MONITORING, REPORTING, AND VERIFICATION PLAN

Copperhead AGI #001

Targa Midstream Services, LLC (Targa)

Version 2.0

April 2025

Table of Contents

1 Introduction

Targa Midstream Services, LLC (Targa) proposes an underground injection project for its Copperhead Gas Processing facility, hereafter referred to as the Plant. The proposed Copperhead Acid Gas Injection (AGI) #001 well, will be located in Section 13, Township 24 South, Range 32 East, Lea County, New Mexico. The well is within the Delaware Basin region of the Permian Basin. (**Figure 1-1**).

Targa submitted an Underground Injection Control (UIC) Class II AGI permit application for the Copperhead AGI #001 well to the New Mexico Oil Conservation Division (NMOCD). Targa submitted additional supporting documentation as part of the application to meet the requirements and current best engineering practices to ensure that the underground source of drinking water (USDW) and the atmosphere are protected from any contamination from injection. The application was approved in August 2024. subject to the requirements of 19.15.26 NMAC.

Targa intends to drill Copperhead AGI #001 in 2025 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% carbon dioxide (CO_2) and 30% hydrogen sulfide (H_2S), with trace components of hydrocarbons methane through heptane (C1 – C7) and nitrogen. The project, with a design life of 30 years, plans to inject TAG through the Copperhead AGI #001 well into the deep subsurface in the Siluro-Devonian (Thirtyone & Wristen), and Fusselman formations.

The Copperhead AGI #001 well will allow 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.

The surface location of the well is within the Plant's boundary. Targa has received authorization to use the Copperhead AGI #001 well to inject TAG at a maximum daily injection rate of 26 million standard cubic feet per day (MMSCFD) of TAG into formations at a depth of approximately 17,299 feet to 18,689 feet, for a total injection interval of 1,400 feet. The overlaying confining zones are the Woodford and the Barnett formations. Their total thickness is 770 feet. The well's maximum surface injection pressure will be approximately 3,460 pounds per square inch gauge (psig).

The Copperhead AGI #001 well will be constructed with four strings of casing cemented to surface and corrosion resistant alloys will be used in the bottom 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 bottom hole injection pressure does not exceed 90% of the determined fracture gradient of the injection interval.

Targa submits this Monitoring, Reporting, and Verification (MRV) plan for the Copperhead AGI #001 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). Targa intends to inject TAG into the Copperhead AGI #001 well for 30 years. Assuming a consistent maximum allowable injection rate of 26MMSCFD for 365 days per year for 30 years of injection, the total volume of TAG injected is estimated to be 287,700 million standard cubic feet. Following the operational period, Targa proposes a post-injection monitoring and site closure period of 15 years. Targa will submit a request to EPA to discontinue reporting according to the requirements of 40 CFR 98.441(b).

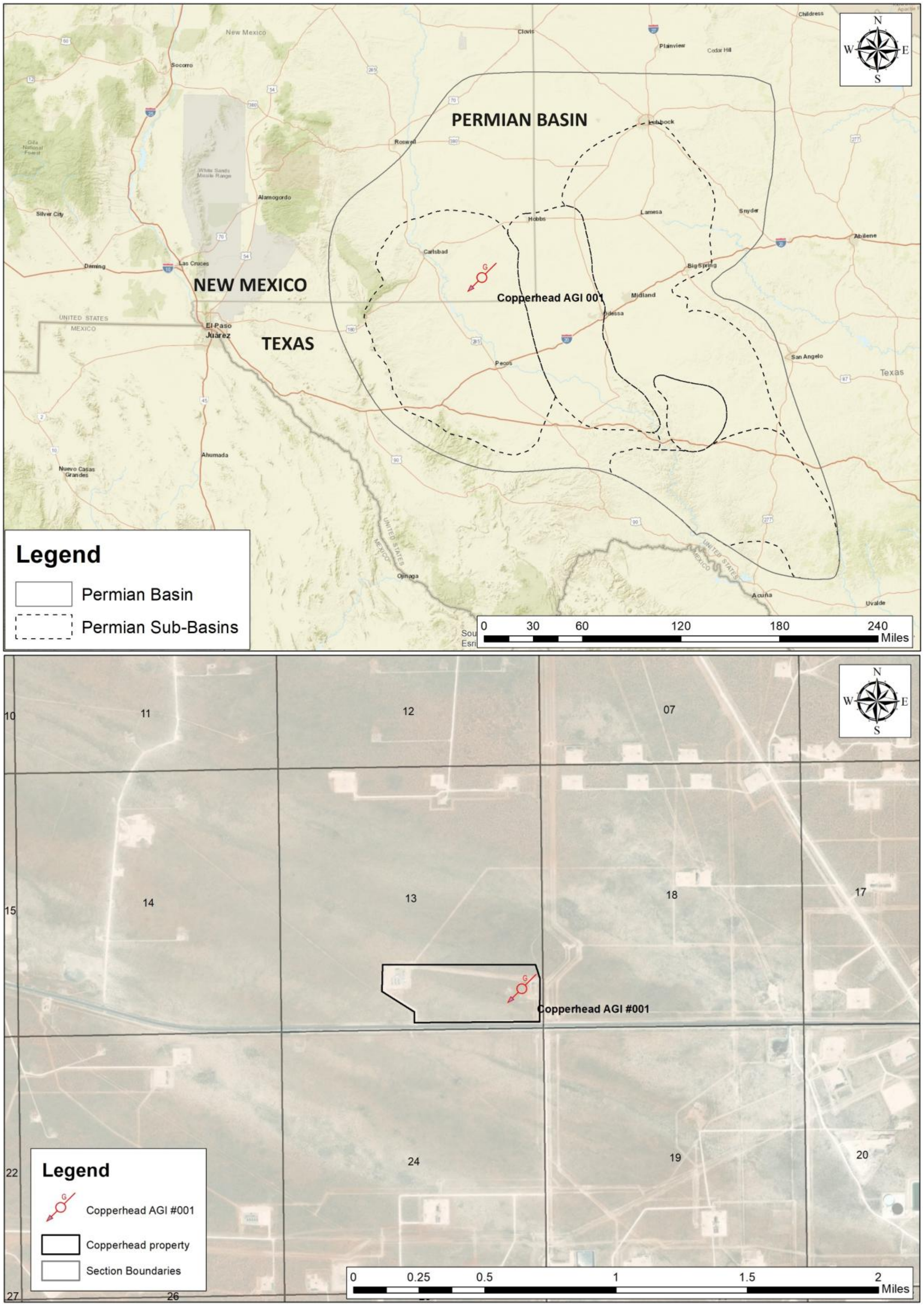


***Figure 1-1**: Location of the Copperhead Facility in the Permian Basin, Texas.*

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

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

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

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

1 API Number	2 Pool Code	3 Pool Name
	97885	AGI; DEVONIAN

4 Property Code	5 Property Name	6 Well Number
	COPPERHEAD AGI	1

7 OGRID No.	8 Operator Name	9 Elevation
24650	TARGA MIDSTREAM SERVICES LLC	3579'

10 Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
P	13	24-S	32-E		793	SOUTH	429'	EAST	LEA

11 Bottom Hole Location If Different From Surface

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

12 Dedicated Acres	13 Joint or Infill	14 Consolidation Code	15 Order No.
40.03			

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

16

D	C	B	A
E	F	G	H
L	K	J	I
M	N	O	P

GEODETIC COORDINATES
NAD 83 NME
X=761583.3
Y=441810.7
LAT. 32°12'45.39"N
LONG. 103°37'16.30"W

429'

793'

17 **OPERATOR CERTIFICATION**

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

Matt Eales — May 4, 2024
Signature — Date

Matt Eales
Printed Name

meales@targaresources.com
E-mail Address

18 SURVEYOR CERTIFICATION

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

FEBRUARY 9, 2024
Date of Survey

Signature and Seal of Professional Surveyor

CLINTON POWERS LOVELL NEW MEXICO 29050 PROFESSIONAL SURVEYOR

Certificate Number CLINTON POWERS LOVELL 29050

Figure 1-2*: Location of the Copperhead Gas Plant and Copperhead AGI #001 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 24650.

2.2 UIC injection well identification numbers

This MRV plan is for the Copperhead AGI #001 well (**Appendix 1**). The details of the injection process are provided in Section 3.7.

2.3 UIC permit class

The New Mexico Oil Conservation Division (NMOCD) has issued a UIC Class II permit under its State Rule 19.15.26 NMAC (see Appendix 2). All oil- and gas-related wells around the Copperhead AGI #001 well are regulated by the NMOCD, 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 Targa.

3.1 General geologic setting / surficial geology

The plant and the well locations are 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 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 Copperhead Gas Plant and the Copperhead AGI #001 well are located at the northern margin of the Delaware Basin, a sub-basin of the larger, encompassing Permian Basin (**Figure 3.2-1**), which covers a large area of southeastern New Mexico and west Texas.

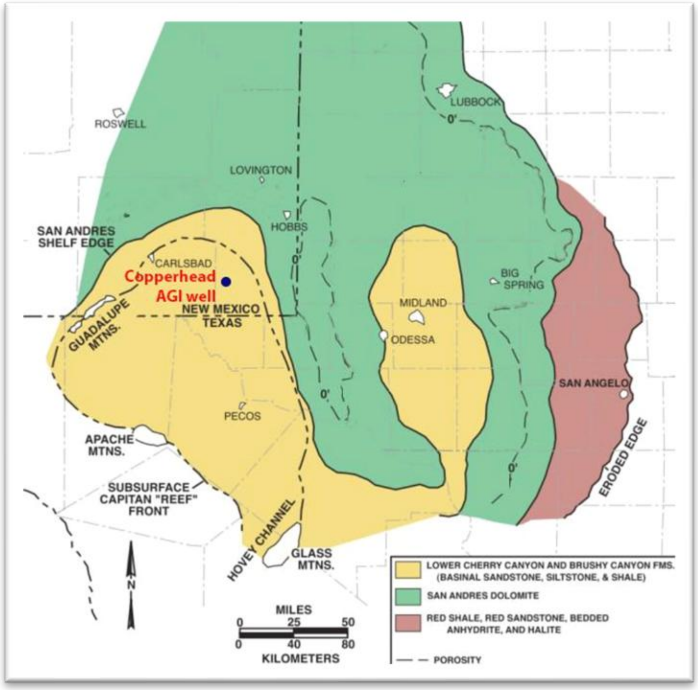


***Figure 3.2-1**: Structural features of the Permian Basin during the Late Permian. Location of the Targa Copperhead AGI #001 well is shown by the black circle. (Modified from Ward, et al (1986)).*

Figure 3.2-2 is a generalized stratigraphic column showing the formations that underlie the Copperhead Gas Plant and Copperhead AGI #001 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. Note that throughout this narrative, the numbers in parentheses after formation names indicate the range in thickness for that unit.

The Copperhead AGI #001 well is in the Delaware Basin portion of the broader Permian Basin. 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 (0 – 1000 feet) 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.

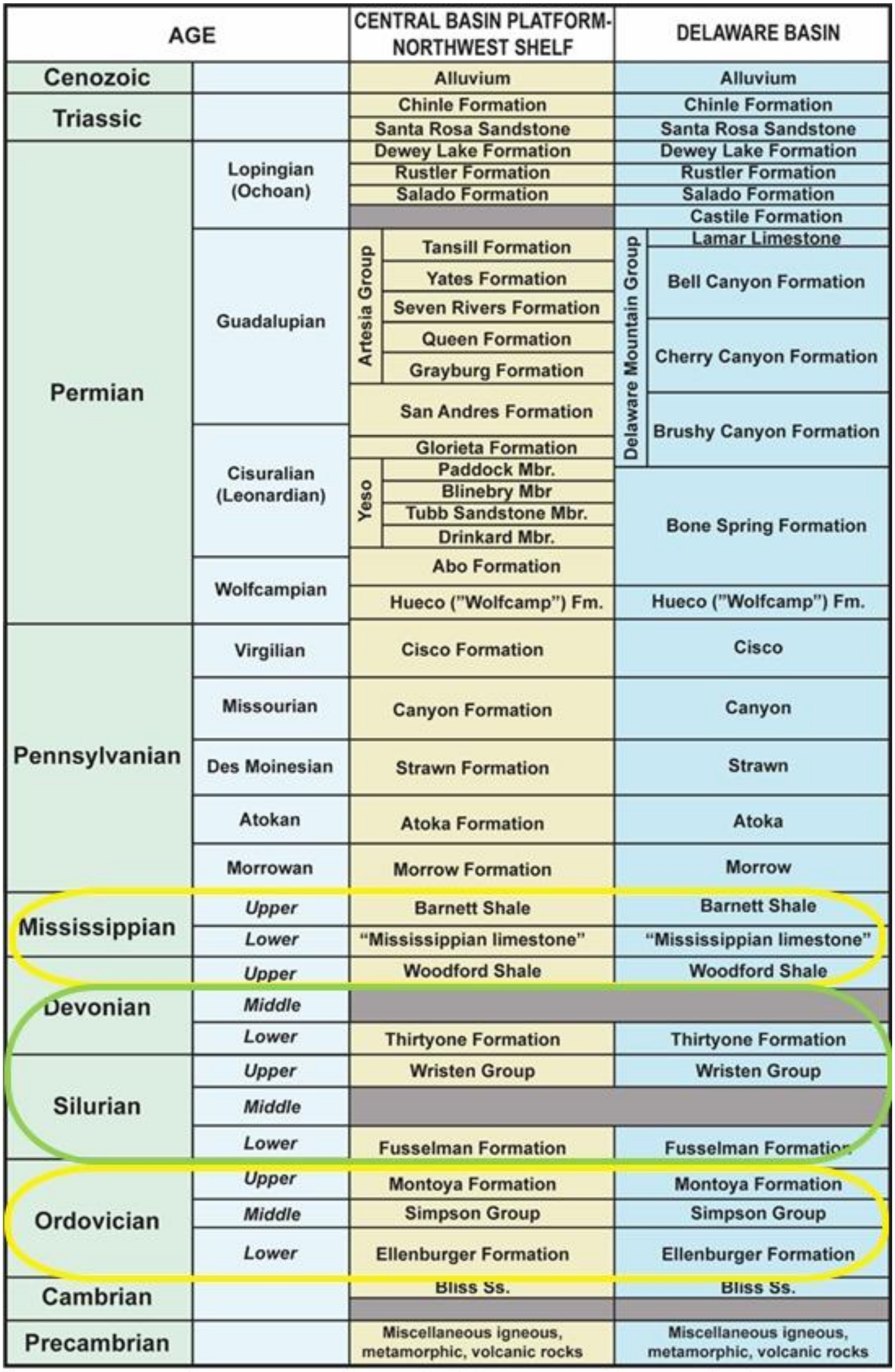


Figure 3.2-2: *Stratigraphic column for the Delaware basin, the Northwest Shelf and Central Basin Platform (modified from Broadhead, 2017). The injection zone for the Copperhead AGI #001 well is circled in green; the confining zones are circled in yellow.*

During Middle to Upper Ordovician time, the seas once again covered the area and deposited first the carbonates, sandstones and shales of the Simpson Group (0 – 1,000 feet) and then the Montoya Formation (0 – 600 feet). 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. 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 has also undergone karstification.

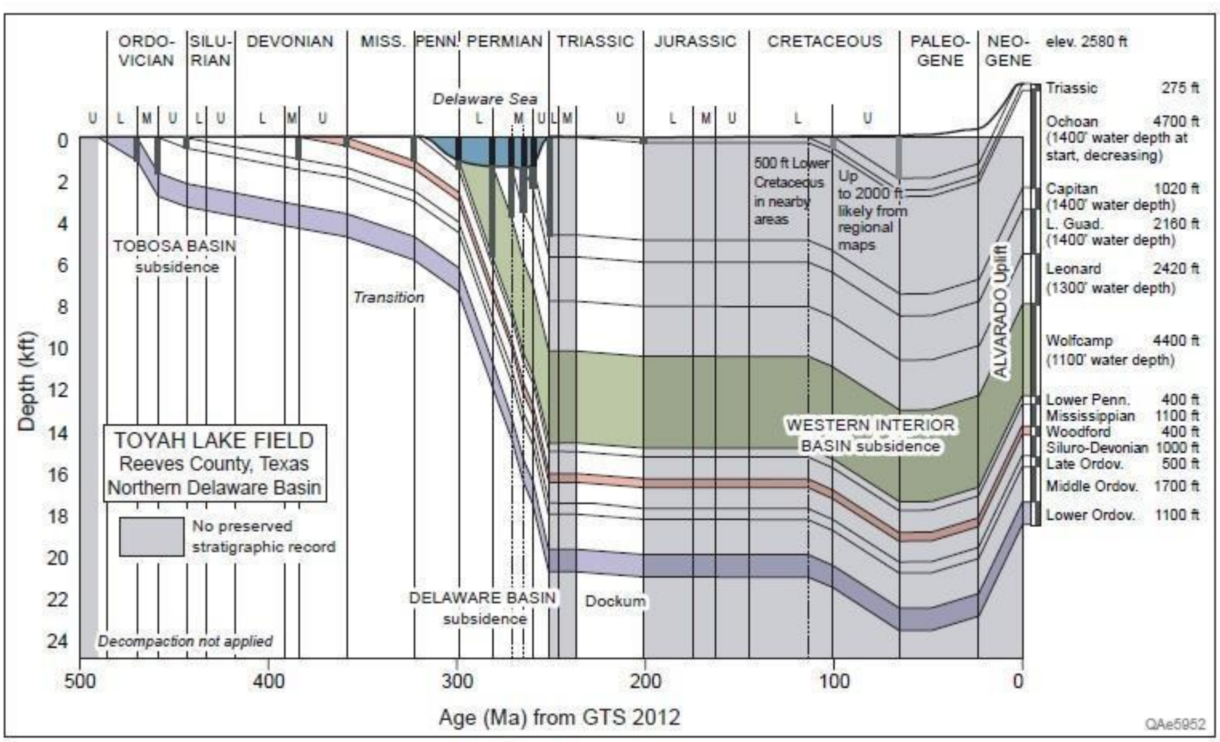


***Figure 3.2-3**: A subsidence chart from Reeves County, Texas showing the timing of development of the Tobosa and Delaware basins during Paleozoic deposition (from Ewing, 2019).*

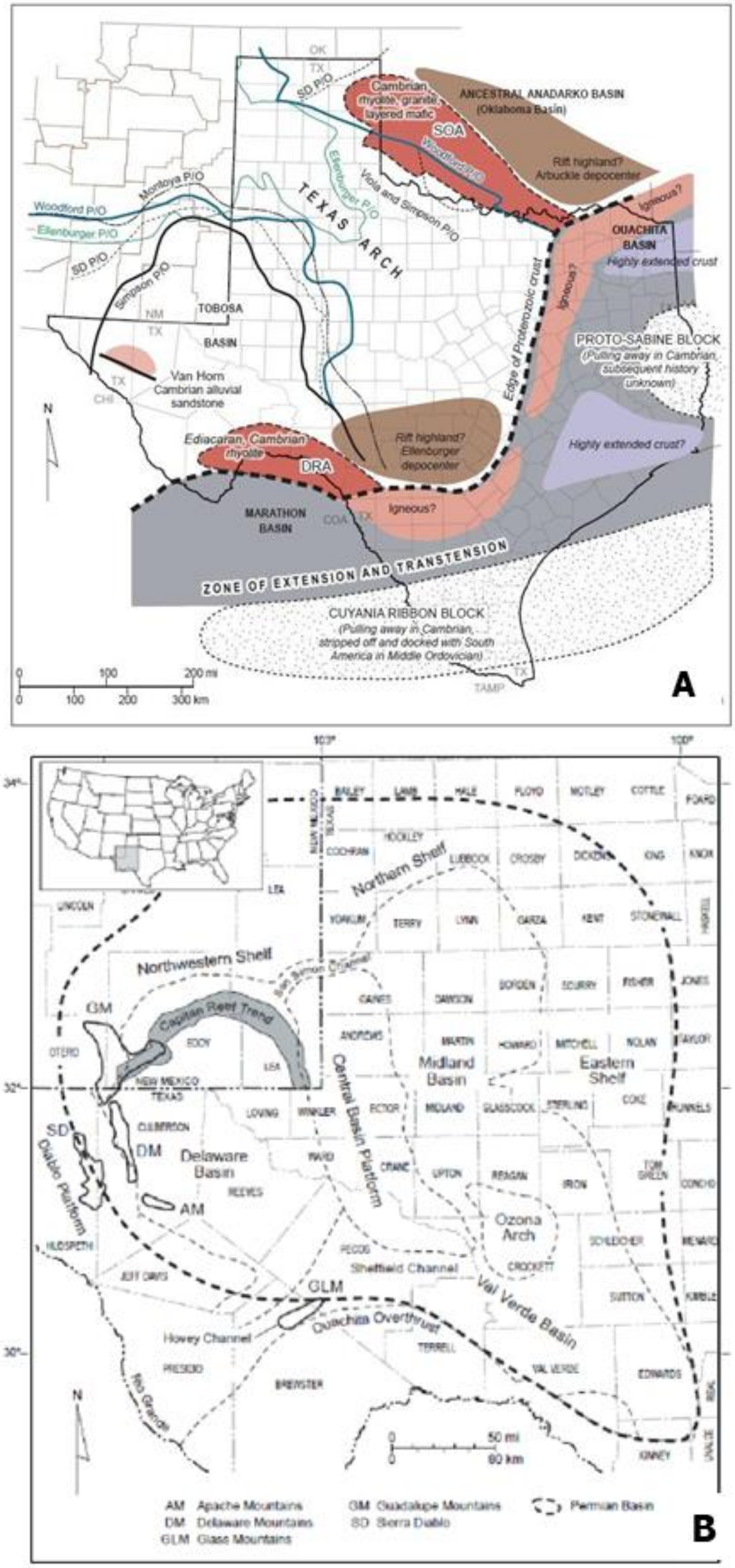


Figure 3.2-4*: Tectonic development of the Tobosa and Permian Basins. A) Late Mississippian (Ewing, 2019). Note the lateral extent (pinchout) for the lower Paleozoic strata. B) Late Permian (Ruppel, 2019a).*

Siluro-Devonian formations consist of the Upper Ordovician to Lower Silurian Fusselman Formation (0 – 1,500 feet), the Upper Silurian to Lower Devonian Wristen Group (0 – 1,400 feet), and the Lower Devonian Thirtyone Formation (0 – 250 feet). The Fusselman Formation is composed of shallow-marine platform deposits of dolostones and limestones (Broadhead, 2017; Ruppel, 2019b). Subaerial exposure and karstification associated with an 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).

