Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 5.0

June 13, 2023

TABLE OF CONTENTS

1 – INTRODUCTION

BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV), is authorized by the Texas Railroad Commission (TRRC) to inject up to 14.5 million standard cubic feet per day (MMscfd), equivalent to approximately 280,000 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Barnett RDC #1 injection well in Wise County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2 from the nearby Bridgeport Gas Processing Plant (Bridgeport Plant), operated by EnLink Midstream Services, LLC (EnLink), into the Barnett RDC #1 well. The project site is located approximately 4.6 miles southwest of Bridgeport, Texas, as shown in **Figure 1**.

dCarbon anticipates drilling the Barnett RDC #1 well in the first half of 2023, completing the well in mid-2023, and beginning injection operations in late 2023. The Barnett RDC #1 has approvedW-14 injection and W-1 drilling permits with the TRRC (Texas Railroad Commission) permit number 17090, UIC number 000125478, API number 42-497-38108). Additionally, copies of the approved W-1 and W-14 are included as Attachment A.

Although dCarbon intends to initiate injection with lower volumes, all calculations in this document have been performed assuming the maximum injection amount allowed by the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately twelve years.

dCarbon submits this Monitoring, Reporting, and Verification (MRV) plan for approval by the Environmental Protection Agency (EPA) in accordance with 40 CFR § 98.440-449, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

dCarbon's TRRC operator number is 100589.

dCarbon's Environmental Protection Agency Identification (EPA ID) number is 110071343305.

The Barnett RDC #1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 58336. All aspects of this MRV plan refer to this well and GHGRP ID number.

Figure 1. Location of the Barnett RDC # 1 Well and EnLink Midstream's Bridgeport Gas Plant.

2 – FACILITY INFORMATION

Gas Plant Facility Name:

Bridgeport Gas Processing Plant
415 Private Road 3502
Bridgeport, Texas 76426

Latitude: 33° 11.74' N
Longitude: 97° 48.22' W

EnLink’s GHGRP ID number for the Bridgeport Plant is 1006373.

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the TRRC regulates oil and gas activity in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program for injection wells. The TRRC has permitted the Barnett RDC #1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Barnett RDC #1, API number 42-497-38108

UIC# 000125478

Barnett RDC #1 GHGRP ID: 58336

The Barnett RDC #1 well will be disposing of CO_2 from the Bridgeport Gas Processing Plant. All aspects of this MRV plan refer to the Barnett RDC #1 well and GHGRP 58336.

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed Barnett RDC #1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Wise County, Texas.

3.1 Overview of Geology

The proposed injection site lies in the western section of Wise County, where the Barnett Shale, Viola, Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenburger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move updip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Pollastro[1] in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (see **Table 1**). The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several subunits of the Ellenburger. Ordovician Viola and Simpson formations overlie the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenburger Group.[2] Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. Although there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett shale and the Ellenburger Group. The Ellenburger Group directly overlies the basement rock and is considered the main reservoir target.

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[1] Pollastro, R.M., 2007. Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 405-436. 2007.

[2] Gao, S. *et al*., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, North Central Texas. *American Association of Petroleum Geologists Bulletin* 105 (12), pgs. 2575-2593. 2021.

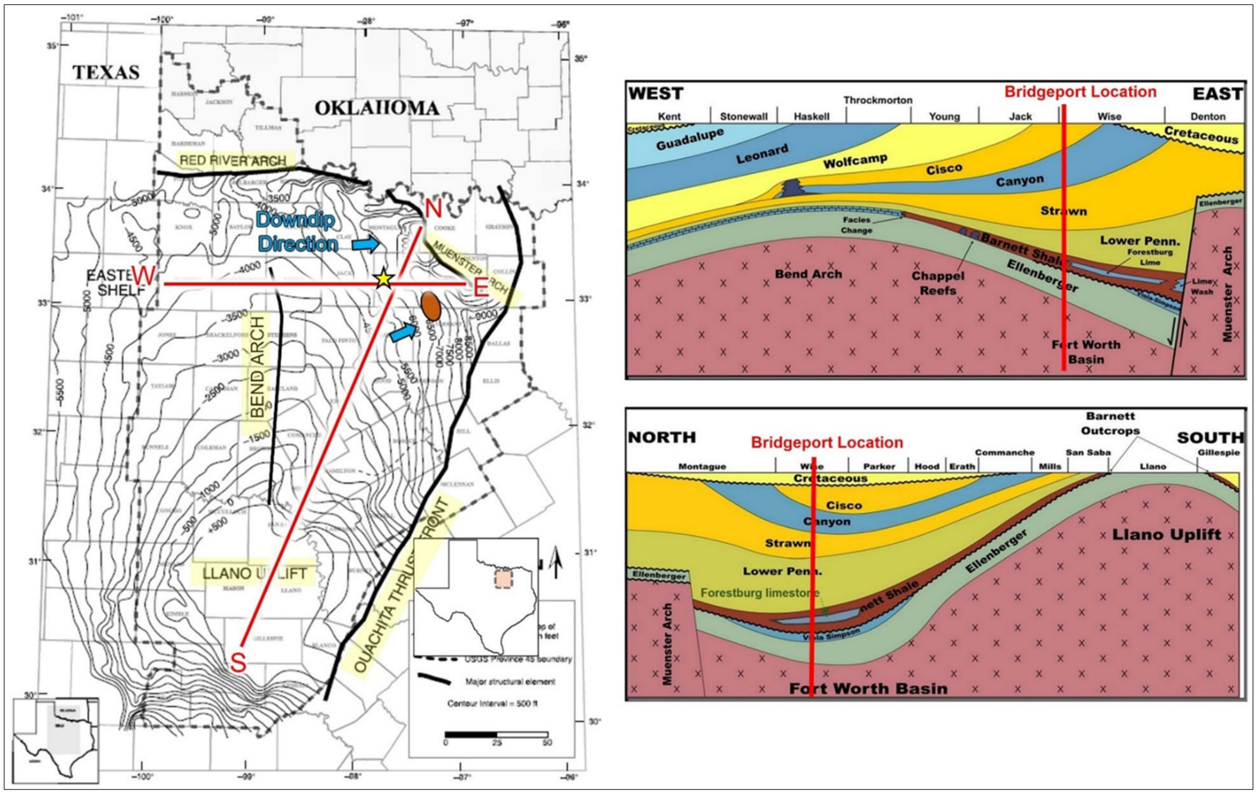

Figure 2. (*Left*) Ellenburger structural contour map modified from Jarvie *et al.*[3] showing the regional structures within and bounding the Fort Worth Basin, Ellenburger structure contours with respect to the final dCarbon area of interest (yellow star). (*Right*) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2 Bedrock Geology

3.2.1 Basin Description

The Fort Worth Basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs.[4] As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as approximately 12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster Arch and is shallowest towards the south.

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[3] Jarvie, D.M., *et al.*, 2007. Unconventional shale-gas systems: The Mississippian Barnett Shale of North Central Texas as one model for thermogenic shale-gas assessment. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 475-499. 2007.

[4] Horne, E.A., Hennings, P.H., and Zahm, C.K., 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn, Callahan, O.A., and Eichhubl, P. (editors), *The University of Texas at Austin, Bureau of Economic Geology Report of Investigations*, Austin, Texas. 2021.

Table 1. Regional Stratigraphy at Barnett RDC #1 Site in North Texas.

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>STAGE</th><th colspan="2">GROUP OR FORMATION</th></tr>
<tr><td>Cretaceous</td><td>Lower</td><td>Comanchean</td><td colspan="2">Trinity Group</td></tr>
<tr><td rowspan="13">Pennsylvanian</td><td>Upper</td><td>Missourian</td><td>Canyon Group</td><td>Jasper Creek Formation</td></tr>
<tr><td rowspan="8">Middle</td><td rowspan="6">Desmonesian</td><td rowspan="3">Strawn Group</td><td>Willow Point Formation</td></tr>
<tr><td>Lone Camp Formation</td></tr>
<tr><td>Millsap Lake Formation</td></tr>
<tr><td rowspan="3">Kickapoo Group</td><td>Ratville Formation</td></tr>
<tr><td>Parks Formation</td></tr>
<tr><td>Caddo Pool Formation</td></tr>
<tr><td rowspan="4">Atokan</td><td rowspan="7">Bend Group</td><td>Caddo Formation</td></tr>
<tr><td>Smithwick Shale</td></tr>
<tr><td rowspan="4">Lower</td><td>Pregnant Shale</td></tr>
<tr><td>Big Saline Formation</td></tr>
<tr><td rowspan="2">Morrowan</td><td>Marble Falls Limestone</td></tr>
<tr><td rowspan="2">Comyn Formation</td></tr>
<tr><td rowspan="4">Mississippian</td><td colspan="2" rowspan="3">Chesterian – Meramecian</td></tr>
<tr><td rowspan="3">Barnett</td><td>Upper Barnett Shale</td></tr>
<tr><td>Forestberg Limestone</td></tr>
<tr><td colspan="2">Osagean</td><td>Lower Barnett Shale</td></tr>
<tr><td>Ordovician</td><td colspan="2">Lower</td><td colspan="2">Ellenburger Group</td></tr>
<tr><td>Precambrian</td><td colspan="2"></td><td colspan="2">Basement</td></tr>
</table>

