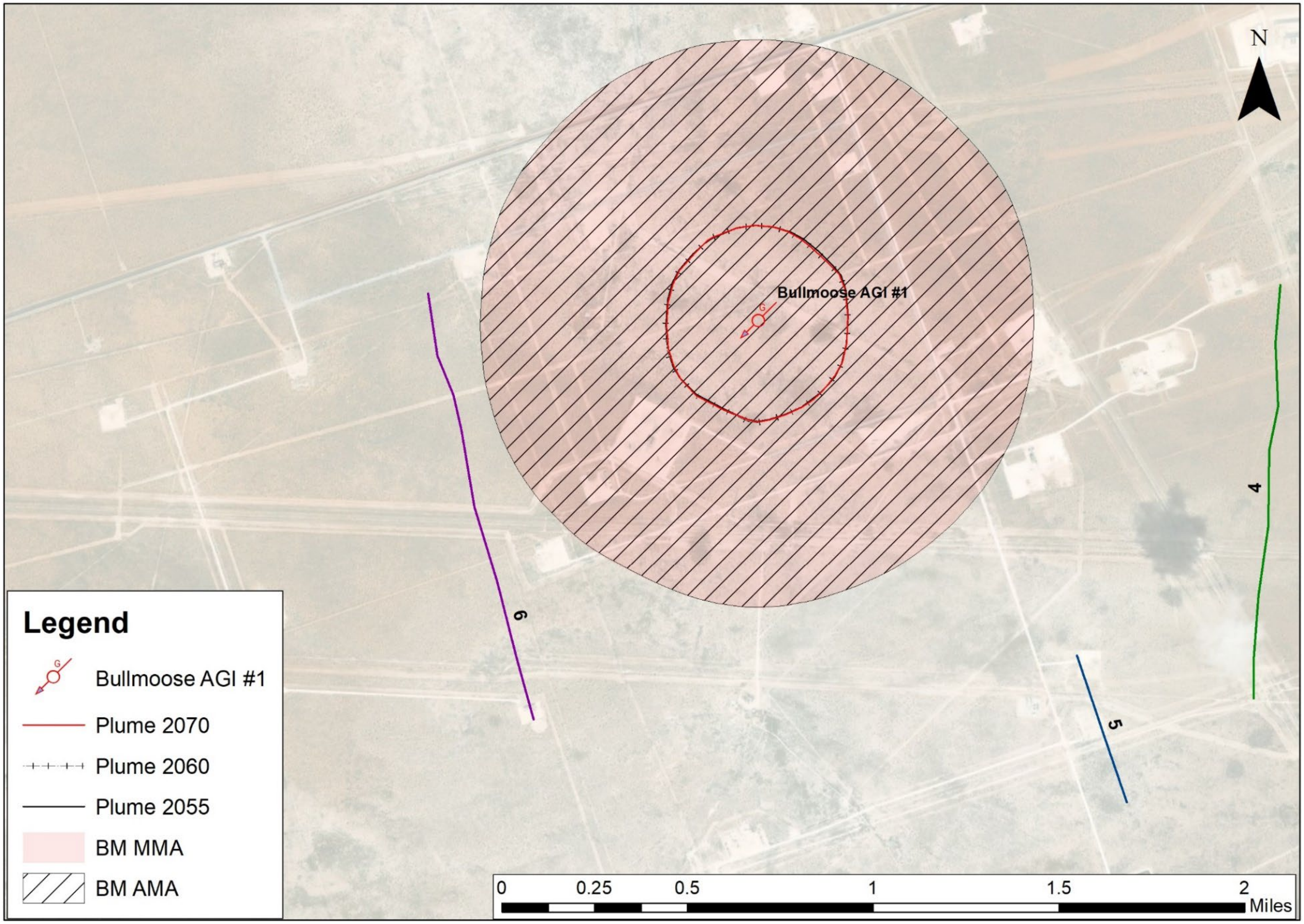


Figure 4.1-2: *Active monitoring area (AMA) and Maximum monitoring area (MMA) for Targa BM AGI #1; and plume at the end of injection (2055), 5 years after end of injection (2060) and stabilized plume (2070)*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

An evaluation of each of the potential leakage pathways is described in the following paragraphs, notably:

1. Potential leakage from surface equipment
2. Potential leakage from approved not yet drilled wells
3. Potential leakage from existing wells
4. Potential leakage through the confining / seal system
5. Potential leakage due to lateral migration
6. Potential leakage through fractures and faults
7. Potential leakage due to natural / induced seismicity

Risk estimates were made using a risk matrix (**Figure 5.1-1**) with a methodology to evaluate risk probability and impact. In addition, Targa used the National Risk Assessment Partnership (NRAP) tools, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage leakage risks at geologic carbon storage sites.

Magnitude

Likelihood

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

Figure 5.1-1: *5x5 Risk Matrix used to evaluate leakage likelihood and magnitude.*

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills".

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

Likelihood:

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2.

Therefore, Targa infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place and the regular inspections and maintenances, the probability of such leakage is considered very unlikely.

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days.

Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

Therefore, the impact (i.e. magnitude) of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable.

5.2 Potential Leakage from Approved Not Yet Drilled Wells

Likelihood:

Approval and construction of oil and gas-related wells, including injection wells, are regulated by TRRC rules (Appendix 2), specifically Rule 13 for casing, cementing, drilling, well control, and completion, which require that wells be constructed in such a manner as to prevent vertical migration of fluids, including gases, behind the casing. Adherence to these requirements will mitigate the risk of potential CO_2 emissions to the surface. In addition, these wells have strict requirements and will be actively monitored for integrity on a regular basis. Therefore, the likelihood of leakage from approved and not yet drilled wells is considered very unlikely.

Magnitude:

Based on worst-case scenario considerations, the following NRAP analysis and the very unlikely risk of leakage happening from approved wells that have not yet been drilled, the magnitude of potential gas leaks through these wells is insignificant.

Timing:

All the wells within the MMA are either injecting, producing, plugged and abandoned or inactive, **Table 5.1-1**. There are no approved and not yet drilled wells based on the available records. Timing evaluations indicate no imminent risk of gas leakage from approved wells that have not yet been drilled.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA, as delineated in Section 4, are shown in **Figure 3.7-2** and detailed in **Appendix 3**.

Targa considered all wells completed and approved within the MMA in the NRAP risk assessment. None of the wells in the MMA penetrate the confining zone nor the injection zone. All of the productive zones lie at more than 5,300 ft above the BM AGI #1 injection zone.

Likelihood:

Even though the risk of CO_2 leakage through the wells that do not penetrate confining zones is very unlikely, (the CO_2 would have to leak through the sealing zone), Targa did not omit any potential source of leakage in the NRAP analysis.

Magnitude:

If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. A total of 29 wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage.

There were 22 active oil wells that were considered in the NRAP risk assessment section. The other wells that were considered for the risk leakage assessment include two injection wells, six abandoned and plugged wells, and one inactive well. Reservoir and seal confinement properties were incorporated into the model, together with CO_2 properties and injection rates and pressures. The injection period was set to 30 years. According to the NRAP results, no leakage mass of CO_2 was recorded throughout the injection period.

Timing: The duration for CO_2 to get to the atmosphere via upward migration through the 5,300 ft of sealing and other geologic formations would be several thousands of years.

The **Table 5.1-1** summarizes the oil and gas wells and their evaluated risk. Based on the previous comments, all the wells expect three have a very low risk of CO_2 leakage. The likelihood of CO_2 leakage is very unlikely and the magnitude insignificant. Three wells have a medium risk, they present an unlikely likelihood of CO_2 leakage but can have a significant magnitude.

Table 5.1-1: *Well within the MMA with their evaluated risk.*

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34978	AGI	INJECTING	VERTICAL	Siluro-Devonian	TBD	2	3	6
42-495-34038	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516	1	1	1
42-495-33871	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630	1	1	1
42-495-34331	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564	1	1	1
42-495-34324	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621	1	1	1
42-495-34488	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627	1	1	1
42-495-34489	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637	1	1	1
42-495-33759	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,811	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,814	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,816	1	1	1
42-495-34325	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858	1	1	1
42-495-33236	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868	1	1	1
42-495-34332	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897	1	1	1
42-495-34483	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972	1	1	1
42-495-34323	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106	1	1	1

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34485	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129	1	1	1
42-495-34481	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145	1	1	1
42-495-34482	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176	1	1	1
42-495-33840	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185	1	1	1
42-495-33726	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188	1	1	1
42-495-34329	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193	1	1	1
42-495-33763	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194	1	1	1
42-495-34326	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208	1	1	1
42-495-34484	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217	1	1	1
42-495-34328	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263	1	1	1
42-495-34330	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537	1	1	1
42-495-34327	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545	1	1	1
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6

5.3.1 Wells Completed in the Injection Zone

The only well completed in the BM AGI #1 well injection zone is the BM AGI #1 well.

Likelihood:

To minimize the likelihood of leaks from new wells, TRRC regulation regarding the casing and cementing of injection wells requires operators to case injection wells with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string.

Magnitude and Timing:

To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, TRRC requires the use of blowout preventers in areas of high pressure at or above the projected depth of the well. These requirements apply to any other new well drilled within the MMA for this MRV plan.

In addition, for safety purposes, Targa will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 flow to the surface by:

- Monitoring H_2S at surface at many locations (H_2S can be a proxy to detect CO_2);
- Employing a high level of caution and care while drilling, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the injection zone.

By drilling through producing zones, there is a possibility of gas emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent and/or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of BM AGI #1 operating parameters by the distributed control system (DCS), Targa considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.3.2 Horizontal Wells

The table in **Appendix 3** and **Figure 3.7-2** show a number of horizontal wells in the area, many of which are producing. As discussed in 5.3, they are all 5,300 ft above the injection zone and the risk of leakage through these wells is considered very unlikely and insignificant.

5.3.3 Groundwater Wells

According to the Texas Water Development Board water database, there are no water wells within the MMA. There are only one North-East of the MMA and South-West of the MMA. Therefore, the risk of leakage through these wells are considered very unlikely and insignificant TWDB

5.4 Potential Leakage through the Confining / Seal System

Although unlikely, Targa considered leakage through confining zones in the NRAP risk assessment.

Likelihood:

The Barnett shale (440 ft), Mississipian limestone (440 ft) and Woodford Shale (660 ft) serve as the major seals or caprock layer to the injection zones. Their low porosity (1%) and permeability (<0.1

mD) provide high seal integrity (Sections 3.2, 3.3) There is. no evidence of faulting or natural fracturing. It is very unlikely that TAG injected into the injection formation will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Magnitude and Timing:

The worst-case scenario is defined as leakage through the seal immediately above the injection well, where CO_2 saturation is highest.

To simulate this scenario, cell blocks were created to cover the MMA, serving as the most prone zone for CO_2 leakage. These cell block locations and CO_2 saturation at the seal and seal properties were incorporated into the NRAP model.

Figures 5.4-1 and 5.4-2 present the leakage rate and cumulative mass of leakage over 60 years. The total leakage mass recorded after 60 years is about 8,000 kg. According to the total mass of CO_2 injected per year alone, after 60 years, the percentage of leakage through confining zone is estimated to be 0.0021%. This is reliably minimal and considering other stratigraphic strata, Targa concludes that the risk of leakage through this pathway is highly unlikely and insignificant.

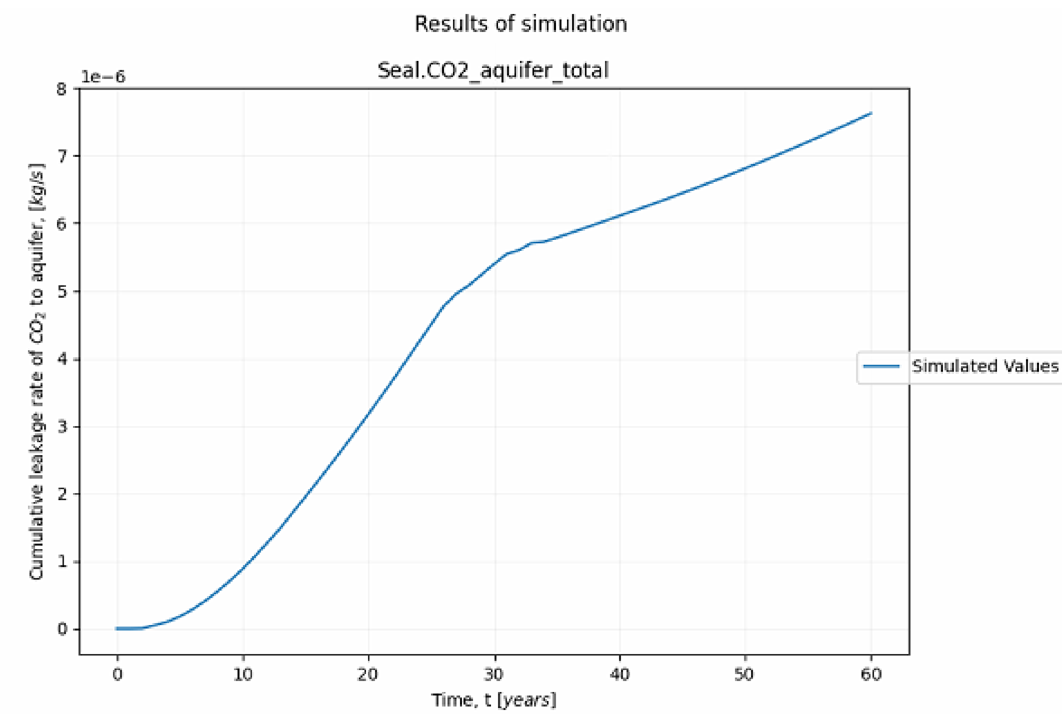


Figure 5.4-1: *Seal leakage rate*

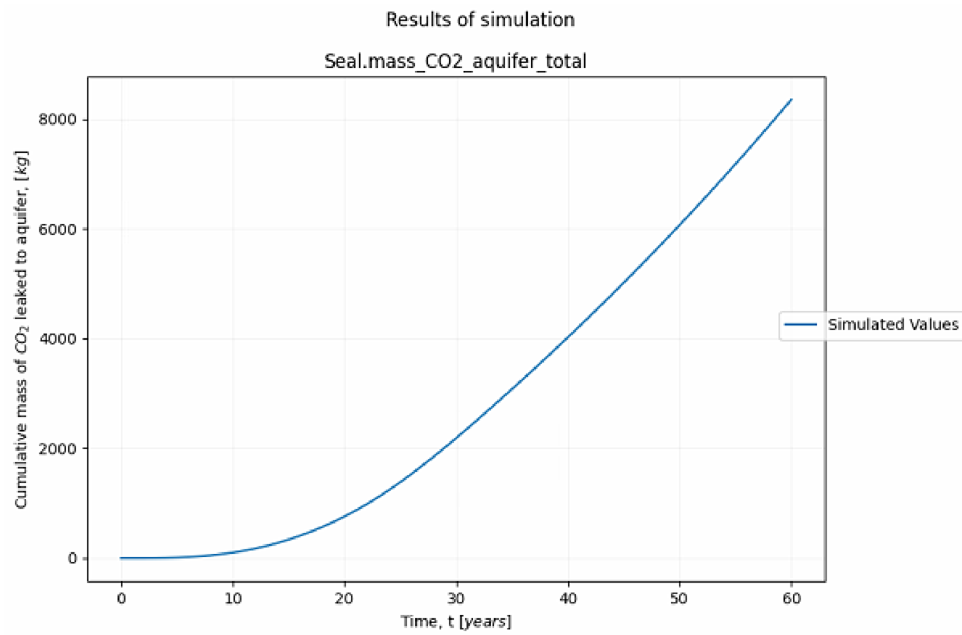


Figure 5.4-1: *Cumulative mass of Seal leakage*

5.5 Potential Leakage due to Lateral Migration

Likelihood:

Regional consideration of the geology (Section 3.3) and the model built suggest that BM AGI #1 injection zones have adequate storage capacity for the proposed injection amount. In addition, simulation (Section 3.9) indicates that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA.

Based on the geological discussion and analysis of the injection zone, Targa considers that the likelihood of CO_2 to migrate laterally is unlikely.

Magnitude and Timing:

Based on simulation results, the TAG is projected to be contained within the injection zone close to the injection well. The sealing zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration occurs.

5.6 Potential Leakage through Fractures and Faults

Likelihood:

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces (numbered 4, 5 and 6) in the vicinity of the Bull Moose plant. The fault number 6 shown on **Figure 5.6-1** is above the injection zone for the BM AGI well. No faults were identified in the injection zone or confining zone within the MMA. Therefore, the likelihood of leakage through faults is considered very unlikely.

Magnitude and Timing:

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. Considering faults that are going through the confining or injection zone, the closest identified fault lies approximately 1.5 miles east of the Bull Moose site and has approximately 1,000 ft of down-to-the-west structural relief.

The nearest fault going through the injection or confining zone is found approximately 7,276 ft east of the BM AGI #1 site. The risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume or lateral migration carries CO_2 to faults. Other nearby faults are 12,031 ft (~2.3 mi)and ft (2.9 mi) east the site, placing them outside the MMA. Hence, leakage through faults will be an unlikely event. This is supported by NRAP simulation results (**Figure 5.6-1**) that consider fault location, geometry, and direction. For faults that do not directly connect with the CO_2 plume, CO_2 leakage rate and mass are estimated to be zero. The estimated cumulative leakage (**Figure 5.6-1**) shows no leakage throughout the period of simulation (60 years).

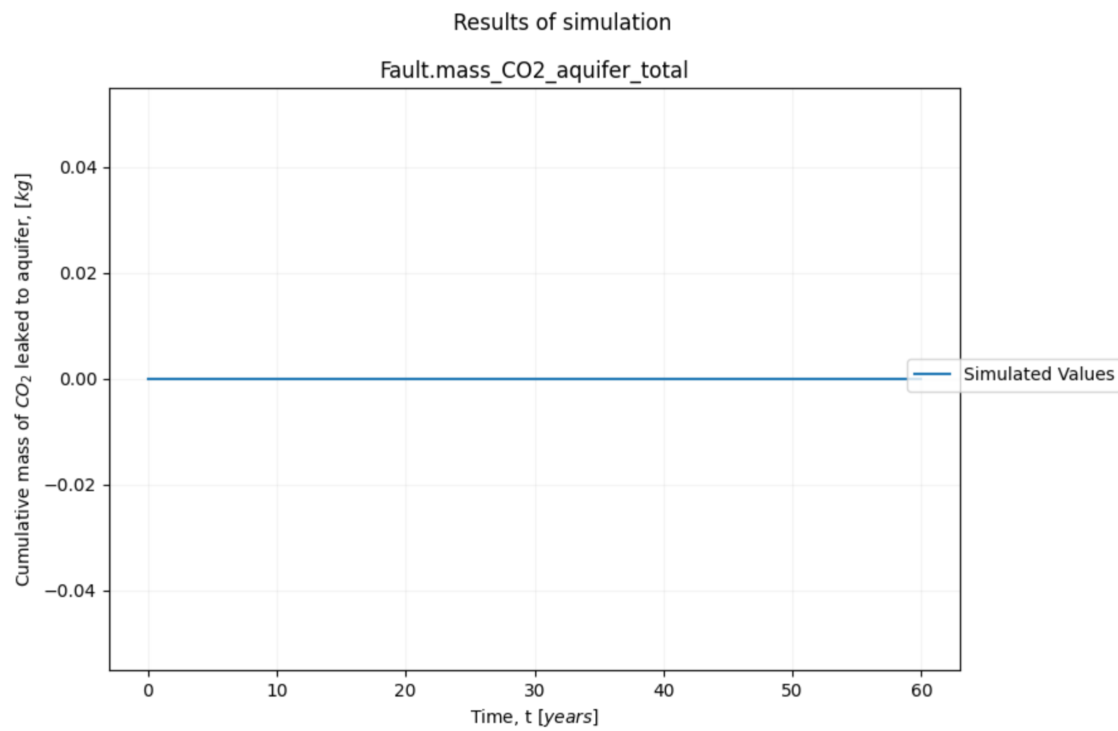


Figure 5.6-1: *Faults 7,276 ft*

Therefore, Targa concludes that the risk of CO_2 leakage through the faults are very unlikely and insignificant.

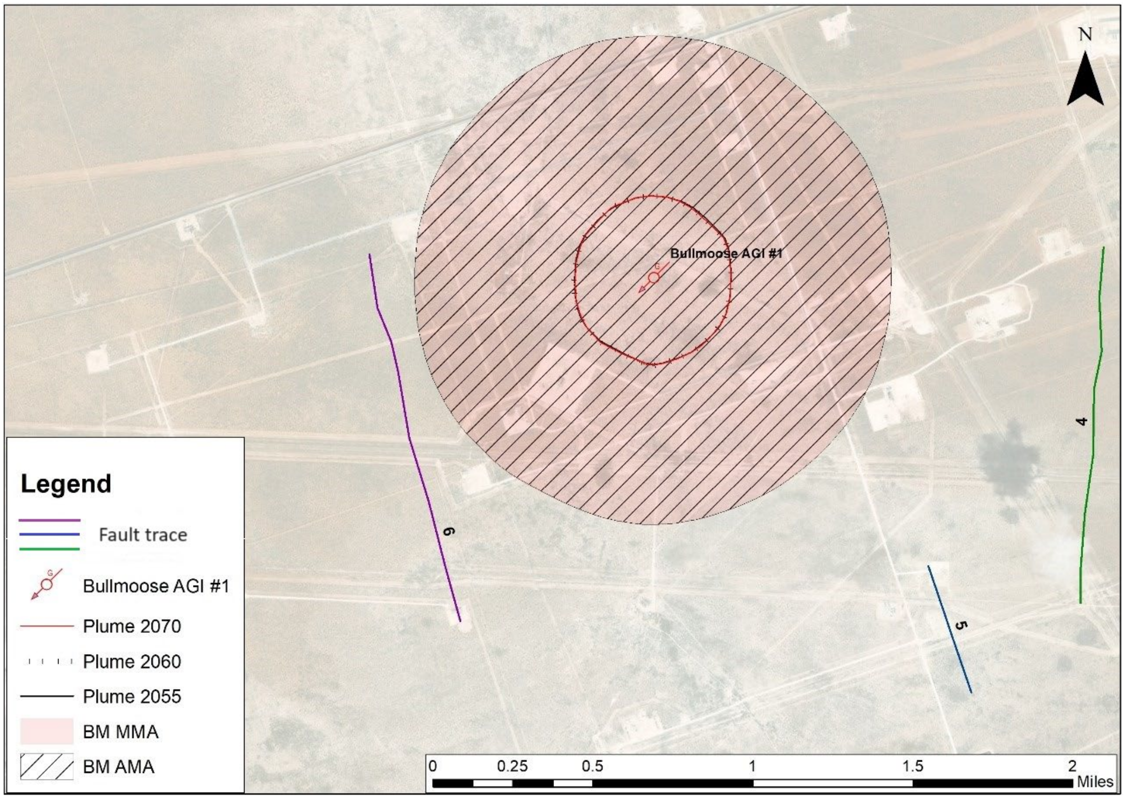


Figure 5.6-1: *Faults surrounding Bull Moose facility relative to the plume and the MMA.*

5.7 Potential Leakage due to Natural / Induced Seismicity

5.7.1 Natural Seismicity

Likelihood:

Due to the distance between the BM AGI #1 well and the location of the seismic events recorded since 2017, the magnitude of these events, and the fact that Targa injects at pressures below fracture opening pressure, Targa considers the likelihood of CO_2 emissions to the surface caused by seismicity to be very unlikely.

Magnitude and Timing:

The magnitude and timing of a seismic event can vary greatly. In the region, the earthquakes ranged from magnitude 1.5 to 4. They are located in clusters that are around 20 miles North-West and South, South-West of Bull Moose.

Based on historical data and the geology of the surroundings, the risk of CO_2 leakage due to seismicity is considered insignificant.

Monitoring of seismic events in the vicinity of the Bull Moose AGI well is discussed in Section 6.7.

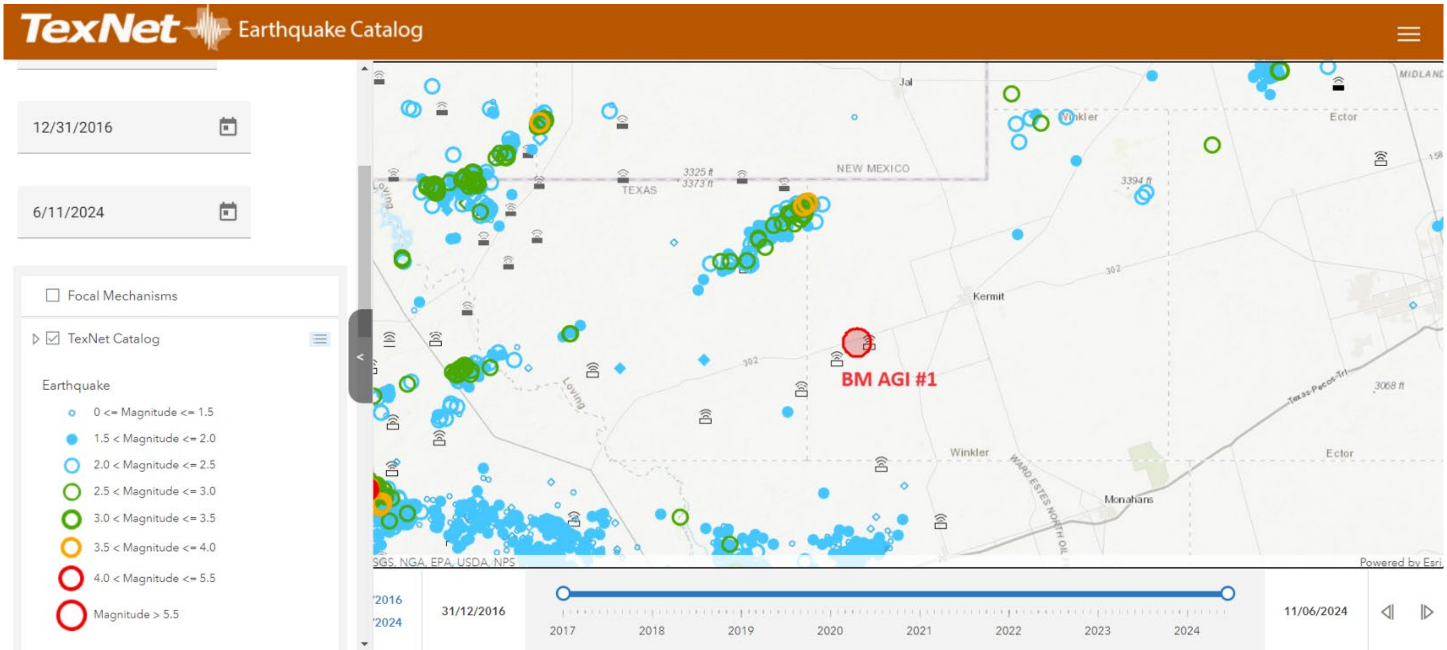


Figure 5.7-1: TexNet seismic events since 2017 and seismic monitoring stations close to Bull Moose plant.

5.7.1 Induced Seismicity

The faults that might be affected by pressure changes have been analyzed to evaluate the risk of induced seismicity, and the risk of leakage due to induced seismicity. The examination of faults identified from the 3D seismic data, illustrated in **Figure 5.7-2**, discloses the presence of 6 major faults traversing the reservoir interval. These faults are far east from BM AGI #1 and they have been further subdivided into 41 sub-fault segments, allowing for a detailed analysis of their slip potentials.

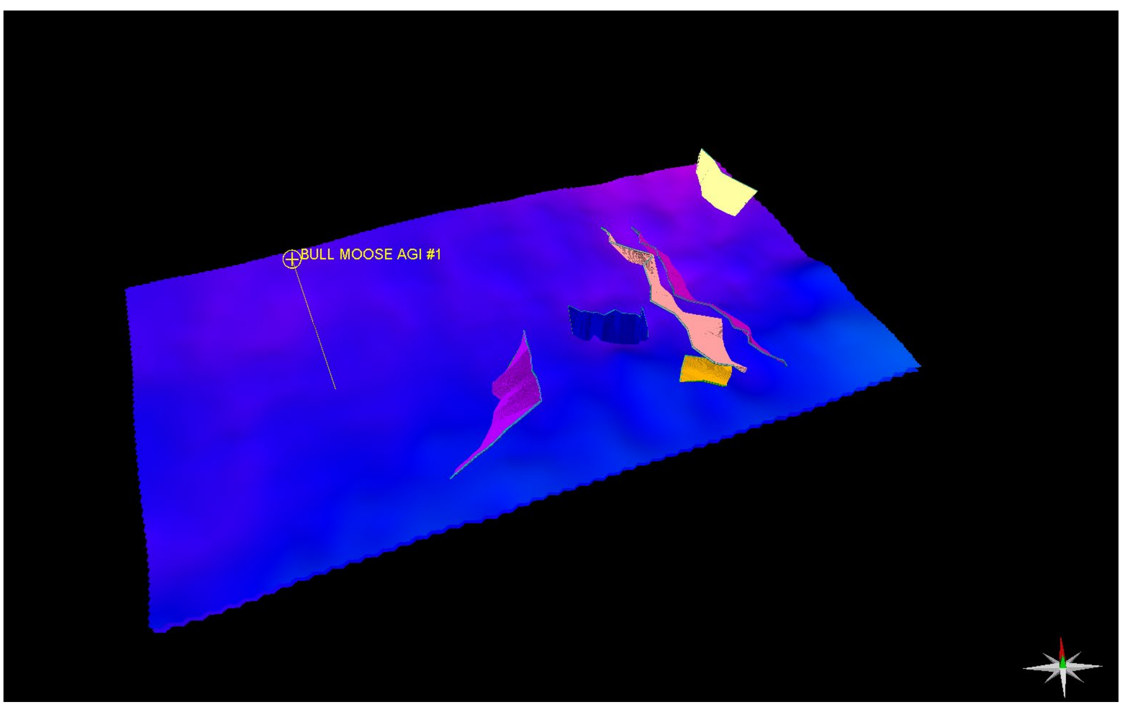


Figure 5.7-2: Structure and fault system picked from 3D seismic data on Silu-Devonian to Ellenburger.

The evaluation of Fault Slip Potential (FSP) using the FSP software version 1.07 involved the utilization of specific parameters (**Table 5.7**). The software requires various inputs or parameters to assess the potential for fault slippage. These parameters are fundamental in assessing the likelihood of fault slippage. The FSP software incorporates and processes these inputs to generate an estimation or analysis of the potential for faults to slip under the given conditions. These parameters could include factors such as: Pressure Changes (the magnitude of pore pressure changes within the geological formations), fault geometry (details about the fault, including its orientation, size, and geometry), stress conditions (information on stress distribution within the rock formations, including the magnitudes and orientations of principal stresses), rock properties (data regarding the mechanical properties of the rocks, such as porosity, permeability, and strength), and seismic data (3D seismic data used to identify and characterize faults geometry). These parameters are from published papers and reports.

Table 5.7: *Fault Slip Potential simulation parameters.*

Fault Friction Coeff (mu)	0.58
Vertical Stress Gradient (psi/ft)	1.07+/-0.01
Maximum Horizontal Stress Direction (deg)	82.5 +/- 7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.465 +/- 0.05
Minimum Horizontal Stress Gradient (psi/ft)	0.5
Maximum Horizontal Stress Gradient (psi/ft)	1
A-Phi Parameter	0.8+/-0.1
Reference Friction Coefficient (mu)	0.58+/-.005
Porosity (%)	15
Permeability (mD)	7.2
Injection Years	2025 to 2055

It appears that the results of the FSP (Fault Slip Potential) analysis indicate that over a 30-year injection period, faults have experienced only a small pressure drop in effective stress. The slippage of fault walls is contingent on having sufficient pore pressure to raise the effective stress to a level that would induce slippage. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation. As shown in **Figure 5.7-3**, 97% of interpreted faults require more than 180 psi effective pressure to cause slip. The predicted value of effective pressure changes on **Figure 5.7-4** and **Figure 5.7-5** shows that the pore pressure will change less than 30 psi after 30 years. The probability of fault slip are shown in **Figure 5.7-5**. These values indicate negligible potential for fault slips for major faults. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation.

Therefore, the risk of leakage due to induced seismicity is considered very low. Its **likelihood, timing and magnitude** are considered very unlikely and insignificant.

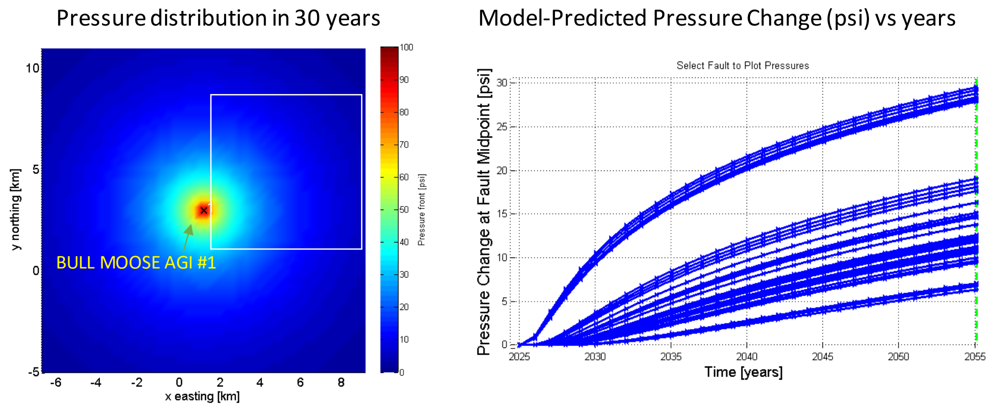


Figure 5.7-3: Visualization of pressure change after 30 years of injection

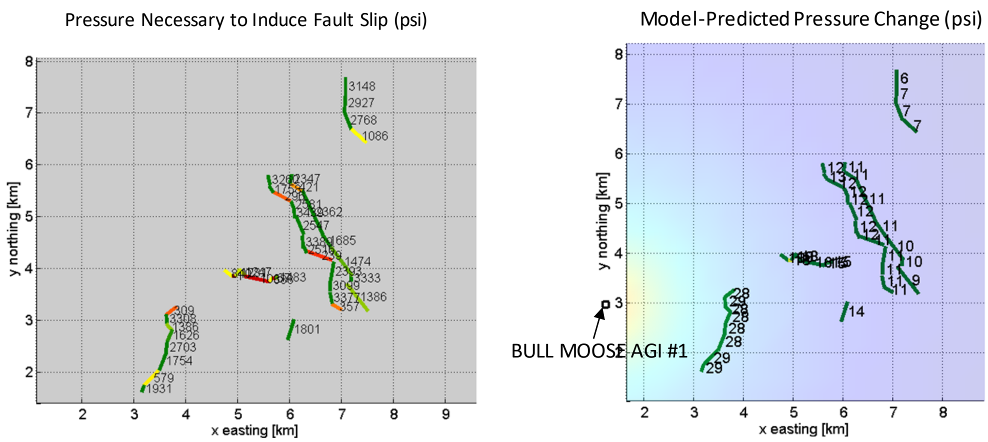


Figure 5.7-4: Visualization of pressure change required to cause fault slip and the predicted pressure after 30 years of injection

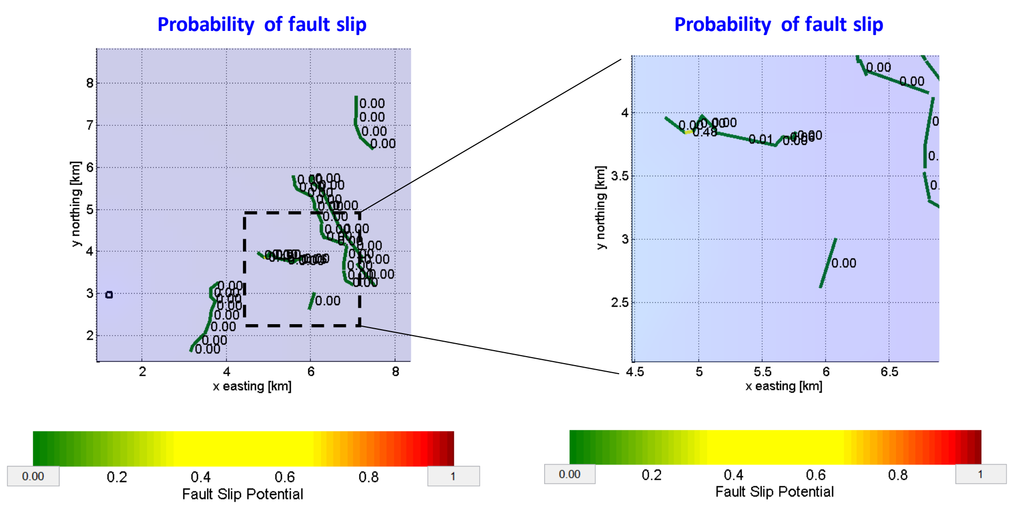


Figure 5.7-5: Fault slip probability after 30 years of injection. Fault color represent the fault slip potential value indicated by color bar and they show almost 0% of fault slip potential.

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2.

Targa will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. Targa considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage close to the plant equipment. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 15-year post-injection period.

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
Wells that have not yet been drilled	• Monitor applications for permit to drill and permit to inject made to the TRRC • Communicate with operators/drillers that are active within the MMA so they are aware that they are drilling in an area that has CO_2/H_2S injection activities.
BM AGI #1 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well pressure/temperature (P/T) sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring

Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring station
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

Targa implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Leaks from surface equipment are detected by Targa field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

Targa also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. This applies to Targa and other operators drilling new wells through the BM AGI #1 injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 BM AGI Well

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

To monitor leakage and wellbore integrity, pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) will be deployed in Targa's BM AGI #1 well.

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

Well Schematic for BM AGI #1 showing installation of pressure and temperature sensors are in **Appendix 1**.

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the BM AGI #1 well, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining / seal system, Targa will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well (see Section 6.8).

6.5 Leakage due to Lateral Migration

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

If monitoring of operational parameters or other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, Targa will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults.

However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, Targa will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. Targa will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

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

If the monitoring systems indicate surface leakage of CO_2 linked to seismic events, Targa will assess whether the CO_2 originated from the BM AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR.

Quantification of major leakage events from surface equipment as identified by the detection techniques listed in **Table 6-1** will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point.

Targa has standard operating procedures to report and quantify all pipeline leaks in accordance with the TRRC regulations. Targa will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by Targa or third parties. Additionally, Targa may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

Here are example quantification strategies specifically designed for surface leakage:

- Direct measurement techniques: Targa will use mass flow meters in surface equipment. These meters can capture CO_2 mass flow rates in real-time, providing direct quantification of emissions as soon as a leak is detected.
- Leak rate models: Targa will use models that incorporate thermodynamic and fluid dynamics principles to estimate the mass of CO_2 escaping from leaks. For example: empirical leak rate

models employ empirical equations that estimate leak rates based on equipment size, the differential pressure across the leak, and gas composition.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 6-1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. Targa may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

Targa field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Bull Moose Gas Plant.

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

Compositional analysis of Targa's gas injectate at the Bull Moose Gas Plant indicates an approximate H_2S concentration of 30% thus requiring Targa to develop and maintain an H_2S Contingency Plan (Plan) according to the TRRC Regulations. Targa considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated BM AGI #1 Well and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Bull Moose Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, Targa will set up a monitoring network for CO_2 leakage detection in the MMA as defined in Section 4.2. In addition, there will be periodic groundwater and soil flux sampling within the MMA. Once the network is set up, Targa will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

Targa adheres to the requirements of TRRC Rules governing the construction, operation and closing of an injection well under the Oil and Gas Act. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. Targa's Routine Operations and Maintenance Procedures for the BM AGI #1 well ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

Targa has Installed a seismometer and a digital recorder to monitor for and record data for any seismic event at the Bull Moose Gas Plant. The seismic station meets the requirements of the TRRC.

In addition, data that is recorded by the TexNet network surrounding the Bull Moose Gas Plant will be analyzed by Targa. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

Targa will monitor groundwater wells for CO_2 leakage as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes TDS, conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Bull Moose Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

Parameters
pH
Alkalinity as HCO^{3-} (mg/L)
Chloride (mg/L)
Fluoride (F^{-}) (mg/L)
Bromide (mg/L)
Nitrate (NO^{3-}) (mg/L)
Phosphate (mg/L)
Sulfate ($SO4^{2-}$) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, Targa can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Bull Moose Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

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

8.1 CO_2 Received

Currently, Targa receives gas to its Bull Moose Gas Plant through pipelines. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. Targa will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to the flow meter (FM) in **Figure 3.7-1**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

Although Targa does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When Targa begins to receive CO_2 in containers, Targa will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2 received in containers. Targa will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Upon completion, Targa will commence injection into BM AGI #1. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to the flow meter (FM) in **Figure 3.7-1**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

8.3 CO_2 Produced / Recycled

Targa does not produce oil or gas or any other liquid at its Bull Moose Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, Targa will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

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

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

(Equation RR-12)

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells 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 [refers to subpart W of the GHGRP rules].

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established by Targa for several years and continues to the present. Targa will begin implementing this MRV plan as soon as it is approved by EPA. After BM AGI #1 is drilled, Targa will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), Targa will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

Targa will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), Targa's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the BM AGI #1 well using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.4 CO_2 produced.

Targa does not produce CO_2 at the Bull Moose Gas Plant.

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

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

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

10.1.6 Measurement devices.

As required by 40CFR98.444(e), Targa will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

Targa will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

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

10.4 Revisions of the MRV Plan

Targa will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of Texas. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), Targa will submit a revised MRV plan addressing the material change. Targa intends to update the MRV plan after BM AGI #1 has been drilled and characterized.

11 Records Retention

Targa will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, Targa will retain the following documents:

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

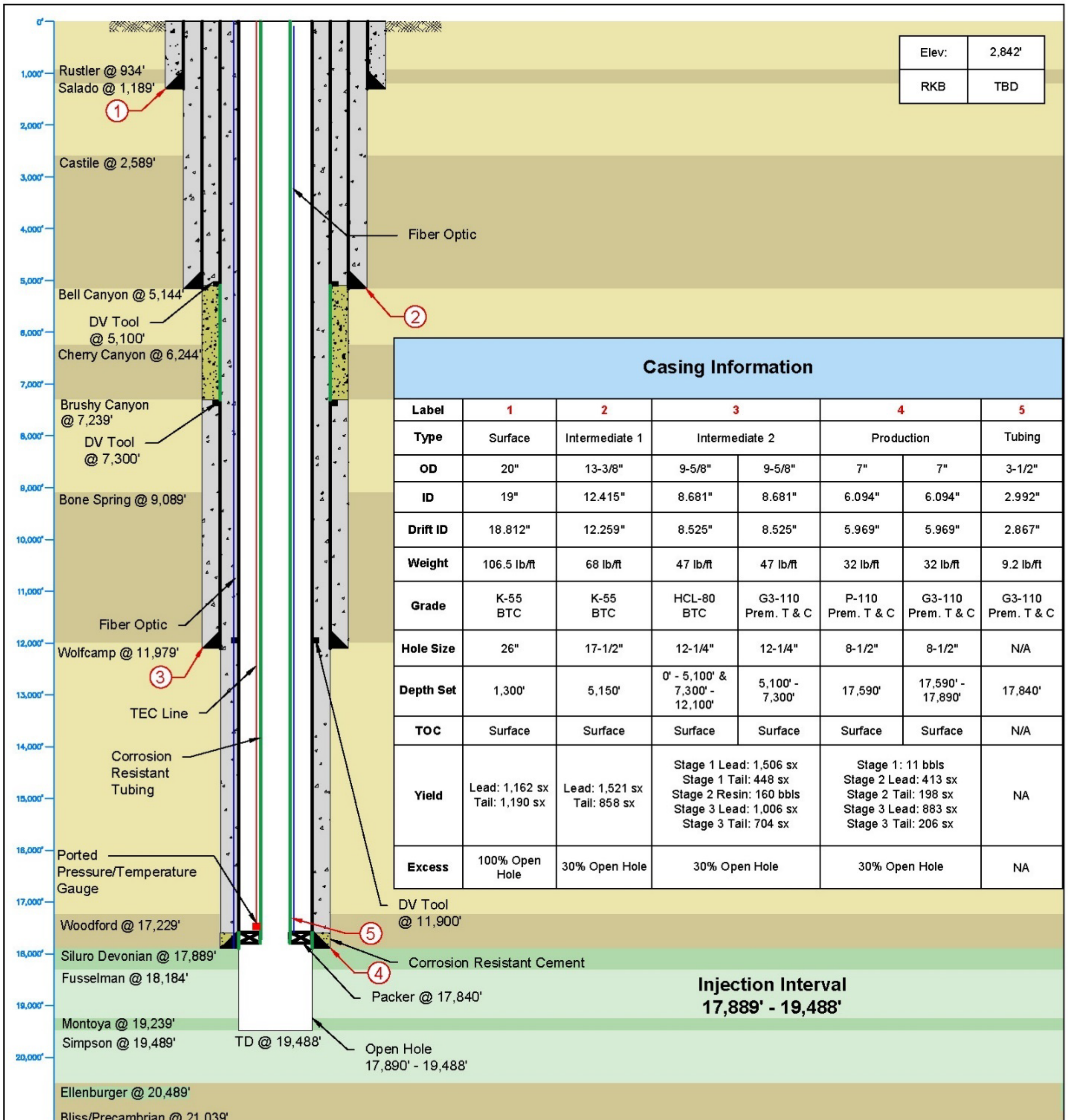
(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

12 Appendices

Appendix 1 Targa Well

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Bull Moose AGI #1 (BM AGI #1)	42-495-34978	1,895' FSL & 2,161' FEL, SEC 42, BLK 27, Public School Land Survey, A-433	KERMIT, TX	To be determined	19,488 ft	17,790 ft



Casing Information

Label	1	2	3		4		5
Type	Surface	Intermediate 1	Intermediate 2		Production		Tubing
OD	20"	13-3/8"	9-5/8"	9-5/8"	7"	7"	3-1/2"
ID	19"	12.415"	8.681"	8.681"	6.094"	6.094"	2.992"
Drift ID	18.812"	12.259"	8.525"	8.525"	5.969"	5.969"	2.867"
Weight	106.5 lb/ft	68 lb/ft	47 lb/ft	47 lb/ft	32 lb/ft	32 lb/ft	9.2 lb/ft
Grade	K-55 BTC	K-55 BTC	HCL-80 BTC	G3-110 Prem. T & C	P-110 Prem. T & C	G3-110 Prem. T & C	G3-110 Prem. T & C
Hole Size	26"	17-1/2"	12-1/4"	12-1/4"	8-1/2"	8-1/2"	N/A
Depth Set	1,300'	5,150'	0' - 5,100' & 7,300' - 12,100'	5,100' - 7,300'	17,590'	17,590' - 17,890'	17,840'
TOC	Surface	Surface	Surface	Surface	Surface	Surface	N/A
Yield	Lead: 1,162 sx Tail: 1,190 sx	Lead: 1,521 sx Tail: 858 sx	Stage 1 Lead: 1,506 sx Stage 1 Tail: 448 sx Stage 2 Resin: 160 bbls Stage 3 Lead: 1,006 sx Stage 3 Tail: 704 sx		Stage 1: 11 bbls Stage 2 Lead: 413 sx Stage 2 Tail: 198 sx Stage 3 Lead: 883 sx Stage 3 Tail: 206 sx		NA
Excess	100% Open Hole	30% Open Hole	30% Open Hole		30% Open Hole		NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS ENERGY ADVISORS AUSTIN · HOUSTON · CALGARY · WICHITA DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON	Targa Delaware LLC	Bull Moose AGI No. 01	
	Country: USA	**State/Province:** Texas	**County/Parish:** Winkler
	Location: Sec. 42, A-433, Blk 27		**District:** 08
	API No: TBD	**Field:**	**Well Type/Status:** AGI Disposal
Texas License F-9147	**Survey:**	**Project No:** F2345	**Date:** 5/6/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** CJL	**Reviewed:** WHG	**Approved:**
	Rev No: 1	**Notes:** Intermediate 2 Revisions Requested by Targa	

Figure Appendix 1-1: Schematic of Targa BM AGI #1 Well

Appendix 2 Referenced Regulations

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

Texas Administrative Code > Title 16, Economic Regulation, > Part 1 Railroad Commissions of Texas > Chapter 3, Oil and Gas Division
CHAPTER 15 - OIL AND GAS

§3.1	Organization Report; Retention of Records; Notice Requirements
§3.2	Commission Access to Properties
§3.3	Identification of Properties, Wells, and Tanks
§3.4	Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
§3.5	Application To Drill, Deepen, Reenter, or Plug Back
§3.6	Application for Multiple Completion
§3.7	Strata To Be Sealed Off
§3.8	Water Protection
§3.9	Disposal Wells
§3.10	Restriction of Production of Oil and Gas from Different Strata
§3.11	Inclination and Directional Surveys Required
§3.12	Directional Survey Company Report
§3.13	Casing, Cementing, Drilling, Well Control, and Completion Requirements
§3.14	Plugging
§3.15	Surface Equipment Removal Requirements and Inactive Wells
§3.16	Log and Completion or Plugging Report
§3.17	Pressure on Bradenhead
§3.18	Mud Circulation Required
§3.19	Density of Mud-Fluid
§3.20	Notification of Fire Breaks, Leaks, or Blow-outs
§3.21	Fire Prevention and Swabbing
§3.22	Protection of Birds
§3.23	Vacuum Pumps
§3.24	Check Valves Required
§3.25	Use of Common Storage

§3.26	Separating Devices, Tanks, and Surface Commingling of Oil
§3.27	Gas to be Measured and Surface Commingling of Gas
§3.28	Potential and Deliverability of Gas Wells to be Ascertained and Reported
§3.29	Hydraulic Fracturing Chemical Disclosure Requirements
§3.30	Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)
§3.31	Gas Reservoirs and Gas Well Allowable
§3.32	Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes
§3.33	Geothermal Resource Production Test Forms Required
§3.34	Gas To Be Produced and Purchased Ratably
§3.35	Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned
§3.36	Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas
§3.37	Statewide Spacing Rule
§3.38	Well Densities
§3.39	Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40	Assignment of Acreage to Pooled Development and Proration Units
§3.41	Application for New Oil or Gas Field Designation and/or Allowable
§3.42	Oil Discovery Allowable
§3.43	Application for Temporary Field Rules
§3.45	Oil Allowables
§3.46	Fluid Injection into Productive Reservoirs
§3.47	Allowable Transfers for Saltwater Injection Wells
§3.48	Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

§3.49	Gas-Oil Ratio
§3.50	Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51	Oil Potential Test Forms Required
§3.52	Oil Well Allowable Production
§3.53	Annual Well Tests and Well Status Reports Required
§3.54	Gas Reports Required
§3.55	Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56	Scrubber Oil and Skim Hydrocarbons
§3.57	Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58	Certificate of Compliance and Transportation Authority; Operator Reports
§3.59	Oil and Gas Transporter's Reports
§3.60	Refinery Reports
§3.61	Refinery and Gasoline Plants
§3.62	Cycling Plant Control and Reports
§3.63	Carbon Black Plant Permits Required
§3.65	Critical Designation of Natural Gas Infrastructure
§3.66	Weather Emergency Preparedness Standards
§3.70	Pipeline Permits Required
§3.71	Pipeline Tariffs
§3.72	Obtaining Pipeline Connections
§3.73	Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76	Commission Approval of Plats for Mineral Development
§3.78	Fees and Financial Security Requirements
§3.79	Definitions
§3.80	Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81	Brine Mining Injection Wells
§3.83	Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84	Gas Shortage Emergency Response

§3.85	Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86	Horizontal Drainhole Wells
§3.91	Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93	Water Quality Certification Definitions
§3.95	Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96	Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97	Underground Storage of Gas in Salt Formations
§3.98	Standards for Management of Hazardous Oil and Gas Waste
§3.99	Cathodic Protection Wells
§3.100	Seismic Holes and Core Holes
§3.101	Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102	Tax Reduction for Incremental Production
§3.103	Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106	Sour Gas Pipeline Facility Construction Permit
§3.107	Penalty Guidelines for Oil and Gas Violations

Appendix 3 Oil and Gas Wells within MMA of the BM AGI Well Site

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34323	SILVER DOLLAR 4231-27 A 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,814
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,811
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,816
42-495-34481	BRIDAL VEIL STATE W 4132-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145
42-495-33759	VALLECITO 37-28 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718
42-495-34328	SILVER DOLLAR 4231-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263
42-495-34331	SILVER DOLLAR 4231-27 E 5H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564
42-495-34485	BRIDAL VEIL STATE W 4132-27 L 12H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129
42-495-33871	MITCHELL 42-27 1	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630
42-495-34488	BRIDAL VEIL STATE W 4132-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627
42-495-34482	BRIDAL VEIL STATE W 4132-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176
42-495-33840	SAINT VRAIN 48-28 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185
42-495-33763	AVALANCHE 42-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194
42-495-33726	SILVER DOLLAR 31-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188
42-495-34484	BRIDAL VEIL STATE W 4132-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217
42-495-34038	MITCHELL 42-27 2	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516
42-495-34489	BRIDAL VEIL STATE W 4132-27 K 11H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637
42-495-34332	SILVER DOLLAR 4231-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897
42-495-34329	SILVER DOLLAR 4231-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193
42-495-34327	SILVER DOLLAR 4231-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545
42-495-34325	SILVER DOLLAR 4231-27 D 4H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-34326	SILVER DOLLAR 4231-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34324	SILVER DOLLAR 4231-27 B 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621
42-495-34330	SILVER DOLLAR 4231-27 C 3H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537
42-495-34483	BRIDAL VEIL STATE W 4132-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972
42-495-33236	HARRISON STATE 41 1H	DEVON	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868

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Appendix 5 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
PPM – Parts Per Million
QA/QC – quality assurance/quality control
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 6 Targa Bull Moose AGI Well - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

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

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

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

Appendix 7 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

Request for Additional Information: Bull Moose Gas Plant
October 31, 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.	2.3	9	"The TRRC has issued an Underground Injection Control (UIC) Class II permit under its Statewide Rule 9 (Appendix 2) for BM AGI #1." Per 40 CFR 98.448(a)(6), please clarify whether the MRV plan contains the "well identification number used for the Underground Injection Control permit" or the "well identification numbers in the permit application" for the injection well.	The following clarifications have been added page 9: TRRC issued the permit to dispose of non-hazardous oil and gas waste by injection into a porous formation not productive of oil and gas no. 17541 to Targa for the Bull Moose AGI lease. Well identification and permit parameters: • BM AGI #1 API Number: 42-495-34978 • UIC Permit Number: 000126603
2.	5.2	51	Section 5.2 of the MRV plan briefly mentions potential leakage from approved wells that have not yet been drilled, but it does not characterize the likelihood, magnitude, and timing of leakage through this pathway. Please include a characterization of potential leakage through future wells, including a discussion of the likelihood, magnitude, and timing of leakage, and update the strategy in Section 6.2 as necessary. Please also update any other applicable sections in the MRV plan as necessary.	Section 5.2 has been modified to evaluate the likelihood, magnitude and timing of potential leakage from approved wells that have not yet been drilled.
3.	5.7	61	"The predicted value of effective pressure changes on Figure 5.7-4 and Figure 5.7-5 shows that the pore pressure will change less than 30 psi after 30." Please clarify what is meant by "after 30" as it appears in the statement above from the MRV plan.	This statement in the revised MRV plan has been edited to read: "…shows that the pore pressure will change less than 30 psi after 30 years."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	6.0	63	We recommend adding a monitoring strategy for future wells to Table 6-1 in the MRV plan.	A monitoring strategy has been added to the Table 6-1 in a new line for "Potential Leakage Pathway" called: "Wells that have not yet been drilled". It includes: - Monitor applications for permit to drill and permit to inject made to the TRRC - Communicate with operators/drillers that are active within the MMA so they are aware that they are drilling in an area that has CO_2/H_2S injection activities.
5.	6.8	67/68	Section 40 CFR 98.448(a)(3) requires "a strategy for detecting and quantifying any surface leakage of CO_2." While Section 6.8 of the MRV plan indicates that the facility will quantify leakage from surface equipment, please provide example quantification strategies that may be applied to the surface leakage pathways identified in the plan.	Section 6.8.1 of the revised MRV plan has been updated to provide example on quantification strategies for surface leakage.
6.	8.1	71	"Receiving flow meter r in the following equations corresponds to meters FE in Figure 3.7-1." While the caption for Figure 3.7-1 in the MRV plan mentions "Flow meter (FE)," the figure shows only a meter labeled "FM". Please clarify.	The abbreviation for "flow meter" has been updated to "FM" throughout the MRV plan.
7.	8.1	71	"r = Receiving **volumetric** flow meter." Per 40 CFR 98.443(a)(2), this variable should be, "r = Receiving flow meter." 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. Additionally, please review the equations in the appendices.	All equations, variables, and text regarding the equations have been checked and updated, as necessary, in the revised MRV plan to ensure that they are consistent with the equations, variables, and text as they appear in 40 CFR 98.443.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	8.2	72	"u = **Volumetric** flow meter." Per 40 CFR 98.443(c)(2), this variable should be, "u = Flow meter." 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.	All equations, variables, and text regarding the equations have been checked and updated, as necessary, in the revised MRV plan to ensure that they are consistent with the equations, variables, and text as they appear in 40 CFR 98.443.
9.	8.6	73	"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 the GHGRP." Per 40 CFR 98.443(f)(2), this variable should be, "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**." 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.	All equations, variables, and text regarding the equations have been checked and updated, as necessary, in the revised MRV plan to ensure that they are consistent with the equations, variables, and text as they appear in 40 CFR 98.443.

MONITORING, REPORTING, AND VERIFICATION PLAN

Bull Moose AGI #1

Targa Northern Delaware, LLC (TND)

Version 2.0

September 24, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) proposes an underground injection project at the Targa Bull Moose Gas Processing Plant (the Plant) located approximately 15 miles west of Kermit in Winkler County, district 08, Texas. The Plant is within the eastern part of the Delaware Basin region of the Permian Basin. (**Figure 1-1**).