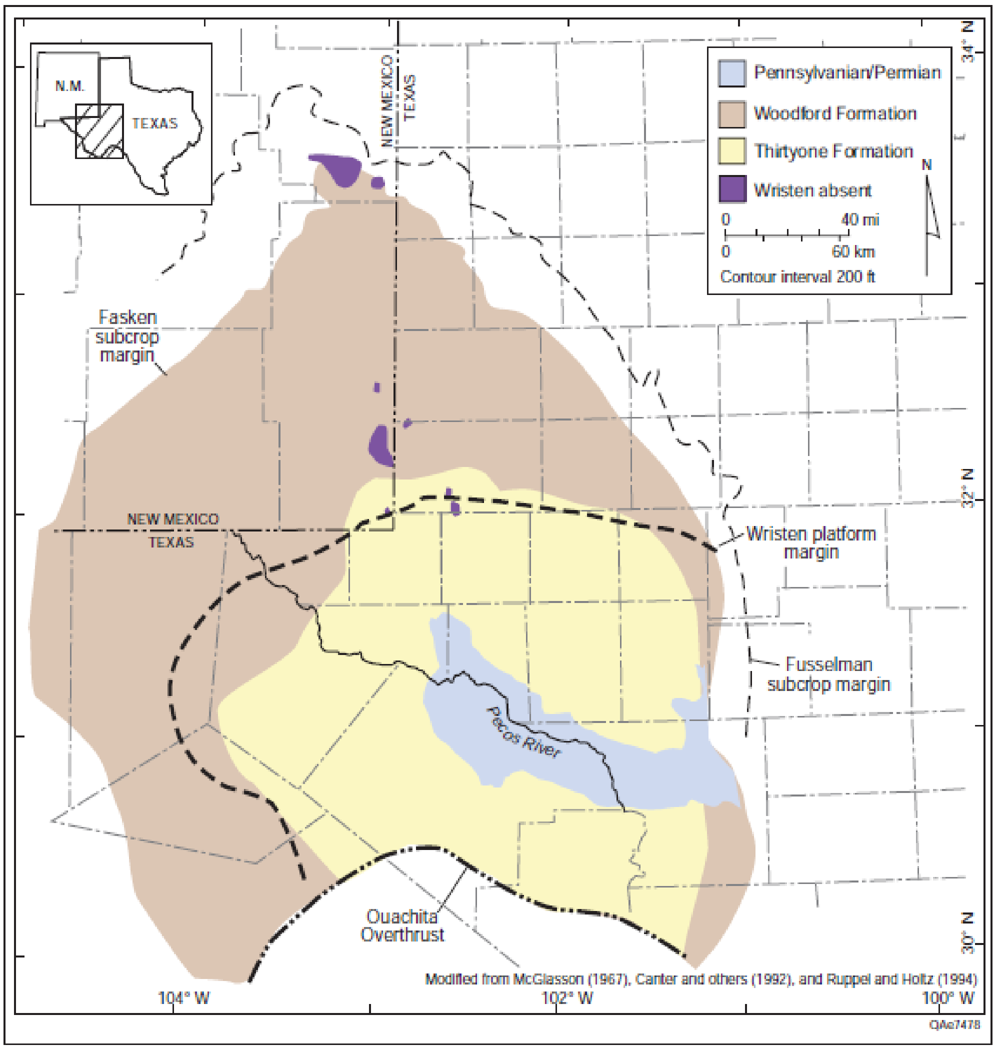


***Figure 3.2-5**: A subcrop map of the Thirtyone and Woodford formations. The Woodford (brown) lies unconformably on top of the Wristen Group where there are no Thirtyone sediments (yellow). Diagram is from Ruppel (2020).*

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 feet) 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 unconformably overlies the Woodford Shale and consists of an un-named carbonate member and the Barnett Shale. The lower Mississippian limestones (0 – 800 feet) are mostly carbonate mudstones with minor argillaceous mudstones and cherts. Where the units have undergone karstification, porosity may approach 4 to 9%, otherwise it is tight and any reservoirs have been of limited size and production (Broadhead, 2017). The Barnett Shale (0 – 400 feet) 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 Morrowan and Atokan-age sediments, informally known within the basin as the Morrow and Atoka formations. Morrowan sediments (0 – 2,000 feet) within the northern Delaware Basin were 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, Atokan sediments (0-500 feet) were deposited during another sea-level transgression, and are 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 feet 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 feet) and Cisco (0 – 500 feet) 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 Group 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 (approximately 400 feet on the NW Shelf, >2,000 feet 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**).

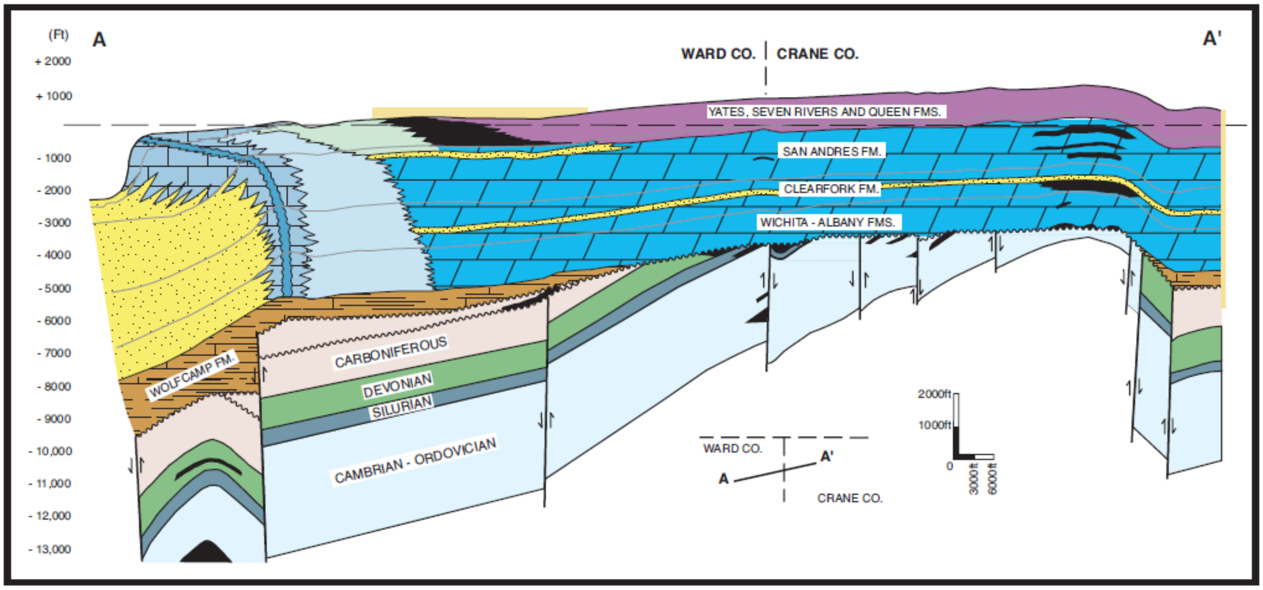


Figure 3.2-6: Cross section through the western Central Basin Platform showing the structural relationship between the Pennsylvanian and older units and Permian strata (modified from Ward et al., 1986; from Scholle et al., 2007).

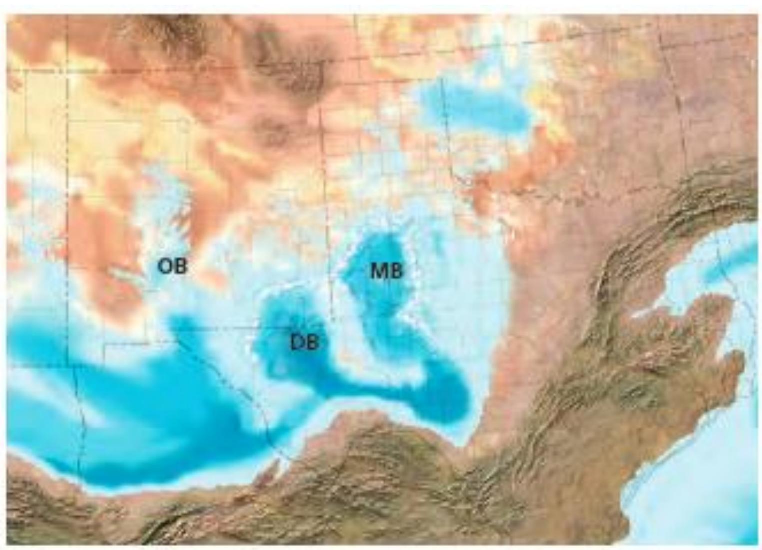


Figure 3.2-7: Reconstruction of southwestern United States about 278 million years ago. The Midland Basin (MB), Delaware Basin (DB) and Orogrande Basin (OB) were the main depositional centers at that time (Scholle et al., 2020).

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 feet 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 hundreds of feet thick around basin margins to only a few feet near the basin center. Unconformably overlying the Hueco Group is the Abo Formation (700 – 1,400 feet). 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 feet), 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 Glorieta 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 feet) and Artesia Group (<1,800 feet) 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 carbonate production was at its greatest, 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 feet, Nance, 2020). Within the basin, the Castile formation, a thick sequence (total thickness approximately 1,800 feet, 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 feet , 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 (approximately 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 comprises most surface sediments in the region. 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 Copperhead AGI #001 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 Copperhead AGI #001 well are discussed below. The cross-section **Figure 3.2-8** highlights the stratigraphy in the region around the Copperhead AGI #001 well.

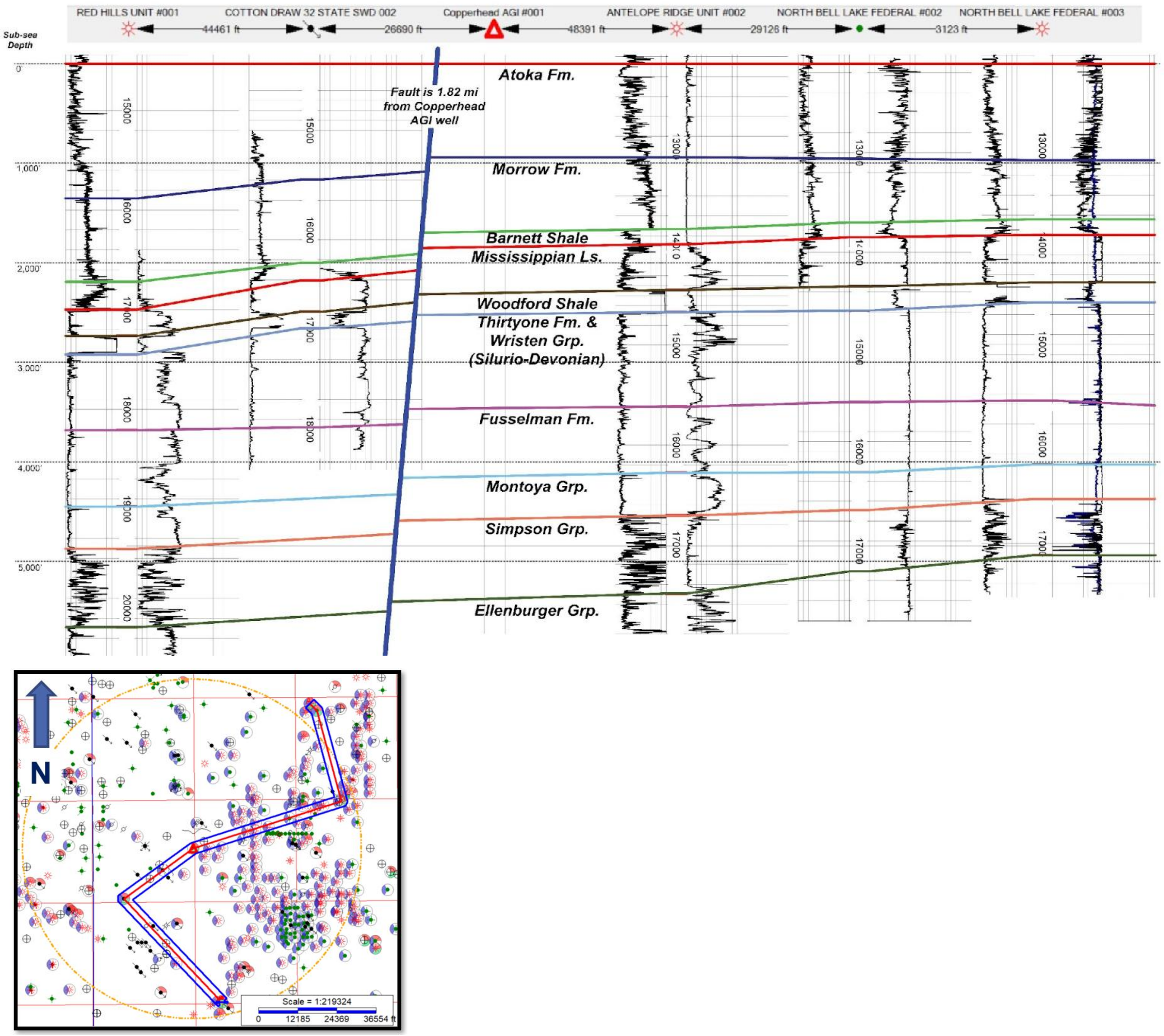


__Figure 3.2-8__: Cross section with the Copperhead AGI #001 well. The top of the Atoka was chosen as reference.

3.3 Injection interval properties

3.3.1 Siluro-Devonian (Thirtyone & Wristen) and Fusselman

In the context of the Copperhead AGI #001 well, the designated injection targets encompass the Siluro-Devonian (Thirtyone & Wristen) and Fusselman sections. These consist of interbedded limestones and dolomites with minor sandstone and shale interbeds. The zones with good porosity and permeability are related to primary porosity within the carbonates and secondary porosity within solution-enlarged pores and breccia. A maximum measured porosity of 10% is noted in both the Siluro-Devonian and Fusselman sections (**Table 3.3-1**)

Table 3.3-1: *Estimated the Copperhead AGI #001 well formation top depths, formation thicknesses, seal and injection zone thicknesses, and average porosity, and permeability. Ground elevation: 3,579 feet. The injection zone is highlighted in green; the confining (seal) zones are highlighted in yellow.*

Formation	Measured Depth (feet)	Thickness (feet)	Porosity (%)	Permeability (md)	Behavior
Rustler	1,155	346			
Salado	1,501	1,288			
Castile	2,789	2,185			
Lamar	4,974	50			
Bell Canyon	5,024	1,028			
Cherry Canyon	6,052	1,627			
Brushy Canyon	7,679	1,265			
Bone Spring	8,944	3,255			
Wolfcamp	12,199	1,880			
Strawn	14,079	340			Secondary seal
Atoka	14,419	1,365			Secondary seal
Morrow	15,784	745			Secondary seal
Barnett Shale	16,529	253	1.00%	0.1	Seal
Mississippian Ls	16,782	392	1.50%	0.1	Seal
Woodford Sh	17,174	125	1.00%	0.04	Seal
Thirtyone Fm	17,299	120	2.20%	1.5	Injection zone
Wristen Gp	17,419	770	3.50%	6	Injection zone
Fusselman	18,189	500	4.00%	2	Injection zone
Montoya	18,689	80	2.00%	1	Seal
Simpson shales	18,769	1615	1.00%	0.6	Seal
Ellenburger Dolomite	20,384	550	1.50%	0.01	Seal
Ground elevation	3,579				

3.3.1.1 Ordovician – Silurian.

Fusselman Formation – The Fusselman Formation is a shallow-water carbonate system that was deposited in the Tobosa Basin. In the Copperhead area, the Fusselman thickens to around 500 feet 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 4%, but there are zones with over 70 feet of porosity exceeding 5%. Reported permeability for shallower sections ranges from 0.001 to 10 millidarcy (mD) (Ruppel, 2019).

3.3.1.2 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 (approximately 890 feet thick). Unlike the Fusselman, Montoya and Ellenburger carbonates, these deposits represent deposition in deeper waters in the Copperhead 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 3.3-1**, 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 improve the porosity (average 4%) in some areas. 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 2 mD of permeability. The formation has an average 3.5% porosity and 6 mD permeability around the Copperhead area. (**Table 3.3-1**; Ruppel et al., 2020a).

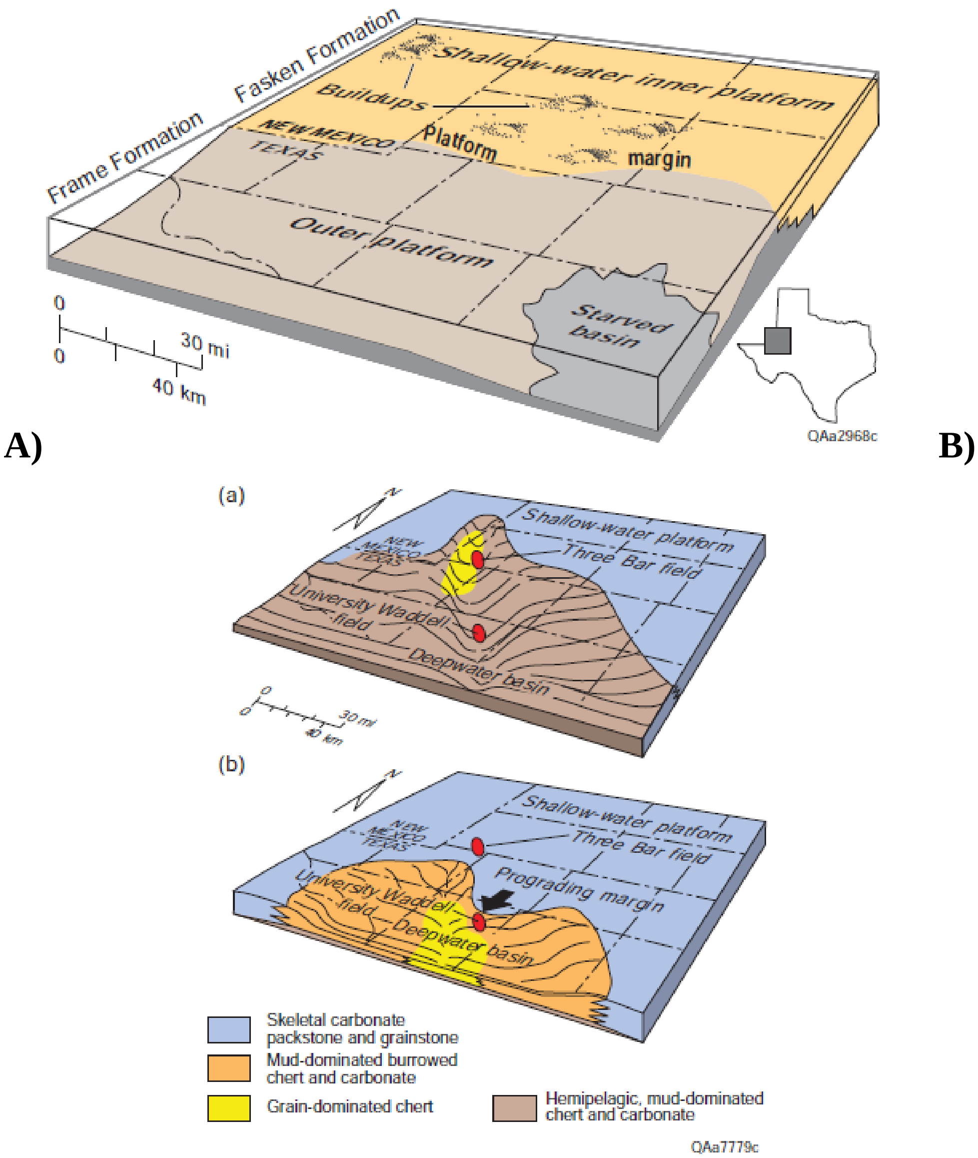


Figure 3.3-1: *Generalized Paleogeography.* ***A)*** *Generalized paleogeography for the Wristen Group (from Ruppel, 2020).* ***B)*** *Generalized paleogeography for the Thirtyone Formation. (a) represents the earliest deposition and the presence of deep-water environments in the Copperhead area. (b) represents the latter deposition (from Ruppel et al., 2020a).*

3.3.2 Upper confining zone properties: Woodford shale/Mississippian limestone

The proposed injection zone is capped by 125-feet-thick, Devonian Woodford Shale followed by 392-feet-thick section of Mississippian limestones and shales and 253 feet of Barnett Shale. These units have negligible porosity (<1.5 %) and permeability (<0.1 mD).