3.2.2 Stratigraphy

The Ellenburger Group contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.*[5] The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit B and the stratigraphic top portion of Ellenburger subunit C were identified as a potential caprock. Below this interval, there are baffles of tighter

[5] Smye, K.M., *et al.*, 2019. Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas. *Texas BEG Report: Interpretation* 7 (4), 2019.

limestone throughout Ellenburger subunits C, C2, and D that would also act as sealing units to the storage interval. Ellenburger subunit E is planned to serve as the storage zone.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the North Tarrant SWD 1 (API number 42-439-31228), as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

The W.S. Coleman #2 (API number 42-497-35807) well, approximately five miles east of the proposed Barnett RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since no wells currently exist at the proposed site. The North Tarrant SWD 1 well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, subunits C and E within the Ellenburger are present and appear to be contiguous in the project area. Subunit C thickness is approximately 750 feet while subunit E thickness varies across the cross sections. It is estimated there is at least 940 feet of subunit C at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenburger subunit E. The cross sections confirm regional trends in dip also apply to the area of interest, down to the north and east.

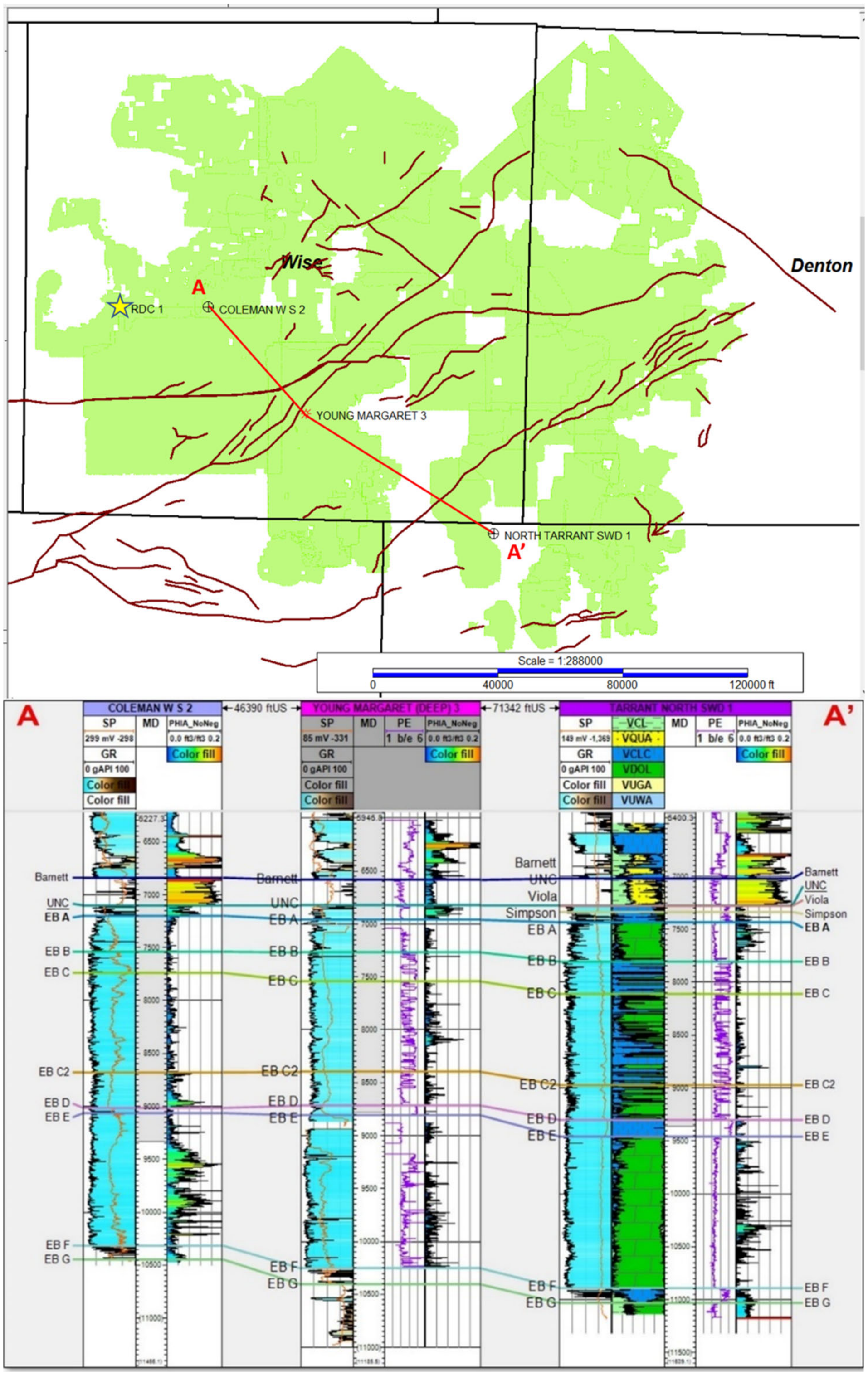

Figure 3. (*Top*) Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), dCarbon 3D seismic extent (green polygon), and a NW-SE cross section (A-A'). (*Bottom*) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD 1 well to the WS Coleman 2 well. Ellenburger subunit C (EB C) is the upper confining zone and Ellenburger subunit E (EB E) is the storage zone.

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults with most of the faults rooting into the Precambrian crystalline basement, as depicted in **Figure 4**. The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the base of the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation.[4] Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Group.

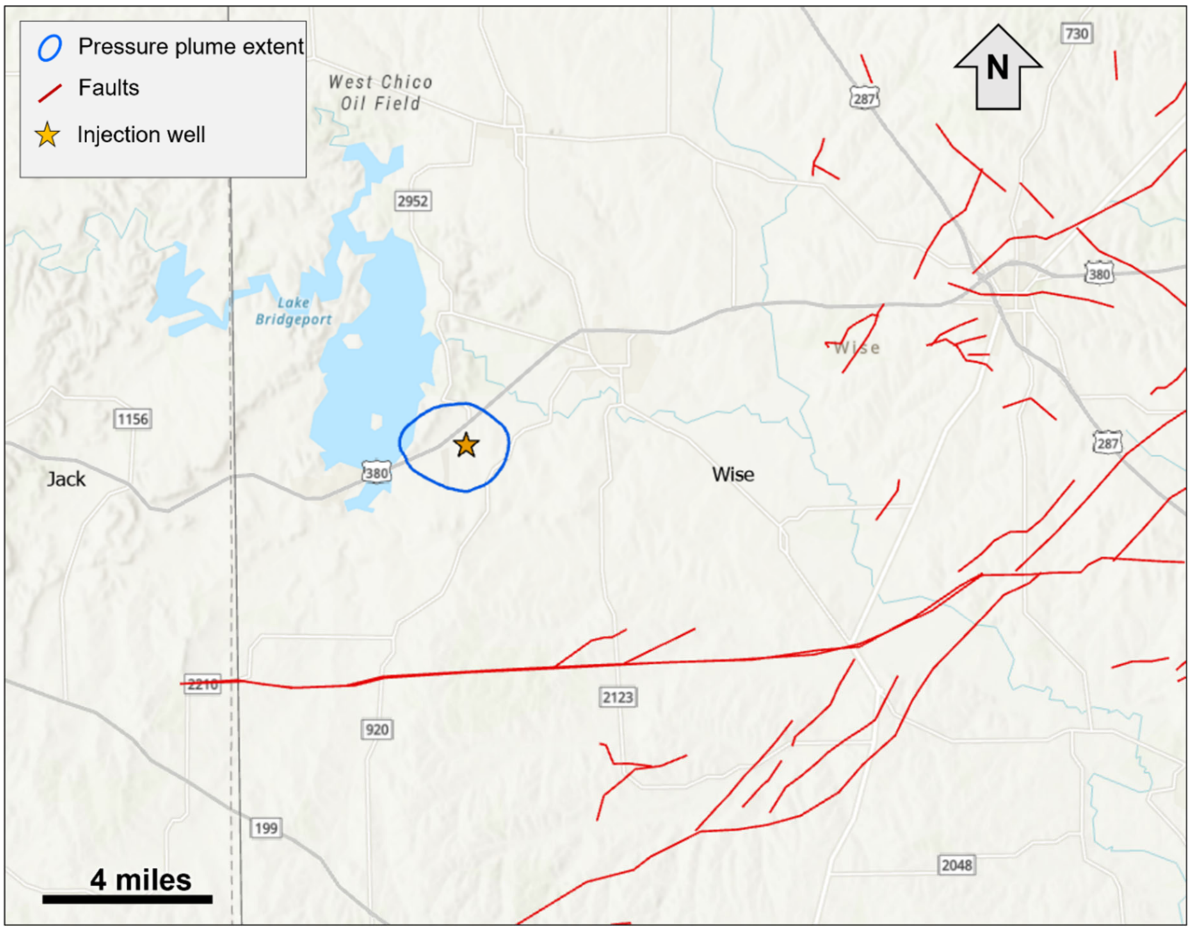

Figure 4. Mapped faults near the proposed injection well from Wood.[6]

3.3 LITHOLOGICAL AND RESERVOIR CHARACTERIZATIONS

Smye *et al.*[5] provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger Group. Prior to understanding the petrophysical

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[6] Wood, V., 2015. Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 2015.

properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume[5]. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5%, while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area.