TND submitted a Class II Acid Gas Injection (AGI) permit application (Form W-14) for the Bull Moose AGI #1 well (BM AGI #1) to the Texas Railroad Commission (TRRC). TND intends to drill BM AGI #1 in Q4 of 2024 for the purpose of disposing of the treated acid gas (TAG) that is a byproduct of natural gas processing operations at the Plant. The TAG stream is anticipated to consist of approximately 70% CO_2 (carbon dioxide) and 30% H_2S (hydrogen sulfide), with trace components of hydrocarbons (C1(methane) – C7(heptane)) and nitrogen. The project, with a design life of 30 years, plans to inject TAG through BM AGI #1 into the deep subsurface in the Siluro-Devonian, Fusselman, and Montoya formations.

The project allows TND to run the Plant at full capacity without discharging large amounts of CO_2 to the atmosphere; replacing the flare with deep injection decreases the negative environmental footprint of the gas plant.

TND has significant experience in the handling and disposal of TAG in this remotely populated area. TND submitted forms and supporting documentation designed to meet the requirements of Texas Administrative Code Title 16 Chapter 3 Rule §3.9 and current best engineering practices to ensure that the USDW and the atmosphere are protected from any contamination from injection.

TND is currently authorized to inject a total of up to 20 million standard cubic feet per day (MMSCFD) of TAG in the approved BM AGI #1 (API 42-495-34978) in accordance with Statewide Rule 9 of the TRRC. TND received authorization to inject H_2S under the TRRC Rule 36. BM AGI #1 is located on the Plant property (**Figure 1-2**). The permitted injection interval is between 17,889 feet (ft) and 19,488 ft.

The BM AGI #1 well will be constructed with four strings of casing cemented to surface. Corrosion resistant alloys will be used in the bottom 300 ft of the long-string, in the confining zone. Acid resistant cements will also be used across the upper confining zone. Monitoring systems will be installed to ensure that bottomhole injection pressure does not exceed 90% of the determined fracture gradient of the injection interval. TND is requesting a maximum allowable surface pressure of 0.5 psi/ft (pounds per square inch per foot), or 8,969 psi.

TND submits this Monitoring, Reporting, and Verification (MRV) plan for the BM AGI #1 well to the United States Environmental Protection Agency (U.S. EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 in BM AGI #1 for 30 years. Following the operational period, TND proposes a post-injection monitoring and site closure period of 15 years.

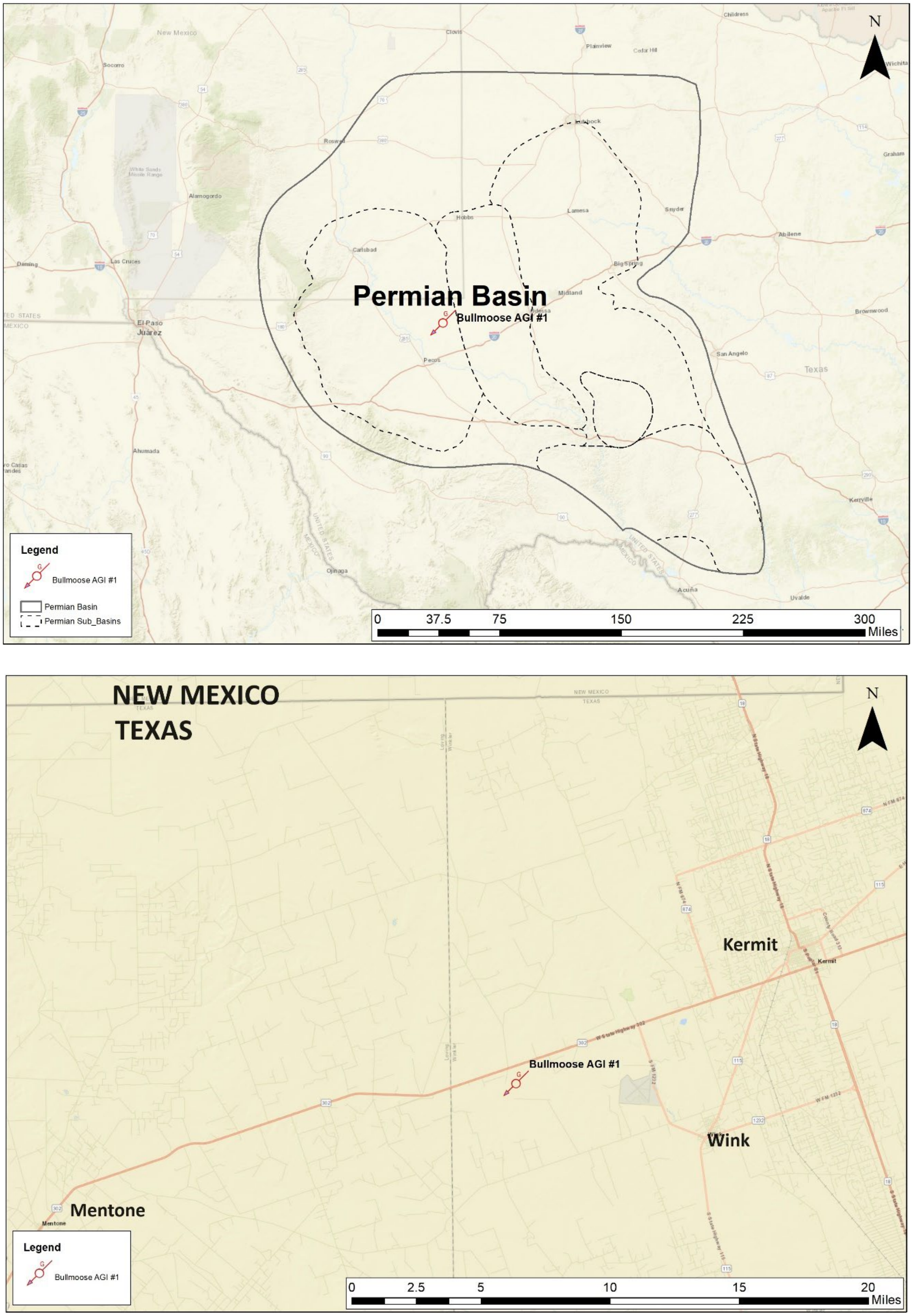


Figure 1-1: *Location of the Bull Moose Facility in the Permian Basin, Texas*

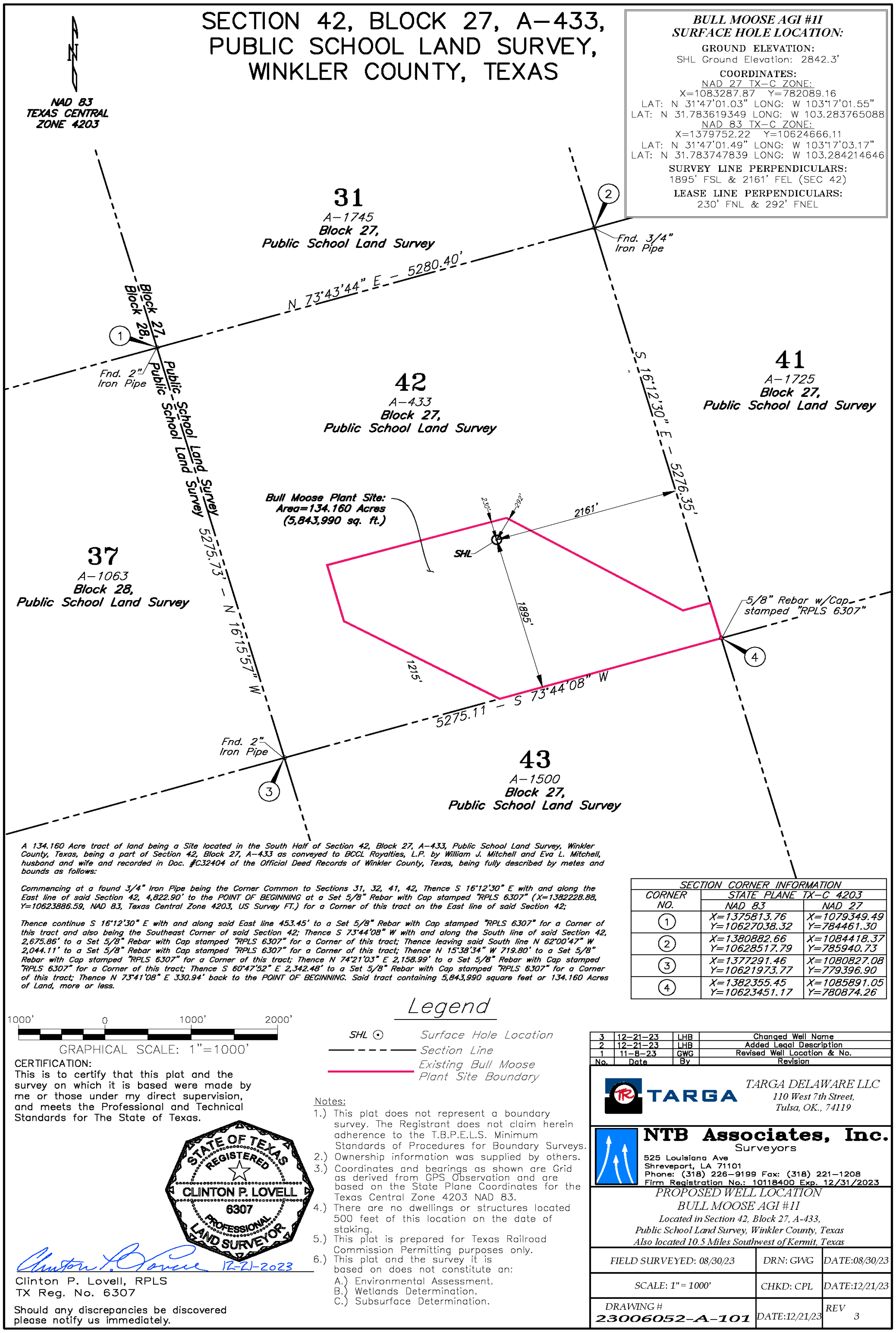


Figure 1-2: Location of the Bull Moose Gas Plant and BM AGI #1 Well

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 589241.

2.2 UIC injection well identification numbers

This MRV plan is for the BM AGI #1 well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The TRRC has issued an Underground Injection Control (UIC) Class II permit under its Statewide Rule 9 (**Appendix 2**) for BM AGI #1. All oil- and gas-related wells around the BM AGI #1 well, including both injection and production wells, are regulated by the TRRC which has primacy to implement the UIC Class II program.

3 Project Description

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

3.1 General Geologic Setting / Surficial Geology

The Plant is located in Sec. 42, A-433, Blk 27, approximately 10.5 miles south-west of Kermit in Winkler County, Texas, immediately adjacent to the BM AGI #1 well **(Figs 1-1, 1-2)**. The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

3.2 Bedrock Geology

3.2.1 Basin Development

The Bull Moose Gas Plant and the BM AGI #1 well are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**).

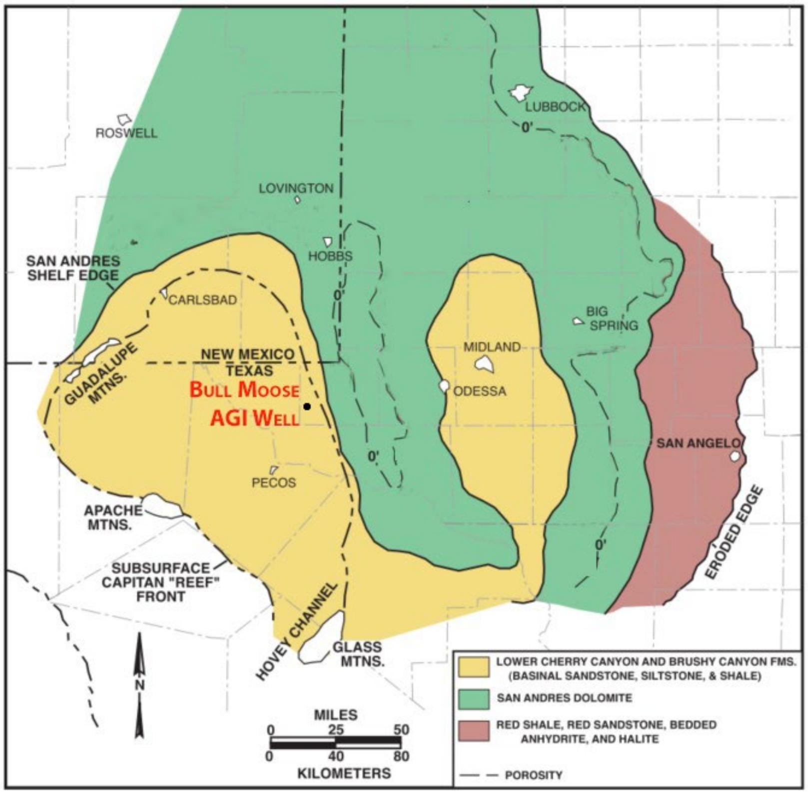


Figure 3.2-1: *Structural features of the Permian Basin during the Late Permian. Location of the TND BM AGI well is shown by the black circle. (Modified from Ward, et al (1986))*

The BM AGI well is in the Delaware Basin portion of the broader Permian Basin. **Figure 3.2-2** is a generalized stratigraphic column showing the formations that underlie the Bull Moose Gas Plant and BM AGI #1 well site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below. Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit.

Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (with formation thickness varying from 0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit’s overall porosity and permeability.

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

Figure 3.2-2: *Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

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

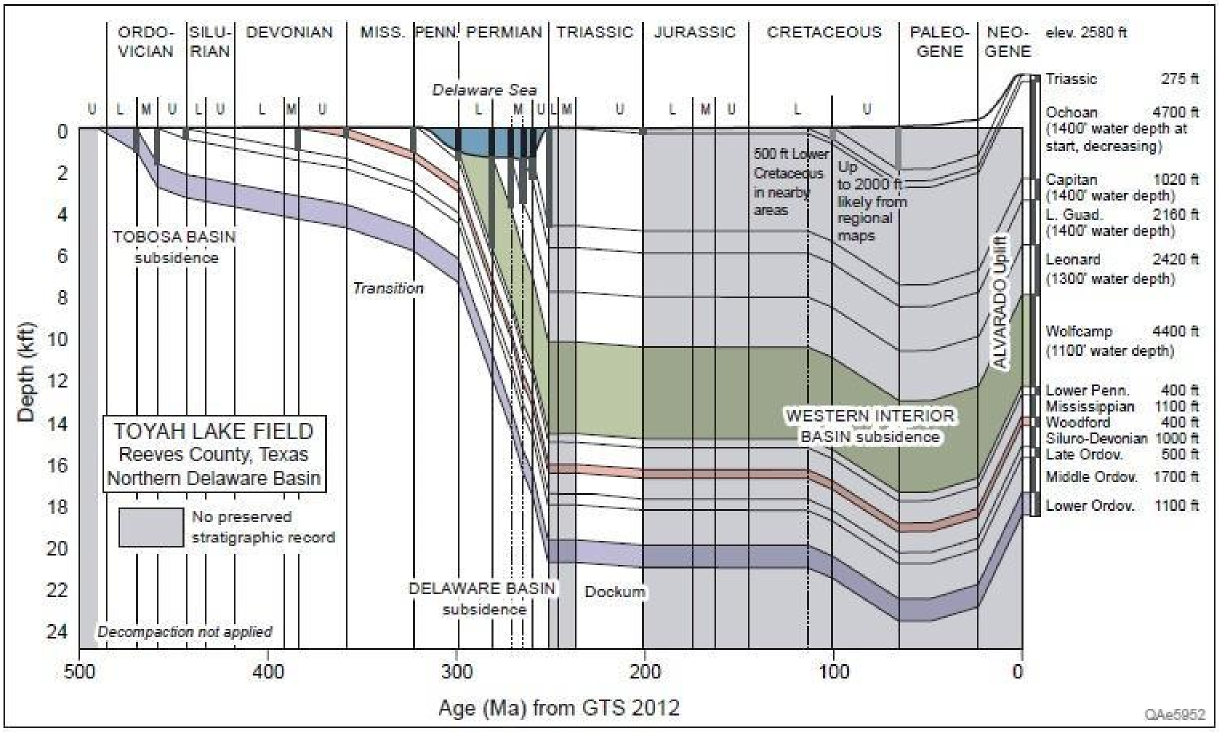


__Figure 3.2-3:__ A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)

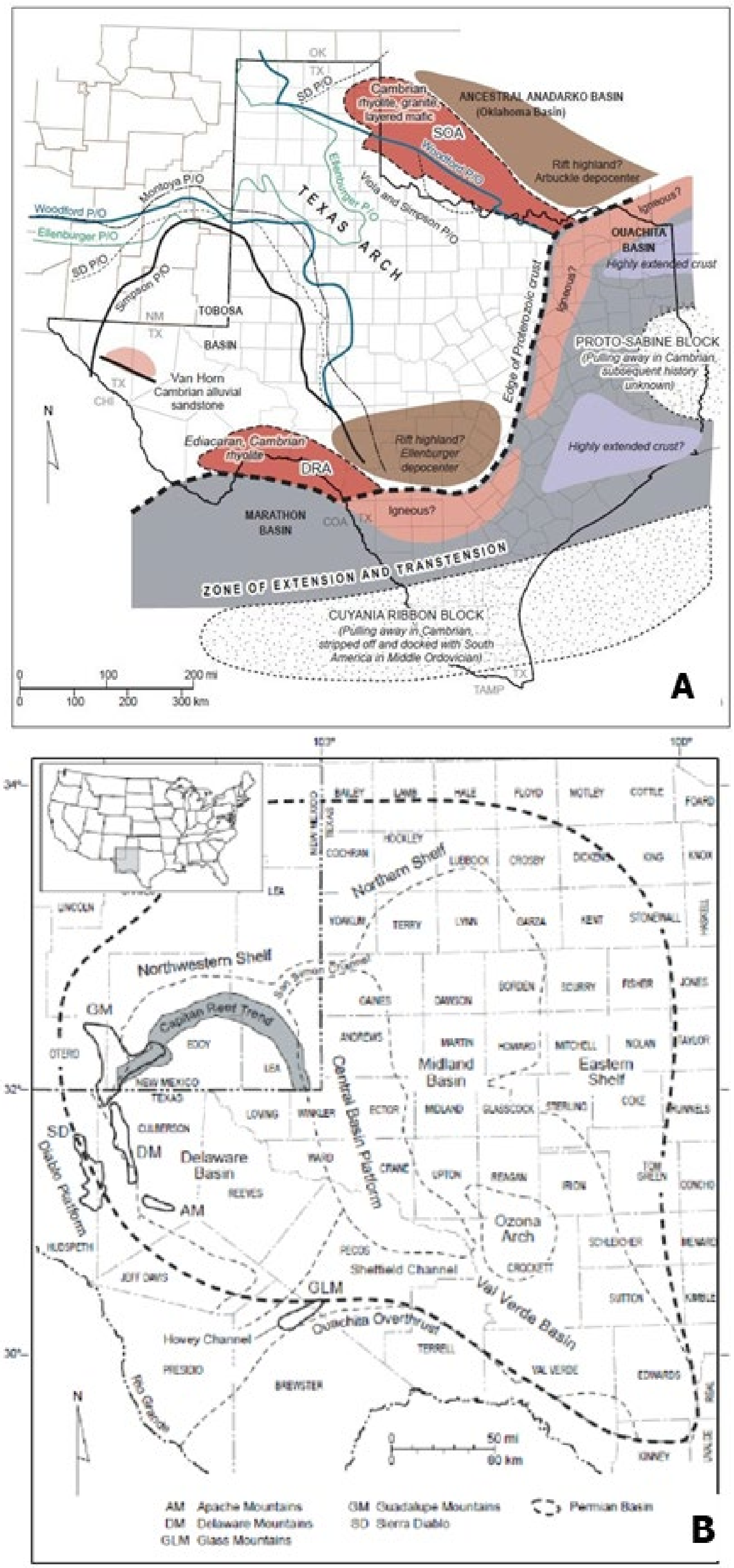


Figure 3.2-4: *Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

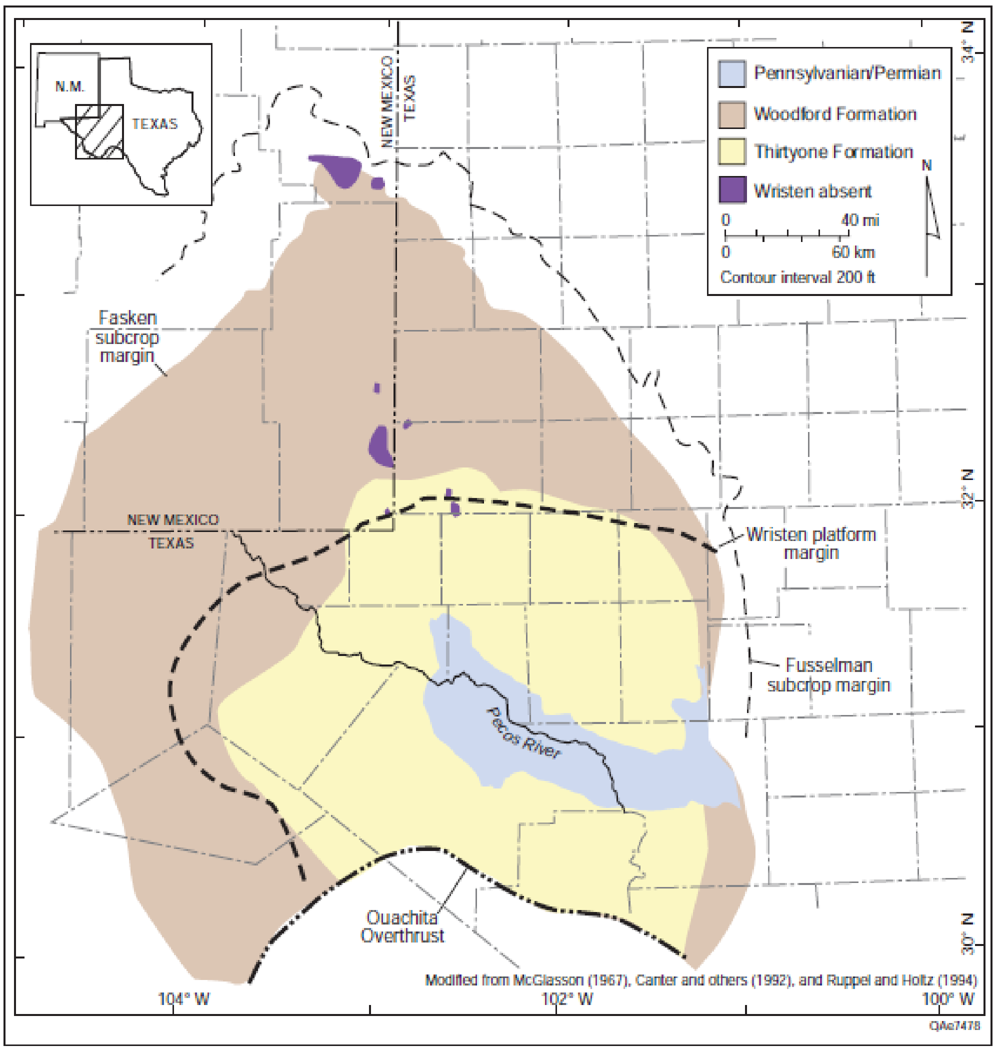


Figure 3.2-5: *A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial

exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

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

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian sediments include the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). In the area, the Atoka Formation (0-500 ft) was deposited during another sea-level transgression. is dominated by siliciclastic sediments, with depositional environments ranging from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

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

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued throughout

the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

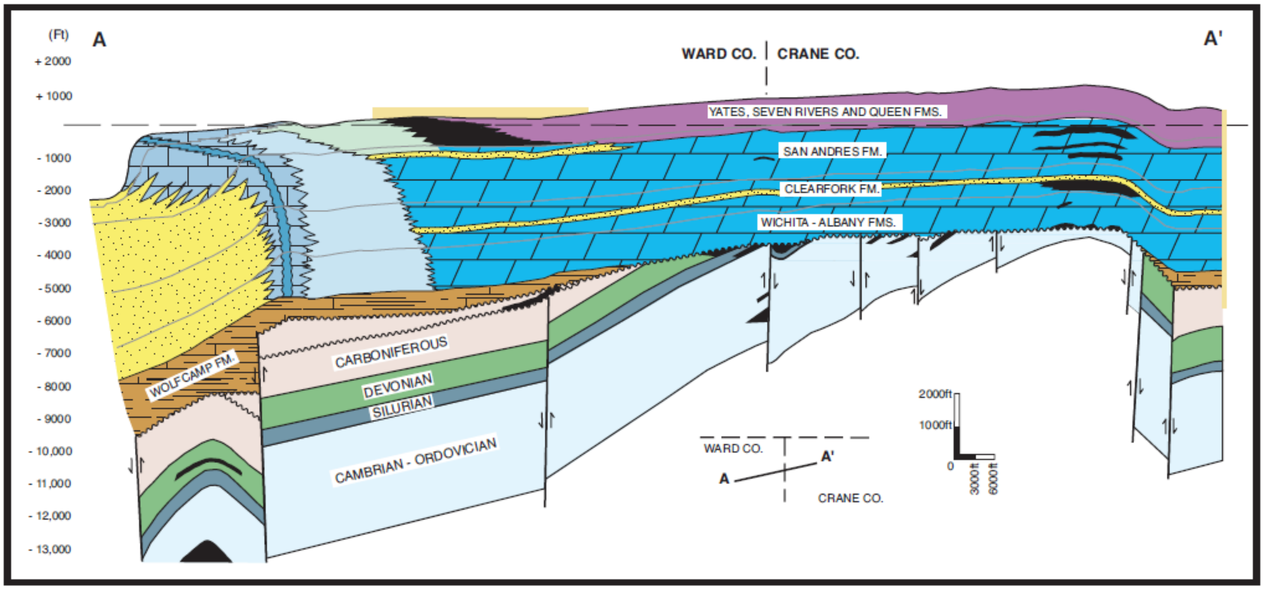


__Figure 3.2-6:__ Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

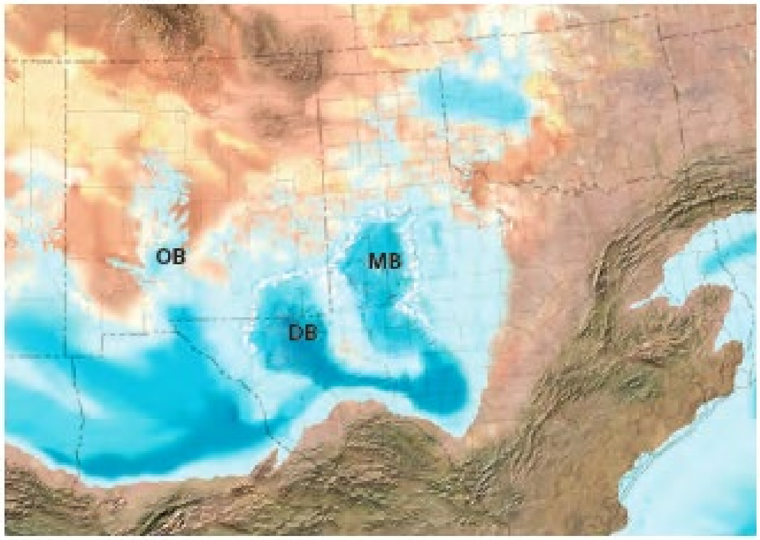


Figure 3.2-7: *Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a “carbonate factory” on the shelf and shelf edge. Carbonate debris beds shed off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s of feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso are the clean white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within

the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon formations.

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

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

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (Figure 3.2-2). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the Bull Moose AGI well, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Within the Bull

Moose area, there is no active production from the Permian Delaware Mountain Group, but there is production from the basinal Bone Spring and Wolfcamp formations. The injection and confining zones for BM AGI #1 are discussed below.

3.3 Injection Interval Properties

3.3.1 Siluro-Devonian to Ellenburger Group

In the context of BM AGI #1, the designated injection targets encompass the Siluro-Devonian formations, specifically the Devonian, Wristen, Fusselman and Montoya strata. The total thickness of the injection interval is estimated to be 1,594 ft (**Table 3.3-1**).

Table 3.3-1: *Estimated BM AGI #1 formation top depths, formation thicknesses, seal and reservoir thicknesses (total), and average porosity, and permeability.*

Formation	Measured Depth (ft)	Formation thickness (ft)	Unit Thickness (ft)	Porosity (%)	Permeability (mD)	Behaviour	Notes*
Rustler Fm.	934	255	4,165			Seal	450' base of useable groundwater
Salado Fm.	1,189	1,400		2.5	0.2	Seal	1200' base of USDW
Castile Fm.	2,589	2,510		1	0.01	Seal	
Lamar Ls.	5,099	45	3,990	15	100	Reservoir	
Bell Canyon Fm.	5,144	1,100		23	110	Reservoir	
Cherry Canyon Fm.	6,244	995		15	12	Reservoir	
Brushy Canyon Fm.	7,239	1,850		12	11	Reservoir	
Bone Spring Fm.	9,089	2,860	2,860	2	0.2	Seal	
Wolfcamp	11,979	1,600				Reservoir	Deepest nearby production wells
Strawn Fm.	13,579	760				Reservoir	
Atoka Fm.	14,339	215				Reservoir	
Morrow Fm.	14,554	1,795				Reservoir	
Barnett Sh.	16,349	440	1,540	1	0.1	3° Seal	
Mississippian Ls.	16,789	440		2	1	2° Seal	
Woodford Sh.	17,229	660		1	0.1	1° Seal	
Wristen Grp. And Thirtyone Fm.(Siluro Devonian)	17,889	289	1,594	5	1	Injection interval	
Fusselman Fm.	18,184	1,055		7	1	Injection interval	
Montoya Grp.	19,239	250		3	1	Injection interval	
Simpson Sands*	19,489	1,000		15	45	Not Drilled	
Ellenburger Grp.	20,489	550		6	15	Not Drilled	
Bliss/Precambrian	21,039					Lower seal	

*Simpson Sands consist of three discrete sand bodies (~300 ft of sands) within the over thousand-feet-thick unit.

ORDOVICIAN.

ELLENBURGER GROUP – The Ordovician Ellenburger Group is below the injection interval and is comprised of dolomites and limestones that are approximately 550 ft thick. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during later tectonic events (**Figure 3.3-1**).

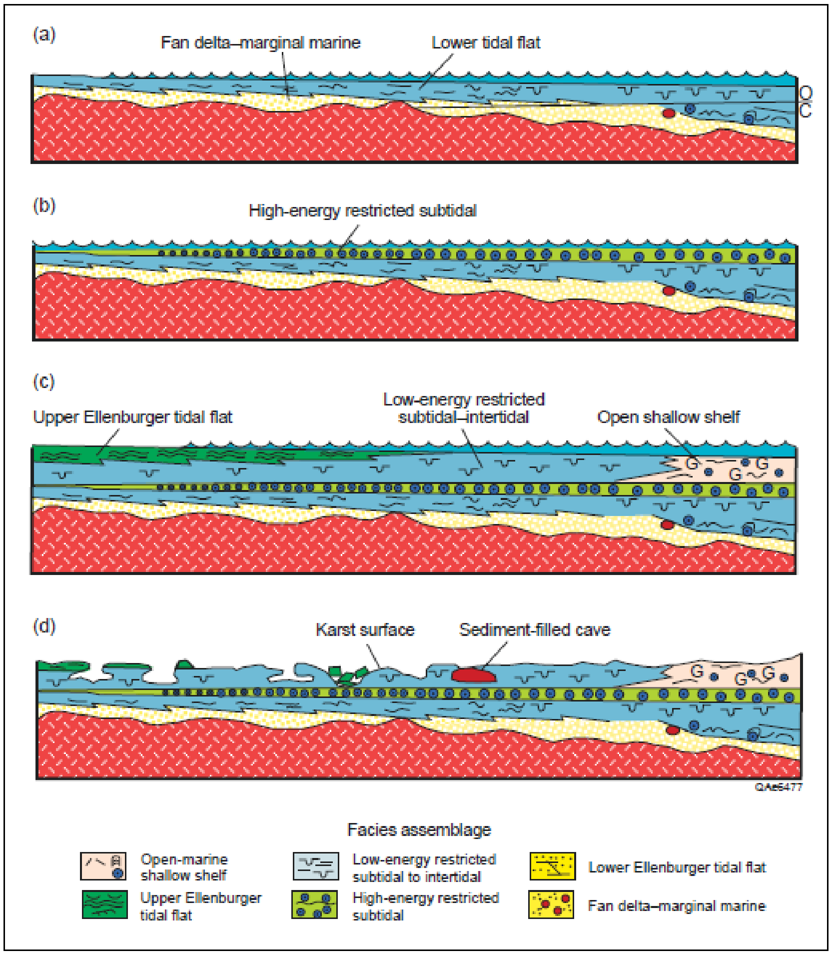


Figure 3.3-1: *Depositional model for Ellenburger Group deposits. The diagram shows a sequence of transgressive sandstones (Bliss Sandstone, yellow) to carbonates (Panels a through c followed by a regressive sequence (Panels c – d) with exposure and karstification in Panel d (from Loucks and Kerans, 2019).*

Within the Ellenburger Group strata, the upper and middle section typically has the highest porosity and permeability due to karsting and cave development as well as later faulting and fracturing (**Figure 3.3-2**). Late diagenesis plays an important role in porosity destruction and resurrection. Based on work by Loucks (2016, unpublished report), the best karst-related porosity is to the east of the Bull Moose area, whereas the Bull Moose area is in the zone of porosity due to tectonically controlled faulting and fracturing.

Porosity and permeability in the Ellenburger section can vary greatly due to the above considerations, but a realistic value for the porosity and permeability, at approximate 20,000 ft depth, is 5-6% and 15 mD (**Table 3.3-1**). Potentially the range of porosity and permeability can range up to 12% and greater than 100 mD (Loucks and Kerans, 2019).

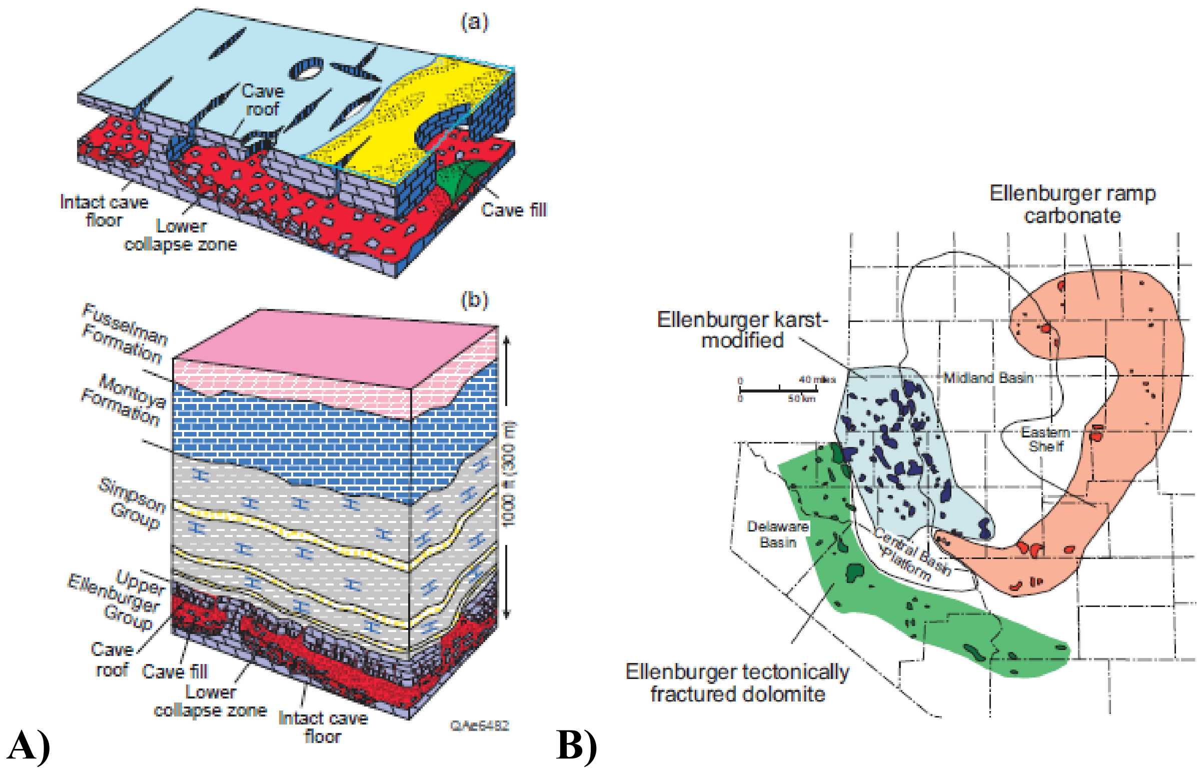


Figure 3.3-2: Karst development. ***A)*** *Cave development in the upper Ellenburger rocks and their potential impact to produce porosity and permeability (from Loucks and Kerans, 2019).* ***B)*** *Zones of potential porosity creation: karst related (blue), fault and fracture (green) and enhanced primary porosity (orange) (from unpublished manuscript by R. Loucks, 2016).*

SIMPSON GROUP – The deposits of the Simpson Group represent a regional transgression after the unconformity at the end of Ellenburger deposition. This group is a thick sequence of carbonates, sandstones, and shales (~1,000 ft) which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. There are several transgressive/regressive cycles within the section, but only the transgressive sandstone sections have significant porosity. The rest of the section typically consists of mud-rich carbonates and shales. Within the sandstones (particularly the McKee Sandstone member), well logs indicate porosity averages around 15% (**Table 3.3-1**). Permeability averages 45 mD (Harrington, 2019), though cementation and compaction may decrease that in the area.

MONTOYA GROUP – The Montoya deposits (~250 feet) are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin (**Figure 3.3-3**). Like the Ellenburger Group, the porosity within the Montoya Group is dependent on depositional environment and diagenesis. Sediments deposited in higher energy environments tend to have better initial porosity than those of low-energy environments. Compaction destroys porosity, while dolomitization produces

secondary porosity and local interactions of these factors determine porosity and permeability in a given area. Based on well logs, the average porosity is approximately 3%, with scattered zones over 5% (**Table 3.3-1**). The probable average permeability is probably less than 1 mD, but fracturing may enhance it.

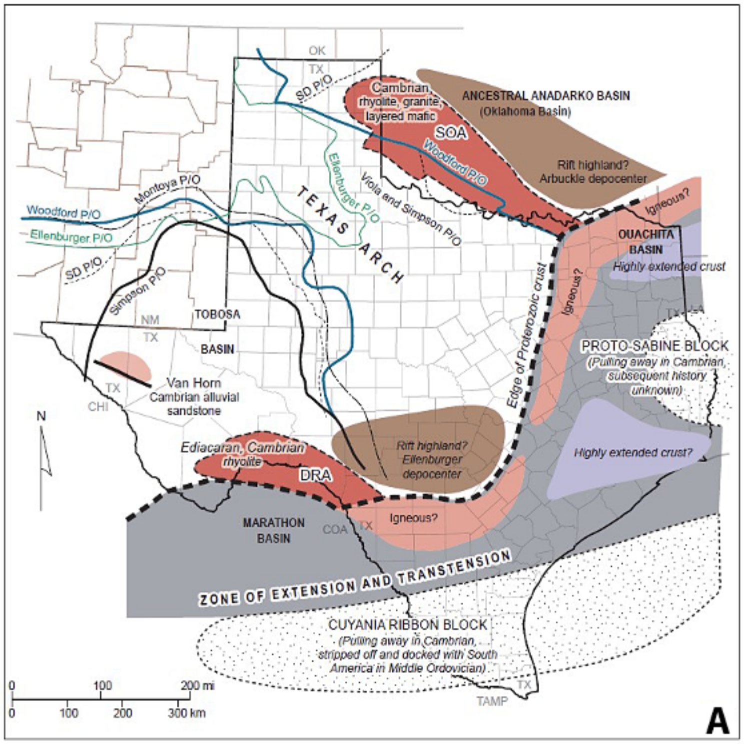


Figure 3.3-3: *Tectonic features during development of the Tobosa and Permian Basins during Late Mississippian time (Ewing, 2019).*

ORDOVICIAN – SILURIAN.

FUSSELMAN FORMATION – The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Bull Moose area, the Fusselman thickens to around 1,000 ft of high-energy packstones to grainstones. Like the Montoya Group, these high-energy sediments started out with the best primary porosity, but diagenesis usually has decreased both the porosity and permeability unless impacted by exposure and dissolution. Based on well logs, the porosity averages around 2%, but there are zones, like in well API No. 42-495-31047, with over 70 ft of greater than 5% porosity. Reported permeability for shallower sections range from 0.001 to 10 mD (Ruppel, 2019).

LOWER DEVONIAN – SILURIAN.

THIRTYONE AND WRISTEN FORMATIONS – Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section (~275 ft thick). Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Bull Moose area. These deposits range from deeper ramp mudstones and wackestones, to chert- and sponge/radiolarian-rich hemipelagic mudstones (Wristen/Thirtyone) to outer ramp packstones (**Figure 3.3-4**, Thirtyone; Ruppel, 2020; Ruppel et al., 2020a). Porosity and permeability in the Wristen are limited in the main body of the unit (1-2%), but exposure events and carbonate dissolution can improve the porosity (~5%). Within Thirtyone deposits, the chert-rich hemipelagic

deposits maintain the best porosity (up to 40%, up to 80 mD), while the limestones have less than 7% porosity and less than 1 mD of permeability (**Table 3.3-1**; Ruppel et al., 2020a).

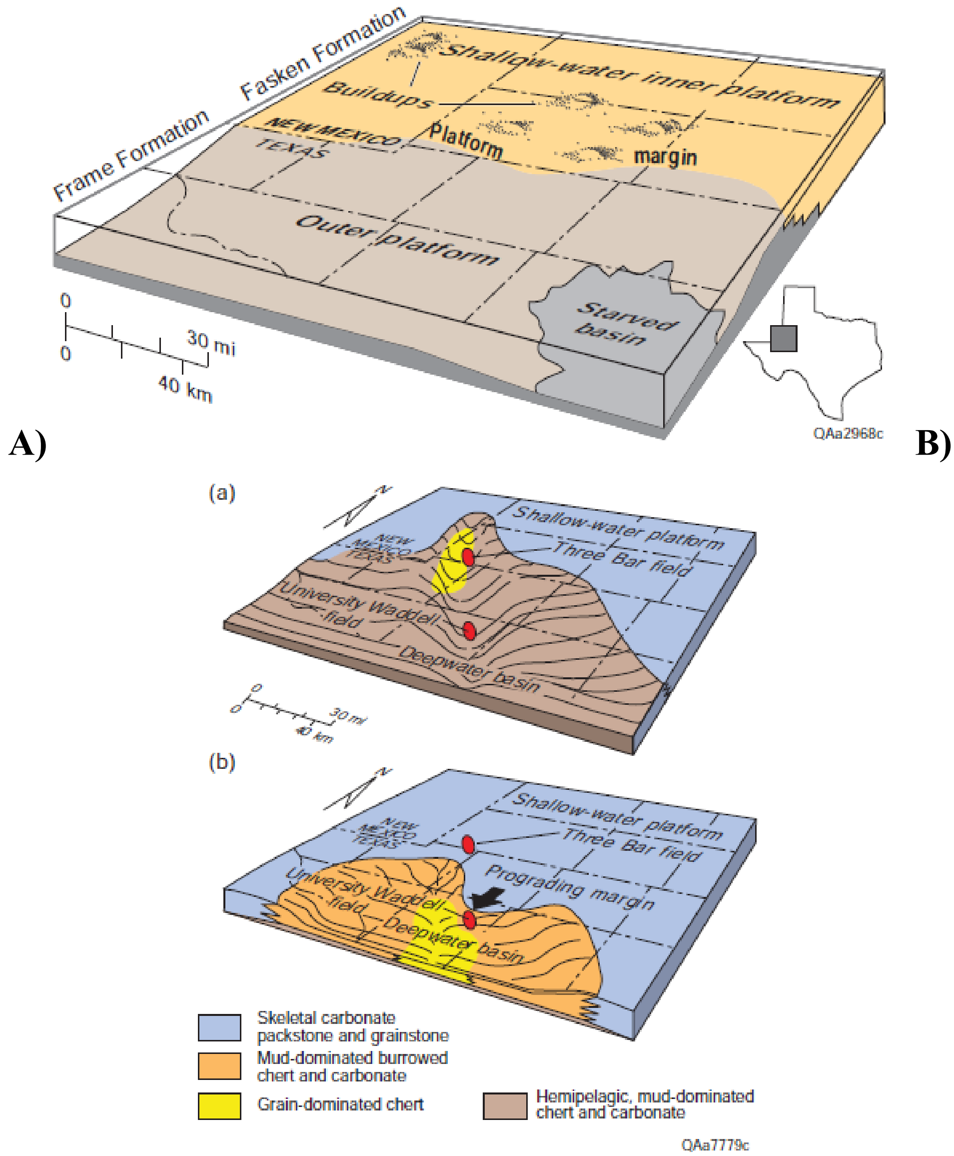


Figure 3.3-4: *Generalized Paleogeography.* ***A)*** *Generalized paleogeography for the Wristen Group (from Ruppel, 2020).* ***B)*** *Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Bull Moose area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

3.3.2 Upper Confining Zone Properties: Woodford Shale/Mississippian Limestone

Mississippian. Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 ft thick in the Bull Moose area and is regionally extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is ~555 ft thick. Known production from this limestone comes from small, one to two well fields that normally have poor porosity (4-9%) and permeability (Broadhead, 2017)

in New Mexico and a few isolated fields in the shallow water, high-energy limestones in Texas. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is ~750 ft thick. Overall, Mississippian units would be good seals in preventing upward fluid movement through the section (**Table 3.3-1**).

Upper Devonian. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units. In combination with the Mississippian section, it makes an excellent seal for potential injection. the Woodford Shale is ~620 ft thick in the Bull Moose area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. Porosity in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). Porosity can reach 10% (Jarvie et al., 2001), but it averages around 1% with very low permeabilities (**Table 3.3-1**).

3.3.3 Lower Confining Zone Properties: Ordovician to Precambrian

Ordovician. The lower approximately 150 to 200 ft of the Ellenburger Group sediments are normally less porous and have lower permeability (1 – 2% porosity and <2 mD) due their original depositional environment and the depth of burial (Loucks and Kerans, 2019), making this zone a potential underlying seal.

Cambrian to Precambrian. The oldest sediment in the area is Cambrian Bliss Sandstone (Broadhead, 2017) which overlies Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland. With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Bliss Sandstone and crystalline Precambrian rocks are potential lower seals. Within the Bull Moose area, no porosity and permeability data could be found. Considering their depth, compactional history, and potential diagenetic alteration, the Bliss sandstones and associated granitic debris (from weathering of the basement rock) are probably relatively tight.

3.4 Structure/Faulting

Structure maps and cross sections for the injection interval and confining zones are provided in **Figures 3.3-5** through **3.3-15**.

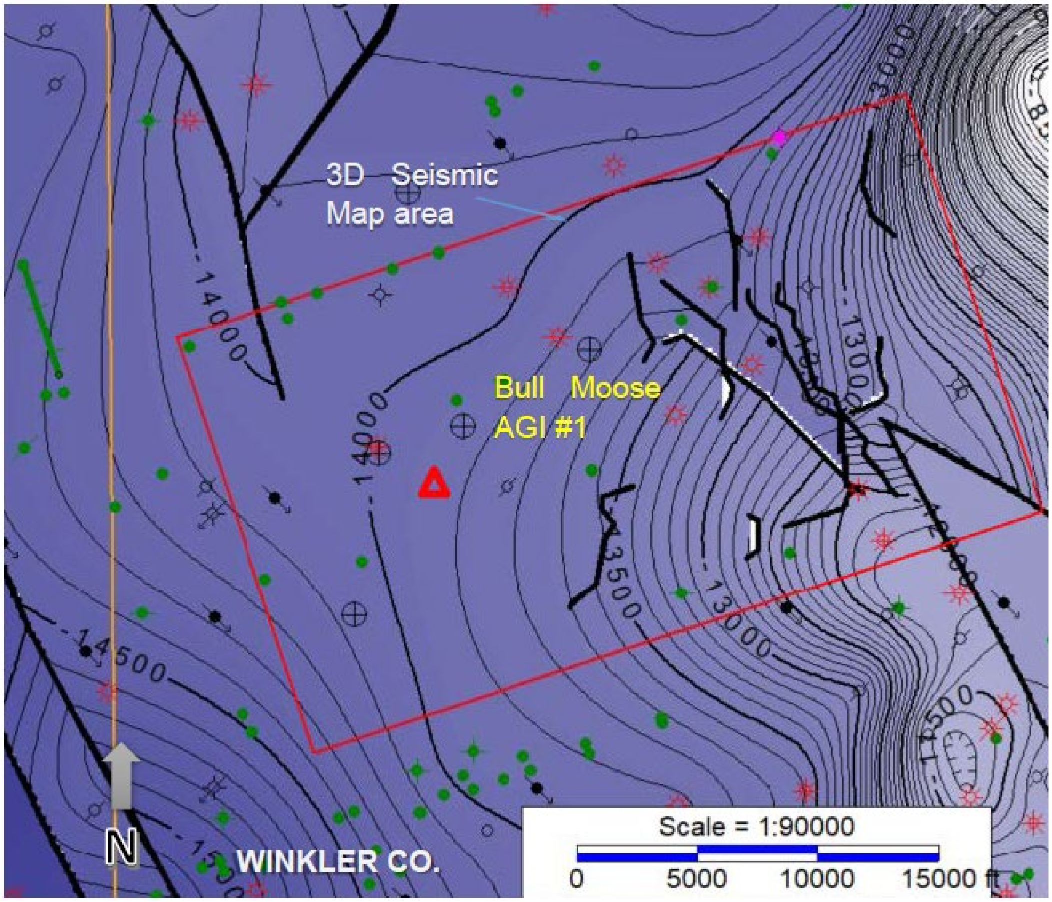


Figure 3.3-5: Mississippian Limestone Subsea Structure Map. CI = 100 ft.

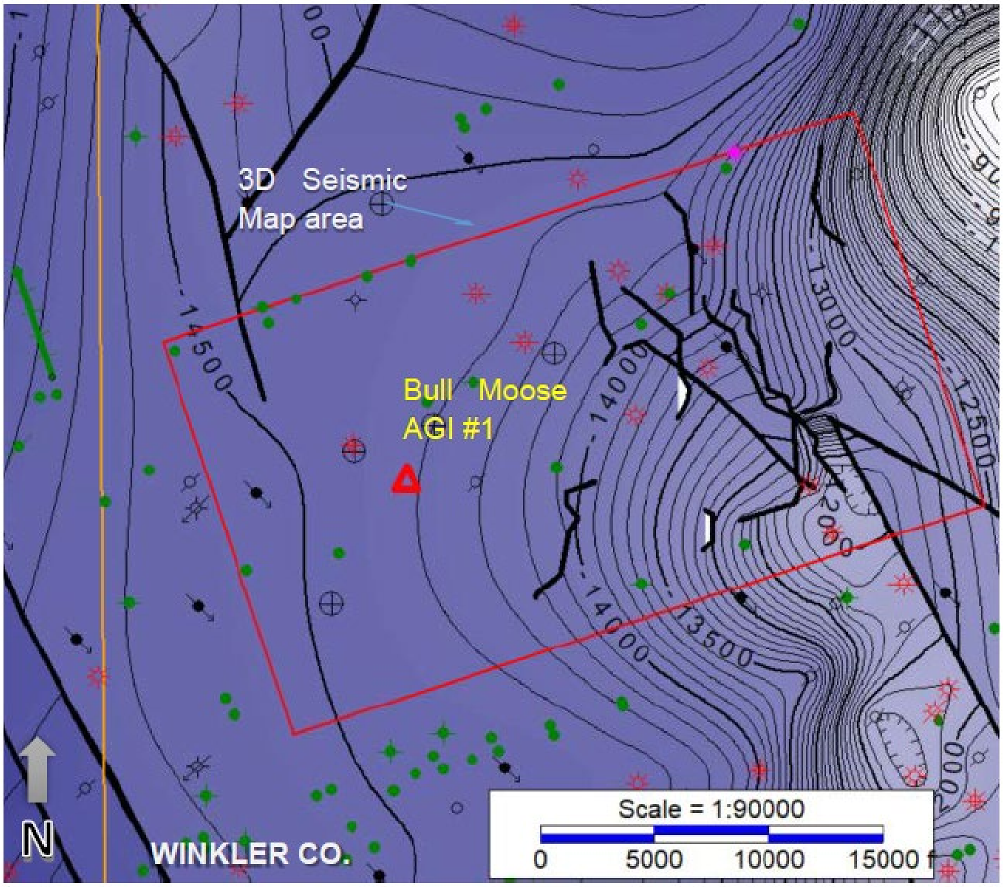


Figure 3.3-6: Woodford Shale Subsea Structure Map. CI = 100 ft.

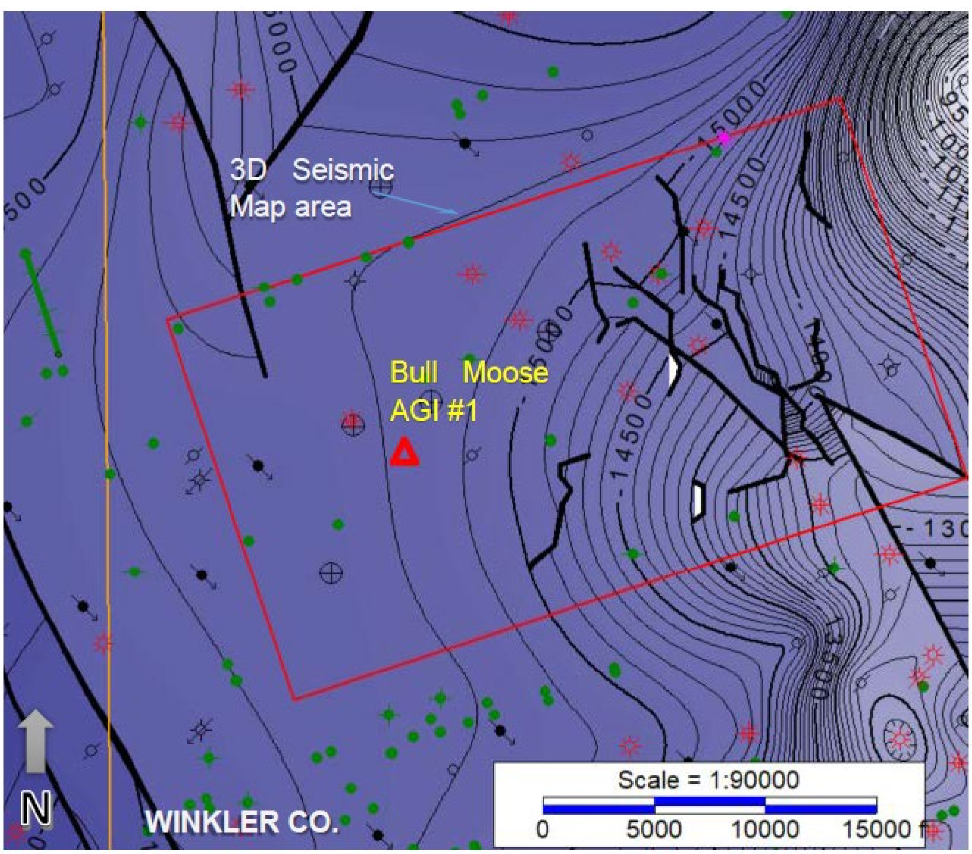


Figure 3.3-7: Siluro-Devonian Strata Subsea Structure Map. CI = 100 ft.

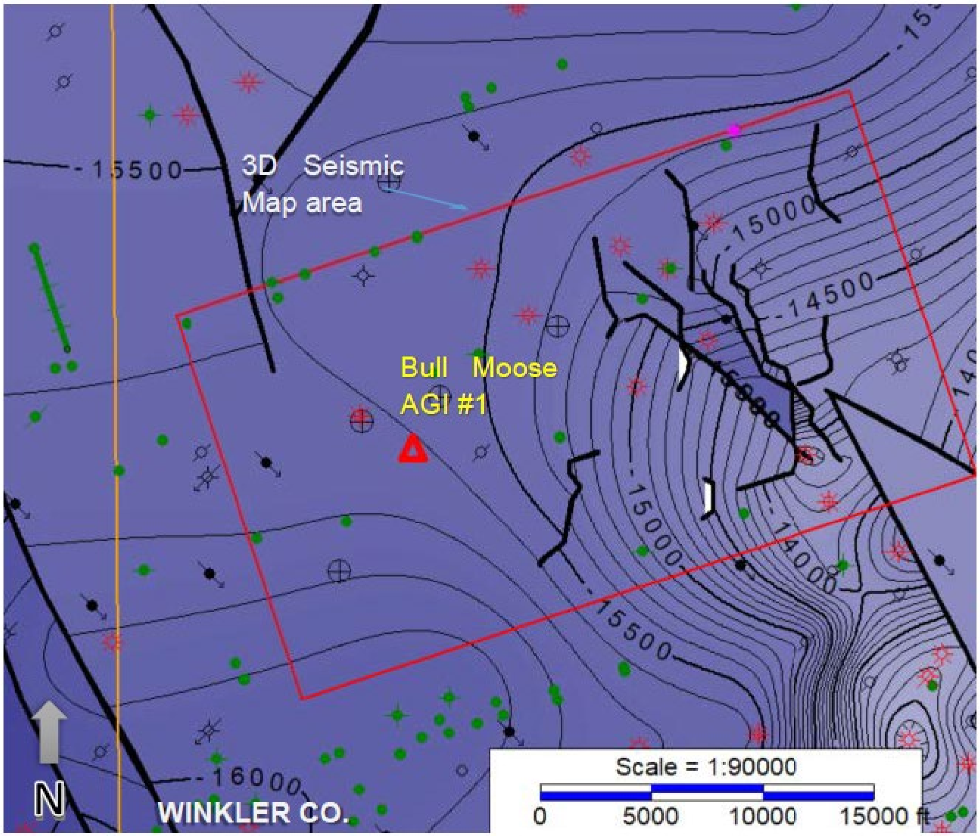


Figure 3.3-8: Fusselman Formation Subsea Structure Map. CI = 100 ft.