Mississippian. Mississippian age deposits are commonly divided (from youngest to oldest) into the Barnett Shale and a Mississippian limestone (an un-named unit) of Lower Mississippian age. The Mississippian section is approximately 1,420 feet thick in the Copperhead area and is regionally extensive. The Lower Mississippian limestone is a dark colored, deep marine limestone with minor cherts and shales and is approximately 555 feet thick. Known production from this limestone in New Mexico comes from small, one to two well fields that normally have poor porosity (4-9%) and permeability (Broadhead, 2017). The Barnett Shale is a widespread, dark, organic shale with very low porosity and permeability and is approximately 750 feet 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 approximately 620 feet thick in the Copperhead 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 feet 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 Copperhead 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

Figures 3.4-1 to 3.4-7 highlight the subsea structure maps, images of the geological model, a base map and a cross section.

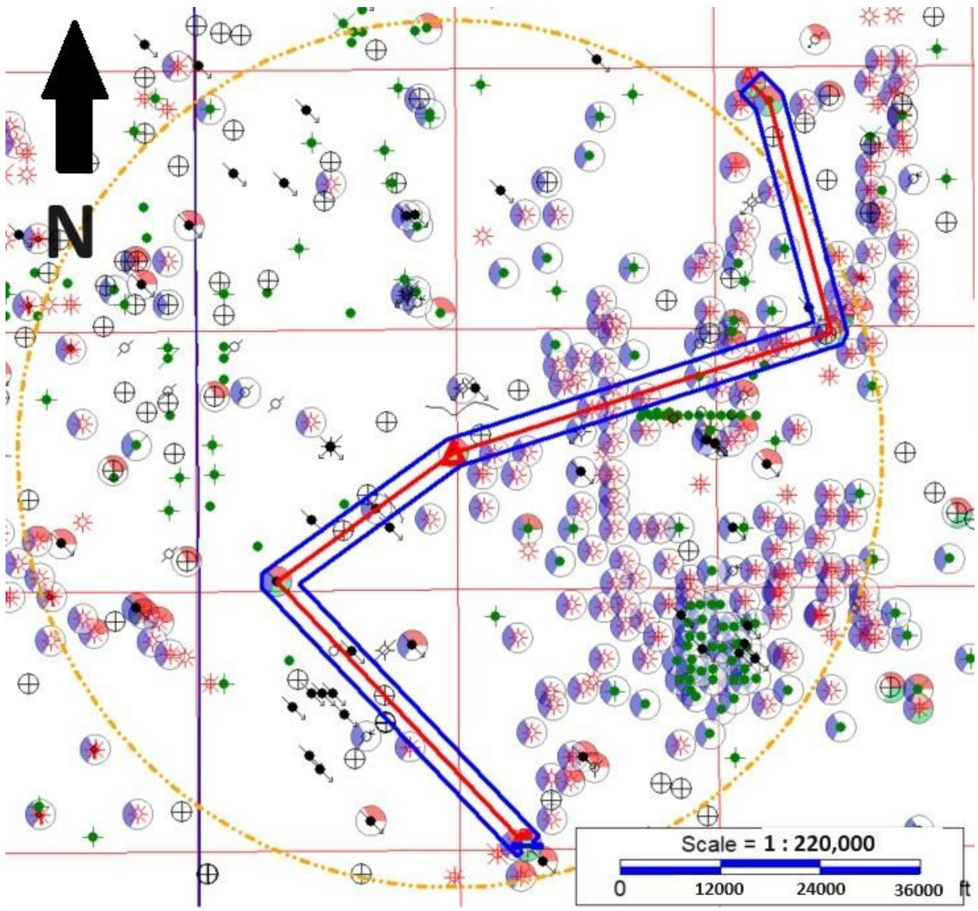


Figure 3.4-1: *Base map for cross sections.*

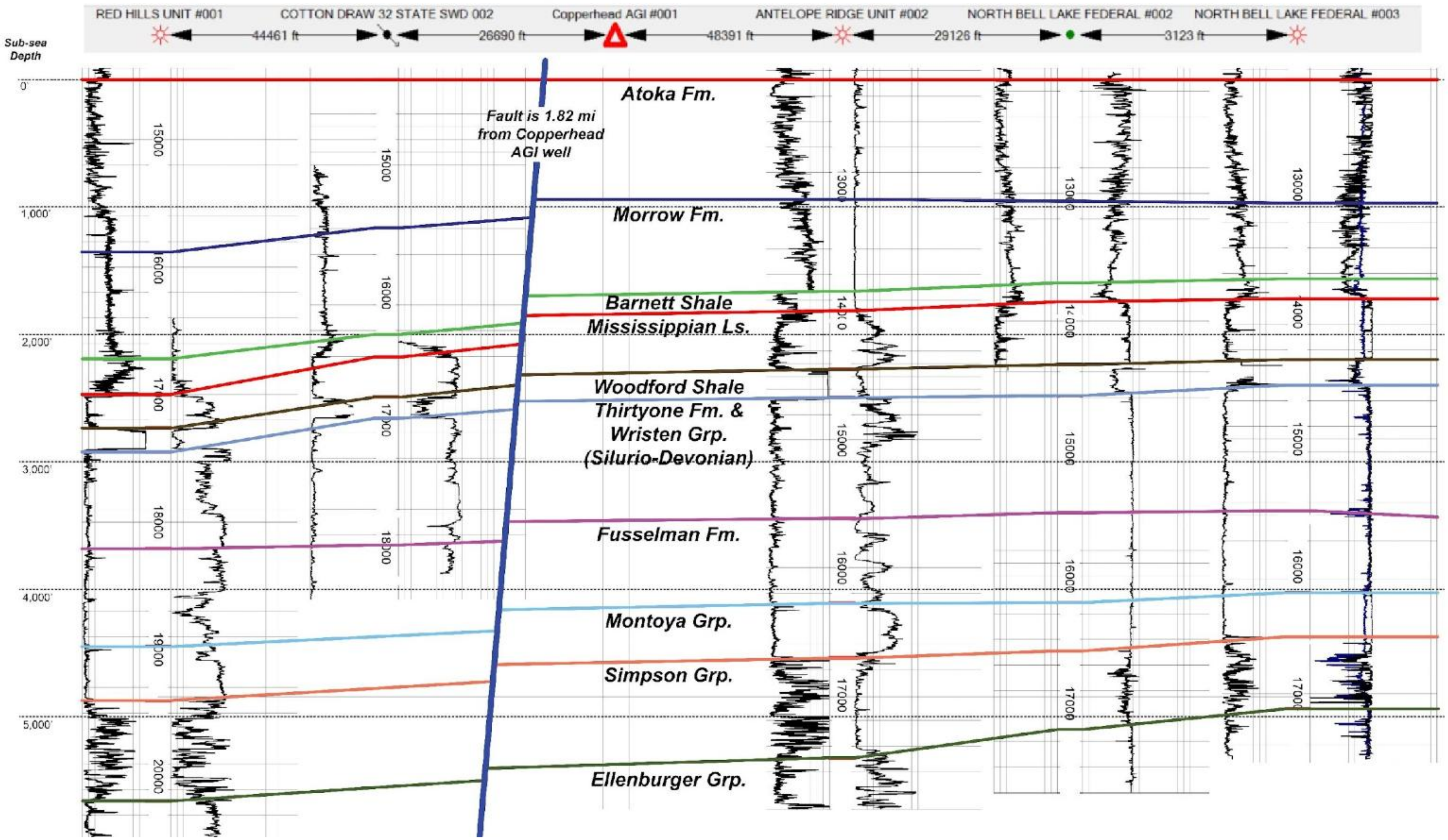


***Figure 3.4-2:** Northwest to southeast cross section.*

The geological model was initially built based upon formation tops from well logs in the area surrounding the well location. Porosity and permeability values were derived from logs, core, and literature. review The model was completed by integration with the model built from interpretation of 3D seismic data. The boundaries of the geological model are shown in **Figure 3.4-3**. Two faults with minor displacement have been identified from seismic interpretation. The closest fault is 0.88 miles from the well, the other 1.82 miles (**Figures 3.4-4**). Both originate below the injection zone and terminate in the lower Wolfcamp, roughly 2000 feet above the Barnett Shale. The faults were included in the 3D geological model (**Figure 3.4-4**). **Figures 3.4-5- 3.4-7** are structure maps for the Woodford Shale, the Mississippian limestone, and the Barnett Shale.

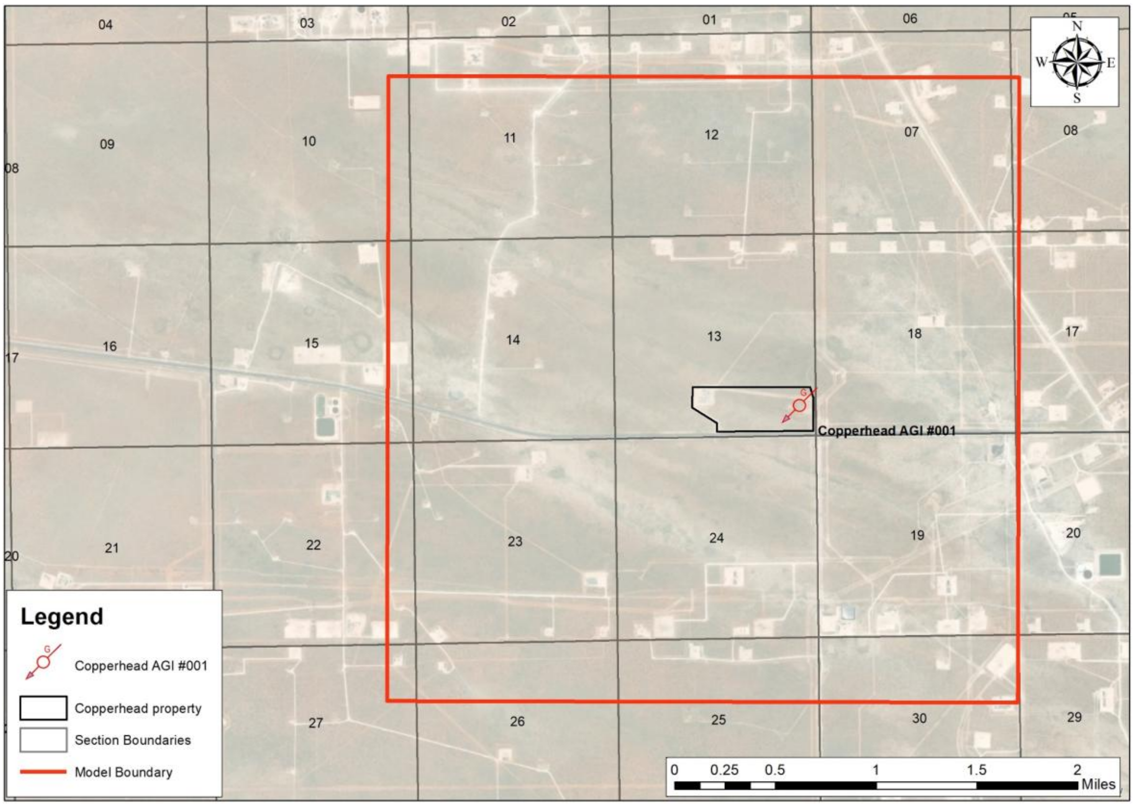


Figure 3.4-3: *Geologic model boundary.*

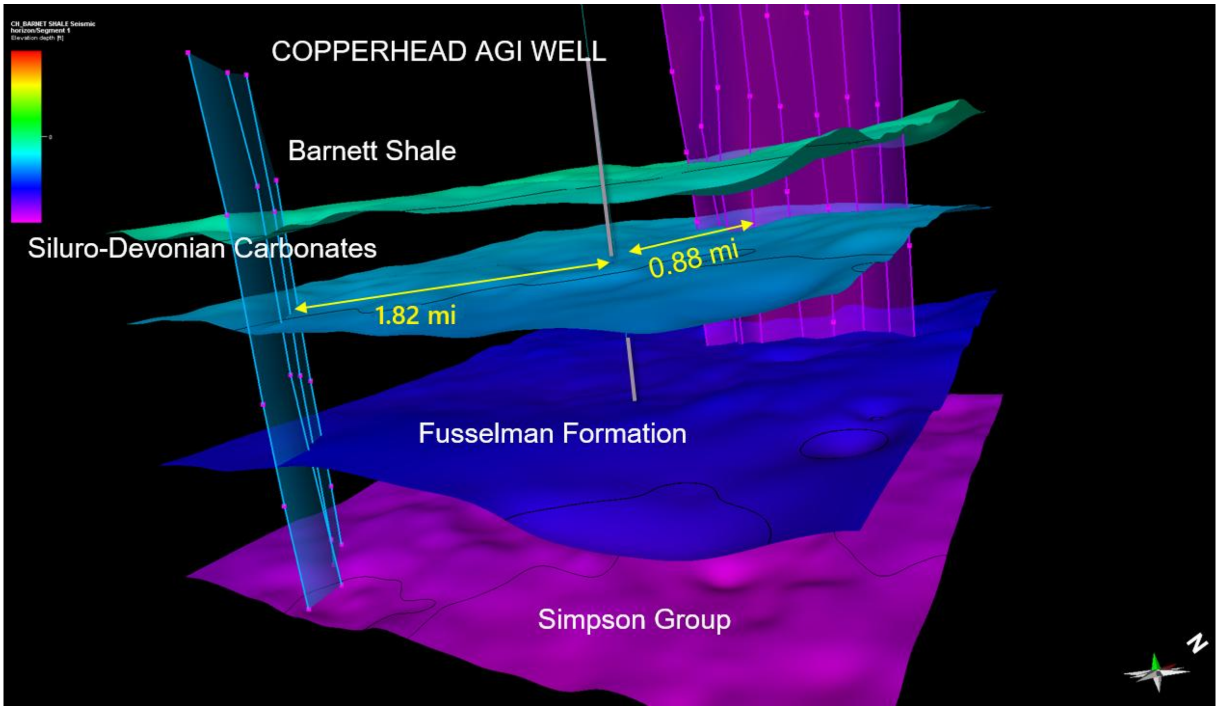


Figure 3.4-4: *3D Geologic model highlighting main formations of interest and the surrounding faults.*

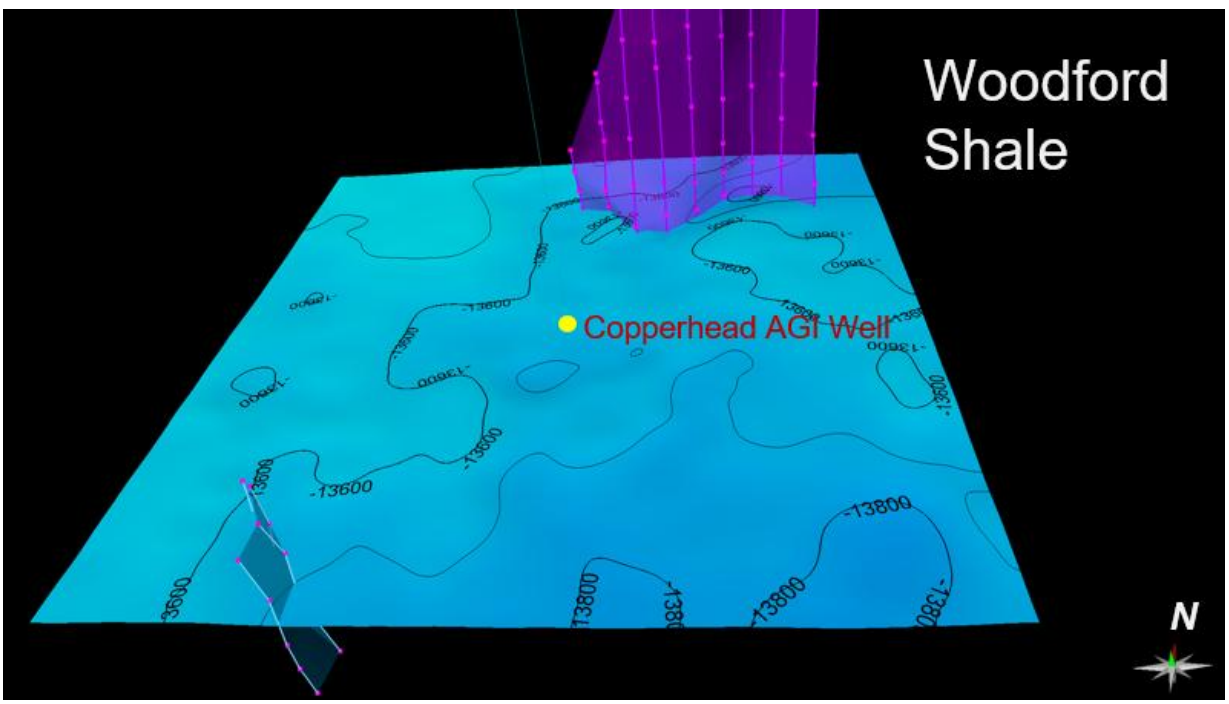


Figure 3.4-5: *Woodford Shale structure map.*

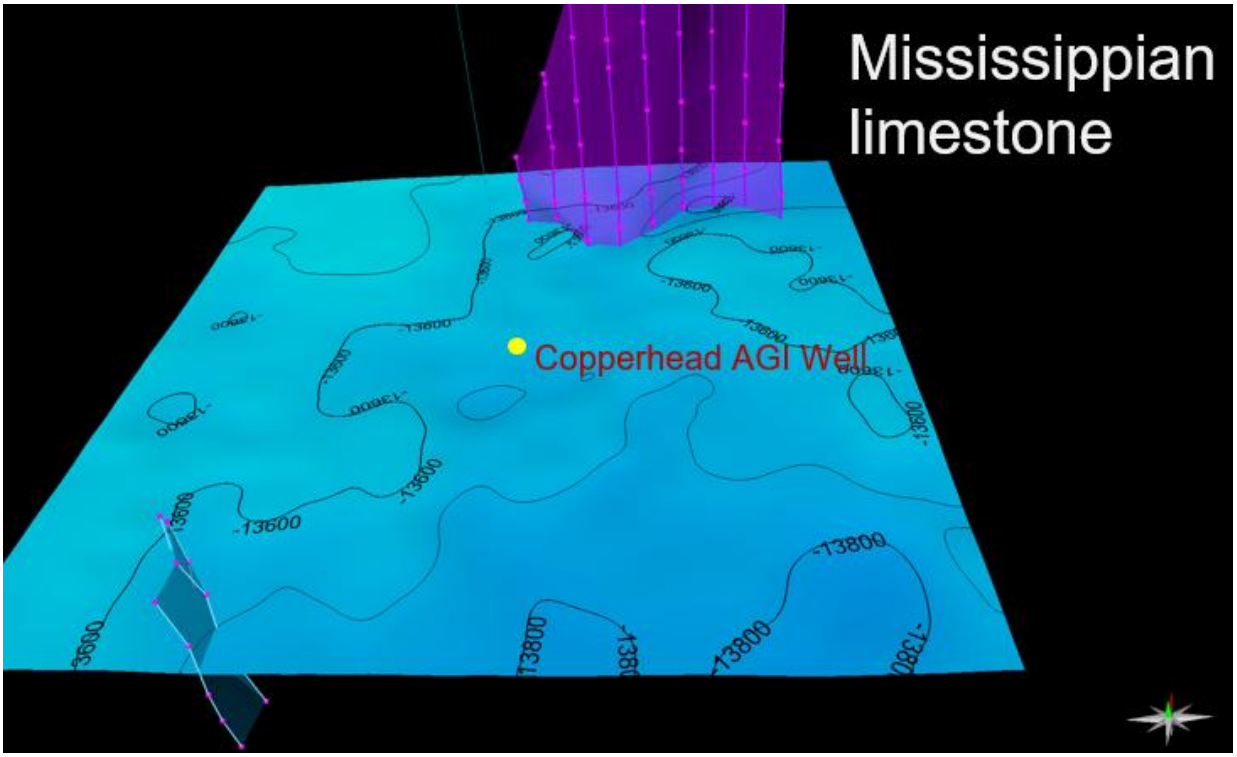


Figure 3.4-6: Mississippian limestone structure map.