To better understand local stratigraphy and petrophysics, lithological characterization was focused on the red dotted area shown in **Figure 5**. The Viola Formation and Simpson Group are listed here overlying Ellenburger subunit A. However, these formations pinch out to the east of the proposed Barnett RDC #1 site, and thus, are not included in subsequent petrophysical analysis.

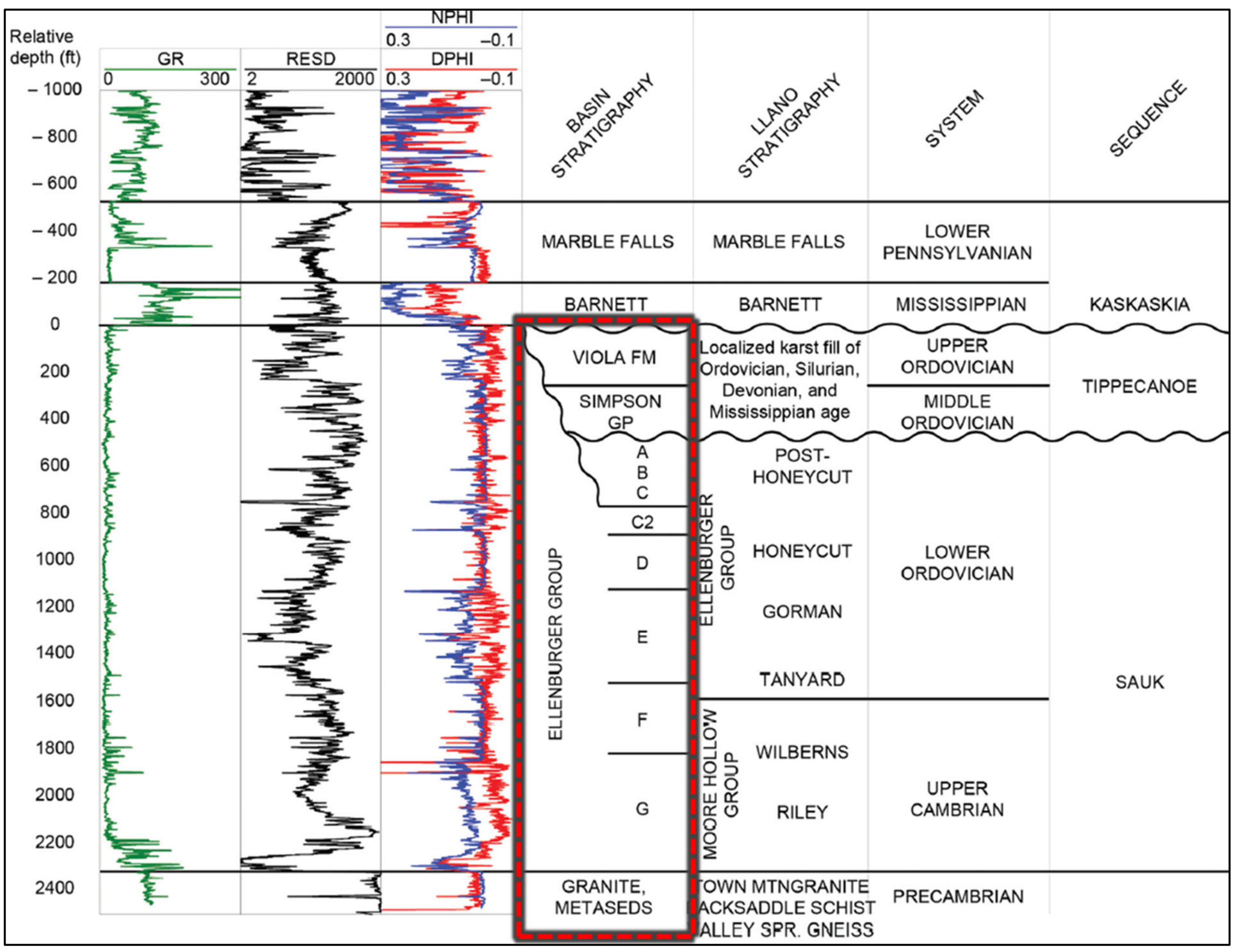

Figure 5. Regional stratigraphy at dCarbon site in North Texas (modified from Smye *et al.*[5]).

The Barnett Shale is anticipated to serve as a secondary confining interval. The Barnett Shale is a source rock and an unconventional reservoir that is extensively drilled in the Fort Worth Basin.

The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which contains both the anticipated storage and confining zones. The Ellenburger could be divided into eight lithostratigraphic units starting with subunit A at the top to subunit G at the bottom which sits on top of the crystalline basement. Subunit G is composed of siliciclastic facies and is largely variable across the region. Though the porosity in subunit G is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this subunit. Consequently, subunit E will serve as the storage zone given it has approximately 4% matrix porosity. Ellenburger subunit E is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit B and subunit C were found to have lower matrix porosities compared to subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger subunit A has been proven to be a reservoir zone with multiple saltwater disposal wells completed in subunit A. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

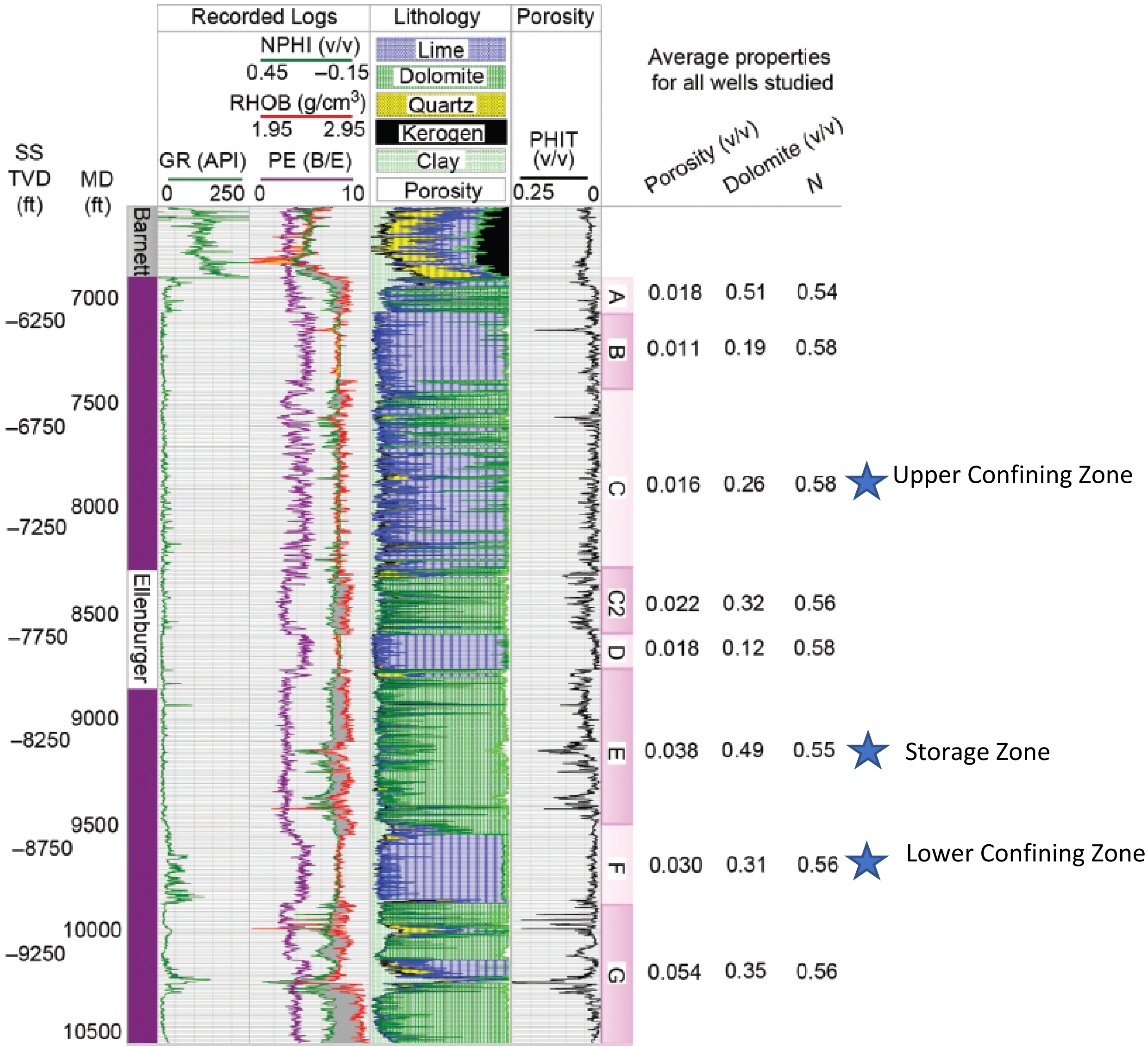

Figure 6. Properties of Ellenburger Group subunits in the project area (modified from Smye *et al.*[5]).