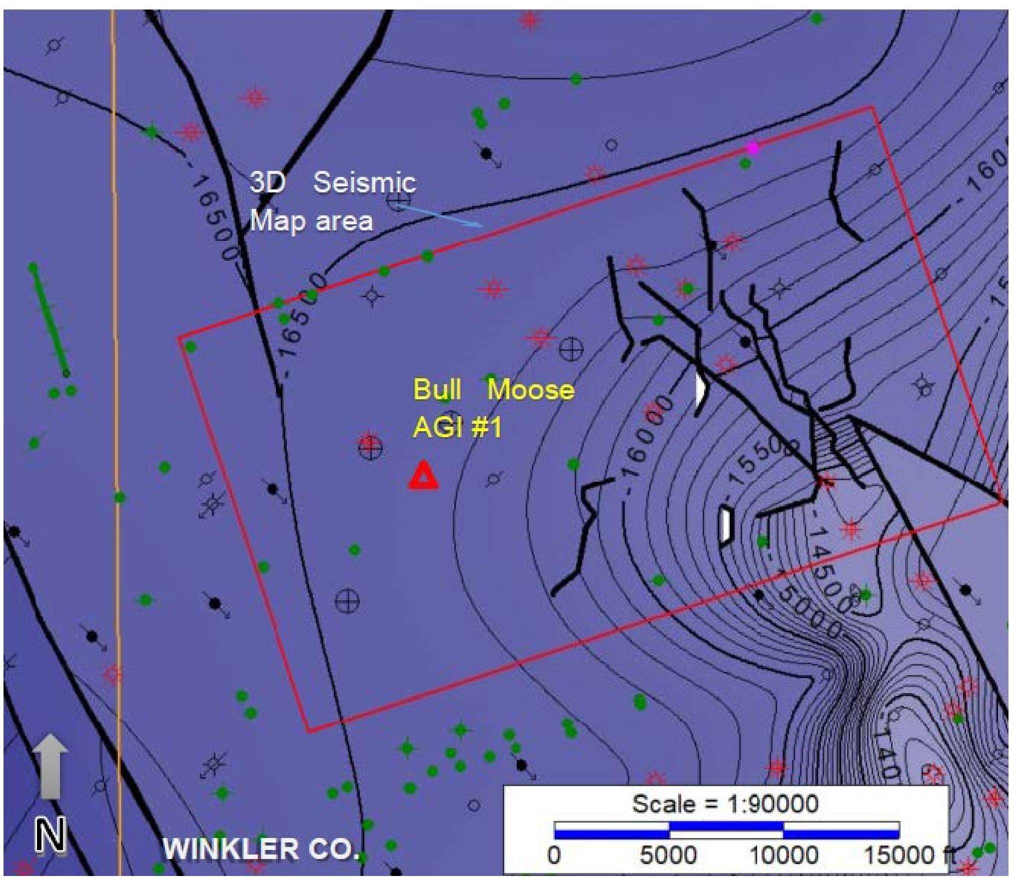


Figure 3.3-9: Montoya Group Subsea Structure Map. CI = 100 ft.

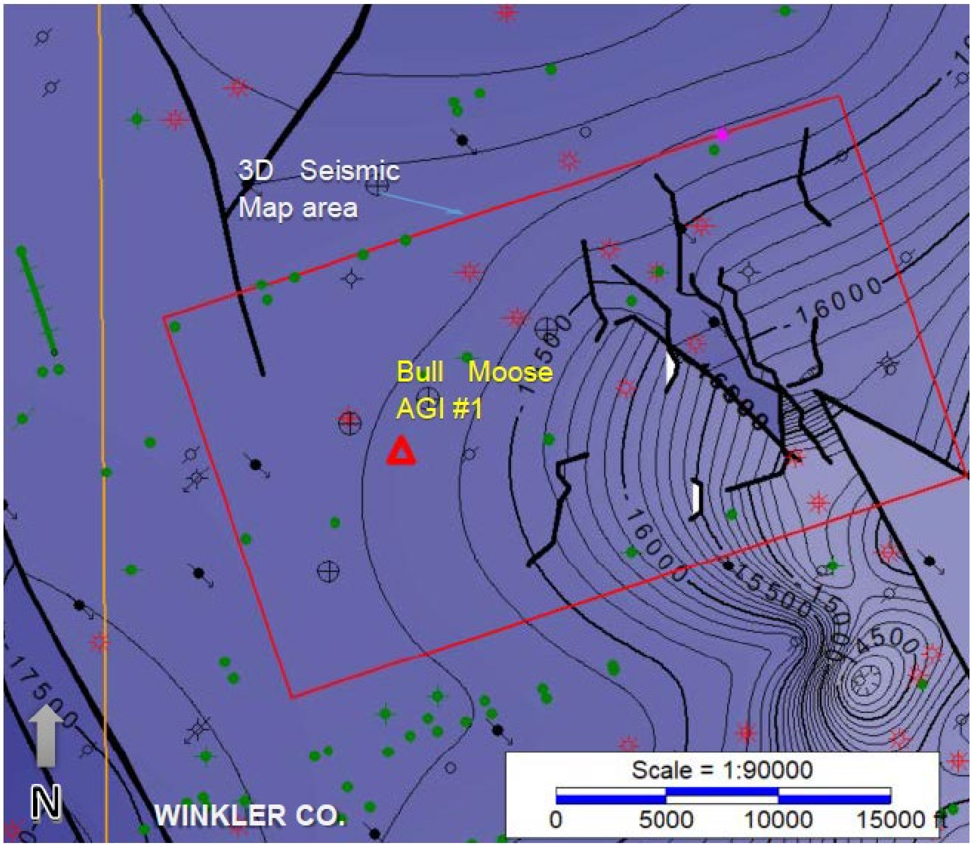


Figure 3.3-10: Simpson Group Subsea Structure Map. CI = 100 ft.

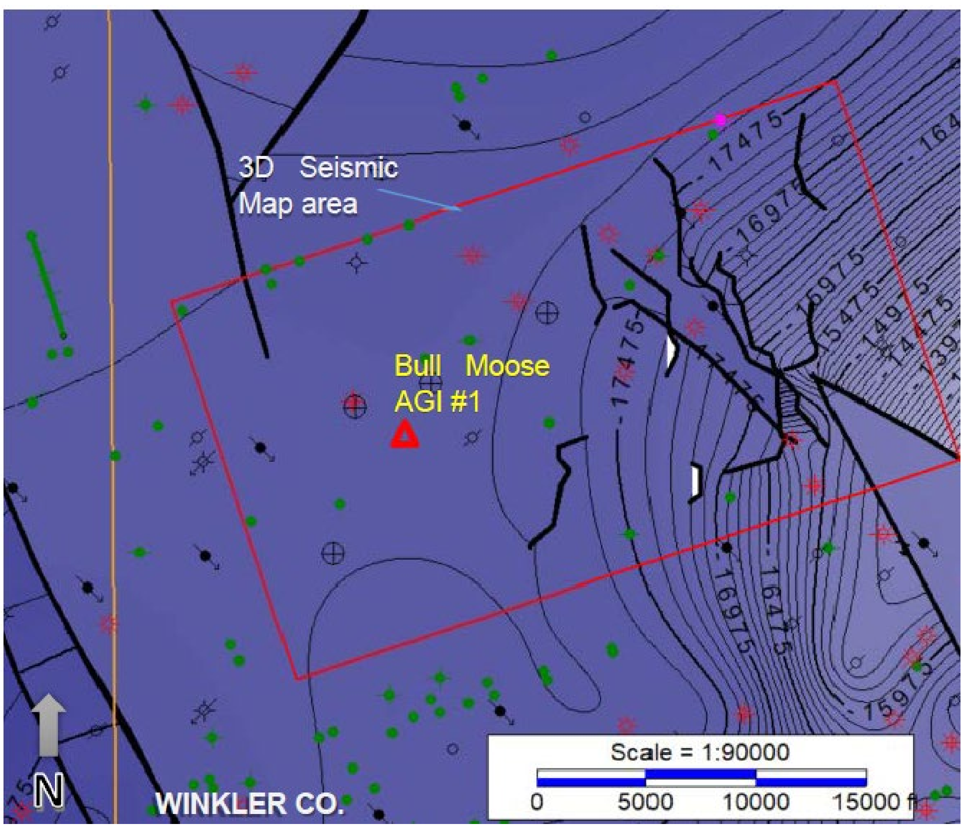


Figure 3.3-11: Ellenburger Group Subsea Structure Map. CI = 100 ft.

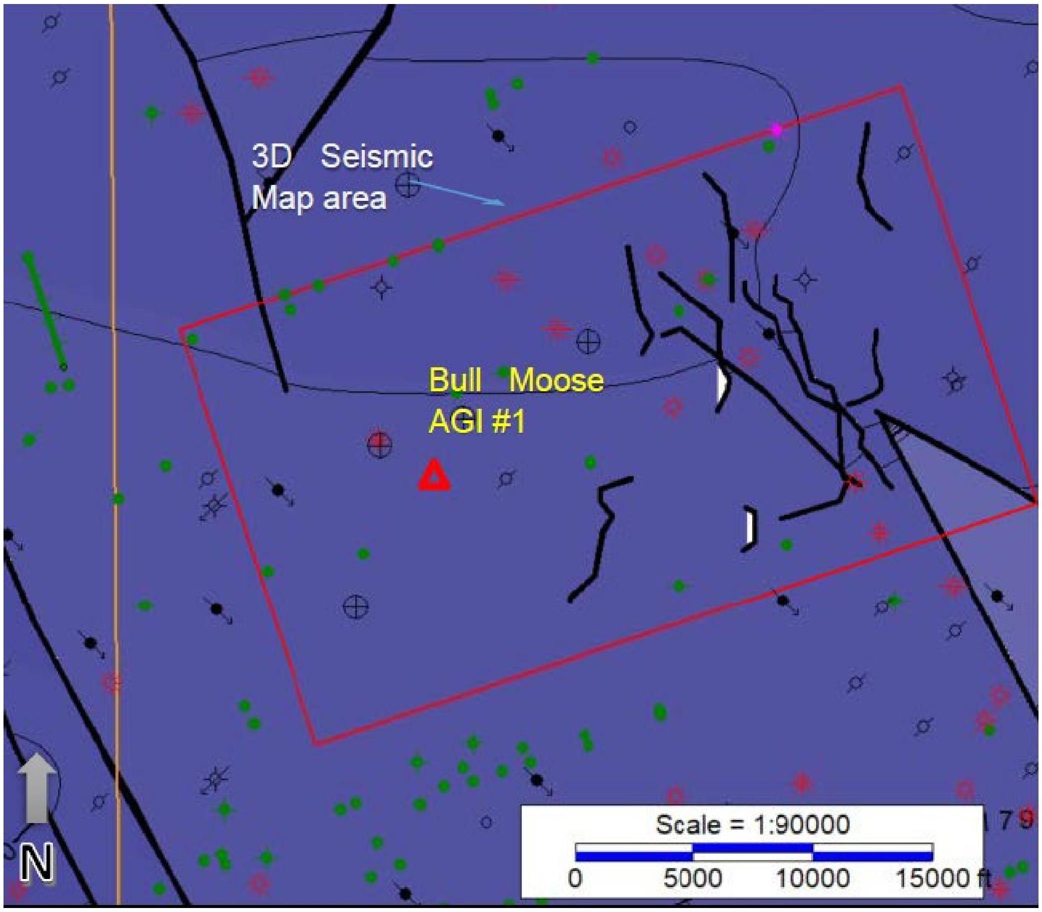


Figure 3.3-12: Precambrian Subsea Structure Map. CI = 100 ft.

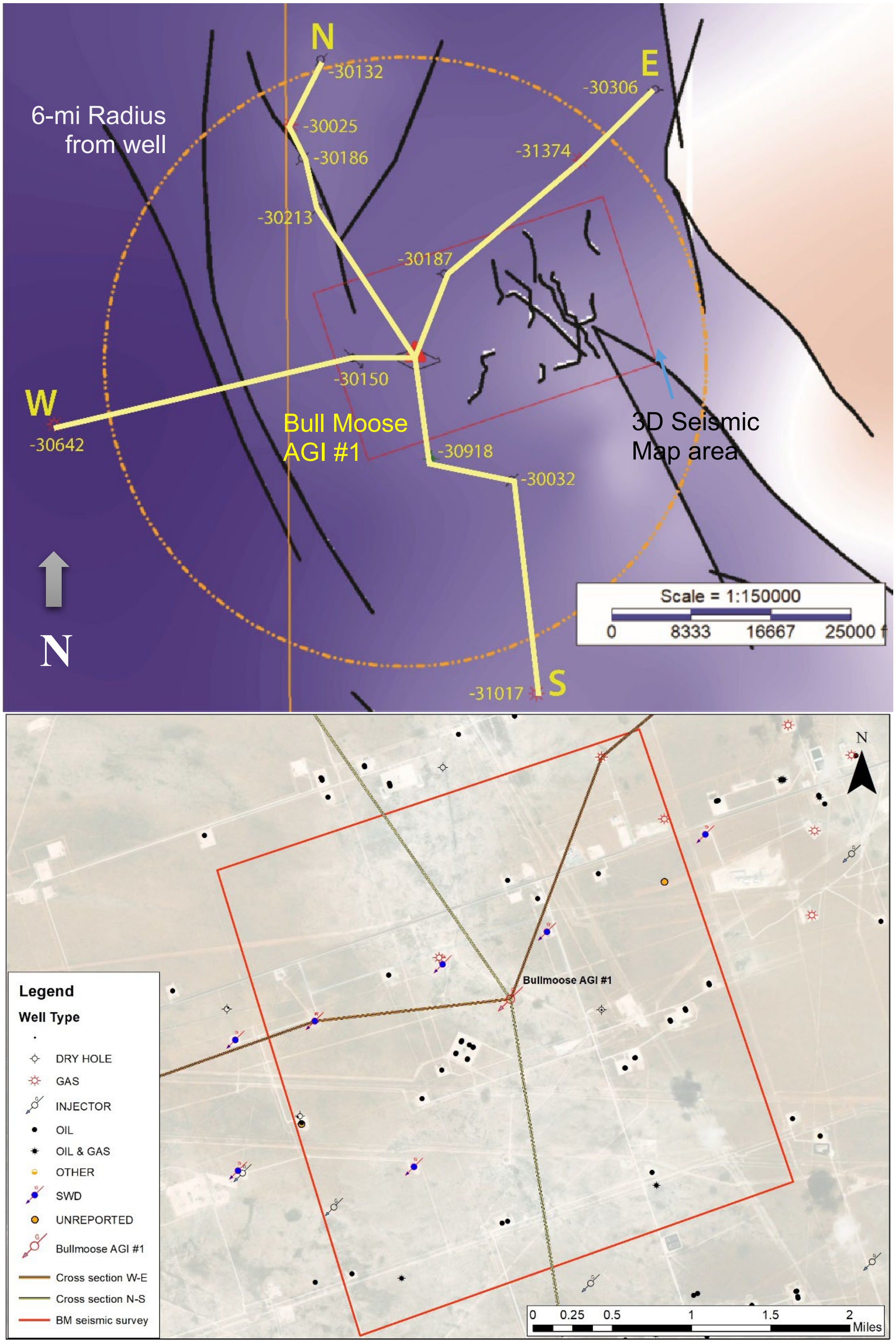


Figure 3.3-13: Base Map for Cross Sections

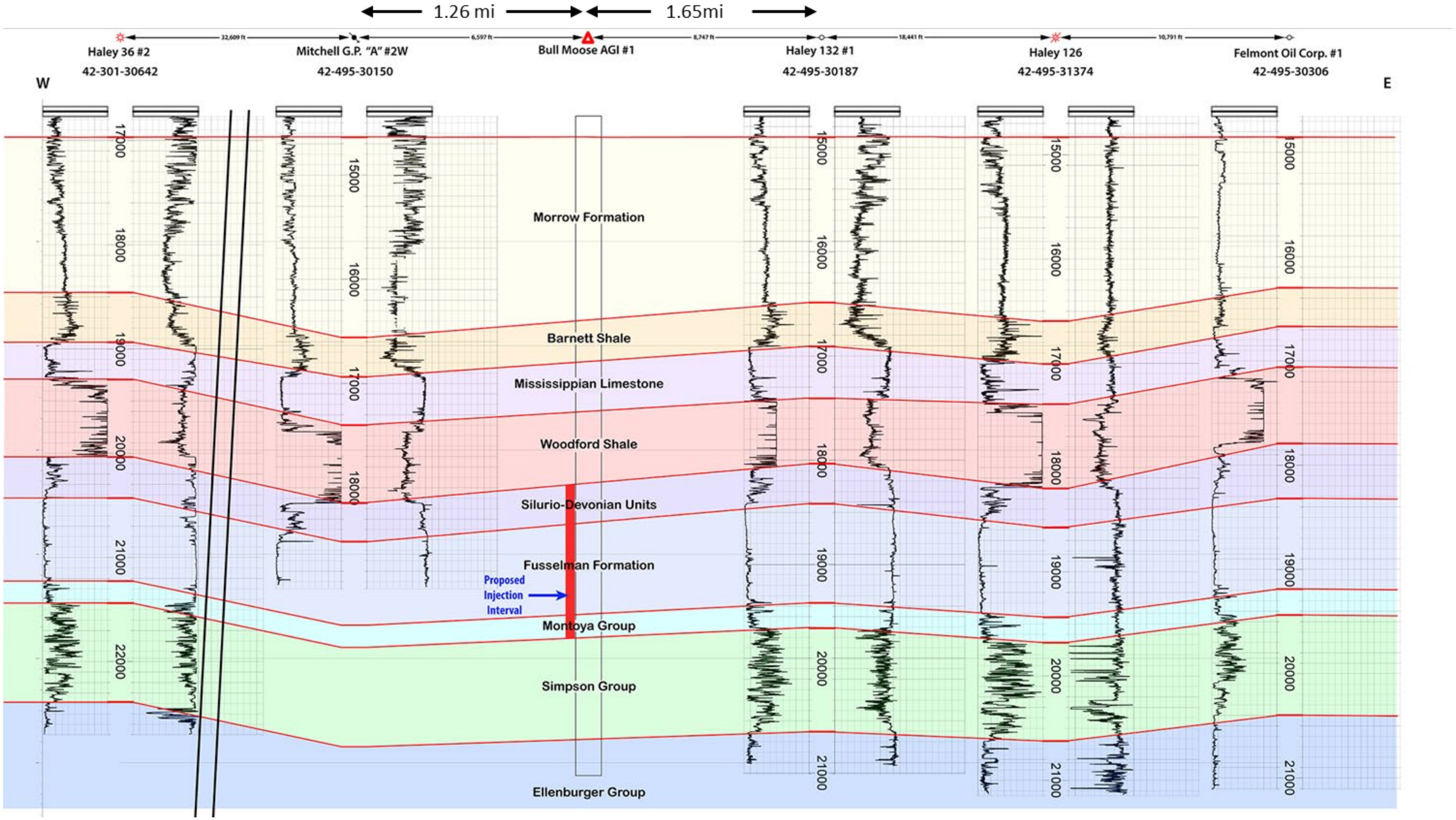


Figure 3.3-14: West to East Cross Section

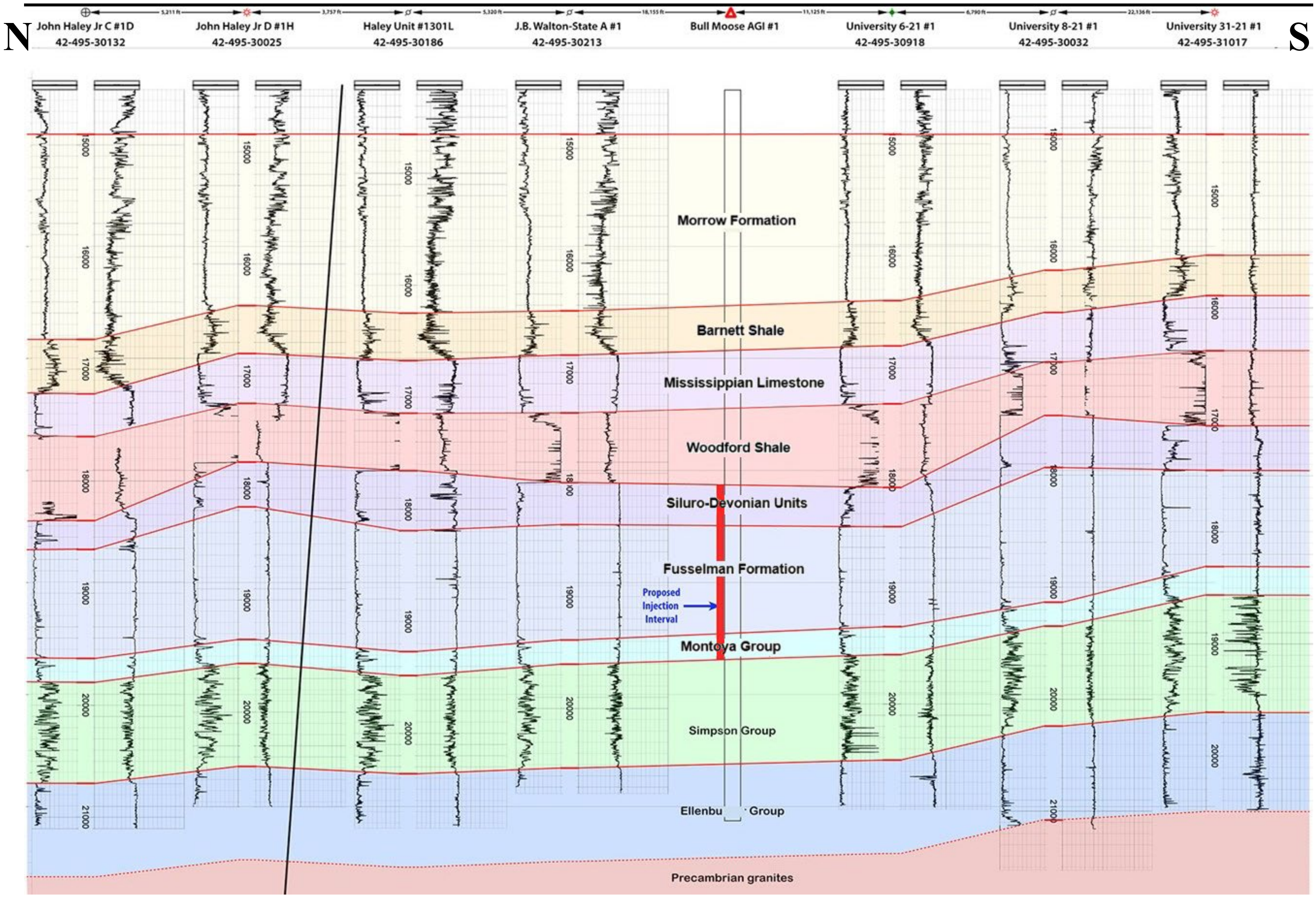


Figure 3.3-15: North to South Cross Section

3.5 Formation Fluid Chemistry

Water data was retrieved from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 (05/22/2019) to determine formation chemistry in the Siluro-Devonian, Fusselman, and Montoya injection intervals for BM AGI #1. Chemical data was plotted in a geographical interface and delineated to a 15-mile boundary around the Bull Moose site to fully constrain each formation's geochemical signature.

There are 12 wells with analyses collected from the Siluro-Devonian, Fusselman, Montoya, and Simpson formations within 15 miles of BM #1 (red squares **Figure 3.5-1).** Samples taken in these formations generally fall within a saline (NaCl) hydrofacies, and concentrations of total dissolved solids (TDS) range from 69,140 to 341,260 milligrams per liter (mg/L) with an average of 140,024 mg/L. High salinity in these formations indicate they are compatible with injection (**Table 3.5-1**).

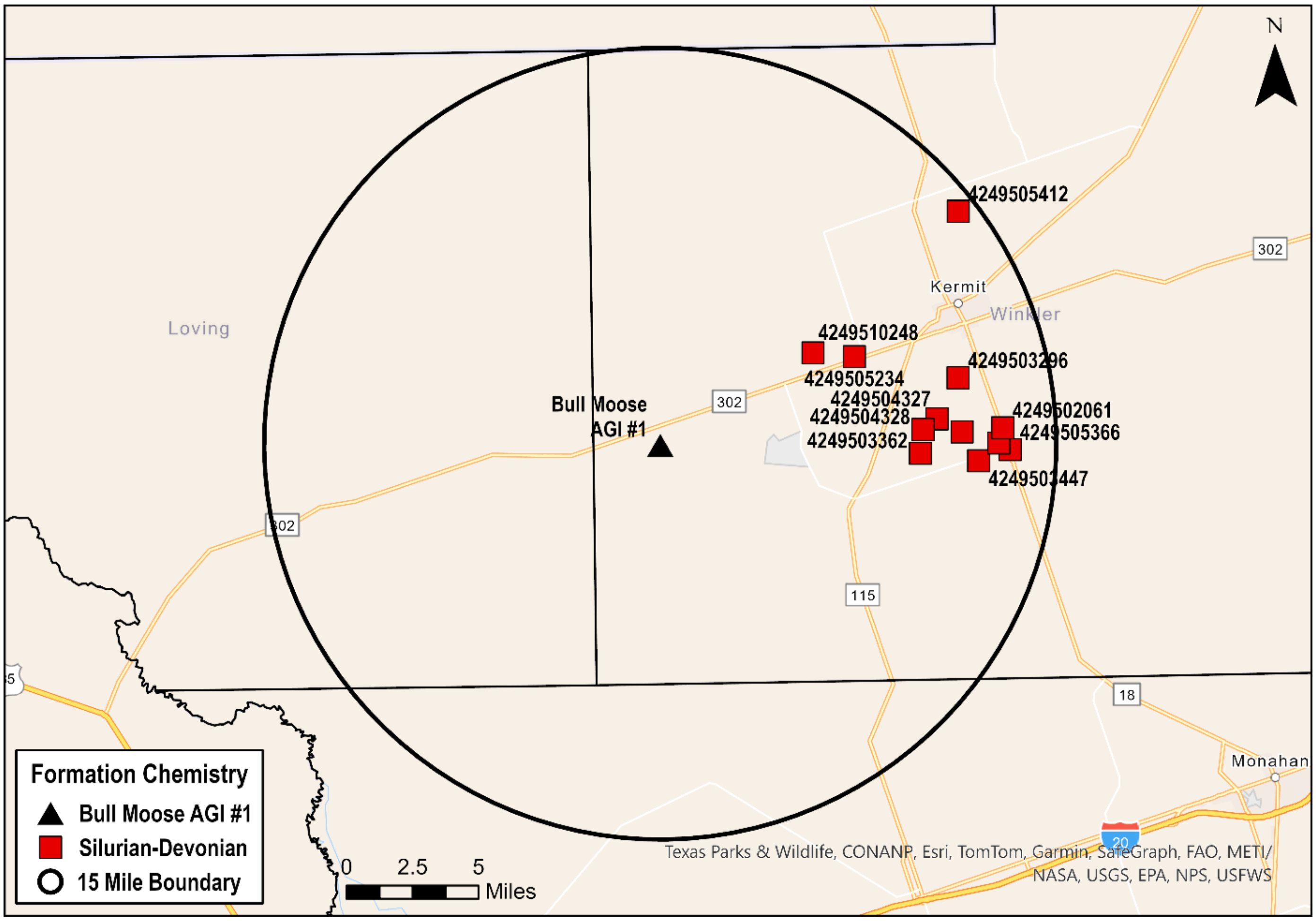


Figure 3.5-1: *Wells with water chemistry in the Silurian, Fusselman, or Devonian formations within 7 to 15 miles of the Bull Moose AGI well from the U.S. Geological Survey National Produced Waters Geochemical Database. Data show these formations are NaCl waters with average TDS of 140,024 mg/L.*

Table 3.5-1: *Water chemistry in mg/L for wells in the Silurian, Fusselman, or Devonian formations within ≈7 to 15 miles of BM AGI #1 from the USGS National Produced Waters Geochemical Database.*

API	Latitude	Longitude	Formation	HCO_3	Ca	Mg	KNa	Cl	SO_4	TDS
4249503296	31.8171	-103.0914	Devonian	1,347	12,410	1,799	10,290	40,390	2,904	69,140
4249503296	31.8171	-103.0914	Devonian	97	14,610	4,052	36,590	92,530	2,480	150,359
4249503296	31.8171	-103.0914	Devonian	145	14,510	4,163	36,590	92,830	2,520	150,758
4249503296	31.8171	-103.0914	Devonian	80	14,610	4,153	36,790	92,830	2,500	150,963
4249503296	31.8171	-103.0914	Devonian	122	14,600	4,028	37,050	92,940	2,437	151,177
4249503362	31.7759	-103.1165	Devonian	352	10,780	2,806	6,470	36,010	1,403	57,821
4249503447	31.7713	-103.0791	Devonian	635	2,900	300	35,500	60,000	475	99,810
4249505366	31.7771	-103.0587	Devonian	151	11,804	2,578	59,112	118,202	1,703	193,550
4249500556	31.7808	-103.0659	Fusselman	362	4,232	881	29,090	53,850	2,857	91,273
4249502061	31.7892	-103.0632	Fusselman	148	6,960	4,440	118,800	208,800	2,112	341,260
4249504327	31.7947	-103.1054	Fusselman	458	4,244	706	29,620	53,810	1,568	90,406
4249504328	31.789	-103.1145	Fusselman	427	4,236	1,016	45,650	78,800	2,420	132,549
4249505210	31.7873	-103.0894	Fusselman	849	10,640	945	24,780	59,440	460	97,114
4249505412	31.9086	-103.0894	Fusselman	202	1,733	536	48,589	73,421	4,400	128,881
4249510248	31.8322	-103.1845	Fusselman	706	499	386	91,284	139,300	4,317	236,491
4249505234	31.8297	-103.1579	Silurian	327	4,758	962	31,960	59,200	1,625	98,832

3.6 Groundwater Hydrology in the Vicinity of the Bull Moose Gas Plant

Regionally, groundwater near the BM AGI #1 site is drawn from one of five sources. From shallow to deep those are Quaternary-Late Tertiary Pecos Valley Deposits, Cretaceous sediments of the Edwards-Trinity Groups, Triassic deposits of the Dockum Group, the Permian (Oochan) aged Rustler Formation, and the Permian (Guadalupian) aged Capitan Reef Complex. Based on current water data with the Texas Water Development Board (TWDB), the primary groundwater sources at the site are the Pecos Valley Alluvium and the Dockum Group (**Figure 3.6-1**). Below we provide a general description of the groundwater sources and the wells within the MMA at the BM AGI #1 site.

3.6.1 Pecos Valley Aquifer

The Pecos Valley Aquifer lies unconformably on portions of the Edwards-Trinity Plateau, Dockum, Rustler, and Capitan Reef aquifers. It covers an area of 6,829 mi^2 and is comprised of sediments that range in size from clay to boulder which were deposited in a variety of continental settings including fluvial, valley-fill, eolian, lacustrine, and solution-collapse environments (Wise et al., 2012). Sediments of the Pecos Valley Aquifer fill several structural basins, the largest of which are Monument Draw Trough in the east and the Pecos Trough in the west. Maximum thickness of the alluvial fill reaches approximately 1,500 ft, and freshwater saturated thickness averages around 250 ft (George et al., 2011).

The water quality is highly variable, with the water typically being hard, and generally better in the Monument Draw Trough than in the Pecos Trough. Total dissolved solids have been found to range from 116 to over 15,000 mg/L depending on location and proximity to oil and gas or halite mining operations in the region (Wise et al., 2012). The aquifer is generally characterized by high levels of sulfate and chloride in excess of secondary drinking water standards which has been linked to previous oil field activities. Also, naturally occurring radionuclides and arsenic can be found in excess of primary drinking water standards (George et al., 2011). More than 80 percent of Pecos

Valley groundwater is used for irrigation, while the remainder is used for municipal supplies, power generation, and industrial use.

3.6.2 Dockum Aquifer

The Upper Triassic Dockum Group covers about 96,000 square miles in parts of Kansas, Oklahoma, Colorado, New Mexico, and Texas. From young to old the Dockum includes the Santa Rosa and Tecovas formations, the Trujillo Sandstone, and the Cooper Canyon Formation. These formations consist of conglomerate, gravel, sandstone, siltstone, mudstone, and shale with recoverable quantities of groundwater located in the sandstone and conglomerate. The largest yields are typically found in the coarsest deposits in the middle and base of the group. Locally any water-bearing sandstone of the Dockum Group is referred to as the Santa Rosa Aquifer (Bradley and Kalaswad, 2003; 2004; George et al., 2011).

Water quality in the Dockum Aquifer varies, ranging from fresh (TDS <1,000 mg/L) on outcrop to brine (TDS >10,000mg/L) where it is confined, typically deteriorating with depth. TDS concentrations have been found to be >60,000 mg/L in the deepest parts of the aquifer. Groundwater in the Dockum aquifer is typically hard, average of 470 mg/L, and radionuclides naturally derived from uranium can be found at concentrations a >5 pCi/L in many areas of the aquifer (Bradley and Kalaswad, 2003; 2004). Locally, the Dockum Aquifer can be vital for irrigation, public supply, livestock watering, manufacturing, and oil-field activity. However, a combination of deep pumping depths, low yields, poor water quality, and declining water levels have hindered a more widespread use (Bradley and Kalaswad, 2003).

3.6.3 Groundwater Wells Within the Bull Moose AGI Site MMA

Data collected from the Texas Water Development Board's (TWDB) Groundwater Database and Submitted Driller Report Database indicate there are 2 freshwater wells located within the MMA for BM AGI #1. Both wells are permitted for domestic use and are shallow, collecting water from 152 to 245 ft depth in Pecos Alluvium and Triassic redbeds of the Dockum Group (Garza and Wesselman, 1963; Ashworth, 1990; Bradley and Kalaswad, 2003; **Table 3.6-1**). General chemistry analysis of one well within the MMA indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L (**Table 3.6-2**). The shallow freshwater aquifers are protected by the surface and intermediate casings and cements in the BM AGI #1 well. While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

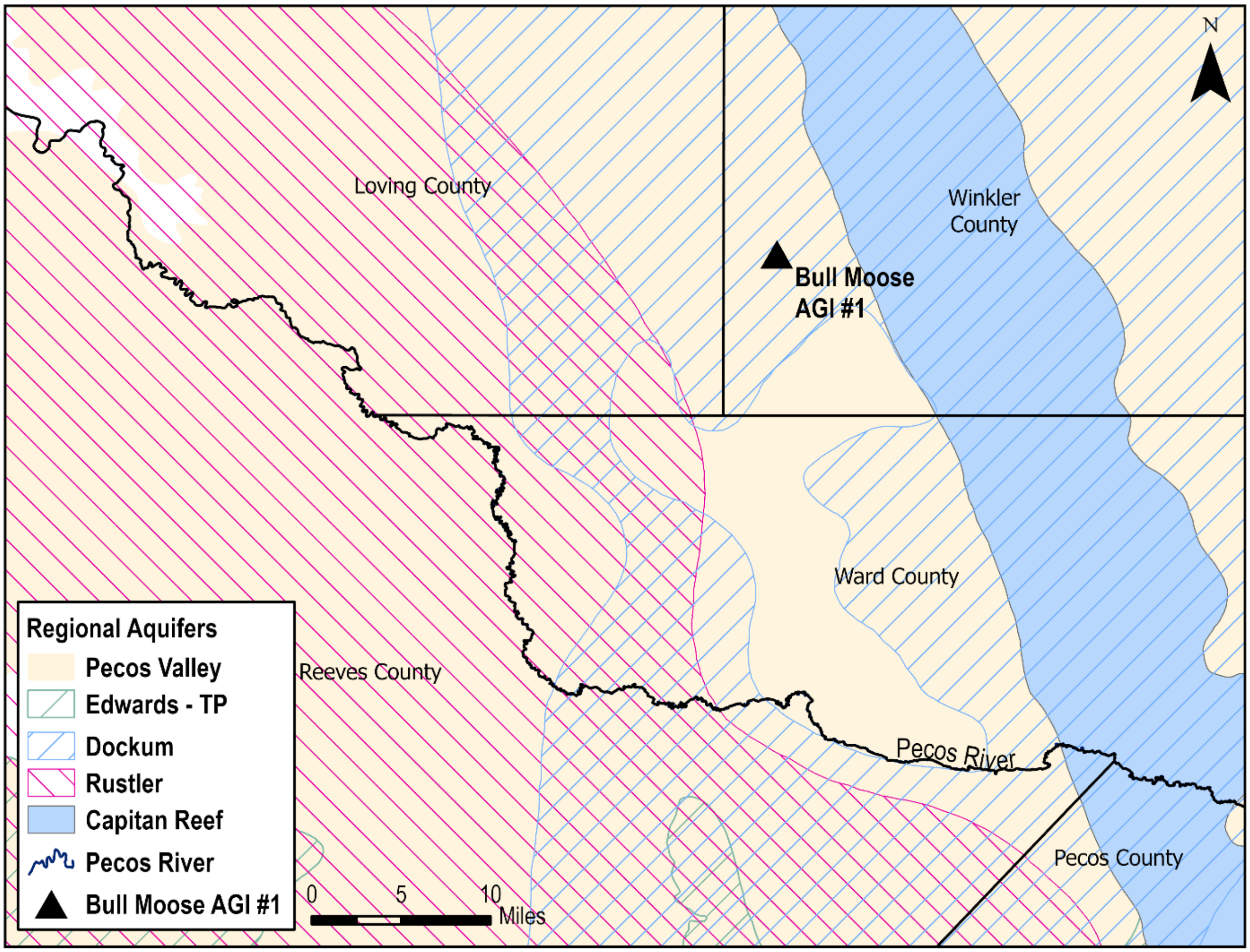


Figure 3.6-1: *Major and minor aquifers of the region. Groundwater at the proposed site is derived from the Pecos Valley Alluvium and Dockum Group.*

Table 3.6-1: *Groundwater wells within the MMA of the Bull Moose AGI site with from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database. Well depth is from 152 to 245 ft. and used for domestic purposes.*

Well ID/Report	Owner_Name	Use	County	Well_Depth	Latitude	Longitude
4614901	D P Anderson	Domestic	Winkler	152	31.76806	-103.285
409232	Frontier Energy	Domestic	Winkler	245	31.79591	-103.277

Table 3.6-2: *Groundwater chemistry for well 4614901 from Table 3.5-1 indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L.*

StateWellID	Aquifer_Code	Date	HCO_3	Ca	Mg	Na	Cl	SO4	TDS
4614901	100CPDG	8/23/1940	256	97	38	43	53	189	557

3.7 Historical Operations

3.7.1 Bull Moose Site

In response to increasing production and to meet the infrastructure needs of producers, TND is constructing a new Bull Moose 275 MMSCFD cryogenic natural gas processing plant. **Figure 3.7-1** shows the simplified process block flow diagram, with the entry point for the CO_2, the flow meter location and the sampling point, before BM AGI #1 well.

3.7.2 Operations within the MMA for the BM AGI Well

TRRC records identify a total of 29 oil- and gas-related wells within the MMA (see **Appendix 3**). **Figure 3.7-2** shows the geometry of producing and injection wells within the MMA. **Appendix 3** summarizes the relevant information for those wells.

Among the 29 wells identified, 25 are horizontal oil wells completed in the Bone Spring (8 wells) or Wolfcamp (17 wells) formations, at depths between 11,564 and 12,545 ft. One is inactive and three are plugged and abandoned.

There are four other vertical wells. There are two vertical plugged and abandoned gas well in the Morrow Formation (16,000 ft). There are also two Saltwater Disposal (SWD) wells that are injecting in the Brushy Canyon (7,516 and 7,630 ft).

All of these productive zones are more than 5,300 ft above the BM AGI #1 injection zone.

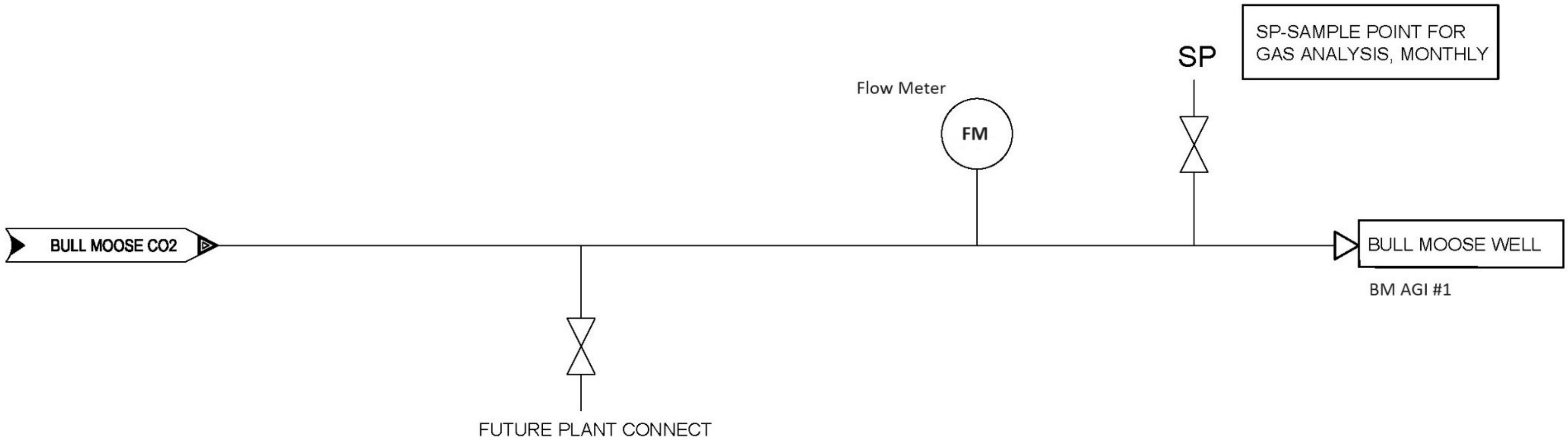


Figure 3.7-1: Process Block Flow Diagram with CO_2 entry, Flow meter (FE), Sampling point (SP) and BM AGI #1.

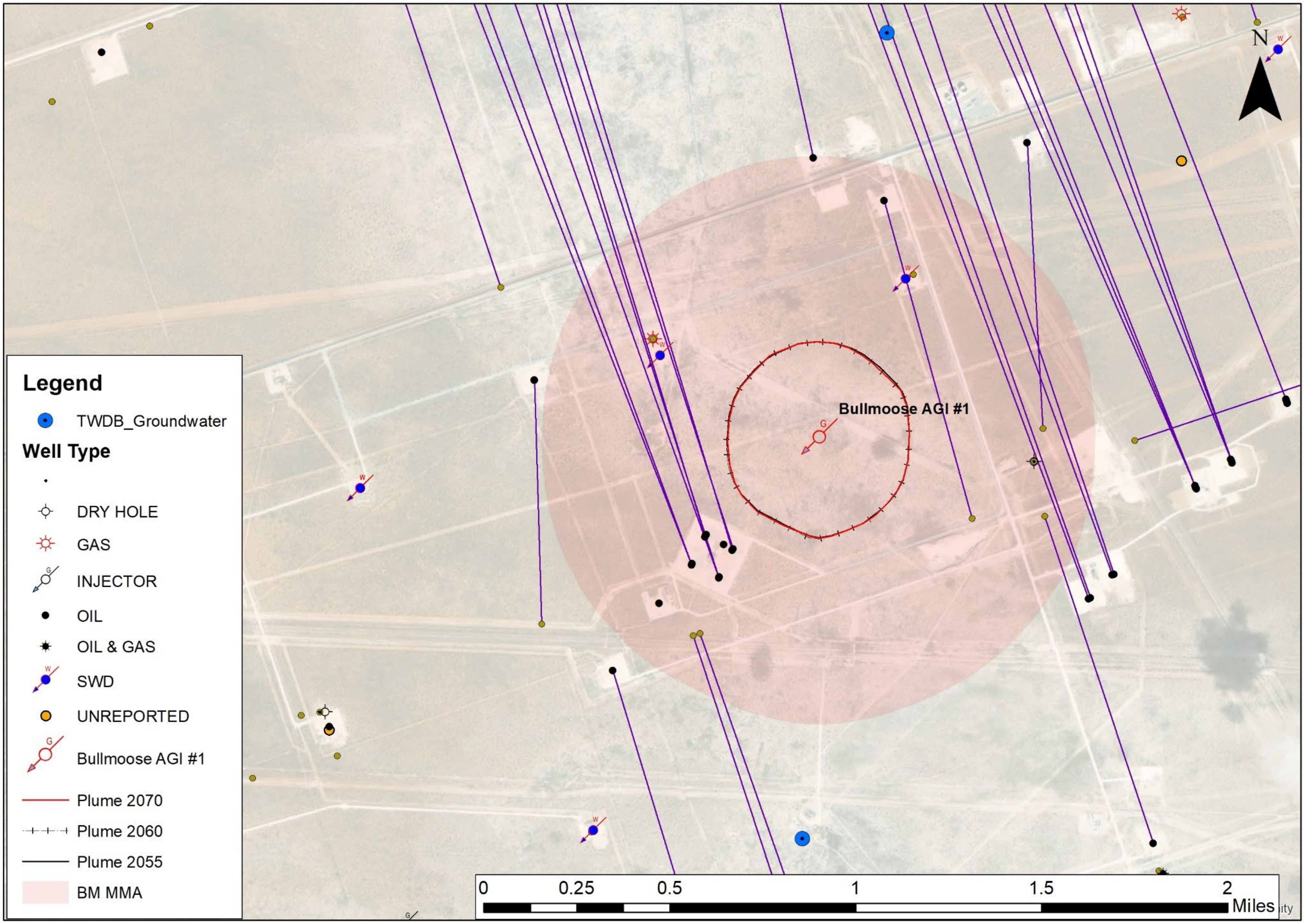


Figure 3.7-2: *Location of all oil- and gas-related wells within the MMA for the BM AGI #1 well. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure.*

3.8 Description of Injection Process

The Bull Moose Gas Plant, including the BM AGI #1 well, will be in operation and staffed 24-hours-a-day, 7-days-a week. The plant gathers and processes produced natural gas. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility. Compressed TAG is then routed to the well via high-pressure rated lines.

The natural gas to be treated at this facility is produced from oil and gas wells in the Permian Basin region, including Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward and Winkler counties, Texas plus Lea and Eddy counties in New Mexico. A sample from TND 's nearby Wildcat facility (5 miles west) was taken on 11/10/2023 and is representative of the injection stream for the Bull Moose facility. The results of that analysis are provided in **Table 3.8-1**.

Table 3.8-1: Sample Gas Composition for Wildcat AGI #1

Component	Mol %
Carbon Dioxide	91.339
Methane	0.350
Ethane	0.054
Propane	0.061
Iso-Butane	0.003
N-Butane	0.022
Iso-Pentane	0.000
Hexanes Plus	0.099
Hydrogen Sulfide	8.072
Nitrogen	0.000
TOTAL	100.00

The composition may change over time based on the amount of H_2S in the natural gas processing inlet stream. For modeling purposes, an injectate composition of 30% H_2S and 70% CO_2 was assumed as a conservative approach.

3.9 Reservoir Characterization Modeling

3.9.1 Inputs and Assumptions

Dynamic reservoir simulation was performed based on a high resolution geological model. The modeling predicts the well injectivity, pressure behaviors, and TAG plume migration.

Schlumberger's Petrel® (Version 2023.3) software was used to construct the geological models used in this work. Computer Modelling Group (CMG) software was used to perform the reservoir simulations presented in this MRV plan. The software was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling. The hydrodynamical model considers aqueous, gaseous, and supercritical phases of the CO_2, simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in an aqueous phase or in a gaseous phase, in a supercritical state.

The static model is constructed using well tops picked from logs and interpretations from 3D seismic survey to interpret and delineate formations and structural features. The geologic model covers a 3.2-miles by 3.0-miles area (**Figure 3.9-1**). The model is divided into 745,200 cells. The average cell size of the active injection area is 150 square ft. **Figure 3.9-2** shows the simulation model in 3D view. The porosity and permeability of the model are evaluated using existing well logs and 3D seismic inversion. The range of the porosity is between 0.01 to 0.31. The initial permeability is interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy is 0.1. (**Figure 3.9-2**).

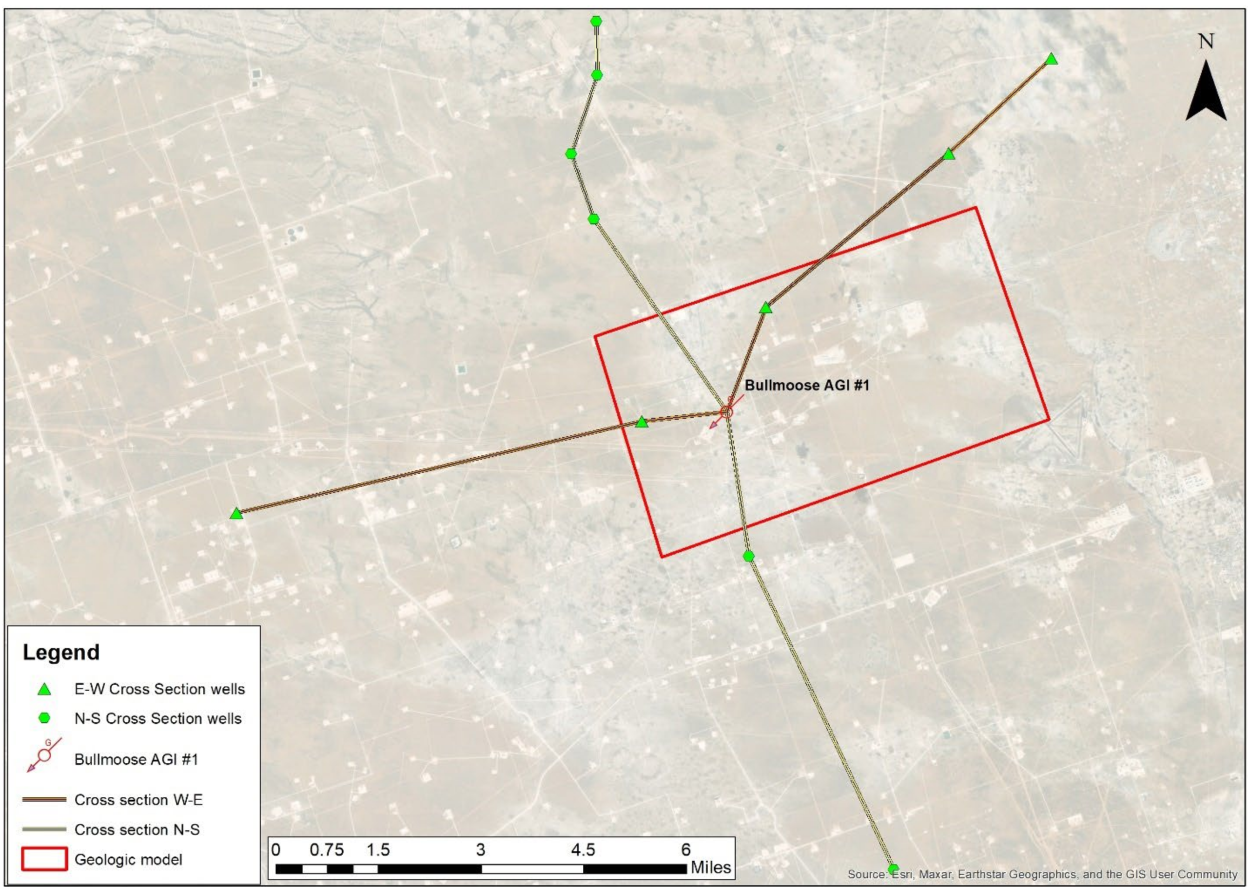


Figure 3.9-1: BM AGI #1 model boundaries

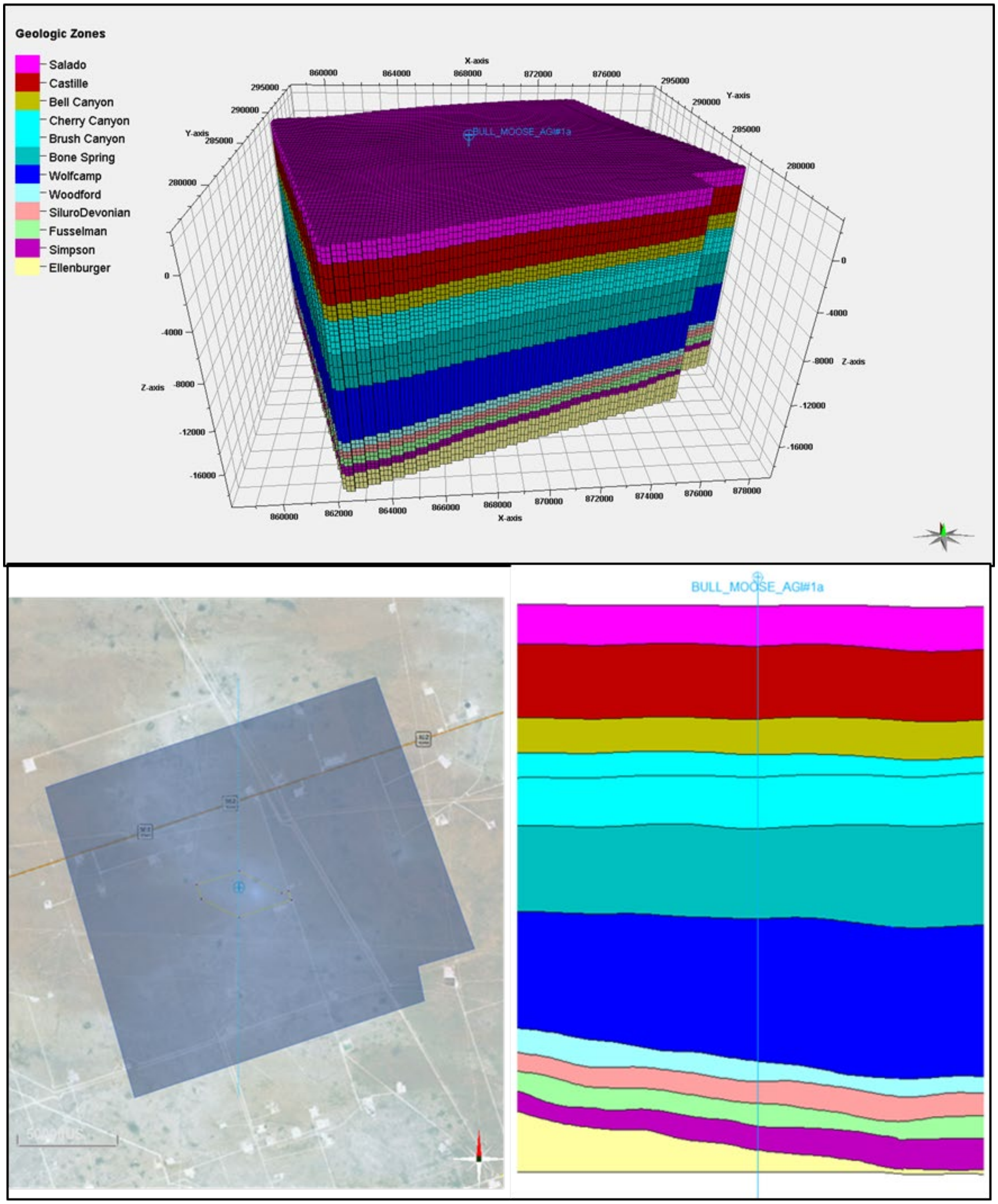


Figure 3.9-2: *3D view of the geological model for the BM AGI #1 well. The model displays the Salado-Castile Formation, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, Simpson and Ellenburger formations. Color legends represent the zones.*

At the initialization of the simulation, the water saturation in the storage reservoir is assumed to be 100%, with a residual water saturation of 20% (Krause, M. H., and Benson, S. M., 2015). The initial salinity is assumed to be 150,000 ppm (Nicot et al., 2020). A geothermal gradient of 1.25°F/100 ft was adopted (Ge, J. et al., 2022). Following standard industry practices, a pore pressure gradient of 0.43 psi/ft is used. Therefore, the reservoir pressure at the top of the Siluro-Devonian at the location is estimated to be 7,650 psi.

The fracture gradient (FG) for the injection interval is calculated using Eaton's equation.

$$FG = \frac{\nu}{1-\nu}\left(OBG - p_p\right) + p_p$$

Where,

ν is the Poisson's ratio,

OBG is the overburden gradient,

p_p is the pore pressure gradient.

An overburden gradient of 1.05 psi/ft is adopted in the calculation. This value is considered best practice when a site-specific number is not available. Poisson's ratio is inferred to be 0.3 in the injection interval. A minimum value of 0.29 and a maximum value of 0.31 are used to quantify uncertainty (Smye et al, 2021, Dvory and Zoback, 2021). The fracture gradient is estimated to be 0.62 to 0.68 psi/ft, therefore the formation fracture pressure calculated at the top of the injection interval is 12,350 psi. In addition, a safety factor of 10% is applied to the resulting fracture gradient. This safety factor ensures injecting pressure will not exceed the fracture gradient in the injection interval, where the maximum bottomhole pressure was set to 0.63 psi/ft during active injection in the simulation. The results are summarized in **Table 3.9-1 & Table 3.9-2**. As these values are calculated based on available legacy well logs and literature listed in the reference, the actual gradient will be measured upon completion of the proposed well, and the modeling and simulation efforts will be updated accordingly.

A review of the TRRC databases identified no saltwater disposal (SWDs) or other injection wells within the model boundaries in the proposed injection interval.

Table 3.9-1: Summary of reservoir simulation inputs.

Reservoir properties of injection zones	Wristen & Fusselman
Porosity	As shown in geologic model
Permeability	As shown in geologic model
Pore pressure gradient	0.43 – 0.45 psi/ft (estimated from DST data in Winkler county – Dvory and Zoback (2021); Luo et al. (1994)
Formation fracture gradient	0.65 $\pm$0.03 psi/ft

Reservoir properties of injection zones	Wristen & Fusselman
Formation temperature	0.014 F/ ft (45 wells BHT data in Winkler– Luo et al. 1994)
Water salinity	150,000 ppm (Nicot et al. 2020 based on P50 of TDS in Winkler County showing 150kppm)
Initial water saturation	100% (assumption made for conservative CO_2 plume)

Table 3.9-2: Summary of well simulation inputs.