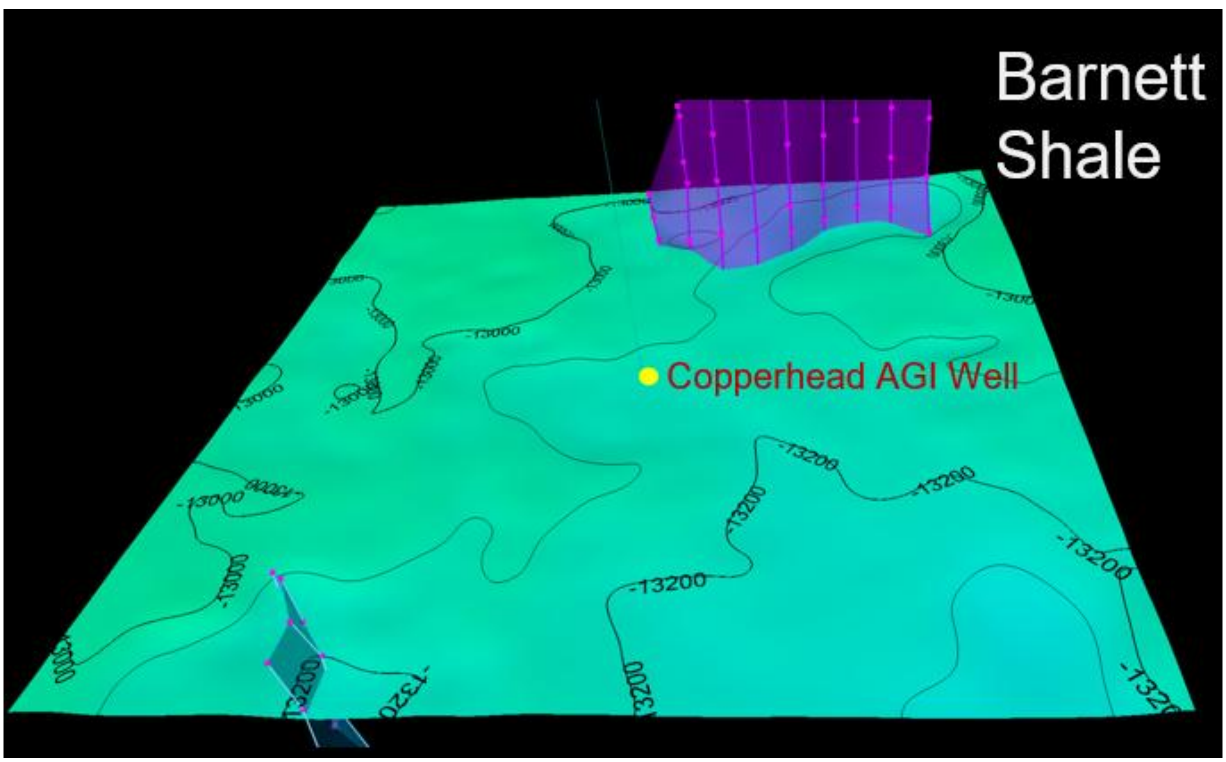


Figure 3.4-7: Barnett Shale structure map.

3.5 Groundwater hydrology and formation fluid chemistry

There are four main sources of underground drinking water in the northern Delaware Basin of NewMexico (Ritchie et al., 1985; Lowry et al., 2018; USBLM, 2020). They include: Cenozoic alluvium,lithologically complex fluvial accumulations of the Pecos River and other streams, windblown sands, playa deposits, gypsite, and others, with Total Dissolved Solids (TDS) ranging from <200 to 15,000 mg/L with an average of 2,319 mg/L; the Santa Rosa member of the Dockum Group, a reddish-brown and gray cross-stratified sandstone with TDS ranging from 205 to 2,990 mg/L which serves as the principal source of groundwater in the eastern part of Eddy County and the western third of Lea County; the Rustler Formation, a brackish to saline (approximately 10,000 to 300,000 mg/L TDS) anhydrite or gypsum formation with two dolomite marker beds and a basal zone of sandstone to shale which is typically utilized for livestock, irrigation, and enhanced oil recovery; and the Capitan Reef, a karst limestone with TDS of <300 to 10,000 mg/L (Ritchie et al., 1985; Lowry et al., 2018; USBLM, 2020).

Based on the New Mexico Water Rights Database from the New Mexico Office of the State Engineer, there are no freshwater wells located within one mile of the Copperhead AGI #001 well. The closest groundwater well (C-01932) is approximately 1.70 miles away, completed to a depth of 492 feet and collecting water in the Triassic Dockum Group (Santa Rosa), with primary use of livestock watering (Ritchie et al., 1985; NMOSE, 2021; **Table 3.5-1; Figure 3.5-1**). The shallow freshwater aquifer is protected by the surface and intermediate casings and cements in the Copperhead AGI #001 well.

Water chemistry is not available for well C-01932. However, image files in the NMOSE water rightsdatabase for the expired application of pod C-01896 which is approximately 1.1 miles away include a chemical analysis of groundwater quality in the Santa Rosa of the Dockum Group (**Table 3.5-2**).

Targa also implements frequent sampling in two additional shallow Triassic groundwater wells, C-03666 POD1 and C-03917 POD1 located adjacent to the Red Hills Gas Plant at distances of 5.2 and 5.7 miles away from the Copperhead AGI #001 well respectively. Samples collected on 07/31/2023 indicate the water is basic with pH of 8-9 and calculated TDS of 453 to 1,380 mg/L. Results of these analyses are consistent with groundwater quality in the Triassic formations throughout the region.

Table 3.5-1: *Groundwater wells within 2 miles of the Copperhead AGI #001 well.*

pod_file	use	status	Well depth	tws	rng	sec	county	easting_13N	northing_13N	own_name
C-01932	STK	ACT	492	24S	32E	12	ED	628633	3567188	MCCLOY

Table 3.5-2. *Geochemistry of Santa Rosa from well C-01896 application.*

Ca	Mg	Na, K	HCO_3	SO_4	Cl	TDS	Spec. Cond
32	26	163	287	219	52	635	1030

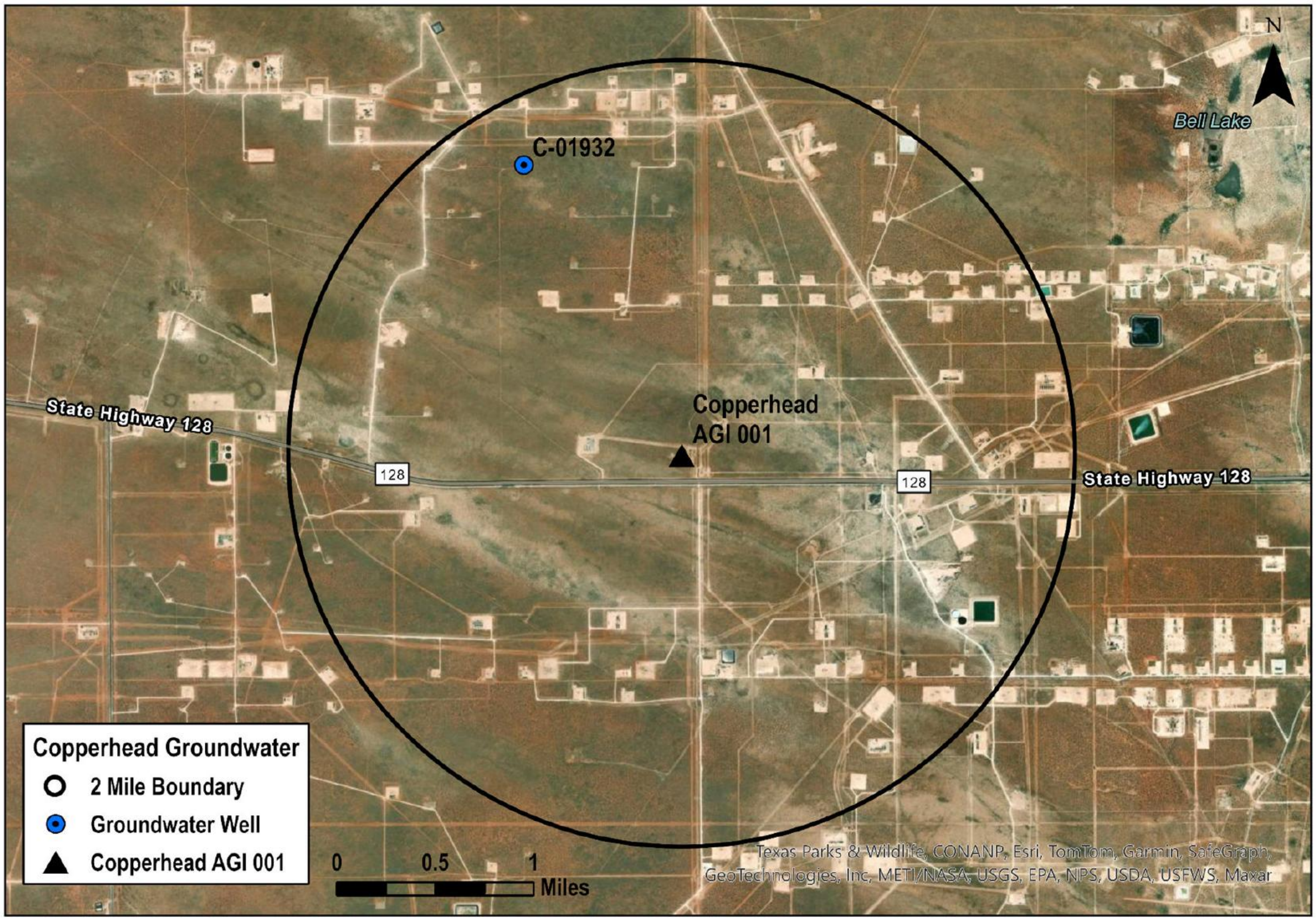


Figure 3.5-1: *Freshwater wells located within two mile of the Copperhead AGI #001 well.*

3.6 Historical operations

3.6.1 Copperhead site

In response to increasing production, to meet the infrastructure needs of producers, and to respect environmental requirements, Targa is developing the Copperhead natural gas processing plant.

3.6.2 Operations surrounding the Copperhead site

The proposed Copperhead AGI #001 well will be drilled for the purpose of injecting TAG into formations at a depth of 17,299feet - 18,699’. No production or injection wells in the area penetrate these formations, nor is there production from any deeper zones. The nearest wells in the vicinity produce primarily from the Bone Spring and Wolfcamp formations. There are also three active gas wells in the Atoka (**Figure 3.6-1**). **Figure 3.6-1** provides a summary of oil and gas wells within half a mile, one mile and two miles from the Copperhead AGI #001 well. The following maps are provided in accordance with NMOCD requirements.

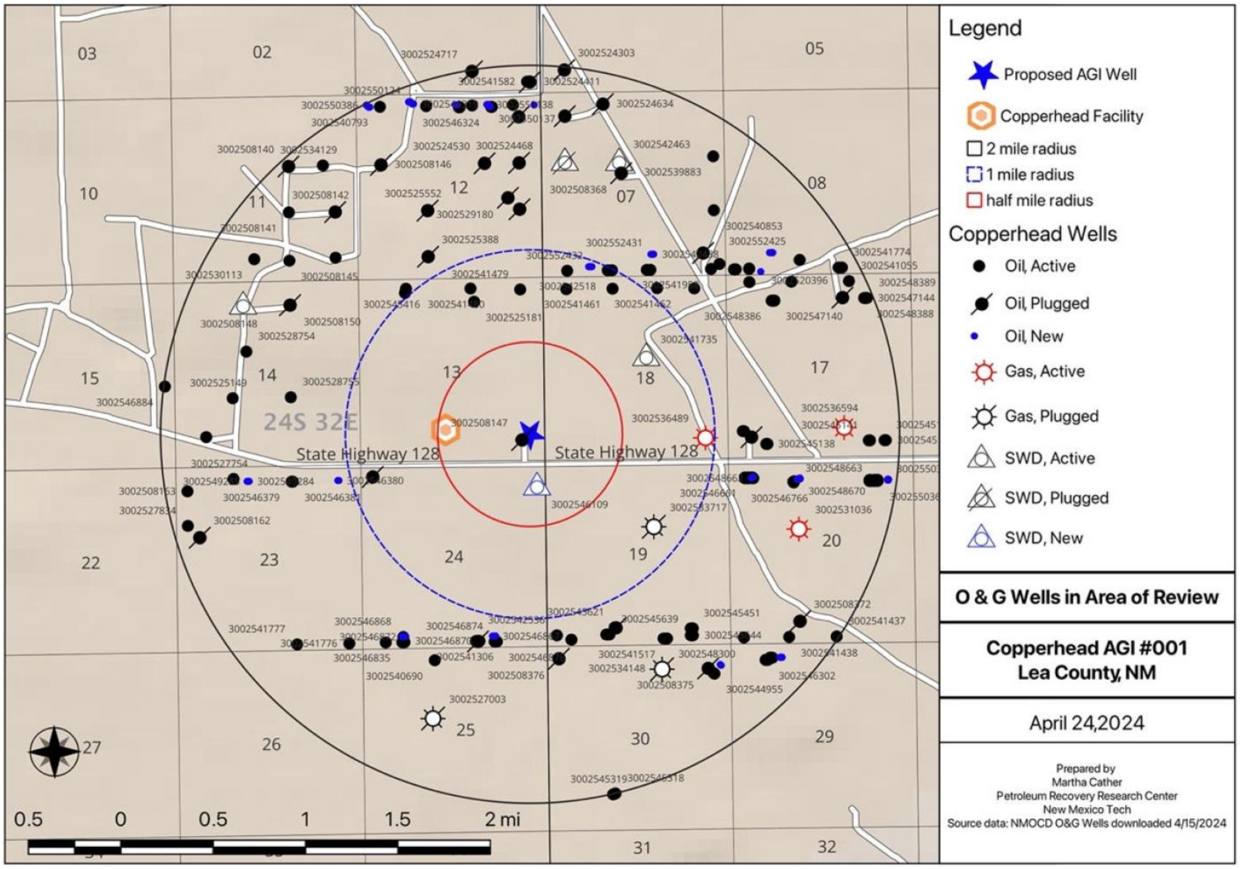


Figure 3.6-1: *Oil and gas wells located within two mile of the Copperhead AGI #001 well.*

3.7 Description of injection process

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.

The Copperhead Gas Plant, including the Copperhead AGI #001 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.

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.

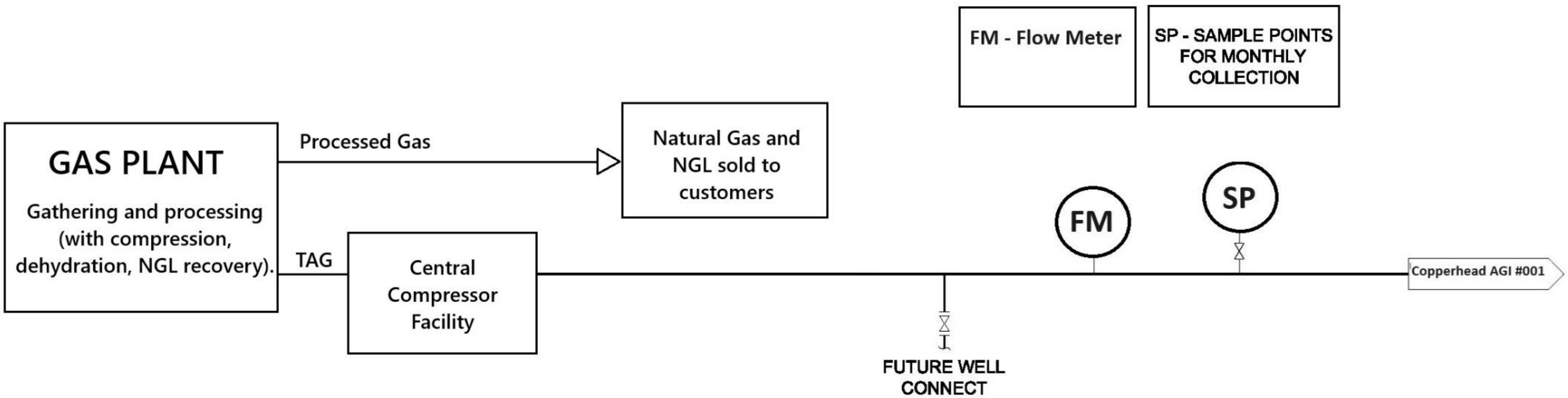


Figure 3.7-1: *Process Block Flow Diagram with CO_2 entry, Flow meter (FM), Sampling point (SP) and the Copperhead AGI #001 well*

3.8 Reservoir characterization modeling

3.8.1 Inputs and assumptions

Numerical simulations of dynamic reservoirs are carried out with the detailed 3D geological model. These simulations analyze the injectivity rates of the well, its pressure dynamics, and the movement of the TAG plume and pressure front.

In this study, we employed advanced software tools for the construction of geological and reservoir simulation models. The TAG involved in the injections was modeled with the potential to exist in both dissolved and supercritical states within the aqueous and gaseous phases, respectively.

The construction of the static model was based on 3D seismic, well logs and formation tops, aiming to accurately characterize and map the structural layers of the caprock. The geological model covers an area of approximately 3.1 by 3.2 miles, represented in a gridded format comprising 164 x 167 x 39 cells, totaling 1,068,132 cells. The grid size in the actively injected areas averages 100 by 100 square feet. The figures below provide detailed visualizations of the model, including a 3D representation of the simulation model (**Figure 3.8-1**), and estimates of porosity and permeability based on available data from well logs (**Figure 3.8-2 and 3.8-3**). In the model, the range of the porosity is between 0.1 to 8.99 %. The permeability is interpolated between 0.001 to 3.40 mD, and the vertical permeability anisotropy is 0.1.

For initialization of the reservoir simulations, several parameters and assumptions were considered. The connate water saturation of the storage reservoir was conservatively set at 100 %, with a residual water saturation of 55 % as per established sources (Jenkins, 1961; Bennion and Bachu, 2005). The initial salinity was assumed at 84,640 parts per million (ppm), an average derived from water chemistry anlyses from three nearby wells, and the well data is from U.S. Geological Survey National Produced Waters Geochemical Database (ver. 3.0, December 2023) (Blondes et al., 2023). Following industry standards and data from drill stem tests in the Delaware Basin, a pore pressure gradient of 0.47 psi/foot was estimated, establishing a reservoir pressure of 7,750 psi at the top of the Thirtyone formation at the initiation phase.