The W.S. Coleman #2 injection well located approximately five miles from the proposed injection site similarly contains Ellenburger subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site should result in site-specific petrophysical properties like those shown here.

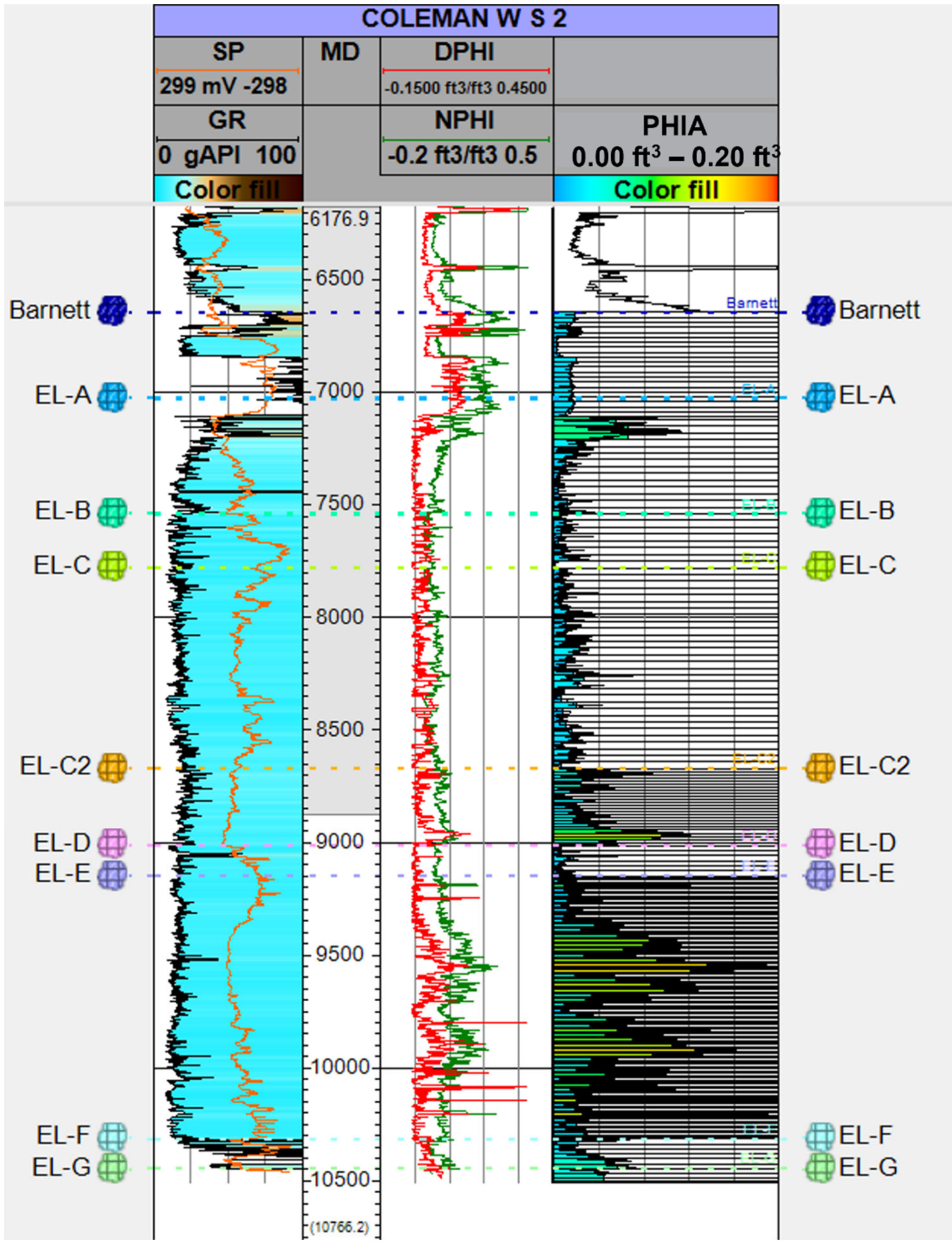

Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (*e.g.*, North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average porosity was calculated for each subunit of the Ellenburger by averaging the average porosity (PHIA) curve from the top to the bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenburger Group properties assessed at the project area.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolomite	338	63	0.186	1.1	
B	Limestone	200	14	0.070	0.8	
C	Limestone	940	187	0.198	1.2	Upper Confining Zone
C2	Dolomite	335	229	0.683	3.5	
D	Limestone	49	3.5	0.072	0.6	
E	Dolomite	1252	879	0.702	5.5	Storage Zone
F	Limestone	130	88.5	0.677	3.2	Lower Confining Zone
G	Dolomite	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature. As noted by Gao *et al.*,[2] regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.47 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.4°F per 100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in Section 3.8.

3.4 Formation Fluid Chemistry

Through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, nine wells within 20 miles of the proposed injection well site were identified within the Pennsylvanian age strata, as shown in **Figure 8**. Formation fluid chemistry analyses for these wells are reported in **Table 3**.

Table 3. Pennsylvanian formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

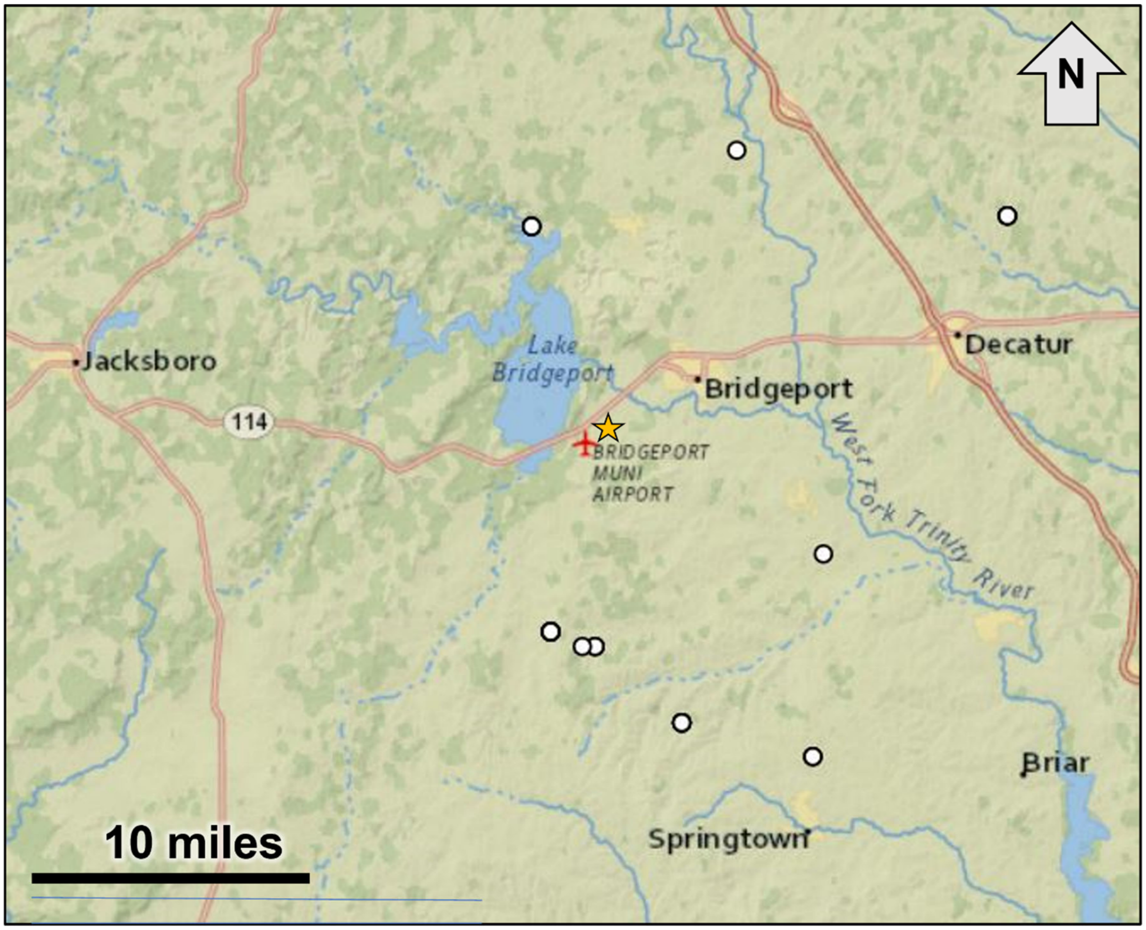

Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analyses for the Ellenburger Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth Basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 Potential of Induced Seismicity – Ellenburger Group

An analysis of historical seismic events within a 100 square mile radius surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U.S. Geological Survey (USGS) Earthquake Catalog, as illustrated in **Figure 9**. TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey.[7] Current findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. A Wise County saltwater disposal well has been permitted for an injection rate of 15,000 barrels per day (bpd) and is located approximately eight miles from the Barnett RDC #1 injection site. This well has been operated without any observed seismic activity.