Injection well setup	Wristen & Fusselman
Bottom hole pressure	90% of formation fracture pressure or 11,300 psi at bottom hole
Well head pressure	0.5 psi/ft to the top of injection interval (approximately 8,945 psi) – RRC Standards and Procedures for Class II Wells
Wellhead temperature	90-100 °F
Injection fluid	70% CO_2, 30% H_2S
Injection rate	20 MMSCFD over 30 years (2025 – 2055)

BM AGI #1 is simulated to inject at the injection rate of 20 MMSCFD. In accordance with the TRRC Injection Storage Manual; Chapter III - Standards and Procedures for Class II Wells, the maximum surface injection pressure may not ordinarily exceed 0.5 psi per foot of depth to the top of the authorized injection or disposal interval. Therefore, a maximum allowable surface injection pressure of 8,945 psi is used in the simulation. Additionally, a maximum bottomhole pressure of 11,300 is enforced and 90% of the estimated formation fracture gradient is set as a secondary

constraint in the simulation. The composition of the injection stream is estimated to be 30% H_2S and 70% CO_2. The simulated injection starts on 01/01/2025 and stops on 01/01/2055, after a 30-year active injection phase. The termination of the simulation is on 01/01/2085, with an additional 30 years of post-injection, to estimate the maximum plume extent and the stabilized plume.

3.9.2 Model Outputs

Simulations indicate BM AGI #1 can inject at the proposed rate throughout the 30-year period without any complications. Linear cumulative injection behavior (**Figure 3.9-3**) also indicates that the Siluro-Devonian, Fusselman and Montoya formations receive the TAG stream freely. **Figure 3.9-3** shows a constant injection rate of 20 MMSCFD of the TAG stream injected over 30 years under the proposed bottom-hole pressure constraint. The modeling results indicate that the formations are capable of safely receiving and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.9-4** shows the cumulative disposed H_2S and CO_2 separately in gas mass.

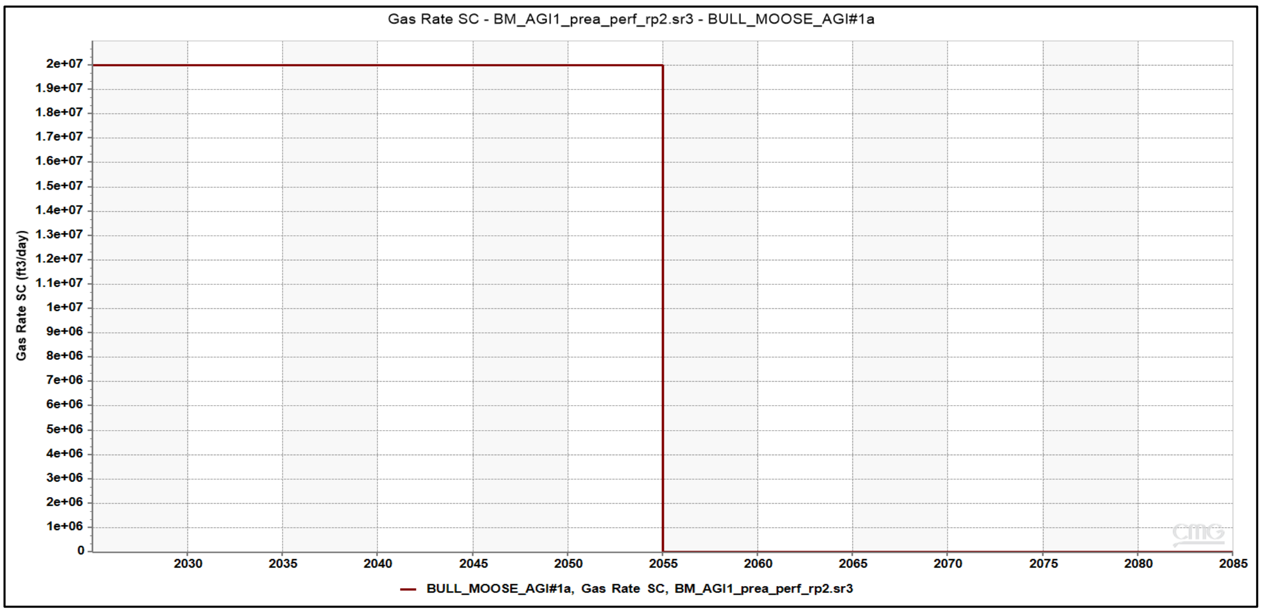


Figure 3.9-3: Average daily injection volume for Bull Moose AGI No. 1 (2025 to 2055, 20 MMSCFD).

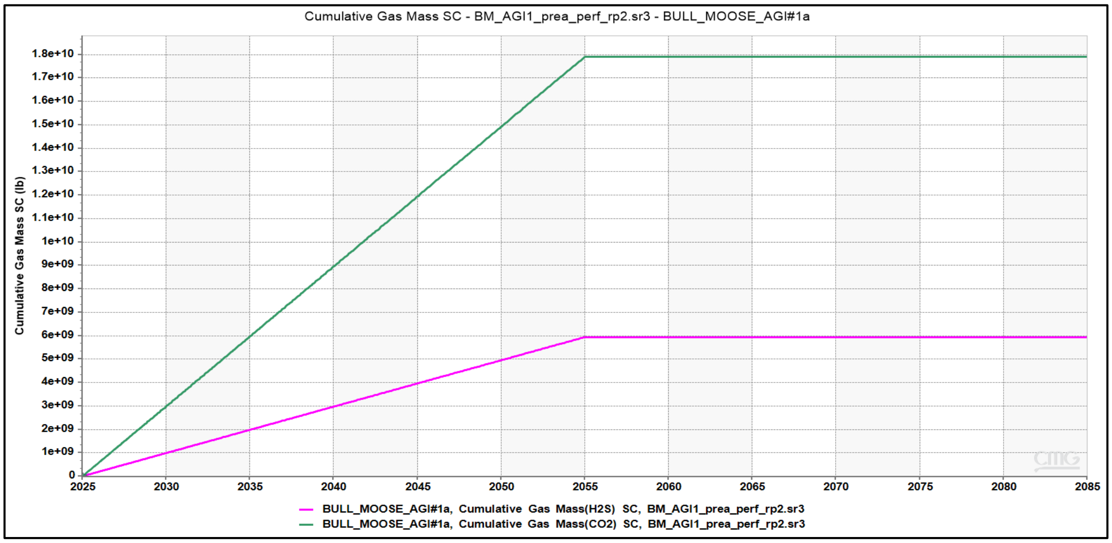


Figure 3.9-4: *Predicted cumulative mass of injected CO_2 and H_2S for BM AGI #1 well (injection operation from 2025 to 2055).*

3.9.3 Treated Acid Gas Plume

Figure 3.9-5 shows the TAG plume evolution for BM AGI #1 in the years 2030, 2035, 2040, 2045, 2050, 2055, marking 5-year increments from the beginning of the injection simulation in 2025. The diameter of the most extensive part of the TAG plume is estimated to be 7,500 ft (1.42 mi), with stabilization achieved in 2070

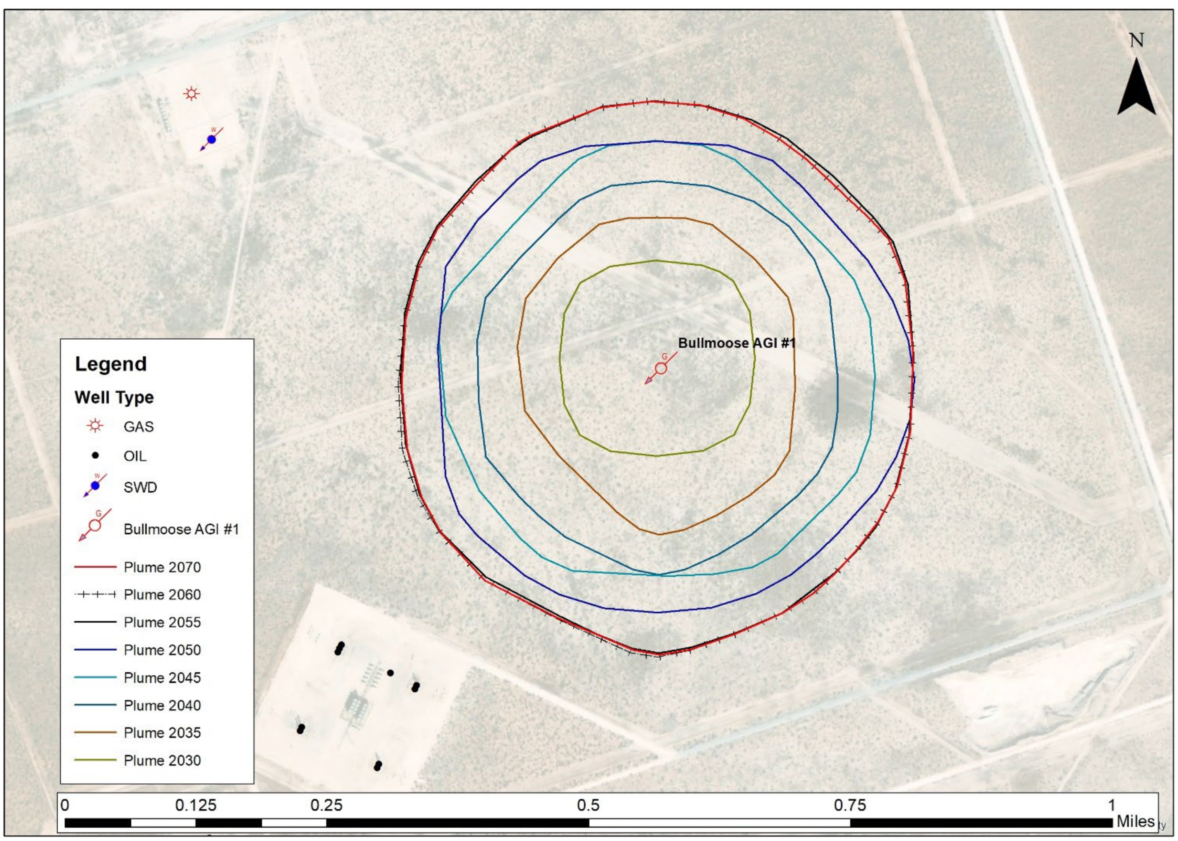


Figure 3.9-5: *Extent of TAG plume (represented by gas saturation with 1% threshold) at years 2030, 2035, 2040, 2045, 2050, 2055 (end of injection = t), 2060 (t+5) and stabilized plume in 2070.*

4 Delineation of the Monitoring Areas

The delineation of the active monitoring area (AMA) and the maximum monitoring area (MMA) are based on the simulation results from section 3.9.

4.1 AMA – Active Monitoring Area

The AMA is shown in **Figure 4-1** and is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

(1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2055), plus an all-around buffer zone of one-half mile **(Figure 4.1-1);**

(2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2060).

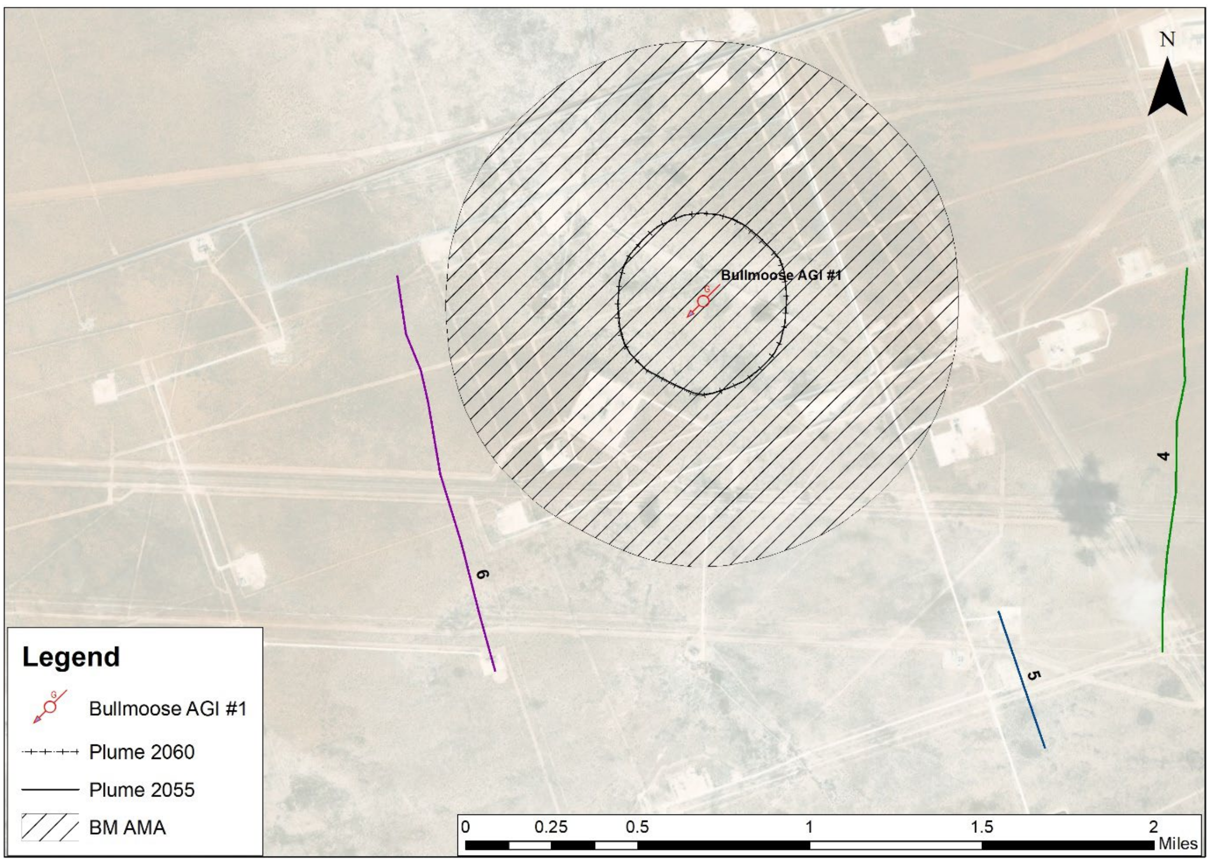


Figure 4.1-1: *Bull Moose AMA according to definition (1).*

TND intends to define the AMA to be the same area as the MMA. The black polygon at year t=2055 is the BM AGI #1 well plume at the end of injection, and the black cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection plus 5 years. The red polygon in **Figure 4.1-2** is the stabilized plume extent 15 years after injection ceases, i.e. 2070. The AMA, which is the hatched area in **Figure 4.1-1** and the MMA shown as the red-filled polygon in **Figure 4.1-2** contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

4.2 MMA – Maximum Monitoring Area

As defined in Section 40 CFR 98.449 of Subpart RR, the MMA is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.9 to define the extent of the plume.

According to the reservoir modeling results, after 30 years of post-injection monitoring (year=2085), the injected gas will remain in the reservoir and no expansion of the TAG footprint is observed after 2070. Therefore, the plume extent at year 2070 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA: **Figure 4.1-2**.

In addition, according to EPA regulation: "The buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that a buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances."

Therefore, TND considered the identified faults surrounding the injection well in order to define the MMA. There was no need to extend the MMA to incorporate the faults plus a one-half-mile buffer around the faults because they are outside the initial AMA and MMA. Therefore, the MMA encompasses the union of two areas:

- The area covered by the stabilized plume plus an all-around buffer zone of one-half mile
- The area covered by the lateral extent of known potential leakage pathways (the trace faults Figure 4.2) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 shows the MMA as defined by Section 40 CFR 98.449 of Subpart RR. The MMA is expected to contain the free phase CO_2 plume throughout the life of the project and the lateral extent of potential leakage pathway plus a one-half mile buffer. The AMA is set equal to the MMA.

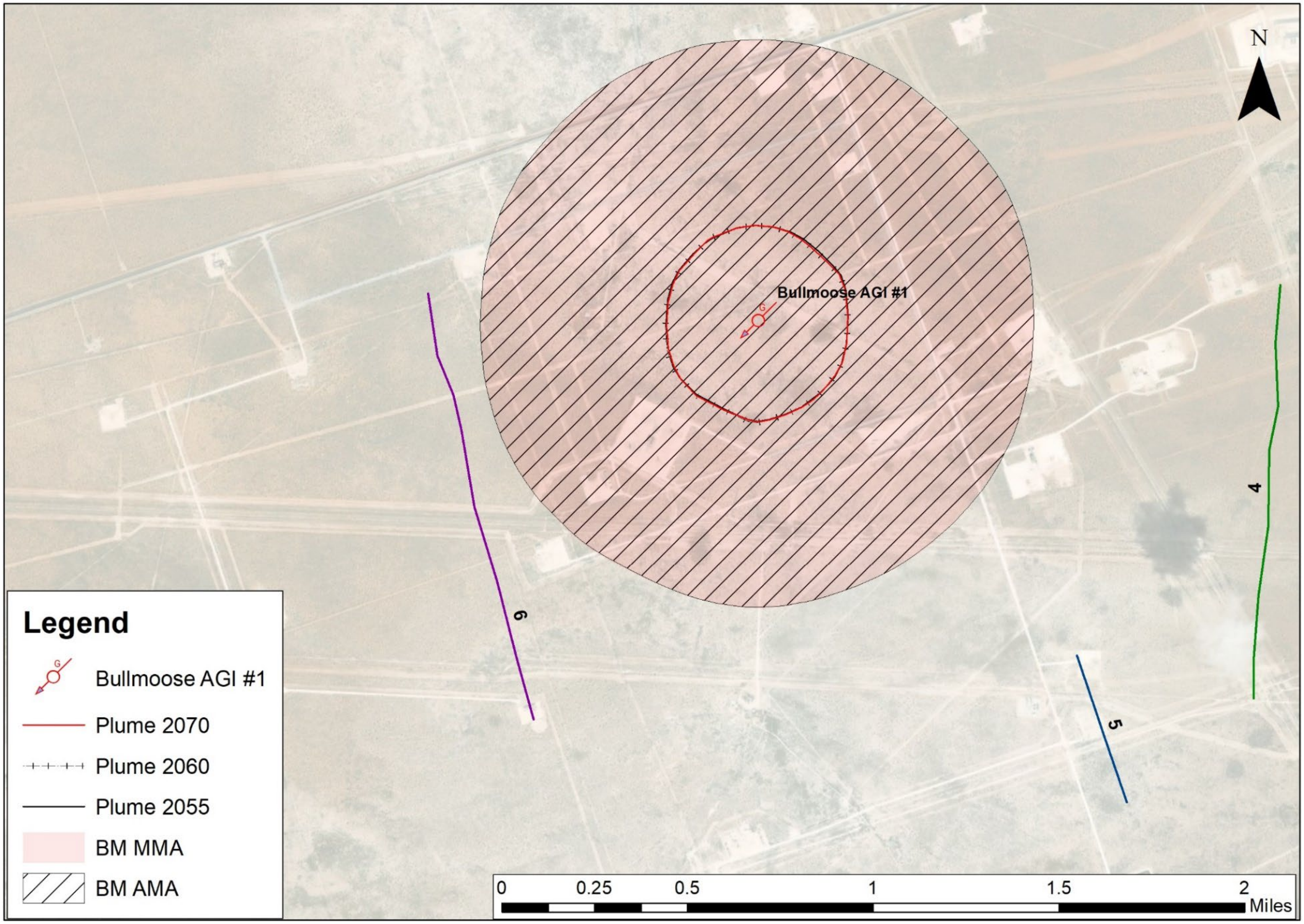


Figure 4.1-2: *Active monitoring area (AMA) and Maximum monitoring area (MMA) for TND BM AGI #1; and plume at the end of injection (2055), 5 years after end of injection (2060) and stabilized plume (2070)*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

An evaluation of each of the potential leakage pathways is described in the following paragraphs, notably:

1. Potential leakage from surface equipment
2. Potential leakage from approved not yet drilled wells
3. Potential leakage from existing wells
4. Potential leakage through the confining / seal system
5. Potential leakage due to lateral migration
6. Potential leakage through fractures and faults
7. Potential leakage due to natural / induced seismicity

Risk estimates were made using a risk matrix (**Figure 5.1-1**) with a methodology to evaluate risk probability and impact. In addition, TND used the National Risk Assessment Partnership (NRAP) tools, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage leakage risks at geologic carbon storage sites.

Magnitude →

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

Figure 5.1-1: *5x5 Risk Matrix used to evaluate leakage likelihood and magnitude.*

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills".

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

Likelihood:

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2.

Therefore, TND infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place and the regular inspections and maintenances, the probability of such leakage is considered very unlikely.

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days.

Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

Therefore, the impact (i.e. magnitude) of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable.

5.2 Potential Leakage from Approved Not Yet Drilled Wells

All the wells within the MMA are either injecting, producing, plugged and abandoned or inactive, **Table 5.1-1**. There are no approved and not yet drilled wells based on the available records.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA, as delineated in Section 4, are shown in **Figure 3.7-2** and detailed in **Appendix 3**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. None of the wells in the MMA penetrate the confining zone nor the injection zone. All of the productive zones lie at more than 5,300 ft above the BM AGI #1 injection zone.

Likelihood:

Even though the risk of CO_2 leakage through the wells that do not penetrate confining zones is very unlikely, (the CO_2 would have to leak through the sealing zone), TND did not omit any potential source of leakage in the NRAP analysis.

Magnitude:

If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. A total of 29 wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage.

There were 22 active oil wells that were considered in the NRAP risk assessment section. The other wells that were considered for the risk leakage assessment include two injection wells, six abandoned and plugged wells, and one inactive well. Reservoir and seal confinement properties were incorporated into the model, together with CO_2 properties and injection rates and pressures. The injection period was set to 30 years. According to the NRAP results, no leakage mass of CO_2 was recorded throughout the injection period.

Timing: The duration for CO_2 to get to the atmosphere via upward migration through the 5,300 ft of sealing and other geologic formations would be several thousands of years.

The **Table 5.1-1** summarizes the oil and gas wells and their evaluated risk. Based on the previous comments, all the wells expect three have a very low risk of CO_2 leakage. The likelihood of CO_2 leakage is very unlikely and the magnitude insignificant. Three wells have a medium risk, they present an unlikely likelihood of CO_2 leakage but can have a significant magnitude.

Table 5.1-1: *Well within the MMA with their evaluated risk.*

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34978	AGI	INJECTING	VERTICAL	Siluro-Devonian	TBD	2	3	6
42-495-34038	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516	1	1	1
42-495-33871	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630	1	1	1
42-495-34331	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564	1	1	1
42-495-34324	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621	1	1	1
42-495-34488	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627	1	1	1
42-495-34489	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637	1	1	1
42-495-33759	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,811	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,814	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,816	1	1	1
42-495-34325	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858	1	1	1
42-495-33236	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868	1	1	1
42-495-34332	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897	1	1	1
42-495-34483	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972	1	1	1
42-495-34323	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106	1	1	1

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
42-495-34485	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129	1	1	1
42-495-34481	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145	1	1	1
42-495-34482	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176	1	1	1
42-495-33840	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185	1	1	1
42-495-33726	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188	1	1	1
42-495-34329	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193	1	1	1
42-495-33763	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194	1	1	1
42-495-34326	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208	1	1	1
42-495-34484	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217	1	1	1
42-495-34328	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263	1	1	1
42-495-34330	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537	1	1	1
42-495-34327	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545	1	1	1
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6

5.3.1 Wells Completed in the Injection Zone

The only well completed in the BM AGI #1 well injection zone is the BM AGI #1 well.

Likelihood:

To minimize the likelihood of leaks from new wells, TRRC regulation regarding the casing and cementing of injection wells requires operators to case injection wells with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string.

Magnitude and Timing:

To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, TRRC requires the use of blowout preventers in areas of high pressure at or above the projected depth of the well. These requirements apply to any other new well drilled within the MMA for this MRV plan.

In addition, for safety purposes, TND will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 flow to the surface by:

- Monitoring H_2S at surface at many locations (H_2S can be a proxy to detect CO_2);
- Employing a high level of caution and care while drilling, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the injection zone.

By drilling through producing zones, there is a possibility of gas emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent and/or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of BM AGI #1 operating parameters by the distributed control system (DCS), TND considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.3.2 Horizontal Wells

The table in **Appendix 3** and **Figure 3.7-2** show a number of horizontal wells in the area, many of which are producing. As discussed in 5.3, they are all 5,300 ft above the injection zone and the risk of leakage through these wells is considered very unlikely and insignificant.

5.3.3 Groundwater Wells

According to the Texas Water Development Board water database, there are no water wells within the MMA. There are only one North-East of the MMA and South-West of the MMA. Therefore, the risk of leakage through these wells are considered very unlikely and insignificant TWDB

5.4 Potential Leakage through the Confining / Seal System

Although unlikely, TND considered leakage through confining zones in the NRAP risk assessment.

Likelihood:

The Barnett shale (440 ft), Mississipian limestone (440 ft) and Woodford Shale (660 ft) serve as the major seals or caprock layer to the injection zones. Their low porosity (1%) and permeability (<0.1

mD) provide high seal integrity (Sections 3.2, 3.3) There is. no evidence of faulting or natural fracturing. It is very unlikely that TAG injected into the injection formation will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Magnitude and Timing:

The worst-case scenario is defined as leakage through the seal immediately above the injection well, where CO_2 saturation is highest.

To simulate this scenario, cell blocks were created to cover the MMA, serving as the most prone zone for CO_2 leakage. These cell block locations and CO_2 saturation at the seal and seal properties were incorporated into the NRAP model.

Figures 5.4-1 and 5.4-2 present the leakage rate and cumulative mass of leakage over 60 years. The total leakage mass recorded after 60 years is about 8,000 kg. According to the total mass of CO_2 injected per year alone, after 60 years, the percentage of leakage through confining zone is estimated to be 0.0021%. This is reliably minimal and considering other stratigraphic strata, TND concludes that the risk of leakage through this pathway is highly unlikely and insignificant.

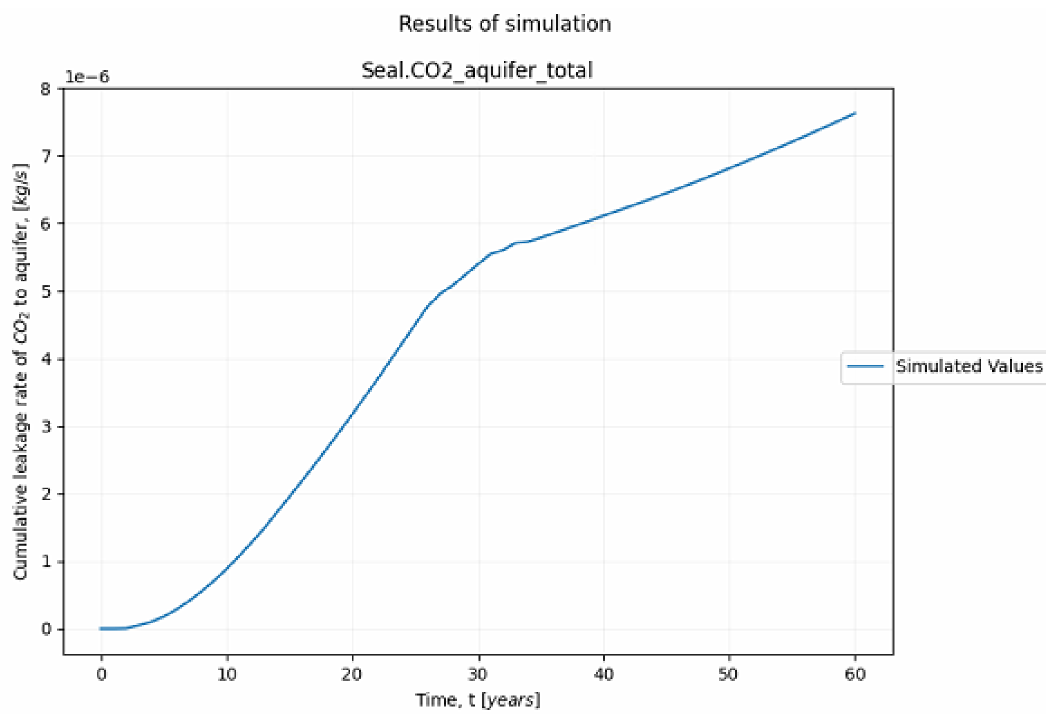


Figure 5.4-1: Seal leakage rate

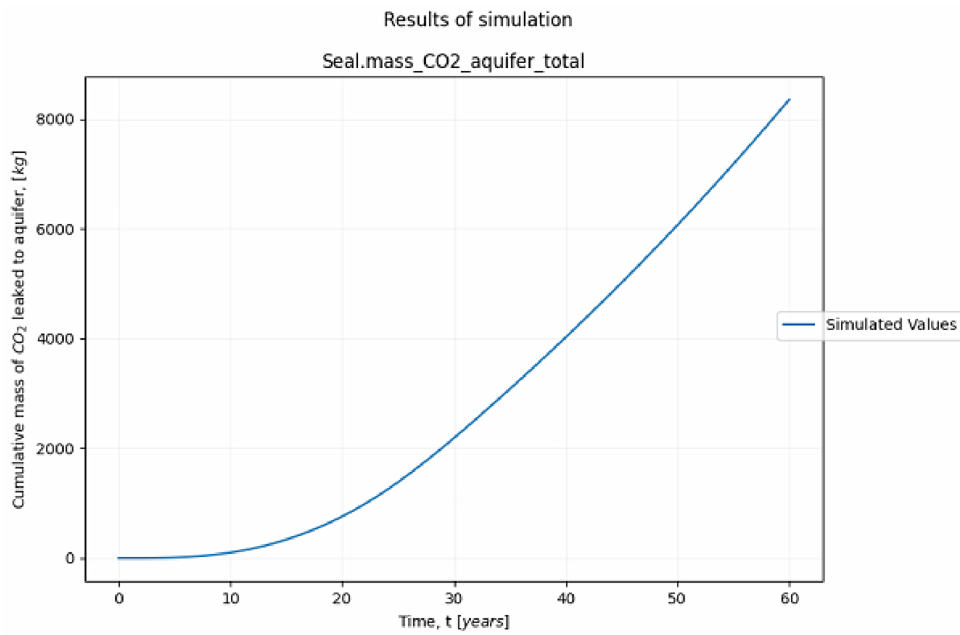


Figure 5.4-1: *Cumulative mass of Seal leakage*

5.5 Potential Leakage due to Lateral Migration

Likelihood:

Regional consideration of the geology (Section 3.3) and the model built suggest that BM AGI #1 injection zones have adequate storage capacity for the proposed injection amount. In addition, simulation (Section 3.9) indicates that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA.

Based on the geological discussion and analysis of the injection zone, TND considers that the likelihood of CO_2 to migrate laterally is unlikely.

Magnitude and Timing:

Based on simulation results, the TAG is projected to be contained within the injection zone close to the injection well. The sealing zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration occurs.

5.6 Potential Leakage through Fractures and Faults

Likelihood:

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces (numbered 4, 5 and 6) in the vicinity of the Bull Moose plant. The fault number 6 shown on **Figure 5.6-1** is above the injection zone for the BM AGI well. No faults were identified in the injection zone or confining zone within the MMA. Therefore, the likelihood of leakage through faults is considered very unlikely.

Magnitude and Timing:

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. Considering faults that are going through the confining or injection zone, the closest identified fault lies approximately 1.5 miles east of the Bull Moose site and has approximately 1,000 ft of down-to-the-west structural relief.

The nearest fault going through the injection or confining zone is found approximately 7,276 ft east of the BM AGI #1 site. The risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume or lateral migration carries CO_2 to faults. Other nearby faults are 12,031 ft (~2.3 mi)and ft (2.9 mi) east the site, placing them outside the MMA. Hence, leakage through faults will be an unlikely event. This is supported by NRAP simulation results (**Figure 5.6-1**) that consider fault location, geometry, and direction. For faults that do not directly connect with the CO_2 plume, CO_2 leakage rate and mass are estimated to be zero. The estimated cumulative leakage (**Figure 5.6-1**) shows no leakage throughout the period of simulation (60 years).

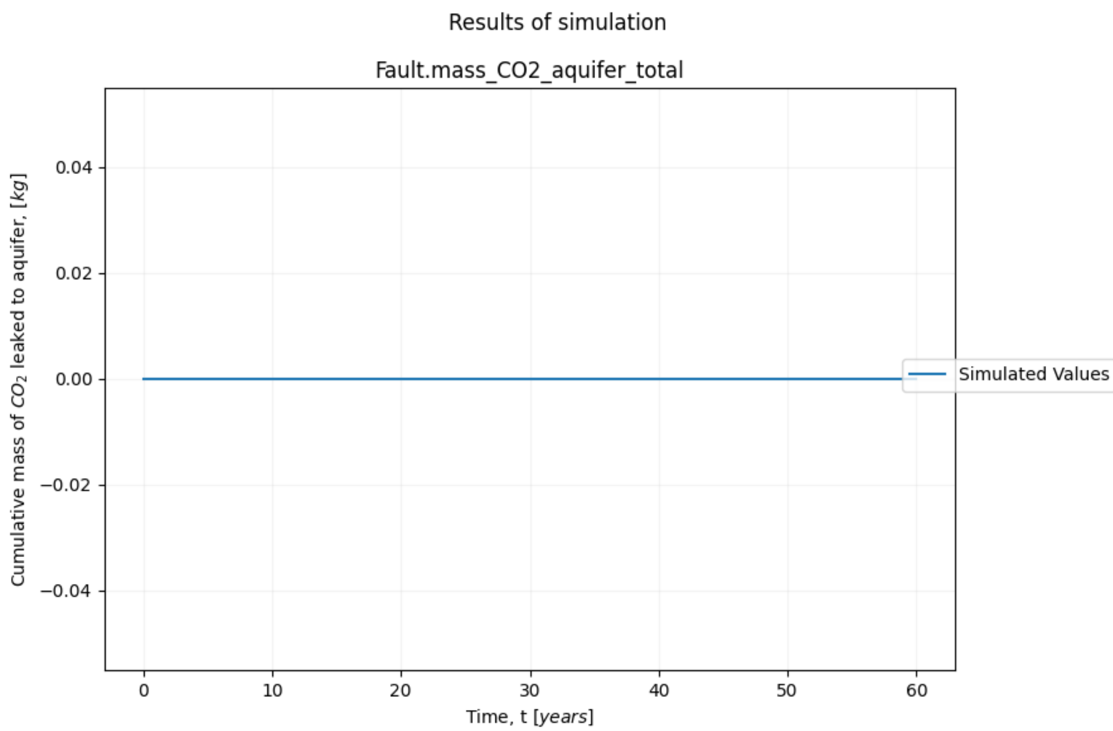


Figure 5.6-1: *Faults 7,276 ft*

Therefore, TND concludes that the risk of CO_2 leakage through the faults are very unlikely and insignificant.

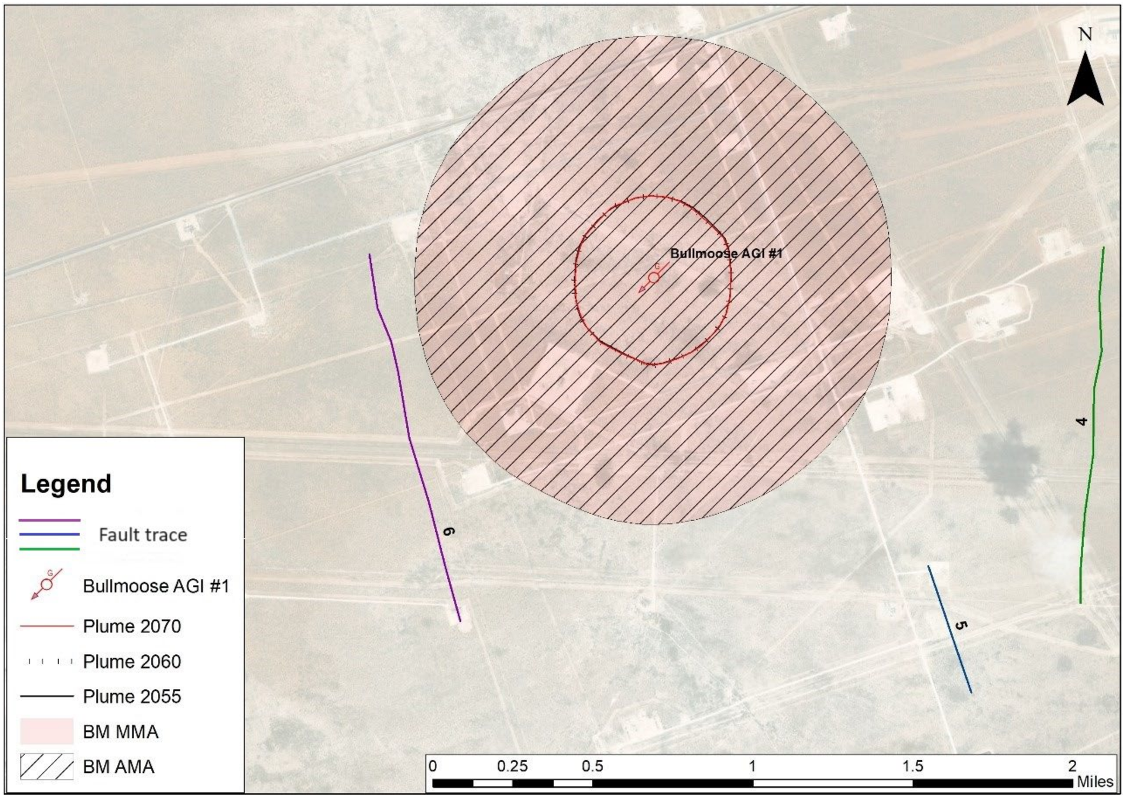


Figure 5.6-1: *Faults surrounding Bull Moose facility relative to the plume and the MMA.*

5.7 Potential Leakage due to Natural / Induced Seismicity

5.7.1 Natural Seismicity

Likelihood:

Due to the distance between the BM AGI #1 well and the location of the seismic events recorded since 2017, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be very unlikely.

Magnitude and Timing:

The magnitude and timing of a seismic event can vary greatly. In the region, the earthquakes ranged from magnitude 1.5 to 4. They are located in clusters that are around 20 miles North-West and South, South-West of Bull Moose.

Based on historical data and the geology of the surroundings, the risk of CO_2 leakage due to seismicity is considered insignificant.

Monitoring of seismic events in the vicinity of the Bull Moose AGI well is discussed in Section 6.7.

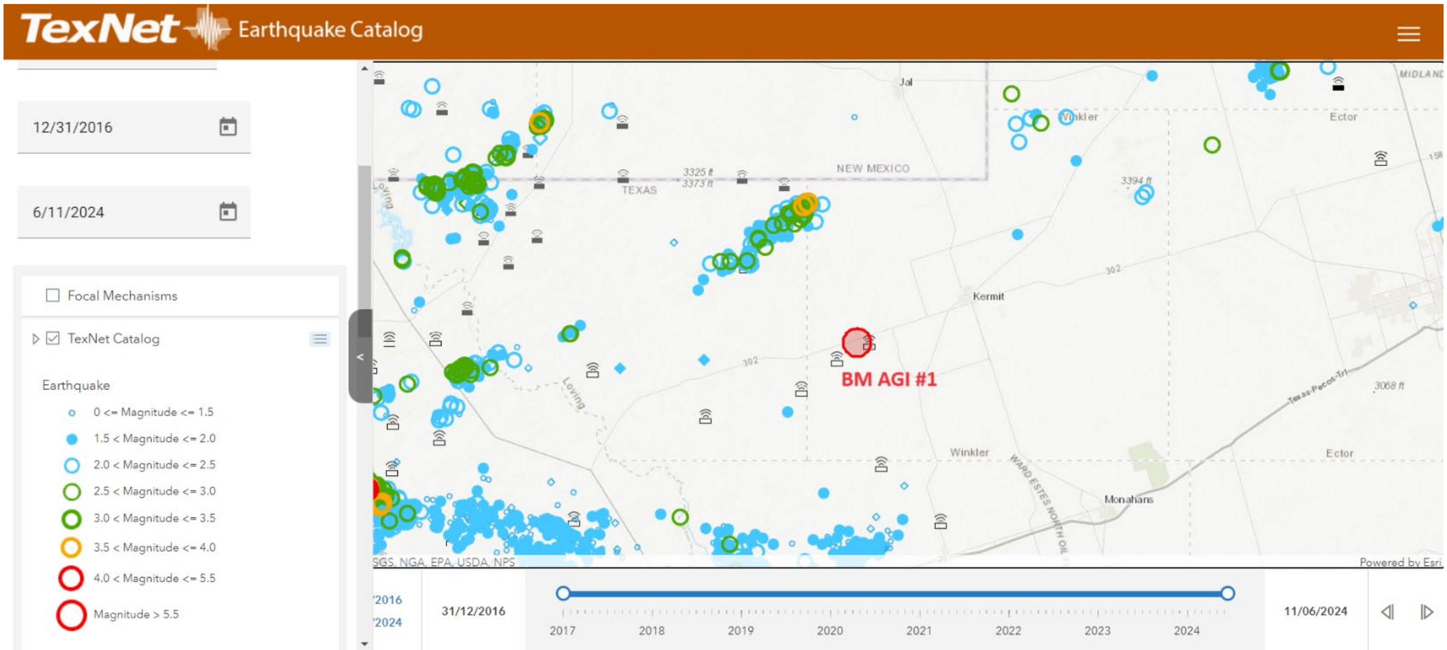


Figure 5.7-1: TexNet seismic events since 2017 and seismic monitoring stations close to Bull Moose plant.

5.7.1 Induced Seismicity

The faults that might be affected by pressure changes have been analyzed to evaluate the risk of induced seismicity, and the risk of leakage due to induced seismicity. The examination of faults identified from the 3D seismic data, illustrated in **Figure 5.7-2**, discloses the presence of 6 major faults traversing the reservoir interval. These faults are far east from BM AGI #1 and they have been further subdivided into 41 sub-fault segments, allowing for a detailed analysis of their slip potentials.

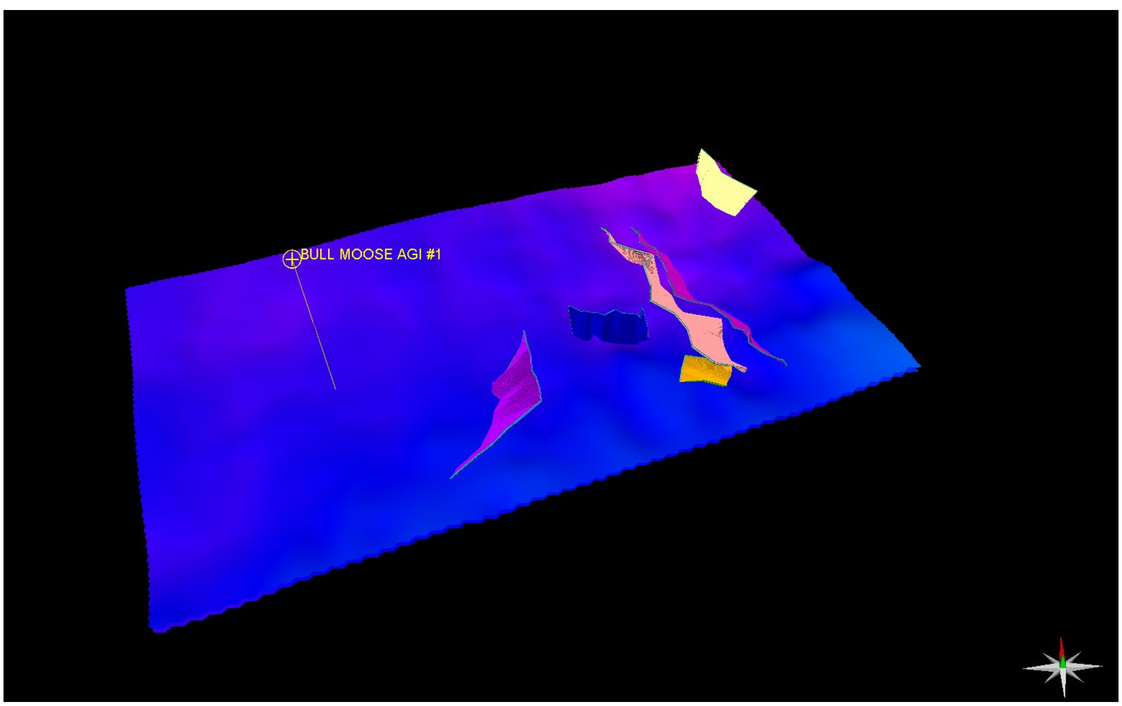


Figure 5.7-2: Structure and fault system picked from 3D seismic data on Silu-Devonian to Ellenburger.

The evaluation of Fault Slip Potential (FSP) using the FSP software version 1.07 involved the utilization of specific parameters (**Table 5.7**). The software requires various inputs or parameters to assess the potential for fault slippage. These parameters are fundamental in assessing the likelihood of fault slippage. The FSP software incorporates and processes these inputs to generate an estimation or analysis of the potential for faults to slip under the given conditions. These parameters could include factors such as: Pressure Changes (the magnitude of pore pressure changes within the geological formations), fault geometry (details about the fault, including its orientation, size, and geometry), stress conditions (information on stress distribution within the rock formations, including the magnitudes and orientations of principal stresses), rock properties (data regarding the mechanical properties of the rocks, such as porosity, permeability, and strength), and seismic data (3D seismic data used to identify and characterize faults geometry). These parameters are from published papers and reports.

Table 5.7: *Fault Slip Potential simulation parameters.*

Fault Friction Coeff (mu)	0.58
Vertical Stress Gradient (psi/ft)	1.07+/-0.01
Maximum Horizontal Stress Direction (deg)	82.5 +/- 7.5
Initial Reservoir Pressure Gradient (psi/ft)	0.465 +/- 0.05
Minimum Horizontal Stress Gradient (psi/ft)	0.5
Maximum Horizontal Stress Gradient (psi/ft)	1
A-Phi Parameter	0.8+/-0.1
Reference Friction Coefficient (mu)	0.58+/-.005
Porosity (%)	15
Permeability (mD)	7.2
Injection Years	2025 to 2055

It appears that the results of the FSP (Fault Slip Potential) analysis indicate that over a 30-year injection period, faults have experienced only a small pressure drop in effective stress. The slippage of fault walls is contingent on having sufficient pore pressure to raise the effective stress to a level that would induce slippage. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation. As shown in **Figure 5.7-3**, 97% of interpreted faults require more than 180 psi effective pressure to cause slip. The predicted value of effective pressure changes on **Figure 5.7-4** and **Figure 5.7-5** shows that the pore pressure will change less than 30 psi after 30. The probability of fault slip are shown in **Figure 5.7-5**. These values indicate negligible potential for fault slips for major faults. This information suggests that the fault system may be relatively stable or that the pore pressure changes have not been significant enough to cause fault activation.

Therefore, the risk of leakage due to induced seismicity is considered very low. Its **likelihood, timing and magnitude** are considered very unlikely and insignificant.

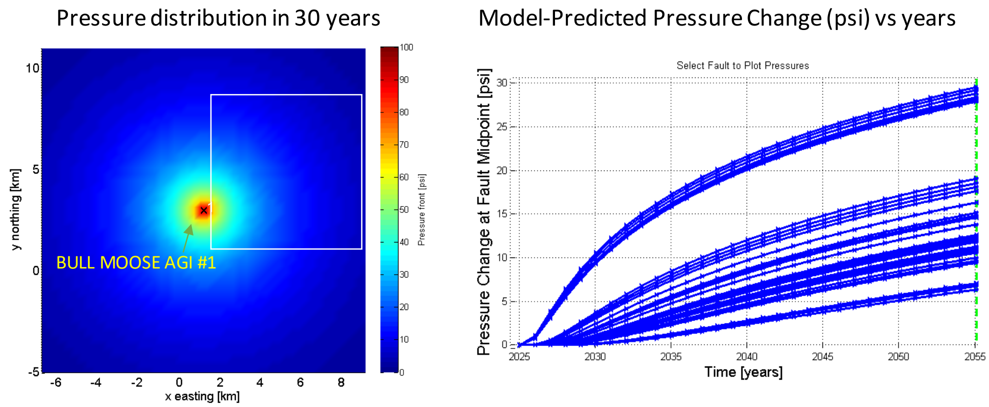


Figure 5.7-3: *Visualization of pressure change after 30 years of injection*

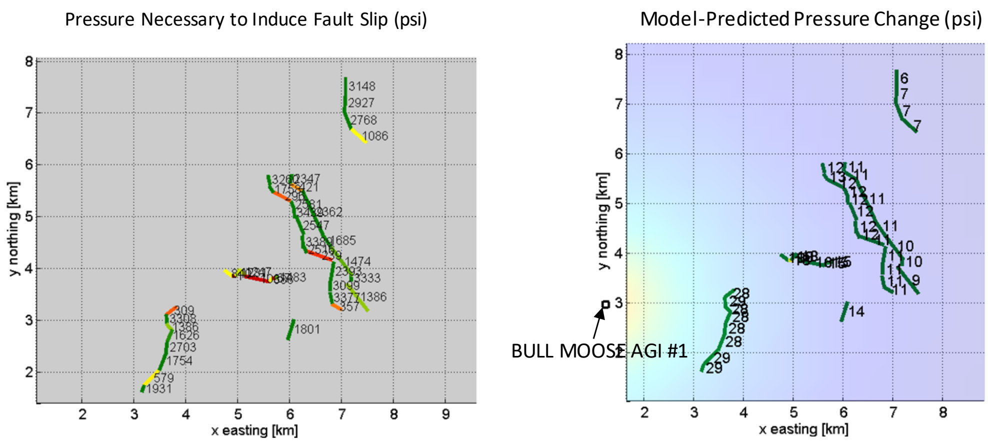


Figure 5.7-4: *Visualization of pressure change required to cause fault slip and the predicted pressure after 30 years of injection*

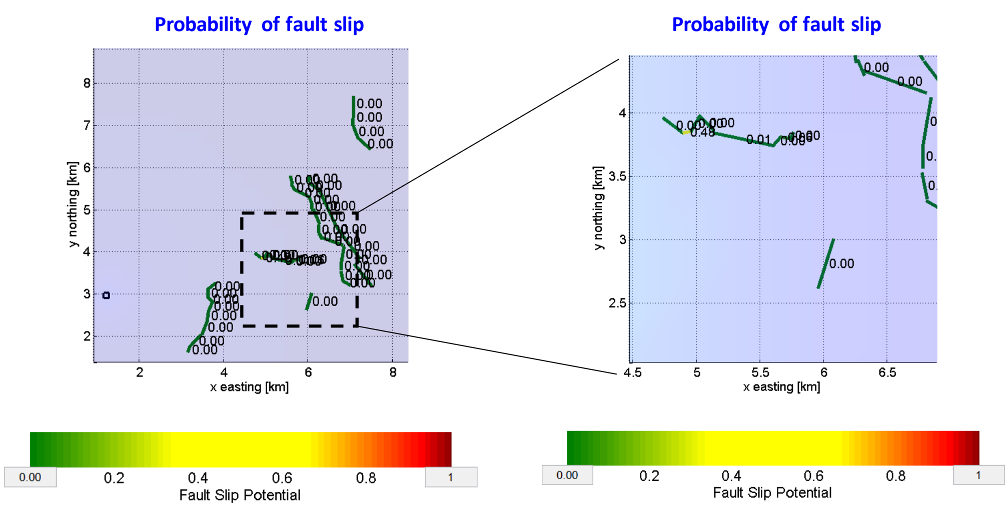


Figure 5.7-5: *Fault slip probability after 30 years of injection. Fault color represent the fault slip potential value indicated by color bar and they show almost 0% of fault slip potential.*

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2.

TND will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage close to the plant equipment. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 15-year post-injection period.

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
BM AGI #1 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well pressure/temperature (P/T) sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring station
Lateral Migration	• DCS surveillance of well operating parameters

	• Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

TND implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Leaks from surface equipment are detected by TND field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

TND also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. This applies to TND and other operators drilling new wells through the BM AGI #1 injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 BM AGI Well

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

To monitor leakage and wellbore integrity, pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) will be deployed in TND's BM AGI #1 well.

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

Well Schematic for BM AGI #1 showing installation of pressure and temperature sensors are in **Appendix 1**.

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the BM AGI #1 well, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining / seal system, TND will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well (see Section 6.8).

6.5 Leakage due to Lateral Migration

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

If monitoring of operational parameters or other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, TND will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults.

However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

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

If the monitoring systems indicate surface leakage of CO_2 linked to seismic events, TND will assess whether the CO_2 originated from the BM AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the TRRC regulations. TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 6-1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. TND may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

TND field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Bull Moose Gas Plant.

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

Compositional analysis of TND's gas injectate at the Bull Moose Gas Plant indicates an approximate H_2S concentration of 30% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the TRRC Regulations. TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated BM AGI #1 Well and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Bull Moose Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, TND will set up a monitoring network for CO_2 leakage detection in the MMA as defined in Section 4.2. In addition, there will be periodic groundwater and soil flux sampling within the MMA. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of TRRC Rules governing the construction, operation and closing of an injection well under the Oil and Gas Act. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the BM AGI #1 well ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a seismometer and a digital recorder to monitor for and record data for any seismic event at the Bull Moose Gas Plant. The seismic station meets the requirements of the TRRC.

In addition, data that is recorded by the TexNet network surrounding the Bull Moose Gas Plant will be analyzed by TND. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

TND will monitor groundwater wells for CO_2 leakage as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes TDS, conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Bull Moose Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

Table 7.7-1: Groundwater Monitoring Parameters

Parameters
pH
Alkalinity as HCO^{3-} (mg/L)
Chloride (mg/L)
Fluoride (F^-) (mg/L)
Bromide (mg/L)
Nitrate (NO^{3-}) (mg/L)
Phosphate (mg/L)
Sulfate ($SO4^{2-}$) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, TND can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Bull Moose Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

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

8.1 CO_2 Received

Currently, TND receives gas to its Bull Moose Gas Plant through pipelines. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters FE in **Figure 3.7-1**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving volumetric flow meter.

$$\mathrm{CO}_2 = \sum_{r=1}^{R} \mathrm{CO}_{2\mathrm{T},\mathrm{r}}$$

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

Although TND does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When TND begins to receive CO_2 in containers, TND will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2

received in containers. TND will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Upon completion, TND will commence injection into BM AGI #1. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the well. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into the well. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to flow meter FE in **Figure 3.7-1**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Volumetric flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

* Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Bull Moose Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established by TND for several years and continues to the present. TND will begin implementing this MRV plan as soon as it is approved by EPA. After BM AGI #1 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

TND will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), TND's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the BM AGI #1 well using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Bull Moose Gas Plant.

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

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

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

10.1.6 Measurement devices.

As required by 40CFR98.444(e), TND will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association

(AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

TND will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of Texas. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after BM AGI #1 has been drilled and characterized.