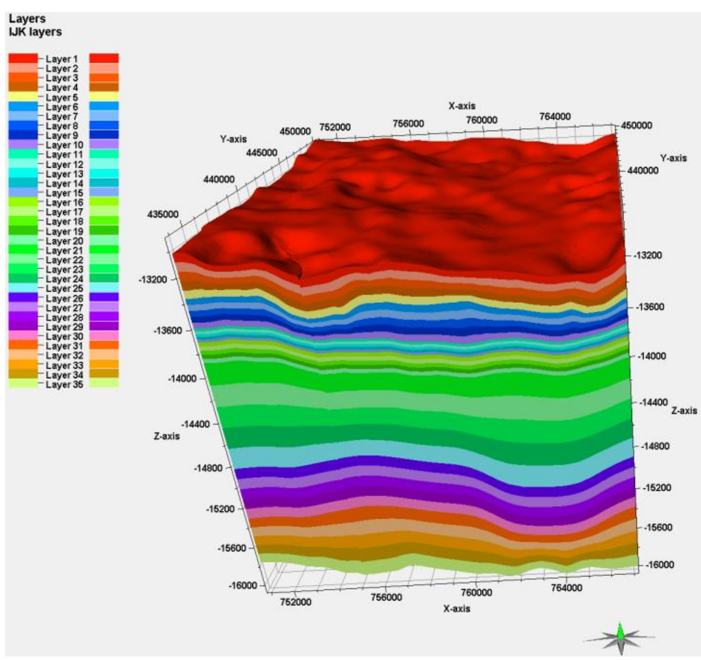


__Figure 3.8-1:__ 3D view of the simulation model.

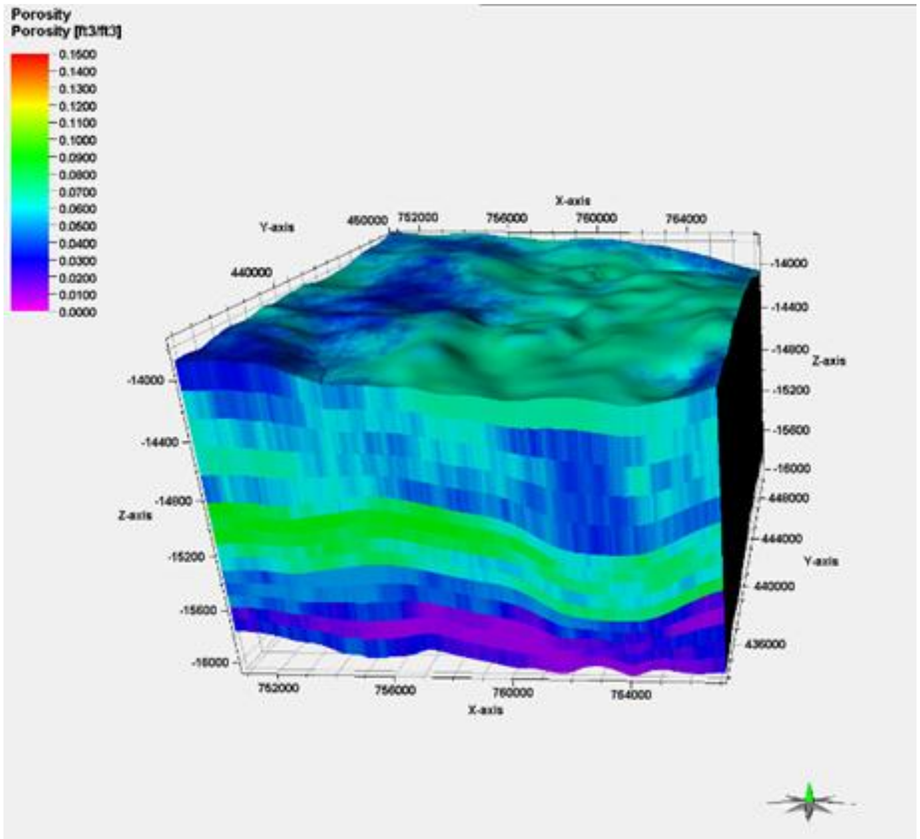


__Figure 3.8-2:__ Porosity estimation of the storage zone.

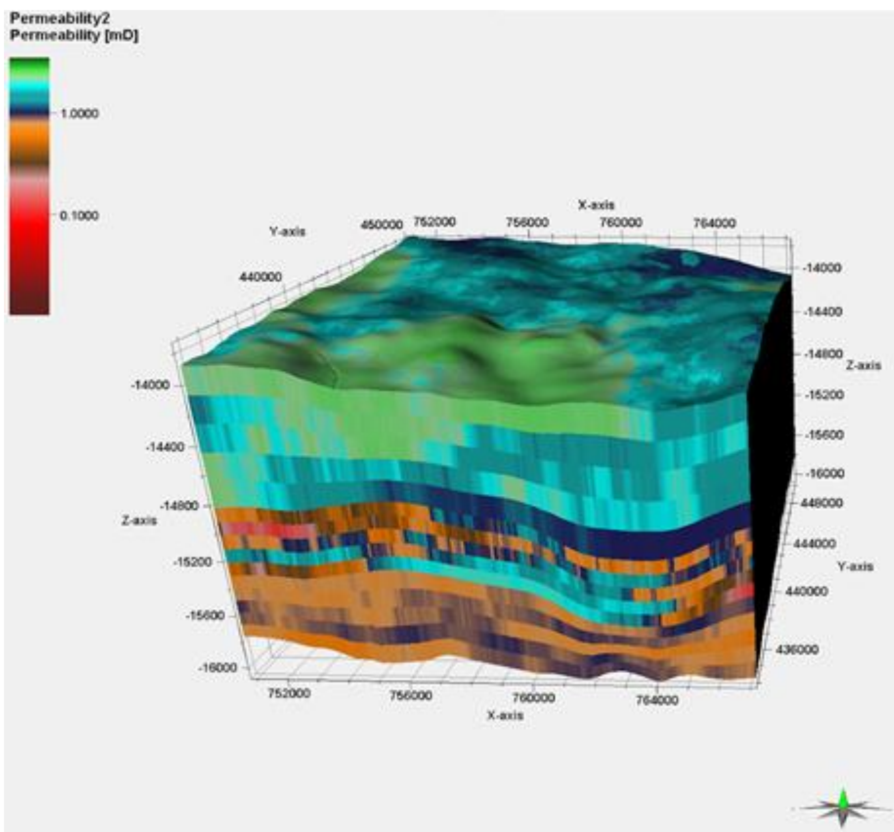


Figure 3.8-3: *Permeability estimation of the storage zone.*

The fracture gradient (FG) for the injection interval was calculated using Eaton's formula, which characterized the formation lithology from Poisson's ratio and stress ratio value:

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

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/foot is typically used in calculations when no site-specific data is available (Luo et al., 1994). Poisson's ratio was assumed to be 0.3 for the injection layer, with a variation between 0.29 and 0.31 to account for uncertainties (Smye et al., 2021; Dvory and Zoback, 2021). The fracture gradient was estimated to be 0.65 to 0.68 psi/foot (Dvory and Zoback, 2021). This led to a calculated bottom hole formation fracture pressure of 10,120 psi. Furthermore, a safety margin of 10% was applied to this fracture gradient to prevent the bottom hole injection pressure (BHP) during active injection from surpassing the fracture gradient, setting the maximum BHP at 0.59 psi/foot in simulations. The geomechanical properties of the reservoir are detailed in **Table 3.8-1**. These parameters, derived from existing well logs and referenced literature, will be validated with actual measurements upon completion of the proposed, with subsequent updates to the modeling and simulation work as necessary.

Table 3.8-1: *Summary of reservoir simulation inputs.*

Parameter	Upper Confining Zone	Injection Interval	Lower Confining Zone
Overburden Gradient (psi/foot)	1.05	1.05	1.05
Pore Pressure Gradient (psi/foot)	0.45	0.45	0.45
Poisson's Ratio	0.29	0.30	0.31
Fracture Gradient (psi/foot)	0.68	0.65	0.68
Fracture Gradient with 10% Safety Factor (psi/foot)	0.61	0.59	0.61

The simulation at the Copperhead AGI #001 well is set to inject at the proposed maximum injection rate of 26 MMSCFD. A maximum allowable surface injection pressure (MAOP) calculated by the NMOCD approved method and bottom hole pressures of 3,460 psi and 10,120 psi, respectively, are set, with an injection composition of 30% H_2S and 70% CO_2. The simulation begins on January 1, 2025, and concludes on January 1, 2085, encompassing a 30-year active injection phase followed by a subsequent 30-year post-injection monitoring phase to estimate the maximum impacted area and the plume stabilization time.

Table 3.8-2: *Summary of well simulation inputs.*

Well Name	Injection Starting Date	Shut-In Date	Injection Rate
Copperhead AGI #001	2025	2055 (expected)	26 MMSCFD (Surface condition)

3.8.2 Model outputs

The injection rate profiles for the Copperhead AGI #001 well suggests that the rate of injection remains constant throughout the injection period, as depicted in **Figure 3.8-4**. The consistent rate of 26 MMSCFD ensures that the target formations can safely receive the treated acid gas (TAG) from the Copperhead #001 well over a 30-year period while adhering to the pressure constraints and maintaining formation integrity (**Figure 3.8-5**).

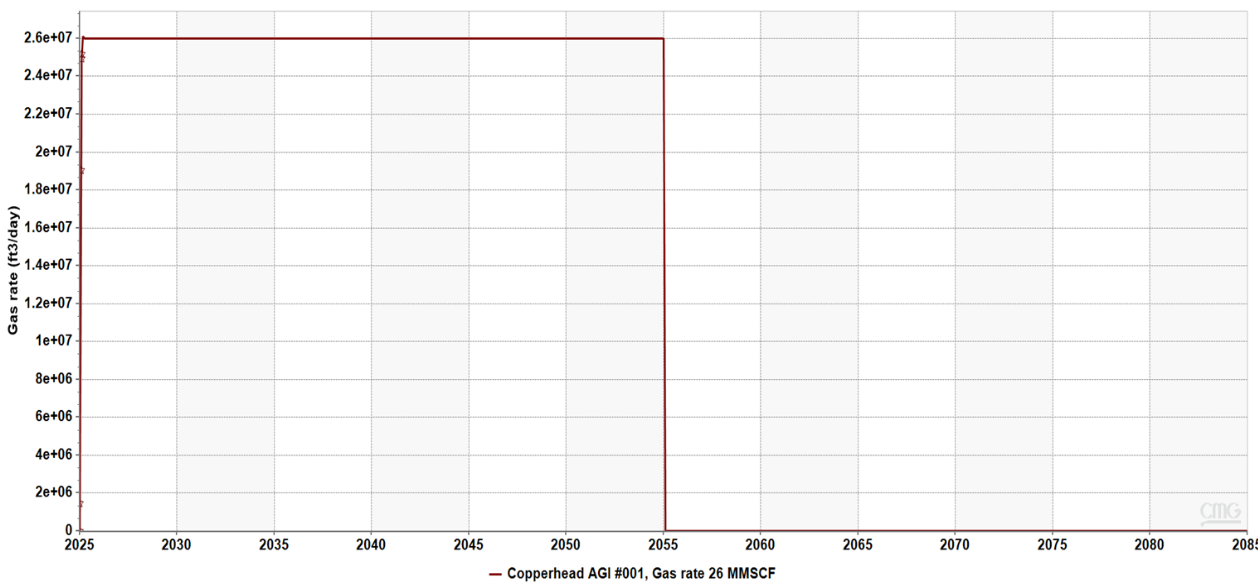


Figure 3.8-4: *Forecast of TAG injection rate of the Copperhead AGI #001 well (2025 to 2055, 26 MMSCFD).*

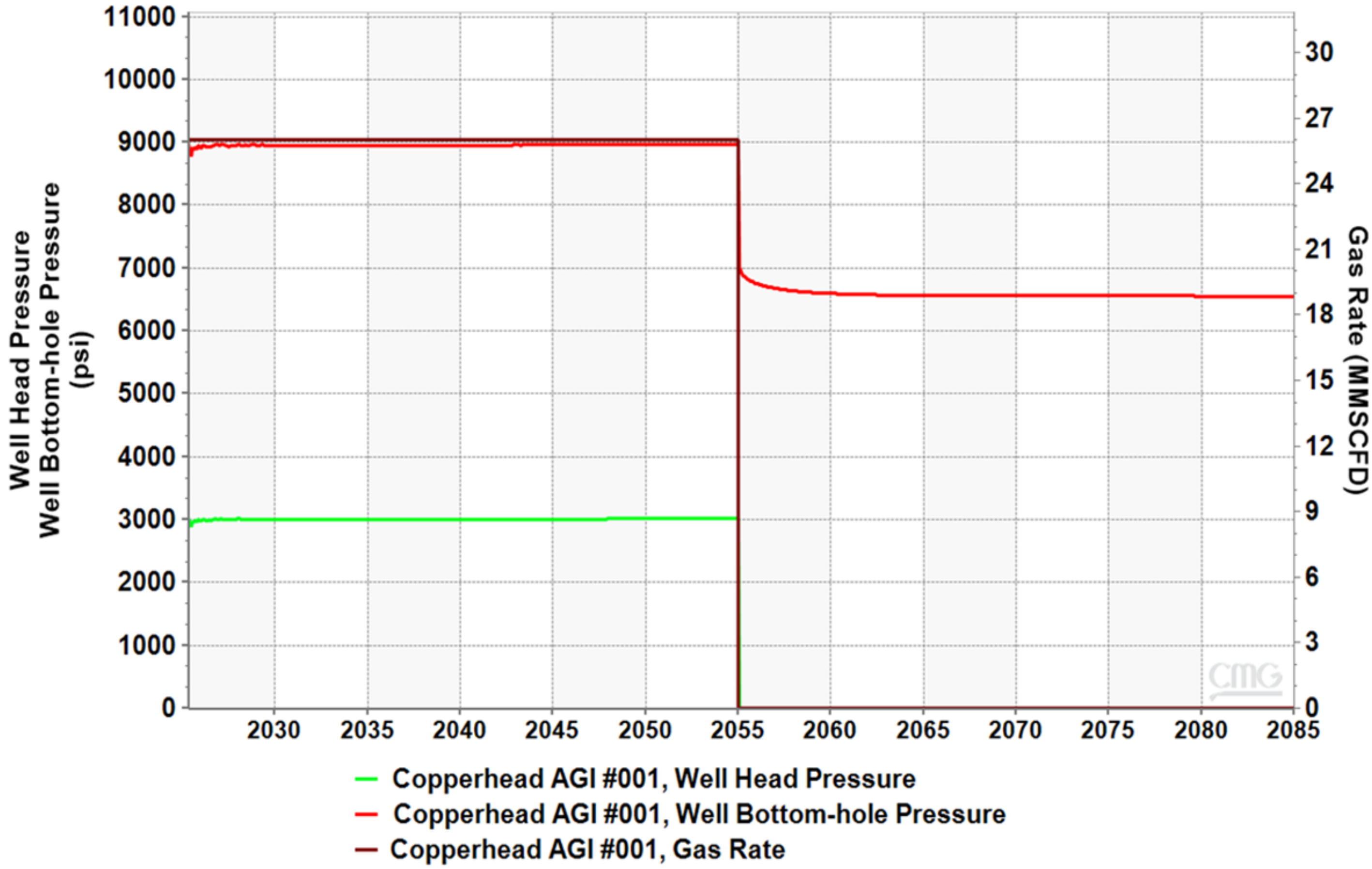


Figure 3.8-5: *Predicted well head and bottom-hole pressures for the Copperhead AGI #001 well.*

3.8.3 Treated acid gas plume

Figure 3.8-6 captures the evolution of the TAG plume for the Copperhead AGI #001 well at various stages: 5, 10, 15, 20, 25, and 30 years post-injection with a commencement in 2025. The maximum extend of the plume is estimated to span 5,471 feet (1.04 miles).

The plume horizontally expands until the end of injection in 2055. As described above, the plume movement and footprint was assessed at 5-year increments after commencement of injection (2025) until two successive 5-year footprints did not differ. In this case, injection ceased in 2055 after 30 years of injection and the plume showed no expansion at 2060 relative to that at the end of injection at 2055 – demonstrating that the plume had stabilized. (**Figure 3.8-6 and 3.8-7**).

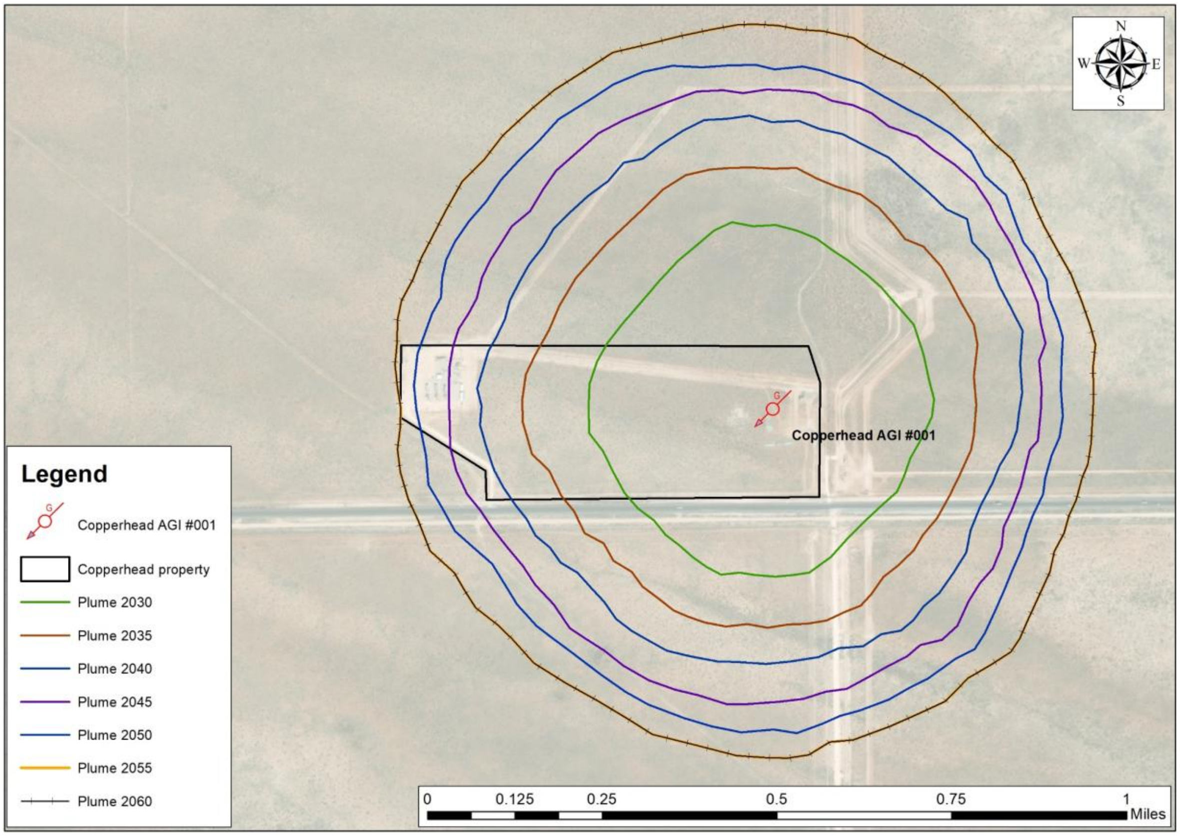


Figure 3.8-6: *Horizontal extent of TAG plume (represented by gas saturation with 1% threshold) at years 2030, 2035, 2040, 2045, 2050, 2055, and stabilized plume in 2060.*

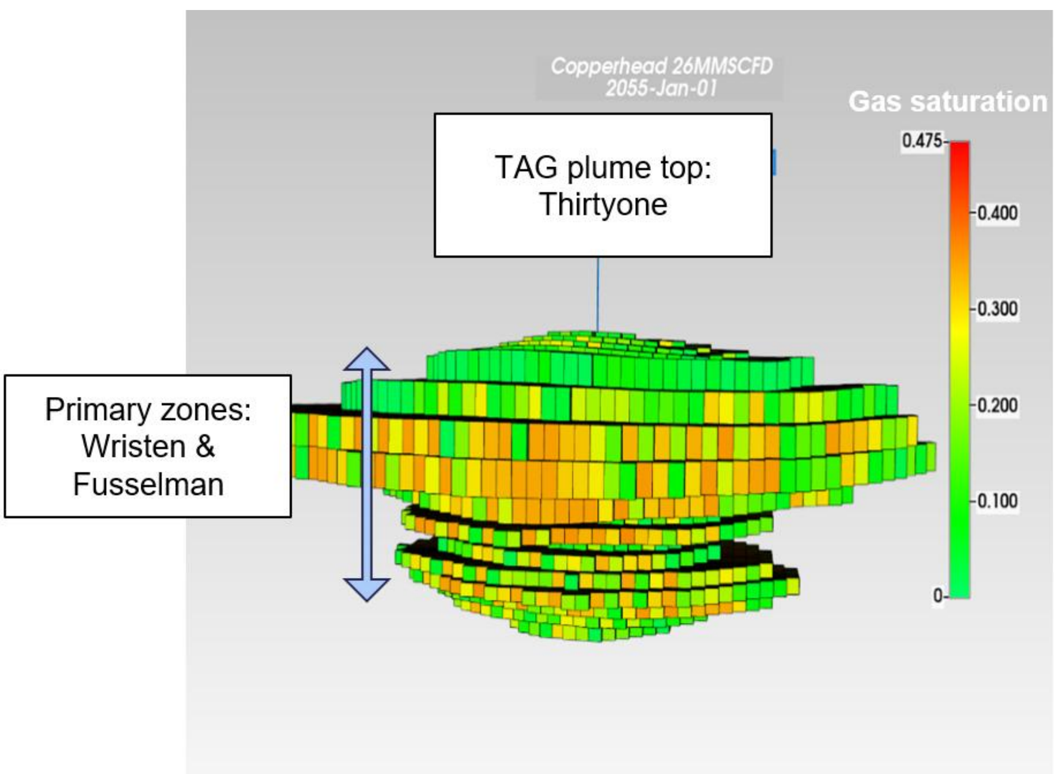


Figure 3.8-6: *Vertical extent of TAG plume at year 2055.*

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 3.8.

4.1 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% was used in the reservoir characterization modeling in Section 3.8 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 2060. Therefore, the plume extent at year 2060 is maximal, and the plume plus a one-half-mile buffer is the initial area with which to define the MMA (**Figure 4.1-1**).

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 extended MMA (**Figure 4.1-2**) from the initial MMA (**Figure 4.1-1**).

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 (**Figure 4.1-1**)
- The area covered by the lateral extent of known potential leakage pathways (the trace fault **Figure 4.1-2**) plus an all-around buffer zone of one-half mile around the traces.

Figure 4.1-2 shows the final MMA in a red polygon, as defined by Section 40 CFR 98.449 of Subpart RR.