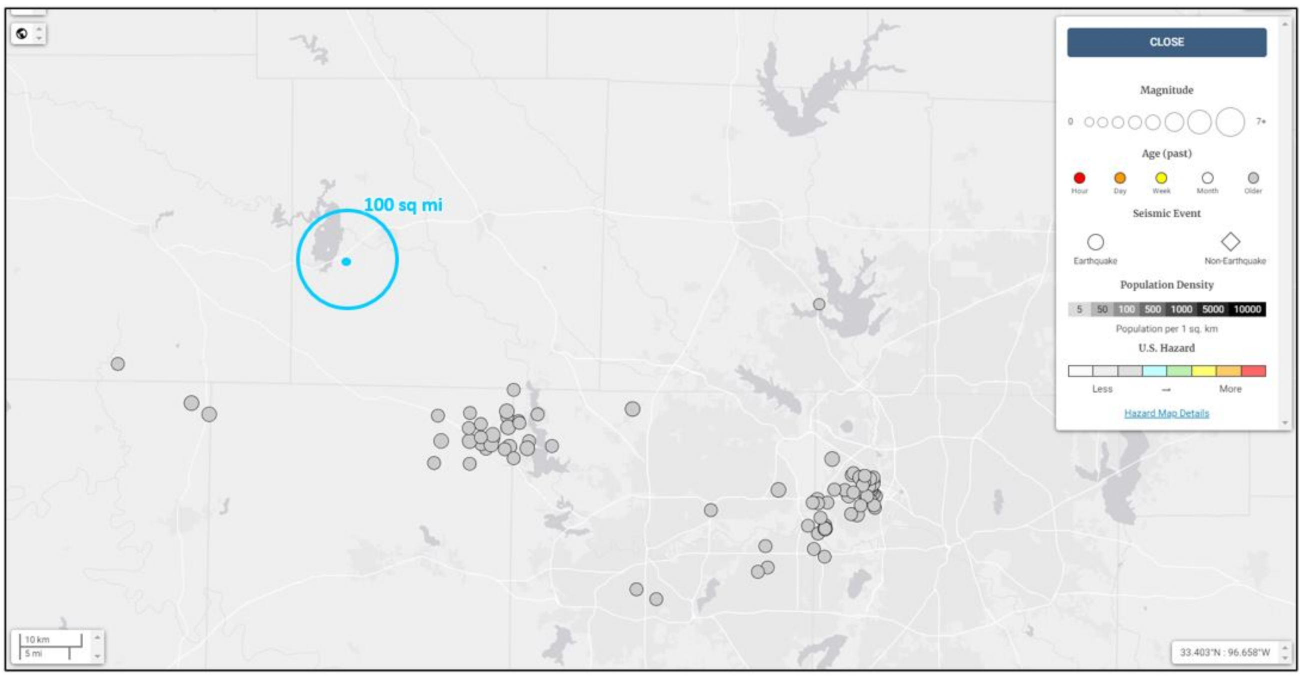

Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Barnett RDC #1 site.

3.6 Groundwater Hydrology in MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board, shown in **Figure 10**. Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of Northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the

[7] Hennings, P.H., *et al*., 2019. Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. *Bulletin of the Seismological Society of America* 20 (20), 2019.

proposed injection site, as seen in **Figure 10** and **Figure 11**. Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site, shown in **Figure 12**. Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System.[8] Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits.[9] These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm.[10] Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm.[11] No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, *et al*.[12] Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches per year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from

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[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin, *Texas Univ. Bur. Econ. Geology Guidebook*, 14 (1973), p. 132.

[9] Blandford, T.N., *et al.*, 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., *et al.*, 2018. U.S. Geological Survey National Produced Waters Geochemical Database (v2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: *Gulf Coast Association of Geological Societies Journa*l (2), pgs. 53-67.

younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity Aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap, with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group. Locally, however, the deepest water well within two miles of the proposed injection well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

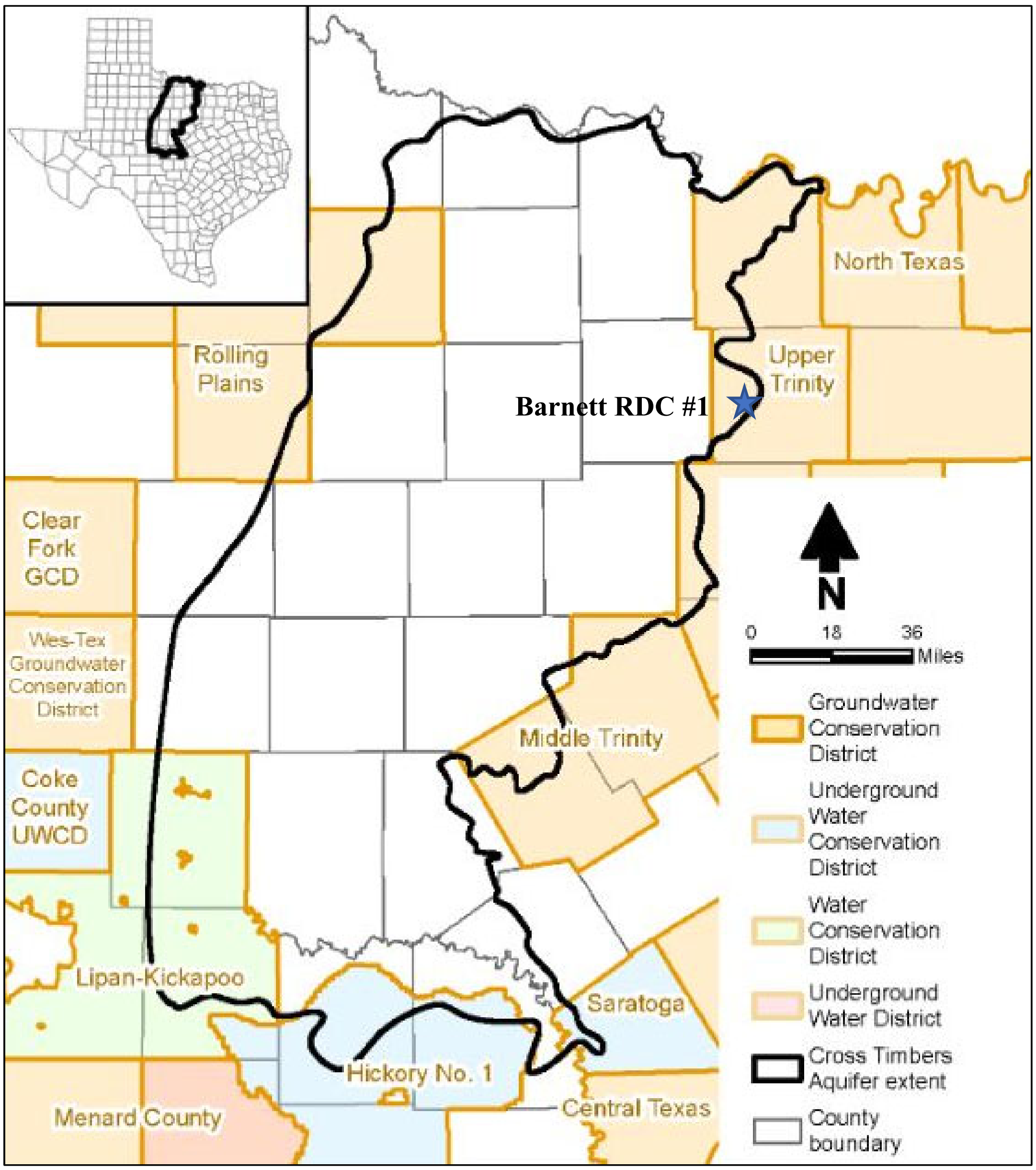

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within North Central Texas, from the Texas Water Development Board. The location of the proposed Barnett RDC #1 is shown with a star.