11 Records Retention

TND will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, TND will retain the following documents:

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

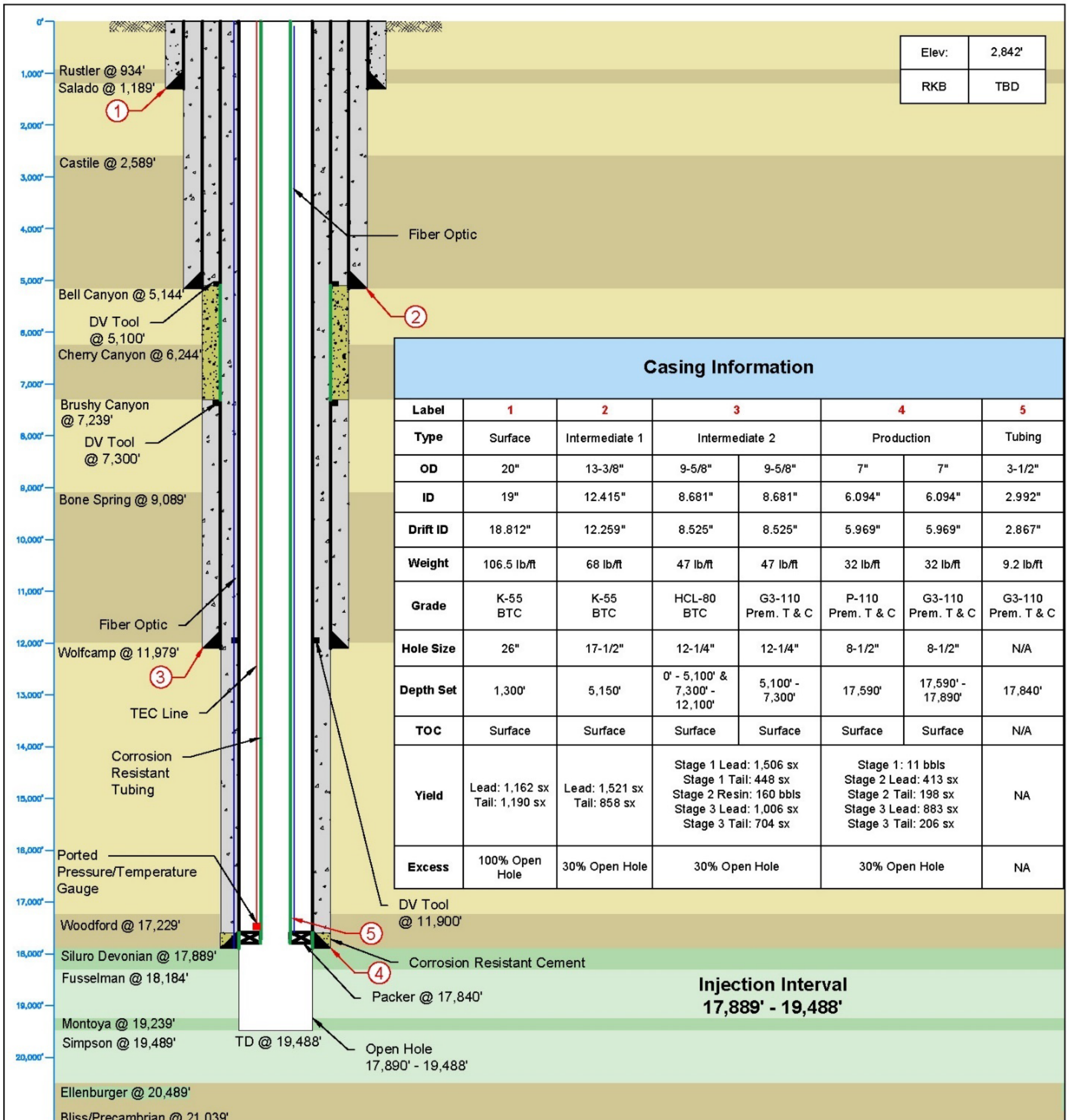
(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

12 Appendices

Appendix 1 TND Well

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Bull Moose AGI #1 (BM AGI #1)	42-495-34978	1,895' FSL & 2,161' FEL, SEC 42, BLK 27, Public School Land Survey, A-433	KERMIT, TX	To be determined	19,488 ft	17,790 ft



Casing Information

Label	1	2	3		4		5
Type	Surface	Intermediate 1	Intermediate 2		Production		Tubing
OD	20"	13-3/8"	9-5/8"	9-5/8"	7"	7"	3-1/2"
ID	19"	12.415"	8.681"	8.681"	6.094"	6.094"	2.992"
Drift ID	18.812"	12.259"	8.525"	8.525"	5.969"	5.969"	2.867"
Weight	106.5 lb/ft	68 lb/ft	47 lb/ft	47 lb/ft	32 lb/ft	32 lb/ft	9.2 lb/ft
Grade	K-55 BTC	K-55 BTC	HCL-80 BTC	G3-110 Prem. T & C	P-110 Prem. T & C	G3-110 Prem. T & C	G3-110 Prem. T & C
Hole Size	26"	17-1/2"	12-1/4"	12-1/4"	8-1/2"	8-1/2"	N/A
Depth Set	1,300'	5,150'	0' - 5,100' & 7,300' - 12,100'	5,100' - 7,300'	17,590'	17,590' - 17,890'	17,840'
TOC	Surface	Surface	Surface	Surface	Surface	Surface	N/A
Yield	Lead: 1,162 sx Tail: 1,190 sx	Lead: 1,521 sx Tail: 858 sx	Stage 1 Lead: 1,506 sx Stage 1 Tail: 448 sx Stage 2 Resin: 160 bbls Stage 3 Lead: 1,006 sx Stage 3 Tail: 704 sx		Stage 1: 11 bbls Stage 2 Lead: 413 sx Stage 2 Tail: 198 sx Stage 3 Lead: 883 sx Stage 3 Tail: 206 sx		NA
Excess	100% Open Hole	30% Open Hole	30% Open Hole		30% Open Hole		NA

LONQUIST & CO. LLC PETROLEUM ENGINEERS · ENERGY ADVISORS AUSTIN · HOUSTON · CALGARY · WICHITA DENVER · COLLEGE STATION · BATON ROUGE · EDMONTON	Targa Delaware LLC	Bull Moose AGI No. 01	
	Country: USA	**State/Province:** Texas	**County/Parish:** Winkler
	Location: Sec. 42, A-433, Blk 27		**District:** 08
	API No: TBD	**Field:**	**Well Type/Status:** AGI Disposal
Texas License F-9147	**Survey:**	**Project No:** F2345	**Date:** 5/6/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** CJL	**Reviewed:** WHG	**Approved:**
	Rev No: 1	**Notes:** Intermediate 2 Revisions Requested by Targa	

Figure Appendix 1-1: Schematic of TND BM AGI #1 Well

Appendix 2 Referenced Regulations

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

Texas Administrative Code > Title 16, Economic Regulation, > Part 1 Railroad Commissions of Texas > Chapter 3, Oil and Gas Division
CHAPTER 15 - OIL AND GAS

§3.1	Organization Report; Retention of Records; Notice Requirements
§3.2	Commission Access to Properties
§3.3	Identification of Properties, Wells, and Tanks
§3.4	Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
§3.5	Application To Drill, Deepen, Reenter, or Plug Back
§3.6	Application for Multiple Completion
§3.7	Strata To Be Sealed Off
§3.8	Water Protection
§3.9	Disposal Wells
§3.10	Restriction of Production of Oil and Gas from Different Strata
§3.11	Inclination and Directional Surveys Required
§3.12	Directional Survey Company Report
§3.13	Casing, Cementing, Drilling, Well Control, and Completion Requirements
§3.14	Plugging
§3.15	Surface Equipment Removal Requirements and Inactive Wells
§3.16	Log and Completion or Plugging Report
§3.17	Pressure on Bradenhead
§3.18	Mud Circulation Required
§3.19	Density of Mud-Fluid
§3.20	Notification of Fire Breaks, Leaks, or Blow-outs
§3.21	Fire Prevention and Swabbing
§3.22	Protection of Birds
§3.23	Vacuum Pumps
§3.24	Check Valves Required
§3.25	Use of Common Storage

§3.26	Separating Devices, Tanks, and Surface Commingling of Oil
§3.27	Gas to be Measured and Surface Commingling of Gas
§3.28	Potential and Deliverability of Gas Wells to be Ascertained and Reported
§3.29	Hydraulic Fracturing Chemical Disclosure Requirements
§3.30	Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)
§3.31	Gas Reservoirs and Gas Well Allowable
§3.32	Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes
§3.33	Geothermal Resource Production Test Forms Required
§3.34	Gas To Be Produced and Purchased Ratably
§3.35	Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned
§3.36	Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas
§3.37	Statewide Spacing Rule
§3.38	Well Densities
§3.39	Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40	Assignment of Acreage to Pooled Development and Proration Units
§3.41	Application for New Oil or Gas Field Designation and/or Allowable
§3.42	Oil Discovery Allowable
§3.43	Application for Temporary Field Rules
§3.45	Oil Allowables
§3.46	Fluid Injection into Productive Reservoirs
§3.47	Allowable Transfers for Saltwater Injection Wells
§3.48	Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

§3.49	Gas-Oil Ratio
§3.50	Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51	Oil Potential Test Forms Required
§3.52	Oil Well Allowable Production
§3.53	Annual Well Tests and Well Status Reports Required
§3.54	Gas Reports Required
§3.55	Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56	Scrubber Oil and Skim Hydrocarbons
§3.57	Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58	Certificate of Compliance and Transportation Authority; Operator Reports
§3.59	Oil and Gas Transporter's Reports
§3.60	Refinery Reports
§3.61	Refinery and Gasoline Plants
§3.62	Cycling Plant Control and Reports
§3.63	Carbon Black Plant Permits Required
§3.65	Critical Designation of Natural Gas Infrastructure
§3.66	Weather Emergency Preparedness Standards
§3.70	Pipeline Permits Required
§3.71	Pipeline Tariffs
§3.72	Obtaining Pipeline Connections
§3.73	Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76	Commission Approval of Plats for Mineral Development
§3.78	Fees and Financial Security Requirements
§3.79	Definitions
§3.80	Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81	Brine Mining Injection Wells
§3.83	Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84	Gas Shortage Emergency Response

§3.85	Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86	Horizontal Drainhole Wells
§3.91	Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93	Water Quality Certification Definitions
§3.95	Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96	Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97	Underground Storage of Gas in Salt Formations
§3.98	Standards for Management of Hazardous Oil and Gas Waste
§3.99	Cathodic Protection Wells
§3.100	Seismic Holes and Core Holes
§3.101	Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102	Tax Reduction for Incremental Production
§3.103	Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106	Sour Gas Pipeline Facility Construction Permit
§3.107	Penalty Guidelines for Oil and Gas Violations

Appendix 3 Oil and Gas Wells within MMA of the BM AGI Well Site

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34323	SILVER DOLLAR 4231-27 A 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,814
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,811
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11,816
42-495-34481	BRIDAL VEIL STATE W 4132-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145
42-495-33759	VALLECITO 37-28 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718
42-495-34328	SILVER DOLLAR 4231-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263
42-495-34331	SILVER DOLLAR 4231-27 E 5H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564
42-495-34485	BRIDAL VEIL STATE W 4132-27 L 12H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129
42-495-33871	MITCHELL 42-27 1	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630
42-495-34488	BRIDAL VEIL STATE W 4132-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627
42-495-34482	BRIDAL VEIL STATE W 4132-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176
42-495-33840	SAINT VRAIN 48-28 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185
42-495-33763	AVALANCHE 42-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194
42-495-33726	SILVER DOLLAR 31-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188
42-495-34484	BRIDAL VEIL STATE W 4132-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217
42-495-34038	MITCHELL 42-27 2	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516
42-495-34489	BRIDAL VEIL STATE W 4132-27 K 11H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637
42-495-34332	SILVER DOLLAR 4231-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897
42-495-34329	SILVER DOLLAR 4231-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193
42-495-34327	SILVER DOLLAR 4231-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545
42-495-34325	SILVER DOLLAR 4231-27 D 4H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16,000
42-495-34326	SILVER DOLLAR 4231-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34324	SILVER DOLLAR 4231-27 B 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621
42-495-34330	SILVER DOLLAR 4231-27 C 3H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537
42-495-34483	BRIDAL VEIL STATE W 4132-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972
42-495-33236	HARRISON STATE 41 1H	DEVON	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868

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Appendix 5 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
PPM – Parts Per Million
QA/QC – quality assurance/quality control
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 6 TND Bull Moose AGI Well - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

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

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

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

Appendix 7 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving mass flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving volumetric flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Mass flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

* Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Separator.

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

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

(Equation RR-9)

where:

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

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

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

w = Separator.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

Request for Additional Information: Bull Moose Gas Plant
August 22, 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.	N/A	N/A	There is a lack of consistency with hyphens, bolding, quotation marks, spelling, and capitalization throughout the MRV plan. Examples include but are not limited to: • Feet vs. ft vs. ’ • Bull Moose AGI #1 well vs. BM AGI #1 • Thousand place separators • Siltones • Formation vs. formation • MMSCFD vs. MMCFD We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review for spelling, grammar, etc.	The text of the revised MRV plan has been edited as follows: - to use ‘ft’ in place of ‘feet’ where appropriate, - Bull Moose AGI #1 well is shortened to BM AGI #1 after first defined, - Commas are added for thousand place separators, - Spelling has been corrected - Formation is capitalized when referring to an individual formation when the word formation is part of the formal name of the formation; formation is not capitalized when referring to formations in general and when referring to two or more formation as in a list.
2.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, “P/T” is not defined within the text.	Acronyms in the text of the revised MRV plan have been defined at their first use.
3.	3.2	19	“Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics.” We recommend revising the statement above for clarity.	The statement has been revised for clarity: “Within the Bull Moose area, there is no active production from the Permian Delaware Mountain Group, but there is production from the basinal Bone Spring and Wolfcamp formations. The injection and confining zones for BM AGI #1 are discussed below.”

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	3.3	19	"The total thickness of the injection interval is estimated to be 3,150 ft (Table 3.3-1)." Section 1 of the MRV plan states "the permitted injection interval is between 17,889 feet and 19,488 feet," which is less than the thickness of the injection interval discussed above. Please address this inconsistency.	Statement addressed: the total thickness of the injection interval is estimated to be 1,594 ft.
5.	3.3	24	"The Bliss Sandstone and crystalline Precambrian rocks are potential lower seals." The MRV plan references multiple potential lower confining zones, but Table 3.3-1 does not identify the formations as such. We recommend adding the lower confining zones to the table.	The Table 3.3-1 has been modified to add the Bliss sandstone / Precambrian as lower seals.
6.	3.4	25	Figures such as 3.3-5 in the MRV plan show two red triangles. While one of the triangles represents the location of the Bull Moose AGI #1 well, please clarify what the other triangle is intended to represent.	The other triangle is another well that is not relevant to this MRV. The figures have been modified and the irrelevant red triangle removed.
7.	3.4	35	In Figure 3.3-15 of the MRV plan, the proposed injection interval obscures the group/formation names. This is not the case in Figure 3.3-14 above. Please clarify.	The formation names in figure 3.3-14 have been modified so that they overlay the red bar indicating the proposed injection interval.
8.	3.9	44	"Dynamic reservoir numerical simulation is performed on a realistic geologic." We recommend revising the statement above for clarity.	The statement has been revised for clarity: the dynamic reservoir simulation was performed based on a high resolution geological model.
9.	3.9	44	"Computer Modeling software were used to perform the reservoir simulations presented in this MRV plan." Please clarify whether the statement above is intended to read "Computer Modeling Group"?	The name of the software used has been modified: Computer Modelling Group (CMG) software.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
10.	3.9	45	"The initial salinity is assumed to be 20,000 ppm." Please clarify why the salinity used in the model is lower than the salinities provided in Tables 3.5-1 and 3.9-1 of the MRV plan.	This is a reporting error, the salinity value used in the simulation is 150,000 ppm, as specified in Table 3.9-1.
11.	4.1/4.2	50/52	There are two figures titled Figure 4.1-1.	The second Figure 4.1-1 was changed to Figure 4.1-2 in the revised MRV plan.
12.	5	53	The subsection headings identified at the beginning of Section 5 in the MRV plan do not match the subsection headings below. Additionally, the section headings in Section 5 do not align with the section headings in Section 6. Please address these inconsistencies.	The MRV plan has been modified to move the "Potential Leakage through BM AGI #1" section down to the "Well Completed in the Injection Zone" section. Section 5.2 was changed to "Potential Leakage from Approved Not Yet Drilled Wells" and the risk assessment has been performed. The subheadings are now aligned.
13.	5.3	56	"The Table 5.1-1 summarizes the oil and gas wells and their evaluated risk. Therefore, CO2 leakage to the surface via existing well can be considered very unlikely and insignificant." Table 5.1-1 identifies multiple wells at level 6, a "medium" risk. Please revise the above conclusion statement to reflect this assessment or clarify as necessary.	The conclusion have been revised to reflect the risk assessment.
14.	5.7	63	Section 5.7 of the MRV plan characterizes the likelihood, magnitude, and timing of leakage through natural seismicity, but it does not specifically mention induced seismicity. Please characterize the risk of leakage through induced seismicity and revise the monitoring strategy in Section 6.7 if necessary.	The risk of leakage through induced seismicity has been assessed thanks to a Fault Slip Potential analysis. The results of the risk assessment analysis did not require a modification of Section 6.7.
15.	6.5	66	"Continuous operational monitoring of the BM AGI wells…" Please clarify in the MRV plan if there are multiple Bull Moose AGI wells.	There is only one Bull Moose AGI well. The statements have been revised.

<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>16.</td><td>6.8</td><td>67</td><td>“Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak.”

Please note that all leakage from equipment located on the surface between the flow meter used to measure the injection quantity and the injection wellhead must be calculated according to 40 CFR 98.444(d).</td><td>The first sentence of Section 6.8.1 has been changed in the revised MRV plan as follows:

“For normal operations, quantification of emissions of CO_2 from surface equipment located between the flow meter used to measure injection quantity and the injection wellhead will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR.”</td></tr>
<tr><td>17.</td><td>8.1/8.2</td><td>72/73</td><td>“Receiving flow meter r in the following equations corresponds to meters M1 and M2 in Figure 3.6-2.”

“Volumetric flow meter u in the following equations corresponds to meters M5 and M6 in Figure 3.6-2.”

The statements above references flow meters M1, M2, M5, and M6 in Figure 3.6-2 of the MRV plan, but there is no Figure 3.6-2 in the MRV plan. Please clarify whether these meters are shown in any of the Figures in the MRV plan.</td><td>The statement was a reporting mistake. There is only one flow meter and sampling point for BM AGI #1. They are described in Figure 3.7-1: Process Block Flow Diagram with CO2 entry, Flow meter (FE), Sampling point (SP) and BM AGI #1.</td></tr>
<tr><td>18.</td><td>8.1</td><td>72</td><td>“r = Receiving volumetric flow meter.”

Per 40 CFR 98.443(a)(2), this variable should be, “r = Receiving flow meter.” 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. Please note the same issue appears in Equation RR-5.</td><td>“volumetric” has been deleted from this statement. All equations and variables have been checked to ensure that they are consistent with the equations and variables as they appear in 40 CFR 98.443.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
19.	8.6	74	"CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells 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.	"covered by this source category" has been inserted in this statement. All equations and variables have been checked to ensure that they are consistent with the equations and variables as they appear in 40 CFR 98.443.

MONITORING, REPORTING, AND VERIFICATION PLAN

Bull Moose AGI #1

Targa Northern Delaware, LLC (TND)

Version 1.0

June 14, 2024

Table of Contents

1 Introduction

Targa Northern Delaware, LLC (TND) proposes an underground injection project at the Targa Bull Moose Gas Processing Plant (the Plant) located approximately 15 miles west of Kermit in Winkler County, district 08, Texas. The Plant is within the eastern part of the Delaware Basin region of the Permian Basin. (**Figure 1-1**).

TND submitted a Class II Acid Gas Injection (AGI) permit application (Form W-14) for the Bull Moose AGI #1 well (BM AGI #1) to the Texas Railroad Commission (TRRC). TND intends to drill BM AGI #1 in Q4 of 2024 for the purpose of disposing of the treated acid gas (TAG) that is a byproduct of natural gas processing operations at the Plant. The TAG stream is anticipated to consist of approximately 70% CO_2 and 30% H_2S, with trace components of hydrocarbons (C1 – C7) and nitrogen. The project, with a design life of 30 years, plans to inject TAG through BM AGI #1 into the deep subsurface in the Siluro-Devonian, Fusselman, and Montoya formations.

The project allows TND to run the Plant at full capacity without discharging large amounts of CO_2 to the atmosphere; replacing the flare with deep injection decreases the negative environmental footprint of the gas plant.

TND has significant experience in the handling and disposal of TAG in this remotely populated area. TND submitted forms and supporting documentation designed to meet the requirements of Texas Administrative Code Title 16 Chapter 3 Rule §3.9 and current best engineering practices to ensure that the USDW and the atmosphere are protected from any contamination from injection.

TND is currently authorized to inject a total of up to 20 million standard cubic feet per day (MMSCFD) of TAG in the approved BM AGI #1 (API 42-495-34978) in accordance with Statewide Rule 9 of the TRRC. TND received authorization to inject H_2S under the TRRC Rule 36. BM AGI #1 is located on the Plant property (**Figure 1-2**). The permitted injection interval is between 17,889 feet and 19,488 feet.

The BM AGI #1 well will be constructed with four strings of casing cemented to surface. Corrosion resistant alloys will be used in the bottom 300 ft of the long-string, in the confining zone. Acid resistant cements will also be used across the upper confining zone. Monitoring systems will be installed to ensure that bottomhole injection pressure does not exceed 90% of the determined fracture gradient of the injection interval. TND is requesting a maximum allowable surface pressure of 0.5 psi/ft, or 8,969 psi.

TND submits this Monitoring, Reporting, and Verification (MRV) plan for the BM AGI #1 well to the United States Environmental Protection Agency (U.S. EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code. TND intends to inject CO_2 in BM AGI #1 for 30 years. Following the operational period, TND proposes a post-injection monitoring and site closure period of 15 years.

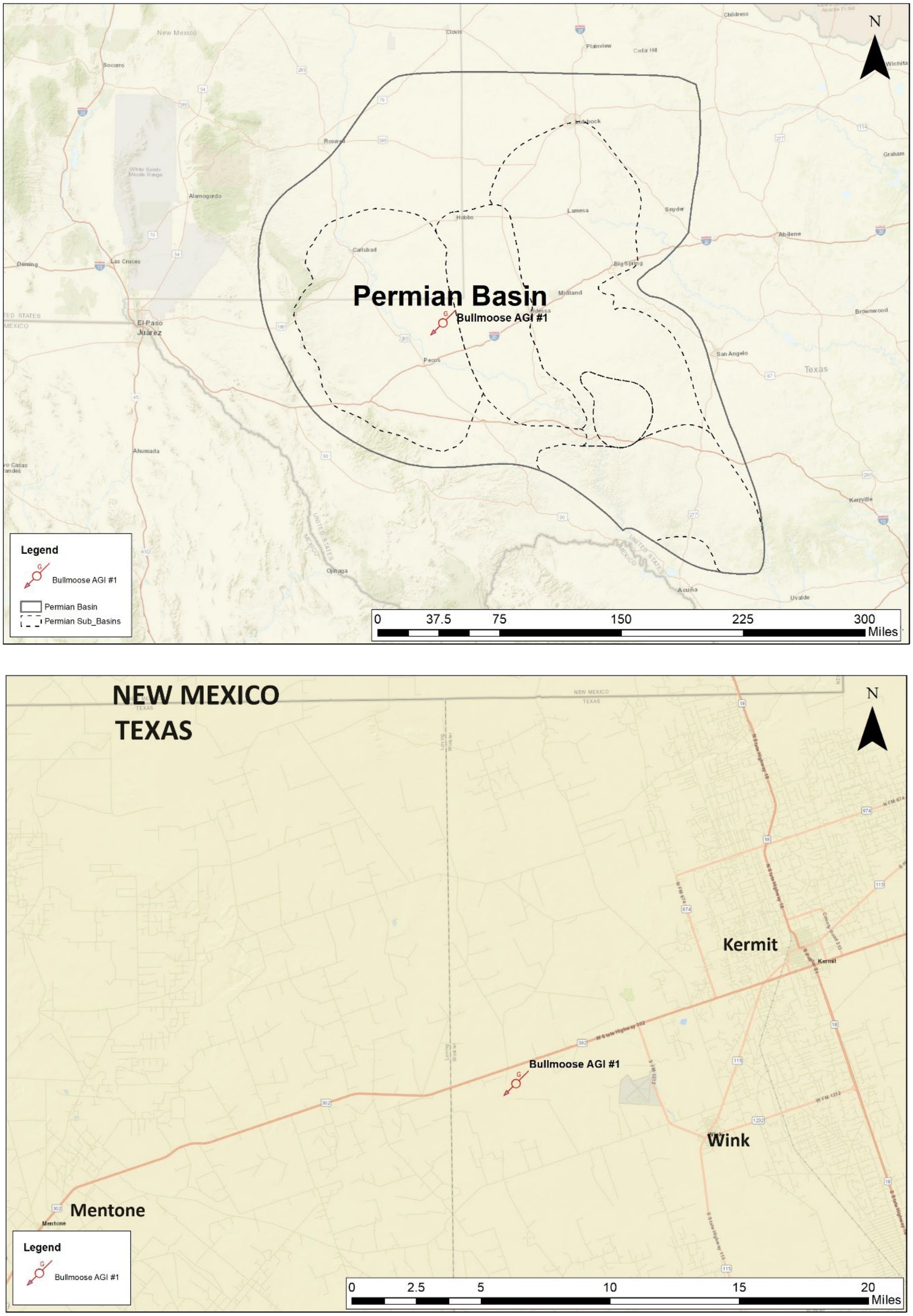


Figure 1-1: *Location of the Bull Moose Facility in the Permian Basin, Texas*

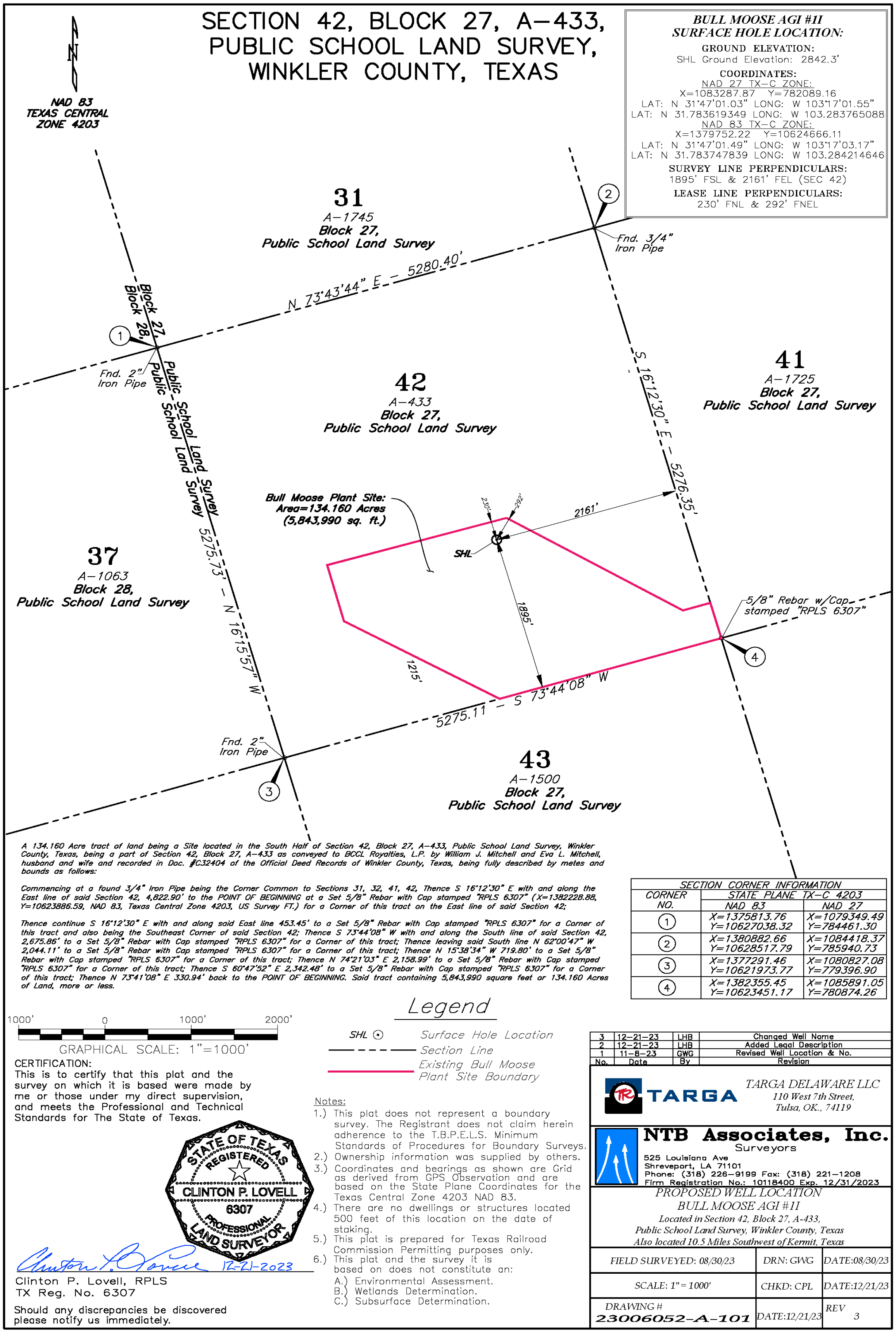


Figure 1-2: Location of the Bull Moose Gas Plant and BM AGI #1 Well

This MRV Plan contains twelve sections:

Section 1 is this Introduction.

Section 2 contains facility information.

Section 3 contains the project description.

Section 4 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40CFR98.449, and as required by 40CFR98.448(a)(1), Subpart RR of the GHGRP.

Section 5 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40CFR98.448(a)(2), Subpart RR of the GHGRP.

Section 6 describes the detection, verification, and quantification of leakage from the identified potential sources of leakage as required by 40CFR98.448(a)(3).

Section 7 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40CFR98.448(a)(4), Subpart RR of the GHGRP.

Section 8 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40CFR98.448(a)(5), Subpart RR of the GHGRP.

Section 9 provides the estimated schedule for implementation of this MRV Plan as required by 40CFR98.448(a)(7).

Section 10 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40CFR98.445.

Section 11 describes the records to be retained according to the requirements of 40CFR98.3(g) of Subpart A of the GHGRP and 40CFR98.447 of Subpart RR of the GRGRP.

Section 12 includes Appendices supporting the narrative of the MRV Plan, including information required by 40CFR98.448(a)(6).

2 Facility Information

2.1 Reporter number

Greenhouse Gas Reporting Program ID is 589241.

2.2 UIC injection well identification numbers

This MRV plan is for the BM AGI #1 well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The TRRC has issued an Underground Injection Control (UIC) Class II permit under its Statewide Rule 9 (**Appendix 2**) for BM AGI #1. All oil- and gas-related wells around the BM AGI #1 well, including both injection and production wells, are regulated by the TRRC which has primacy to implement the UIC Class II program.

3 Project Description

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

3.1 General Geologic Setting / Surficial Geology

The Plant is located in Sec. 42, A-433, Blk 27, approximately 10.5 miles south-west of Kermit in Winkler County, Texas, immediately adjacent to the BM AGI #1 well **(Figs 1-1, 1-2)**. The plant location is within a portion of the Pecos River basin referred to as the Querecho Plains reach (Nicholson & Clebsch, 1961). This area is relatively flat and largely covered by sand dunes underlain by a hard caliche surface. The dune sands are locally stabilized with shin oak, mesquite, and some burr-grass. There are no natural surface bodies of water or groundwater discharge sites within one mile of the plant and where drainages exist in interdunal areas, they are ephemeral, discontinuous, dry washes. The plant site is underlain by Quaternary alluvium overlying the Triassic red beds of the Santa Rosa Formation (Dockum Group), both of which are local sources of groundwater.

3.2 Bedrock Geology

3.2.1 Basin Development

The Bull Moose Gas Plant and the Bull Moose AGI #1 well are located on the eastern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**).

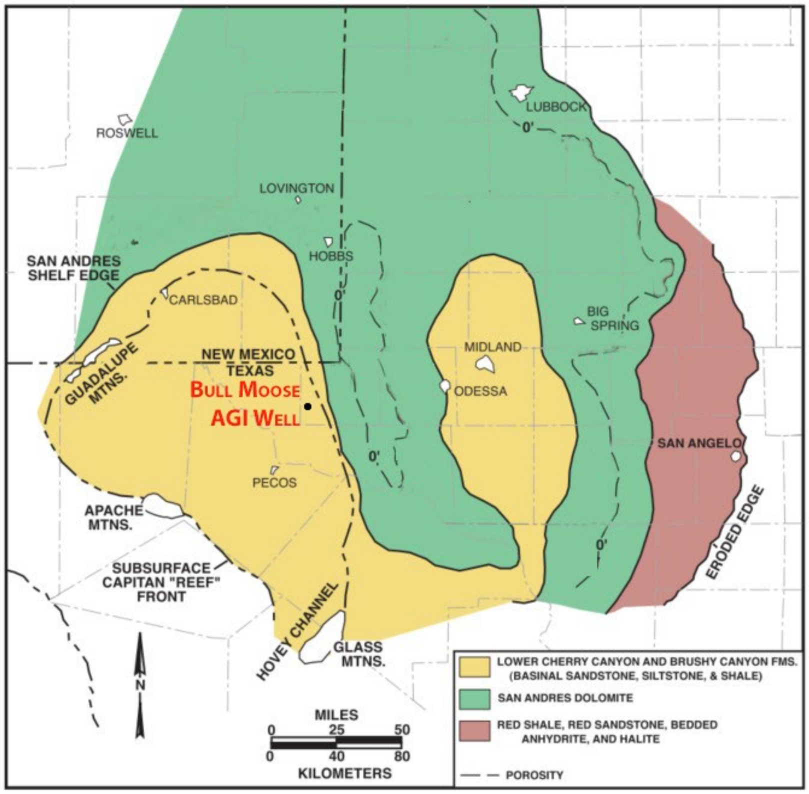


Figure 3.2-1: *Structural features of the Permian Basin during the Late Permian. Location of the TND BM AGI well is shown by the black circle. (Modified from Ward, et al (1986))*

The BM AGI well is in the Delaware Basin portion of the broader Permian Basin. **Figure 3.2-2** is a generalized stratigraphic column showing the formations that underlie the Bull Moose Gas Plant and BM AGI #1 well site. The thick sequences of Permian through Cambrian rocks are described below. A general description of the stratigraphy of the area is provided in this section. A more detailed discussion of the injection zone and the upper and lower confining zones is presented in Section 3.3 below. Throughout this narrative, the numbers after the formations indicate the range in thickness for that unit.

Sediments in the area date back to the Cambrian Bliss Sandstone (Broadhead, 2017; **Figure 3.2-2**) and overlay Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland (**Figure 3.2-3**). With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Ellenburger Formation (with formation thickness varying from 0 – 1000 ft) is dominated by dolostones and limestones that were deposited on restricted carbonate shelves (Broadhead, 2017; Loucks and Kerans, 2019). Tectonic activity near the end of Ellenburger deposition resulted in subaerial exposure and karstification of these carbonates which increased the unit’s overall porosity and permeability.

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

***Figure 3.2-2**: Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017).*

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

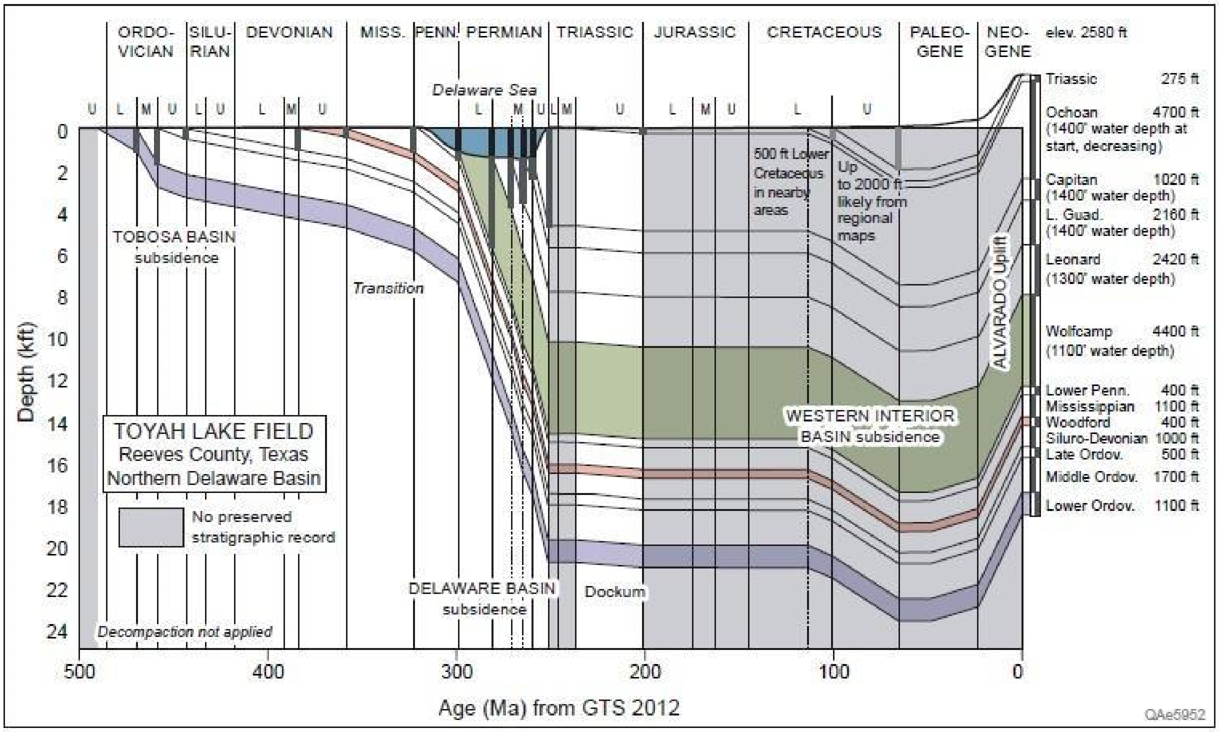


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019)*

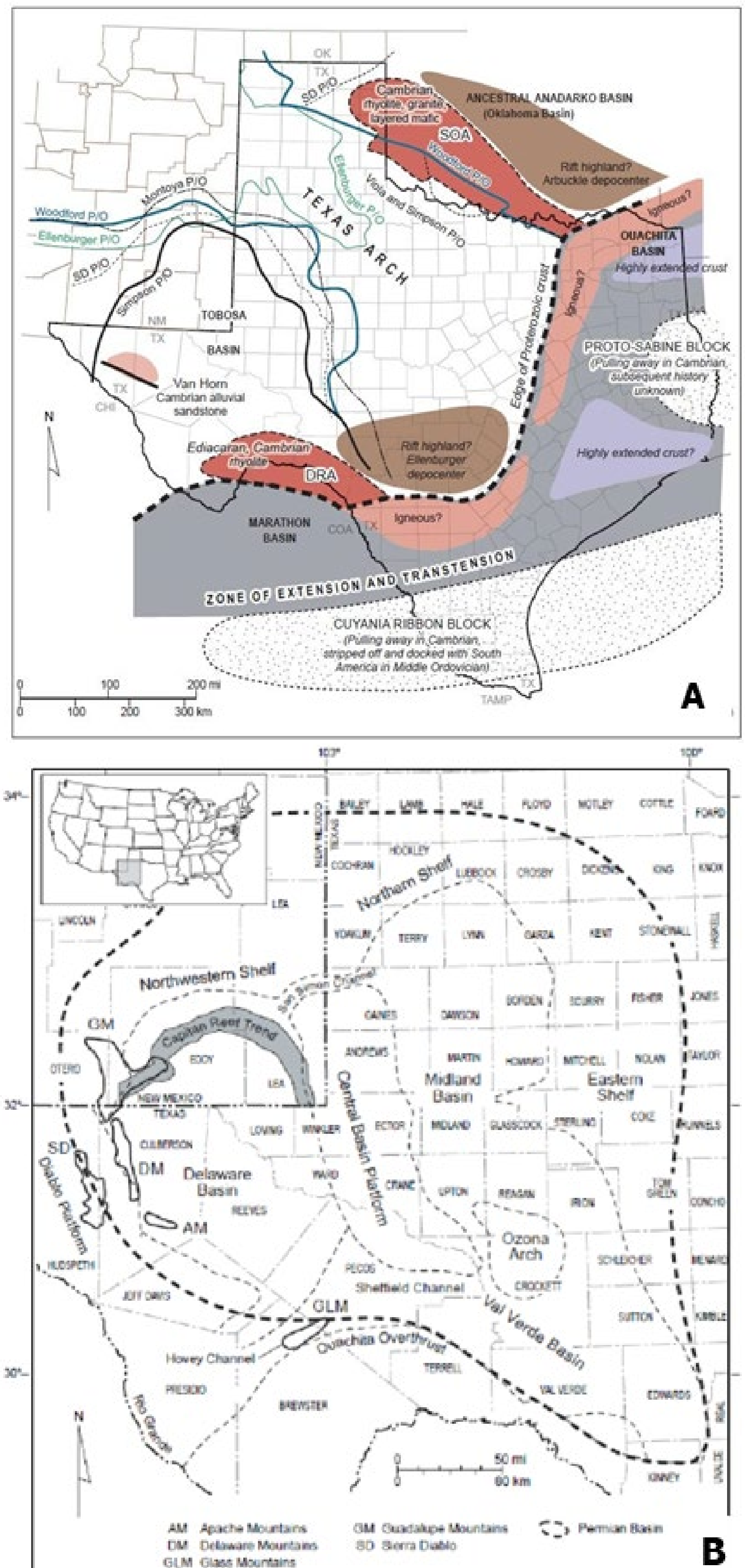


Figure 3.2-4*: Tectonic Development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

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

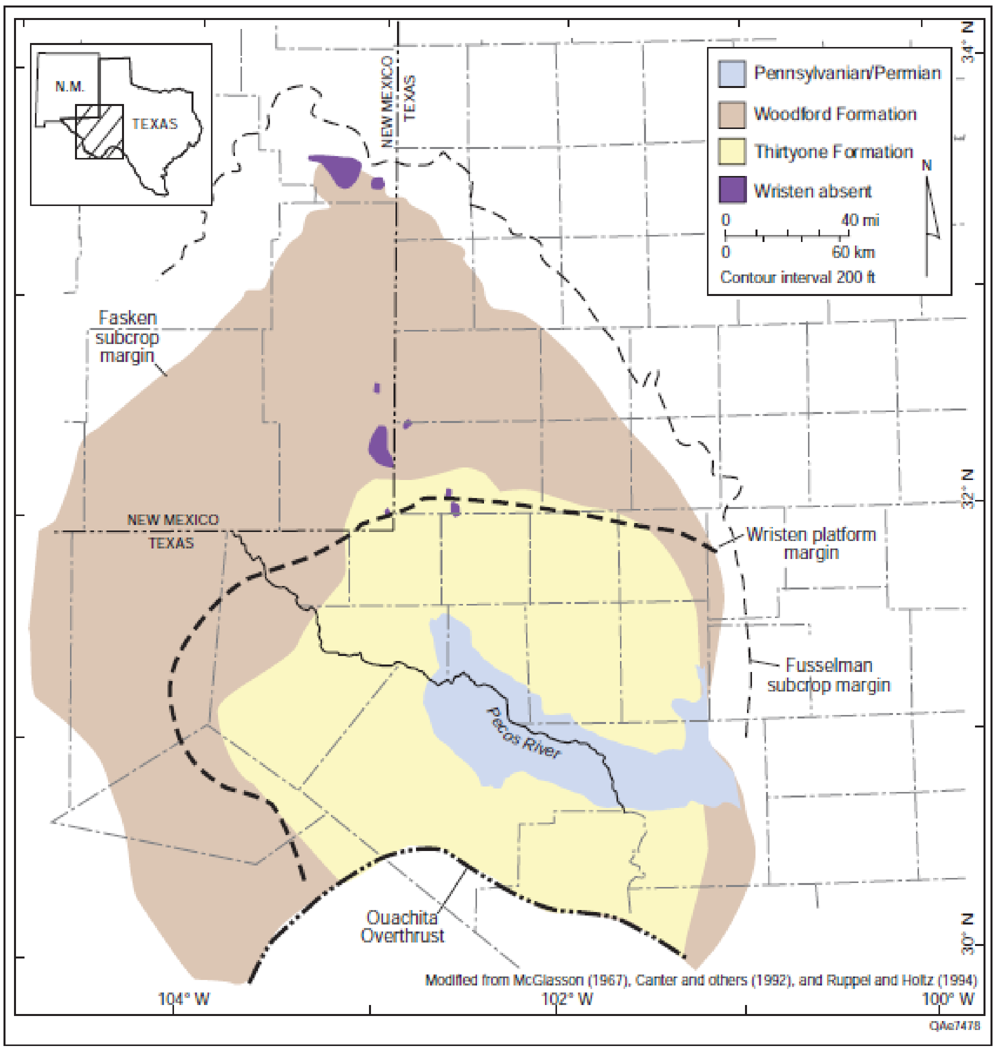


***Figure 3.2-5**: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

The Siluro-Devonian units are saltwater injection zones within the Delaware Basin and are typically dolomitized, shallow marine limestones that have secondary porosity produced by subaerial

exposure, karstification and later fracturing/faulting. These units will be discussed in more detail in Section 3.2.2.

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

The Mississippian strata within the Delaware Basin consists of an un-named carbonate member and the Barnett Shale and unconformably overlies the Woodford Shale. The lower Mississippian limestone (0 – 800 ft) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. These units were deposited on a Mississippian ramp/shelf and have mostly been overlooked because of the reservoirs limited size. Where the units have undergone karstification, porosity may approach 4 to 9% (Broadhead, 2017), otherwise it is tight. The Barnett Shale (0 – 400 ft) unconformably overlies the Lower Mississippian carbonates and consists of Upper Mississippian carbonates deposited on a shelf to basinal, siliciclastic deposits (the Barnett Shale).

Pennsylvanian sedimentation is dominated by glacio-eustatic sea-level cycles that produced shallowing upward cycles of sediments, ranging from deep marine siliciclastic and carbonate deposits to shallow-water limestones and siliciclastics, and capping terrestrial siliciclastic sediments and karsted limestones. Lower Pennsylvanian sediments include the Morrow and Atoka formations. The Morrow Formation (0 – 2,000 ft) within the northern Delaware Basin was deposited as part of a deepening upward cycle with depositional environments ranging from fluvial/deltaic deposits at the base, sourced from the crystalline rocks of the Pedernal Uplift to the northwest, to high-energy, near-shore coastal sandstones and deeper and/or low-energy mudstones (Broadhead, 2017; Wright, 2020). In the area, the Atoka Formation (0-500 ft) was deposited during another sea-level transgression. is dominated by siliciclastic sediments, with depositional environments ranging from fluvial/deltas, shoreline to near-shore coastal barrier bar systems to occasional shallow-marine carbonates (Broadhead, 2017; Wright, 2020).

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

Upper Pennsylvanian Canyon (0 – 1,200 ft) and Cisco (0 – 500 ft) group deposits are dominated by marine, carbonate-ramp deposits and basinal, anoxic, organic-rich shales.

Deformation, folding and high-angle faulting, associated with the Upper Pennsylvanian/Early Permian Ouachita Orogeny, created the Permian Basin and its two sub-basins, the Midland and Delaware basins (Hills, 1984; King, 1948), the Northwest Shelf (NW Shelf), and the Central Basin Platform (CBP; **Figures 3.2-4, 3.2-6, 3.2-7**). The Permian "Wolfcamp" or Hueco Formation was deposited after the creation of the Permian Basin. The Wolfcampian sediments were the first sediments to fill in the structural relief (**Figure 3.2-6**). The Wolfcampian Hueco Group (~400 ft on the NW Shelf, >2,000 ft in the Delaware Basin) consists of shelf margin deposits ranging from barrier reefs and fore slope deposits, bioherms, shallow-water carbonate shoals, and basinal carbonate mudstones (Broadhead, 2017; Fu et al., 2020). Since deformation continued throughout

the Permian, the Wolfcampian sediments were truncated in places like the Central Basin Platform (**Figure 3.2-6**).

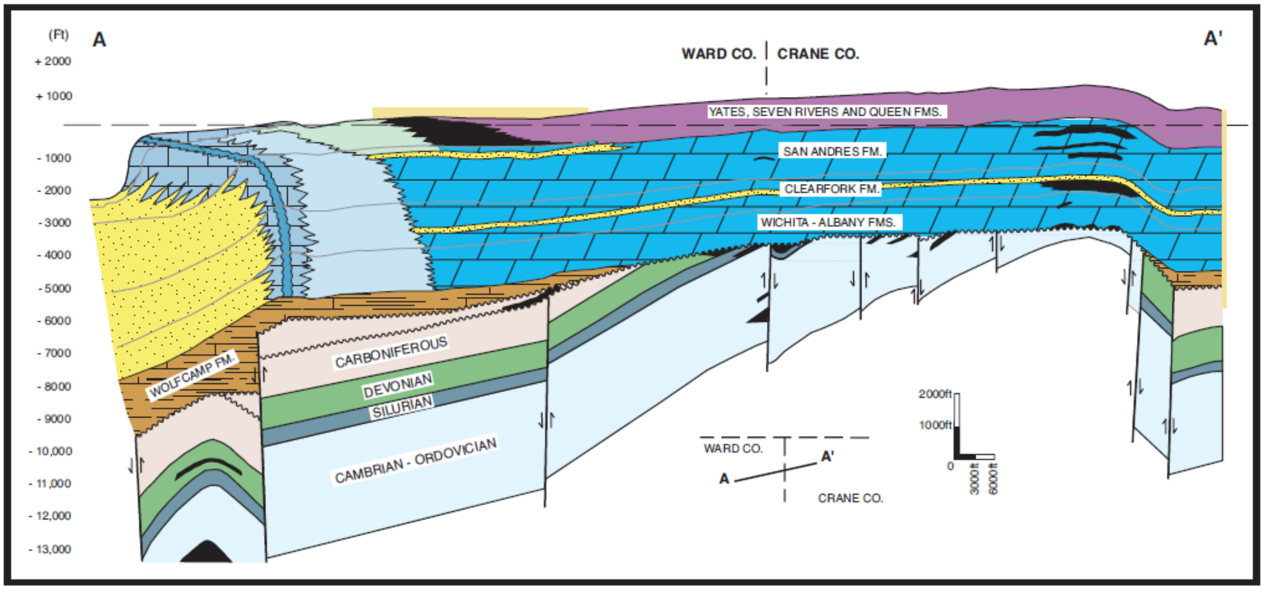


Figure 3.2-6 -- Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

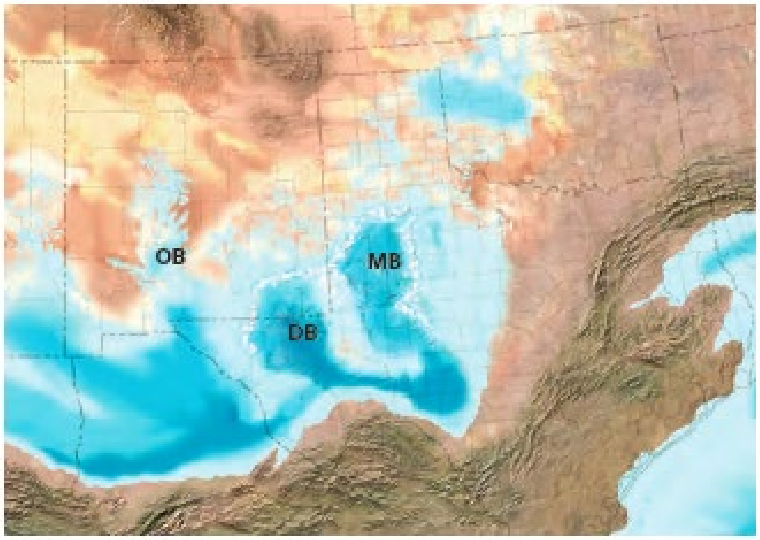


Figure 3.2-7 *-- Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).*

Differential sedimentation, continual subsidence, and glacial eustasy impacted Permian sedimentation after Hueco deposition and produced carbonate shelves around the edges of deep sub-basins. Within the Delaware Basin, this subsidence resulted in deposition of roughly 12,000 ft of siliciclastics, carbonates, and evaporites (King, 1948). Eustatic sea-level changes and differential sedimentation played an important role in the distribution of sediments/facies within the Permian Basin (**Figure 3.2-2**). During sea-level lowstands, thousands of feet of siliciclastic sediments bypassed the shelves and were deposited in the basin. Scattered, thin sandstones and siltstones as well as fracture and pore filling sands found up on the shelves correlate to those lowstands. During sea-level highstands, thick sequences of carbonates were deposited by a “carbonate factory” on the shelf and shelf edge. Carbonate debris beds shed off the shelf margin were transported into the basin (Wilson, 1972; Scholle et al., 2007). Individual debris flows thinned substantially from the margin to the basin center (from 100s feet to feet).

Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 ft). Abo deposits range from carbonate grainstone banks and buildups along Northwest Shelf margin to shallow-marine, back-reef carbonates behind the shelf margin. Further back on the margin, the backreef sediments grade into intertidal carbonates to siliciclastic-rich sabkha red beds to eolian and fluvial deposits closer to the Sierra Grande and Uncompahgre uplifts (Broadhead, 2017, Ruppel, 2019a). Sediments basinward of the Abo margin are equivalent to the lower Bone Spring Formation. The Yeso Formation (1,500 – 2,500 ft), like the Abo Formation, consists of carbonate banks and buildups along the Abo margin. Unlike Abo sediments, the Yeso Formation contains more siliciclastic sediments associated with eolian, sabkha, and tidal flat facies (Ruppel, 2019a). The Yeso shelf sandstones are commonly subdivided into the Drinkard, Tubb, Blinebry, Paddock members (from base to top of section). The Yeso Formation is equivalent to the upper Bone Spring Formation. The Bone Spring Formation is a thick sequence of alternating carbonate and siliciclastic horizons that formed because of changes in sea level; the carbonates during highstands, and siliciclastics during lowstands. Overlying the Yeso are the clean white eolian sandstones of the Glorietta Formation, a key marker bed in the region, both on outcrop and in the subsurface. Within

the basin, it is equivalent to the lowermost Brushy Canyon Formation of the Delaware Mountain Group.

The Guadalupian San Andres Formation (600 – 1,600 ft) and Artesia Group (<1,800 ft) reflect the change in the shelf margin from a distally steepened ramp to a well-developed barrier reef complex. The San Andres Formation consists of supratidal to sandy subtidal carbonates and banks deposited a distally steepened ramp. Within the San Andres Formation, several periods of subaerial exposure have resulted in karstification and pervasive dolomitization of the unit. These exposure events/sea-level lowstands are correlated to sandstones/siltstones that moved out over the exposed shelf leaving on minor traces of their presence on the shelf but formed thick sections of sandstones and siltstones in the basin. Within the Delaware Basin, the San Andres Formation is equivalent to the Brushy and lower Cherry Canyon Formations.

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

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

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

3.2.2 Stratigraphy

The Permian rocks found in the Delaware Basin are divided into four series, the Ochoa (most recent, renamed Lopingian), Guadalupian, Leonardian (renamed Cisuralian), and Wolfcampian (oldest) (Figure 3.2-2). This sequence of shallow marine carbonates and thick, basinal siliciclastic deposits contains abundant oil and gas resources and are the main source of oil within New Mexico. In the area around the Bull Moose AGI well, Permian strata are mainly basin deposits consisting of sandstones, siltstones, shales, and lesser amounts of carbonates. Besides production in the Delaware Mountain Group, there is also production, mainly gas, in the basin Bone Spring Formation, a sequence of carbonates and siliciclastics. The injection and confining zones for BM AGI #1 are discussed below.

3.3 Injection Interval Properties: Permian Guadalupian Series

3.3.1 Siluro-Devonian to Ellenburger Group

In the context of BM AGI #1, the designated injection targets encompass the Siluro-Devonian formations, specifically the Devonian, Wristen, Fusselman and Montoya strata. The total thickness of the injection interval is estimated to be 3,150 ft (**Table 3.3-1**).

***Table 3.3-1:** Estimated BM AGI #1 formation top depths, formation thicknesses, seal and reservoir thicknesses (total), and average porosity, and permeability.*

Formation	Measured Depth (ft)	Formation thickness (ft)	Unit Thickness (ft)	Porosity (%)	Permeability (mD)	Behaviour	Notes*
Rustler Fm.	934	255	4,165			Seal	450' base of useable groundwater
Salado Fm.	1,189	1,400		2.5	0.2	Seal	1200' base of USDW
Castile Fm.	2,589	2,510		1	0.01	Seal	
Lamar Ls.	5,099	45	3,990	15	100	Reservoir	
Bell Canyon Fm.	5,144	1,100		23	110	Reservoir	
Cherry Canyon Fm.	6,244	995		15	12	Reservoir	
Brushy Canyon Fm.	7,239	1,850		12	11	Reservoir	
Bone Spring Fm.	9,089	2,860	2,860	2	0.2	Seal	
Wolfcamp	11,979	1,600				Reservoir	Deepest nearby production wells
Strawn Fm.	13,579	760				Reservoir	
Atoka Fm.	14,339	215				Reservoir	
Morrow Fm.	14,554	1,795				Reservoir	
Barnett Sh.	16,349	440	1,540	1	0.1	3° Seal	
Mississippian Ls.	16,789	440		2	1	2° Seal	
Woodford Sh.	17,229	660		1	0.1	1° Seal	
Wristen Grp. And Thirtyone Fm.(Siluro Devonian)	17,889	289	1,594	5	1	Injection interval	
Fusselman Fm.	18,184	1,055		7	1	Injection interval	
Montoya Grp.	19,239	250		3	1	Injection interval	
Simpson Sands*	19,489	1,000		15	45	Not Drilled	
Ellenburger Grp.	20,489	550		6	15	Not Drilled	
Bliss/Precambrian	21,039					Not Drilled	

*Simpson Sands consist of three discrete sand bodies (~300 ft of sands) within the over thousand-feet-thick unit.

ORDOVICIAN.

ELLENBURGER GROUP – The Ordovician Ellenburger Group is below the injection interval and is comprised of dolomites and limestones that are approximately 550 ft thick. The Ellenburger Group sediments were deposited in subtropical to tropical belt of shallow-water platform carbonates that covered most of what is now North America and Greenland. The Ellenburger carbonates in the Permian Basin area have been extensively altered by later diagenesis that includes several intervals of exposure and karstification, dolomitization, and fracturing and faulting during later tectonic events (**Figure 3.3-1**).

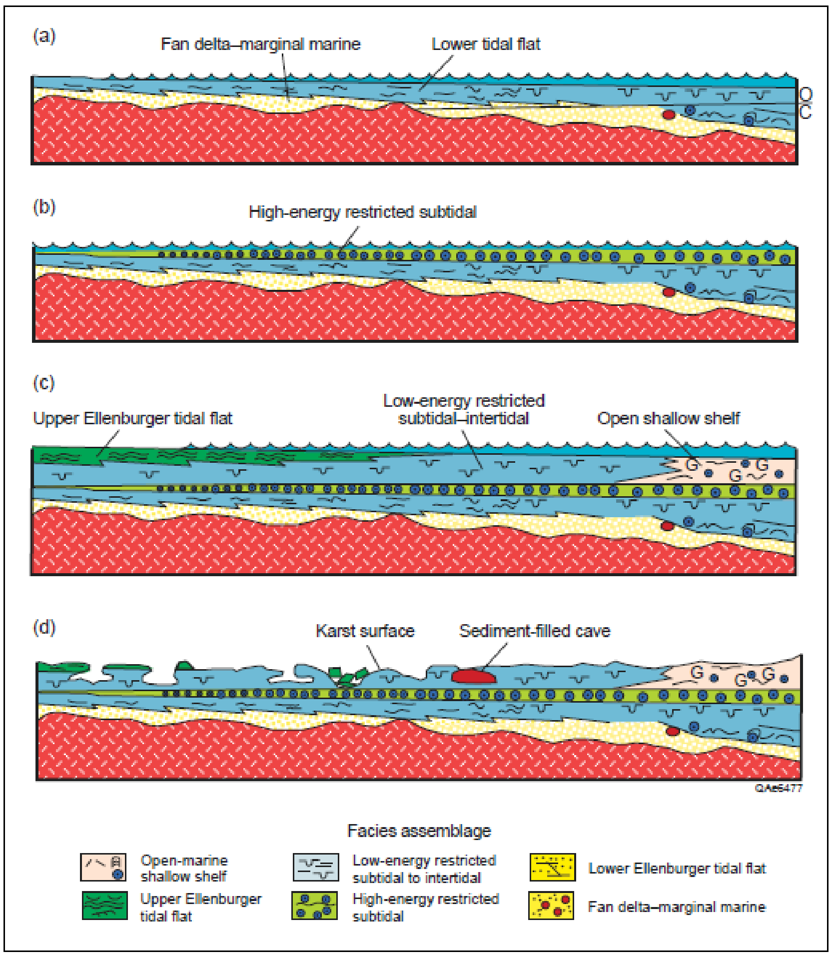


Figure 3.3-1: Depositional model for Ellenburger Group deposits. The diagram shows a sequence of transgressive sandstones (Bliss Sandstone, yellow) to carbonates (Panels a through c followed by a regressive sequence (Panels c – d) with exposure and karstification in Panel d (from Loucks and Kerans, 2019).

Within the Ellenburger Group strata, the upper and middle section typically has the highest porosity and permeability due to karsting and cave development as well as later faulting and fracturing (**Figure 3.3-2**). Late diagenesis plays an important role in porosity destruction and resurrection. Based on work by Loucks (2016, unpublished report), the best karst-related porosity is to the east of the Bull Moose area, whereas the Bull Moose area is in the zone of porosity due to tectonically controlled faulting and fracturing.

Porosity and permeability in the Ellenburger section can vary greatly due to the above considerations, but a realistic value for the porosity and permeability, at approximate 20,000 ft depth, is 5-6% and 15 mD (**Table 3.3-1**). Potentially the range of porosity and permeability can range up to 12% and greater than 100 mD (Loucks and Kerans, 2019).