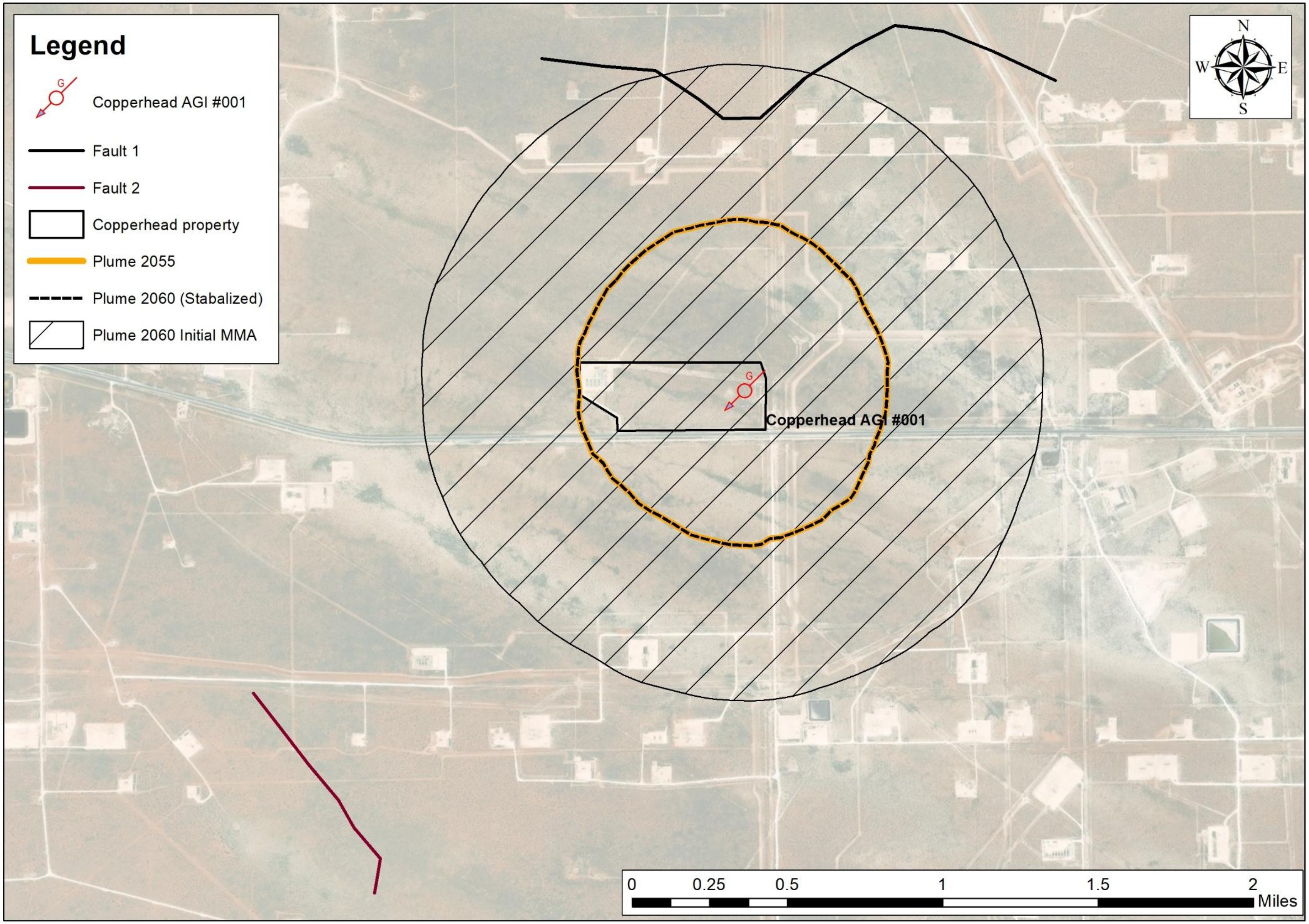


Figure 4.1-1: *Area covered by the stabilized plume plus an all-around buffer zone of one-half mile.*

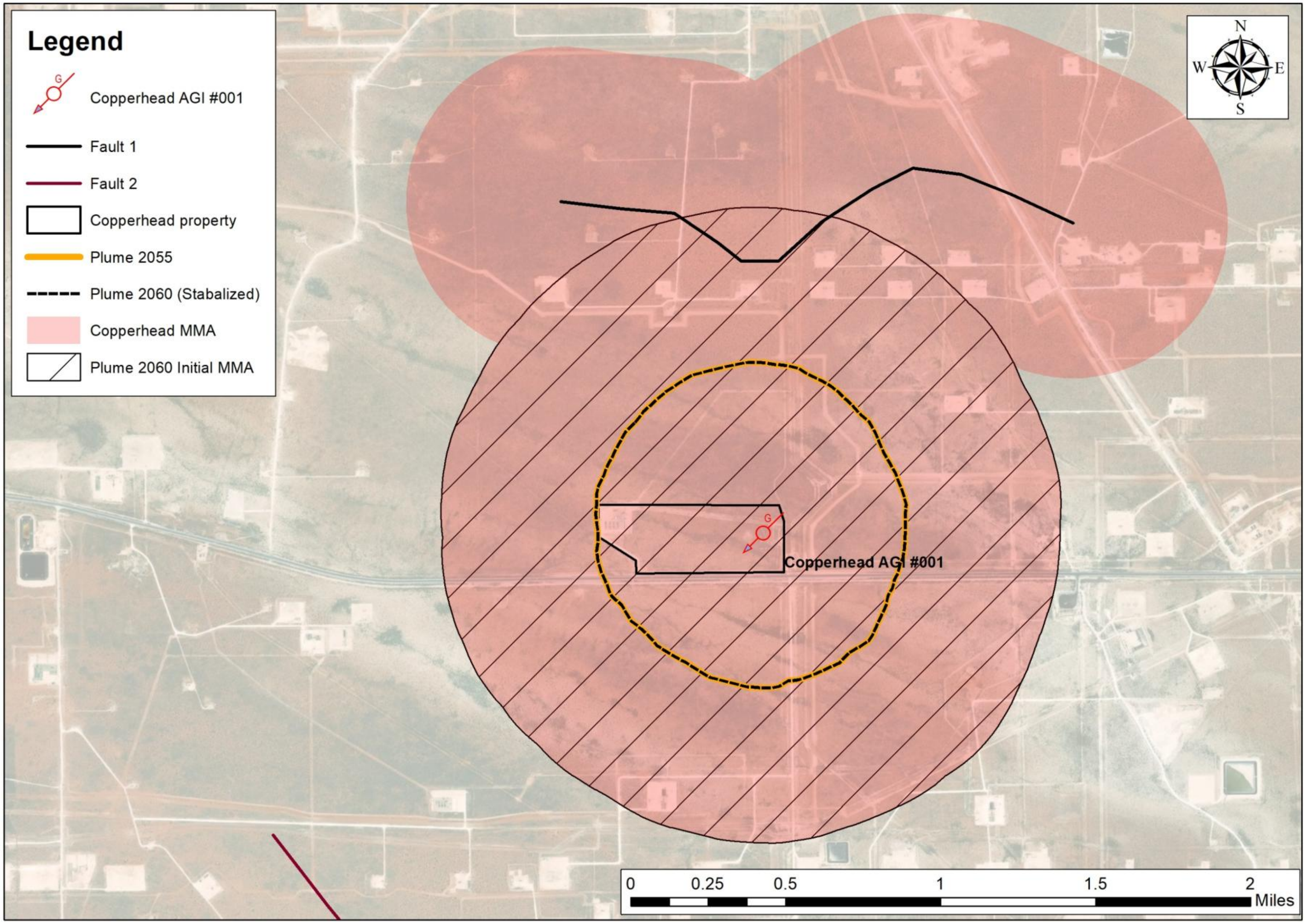


Figure 4.1-2: *The area covered by the lateral extent of known potential leakage pathways (the trace of the northern fault) plus an all-around buffer zone of one-half mile around the traces.*

4.2 AMA – Active Monitoring Area

As defined in Subpart RR, the AMA is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing 2 areas:

(Criteria 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.

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

Targa has chosen t=2055, which corresponds to the end of a 30-year injection period, for the purpose of calculating the AMA. The plume at t=2055 is plotted in an orange line in Figure 4.1-2.

The area defined by Criteria 1 is plotted and delineated by a red polygon. It is greater than the area projected to contain the free phase CO_2 plume at the end of year t=2055, plus an all-around buffer zone of one-half mile (black circle with grid lines) because it encompass the identified leakage pathways in Figure 4.1-2.

The area corresponding to Criteria 2 is plotted in Figure 4.1-2 and corresponds to the dotted line (plume a t+5=2060). According to the superimposition of the areas defined by Criteria 1 and Criteria 2, the AMA will correspond to the area delineated by the red polygon in Figure 4.1-2.

By applying the criteria defined by Subpart RR, Targa estimates that there are no advantages to establishing an AMA that is less than the MMA.

The analysis with t=2055 demonstrates that the AMA is contained within the MMA. Therefore, Targa considers the AMA equal to the MMA.

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 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. Risk of leakage through surface equipment;
2. Risk of leakage through oil & gas wells;
3. Risk of leakage through confining zone;
4. Risk of leakage due to lateral migration and faults;
5. Risk of leakage due to seismicity.

Risk estimates for the wells were made using a risk matrix (**Figure 5.1-1**) with a methodology to evaluate risk likelihood and magnitude. For likelihood of leakage, Targa attributed the value "1 – very unlikely" for all the wells that are outside the plume extent, outside the injection zone and outside the MMA. The values that were attributed according to the well location and depth are described in **Figure 5.1-2 and 5.1-3.**

For advanced risk analysis, 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.*

Likelihood	Within the plume	Within the MMA	Outside the MMA	
Inside IZ	4	3	2	*4 = Likely*
Below IZ	3	2	1	*3 = Moderate*
Above IZ	2	1	1	*2 = Unlikely*
				1 = Very Unlikely

Figure 5.1-2: *Value attribution for the risk matrix to evaluate the likelihood of an event.*

Magnitude	Within the plume	Within the MMA	Outside the MMA	
Inside IZ	4	3	2	*4 = Major*
Below IZ	3	2	1	*3 = Significant*
Above IZ	2	1	1	*2 = Minor*
				1 = Insignificant

Figure 5.1-3: *Value attribution for the risk matrix to evaluate the magnitude of an event.*

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 existing wells and the Copperhead AGI #001 well

Existing oil and gas wells within the MMA, as delineated in Section 4, are shown in **Figure 5.2-1** and detailed in **Table 5.2-1**. There are no active groundwater wells within the MMA. The only record for the only groundwater well (C-04427-POD1) located within the MMA indicates the well application was approved. This well was permitted as a monitoring well in the shallow alluvium to monitor an oil spill at one of the nearby facilities. However, there are no records for this well indicating it was actually drilled.

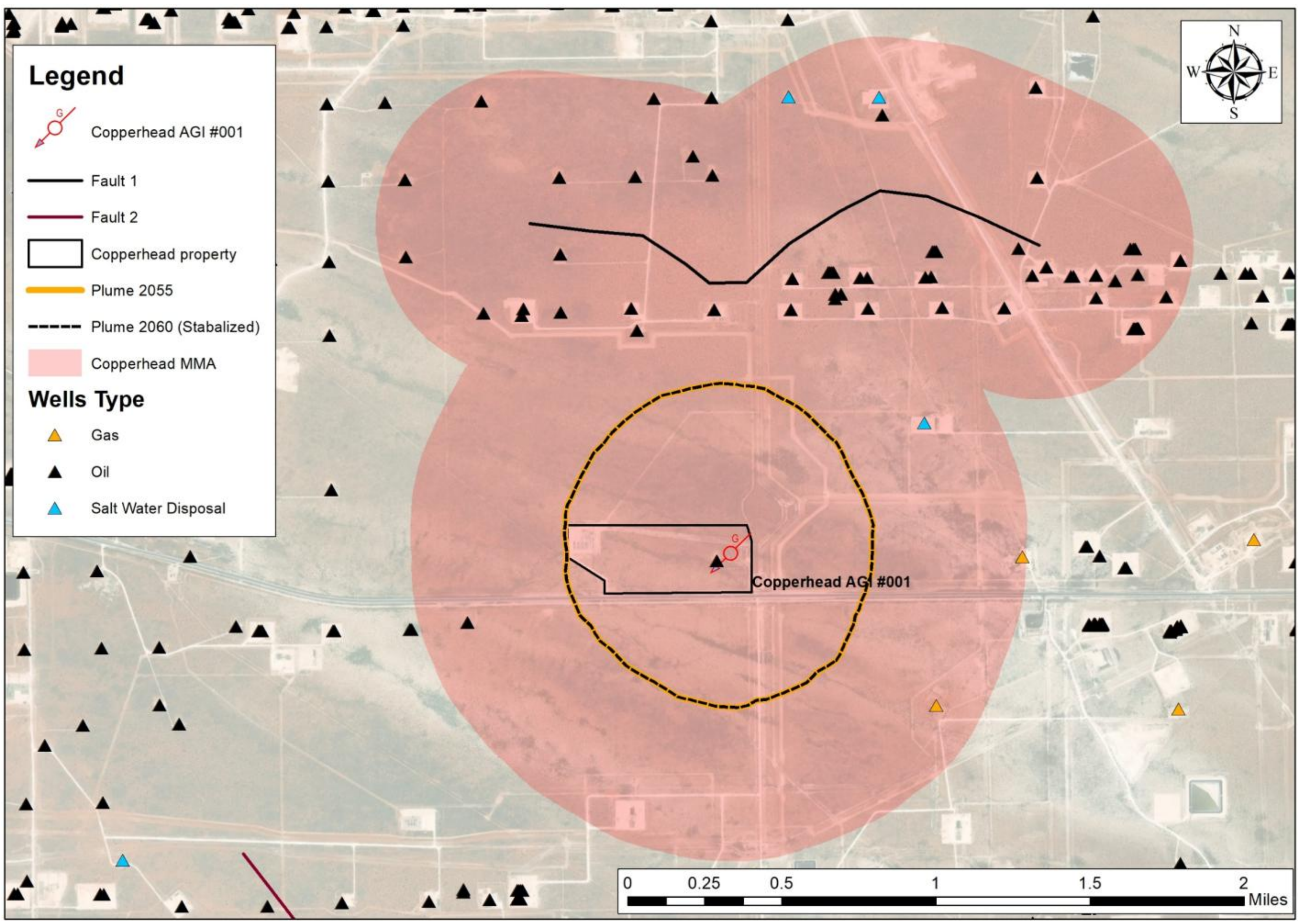


Figure 5.2-1: Existing wells within the monitoring areas.

Targa considered all wells completed and approved within the MMA in the NRAP risk assessment. None of the wells within the MMA penetrate the confining zone nor the injection zone. The active wells are completed within productive zones that are above the Copperhead AGI #001 well and lie at more than 5,100 feet above the top of the injection zone. They are all outside the stabilized plume, except for the plugged and abandoned well: Woolley #001, API #3002508147.

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 first), Targa did not omit any potential source of leakage in the risk analysis. Targa also analyzed the risk of leakage through the Copperhead AGI #001 well in the following sections.

The likelihood of risk of leakage through the permitted groundwater well is considered very unlikely.

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 6 wells inside MMA were addressed in the risk and NRAP analysis (**Table 5.2-1**). The reservoir and seal properties, well data, faults, formation stratigraphy, and MMA area were incorporated into the NRAP tool to forecast the potential rate and mass of CO_2 leakage.

A special consideration was given to the Woolley #001 well that is located within the plume extent and as a risk identified as low (**Table 5.1-1**). According to the NRAP results, an infinitesimal mass of CO_2 leaked through the Woolley #001 well over the 30 years injection period. Therefore, the magnitude of the risk of leakage is insignificant.

The magnitude leakage through the permitted groundwater well is considered insignificant.

Timing: The duration for an infinitesimal amount of CO_2 to get to the atmosphere via upward migration through the 5,300 feet of sealing rock then the plugged Woolley #001 well would be several thousands of years.

The same statement applies for the permitted groundwater well.

Table 5.2-1 summarizes the oil and gas wells and their evaluated risk. The risk of leakage through existing wells are all very low, except for Woolley #001 well, where the risk of leakage is considered low. The risk of leakage through the permitted groundwater well is very low.

To conclude, CO_2 leakage to the surface via existing wells can be considered very unlikely and insignificant.

Table 5.2-1: Oil and Gas-Related Wells within the MMA with their evaluated risk.

API	Well Name	Well Type	Well Status	Formation	Risk Likelihood (1-5)	Risk Magnitude (1-5)	Total Risk Rating (0-25)
30-025-08142	PRE-ONGARD WELL #003	Oil	Plugged	DELAWARE	1	1	1
30-025-08144	GULF HANAGAN FEDERAL #001	Oil	Active	DELAWARE	1	1	1
30-025-08146	PRE-ONGARD WELL #003	Oil	Plugged	DELAWARE	1	1	1
30-025-08147	PRE-ONGARD WELL #001	Oil	Plugged		2	2	4
30-025-08164	PRE-ONGARD WELL #001	Oil	Plugged		1	1	1
30-025-08368	PRE-ONGARD WELL #002	Oil	Plugged		1	1	1
30-025-08369	PRE-ONGARD WELL #001	Oil	Plugged		1	1	1
30-025-24432	INGRAM O STATE #002	Salt Water Disposal	Plugged	DELAWARE	1	1	1
30-025-24530	WIMBERLY #004	Oil	Plugged	DELAWARE	1	1	1
30-025-25181	WIMBERLY A #001	Oil	Active	DELAWARE	1	1	1
30-025-25388	PRE-ONGARD WELL #007	Oil	Plugged		1	1	1
30-025-25552	PRE-ONGARD WELL #008	Oil	Plugged	DELAWARE	1	1	1
30-025-26643	PRE-ONGARD WELL #002	Oil	Plugged	DELAWARE	1	1	1
30-025-29180	PRE-ONGARD WELL #001	Oil	Plugged		1	1	1
30-025-29181	PRE-ONGARD WELL #002	Oil	Cancelled		1	1	1
30-025-33717	STATE 19 #001	Gas	Plugged	WOLFCAMP	1	1	1
30-025-36489	COPPERHEAD 18 STATE #001	Gas	Active	WOLFCAMP	1	1	1
30-025-39883	MACHO NACHO STATE #002H	Oil	Active	BONE SPRING	1	1	1
30-025-40570	EATA FAJITA STATE #002H	Oil	Active	BONE SPRING	1	1	1
30-025-40582	EATA FAJITA STATE #001H	Oil	Active	BONE SPRING	1	1	1
30-025-40853	MACHO NACHO STATE #003H	Oil	Active	BONE SPRING	1	1	1
30-025-41056	HEARTTHROB BSX STATE #001H	Oil	Active	BONE SPRING	1	1	1
30-025-41057	HEARTTHROB BSX STATE #002H	Oil	Active	BONE SPRING	1	1	1
30-025-41126	MACHO NACHO STATE #004H	Oil	Active	BONE SPRING	1	1	1
30-025-41460	COPPERHEAD 18 STATE #002H	Oil	Active	BONE SPRING	1	1	1
30-025-41461	COPPERHEAD 18 STATE #003H	Oil	Active	BONE SPRING	1	1	1

30-025-41462	COPPERHEAD 18 STATE #004H	Oil	Active	BONE SPRING	1	1	1
30-025-41463	COPPERHEAD 18 STATE #005H	Oil	Active	BONE SPRING	1	1	1
30-025-41477	DOS EQUIS 13 FEDERAL COM #003H	Oil	Cancelled	BONE SPRING	1	1	1
30-025-41478	DOS EQUIS 13 FEDERAL COM #004H	Oil	Cancelled	BONE SPRING	1	1	1
30-025-41479	DOS EQUIS 13 FEDERAL COM #001H	Oil	Active	BONE SPRING	1	1	1
30-025-41480	DOS EQUIS 13 FEDERAL COM #002H	Oil	Active	BONE SPRING	1	1	1
30-025-41735	COPPERHEAD 18 STATE SWD #001	Salt Water Disposal	Active	DELAWARE	1	1	1
30-025-41958	MACHO NACHO STATE COM #005H	Oil	Active	BONE SPRING	1	1	1
30-025-41999	EATA FAJITA STATE #008C	Oil	Cancelled	BONE SPRING	1	1	1
30-025-42345	COPPERHEAD 18 CN STATE #001C	Oil	Cancelled	BONE SPRING	1	1	1
30-025-42346	COPPERHEAD 18 DM STATE #002C	Oil	Cancelled	BONE SPRING	1	1	1
30-025-42439	COPPERHEAD 18 DM CN STATE #001C	Oil	Cancelled	BONE SPRING	1	1	1
30-025-42453	MACHO NACHO STATE COM #010H	Oil	Active	BONE SPRING	1	1	1
30-025-42463	MACHO NACHO 7 STATE SWD #001	Salt Water Disposal	Active	BELL CHERRY CANYON	1	1	1
30-025-42487	EATA FAJITA STATE #013H	Oil	Active	BONE SPRING	1	1	1
30-025-42488	MACHO NACHO STATE COM #006H	Oil	Active	BONE SPRING	1	1	1
30-025-42489	MACHO NACHO STATE COM #007H	Oil	Active	BONE SPRING	1	1	1
30-025-42505	EATA FAJITA STATE #011H	Oil	Active	BONE SPRING	1	1	1
30-025-42506	EATA FAJITA STATE #012H	Oil	Active	BONE SPRING	1	1	1
30-025-42517	MACHO NACHO STATE COM #008H	Oil	Active	BONE SPRING	1	1	1

30-025-42518	MACHO NACHO STATE COM #009H	Oil	Active	BONE SPRING	1	1	1
30-025-45416	DOS EQUIS 13 FEDERAL COM #009H	Oil	Active	WOLFCAMP	1	1	1
30-025-45417	DOS EQUIS 13 FEDERAL COM #010H	Oil	Active	BONE SPRING	1	1	1
30-025-47137	HEARTTHROB 17 STATE #201H	Oil	Active	BONE SPRING	1	1	1
30-025-47138	HEARTTHROB 17 STATE #202H	Oil	Active	BONE SPRING	1	1	1
30-025-47139	HEARTTHROB 17 STATE #203H	Oil	Active	BONE SPRING	1	1	1
30-025-47140	HEARTTHROB 17 STATE #204H	Oil	Active	BONE SPRING	1	1	1
30-025-48386	HEARTTHROB 17 STATE #101H	Oil	Active	BONE SPRING	1	1	1
30-025-48387	HEARTTHROB 17 STATE #102H	Oil	Active	BONE SPRING	1	1	1
30-025-52370	EATA FAJITA STATE COM #605H	Oil	New	BONE SPRING	1	1	1
30-025-52371	EATA FAJITA STATE COM #607H	Oil	New	BONE SPRING	1	1	1
30-025-52372	EATA FAJITA STATE COM #608H	Oil	New	WOLFCAMP	1	1	1
30-025-52425	EATA FAJITA STATE COM #606H	Oil	New	WOLFCAMP	1	1	1
30-025-52426	MACHO NACHO STATE COM #601H	Oil	New	BONE SPRING	1	1	1
30-025-52427	MACHO NACHO STATE COM #603H	Oil	New	BONE SPRING	1	1	1
30-025-52428	MACHO NACHO STATE COM #605H	Oil	New	BONE SPRING	1	1	1
30-025-52429	MACHO NACHO STATE COM #607H	Oil	New	BONE SPRING	1	1	1
30-025-52430	MACHO NACHO STATE COM #602H	Oil	New	WOLFCAMP	1	1	1
30-025-52431	MACHO NACHO STATE COM #604H	Oil	New	WOLFCAMP	1	1	1
30-025-52432	MACHO NACHO STATE COM #606H	Oil	New	WOLFCAMP	1	1	1
30-025-52433	MACHO NACHO STATE COM #608H	Oil	New	WOLFCAMP	1	1	1

5.3 Potential leakage through the confining/seal system

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

Likelihood:

The Barnett Shale (253 feet), Mississippian Limestone (392 feet) and Woodford Shale (125 feet) serve as the major seals or caprock layers to the injection zones. Their low porosity (<1.5%) and permeability (<0.1 mD) provide high seal integrity (**Sections 3.2, 3.3**). Leakage through confining zones can occur through low permeability shales containing natural fractures. There is no evidence of faulting or natural fracturing in the confining zone within the maximum plume boundary. Though there are no reported fractures within the confining zones, the NRAP risk assessment was still carried out to ascertain the sealing integrity. 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 model.