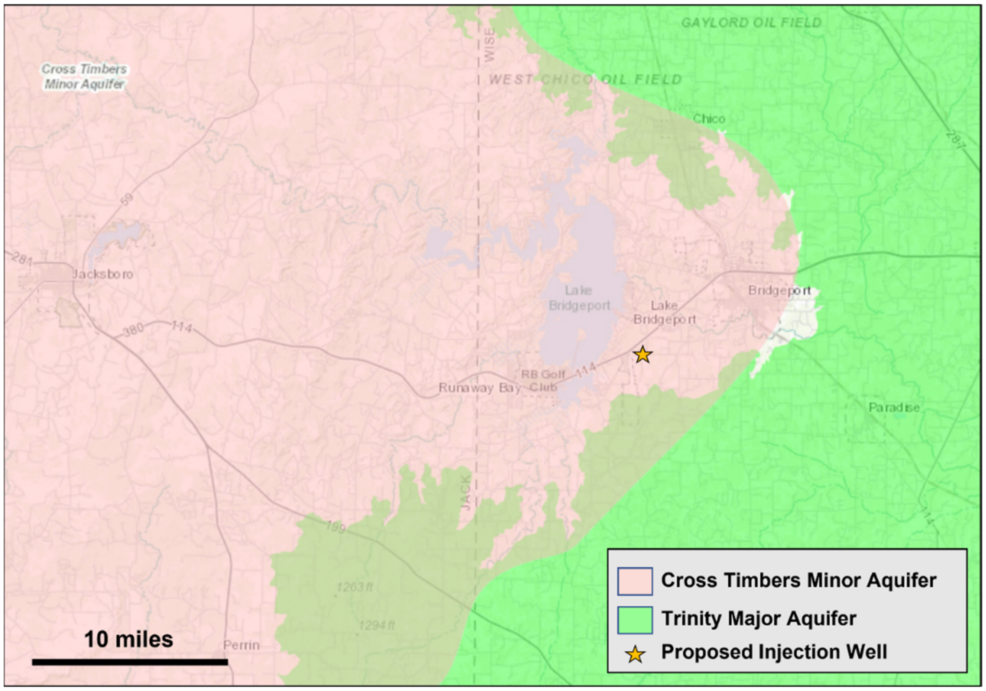

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with the Barnett RDC #1 location labeled with a star.

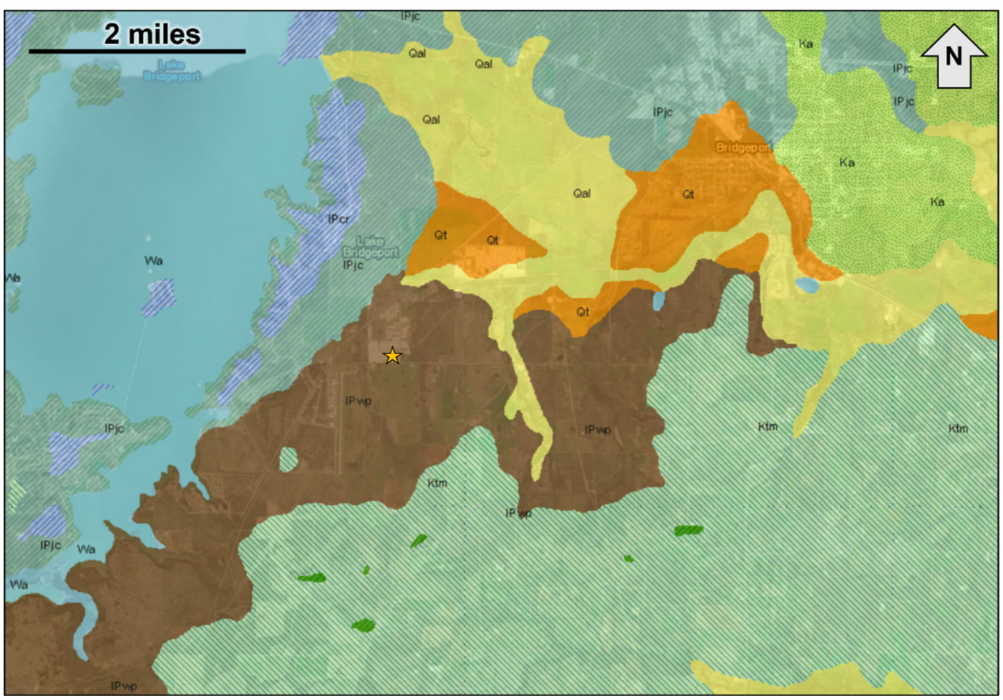

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountains formation, and Ka = Antlers sand.

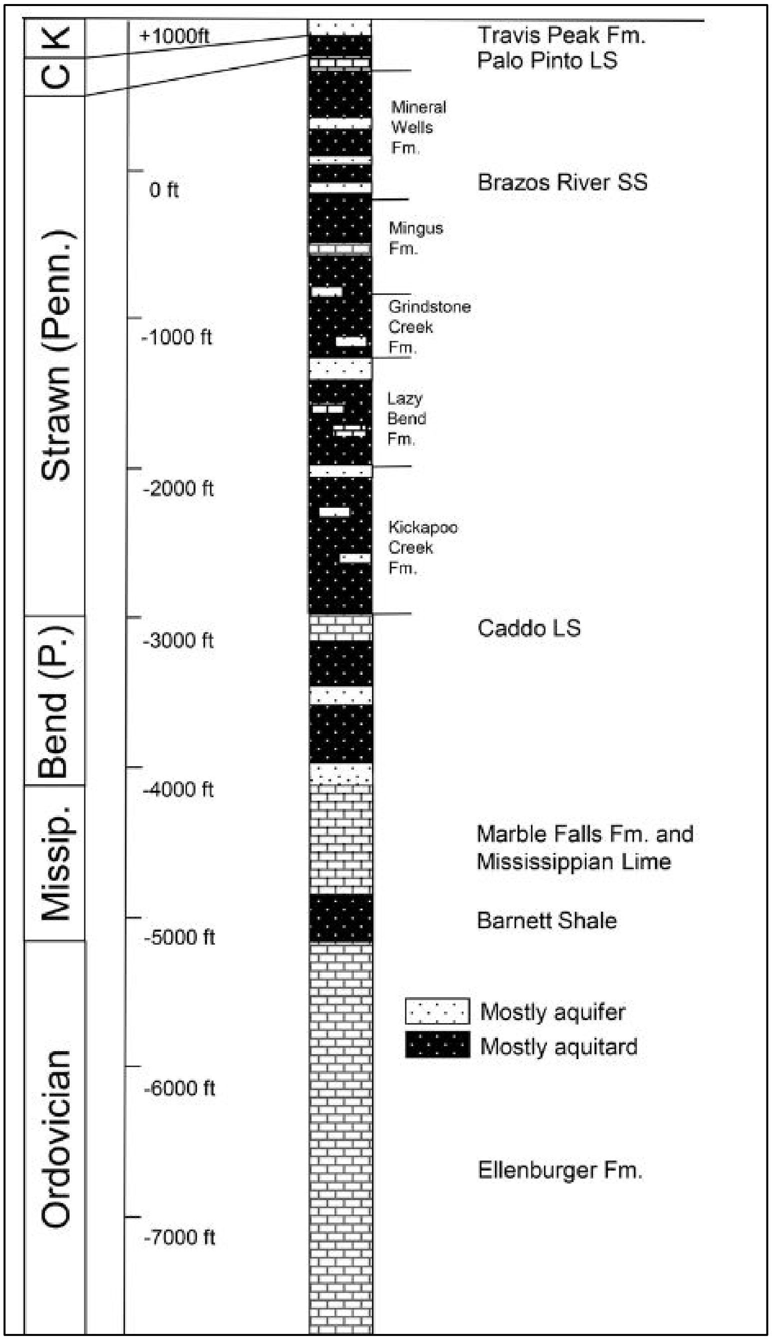

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot *et al*.[13]

There are 105 freshwater wells within a two-mile radius and 26 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, shown in **Figure 14** and listed in **Table 5**.

[13] Nicot, J, *et al*., 2011. Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" University of Texas, 2011, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1.