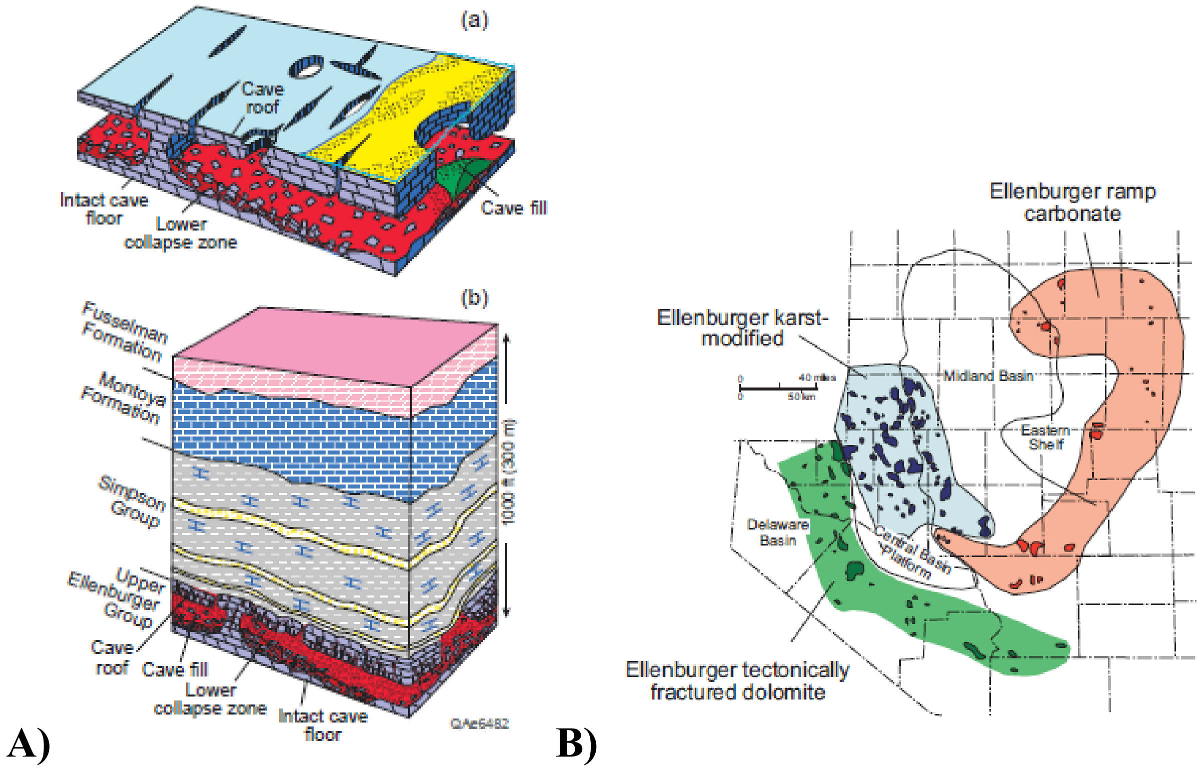


__Figure 3.3-2__: Karst development. __A)__ Cave development in the upper Ellenburger rocks and their potential impact to produce porosity and permeability (from Loucks and Kerans, 2019). __B)__ Zones of potential porosity creation: karst related (blue), fault and fracture (green) and enhanced primary porosity (orange) (from unpublished manuscript by R. Loucks, 2016).

SIMPSON GROUP – The deposits of the Simpson Group represent a regional transgression after the unconformity at the end of Ellenburger deposition. This group is a thick sequence of carbonates, sandstones, and shales (~1,000 ft) which has a depocenter roughly equivalent to the Delaware Basin/Tobosa Basin. There are several transgressive/regressive cycles within the section, but only the transgressive sandstone sections have significant porosity. The rest of the section typically consists of mud-rich carbonates and shales. Within the sandstones (particularly the McKee Sandstone member), well logs indicate porosity averages around 15% (**Table 3.3-1**). Permeability averages 45 mD (Harrington, 2019), though cementation and compaction may decrease that in the area.

MONTOYA GROUP – The Montoya deposits (~250 feet) are dominated by shallow-water, ramp limestones that were deposited in the Tobosa Basin (**Figure 3.3-3**). Like the Ellenburger Group, the porosity within the Montoya Group is dependent on depositional environment and diagenesis. Sediments deposited in higher energy environments tend to have better initial porosity than those of low-energy environments. Compaction destroys porosity, while dolomitization produces secondary porosity and local interactions of these factors determine porosity and permeability in a given area. Based on well logs, the average porosity is approximately 3%, with scattered zones over 5% (**Table 3.3-1**). The probable average permeability is probably less than 1 mD, but fracturing may enhance it.

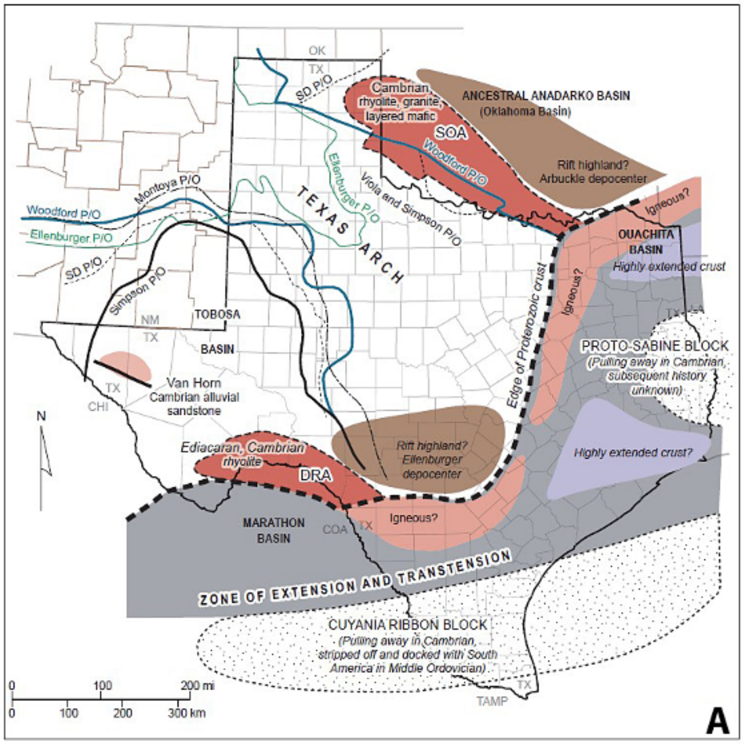


Figure 3.3-3: Tectonic features during development of the Tobosa and Permian Basins during Late Mississippian time (Ewing, 2019).

Ordovician – Silurian.

Fusselman Formation – The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Bull Moose area, the Fusselman thickens to around 1,000 ft of high-energy packstones to grainstones. Like the Montoya Group, these high-energy sediments started out with the best primary porosity, but diagenesis usually has decreased both the porosity and permeability unless impacted by exposure and dissolution. Based on well logs, the porosity averages around 2%, but there are zones, like in well API No. 42-495-31047, with over 70 ft of greater than 5% porosity. Reported permeability for shallower sections range from 0.001 to 10 mD (Ruppel, 2019).

Lower Devonian – Silurian.

Thirtyone and Wristen Formations – Underlying the Woodford Shale are the interbedded dolomites and dolomitic limestones of the Devonian Thirtyone Formation and the Silurian Wristen Group, collectively referred to as the Siluro-Devonian section (~275 ft thick). Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Bull Moose area. These deposits range from deeper ramp mudstones and wackestones, to chert- and sponge/radiolarian-rich hemipelagic mudstones (Wristen/Thirtyone) to outer ramp packstones (**Figure 3.3-4**, Thirtyone; Ruppel, 2020; Ruppel et al., 2020a). Porosity and permeability in the

Wristen are limited in the main body of the unit (1-2%), but exposure events and carbonate dissolution can improve the porosity (~5%). Within Thirtyone deposits, the chert-rich hemipelagic deposits maintain the best porosity (up to 40%, up to 80 mD), while the limestones have less than 7% porosity and less than 1 mD of permeability (**Table 3.3-1**; Ruppel et al., 2020a).

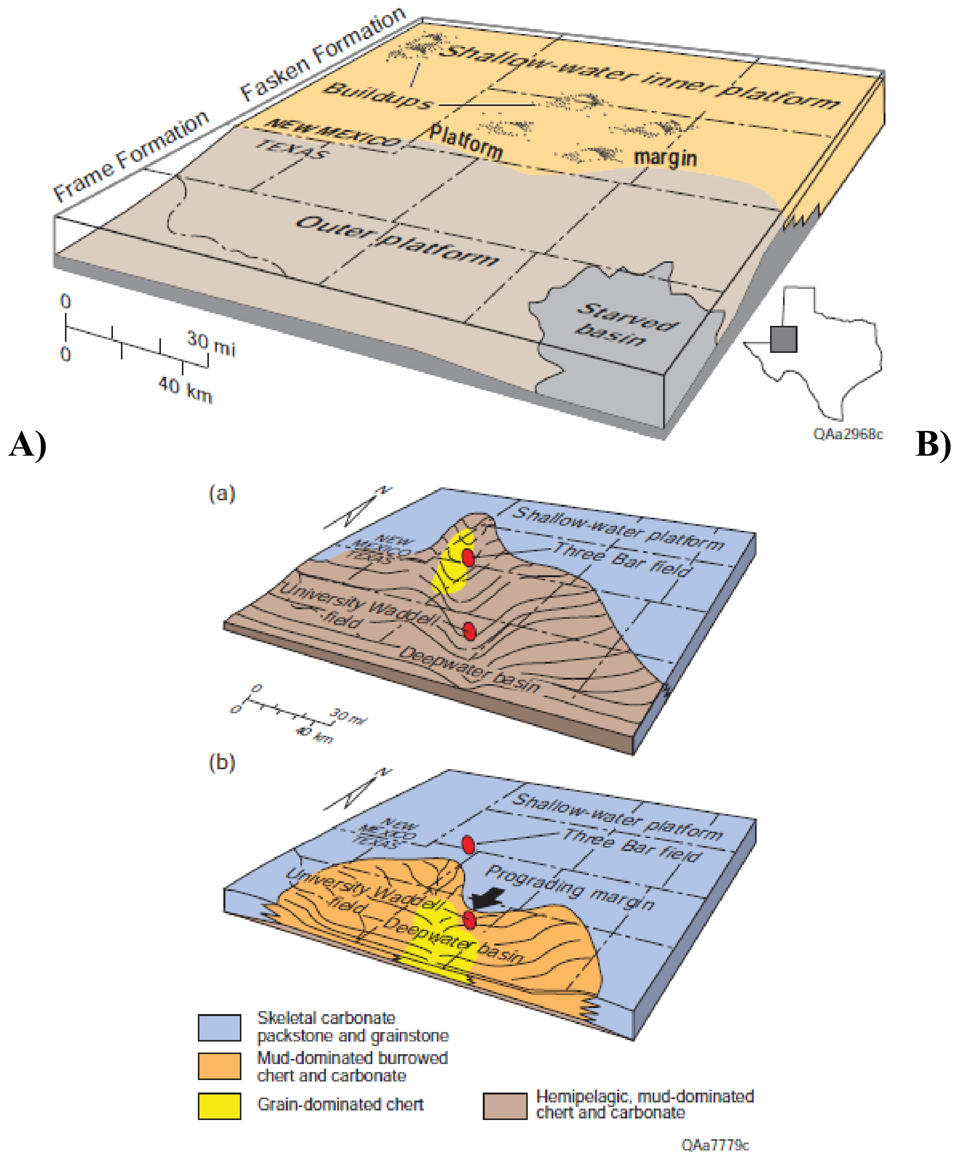


Figure 3.3-4: *Generalized Paleogeography. **A)** Generalized paleogeography for the Wristen Group (from Ruppel, 2020). **B)** Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Bull Moose area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

3.3.2 Upper Confining Zone Properties: Woodford Shale/Mississippian Limestone

Mississippian. Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and the Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 ft thick in the Bull Moose area and is regionally extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is ~555 ft thick. Known production from this limestone comes from small, one to two well fields that normally have poor porosity (4-9%) and permeability (Broadhead, 2017) in New Mexico and a few isolated fields in the shallow water, high-energy limestones in Texas. The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is ~750 ft thick. Overall, Mississippian units would be good seals in preventing upward fluid movement through the section (**Table 3.3-1**).

Upper Devonian. Within the Permian Basin, the Upper Devonian Woodford Shale serves as a seal to hydrocarbon migration out of Devonian and older units. In combination with the Mississippian section, it makes an excellent seal for potential injection. the Woodford Shale is ~620 ft thick in the Bull Moose area and is laterally continuous, organic- and shale-rich, siliceous (radiolarians) mudstone. Porosity in the Woodford Shale is usually micro-porosity associated with organic material and not connected (i.e., low permeability). Porosity can reach 10% (Jarvie et al., 2001), but it averages around 1% with very low permeabilities (**Table 3.3-1**).

3.3.3 Lower Confining Zone Properties: Ordovician to Precambrian

Ordovician. The lower approximately 150 to 200 ft of the Ellenburger Group sediments are normally less porous and have lower permeability (1 – 2% porosity and <2 mD) due their original depositional environment and the depth of burial (Loucks and Kerans, 2019), making this zone a potential underlying seal.

Cambrian to Precambrian. The oldest sediment in the area is Cambrian Bliss Sandstone (Broadhead, 2017) which overlies Precambrian granites. These late Cambrian transgressive sandstones were the initial deposits from a shallow marine sea that covered most of North America and Greenland. With continued down warping and/or sea-level rise, a broad, relatively shallow marine basin formed. The Bliss Sandstone and crystalline Precambrian rocks are potential lower seals. Within the Bull Moose area, no porosity and permeability data could be found. Considering their depth, compactional history, and potential diagenetic alteration, the Bliss sandstones and associated granitic debris (from weathering of the basement rock) are probably relatively tight.

3.4 Structure/Faulting

Structure maps and cross sections for the injection interval and confining zones are provided in **Figures 3.3-5 through 3.3-15**.

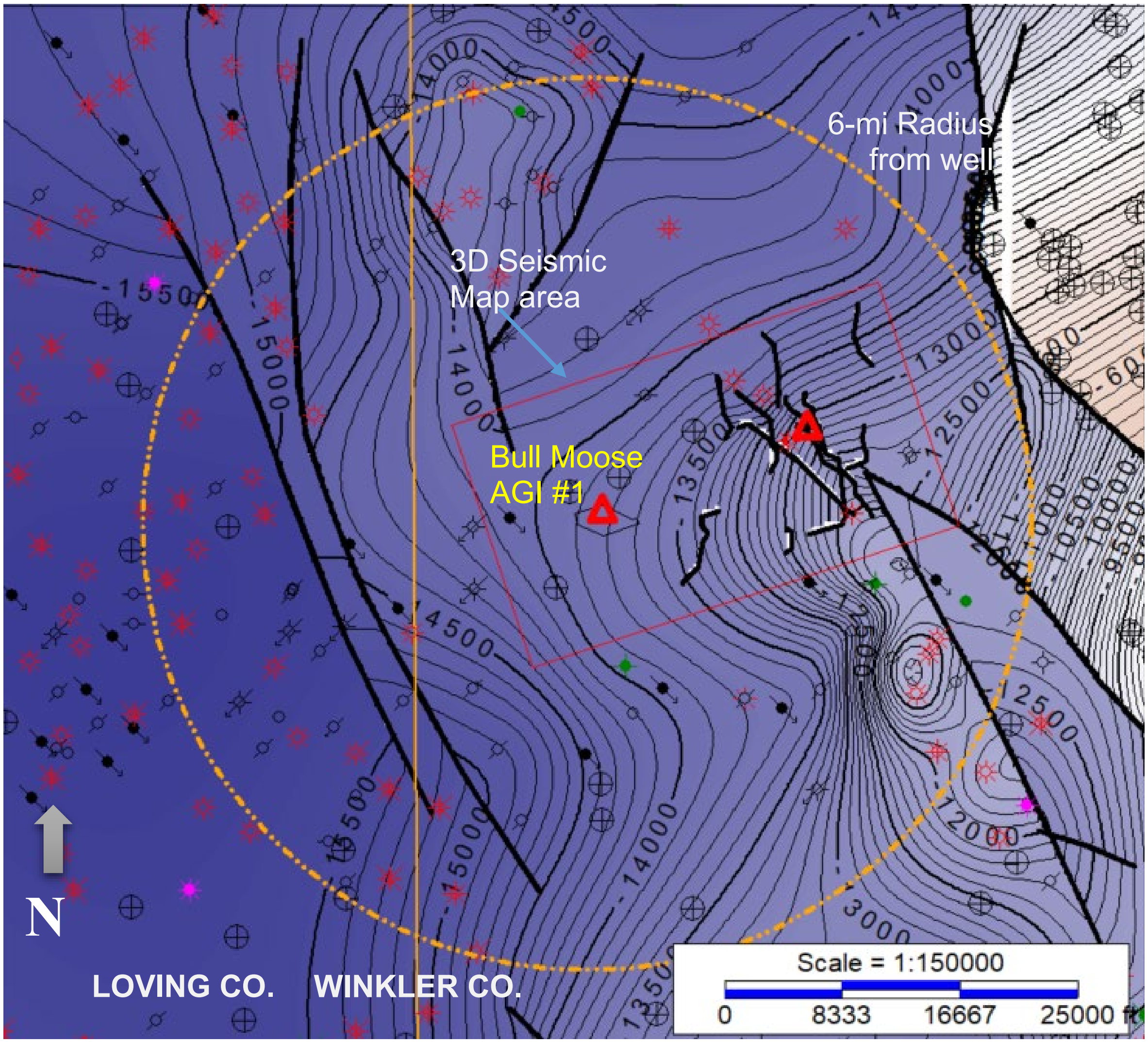


Figure 3.3-5*: Mississippian Limestone Subsea Structure Map. CI = 100 ft.*

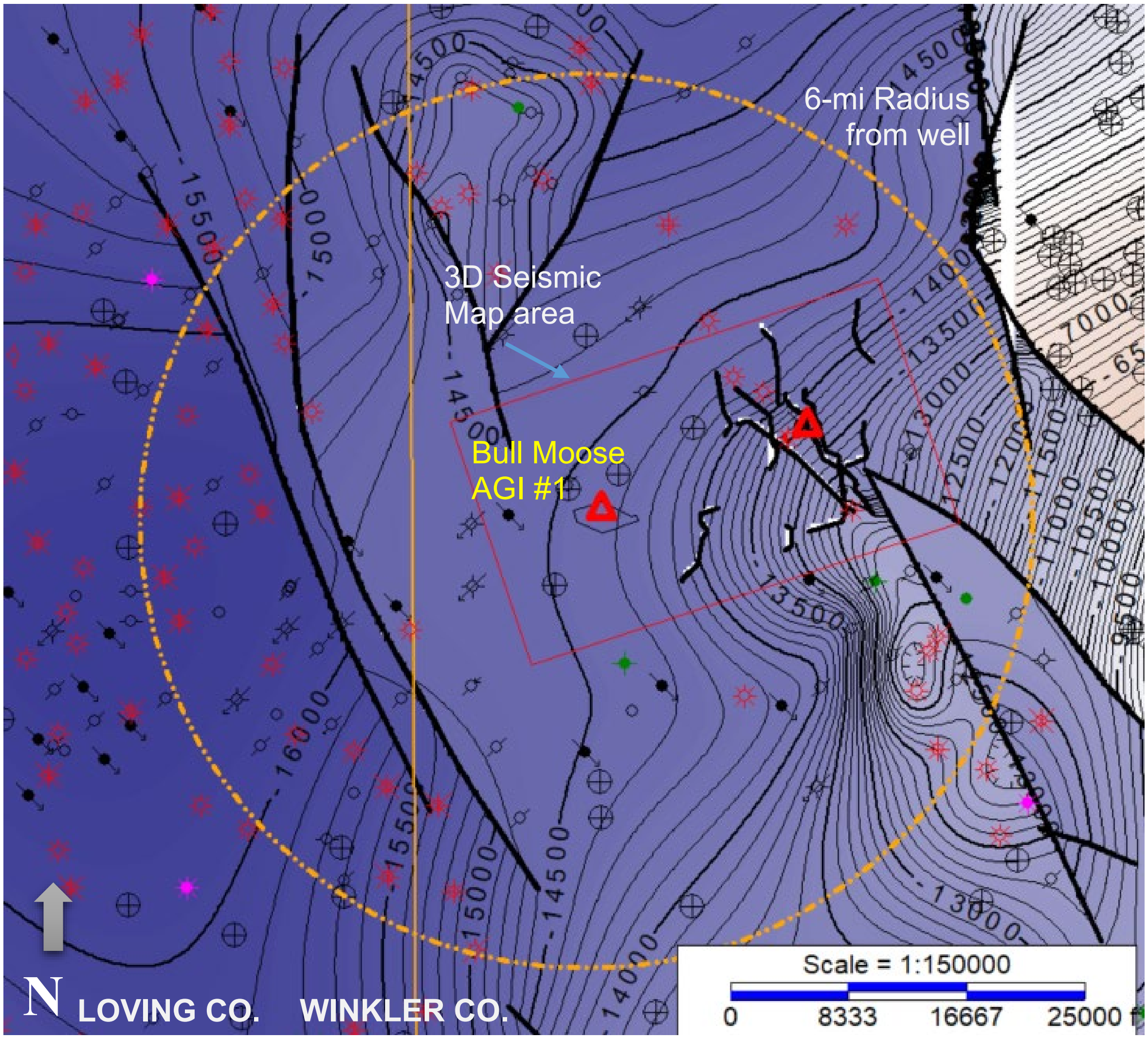


Figure 3.3-6: *Woodford Shale Subsea Structure Map. CI = 100 ft.*

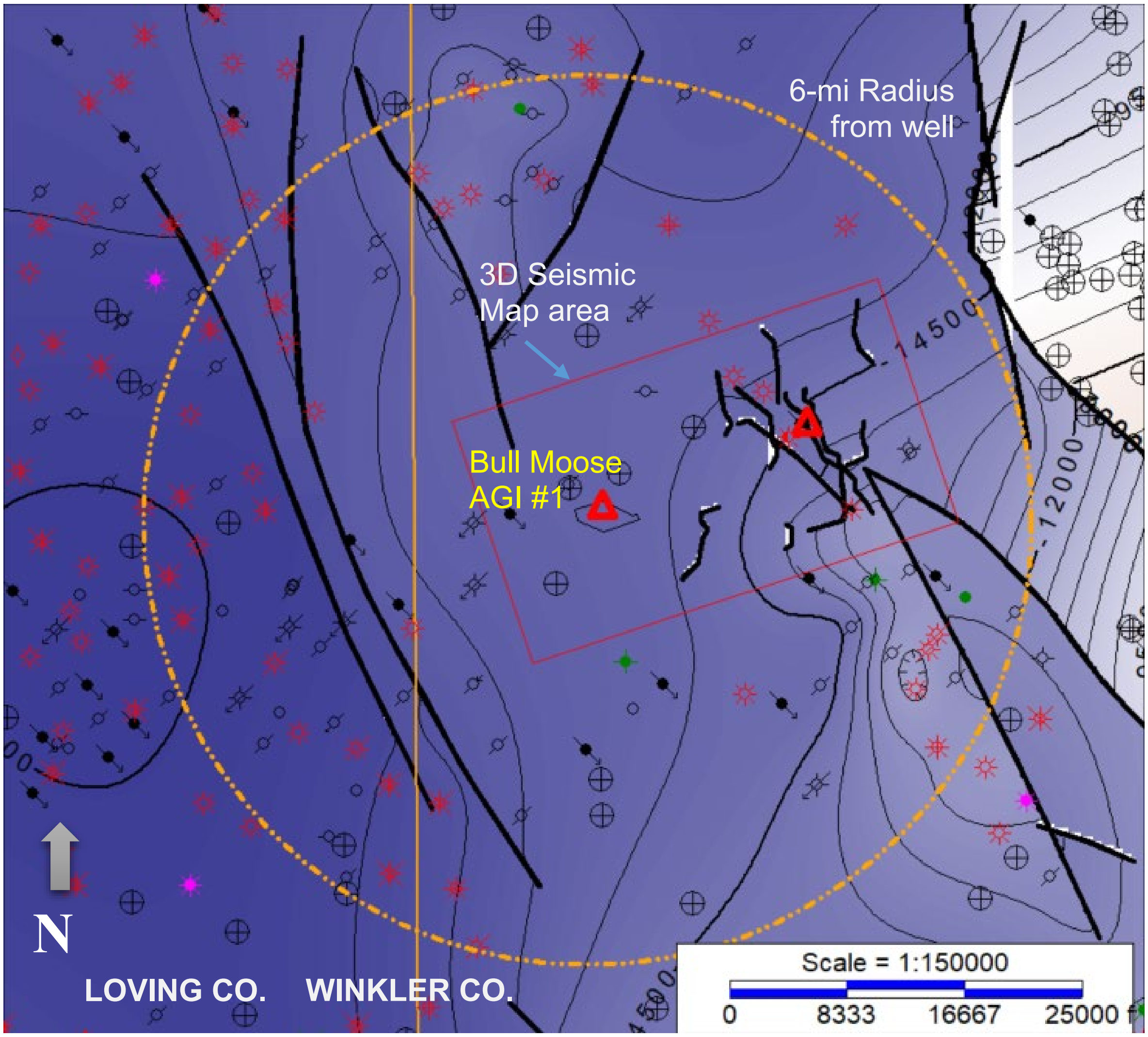


Figure 3.3-7: *Siluro-Devonian Strata Subsea Structure Map. CI = 100 ft.*

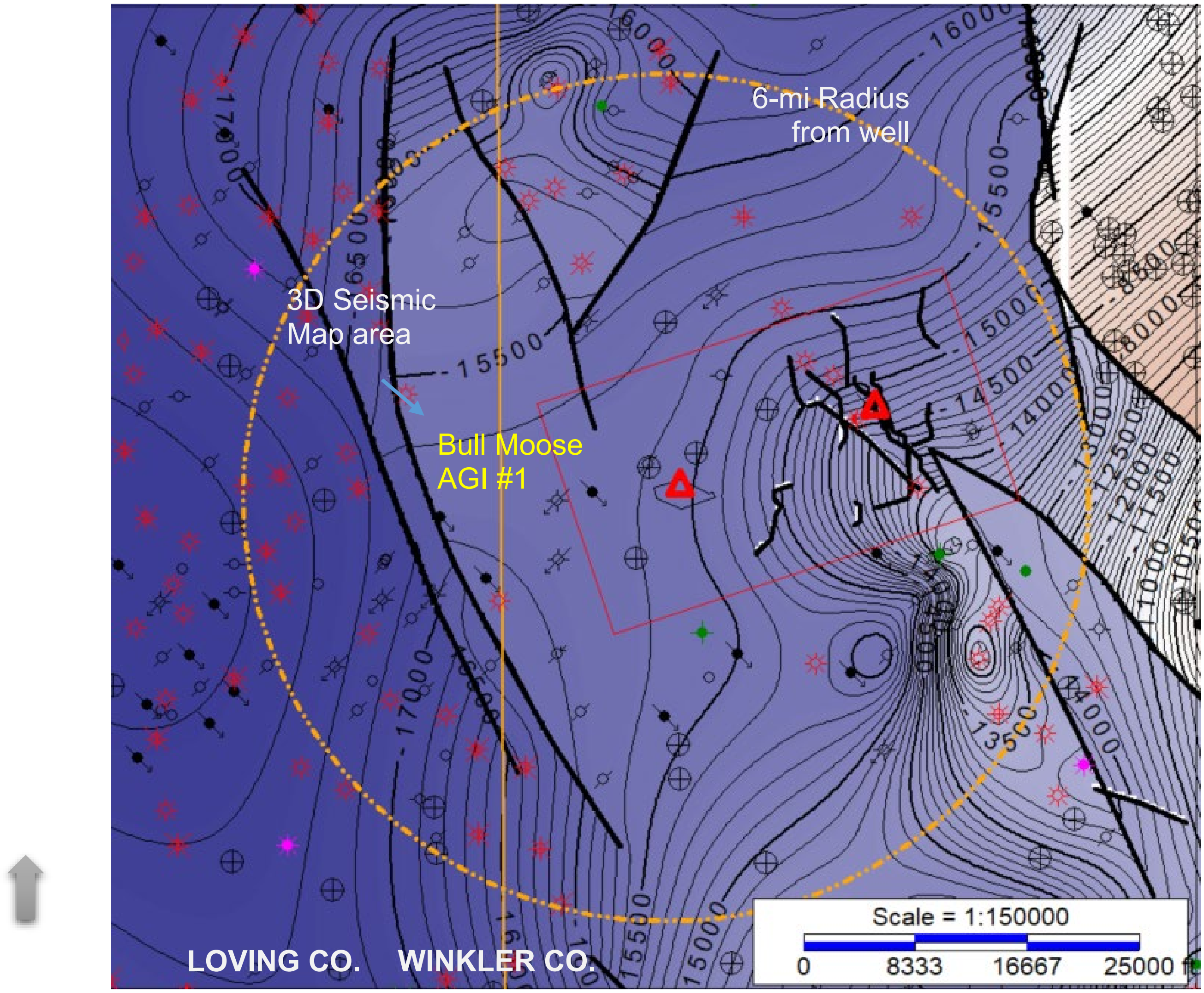


Figure 3.3-8: *Fusselman Formation Subsea Structure Map. CI = 100 ft.*

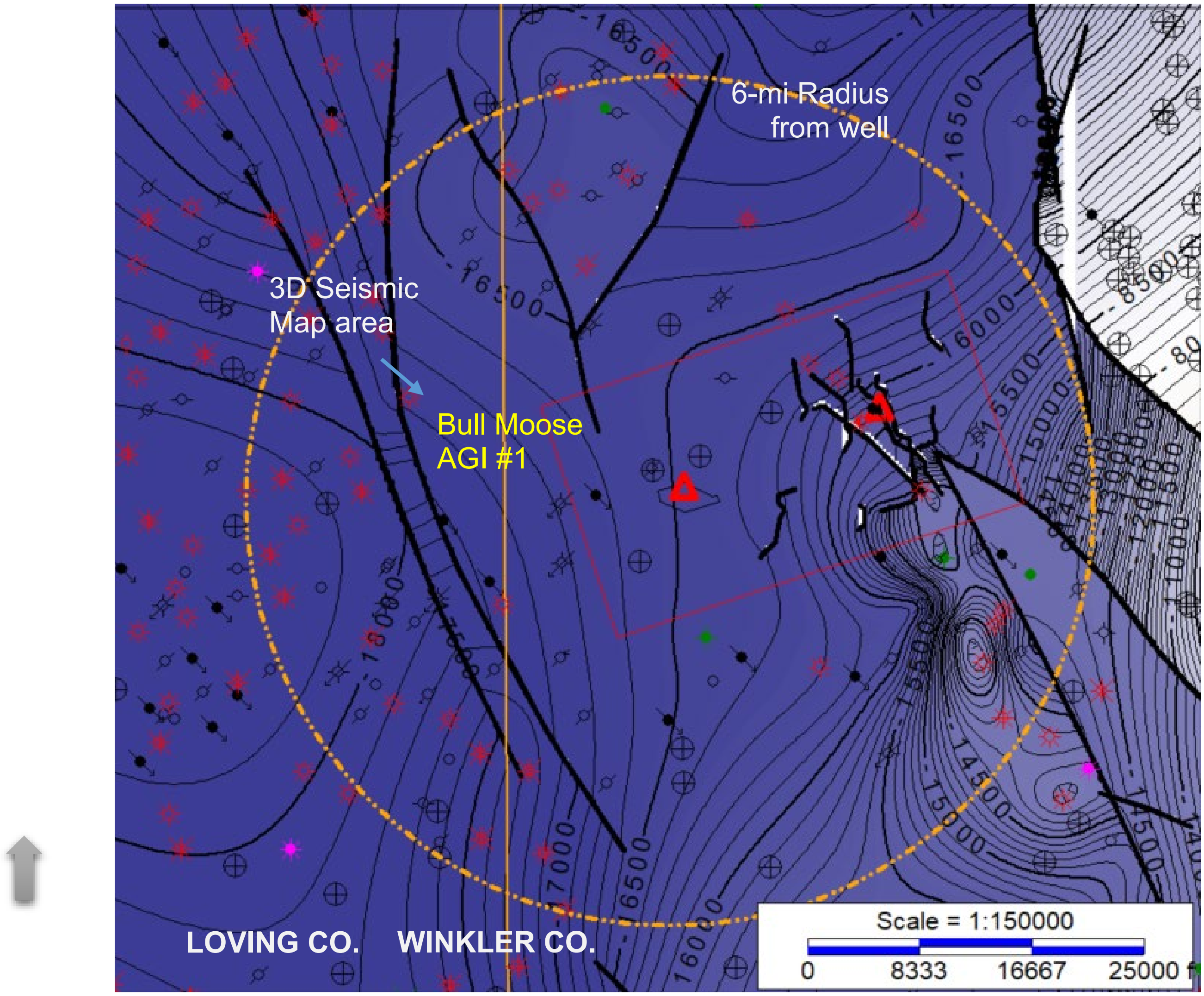


__Figure 3.3-9__: Montoya Group Subsea Structure Map. CI = 100 ft.

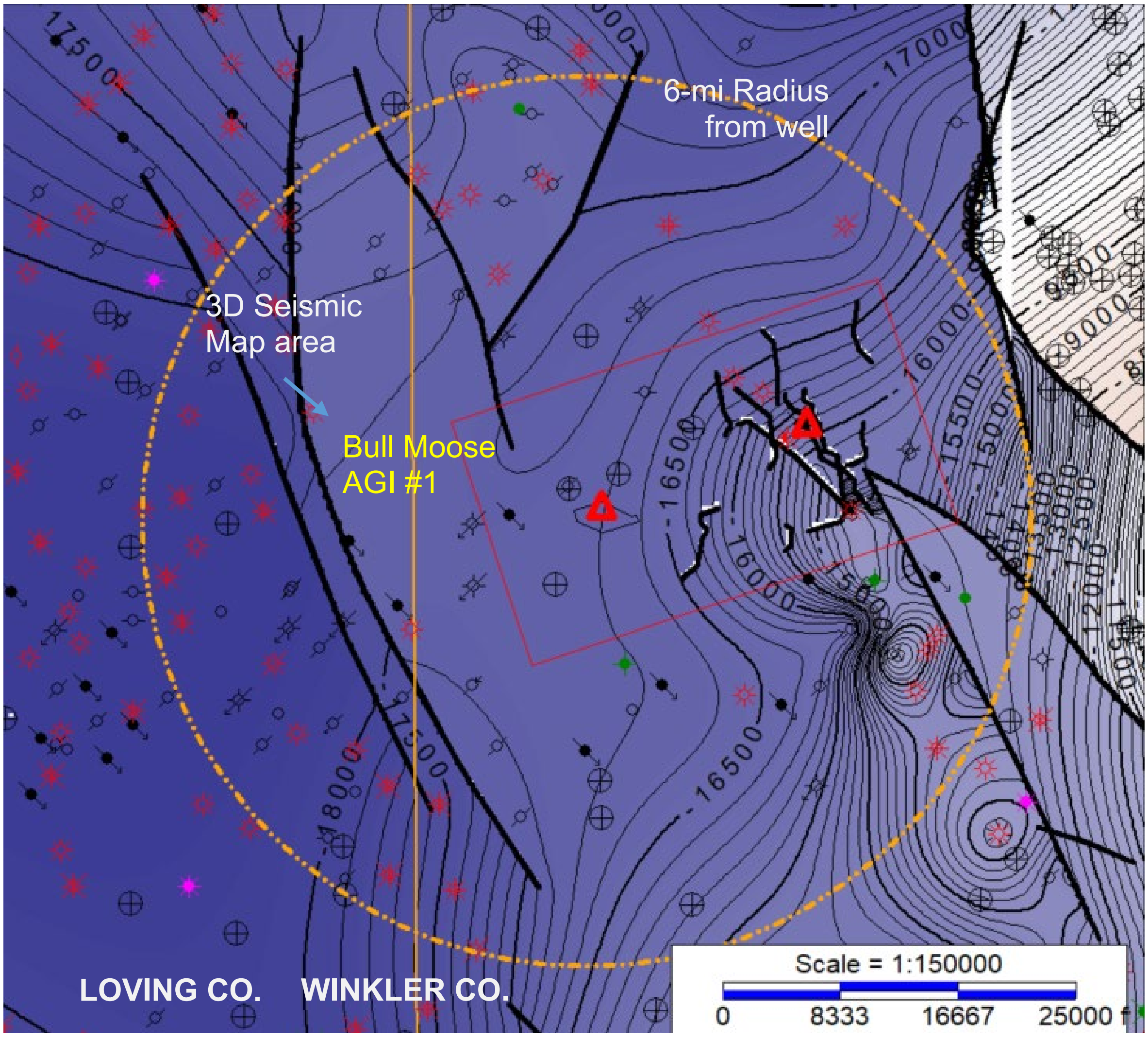


***Figure 3.3-10**: Simpson Group Subsea Structure Map. CI = 100 ft.*

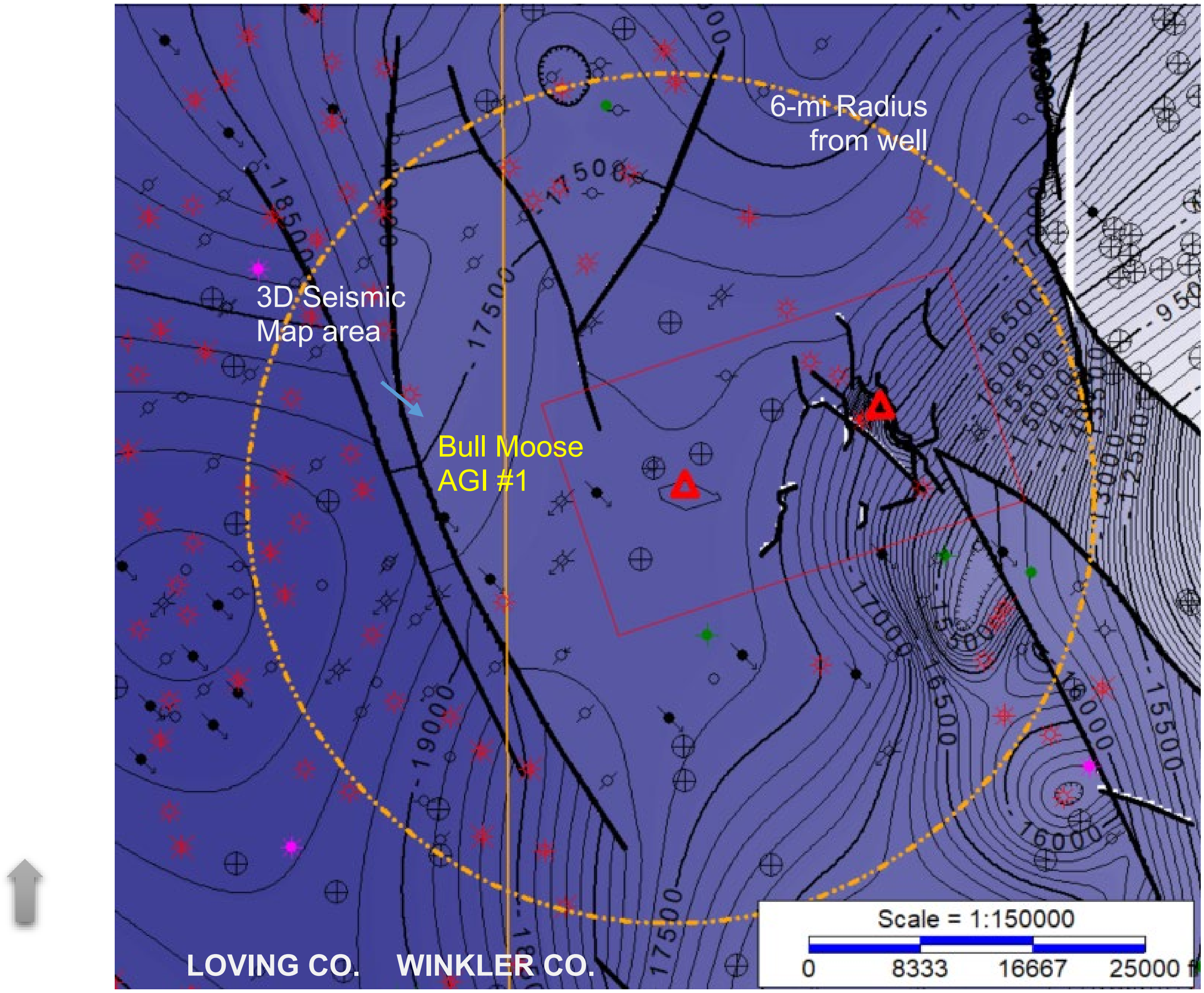


Figure 3.3-11: Ellenburger Group Subsea Structure Map. CI = 100 ft.

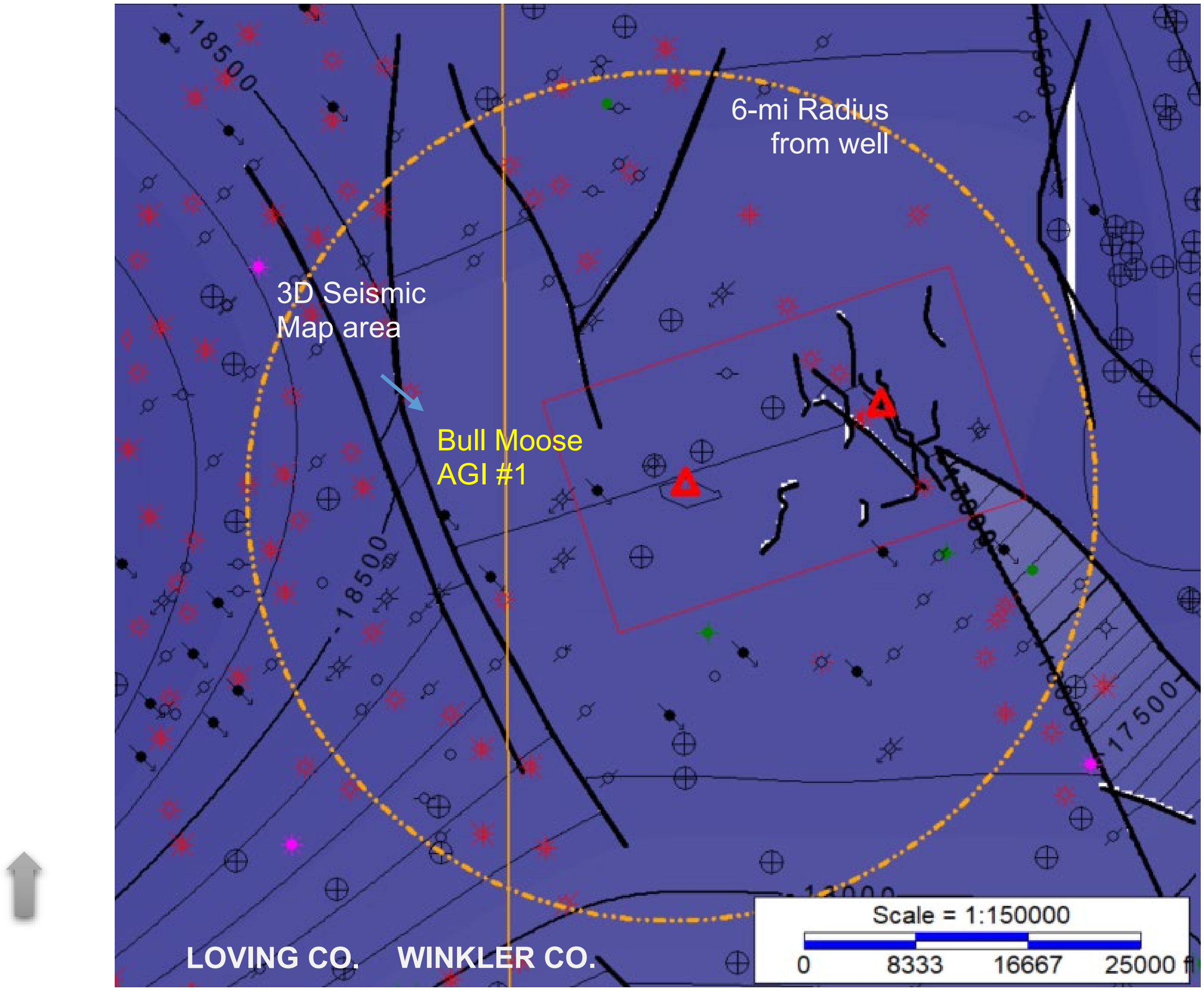


Figure 3.3-12: Precambrian Subsea Structure Map. CI = 100 ft.

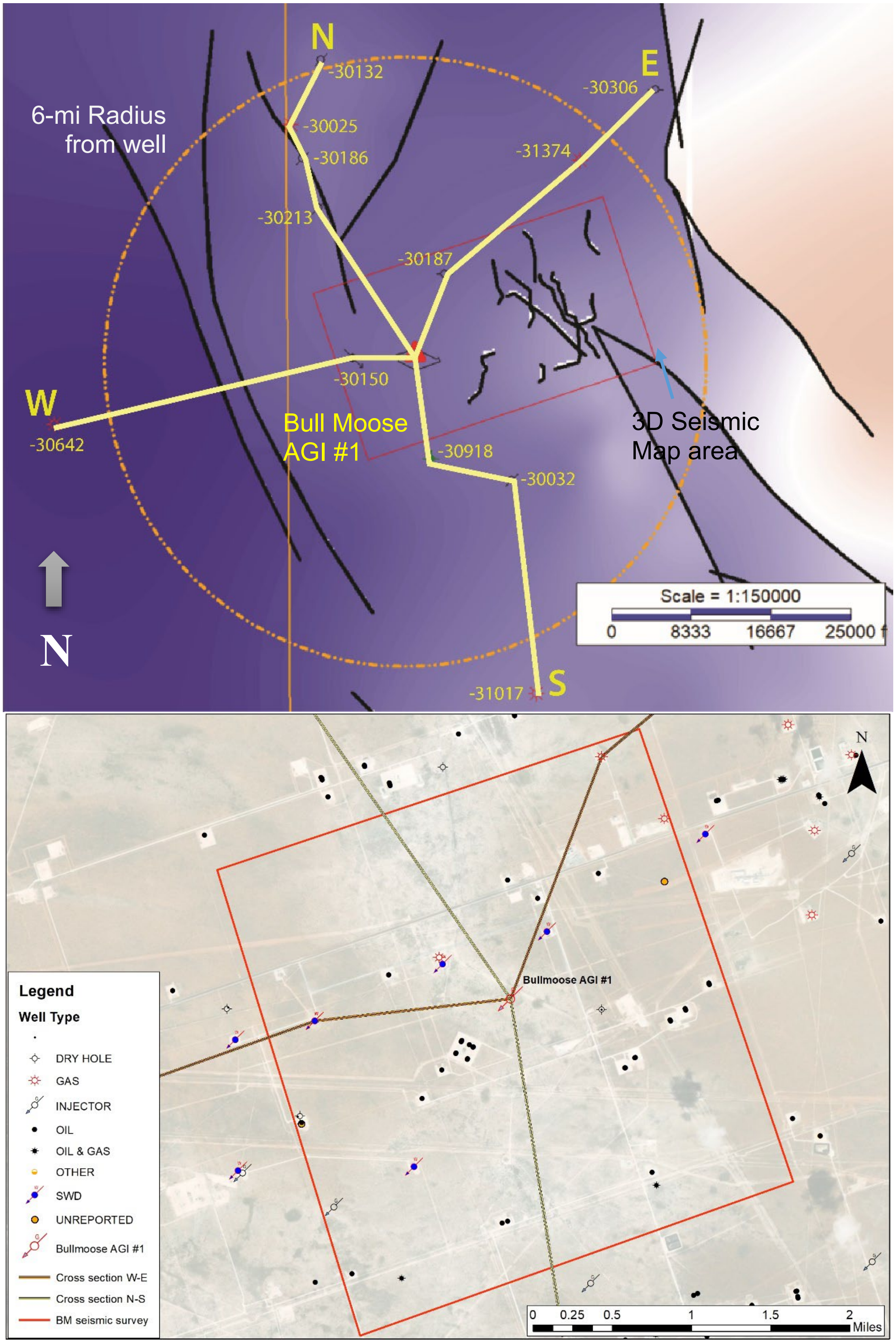


Figure 3.3-13: *Base Map for Cross Sections*

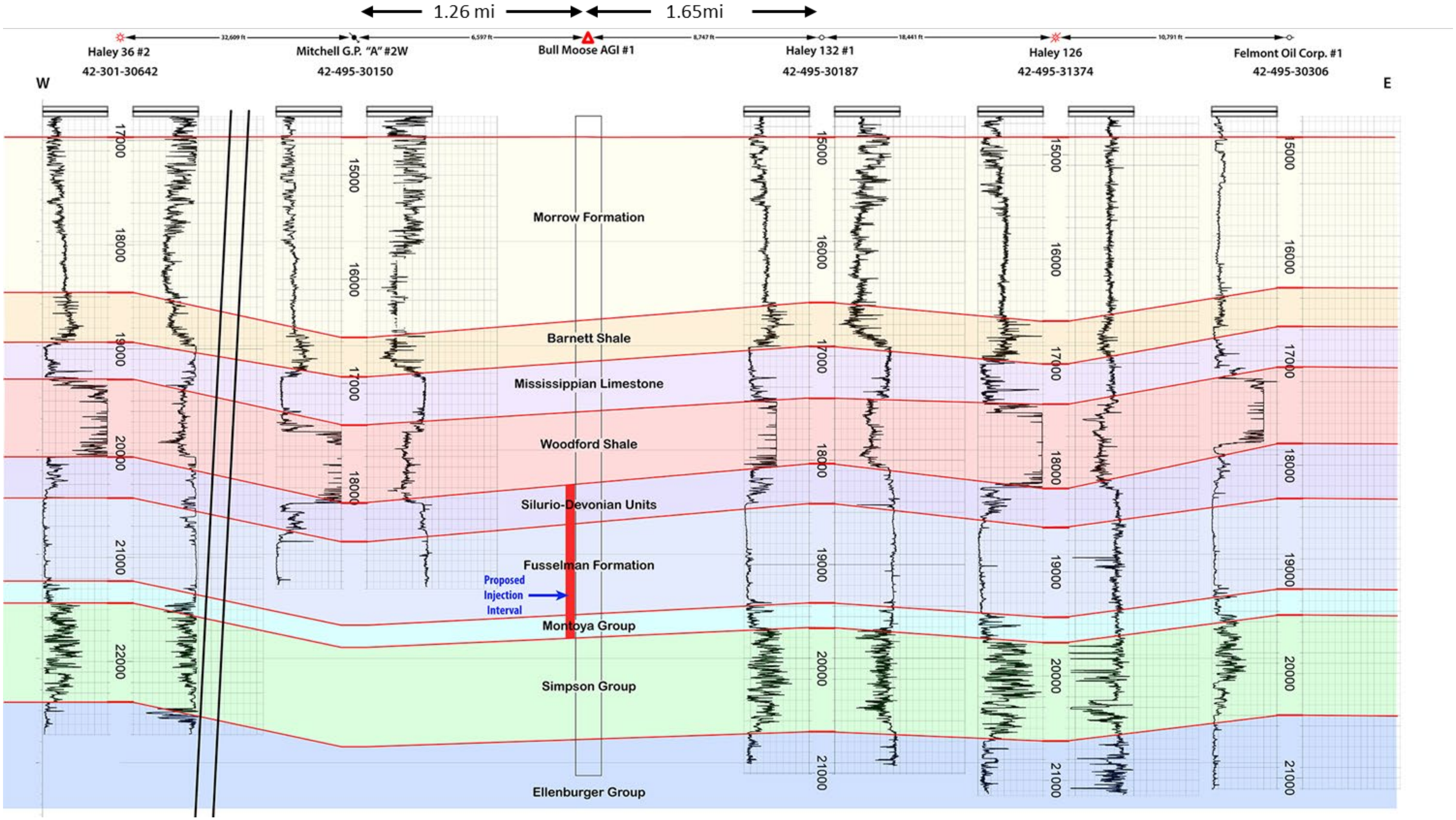


Figure 3.3-14: West to East Cross Section

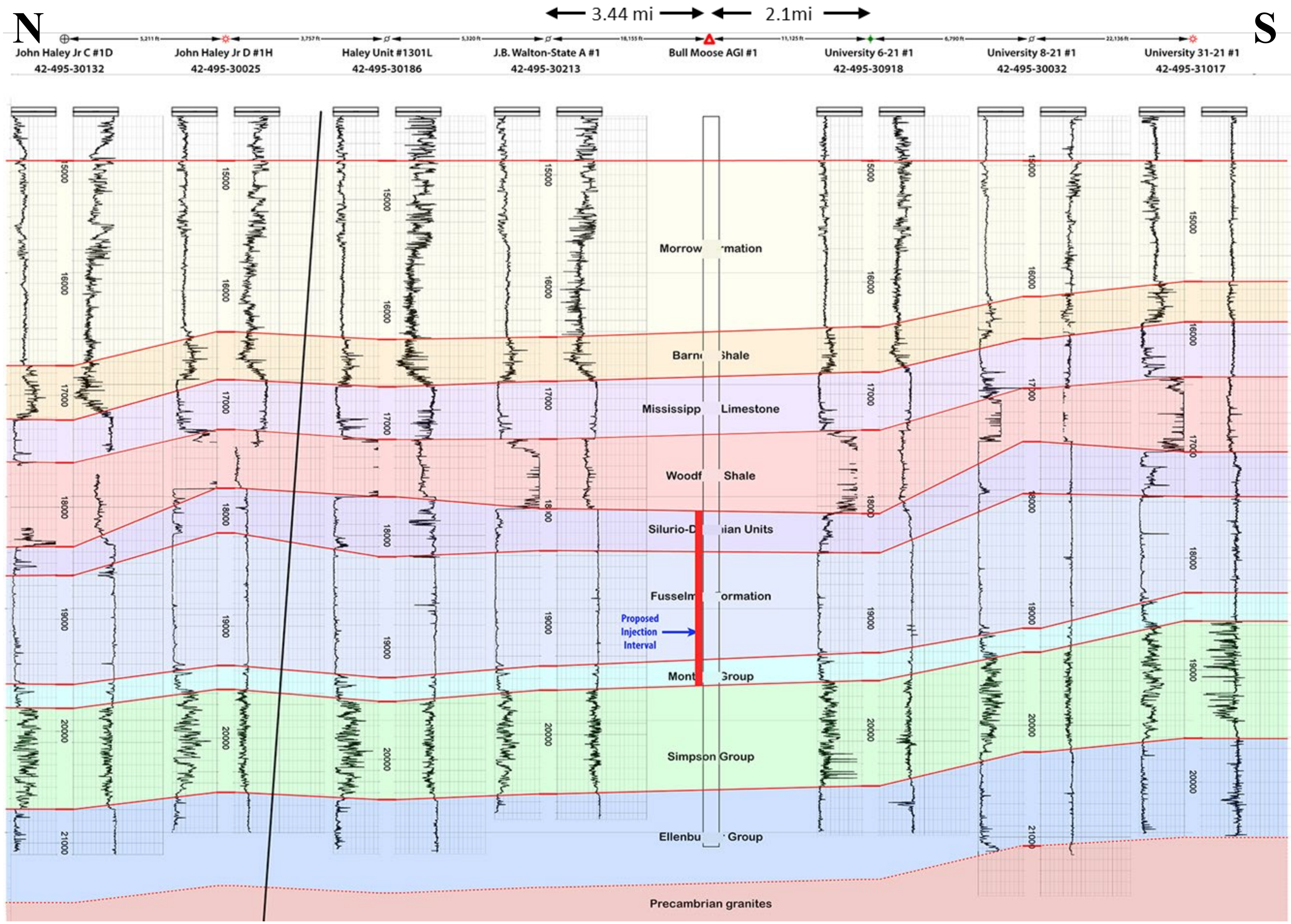


Figure 3.3-15: North to South Cross Section

3.5 Formation Fluid Chemistry

Water data was retrieved from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 (05/22/2019) to determine formation chemistry in the Siluro-Devonian, Fusselman, and Montoya injection intervals for Bull Moose AGI #1. Chemical data was plotted in a geographical interface and delineated to a 15-mile boundary around the Bull Moose site to fully constrain each formation's geochemical signature.

There are 12 wells with analyses collected from the Siluro-Devonian, Fusselman, Montoya, and Simpson formations within 15 miles of Bull Moose AGI #1 (red squares **Figure 3.5-1).** Samples taken in these formations generally fall within a saline (NaCl) hydrofacies, and concentrations of total dissolved solids (TDS) range from 69,140 to 341,260 milligrams per liter (mg/L) with an average of 140,024 mg/L. High salinity in these formations indicate they are compatible with injection (**Table 3.5-1**).