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 for the NRAP analysis is defined as leakage through the seal immediately above the injection wells, where CO_2 saturation is highest.

Figure 5.3-1 presents the leakage rate and cumulative mass of leakage over 50 years. The total leakage mass recorded after 50 years is about 4,000 kg. According to the total mass of CO_2 injected per year alone, after 50 years, the percentage of leakage through confining zone is estimated to be infinitesimal. Considering other stratigraphic strata above the primary seal and the subsequent seals, Targa concludes that the risk of leakage through this pathway is highly unlikely and insignificant.

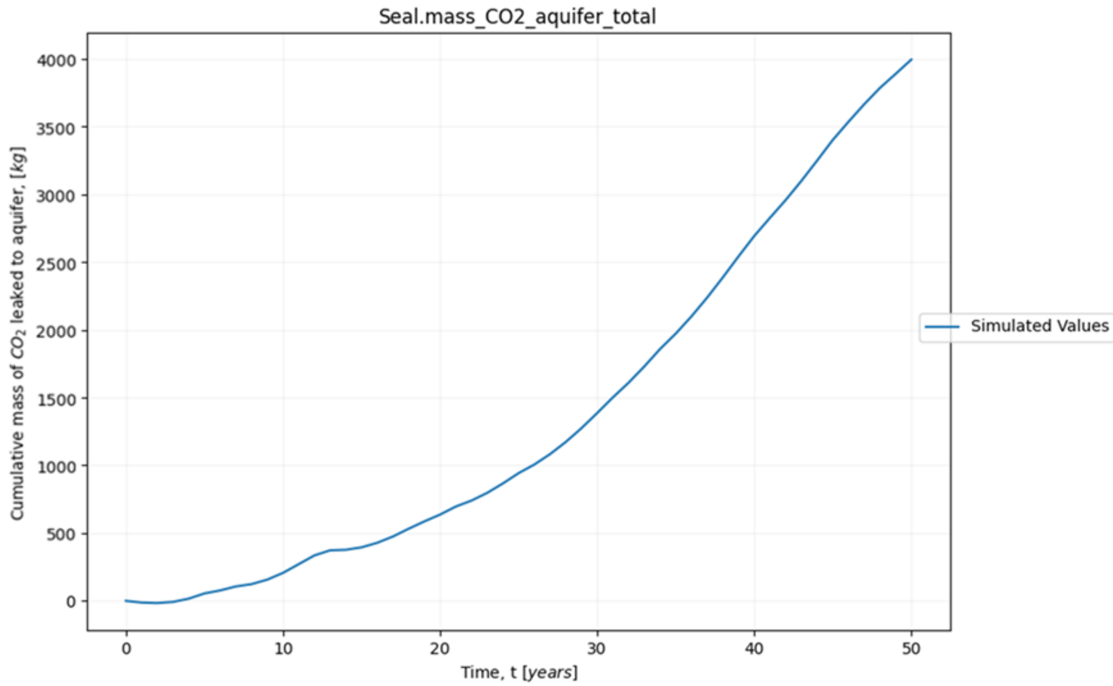


Figure 5.3-1: *Estimated seal leakage rate.*

5.4 Potential leakage due to lateral migration

Likelihood:

Regional consideration of the geology (Section 3.2 and 3.3) and the geological model built suggest that the Copperhead AGI #001 well injection zone has adequate storage capacity and the confining zone is uniform above the proposed injection zone. In addition, simulations (Section 3.8) indicate 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 and NRAP analysis, 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.

Based on this analysis, the potential magnitude of a leak due to lateral migration is considered insignificant.

Therefore, risk of leakage due to lateral migration is considered to be very low.

5.5 Potential leakage through fractures and faults

Likelihood:

A thorough geological characterization of the injection zone and surrounding formations was performed (see Section 3) to understand the geology and to identify and understand the distribution of faults and fractures. **Figure 4.1-1** shows the fault traces (numbered 1 and 2) in the vicinity of the Copperhead plant and within the Siluro-Devonian formations. Fault 2 is outside the MMA. Fault 1 is inside the MMA. The MMA encompasses a half mile buffer zone to make sure there are no risk of leakage due to lateral migration. Therefore, considering the maximum plume extent boundaries, the likelihood of leakage through faults is considered very unlikely.

Magnitude and Timing:

The closest identified fault is Fault 1 in **Figure 5.5-1**, it lies approximately 0.88 miles North of the Copperhead site. Fault 1 penetrates the injection and confining zones and dying in the Lower Wolfcamp. However, the risk of leakage through Fault 1 only occurs if there is lateral migration of CO_2 or if the fault directly cuts through the CO_2 plume. Fault 1 is inside the MMA and the risk of lateral migration is very unlikely. Hence, leakage through this fault would be a very unlikely event. This is supported by NRAP simulation results 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 very unlikely and insignificant. The estimated cumulative leakage shows no leakage throughout the period of simulation.

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

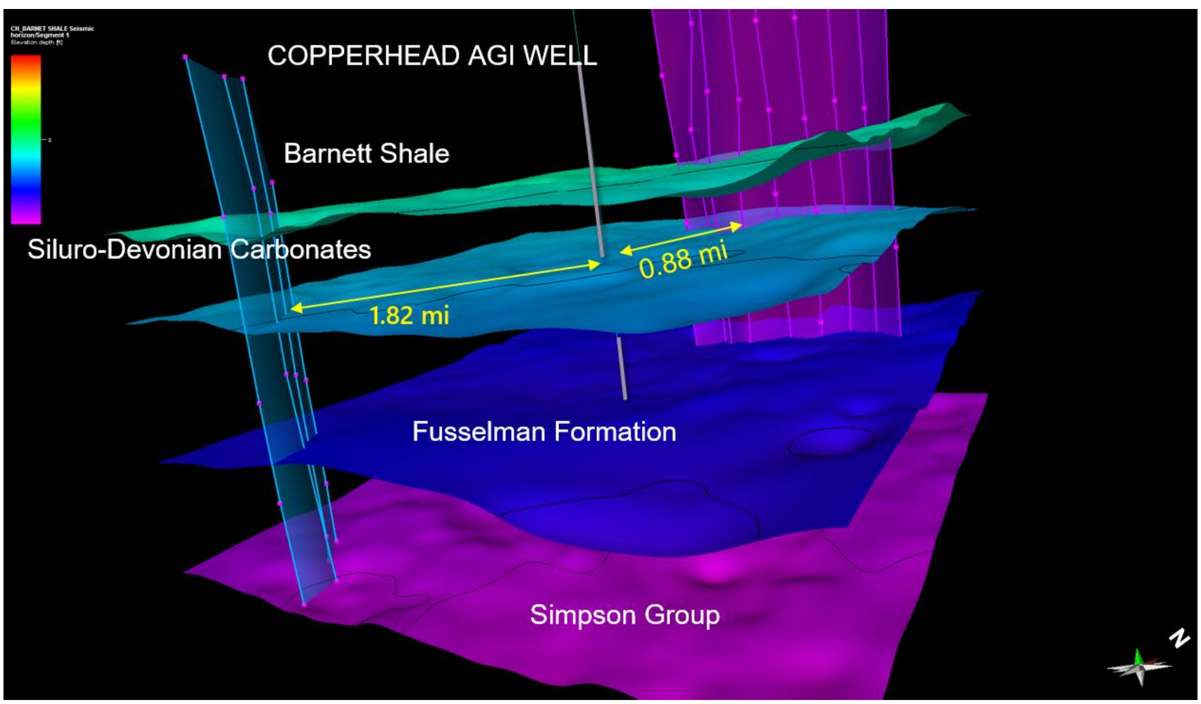


Figure 5.5-1: *Faults surrounding the Copperhead AGI #001 well, injection zone and confining zones.*

5.6 Potential leakage due to natural and induced seismicity

Likelihood:

Figure 5.5-1 highlights the recorded seismic events since 2017 within 20 miles of Copperhead. The events magnitude ranged from M 2.0 – M 4.03. The closest event to the Copperhead AGI #001 well was a M 2.0 event, 8.3 miles away. The largest event was a M 4.03 event, approximately 9.7 miles away from the well location. All other events within 10-mile radius are M 3.0 or less. Most events within a 20-mile radius are clustered to the southwest of the well location, with the majority almost 20 miles away.

Due to the distance between the Copperhead AGI #001 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 or induced seismicity to be very unlikely.

Magnitude and Timing:

The impact of a seismic event on confining zones, wells and surface installation integrity can vary greatly according to events magnitude or frequency. However, based on historical data and the geology of the surrounding area, seismic activity around the Copperhead AGI #001 well are low. If the integrity of either the Copperhead AGI #001 well or the Copperhead infrastructure were compromised due to seismic event(s) Targa would shut down operations immediately.

Therefore, Targa considers the risk of CO_2 leakage following a seismic event to be unlikely and insignificant. Monitoring of seismic events in the vicinity of the Copperhead AGI #001 well is discussed in Section 6.7.

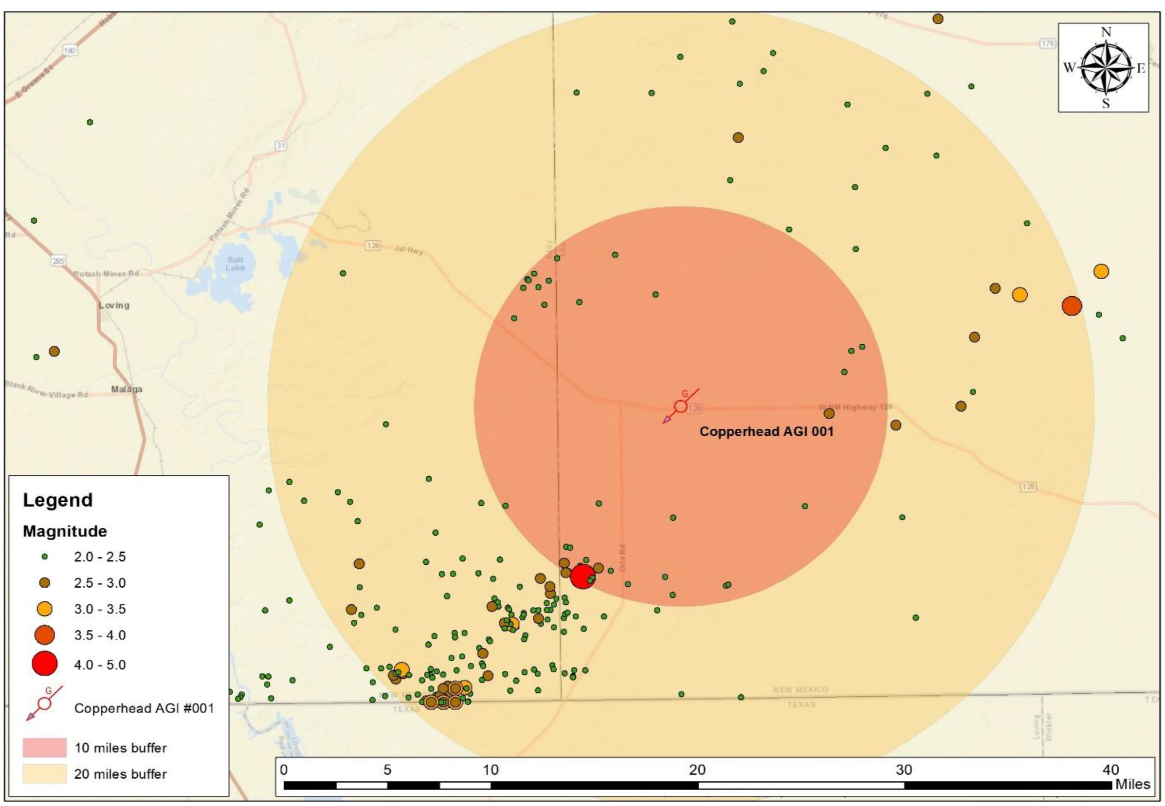


Figure 5.5-1: *Data from New Mexico Tech Seismological Observatory and USGS databases, showing all seismic events of magnitude 2.0 or greater. Circles show 10- and 20-mile radius buffer around the Copperhead AGI #001 well. Data for the period 1/12/17 to 4/12/2024.*

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 monitoring techniques that will be employed to identify leaks.

Monitoring will occur for the duration of injection period and the 5-year post-injection period. The plume is stabilized after 5 years without injection (2060).

Table 6-1: *Summary of leak detection monitoring strategies*

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 (LiCor) • Personal and hand-held gas monitors
Copperhead AGI #001 Well	• DCS surveillance of well operating parameters • Visual inspections • Mechanical integrity tests (MIT) • Fixed in-field gas monitors • CO_2 flux monitoring network (LiCor) • 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 (LiCor) • Groundwater monitoring
Confining Zone / Seal	• DCS surveillance of well operating parameters • Fixed in-field gas monitors • CO_2 flux monitoring network (LiCor) • 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 (LiCor) • Groundwater monitoring
Additional Monitoring	• Groundwater monitoring • Soil flux monitoring

6.1 Leakage from surface equipment

Targa implements several tiers of monitoring for leakage from surface equipment 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 and maintenance 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

Currently there are no approved-not-yet-drilled wells within the MMA. However, 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 or within the Copperhead AGI #001 injection zone within the MMA. This requirement will be made by NMOCD in regulating applications for permit to drill (APD) and in ensuring that the operator and driller are aware that they are drilling through an H_2S injection zone in order to access their target production formation. NMAC 19.15.11 for Hydrogen Sulfide Gas includes standards for personnel and equipment safety and H_2S detection and monitoring during well drilling, completion, well workovers, and well servicing operations all of which apply for wells drilled through the Copperhead AGI #001 well TAG plume. The purpose of these special precautions is to identify immediately the occurrence of a surface leak of the TAG stream which is followed by immediate response to minimize the likelihood and magnitude of the leak.

6.3 Leakage from existing wells

6.3.1 Copperhead AGI #001 well

As part of ongoing Targa operations, Targa continuously monitors and collects gases 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, Targa will deploy pressure and temperature gauges, Distributed Temperature Sensing (DTS) and a fiber optic line (DAS). One gauge is designated to monitor the tubing ID (reservoir) pressure and temperature and the second gauge monitors the annular space between the tubing and the long string casing (**Appendix 1**). The DTS system is clamped to the tubing, and it monitors the temperature profiles of the annulus. DTS can detect variation in the temperature profile events throughout the tubing and or casing. Temperature variation could be an indicator of leaks. Data from temperature and pressure gauges is recorded by an interrogator housed in an onsite control room. DTS (temperature) data is recorded by a separate interrogator that is also housed in the onsite control room. Data from both interrogators are transmitted to a remote location for daily real time or historical data analysis.

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 schematics for the Copperhead AGI #001 well 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, soil CO_2 flux, and groundwater 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 Copperhead AGI #001 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 techniques 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 monitoring within the MMA during and after the period of 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 seismic network and an onsite seismometer that will be installed. The network consists of seismic monitoring stations that detect and locate seismic events in real time. Continuous monitoring helps differentiate between natural and induced seismicity. The network surrounding the Copperhead Gas Processing Plant has been displayed on **Figure 5.6-2**. 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 a seismic event, Targa will assess the integrity of the Copperhead plant and well. If the event caused CO_2 leaks, Targa will act 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.

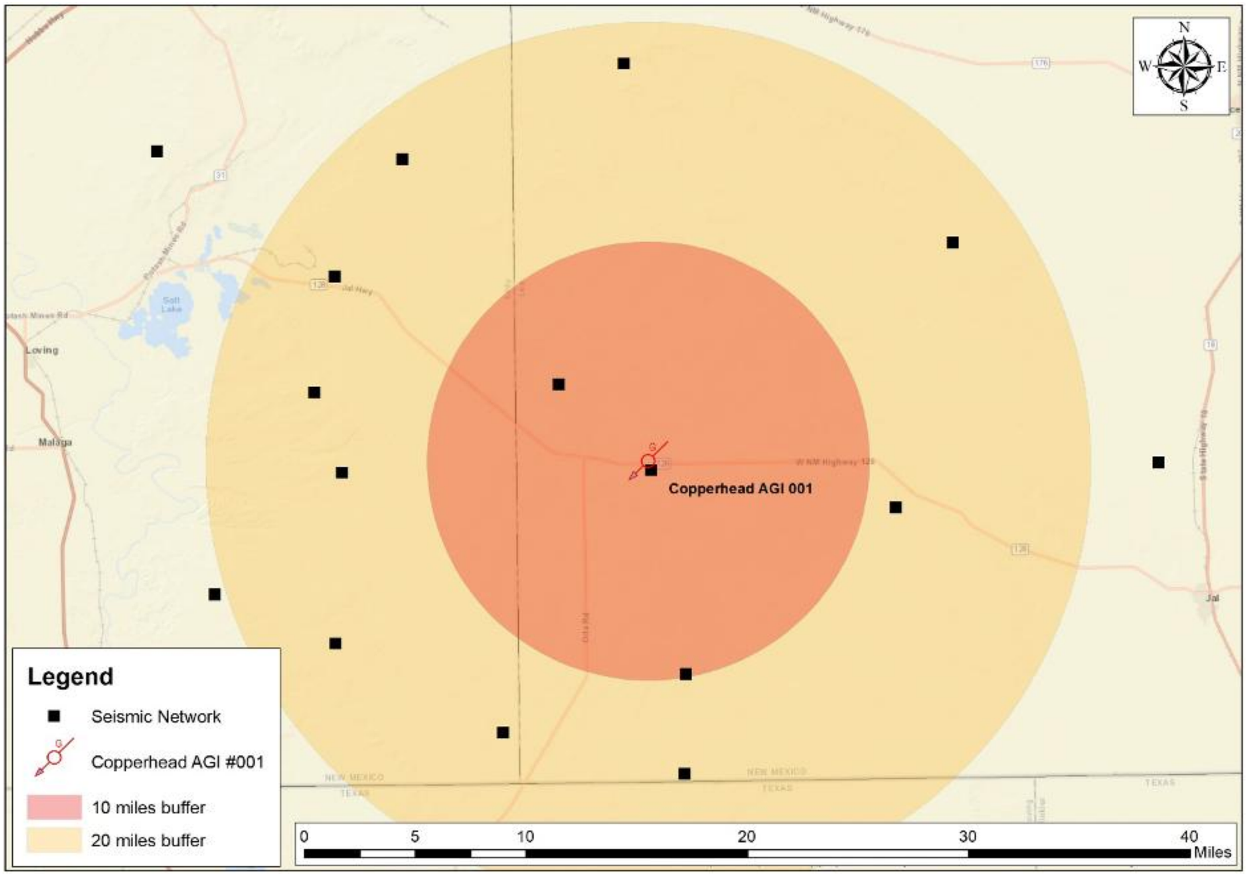


Figure 6.7-1: *Seismic monitoring stations from New Mexico Tech Seismological Observatory.*

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. Targa has standard operating procedures to report and quantify all pipeline leaks in accordance with the NMOCD 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.