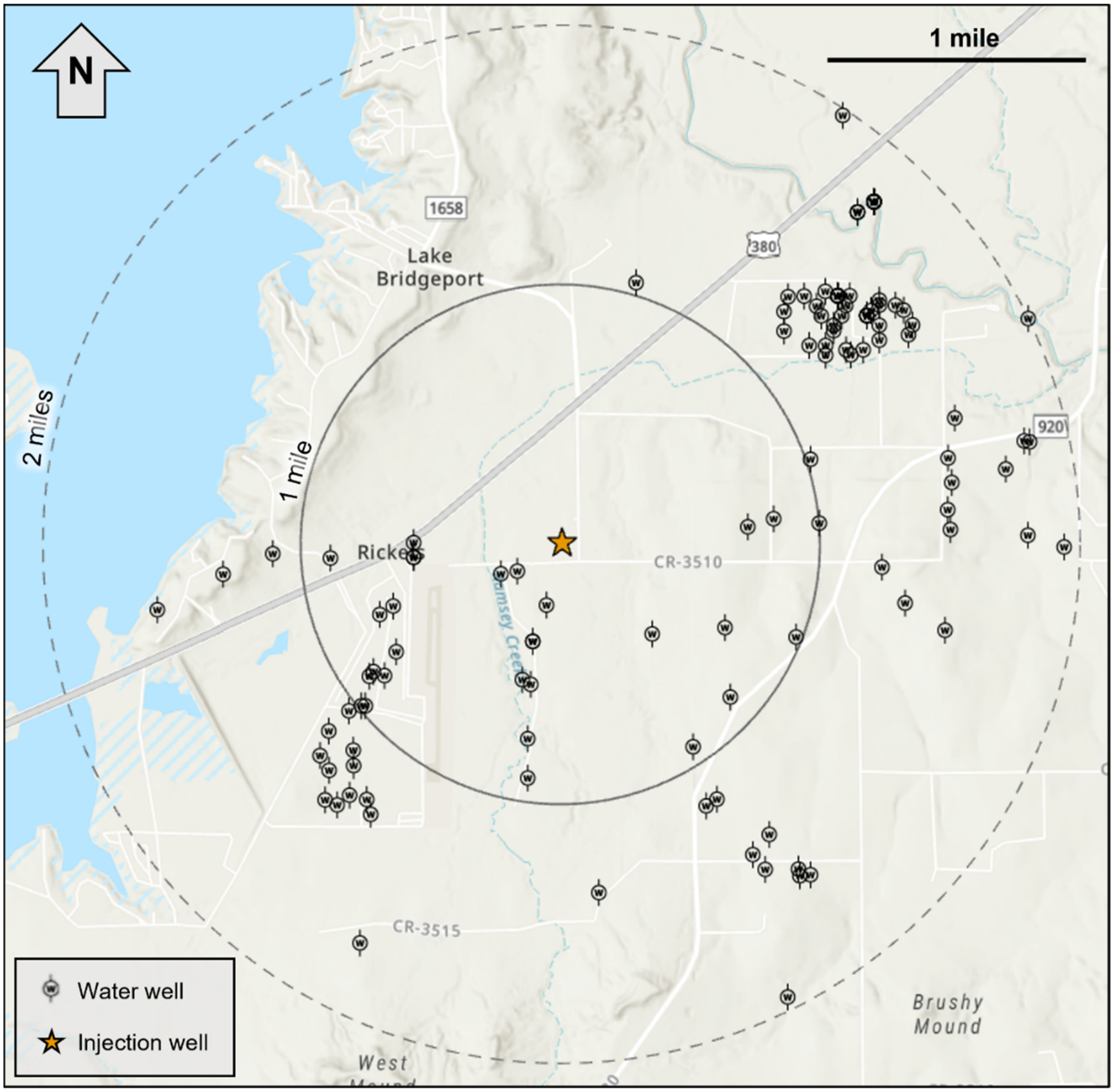

Figure 14. Water wells within one and two miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Private and state-owned groundwater wells in project area.

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Wells				
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7 Description of CO_2 Project Facilities

dCarbon will accept CO_2 from by the Bridgeport Plant (**Figure 15**). The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon will then transport the CO_2 via pipeline approximately 6,815 feet to the Barnett RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	**Normalized Weight Percent**	**Normalized Mole Percent**	**Normalized Liquid Volume Percent**
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H_2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

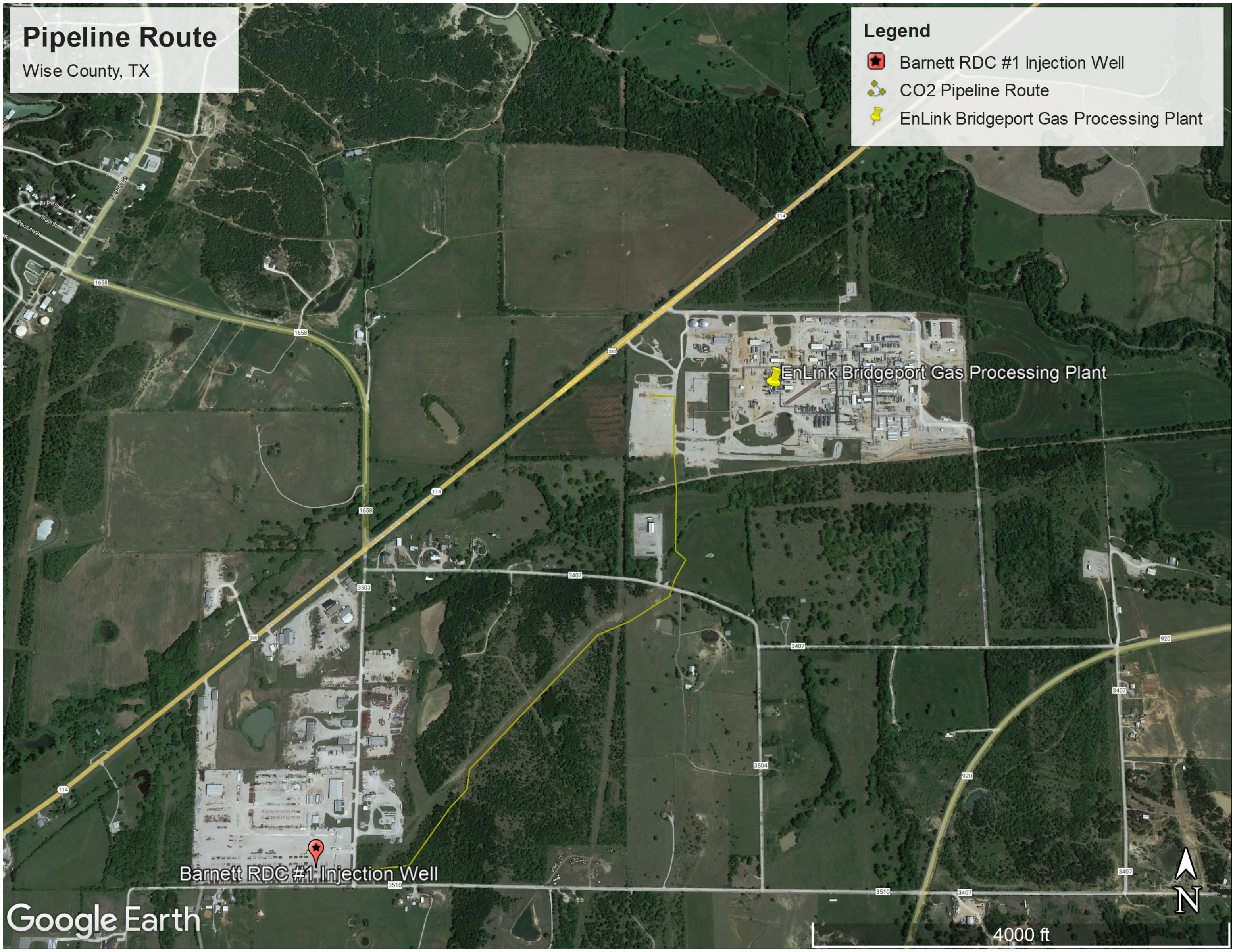

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional model encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel software. The model incorporates available well petrophysical data and generates a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (approximately five miles east of Barnett RDC #1, as discussed in previous sections). The reservoir is characterized by low matrix porosities as well as naturally existing fractures which are likely to contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates and volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the Barnett RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models, as well as injection forecasts and the MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection.
2. Determine the ability of the target formation to handle the required injection rate.
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger subunit E is modeled as the reservoir unit while Ellenburger C subunit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett Shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. The lower confining zone for the reservoir is provided by the Ellenburger F subunit. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel software based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group's General Equation of State Model (CMG-GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS, which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering with relationship to simulated CO_2 saturation profile in the model. The injection rate modeled was 280,000 MT/year for 12 years followed by 100 years of post-injection timeframe to observe post-injection movement of CO_2.