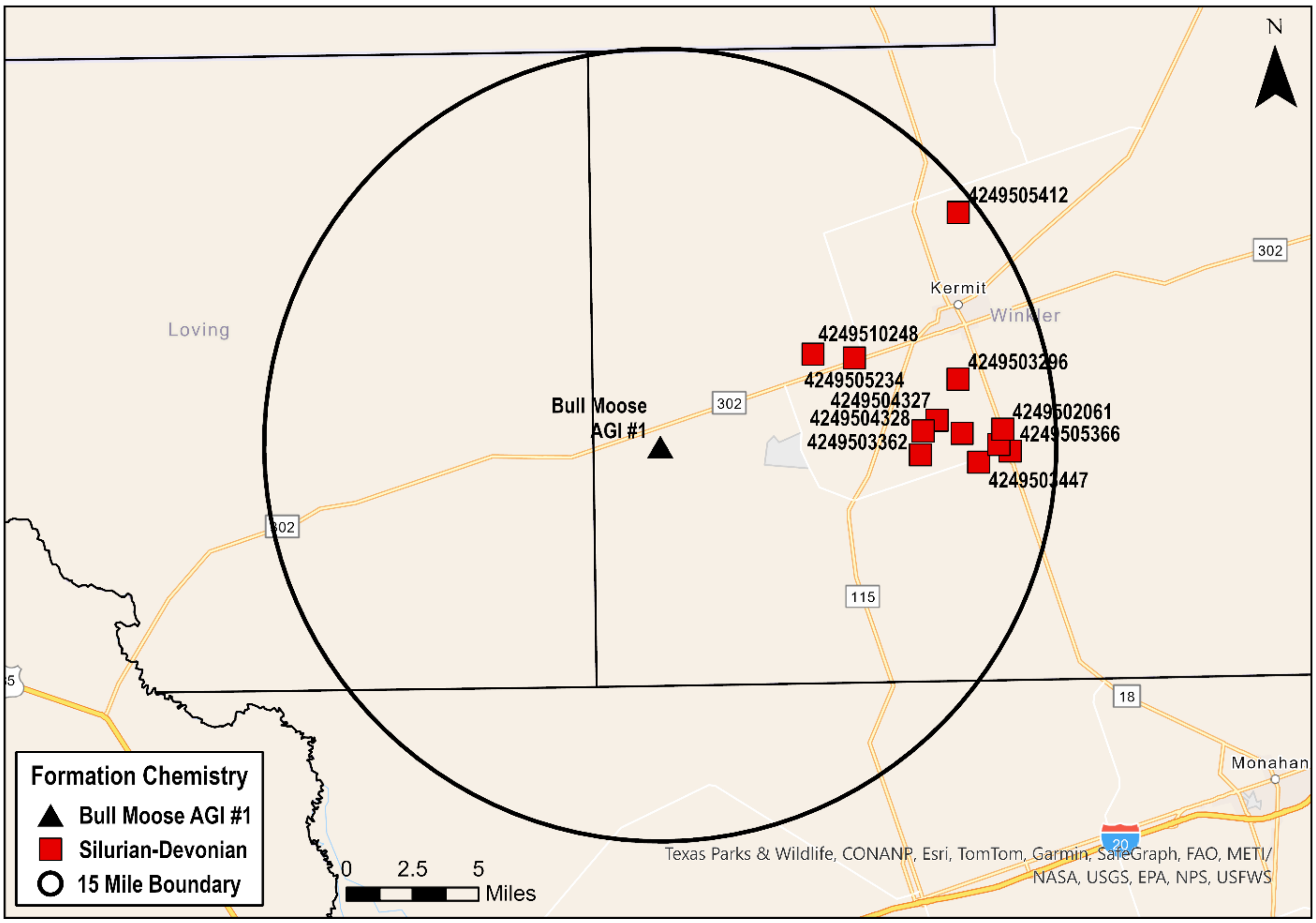


Figure 3.5-1: *Wells with water chemistry in the Silurian, Fusselman, or Devonian formations within 7 to 15 miles of the Bull Moose AGI well from the U.S. Geological Survey National Produced Waters Geochemical Database. Data show these formations are NaCl waters with average TDS of 140,024 mg/L.*

Table 3.5-1. *Water chemistry in mg/L for wells in the Silurian, Fusselman, or Devonian formations within ≈7 to 15 miles of Bull Moose AGI #1 from the USGS National Produced Waters Geochemical Database.*

API	Latitude	Longitude	Formation	HCO_3	Ca	Mg	KNa	Cl	SO_4	TDS
4249503296	31.8171	-103.0914	Devonian	1,347	12,410	1,799	10,290	40,390	2,904	69,140
4249503296	31.8171	-103.0914	Devonian	97	14,610	4,052	36,590	92,530	2,480	150,359
4249503296	31.8171	-103.0914	Devonian	145	14,510	4,163	36,590	92,830	2,520	150,758
4249503296	31.8171	-103.0914	Devonian	80	14,610	4,153	36,790	92,830	2,500	150,963
4249503296	31.8171	-103.0914	Devonian	122	14,600	4,028	37,050	92,940	2,437	151,177
4249503362	31.7759	-103.1165	Devonian	352	10,780	2,806	6,470	36,010	1,403	57,821
4249503447	31.7713	-103.0791	Devonian	635	2,900	300	35,500	60,000	475	99,810
4249505366	31.7771	-103.0587	Devonian	151	11,804	2,578	59,112	118,202	1,703	193,550
4249500556	31.7808	-103.0659	Fusselman	362	4,232	881	29,090	53,850	2,857	91,273
4249502061	31.7892	-103.0632	Fusselman	148	6,960	4,440	118,800	208,800	2,112	341,260
4249504327	31.7947	-103.1054	Fusselman	458	4,244	706	29,620	53,810	1,568	90,406
4249504328	31.789	-103.1145	Fusselman	427	4,236	1,016	45,650	78,800	2,420	132,549
4249505210	31.7873	-103.0894	Fusselman	849	10,640	945	24,780	59,440	460	97,114
4249505412	31.9086	-103.0894	Fusselman	202	1,733	536	48,589	73,421	4,400	128,881
4249510248	31.8322	-103.1845	Fusselman	706	499	386	91,284	139,300	4,317	236,491
4249505234	31.8297	-103.1579	Silurian	327	4,758	962	31,960	59,200	1,625	98,832

3.6 Groundwater Hydrology in the Vicinity of the Bull Moose Gas Plant

Regionally, groundwater near the BM AGI #1 site is drawn from one of five sources. From shallow to deep those are Quaternary-Late Tertiary Pecos Valley Deposits, Cretaceous sediments of the Edwards-Trinity Groups, Triassic deposits of the Dockum Group, the Permian (Oochan) aged Rustler Formation, and the Permian (Guadalupian) aged Capitan Reef Complex. Based on current water data with the Texas Water Development Board (TWDB), the primary groundwater sources at the site are the Pecos Valley Alluvium and the Dockum Group (**Figure 3.6-1**). Below we provide a general description of the groundwater sources and the wells within the Maximum Monitoring Area (MMA) at the BM AGI #1 site.

3.6.1 Pecos Valley Aquifer

The Pecos Valley Aquifer lies unconformably on portions of the Edwards-Trinity Plateau, Dockum, Rustler, and Capitan Reef aquifers. It covers an area of 6,829 mi^2 and is comprised of sediments that range in size from clay to boulder which were deposited in a variety of continental settings including fluvial, valley-fill, eolian, lacustrine, and solution-collapse environments (Wise et al., 2012). Sediments of the Pecos Valley Aquifer fill several structural basins, the largest of which are Monument Draw Trough in the east and the Pecos Trough in the west. Maximum thickness of the alluvial fill reaches approximately 1,500 feet, and freshwater saturated thickness averages around 250 feet (George et al., 2011).

The water quality is highly variable, with the water typically being hard, and generally better in the Monument Draw Trough than in the Pecos Trough. Total dissolved solids have been found to range from 116 to over 15,000 mg/L depending on location and proximity to oil and gas or halite mining operations in the region (Wise et al., 2012). The aquifer is generally characterized by high levels of sulfate and chloride in excess of secondary drinking water standards which has been linked to previous oil field activities. Also, naturally occurring radionuclides and arsenic can be found in excess of primary drinking water standards (George et al., 2011). More than 80 percent of Pecos

Valley groundwater is used for irrigation, while the remainder is used for municipal supplies, power generation, and industrial use.

3.6.2 Dockum Aquifer

The Upper Triassic Dockum Group covers about 96,000 square miles in parts of Kansas, Oklahoma, Colorado, New Mexico, and Texas. From young to old the Dockum includes the Santa Rosa and Tecovas Formations, the Trujillo Sandstone, and the Cooper Canyon Formation. These formations consist of conglomerate, gravel, sandstone, siltstone, mudstone, and shale with recoverable quantities of groundwater located in the sandstone and conglomerate. The largest yields are typically found in the coarsest deposits in the middle and base of the group. Locally any water-bearing sandstone of the Dockum Group is referred to as the Santa Rosa Aquifer (Bradley and Kalaswad, 2003; 2004; George et al., 2011).

Water quality in the Dockum Aquifer varies, ranging from fresh (TDS <1,000 mg/L) on outcrop to brine (TDS >10,000mg/L) where it is confined, typically deteriorating with depth. TDS concentrations have been found to be >60,000 mg/L in the deepest parts of the aquifer. Groundwater in the Dockum aquifer is typically hard, average of 470 mg/L, and radionuclides naturally derived from uranium can be found at concentrations a >5 pCi/L in many areas of the aquifer (Bradley and Kalaswad, 2003; 2004). Locally, the Dockum Aquifer can be vital for irrigation, public supply, livestock watering, manufacturing, and oil-field activity. However, a combination of deep pumping depths, low yields, poor water quality, and declining water levels have hindered a more widespread use (Bradley and Kalaswad, 2003).

3.6.3 Groundwater Wells Within the Bull Moose AGI Site MMA

Data collected from the Texas Water Development Board's (TWDB) Groundwater Database and Submitted Driller Report Database indicate there are 2 freshwater wells located within the MMA for BM AGI #1. Both wells are permitted for domestic use and are shallow, collecting water from 152 to 245 feet depth in Pecos Alluvium and Triassic redbeds of the Dockum Group (Garza and Wesselman, 1963; Ashworth, 1990; Bradley and Kalaswad, 2003; **Table 3.6-1**). General chemistry analysis of one well within the MMA indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L (**Table 3.6-2**). The shallow freshwater aquifers are protected by the surface and intermediate casings and cements in the BM AGI #1 well. While the casings and cements protect shallow freshwater aquifers, they also serve to prevent CO_2 leakage to the surface along the borehole.

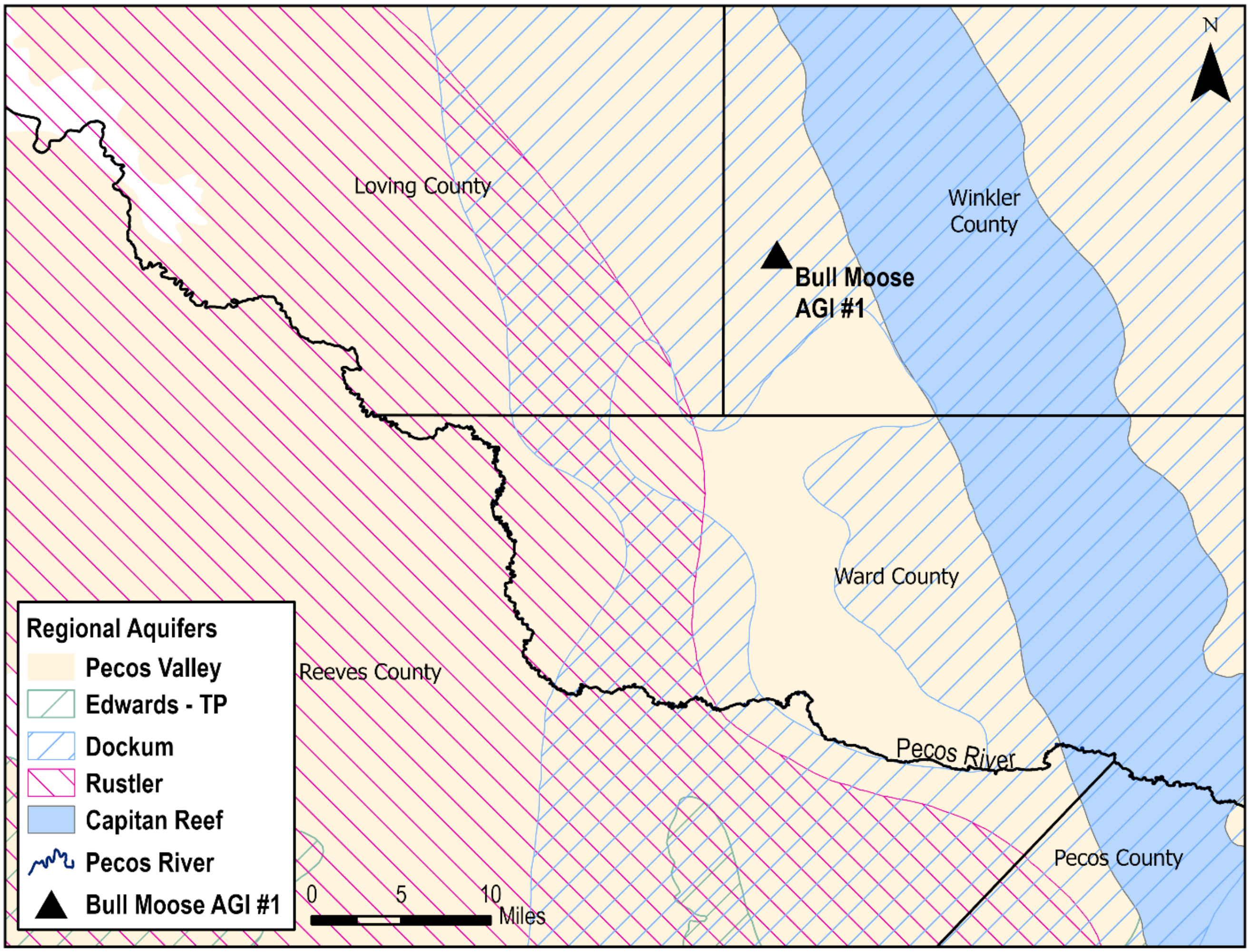


Figure 3.6-1: *Major and minor aquifers of the region. Groundwater at the proposed site is derived from the Pecos Valley Alluvium and Dockum Group.*

Table 3.6-1: *Groundwater wells within the MMA of the Bull Moose AGI site with from the Texas Water Development Board (TWDB) Groundwater Database (GWDB) and Submitted Driller Report (SDR) Database. Well depth is from 152 to 245 ft. and used for domestic purposes.*

Well ID/Report	Owner_Name	Use	County	Well_Depth	Latitude	Longitude
4614901	D P Anderson	Domestic	Winkler	152	31.76806	-103.285
409232	Frontier Energy	Domestic	Winkler	245	31.79591	-103.277

Table 3.6-2: *Groundwater chemistry for well 4614901 from Table 3.5-1 indicates that the Pecos Valley Alluvium/Dockum Group is a Ca-HCO_3/SO_4^{2-} water with TDS of 567 mg/L.*

StateWellID	Aquifer_Code	Date	HCO_3	Ca	Mg	Na	Cl	SO4	TDS
4614901	100CPDG	8/23/1940	256	97	38	43	53	189	557

3.7 Historical Operations

3.7.1 Bull Moose Site

In response to increasing production and to meet the infrastructure needs of producers, TND is constructing a new Bull Moose 275 MMCFD cryogenic natural gas processing plant. **Figure 3.7-1** shows the simplified process block flow diagram, with the entry point for the CO_2, the flow meter location and the sampling point, before BM AGI #1 well.

3.7.2 Operations within the MMA for the BM AGI Wells

TRRC records identify a total of 29 oil- and gas-related wells within the MMA (see **Appendix 3**). **Figure 3.7-2** shows the geometry of producing and injection wells within the MMA. **Appendix 3** summarizes the relevant information for those wells.

Among the 29 wells identified, 25 are horizontal oil wells completed in the Bone Spring (8 wells) or Wolfcamp (17 wells) formations, at depths between 11,564 and 12,545 ft. One is inactive and three are plugged and abandoned.

There are four other vertical wells. There are two vertical plugged and abandoned gas well in the Morrow formation (16,000 ft). There are also two Saltwater Disposal (SWD) wells that are injecting in the Brushy Canyon (7,516 and 7,630 ft).

All of these productive zones are more than 5,300 ft above the BM AGI #1 injection zone.

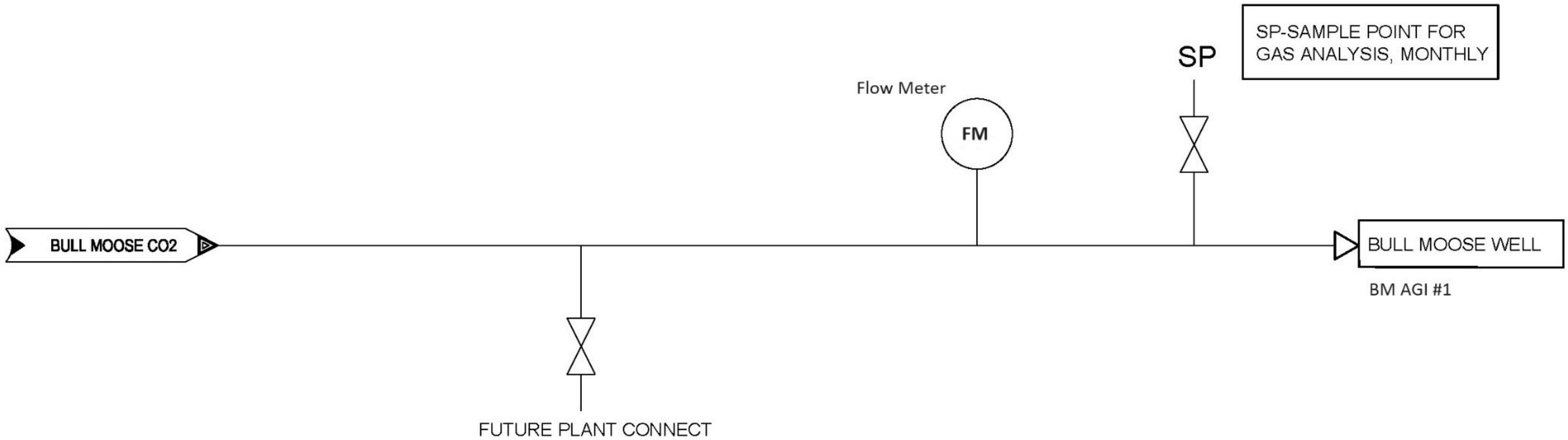


Figure 3.7-1: *Process Block Flow Diagram with CO_2 entry, Flow meter (FE), Sampling point (SP) and BM AGI #1.*

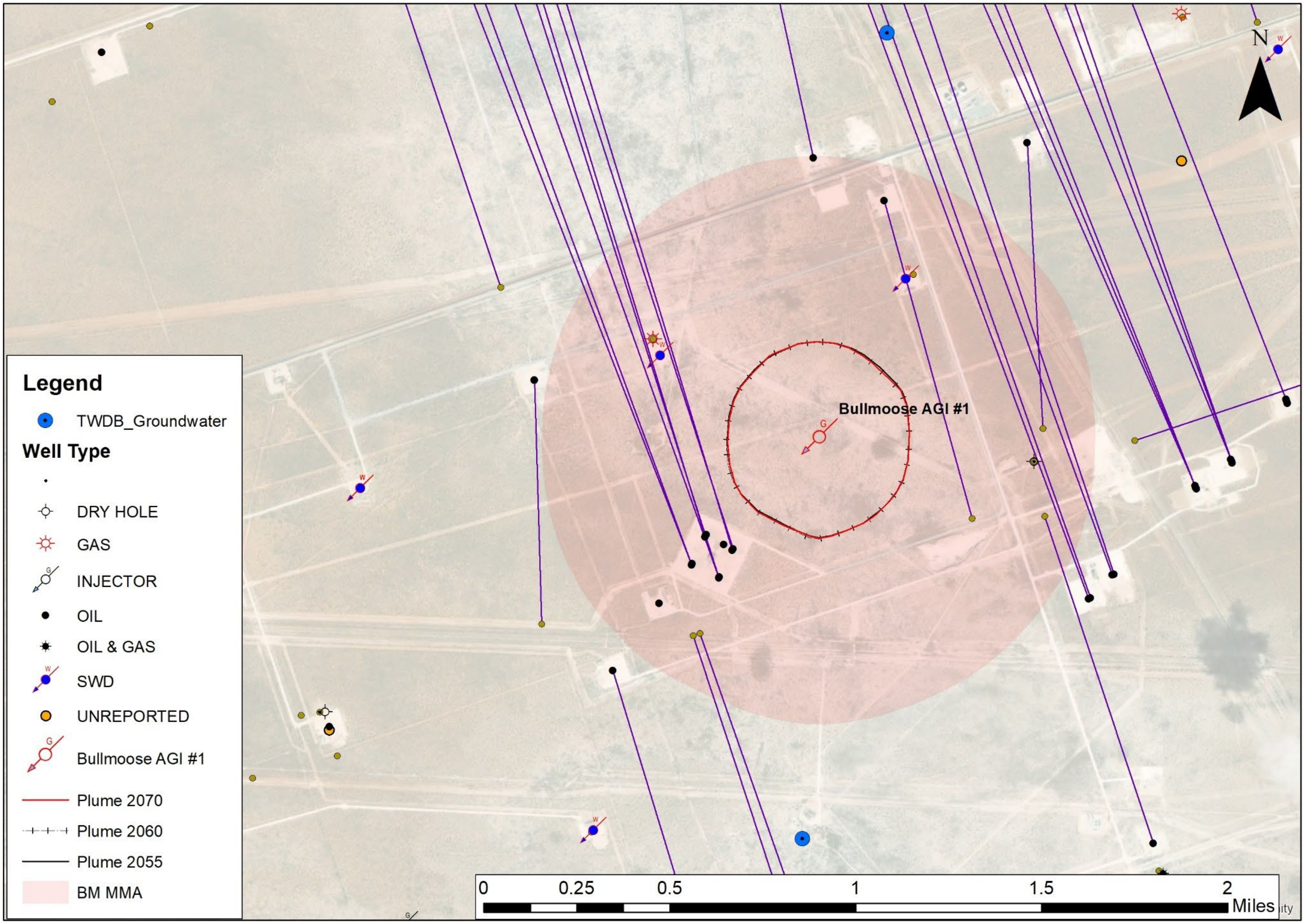


***Figure 3.7-2**: Location of all oil- and gas-related wells within the MMA for the BM AGI #1 well. Both the surface hole locations (SHL) and bottom hole locations (BHL) are labeled on the figure.*

3.8 Description of Injection Process

The Bull Moose Gas Plant, including the BM AGI #1 well, will be in operation and staffed 24-hours-a-day, 7-days-a week. The plant gathers and processes produced natural gas. Once gathered at the plant, the produced natural gas is compressed, dehydrated to remove the water content, and processed to remove and recover natural gas liquids. The processed natural gas and recovered natural gas liquids are then sold and shipped to various customers. The inlet gathering lines and pipelines that bring gas into the plant are regulated by U.S. Department of Transportation (DOT), National Association of Corrosion Engineers (NACE) and other applicable standards which require that they be constructed and marked with appropriate warning signs along their respective rights-of-way. TAG from the plant's sweeteners will be routed to a central compressor facility. Compressed TAG is then routed to the wells via high-pressure rated lines.

The natural gas to be treated at this facility is produced from oil and gas wells in the Permian Basin region, including Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward and Winkler counties, Texas plus Lea and Eddy counties in New Mexico. A sample from TND 's nearby Wildcat facility (5 miles west) was taken on 11/10/2023 and is representative of the injection stream for the Bull Moose facility. The results of that analysis are provided in **Table 3.8-1**.

Table 3.8-1: *Sample Gas Composition for Wildcat AGI #1*

Component	Mol %
Carbon Dioxide	91.339
Methane	0.350
Ethane	0.054
Propane	0.061
Iso-Butane	0.003
N-Butane	0.022
Iso-Pentane	0.000
Hexanes Plus	0.099
Hydrogen Sulfide	8.072
Nitrogen	0.000
TOTAL	100.00

The composition may change over time based on the amount of H_2S in the natural gas processing inlet stream. For modeling purposes, an injectate composition of 30% H_2S and 70% CO_2 was assumed as a conservative approach.

3.9 Reservoir Characterization Modeling

3.9.1 Inputs and Assumptions

Dynamic reservoir numerical simulation is performed on a realistic geologic. The modeling predicts the well injectivity, pressure behaviors, and TAG plume migration.

Schlumberger's Petrel® (Version 2023.3) software was used to construct the geological models used in this work. Computer Modeling software were used to perform the reservoir simulations presented in this MRV plan. The software was used to perform PVT calculation through Equation of States and properties interactions among various compositions to feed the hydrodynamic modeling. The hydrodynamical model considers aqueous, gaseous, and supercritical phases of the CO_2, simulates the storage mechanisms including structural trapping, residual gas trapping, and solubility trapping. Injected TAG may exist in an aqueous phase or in a gaseous phase, in a supercritical state.

The static model is constructed using well tops picked from logs and interpretations from 3D seismic survey to interpret and delineate formations and structural features. The geologic model covers a 3.2-miles by 3.0-miles area (**Figure 3.9-1**). The model is divided in 745,200 cells. The average cell size of the active injection area is 150 square ft. **Figure 3.9-2** shows the simulation model in 3D view. The porosity and permeability of the model are evaluated using existing well logs and 3D seismic inversion. The range of the porosity is between 0.01 to 0.31. The initial permeability is interpolated between 0.02 to 155 millidarcy (mD), and the vertical permeability anisotropy is 0.1. (**Figure 3.9-2**).

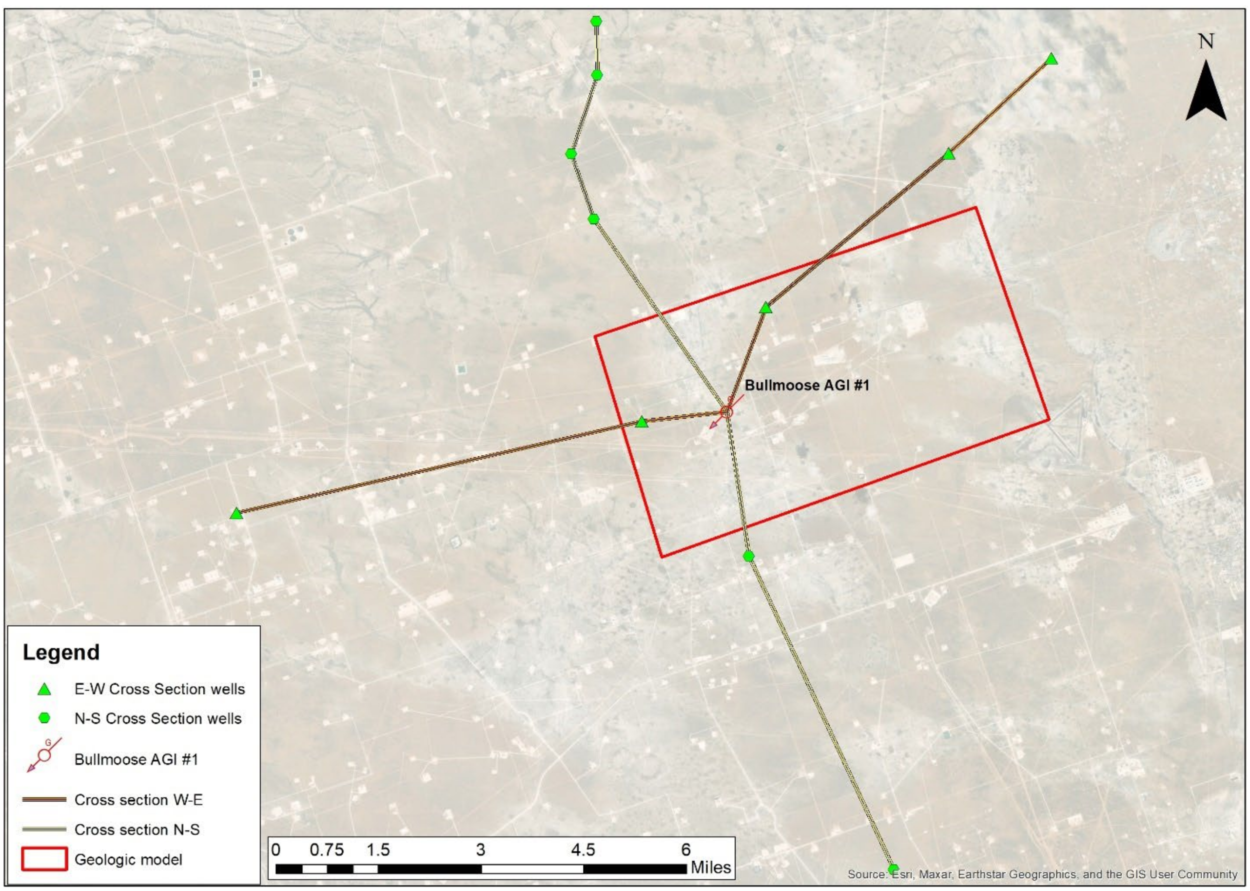


Figure 3.9-1: *Bull Moose AGI #1 model boundaries*

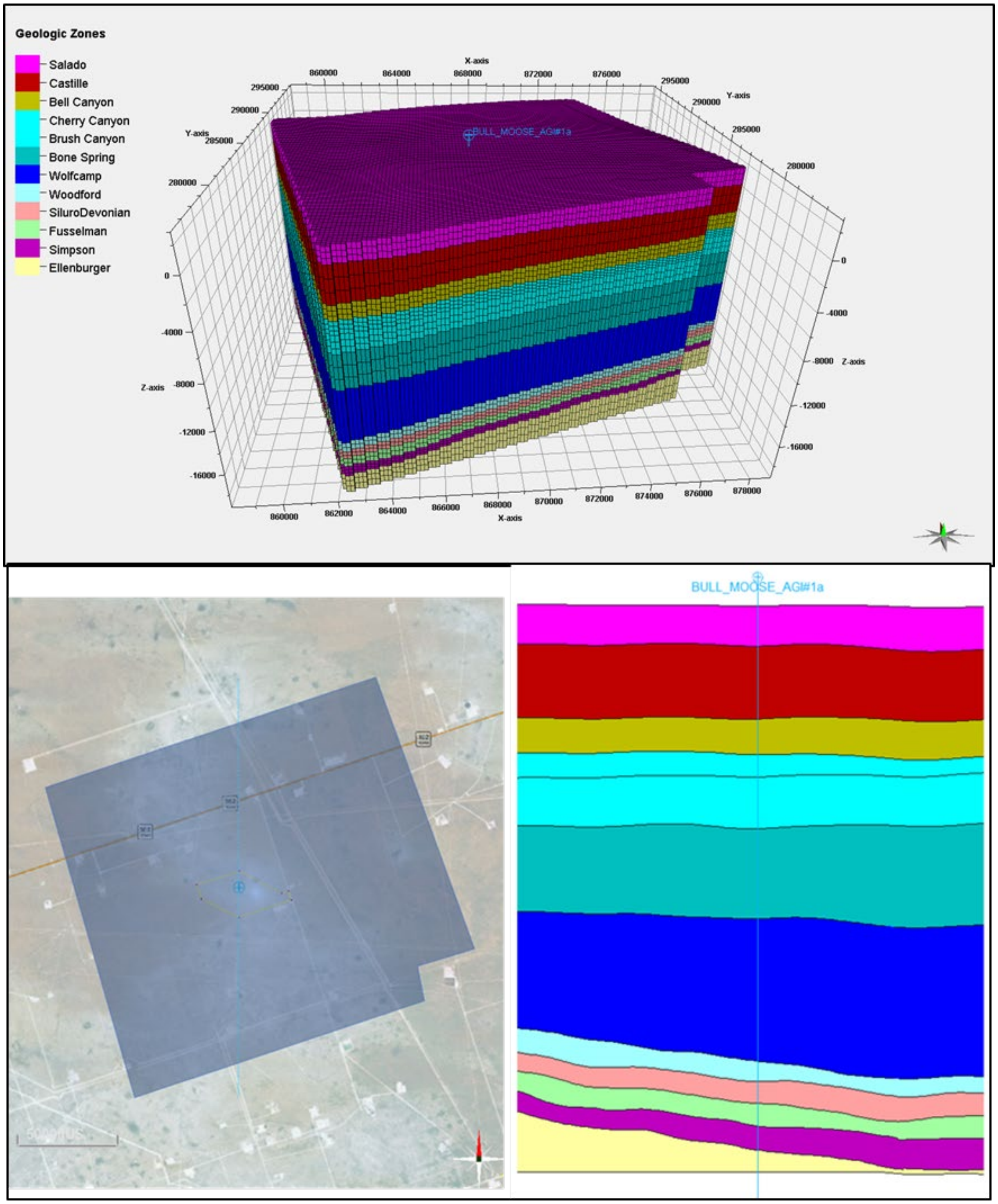


Figure 3.9-2: *3D view of the geological model for the Bull Moose AGI #1 well. The model displays the Salado-Castile formation, Lamar limestone, Bell Canyon, Cherry Canyon, Brushy Canyon, Bone Spring, Wolfcamp, Woodford, Siluro-Devonian, Fusselman, Simpson and Ellenburger formations. Color legends represent the zones.*

At the initialization of the simulation, the water saturation in the storage reservoir is assumed to be 100%, with a residual water saturation of 20% (Krause, M. H., and Benson, S. M., 2015). The initial salinity is assumed to be 20,000 ppm (Nicot et al., 2020). A geothermal gradient of 1.25°F/100 ft was adopted (Ge, J. et al., 2022). Following standard industry practices, a pore pressure gradient of 0.43 psi/ft is used. Therefore, the reservoir pressure at the top of the Siluro-Devonian at the location is estimated to be 7,650 psi.

The fracture gradient (FG) for the injection interval is calculated using Eaton's equation.

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

Where,

ν is the Poisson's ratio,

OBG is the overburden gradient,

p_p is the pore pressure gradient.

An overburden gradient of 1.05 psi/ft is adopted in the calculation. This value is considered best practice when a site-specific number is not available. Poisson's ratio is inferred to be 0.3 in the injection interval. A minimum value of 0.29 and a maximum value of 0.31 are used to quantify uncertainty (Smye et al, 2021, Dvory and Zoback, 2021). The fracture gradient is estimated to be 0.62 to 0.68 psi/ft, therefore the formation fracture pressure calculated at the top of the injection interval is 12,350 psi. In addition, a safety factor of 10% is applied to the resulting fracture gradient. This safety factor ensures injecting pressure will not exceed the fracture gradient in the injection interval, where the maximum bottomhole pressure was set to 0.63 psi/ft during active injection in the simulation. The results are summarized in **Table 3.9-1 & Table 3.9-2**. As these values are calculated based on available legacy well logs and literature listed in the reference, the actual gradient will be measured upon completion of the proposed well, and the modeling and simulation efforts will be updated accordingly.

A review of the TRRC databases identified no saltwater disposal (SWDs) or other injection wells within the model boundaries in the proposed injection interval.

Table 3.9-1: *Summary of reservoir simulation inputs.*

Reservoir properties of injection zones	Wristen & Fusselman
Porosity	As shown in geologic model
Permeability	As shown in geologic model
Pore pressure gradient	0.43 – 0.45 psi/ft (estimated from DST data in Winkler county – Dvory and Zoback (2021); Luo et al. (1994)
Formation fracture gradient	0.65 $\pm$0.03 psi/ft

Formation temperature	0.014 F/ ft (45 wells BHT data in Winkler–Luo et al. 1994)
Water salinity	150,000 ppm (Nicot et al. 2020 based on P50 of TDS in Winkler County showing 150kppm)
Initial water saturation	100% (assumption made for conservative CO_2 plume)

Table 3.9-2: *Summary of well simulation inputs.*

Injection well setup	Wristen & Fusselman
Bottom hole pressure	90% of formation fracture pressure or 11,300 psi at bottom hole
Well head pressure	0.5 psi/ft to the top of injection interval (approximately 8,945 psi) – RRC Standards and Procedures for Class II Wells
Wellhead temperature	90-100 °F
Injection fluid	70% CO_2, 30% H_2S
Injection rate	20 MMSCFD over 30 years (2025 – 2055)

Bull Moose AGI #1 is simulated to inject at the injection rate of 20 MMSCFD. In accordance with the TRRC Injection Storage Manual; Chapter III - Standards and Procedures for Class II Wells, the maximum surface injection pressure may not ordinarily exceed 0.5 psi per foot of depth to the top of the authorized injection or disposal interval. Therefore, a maximum allowable surface injection pressure of 8,945 psi is used in the simulation. Additionally, a maximum bottomhole pressure of 11,300 is enforced and 90% of the estimated formation fracture gradient is set as a secondary constraint in the simulation. The composition of the injection stream is estimated to be 30% H_2S and 70% CO_2. The simulated injection starts on 01/01/2025 and stops on 01/01/2055, after a 30-year active injection phase. The termination of the simulation is on 01/01/2085, with an additional 30 years of post-injection, to estimate the maximum plume extent and the stabilized plume.

3.9.2 Model Outputs

Simulations indicate BM AGI #1 can inject at the proposed rate throughout the 30-year period without any complications. Linear cumulative injection behavior (**Figure 3.9-3**) also indicates that the Siluro-Devonian, Fusselman and Montoya formations receive the TAG stream freely. Figure 39 shows a constant injection rate of 20 MMSCFD of the TAG stream injected over 30 years under the proposed bottom-hole pressure constraint. The modeling results indicate that the formations are capable of safely receiving and containing the proposed gas volume without violating the permitted rate and pressure. **Figure 3.9-4** shows the cumulative disposed H_2S and CO_2 separately in gas mass.

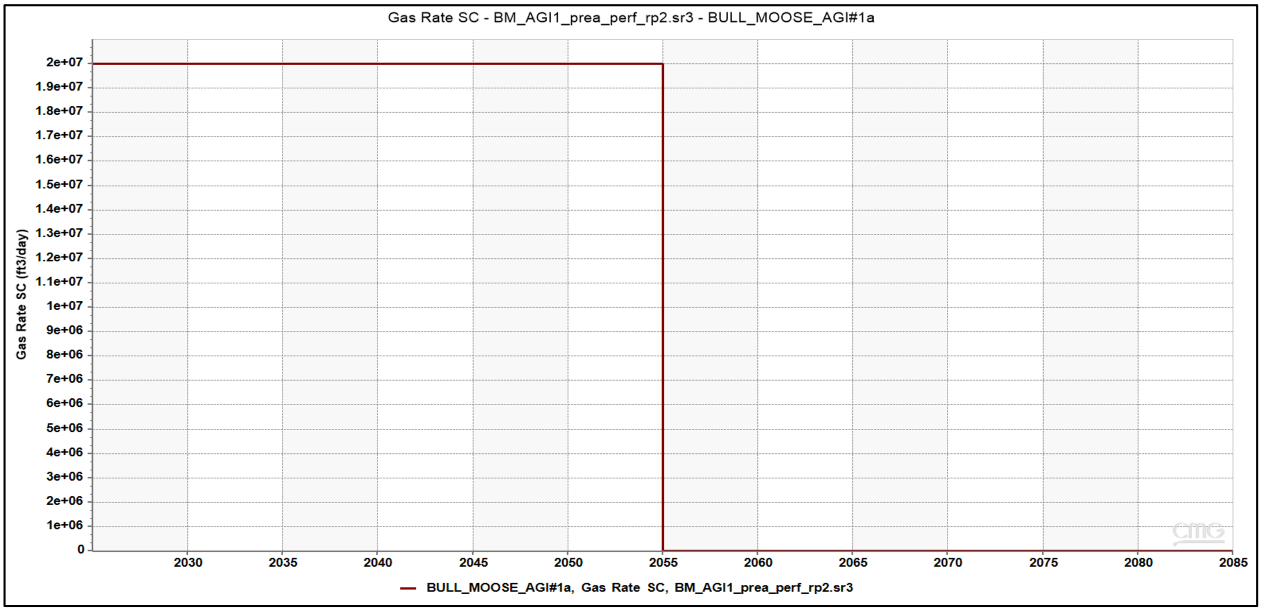


Figure 3.9-3: *Average daily injection volume for Bull Moose AGI No. 1 (2025 to 2055, 20 MMSCFD).*

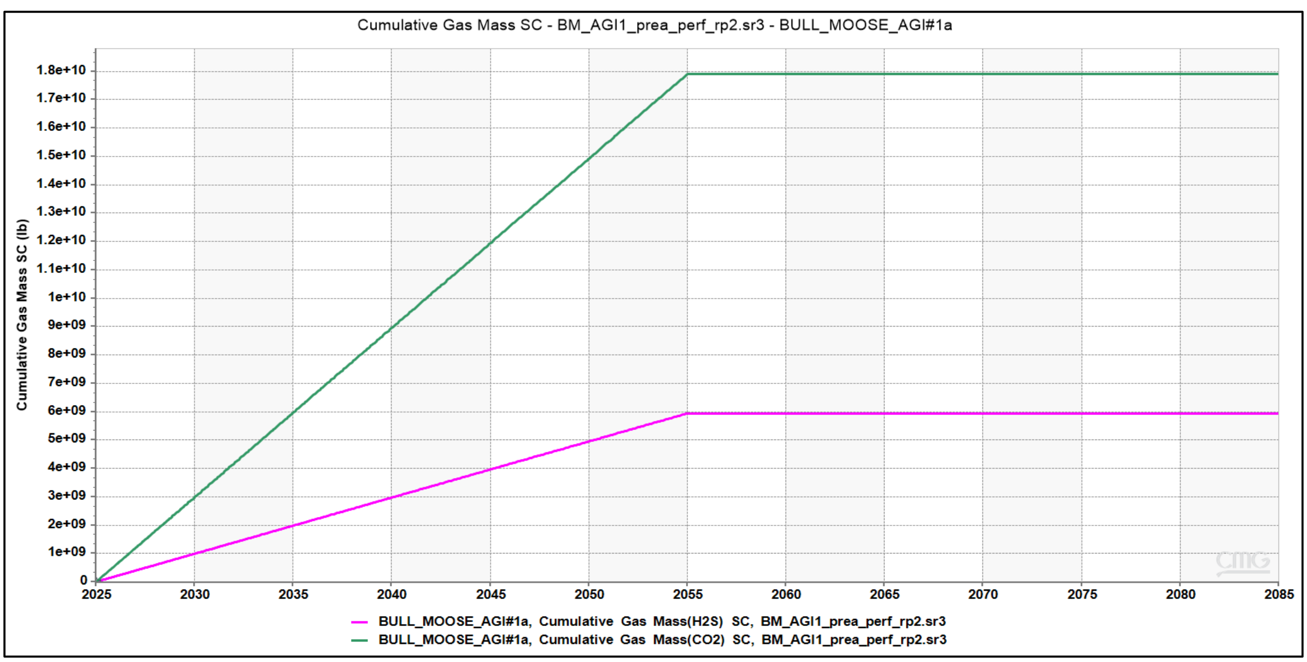


Figure 3.9-4: Predicted cumulative mass of injected CO_2 and H_2S for Bull Moose AGI #1 well (injection operation from 2025 to 2055).

3.9.3 Treated Acid Gas Plume

Figure 3.9-5 shows the TAG plume evolution for BM AGI #1 in the years 2030, 2035, 2040, 2045, 2050, 2055, marking 5-year increments from the beginning of the injection simulation in 2025. The diameter of the most extensive part of the TAG plume is estimated to be 7,500 ft (1.42 mi), with stabilization achieved in 2070

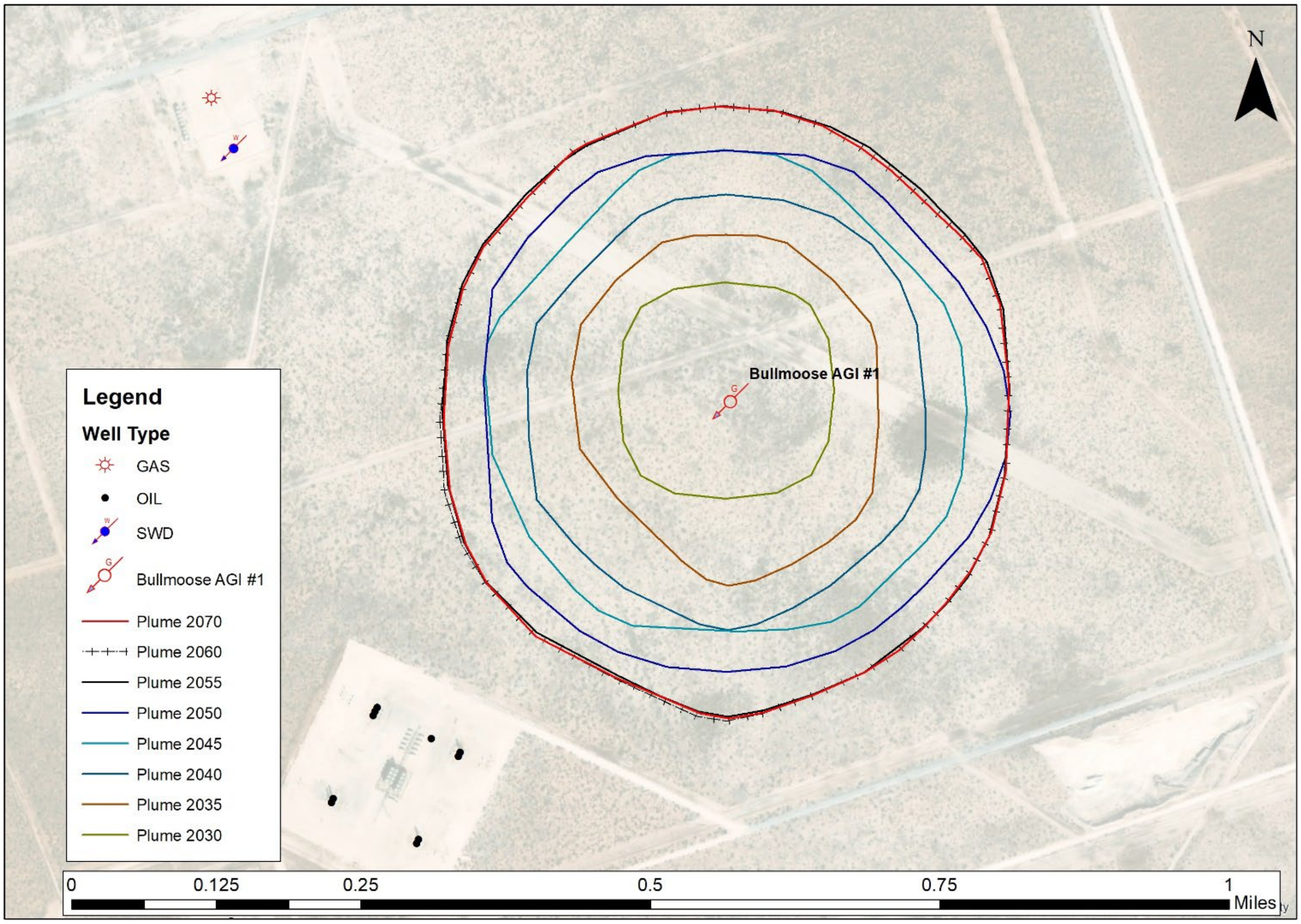


Figure 3.9-5: Extent of TAG plume (represented by gas saturation with 1% threshold) at years 2030, 2035, 2040, 2045, 2050, 2055 (end of injection = t), 2060 (t+5) and stabilized plume in 2070.

4 Delineation of the Monitoring Areas

The delineation of the Active Monitoring Area (AMA) and the MMA are based on the simulation results from section 3.9.

4.1 AMA – Active Monitoring Area

The Active Monitoring Area (AMA) is shown in **Figure 4-1**. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

(1) to contain the free phase CO_2 plume for the duration of the project (year t, t = 2055), plus an all-around buffer zone of one-half mile **(Figure 4.1-1);**

(2) to contain the free phase CO_2 plume for at least 5 years after injection ceases (year t + 5, t + 5 = 2060).

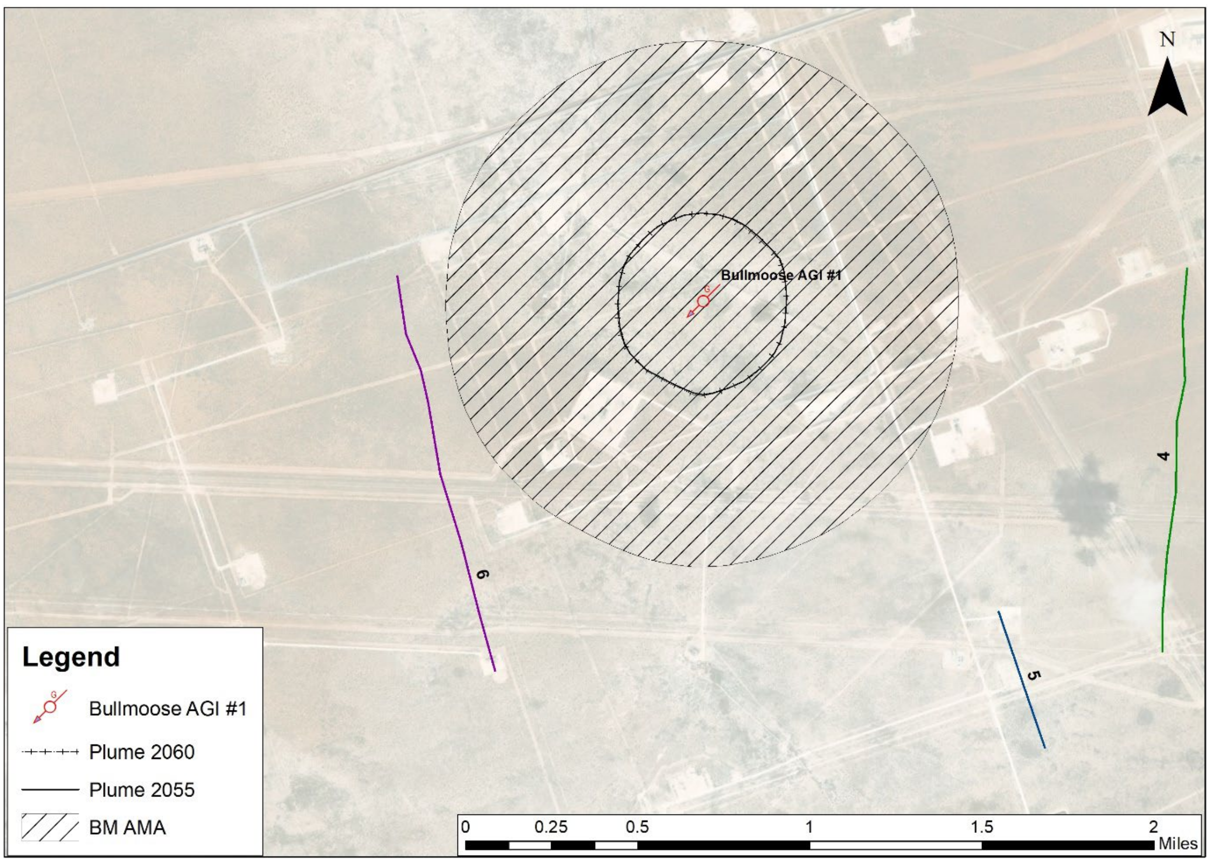


Figure 4.1-1: *Bull Moose AMA according to definition (1).*

TND intends to define the active monitoring area (AMA) to be the same area as the MMA. The black polygon at year t=2055 is the BM AGI #1 well plume at the end of injection, and the black cross-hatched polygon in **Figure 4.1-1** is the plume extent at the end of injection plus 5 years. The red polygon in **Figure 4.1-2** is the stabilized plume extent 15 years after injection ceases, i.e. 2070. The AMA, which is the hatched area in **Figure 4.1-1** and the MMA shown as the red-filled polygon in **Figure 4.1-2** contains the CO_2 plume during the duration of the project and at the time the plume has stabilized.

4.2 MMA – Maximum Monitoring Area

As defined in Section 40 CFR 98.449 of Subpart RR, the maximum monitoring area (MMA) is "equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." A CO_2 saturation threshold of 1% is used in the reservoir characterization modeling in Section 3.9 to define the extent of the plume.

According to the reservoir modeling results, after 30 years of post-injection monitoring (year=2085), the injected gas will remain in the reservoir and no expansion of the TAG footprint is observed after 2070. Therefore, the plume extent at year 2070 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA: **Figure 4.1-2**.

In addition, according to EPA regulation: "The buffer is intended to encompass leaks that might migrate laterally as they move towards the surface. EPA has determined that a buffer zone of at least one-half mile will have an acceptable probability of encountering leaks in many circumstances."

Therefore, TND considered the identified faults surrounding the injection well in order to define the MMA. There was no need to extended the MMA to incorporate the faults plus a one-half-mile buffer around the faults because they are outside the initial AMA and MMA. Therefore, the MMA encompasses the union of two areas:

- The area covered by the stabilized plume plus an all-around buffer zone of one-half mile
- The area covered by the lateral extent of known potential leakage pathways (the trace faults Figure 4.2) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 shows the MMA as defined by Section 40 CFR 98.449 of Subpart RR. The MMA is expected to contain the free phase CO_2 plume throughout the life of the project and the lateral extent of potential leakage pathway plus a one-half mile buffer. The AMA is set equal to the MMA.

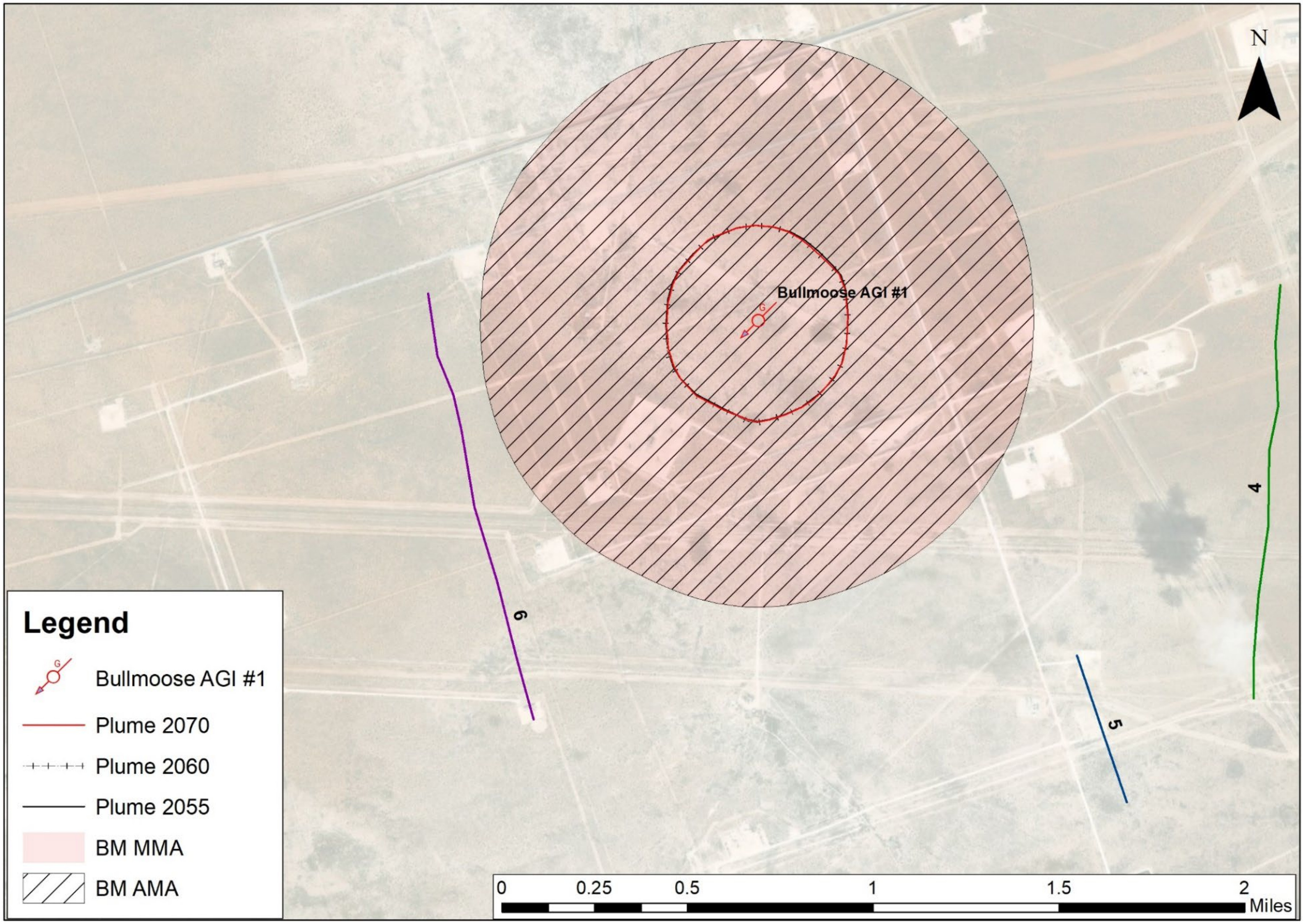


Figure 4.1-1: *Active monitoring area (AMA) and Maximum monitoring area (MMA) for TND Bull Moose AGI #1; and plume at the end of injection (2055), 5 years after end of injection (2060) and stabilized plume (2070)*

5 Identification and Evaluation of Potential Leakage Pathways to the Surface

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

An evaluation of each of the potential leakage pathways is described in the following paragraphs, notably:

1. Leakage through surface equipment;
2. Leakage through abandoned oil & gas wells;
3. Leakage through confining zone;
4. Leakage through lateral migration and faults;
5. Leakage due to seismicity.

Risk estimates were made using a risk matrix (**Figure 5.1-1**) with a methodology to evaluate risk probability and impact. In addition, TND used the National Risk Assessment Partnership (NRAP) tools, developed by five national laboratories: NETL, Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), and Pacific Northwest National Laboratory (PNNL). The NRAP collaborative research effort leveraged broad technical capabilities across the Department of Energy (DOE) to develop the integrated science base, computational tools, and protocols required to assess and manage leakage risks at geologic carbon storage sites.

Magnitude →

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

Figure 5.1-1: *5x5 Risk Matrix used to evaluate leakage likelihood and magnitude.*

5.1 Potential Leakage from Surface Equipment

Due to the corrosive nature of CO_2 and H_2S, there is a potential for leakage from surface equipment at sour gas facilities. Preventative risk mitigation includes adherence to relevant regulatory requirements and industry standards governing the construction, operation, and maintenance of gas plants. Specifically, NMAC 19.15.26.10 requires injection well operators to operate and maintain "surface facilities in such a manner as will confine the injected fluids to the interval or intervals approved and prevent surface damage or pollution resulting from leaks, breaks or spills".

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

Likelihood:

Although mitigative measures are in place to minimize CO_2 emissions from surface equipment, such emissions are possible. Any leaks from surface equipment would result in immediate (timing) emissions of CO_2 to the atmosphere, the magnitude of which would depend on the duration of the leak and the operational conditions at the time and location of the leak.

The injection well and the pipeline that carries CO_2 to it are the most likely surface components of the system to allow CO_2 to leak to the surface. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable source of the leakage.

Another possible source of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, which releases CO_2.

Therefore, TND infers that there is a potential risk for leakage via this route. However, due to the standards enforced during construction, the monitoring equipment in place and the regular inspections and maintenances, the probability of such leakage is considered very unlikely.

Magnitude and Timing:

Depending on the component's failure mode, the magnitude and timing of the leak can vary greatly. For example, a rapid break or rupture could release thousands of pounds of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a few pounds of CO_2 over several hours or days.

Surface component leakage or venting is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

Therefore, the impact (i.e. magnitude) of such a leakage is considered to vary from insignificant to severe according to scenarios. The timing is also variable.