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 Copperhead Gas Plant.

7.2 Fixed in-field, handheld, and personal H_2S monitors

Compositional analysis of Targa's gas injectate at the Copperhead 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 NMOCD 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 Copperhead AGI #001 well and documents procedures that would be followed in case of such an event.

7.2.1 Fixed in-field H_2S monitors

The Copperhead 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 NMOCD 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, NMOCD 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 Copperhead AGI #001 well ensure frequent periodic inspection of the well and opportunities to detect leaks and implement corrective action.

7.6 Seismic (microseismic) monitoring stations

Targa will install a seismometer and a digital recorder to monitor and record data for any seismic event at the Copperhead Gas Plant. The seismic station meets the requirements of the NMOCD.

In addition, data that is recorded by the New Mexico Tech Seismological Observatory network surrounding the Copperhead 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 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 Copperhead 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 ($NO3^{-}$) (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

Soil flux data will be used assess any 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. 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 a baseline and understand seasonal and other variations at the Copperhead 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 Copperhead 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 Copperhead 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 meters 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 the Copperhead AGI #001 well. Equation RR-5 will be used to calculate CO_2 measured through volumetric flow meter 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 described 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.

* Refer to RR-4 or RR-5 for the calculation of $CO_{2,u}$

8.3 CO_2 produced / recycled

Targa does not produce oil or gas or any other liquid at its Copperhead 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 Copperhead 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 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 Targa for several years at other locations and continue to the present. They will be implemented at Copperhead facility. Targa will begin implementing this MRV plan as soon as it is approved by EPA. After the Copperhead AGI #001 well 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 Copperhead AGI #001 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 Copperhead 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 the Copperhead AGI #001 well 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.

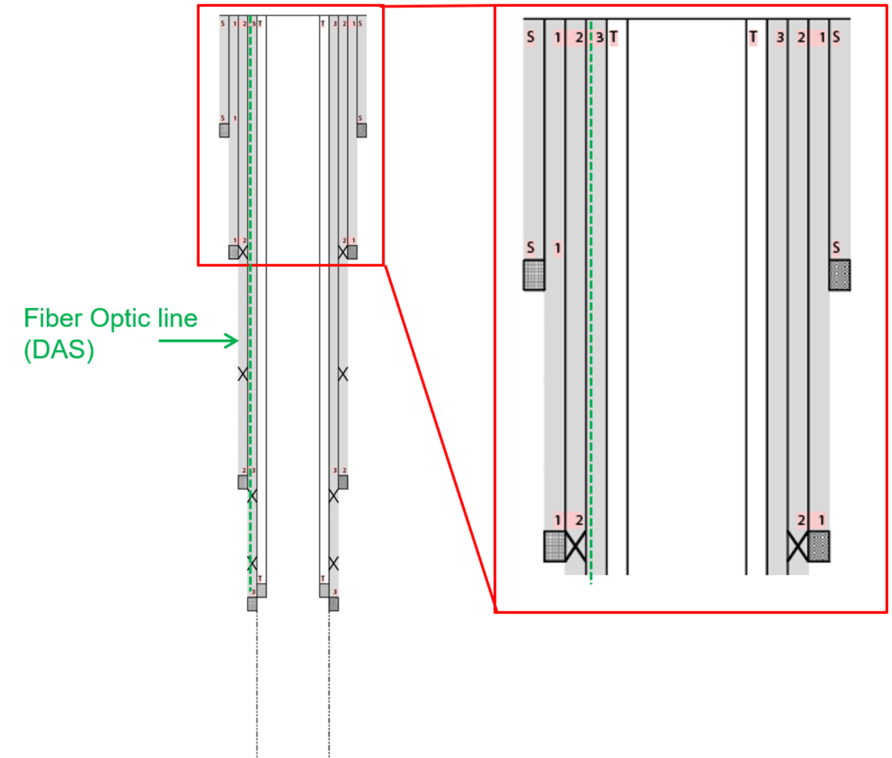
(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(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	Rate	Total Depth
Copperhead AGI #001	To be determined	Section 13, Township 24 South, Range 32 East	Lea County, New Mexico	26 million standard cubic feet per day	18,689 feet



Surface - (Conventional)

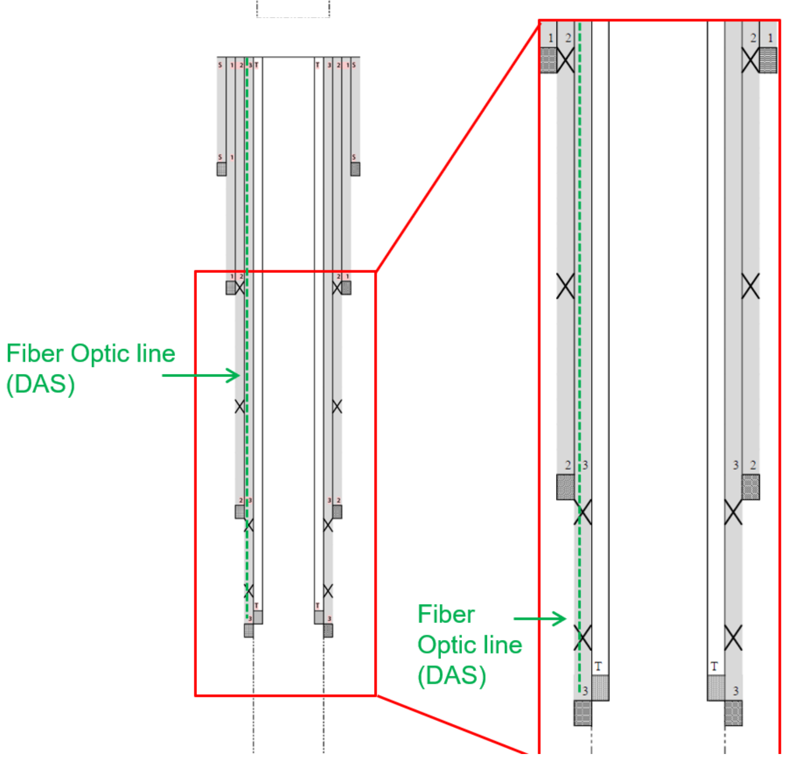
Hole Size:	26"
Casing:	20" - 106.5# J-55 BTC Casing
Depth Top:	Surface
Depth Btm:	1208'
Cement:	Lead Class C 1680 sks, 12.9 ppg, 1.97 cuft/sk Tail Class C 200 sks, 14.8 ppg, 1.34
Cement Top:	cuft/sk Surface - (Circulate)

Intermediate #1 - (Conventional)

Hole Size:	17.5"
Casing:	13.375" - 72L-80 BTC Casing
Depth Top:	Surface
Depth Btm:	5034'
Cement:	Lead Class C, 1450 sks, 11.8 ppg, 2.45 cuft/sk Tail CorrosaCem, 200 sks, 14.5 ppg, 1.30 cuft/sk
Cement Top:	Surface - (Circulate)

Intermediate #2 - (Conventional)

Hole Size:	12.25"
Casing:	9.625" - 47# HCL-80 BTC Casing Bond Coat 5034'-7100'
Depth Top:	Surface
Depth Btm:	12250'
Cement 1:	Lead Class C, 892 sks, 12.5 ppg, 1.63 cuft/sk Tail Class C, 100 sks, 14.8 ppg, 1.33 cuft/sk
Cement Top:	7100' - (Circulate)
ECP/DV Tool:	7100'
Cement 2:	362 sks-CorrosaCem, 12.0 ppg, 1.75 cuft/sk
Cement 2 Top:	5070'- (Circulate)
DV Tool:	5070'
Cement 3:	Lead Class C, 850 sks, 12.5 ppg, 1.63 cuft/sk Tail Class C, 200 sks, 14.8 ppg, 1.33 cuft/sk
Cement 3 Top:	Surface - (Circulate)



Production

Hole Size:	8.5"
Casing #1:	7" - 32# P-110 TCPC Casing (or equivalent)
Depths:	Surface - 16999'
Casing #2:	7" - 32# G3-110 TCPC Casing (or equivalent)
Depths:	16999' - 17299'
Cement:	7 bbl WellLock Resin
Cement Top:	12,200'
ECP/DV Tool:	16,999'
Cement 2:	Lead Class H, 263 sks, 12.5 ppg, 1.63 cuft/sk Tail Class H, 200 sks, 14.8 ppg, 1.33 cuft/sk
Cement 2 Top:	12200' - (Circulate)
ECP/DV Tool:	12200'
Cement 3:	Lead Class C 1013 sks, 12.5 ppg, 1.63 cuft/sk Tail Class C 200 sks, 14.8 ppg, 1.33 cuft/sk
Cement 3 Top:	Surface - (Circulate)

Intermediate #4 - (Open Hole)

Hole Size:	5.875"
Depth:	18699'
Inj. Interval:	17299' - 18699'

Tubing - (Conventional)

Tubing Depth:	0 - 16950' L80, 16950 - 17250 G3
Tubing:	3.5" - 9.2# G3-110 VAMTOP (or equivalent)
Packer Depth:	17250'
Packer:	3.5" - "Perma-Pak" or Equivalent (Inconel)
Packer Fluid:	Diesel + Additives

Figure Appendix 1-1: *Schematic of the Copperhead AGI #001 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

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

CHAPTER 15 - OIL AND GAS

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

19.15.25 NMAC	PLUGGING AND ABANDONMENT OF WELLS
19.15.26 NMAC	INJECTION
19.15.27 - 28 NMAC	[RESERVED] PARTS 27 - 28
19.15.29 NMAC	RELEASES
19.15.30 NMAC	REMEDIATION
19.15.31 - 33 NMAC	[RESERVED] PARTS 31 - 33
19.15.34 NMAC	PRODUCED WATER, DRILLING FLUIDS AND LIQUID OIL FIELD WASTE
19.15.35 NMAC	WASTE DISPOSAL
19.15.36 NMAC	SURFACE WASTE MANAGEMENT FACILITIES
19.15.37 NMAC	REFINING
19.15.38 NMAC	[RESERVED]
19.15.39 NMAC	SPECIAL RULES
19.15.40 NMAC	NEW MEXICO LIQUIFIED PETROLEUM GAS STANDARD
19.15.41 - 102 NMAC	[RESERVED] PARTS 41 - 102
19.15.103 NMAC	SPECIFICATIONS, TOLERANCES, AND OTHER TECHNICAL REQUIREMENTS FOR COMMERCIAL WEIGHING AND MEASURING DEVICES
19.15.104 NMAC	STANDARD SPECIFICATIONS/MODIFICATIONS FOR PETROLEUM PRODUCTS
19.15.105 NMAC	LABELING REQUIREMENTS FOR PETROLEUM PRODUCTS
19.15.106 NMAC	OCTANE POSTING REQUIREMENTS
19.15.107 NMAC	APPLYING ADMINISTRATIVE PENALTIES
19.15.108 NMAC	BONDING AND REGISTRATION OF SERVICE TECHNICIANS AND SERVICE ESTABLISHMENTS FOR COMMERCIAL WEIGHING OR MEASURING DEVICES
19.15.109 NMAC	NOT SEALED NOT LEGAL FOR TRADE
19.15.110 NMAC	BIODIESEL FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.111 NMAC	E85 FUEL SPECIFICATION, DISPENSERS, AND DISPENSER LABELING REQUIREMENTS [REPEALED]
19.15.112 NMAC	RETAIL NATURAL GAS (CNG / LNG) REGULATIONS [REPEALED]

Appendix 3: Oil and gas wells within the MMA of Copperhead AGI #001

API	Well Name	Operator	Well Type	Well Status	Formation
30-025-08147	WOLLEY 001	PRE-ONGARD WELL OPERATOR	Oil and Gas	Plugged	DELAWARE
30-025-41480	DOS EQUIS 13 FEDERAL COM 002H	CIMAREX ENERGY CO.	Oil and Gas	Active	Bone Spring
30-025-41460	COPPERHEAD 18 STATE 002H	OXY USA INC	Oil and Gas	Active	Bone Spring
30-025-25181	WIMBERLY A 001	Finaly Resources LLC	Oil and Gas	Active	DELAWARE
30-025-41735	COPPERHEAD 18 STATE SWD 001	OXY USA INC	Salt Water Disposal	Active	DELAWARE
30-025-41479	DOS EQUIS 13 FEDERAL COM 001H	CIMAREX ENERGY CO.	Oil and Gas	Active	Bone Spring

Appendix 4: References

Ashworth, J. B., 1990, Evaluation of ground-water resources in parts of Loving, Pecos, Reeves, Ward, and Winkler counties, Texas: Texas Water Development Board, Report 317, 51 p.

Broadhead, R.F., 2017. Energy and Mineral Resources of New Mexico: Petroleum Geology; Socorro, New Mexico Bureau of Geology and Mineral Resources: 104 p.

Bradley, R.G., and Kalaswad, S., 2003, The Groundwater Resources of the Dockum Aquifer in Texas: Texas Water Development Board Report, 359

Bradley, R.G. and Kalaswad, S., 2004, The Dockum aquifer in the Edwards Plateau: in. Aquifers of the Edwards Plateau: Texas Water Development Board Report, 360, pp.149-164.

Case No. 20779, Notice Regarding Hearing Exhibits, Application of Lucid Energy Delaware, LLC for Authorization to Inject, Lea County, New Mexico

Garza, S., and Wesselman, J.B., 1963, Geology and ground-water resources of Winkler County, Texas: U.S. Government Printing Office 1582, doi:10.3133/wsp1582.

Ewing, E., 2019. Tectonics of the West Texas (Permian) Basin—Origins, structural geology, subsidence, and later modification: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 63-96.

Fu, Q., Baumgardner, R.W., Jr., and Hamlin, H.S., 2020. Early Permian (Wolfcampian) succession in the Permian Basin: icehouse platform, slope carbonates, and basinal mudrocks: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 185-225.

Ge, J., Nicot, J.P., Hennings, P.H., Smye, K.M., Hosseini, S.A., Gao, R.S., and Breton, C.L., 2022. Recent water disposal and pore pressure evolution in the Delaware Mountain Group, Delaware Basin, Southeast New Mexico and West Texas, USA: Journal of Hydrology: Regional Studies 40: 101041.

George, P.G., Mace, R.E., and Petrossian, R., 2011, Aquifers of Texas: Texas Water Development Board, Report 380, 172 p.

Harrington, R., 2019. The Middle–Upper Ordovician Simpson Group of the Permian Basin: stratigraphy, lithofacies, and reservoir development: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 331-352.

Harrington, R. and Ruppel, S., 2019. Patterns of Montoya Group (Middle Ordovician) deposition, diagenesis, and reservoir development in the Permian Basin: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 353-378.

Hills, J.M., 1984. Sedimentation, tectonism, and hydrocarbon generation in Delaware Basin, west Texas and southeastern New Mexico: The American Association of Petroleum Geologists Bulletin 68: 250-267.

King, P.B., 1948. Geology of the southern Guadalupe Mountains, Texas: United States Geological Survey Professional Paper 215: 183 p.

Loucks, R. and Kerans, C., 2019. A Geologic review of the Lower Ordovician Ellenburger Group of the Permian Basin, West Texas and southeast New Mexico: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 295-330.

Luo, Ming; Baker, Mark R.; and LeMone, David V.; 1994, Distribution and Generation of the Overpressure System, Eastern Delaware Basin, Western Texas and Southern New Mexico, AAPG Bulletin, V.78, No. 9 (September 1994) p. 1386-1405.

Nance, H.S., 2020. Upper Permian Delaware Mountain Group: Record of highstand/lowstand platform: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 399-436.

Nance, H.S., Hamlin, H.S., 2020. The Bone Spring Formation (Leonardian) of the Delaware Basin: deepwater lithofacies and stratigraphy: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 321-348.

Nicholson, A., Jr., Clebsch, A., Jr., 1961. *Geology and ground-water conditions in southern Lea County, New Mexico.* New Mexico Bureau of Mines and Mineral Resources, Ground-Water Report 6, 123 pp., 2 Plates.

Ruppel, S., 2019a. Anatomy of a Paleozoic basin: the Permian Basin, USA: Introduction, overview, and evolution: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 1-27.

Ruppel, S., 2019b. The Fusselman of the Permian Basin: patterns in depositional and diagenetic facies development on a stable platform during the Late Ordovician–Early Silurian icehouse: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 1), Austin, The University of Texas at Austin, Bureau of Economic Geology: 379-399.

Ruppel, S., 2020. The Middle Silurian–Lower Devonian Wristen Group, Permian Basin: impact of tectonic subsidence on patterns of deposition, diagenesis, and reservoir development: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 1-36.

Ruppel, S., Hovorka, S., Barnaby, R., 2020a. Proximal shallow-water carbonates and distal biosiliceous cherts of the Lower Devonian Thirtyone Formation, Permian Basin: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 37-74.

Ruppel, S.C., Rowe, H., Reed, R., Barrick, J.E., James, E.W., Loucks, R.G., 2020b. The Woodford Formation of the Permian Basin: regional, Middle to Late Devonian transgression of the southern Midcontinent and accompanying global anoxia: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 75-124.

Scholle, P.A., Goldstein, R.H., Ulmer-Scholle, D.S., 2007. Classic Upper Paleozoic reefs and bioherms of West Texas and New Mexico: Field guide to the Guadalupe and Sacramento Mountains of West Texas and New Mexico. Socorro, New Mexico Bureau of Geology and Mineral Resources, Open-File Report 504: 178 p.

Scholle, P., Broadhead, R.F., McLemore, V., 2020. The Permian Basin: Scholle, P., Ulmer-Scholle, D., Cather, and S., Kelley, S. (eds.), The Geology of Southern New Mexico Parks, Monuments, and Public Lands: Socorro, New Mexico Bureau of Geology and Mineral Resources: 285-295.

Smye, K.D., Banerji, A., Eastwood, R., McDaid, G., and Hennings, P., 2021. Lithology and reservoir properties of the Delaware Mountain Group of the Delaware Basin and implications for saltwater disposal and induced seismicity: Journal of Sedimentary Research 91 (11): 1113–1132.

Texas Water Development Board (TWDB), 2024, Groundwater Database and Submitsubmitted Driller Report Database, https://www.twdb.texas.gov/groundwater/data/gwdbrpt.asp, accessed April 2024

US EPA, O., 2015, *Procedures for Groundwater Sampling in the Laboratory Services and Applied Science Division*: https://www.epa.gov/quality/procedures-groundwater-sampling-laboratory-services-and-applied-science-division (accessed September 2023).

Ward, R.F., Kendall, C.G.St.C., Harris, P.M., 1986. Upper Permian (Guadalupian) facies and their association with hydrocarbons – Permian Basin, west Texas and New Mexico. *The American Association of Petroleum Geologists Bulletin* 70: 239-262.

Wilson, J.L., 1972. Cyclic and reciprocal sedimentation in Virgilian strata of southern New Mexico: J.G. Elam, S. Chuber (eds.), Cyclic Sedimentation in the Permian Basin (2nd edition), Midland, West Texas Geological Society: 82-99.

Wise, M.R., Kalaswad, S., and Meyer, J.E., 2012, Pecos Valley Aquifer, West Texas : structure and brackish groundwater, https://www.semanticscholar.org/paper/Pecos-Valley-Aquifer%2C-West-Texas-%3A-structure-and-Wise-Kalaswad/1b7d17603b0852b54360271983d3e519eb130afb (accessed November 2023).

Wright, W., 2020. Pennsylvanian (upper Carboniferous) paleodepositional evolution of the greater Permian Basin, Texas and New Mexico: depositional systems and hydrocarbon reservoir: S. Ruppel (ed.), Anatomy of a Paleozoic Basin: The Permian Basin, USA (v. 2), Austin, The University of Texas at Austin, Bureau of Economic Geology: 159-183.

Xiao, Ting et al. (2024). *A review of risk and uncertainty assessment for geologic carbon storage*. Renewable and Sustainable Energy Reviews 189 (2024) 113945

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
UIC
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 Copperhead AGI #001 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 (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

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Equation RR-9)}$$

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 liquid 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

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

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.

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.

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.