5.2 Potential Leakage through Bull Moose AGI #1 casing

Likelihood:

To minimize the likelihood of leaks from new wells, TRRC regulation regarding the casing and cementing of injection wells requires operators to case injection wells with safe and adequate casing or tubing so as to prevent leakage and set and cement the casing or tubing to prevent the movement of formation or injected fluid from the injection zone into another injection zone or to the surface around the outside of the casing string.

Magnitude and Timing:

To minimize the magnitude and duration (timing) of CO_2 leakage to the surface, TRRC requires the use of blowout preventers in areas of high pressure at or above the projected depth of the well. These requirements apply to any other new well drilled within the MMA for this MRV plan.

In addition, for safety purposes, TND will be implementing enhanced safety protocols to ensure that no H_2S or CO_2 flow to the surface by:

- Monitoring H_2S at surface at many locations (H_2S can be a proxy to detect CO_2);
- Employing a high level of caution and care while drilling, including use of slower drilling processes and more vigilant mud level monitoring in the returns while drilling into the injection zone.

By drilling through producing zones, there is a possibility of gas emission to the surface from the pressurized zone. The emission would be nearly immediate. The magnitude of such an emission would be estimated based on field conditions at the time of the detected leak. The safety protocols described above are in place to prevent and/or minimize the magnitude of such a leak should one occur.

Due to these safeguards and the continuous monitoring of BM AGI #1 operating parameters by the distributed control system (DCS), TND considers that while the likelihood of surface emission of CO_2 is possible, the magnitude of such a leak would be minimal as detection of the leak would be nearly instantaneous followed by immediately shutting in the well and remediation.

5.3 Potential Leakage from Existing Wells

Existing oil and gas wells within the MMA, as delineated in Section 4, are shown in **Figure 3.7-2** and detailed in **Appendix 3**.

TND considered all wells completed and approved within the MMA in the NRAP risk assessment. None of the wells in the MMA penetrate the confining zone nor the injection zone. All of the productive zones lie at more than 5,300 ft above the BM AGI #1 injection zone.

Likelihood:

Even though the risk of CO_2 leakage through the wells that do not penetrate confining zones is very unlikely, (the CO_2 would have to leak through the sealing zone), TND did not omit any potential source of leakage in the NRAP analysis.

Magnitude:

If leakage through wellbores happens, the worst-case scenario is predicted using the NRAP tool to quantitatively assess the amount of CO_2 leakage through existing and approved wellbores within the MMA. A total of 29 wells inside MMA were addressed in the NRAP analysis. The reservoir properties, well data, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the rate and mass of CO_2 leakage.

There were 22 active oil wells that were considered in the NRAP risk assessment section. The other wells that were considered for the risk leakage assessment include two injection wells, six abandoned and plugged wells, and one inactive well. Reservoir and seal confinement properties were incorporated into the model, together with CO_2 properties and injection rates and pressures. The injection period was set to 30 years. According to the NRAP results, no leakage mass of CO_2 was recorded throughout the injection period.

Timing: The duration for CO_2 to get to the atmosphere via upward migration through the 5,300 feet of sealing and other geologic formations would be several thousands of years.

The **Table 5.1-1** summarizes the oil and gas wells and their evaluated risk.

Therefore, CO_2 leakage to the surface via existing well can be considered very unlikely and insignificant.

Table 5.1-1: Well within the MMA with their evaluated risk.

API	Well Type	Well Status	Trajectory	Formation	TVD (ft)	Risk Probability (1-5)	Risk Impact (1-5)	Total Risk Rating
	AGI	INJECTING	VERTICAL	Siluro-Devonian		2	3	6
42-495-34038	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,516	1	1	1
42-495-33871	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7,630	1	1	1
42-495-34331	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,564	1	1	1
42-495-34324	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,621	1	1	1
42-495-34488	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,627	1	1	1
42-495-34489	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,637	1	1	1
42-495-33759	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11,718	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,811	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,814	1	1	1
42-495-33230	OIL	P & A	HORIZONTAL	BONE SPRING	11,816	1	1	1
42-495-34325	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,858	1	1	1
42-495-33236	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11,868	1	1	1
42-495-34332	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,897	1	1	1
42-495-34483	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11,972	1	1	1
42-495-34323	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,106	1	1	1

42-495-34485	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,129	1	1	1
42-495-34481	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,145	1	1	1
42-495-34482	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,176	1	1	1
42-495-33840	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,185	1	1	1
42-495-33726	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,188	1	1	1
42-495-34329	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,193	1	1	1
42-495-33763	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,194	1	1	1
42-495-34326	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,208	1	1	1
42-495-34484	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,217	1	1	1
42-495-34328	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,263	1	1	1
42-495-34330	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,537	1	1	1
42-495-34327	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12,545	1	1	1
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6
42-495-32972	GAS	P & A	VERTICAL	MORROW	16,000	3	2	6

5.3.1 Wells Completed in the Injection zone

There are no wells completed in the injection zone.

5.3.2 Horizontal Wells

The table in **Appendix 3** and **Figure 3.7-2** show a number of horizontal wells in the area, many of which are producing. As discussed in 5.3, they are all 5,300 feet above the injection zone and the risk of leakage through these wells is considered very unlikely and insignificant.

5.3.3 Groundwater Wells

According to the Texas Water Development Board water database, there are no water wells within the MMA. There are only one North-East of the MMA and South-West of the MMA. Therefore, the risk of leakage through these wells are considered very unlikely and insignificant TWDB

5.4 Potential Leakage through the Confining / Seal System

Although unlikely, TND considered leakage through confining zones into in the NRAP risk assessment.

Likelihood:

The Barnett shale (440 ft), Mississipian limestone (440 ft) and Woodford shale (660 ft) serve as the major seals or caprock layer to the injection zones. Their low porosity (1%) and permeability (<0.1 mD) providehigh seal integrity (Sections 3.2, 3.3) There is. no evidence of faulting or natural fracturing. It is very unlikely that TAG injected into the injection formation will leak through this confining zone to the surface. Limiting the injection pressure to less than the fracture pressure of the confining zone will minimize the likelihood of CO_2 leakage through this potential pathway to the surface.

Magnitude and Timing:

The worst-case scenario is defined as leakage through the seal immediately above the injection wells, where CO_2 saturation is highest.

To simulate this scenario, cell blocks were created to cover the MMA, serving as the most prone zone for CO_2 leakage. These cell block locations and CO_2 saturation at the seal and seal properties were incorporated into the NRAP model.

Figures 5.4-1 and 5.4-2 present the leakage rate and cumulative mass of leakage over 60 years. The total leakage mass recorded after 60 years is about 8,000 kg. According to the total mass of CO_2 injected per year alone, after 60 years, the percentage of leakage through confining zone is estimated to be 0.0021%. This is reliably minimal and considering other stratigraphic strata, TND concludes that the risk of leakage through this pathway is highly unlikely and insignificant.

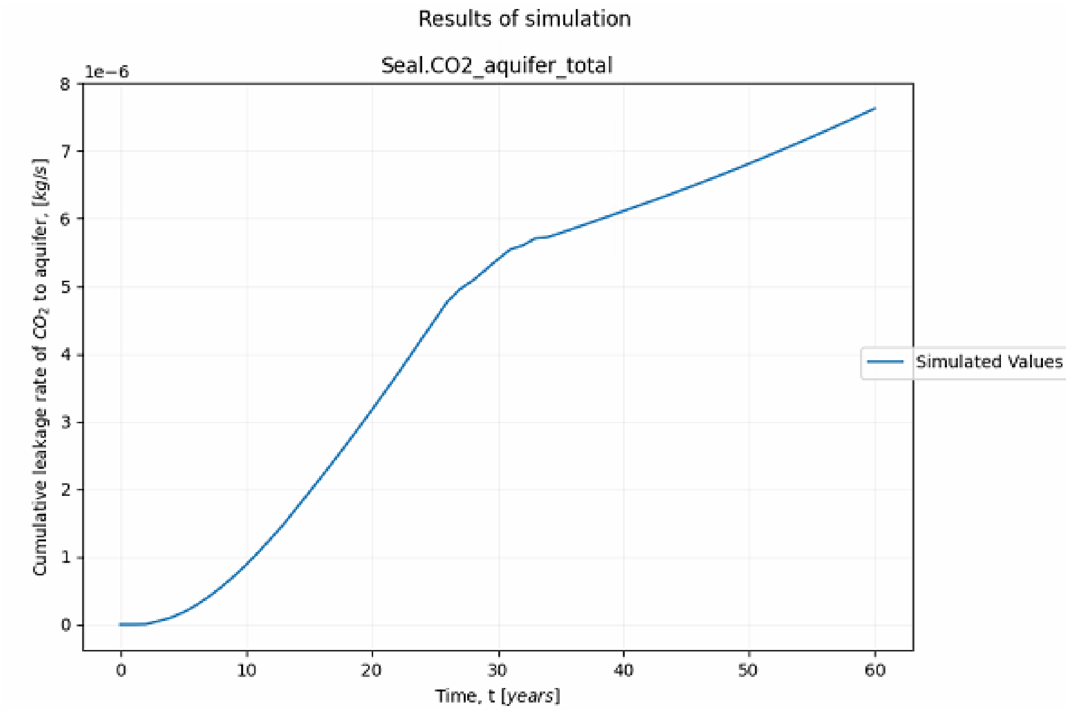


Figure 5.4-1: Seal leakage rate

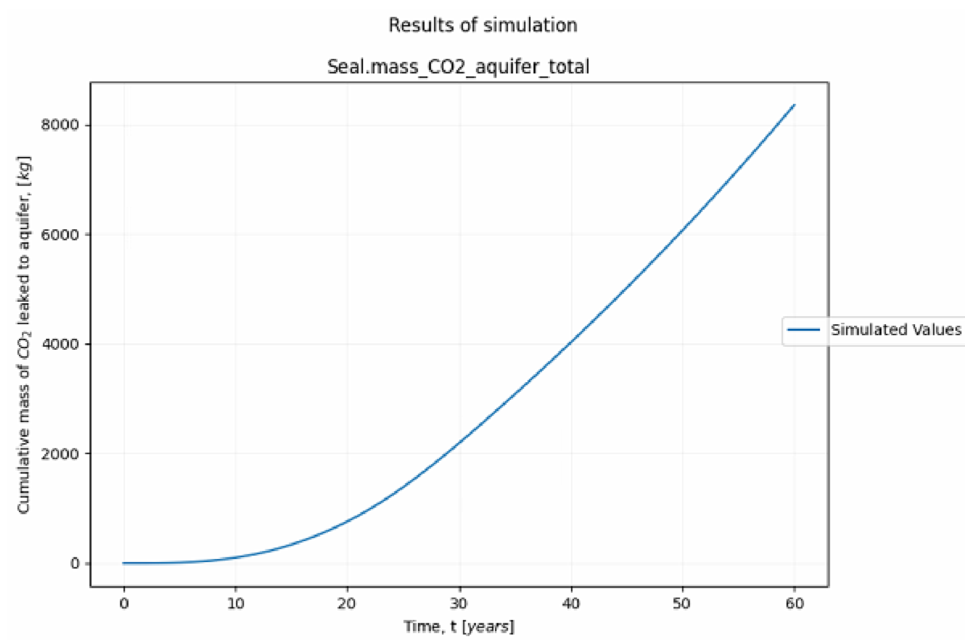


Figure 5.4-1: Cumulative mass of Seal leakage

5.5 Potential Leakage due to Lateral Migration

Likelihood:

Regional consideration of the geology (Section 3.3) and the model built suggest that BM AGI #1 injection zones have adequate storage capacity for the proposed injection amount. In addition, simulation (Section 3.9) indicates that the injected TAG will be easily contained close to the injection well, thus minimizing the likelihood of lateral migration of TAG outside the MMA.

Based on the geological discussion and analysis of the injection zone, TND considers that the likelihood of CO_2 to migrate laterally is unlikely.

Magnitude and Timing:

Based on simulation results, the TAG is projected to be contained within the injection zone close to the injection wells. The sealing zones are thick and continuous, which would prevent any upward migration through the confining zone even if lateral migration occurs.

5.6 Potential Leakage through Fractures and Faults

Likelihood:

Prior to injection, a thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology as well as identify and understand the distribution of faults and fractures. **Figure 5.6-1** shows the fault traces (numbered 4, 5 and 6) in the vicinity of the Bull Moose plant. The fault number 6 shown on **Figure 5.6-1** is above the injection zone for the BM AGI well. No faults were identified in the injection zone or confining zone within the MMA. Therefore, the likelihood of leakage through faults is considered very unlikely.

Magnitude and Timing:

No faults were identified within the MMA which could potentially serve as conduits for surface CO_2 emission. Considering faults that are going through the confining or injection zone, the closest identified fault lies approximately 1.5 miles east of the Bull Moose site and has approximately 1,000 ft of down-to-the-west structural relief.

The nearest fault going through the injection or confining zone is found approximately 7,276 ft east of the BM AGI #1 site. The risk of leakage through faults only occurs if the faults directly cut through the CO_2 plume or lateral migration carries CO_2 to faults. Other nearby faults are 12,031 ft (~2.3 mi)and ft (2.9 mi) east the site, placing them outside the MMA. Hence, leakage through faults will be an unlikely event. This is supported by NRAP simulation results (**Figure 5.6-1**) that consider fault location, geometry, and direction. For faults that do not directly connect with the CO_2 plume, CO_2 leakage rate and mass are estimated to be zero. The estimated cumulative leakage (**Figure 5.6-1**) shows no leakage throughout the period of simulation (60 years).

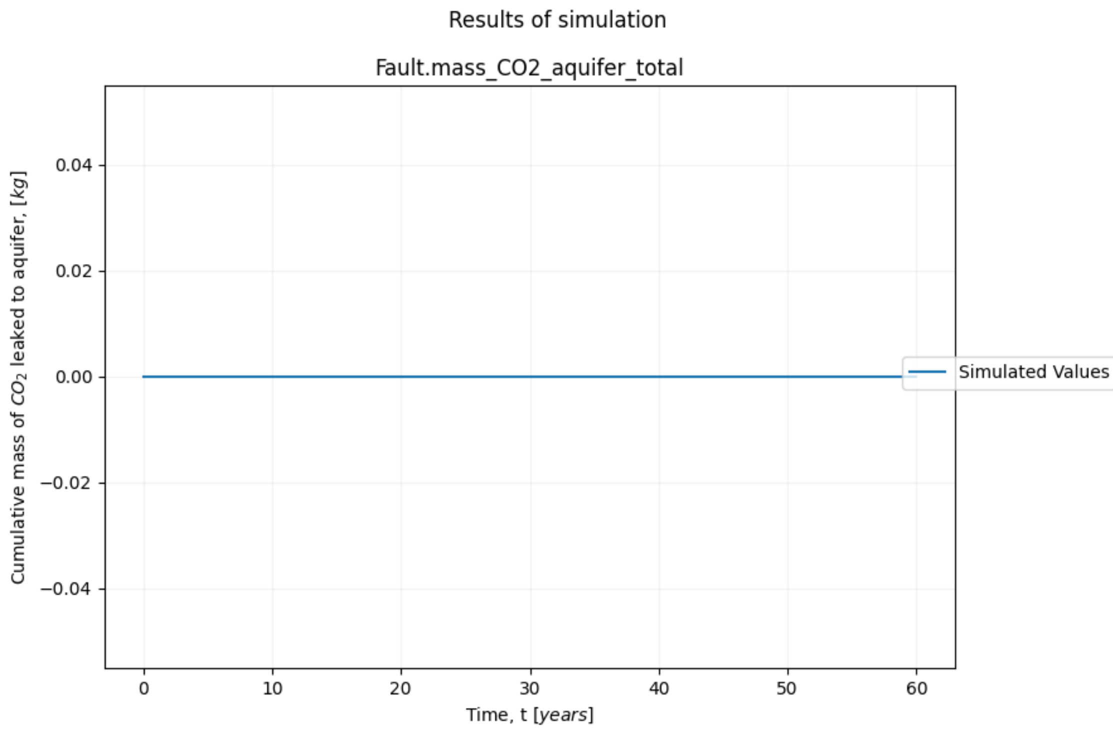


Figure 5.6-1 Faults 7276 ft

Therefore, TND concludes that the risk of CO_2 leakage through the faults are very unlikely and insignificant.

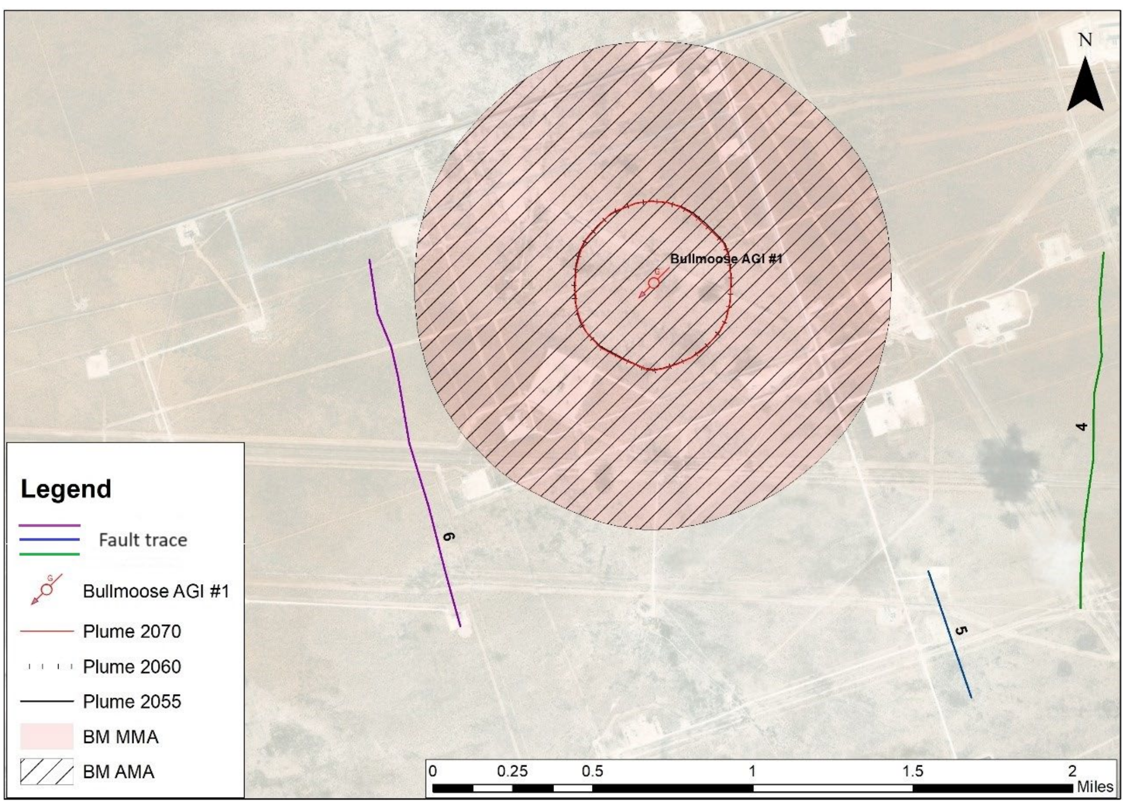


Figure 5.6-1: *Faults surrounding Bull Moose facility relative to the plume and the MMA.*

5.7 Potential Leakage due to Natural / Induced Seismicity

Likelihood:

Due to the distance between the BM AGI #1 well and the location of the seismic events recorded since 2017, the magnitude of these events, and the fact that TND injects at pressures below fracture opening pressure, TND considers the likelihood of CO_2 emissions to the surface caused by seismicity to be very unlikely.

Magnitude and Timing:

The magnitude and timing of a seismic event can vary greatly. In the region, the earthquakes ranged from magnitude 1.5 to 4. They are located in clusters that are around 20 miles North-West and South, South-West of Bull Moose.

Based on historical data and the geology of the surroundings, the risk of CO_2 leakage due to seismicity is considered insignificant.

Monitoring of seismic events in the vicinity of the Bull Moose AGI wells is discussed in Section 6.7.

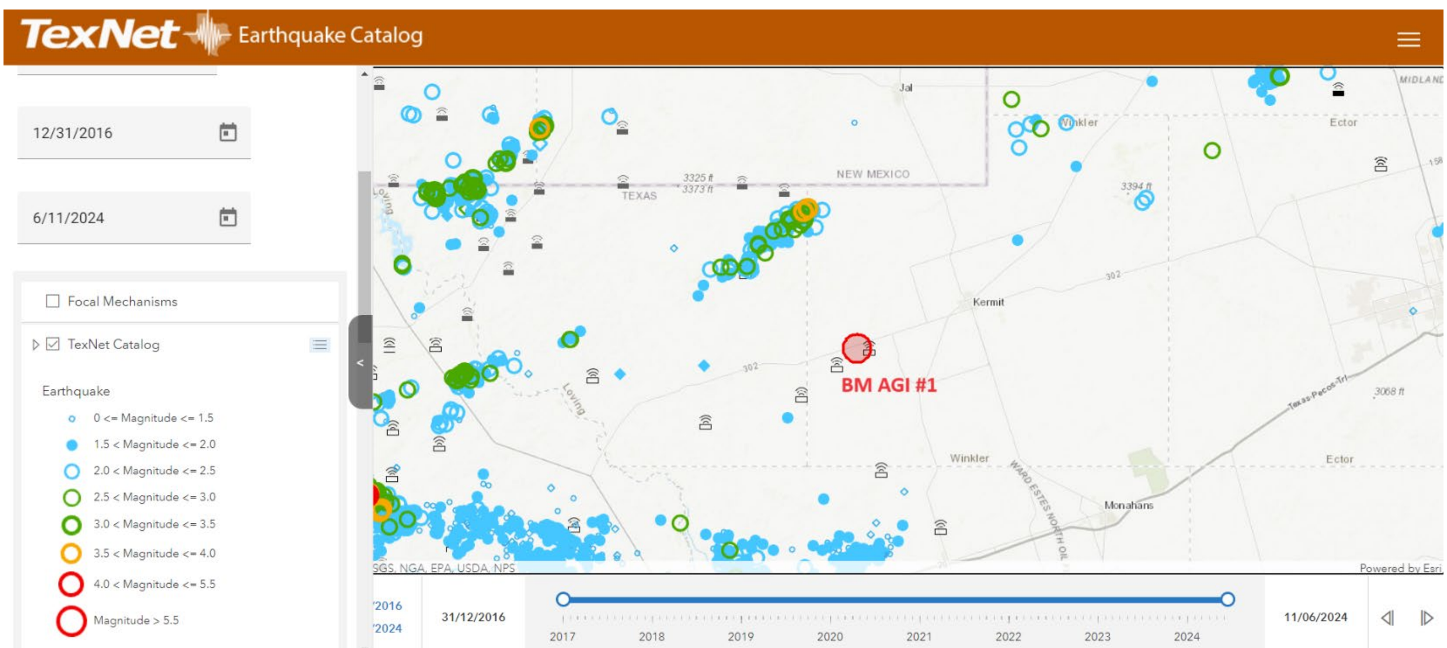


Figure 5.7-1: *TexNet seismic events since 2017 and seismic monitoring stations close to Bull Moose plant.*

6 Strategy for Detecting and Quantifying Surface Leakage of CO_2

Subpart RR at 40 CFR 448(a)(3) requires a strategy for detecting and quantifying surface leakage of CO_2.

TND will employ the following strategy for detecting, verifying, and quantifying CO_2 leakage to the surface through the potential pathways for CO_2 surface leakage identified in Section 5. TND considers H_2S to be a proxy for CO_2 leakage to the surface and as such will employ and expand upon methodologies detailed in their H_2S Contingency plan to detect, verify, and quantify CO_2 surface leakage close to the plant equipment. **Table 6-1** summarizes the leakage monitoring of the identified leakage pathways. Monitoring will occur for the duration of injection and the 15-year post-injection period.

Table 6-1: Summary of Leak Detection Monitoring

Potential Leakage Pathway	Detection Monitoring
Surface Equipment	• Distributed control system (DCS) surveillance of plant operations • Visual inspections • Inline inspections • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors
BM AGI #1 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors/CO_2 flux monitoring network • Personal and hand-held gas monitors • In-well P/T sensors • Groundwater monitoring
Fractures and Faults	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Natural / Induced Seismicity	• DCS surveillance of well operating parameters • Seismic monitoring station
Lateral Migration	• DCS surveillance of well operating parameters • Fixed in-field gas monitors/CO_2 flux monitoring network • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from Surface Equipment

TND implements several tiers of monitoring for surface leakage including frequent periodic visual inspection of surface equipment, use of fixed in-field and personal H_2S sensors, and continual monitoring of operational parameters. Leaks from surface equipment are detected by TND field personnel, wearing personal H_2S monitors, following daily and weekly inspection protocols which include reporting and responding to any detected leakage events.

TND also maintains in-field gas monitors to detect H_2S and CO_2. The in-field gas monitors are connected to the DCS housed in the onsite control room. If one of the gas detectors sets off an alarm, it would trigger an immediate response to address and characterize the situation.

6.2 Leakage from Approved Not Yet Drilled Wells

Special precautions will be taken in the drilling of any new wells that will penetrate the injection zones including more frequent monitoring during drilling operations. This applies to TND and other operators drilling new wells through the BM AGI #1 injection zone within the MMA.

6.3 Leakage from Existing Wells

6.3.1 BM AGI Well

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

To monitor leakage and wellbore integrity, pressure and temperature gauges as well as Distributed Temperature Sensing (DTS) will be deployed in TND's BM AGI #1 well.

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

Well Schematic for BM AGI #1 showing installation of pressure and temperature sensors are in **Appendix 1**.

6.3.2 Other Existing Wells within the MMA

The CO_2 monitoring network described in Section 7.3 and well surveillance by other operators of existing wells will provide an indication of CO_2 leakage. Additionally, groundwater and soil CO_2 flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

6.4 Leakage through the Confining / Seal System

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through the confining zone. Continuous operational monitoring of the BM AGI #1 well, described in Sections 6.3 and 7.5, will provide an indicator if CO_2 leaks out of the injection zone. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details.

If changes in operating parameters or other monitoring listed in **Table 6-1** indicate leakage of CO_2 through the confining / seal system, TND will take actions to quantify the amount of CO_2 released and take mitigative action to stop it, including shutting in the well (see Section 6.8).

6.5 Leakage due to Lateral Migration

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

If monitoring of operational parameters or other monitoring methods listed in Table 6-1 indicates that the CO_2 plume extends beyond the area modeled in Section 3.8 and presented in Section 4, TND will reassess the plume migration modeling for evidence that the plume may have intersected a pathway for CO_2 migration. As this scenario would be considered a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d). See Section 6.8 for additional information on quantification strategies.

6.6 Leakage from Fractures and Faults

As discussed in Section 5, it is very unlikely that CO_2 leakage to the surface will occur through faults.

However, if monitoring of operational parameters and the fixed in-field gas monitors indicate possible CO_2 leakage to the surface, TND will identify which of the pathways listed in this section are responsible for the leak, including the possibility of unidentified faults or fractures within the MMA. TND will take measures to quantify the mass of CO_2 emitted based on the operational conditions that existed at the time of surface emission, including pressure at the point of emission, flowrate at the point of emission, duration of the emission, and estimation of the size of the emission site. Additionally, groundwater and soil flux monitoring locations throughout the MMA will also provide an indication of CO_2 leakage to the surface. See Sections 7.7 and 7.8 for details. See Section 6.8 for additional information on quantification strategies.

6.7 Leakage due to Natural / Induced Seismicity

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

If the monitoring systems indicate surface leakage of CO_2 linked to seismic events, TND will assess whether the CO_2 originated from the BM AGI #1 well and, if so, take measures to quantify the mass of CO_2 emitted to the surface based on operational conditions at the time the leak was detected. See Section 7.6 for details regarding seismic monitoring and analysis. See Section 6.8 for additional information on quantification strategies.

6.8 Strategy for Quantifying CO_2 Leakage and Response

6.8.1 Leakage from Surface Equipment

For normal operations, quantification of emissions of CO_2 from surface equipment will be assessed by employing the methods detailed in Subpart W according to the requirements of 98.444(d) of Subpart RR. Quantification of major leakage events from surface equipment as identified by the detection techniques listed in Table 6-1 will be assessed by employing methods most appropriate for the site of the identified leak. Once a leak has been identified the leakage location will be isolated to prevent additional emissions to the atmosphere. Quantification will be based on the length of time of the leak and parameters that existed at the time of the leak such as pressure, temperature, composition of the gas stream, and size of the leakage point. TND has standard operating procedures to report and quantify all pipeline leaks in accordance with the TRRC regulations. TND will modify this procedure to quantify the mass of carbon dioxide from each leak discovered by TND or third parties. Additionally, TND may employ available leakage models for characterizing and predicting gas leakage from gas pipelines. In addition to the physical conditions listed above, these models are capable of incorporating the thermodynamic parameters relevant to the leak thereby increasing the accuracy of quantification.

6.8.2 Subsurface Leakage

Selection of a quantification strategy for leaks that occur in the subsurface will be based on the leak detection method (Table 6-1) that identifies the leak. Leaks associated with the point sources, such as the injection wells, and identified by failed MITs, variations of operational parameters outside acceptable ranges, and in-well P/T sensors can be addressed immediately after the injection well has been shut in. Quantification of the mass of CO_2 emitted during the leak will depend on characterization of the subsurface leak, operational conditions at the time of the leak, and knowledge of the geology and hydrogeology at the leakage site. Conservative estimates of the mass of CO_2 emitted to the surface will be made assuming that all CO_2 released during the leak will reach the surface. TND may choose to estimate the emissions to the surface more accurately by employing transport, geochemical, or reactive transport model simulations.

Other wells within the MMA will be monitored with the atmospheric and CO_2 flux monitoring network placed strategically in their vicinity.

Nonpoint sources of leaks such as through the confining zone, along faults or fractures, or which may be initiated by seismic events and as may be identified by variations of operational parameters outside acceptable ranges will require further investigation to determine the extent of leakage and may result in cessation of operations.

6.8.3 Surface Leakage

A recent review of risk and uncertainty assessment for geologic carbon storage (Xiao et al., 2024) discussed monitoring for sequestered CO_2 leaking back to the surface emphasizing the importance of monitoring network design in detecting such leaks. Leaks detected by visual inspection, hand-held gas sensors, fixed in-field gas sensors, atmospheric, and CO_2 flux monitoring will be assessed to determine if the leaks originate from surface equipment, in which case leaks will be quantified according to the strategies in Section 6.8.1, or from the subsurface. In the latter case, CO_2 flux monitoring methodologies, as described in Section 7.8, will be employed to quantify the surface leaks.

7 Strategy for Establishing Expected Baselines for Monitoring CO_2 Surface Leakage

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

7.1 Visual Inspection

TND field personnel conduct frequent periodic inspections of all surface equipment providing opportunities to assess baseline concentrations of H_2S, a proxy for CO_2, at the Bull Moose Gas Plant.

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

Compositional analysis of TND's gas injectate at the Bull Moose Gas Plant indicates an approximate H_2S concentration of 30% thus requiring TND to develop and maintain an H_2S Contingency Plan (Plan) according to the TRRC Regulations. TND considers H_2S to be a proxy for CO_2 leaks at the plant. The Plan contains procedures to provide for an organized response to an unplanned release of H_2S from the plant or the associated BM AGI #1 Well and documents procedures that would be followed in case of such an event.

7.2.1 Fixed In-Field H_2S Monitors

The Bull Moose Gas Plant utilizes numerous fixed-point monitors, strategically located throughout the plant, to detect the presence of H_2S in ambient air. The sensors are connected to the Control Room alarm panel's Programmable Logic Controllers (PLCs), and then to the DCS. Upon detection of H_2S at 10 ppm at any detector, visible amber beacons are activated, and horns are activated with a continuous warbling alarm. Upon detection of hydrogen sulfide at 90 ppm at any monitor, an evacuation alarm is sounded throughout the plant at which time all personnel will proceed immediately to a designated evacuation area.

7.2.2 Handheld and Personal H_2S Monitors

Handheld gas detection monitors are available at strategic locations around the plant so that plant personnel can check specific areas and equipment prior to initiating maintenance or other work. The handheld gas detectors have sensors for oxygen, LEL (explosive hydrocarbon atmospheres), H_2S and CO_2.

All personnel, including contractors who perform operations, maintenance and/or repair work in sour gas areas within the plant must wear personal H_2S monitoring devices to assist them in detecting the presence of unsafe levels of H_2S. Personal monitoring devices will give an audible alarm and vibrate at 10 ppm.

7.3 CO_2 Detection

In addition to the handheld gas detection monitors described above, TND will set up a monitoring network for CO_2 leakage detection in the MMA as defined in Section 4.2. In addition, there will be periodic groundwater and soil flux sampling within the MMA. Once the network is set up, TND will assume responsibility for monitoring, recording, and reporting data collected from the system for the duration of the project.

7.4 Continuous Parameter Monitoring

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

7.5 Well Surveillance

TND adheres to the requirements of TRRC Rules governing the construction, operation and closing of an injection well under the Oil and Gas Act. It includes requirements for testing and monitoring of Class II injection wells to ensure they maintain mechanical integrity at all times. Furthermore, TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well, if they are deemed necessary. TND's Routine Operations and Maintenance Procedures for the BM AGI #1 well ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.

7.6 Seismic (Microseismic) Monitoring Stations

TND has Installed a seismometer and a digital recorder to monitor for and record data for any seismic event at the Bull Moose Gas Plant. The seismic station meets the requirements of the TRRC.

In addition, data that is recorded by the TexNet network surrounding the Bull Moose Gas Plant will be analyzed by TND. A report will be periodically generated with a map showing the magnitudes of recorded events from seismic activity. By examining historical data, a seismic baseline prior to the start of TAG injection can be well established and used to verify anomalous events that occur during current and future injection activities. If necessary, a certain period of time can be extracted from the overall data set to identify anomalous events during that period.

7.7 Groundwater Monitoring

TND will monitor groundwater wells for CO_2 leakage as defined in Section 4.2. Water samples will be collected and analyzed on a monthly basis for 12 months to establish baseline data. After establishing the water chemistry baseline, samples will be collected and analyzed bi-monthly for one year and then quarterly. Samples will be collected according to EPA methods for groundwater sampling (U.S. EPA, 2015).

The water analysis includes total dissolved solids (TDS), conductivity, pH, alkalinity, major cations, major anions, oxidation-reduction potentials (ORP), inorganic carbon (IC), and non-purgeable organic carbon (NPOC). Charge balance of ions will be completed as quality control of the collected groundwater samples. See **Table 7.7-1**. Baseline analyses will be compiled and compared with regional historical data to determine patterns of change in groundwater chemistry not related to injection processes at the Bull Moose Gas Plant. A report of groundwater chemistry will be developed from this analysis. Any water quality samples not within the expected variation will be further investigated to determine if leakage has occurred from the injection zone.

***Table 7.7-1**: Groundwater Monitoring Parameters*

Parameters
pH
Alkalinity as HCO3- (mg/L)
Chloride (mg/L)
Fluoride (F-) (mg/L)
Bromide (mg/L)
Nitrate (NO3-) (mg/L)
Phosphate (mg/L)
Sulfate (SO42-) (mg/L)
Lithium (Li) (mg/L)
Sodium (Na) (mg/L)
Potassium (K) (mg/L)
Magnesium (Mg) (mg/L)
Calcium (Ca) (mg/L)
TDS Calculation (mg/L)
Total cations (meq/L)
Total anions (meq/L)
Percent difference (%)
ORP (mV)
IC (ppm)
NPOC (ppm)

7.8 Soil CO_2 Flux Monitoring

A vital part of the monitoring program is to identify potential leakage of CO_2 and/or brine from the injection horizon into the overlying formations and to the surface. One method that will be deployed is to gather and analyze soil CO_2 flux data which serves as a means for assessing potential migration of CO_2 through the soil and its escape to the atmosphere. By taking CO_2 soil flux measurements at periodic intervals, TND can continuously characterize the interaction between the subsurface and surface to understand potential leakage pathways. Actionable recommendations can be made based on the collected data.

Soil CO_2 flux will be collected on a monthly basis for 12 months to establish the baseline and understand seasonal and other variation at the Bull Moose Gas Plant. After the baseline is established, data will be collected bi-monthly for one year and then quarterly.

Soil CO_2 flux measurements will be taken using a LI-COR LI-8100A flux chamber, or similar instrument, at pre planned locations at the site. PVC soil collars (8cm diameter) will be installed in accordance with the LI-8100A specifications. Measurements will be subsequently made by placing the LI-8100A chamber on the soil collars and using the integrated iOS app to input relevant parameters, initialize measurement, and record the system's flux and coefficient of variation (CV) output. The soil collars will be left in place such that each subsequent measurement campaign will use the same locations and collars during data collection.

8 Site Specific Considerations for Determining the Mass of CO_2 Sequestered

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

8.1 CO_2 Received

Currently, TND receives gas to its Bull Moose Gas Plant through pipelines. The gas is processed as described in Section 3.8 to produce compressed TAG which is then routed to the wellhead and pumped to injection pressure through NACE-rated (National Association of Corrosion Engineers) pipeline suitable for injection. TND will use Equation RR-2 for Pipelines to calculate the mass of CO_2 received through pipelines and measured through volumetric flow meters. The total annual mass of CO_2 received through these pipelines will be calculated using Equation RR-3. Receiving flow meter r in the following equations corresponds to meters M1 and M2 in **Figure 3.6-2**.

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving volumetric flow meter.

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

Although TND does not currently receive CO_2 in containers for injection, they wish to include the flexibility in this MRV plan to receive gas from containers. When TND begins to receive CO_2 in containers, TND will use Equations RR-1 and RR-2 for Containers to calculate the mass of CO_2

received in containers. TND will adhere to the requirements in 40CFR98.444(a)(2) for determining the quarterly mass or volume of CO_2 received in containers.

If CO_2 received in containers results in a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change.

8.2 CO_2 Injected

Upon completion, TND will commence injection into BM AGI #1. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meters before being injected into the wells. Equation RR-6 will be used to calculate the total annual mass of CO_2 injected into both wells. The calculated total annual CO_2 mass injected is the parameter CO_{2I} in Equation RR-12. Volumetric flow meter u in the following equations corresponds to meters M5 and M6 in **Figure 3.6-2**.

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Volumetric flow meter.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

* Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

8.3 CO_2 Produced / Recycled

TND does not produce oil or gas or any other liquid at its Bull Moose Gas Plant so there is no CO_2 produced or recycled.

8.4 CO_2 Lost through Surface Leakage

Equation RR-10 will be used to calculate the annual mass of CO_2 lost due to surface leakage from the leakage pathways identified and evaluated in Section 5 above. The calculated total annual CO_2 mass emitted by surface leakage is the parameter CO_{2E} in Equation RR-12 addressed in Section 8.6 below. Quantification strategies for leaks from the identified potential leakage pathways is discussed in Section 6.8.

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

where:

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

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

x = Leakage pathway.

8.5 CO_2 Emitted from Equipment Leaks and Vented Emissions

As required by 98.444(d) of Subpart RR, TND will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases. Parameter CO_{2FI} in Equation RR-12 is the total annual CO_2 mass emitted or vented from equipment located between the flow meter for measuring injection quantity and the injection wellhead. A calculation procedure is provided in subpart W.

8.6 CO_2 Sequestered

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

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

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

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

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

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

9 Estimated Schedule for Implementation of MRV Plan

The baseline monitoring and leakage detection and quantification strategies described herein have been established by TND for several years and continues to the present. TND will begin implementing this MRV plan as soon as it is approved by EPA. After BM AGI #1 is drilled, TND will reevaluate the MRV plan and if any modifications are a material change per 40CFR98.448(d)(1), TND will submit a revised MRV plan as required by 40CFR98.448(d).

10 GHG Monitoring and Quality Assurance Program

TND will meet the monitoring and QA/QC requirements of 40CFR98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 40CFR98.444(d).

10.1 GHG Monitoring

As required by 40CFR98.3(g)(5)(i), TND's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.1.1 General

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GPA) standards. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40CFR98.444(a)(3).

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

10.1.2 CO_2 received.

Daily CO_2 received is recorded by totalizers on the volumetric flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.3 CO_2 injected.

Daily CO_2 injected is recorded by totalizers on the volumetric flow meters on the pipelines to the BM AGI #1 well using accepted flow calculations for CO_2 according to the AGA Report #1.

10.1.4 CO_2 produced.

TND does not produce CO_2 at the Bull Moose Gas Plant.

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

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

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

10.1.6 Measurement devices.

As required by 40CFR98.444(e), TND will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40CFR98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association

(AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.2 QA/QC Procedures

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

10.3 Estimating Missing Data

TND will estimate any missing data according to the following procedures in 40CFR98.445 of Subpart RR of the GHGRP, as required.

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

10.4 Revisions of the MRV Plan

TND will revise the MRV plan as needed to reflect changes in monitoring instrumentation and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime; or to address additional requirements as directed by the USEPA or the State of Texas. If any operational changes constitute a material change as described in 40CFR98.448(d)(1), TND will submit a revised MRV plan addressing the material change. TND intends to update the MRV plan after BM AGI #1 has been drilled and characterized.

11 Records Retention

TND will meet the recordkeeping requirements of paragraph 40CFR98.3(g) of Subpart A of the GHGRP. As required by 40CFR98.3(g) and 40CFR98.447, TND will retain the following documents:

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

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

(i) The GHG emissions calculations and methods used

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

(iii) The results of all required analyses

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

(3) The annual GHG reports.

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

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

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

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

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

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

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

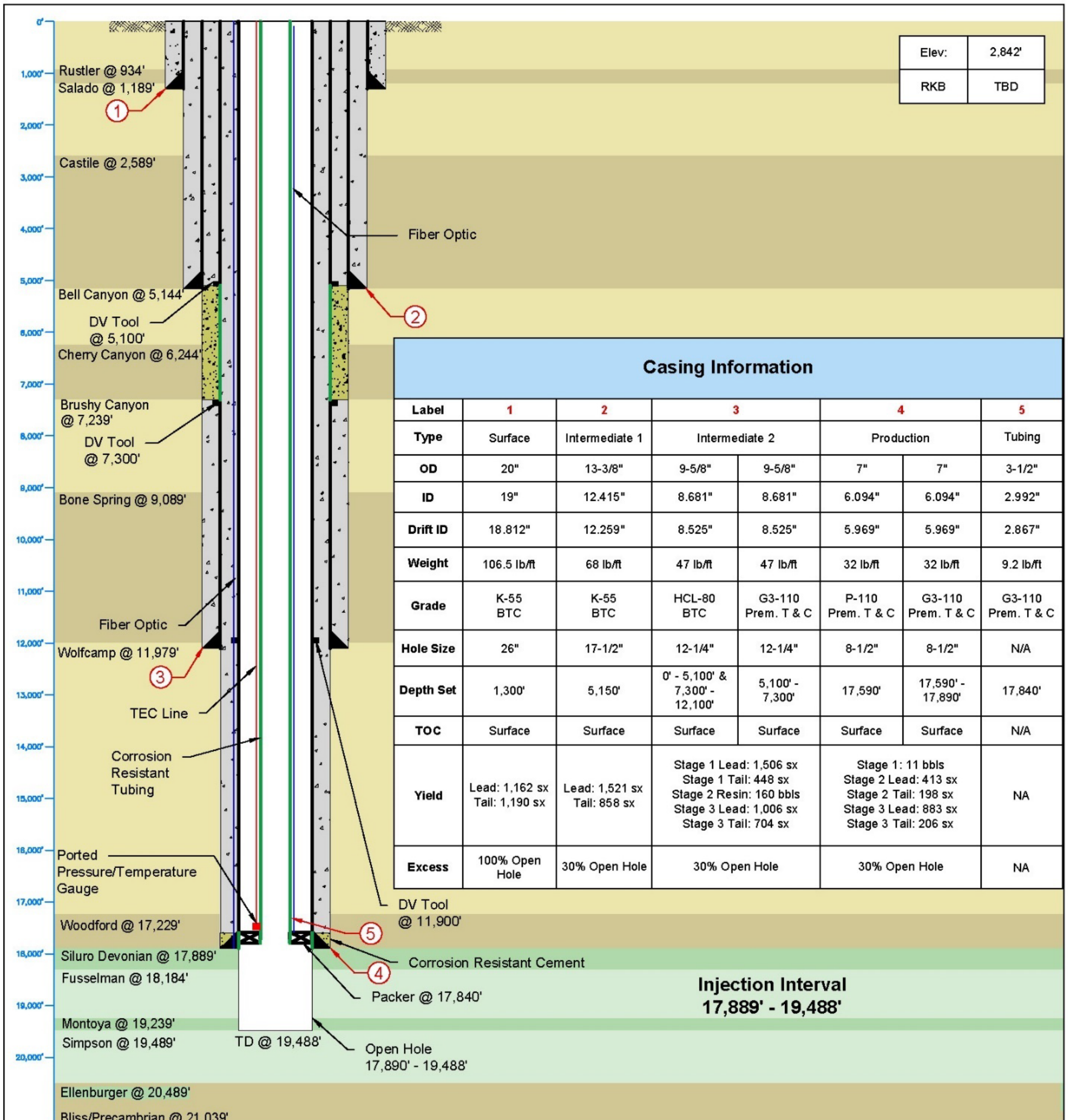
(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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

12 Appendices

Appendix 1 TND Wells

Well Name	API #	Location	County	Spud Date	Total Depth	Packer
Bull Moose AGI #1	42-495-34978	1,895' FSL & 2,161' FEL, SEC 42, BLK 27, Public School Land Survey, A-433	KERMIT, TX	To be determined	19,488 ft	17,790 ft



Casing Information

Label	1	2	3		4		5
Type	Surface	Intermediate 1	Intermediate 2		Production		Tubing
OD	20"	13-3/8"	9-5/8"	9-5/8"	7"	7"	3-1/2"
ID	19"	12.415"	8.681"	8.681"	6.094"	6.094"	2.992"
Drift ID	18.812"	12.259"	8.525"	8.525"	5.969"	5.969"	2.867"
Weight	106.5 lb/ft	68 lb/ft	47 lb/ft	47 lb/ft	32 lb/ft	32 lb/ft	9.2 lb/ft
Grade	K-55 BTC	K-55 BTC	HCL-80 BTC	G3-110 Prem. T & C	P-110 Prem. T & C	G3-110 Prem. T & C	G3-110 Prem. T & C
Hole Size	26"	17-1/2"	12-1/4"	12-1/4"	8-1/2"	8-1/2"	N/A
Depth Set	1,300'	5,150'	0' - 5,100' & 7,300' - 12,100'	5,100' - 7,300'	17,590'	17,590' - 17,890'	17,840'
TOC	Surface	Surface	Surface	Surface	Surface	Surface	N/A
Yield	Lead: 1,162 sx Tail: 1,190 sx	Lead: 1,521 sx Tail: 858 sx	Stage 1 Lead: 1,506 sx Stage 1 Tail: 448 sx Stage 2 Resin: 160 bbls Stage 3 Lead: 1,006 sx Stage 3 Tail: 704 sx		Stage 1: 11 bbls Stage 2 Lead: 413 sx Stage 2 Tail: 198 sx Stage 3 Lead: 883 sx Stage 3 Tail: 206 sx		NA
Excess	100% Open Hole	30% Open Hole	30% Open Hole		30% Open Hole		NA

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Targa Delaware LLC

Bull Moose AGI No. 01

	Country: USA	**State/Province:** Texas	**County/Parish:** Winkler
	Location: Sec. 42, A-433, Blk 27		**District:** 08
	API No: TBD	**Field:**	**Well Type/Status:** AGI Disposal
Texas License F-9147	**Survey:**	**Project No:** F2345	**Date:** 5/6/2024
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** CJL	**Reviewed:** WHG	**Approved:**
	Rev No: 1	**Notes:** Intermediate 2 Revisions Requested by Targa	

Figure Appendix 1-1: *Schematic of TND BM AGI #1 Well*

Appendix 2 Referenced Regulations

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

Texas Administrative Code > Title 16, Economic Regulation, > Part 1 Railroad Commissions of Texas > Chapter 3, Oil and Gas Division

CHAPTER 15 - OIL AND GAS

§3.1	Organization Report; Retention of Records; Notice Requirements
§3.2	Commission Access to Properties
§3.3	Identification of Properties, Wells, and Tanks
§3.4	Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms
§3.5	Application To Drill, Deepen, Reenter, or Plug Back
§3.6	Application for Multiple Completion
§3.7	Strata To Be Sealed Off
§3.8	Water Protection
§3.9	Disposal Wells
§3.10	Restriction of Production of Oil and Gas from Different Strata
§3.11	Inclination and Directional Surveys Required
§3.12	Directional Survey Company Report
§3.13	Casing, Cementing, Drilling, Well Control, and Completion Requirements
§3.14	Plugging
§3.15	Surface Equipment Removal Requirements and Inactive Wells
§3.16	Log and Completion or Plugging Report
§3.17	Pressure on Bradenhead
§3.18	Mud Circulation Required
§3.19	Density of Mud-Fluid
§3.20	Notification of Fire Breaks, Leaks, or Blow-outs
§3.21	Fire Prevention and Swabbing
§3.22	Protection of Birds
§3.23	Vacuum Pumps
§3.24	Check Valves Required
§3.25	Use of Common Storage

§3.26	Separating Devices, Tanks, and Surface Commingling of Oil
§3.27	Gas to be Measured and Surface Commingling of Gas
§3.28	Potential and Deliverability of Gas Wells to be Ascertained and Reported
§3.29	Hydraulic Fracturing Chemical Disclosure Requirements
§3.30	Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)
§3.31	Gas Reservoirs and Gas Well Allowable
§3.32	Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes
§3.33	Geothermal Resource Production Test Forms Required
§3.34	Gas To Be Produced and Purchased Ratably
§3.35	Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned
§3.36	Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas
§3.37	Statewide Spacing Rule
§3.38	Well Densities
§3.39	Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40	Assignment of Acreage to Pooled Development and Proration Units
§3.41	Application for New Oil or Gas Field Designation and/or Allowable
§3.42	Oil Discovery Allowable
§3.43	Application for Temporary Field Rules
§3.45	Oil Allowables
§3.46	Fluid Injection into Productive Reservoirs
§3.47	Allowable Transfers for Saltwater Injection Wells
§3.48	Capacity Oil Allowables for Secondary or Tertiary Recovery Projects

§3.49	Gas-Oil Ratio
§3.50	Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51	Oil Potential Test Forms Required
§3.52	Oil Well Allowable Production
§3.53	Annual Well Tests and Well Status Reports Required
§3.54	Gas Reports Required
§3.55	Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56	Scrubber Oil and Skim Hydrocarbons
§3.57	Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58	Certificate of Compliance and Transportation Authority; Operator Reports
§3.59	Oil and Gas Transporter's Reports
§3.60	Refinery Reports
§3.61	Refinery and Gasoline Plants
§3.62	Cycling Plant Control and Reports
§3.63	Carbon Black Plant Permits Required
§3.65	Critical Designation of Natural Gas Infrastructure
§3.66	Weather Emergency Preparedness Standards
§3.70	Pipeline Permits Required
§3.71	Pipeline Tariffs
§3.72	Obtaining Pipeline Connections
§3.73	Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76	Commission Approval of Plats for Mineral Development
§3.78	Fees and Financial Security Requirements
§3.79	Definitions
§3.80	Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81	Brine Mining Injection Wells
§3.83	Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84	Gas Shortage Emergency Response

§3.85	Manifest To Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86	Horizontal Drainhole Wells
§3.91	Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93	Water Quality Certification Definitions
§3.95	Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96	Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97	Underground Storage of Gas in Salt Formations
§3.98	Standards for Management of Hazardous Oil and Gas Waste
§3.99	Cathodic Protection Wells
§3.100	Seismic Holes and Core Holes
§3.101	Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102	Tax Reduction for Incremental Production
§3.103	Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106	Sour Gas Pipeline Facility Construction Permit
§3.107	Penalty Guidelines for Oil and Gas Violations

Appendix 3 Oil and Gas Wells within MMA of the BM AGI Well Site

API	Well Name	Operator	Well Type	Well Status	Trajectory	Formation	TVD (ft)
42-495-34323	SILVER DOLLAR 4231-27 A 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12106
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11814
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11811
42-495-33230	MITCHELL 28-37 1H	DEVON	OIL	P & A	HORIZONTAL	BONE SPRING	11816
42-495-34481	BRIDAL VEIL STATE W 4132-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12145
42-495-33759	VALLECITO 37-28 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11718
42-495-34328	SILVER DOLLAR 4231-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12263
42-495-34331	SILVER DOLLAR 4231-27 E 5H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11564
42-495-34485	BRIDAL VEIL STATE W 4132-27 L 12H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12129
42-495-33871	MITCHELL 42-27 1	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7630
42-495-34488	BRIDAL VEIL STATE W 4132-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11627
42-495-34482	BRIDAL VEIL STATE W 4132-27 H 8H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12176
42-495-33840	SAINT VRAIN 48-28 1H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12185
42-495-33763	AVALANCHE 42-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12194
42-495-33726	SILVER DOLLAR 31-27 2H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12188
42-495-34484	BRIDAL VEIL STATE W 4132-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12217
42-495-34038	MITCHELL 42-27 2	PILOT WATER SOLUTIONS	SWD	INJECTING	VERTICAL	BRUSHY CANYON	7516
42-495-34489	BRIDAL VEIL STATE W 4132-27 K 11H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11637
42-495-34332	SILVER DOLLAR 4231-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11897
42-495-34329	SILVER DOLLAR 4231-27 J 10H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12193
42-495-34327	SILVER DOLLAR 4231-27 G 7H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12545
42-495-34325	SILVER DOLLAR 4231-27 D 4H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11858
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16000
42-495-32972	MITCHELL 42 1	DEVON	GAS	P & A	VERTICAL	MORROW	16000
42-495-34326	SILVER DOLLAR 4231-27 F 6H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12208

42-495-34324	SILVER DOLLAR 4231-27 B 2H	DEVON	OIL	PRODUCING	HORIZONTAL	BONE SPRING	11621
42-495-34330	SILVER DOLLAR 4231-27 C 3H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	12537
42-495-34483	BRIDAL VEIL STATE W 4132-27 I 9H	DEVON	OIL	PRODUCING	HORIZONTAL	WOLFCAMP	11972
42-495-33236	HARRISON STATE 41 1H	DEVON	OIL	INACTIVE PRODUCER	HORIZONTAL	BONE SPRING	11868

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Appendix 5 Abbreviations and Acronyms

3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
API – American Petroleum Institute
CFR – Code of Federal Regulations
C1 – methane
C6 – hexane
C7 - heptane
CO_2 – carbon dioxide
DCS – distributed control system
EPA – US Environmental Protection Agency, also USEPA
ft – foot (feet)
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
m – meter(s)
md – millidarcy(ies)
mg/l – milligrams per liter
MIT – mechanical integrity test
MMA – maximum monitoring area
MSCFD– thousand standard cubic feet per day
MMSCFD – million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
MT -- Metric tonne
NIST - National Institute of Standards and Technology
PPM – Parts Per Million
QA/QC – quality assurance/quality control
TAG – Treated Acid Gas
TDS – Total Dissolved Solids
TVD – True Vertical Depth
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

Appendix 6 TND Bull Moose AGI Wells - Subpart RR Equations for Calculating CO_2 Geologic Sequestration

	Subpart RR Equation	Description of Calculations and Measurements*	Pipeline	Containers	Comments
CO_2 Received	RR-1	calculation of CO_2 received and measurement of CO_2 mass…	through mass flow meter.	in containers. **	
	RR-2	calculation of CO_2 received and measurement of CO_2 volume…	through volumetric flow meter.	in containers. ***	
	RR-3	summation of CO_2 mass received …	through multiple meters.		
CO_2 Injected	RR-4	calculation of CO_2 mass injected, measured through mass flow meters.			
	RR-5	calculation of CO_2 mass injected, measured through volumetric flow meters.			
	RR-6	summation of CO_2 mass injected, as calculated in Equations RR-4 and/or RR-5.			
CO_2 Produced / Recycled	RR-7	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through mass flow meters.			
	RR-8	calculation of CO_2 mass produced / recycled from gas-liquid separator, measured through volumetric flow meters.			
	RR-9	summation of CO_2 mass produced / recycled from multiple gas-liquid separators, as calculated in Equations RR-7 and/or RR8.			
CO_2 Lost to Leakage to the Surface	RR-10	calculation of annual CO_2 mass emitted by surface leakage			
CO_2 Sequestered	RR-11	calculation of annual CO_2 mass sequestered for operators ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, produced, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head, and emitted from surface equipment between production well head and production flow meter.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.
	RR-12	calculation of annual CO_2 mass sequestered for operators NOT ACTIVELY producing oil or gas or any other fluid; includes terms for CO_2 mass injected, emitted by surface leakage, emitted from surface equipment between injection flow meter and injection well head.			Calculation procedures are provided in Subpart W of GHGRP for CO_{2FI}.

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

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

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

Appendix 7 Subpart RR Equations for Calculating Annual Mass of CO_2 Sequestered

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

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

(Equation RR-1 for Pipelines)

where:

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

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

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

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

p = Quarter of the year.

r = Receiving mass flow meter.

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

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

(Equation RR-1 for Containers)

where:

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

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

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

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

p = Quarter of the year.

r = Containers.

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

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

(Equation RR-2 for Pipelines)

where:

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

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

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

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

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

p = Quarter of the year.

r = Receiving volumetric flow meter.

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

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

(Equation RR-2 for Containers)

where:

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

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

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

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

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

p = Quarter of the year.

r = Container.

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

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

(Equation RR-3 for Pipelines)

where:

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

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

r = Receiving flow meter.

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

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

(Equation RR-4)

where:

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

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

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

p = Quarter of the year.

u = Mass flow meter.

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

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

(Equation RR-5)

where:

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

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

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

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

p = Quarter of the year.

u = Volumetric flow meter.

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

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

(Equation RR-6)

where:

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

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

u = Flow meter.

*Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

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

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

(Equation RR-7)

where:

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

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

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

p = Quarter of the year.

w = Gas / Liquid Separator.

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

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

(Equation RR-8)

where:

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

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

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

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

p = Quarter of the year.

w = Gas / Liquid Separator.

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

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

(Equation RR-9)

where:

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

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

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year as calculated in Equation RR-7 or RR-8 .

w = Flow meter.

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

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

(Equation RR-10)

where:

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

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

x = Leakage pathway.

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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