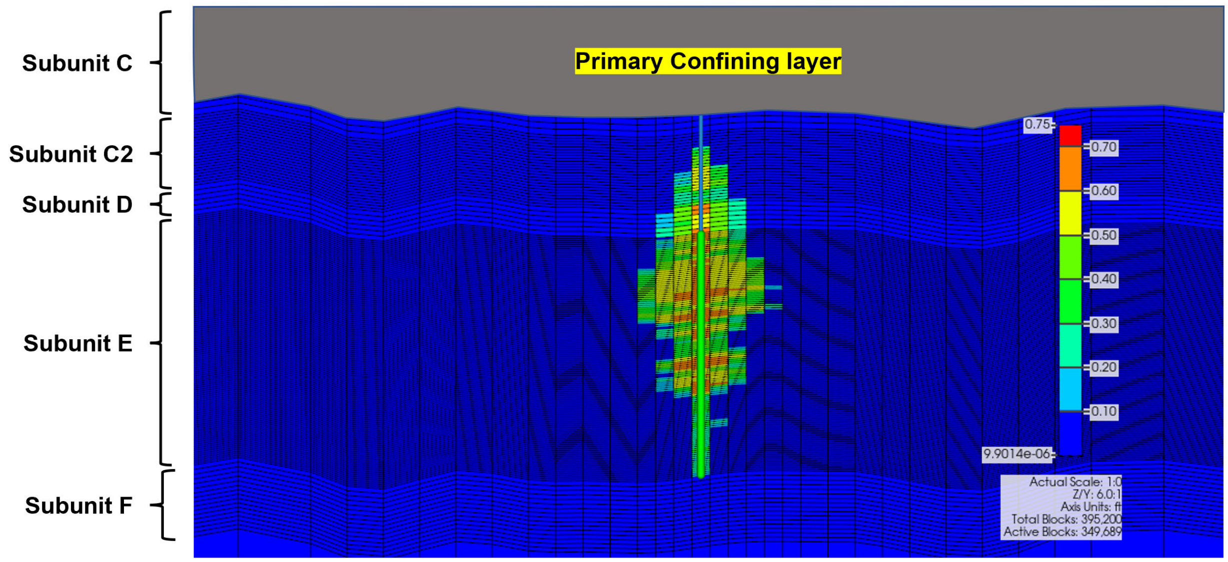

Figure 16. Vertical CO_2 saturation Profile of the CMG-GEM Model for Barnett RDC #1 Well. Color scale in Figure 16 indicates CO_2 gas saturation.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model was sourced from literature[14] using data from the Wabamun Carbonate reservoir formation, which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients derived from literature.[2] The pressure gradient was assumed to be 0.47 psi per foot, which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5°F per 100 feet, resulting in an estimated temperature of 201°F at the top of the reservoir. Fracture pressures were estimated at 0.7 psi per foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

As mentioned earlier, injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows generally west, which is the regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (approximately 29%) and the plume stops moving after 50 years.

[14] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995.

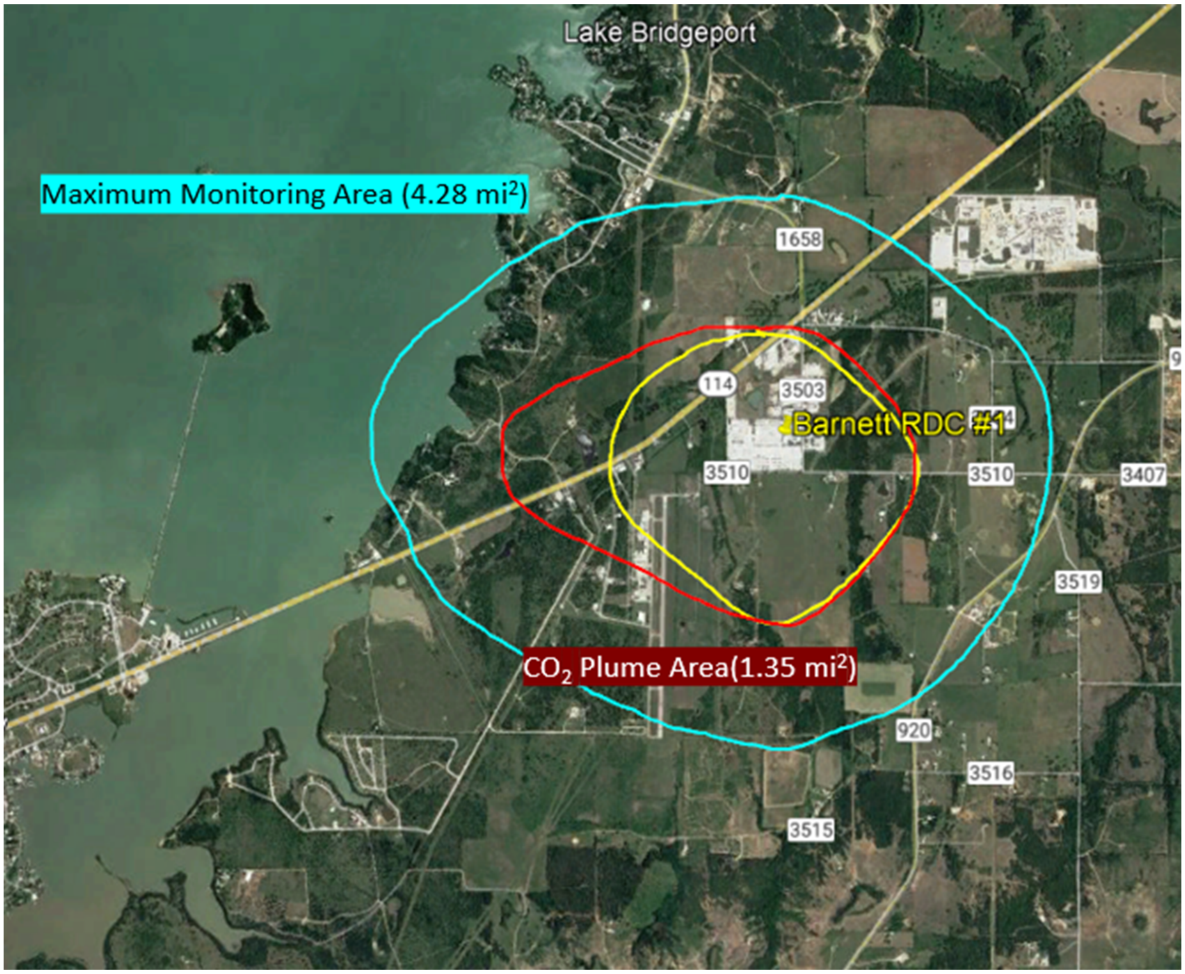

Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint), which occurs six months after the start of injection. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

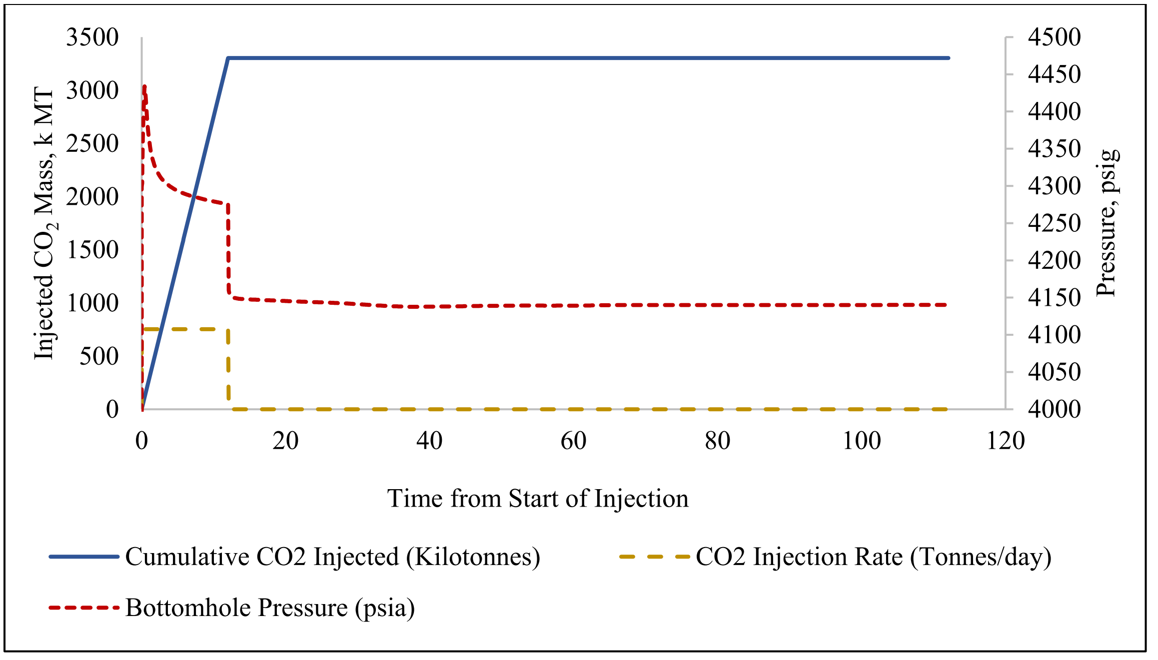

Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

4 – DELINIATION OF MONITORING AREA

4.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenburger subunit E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

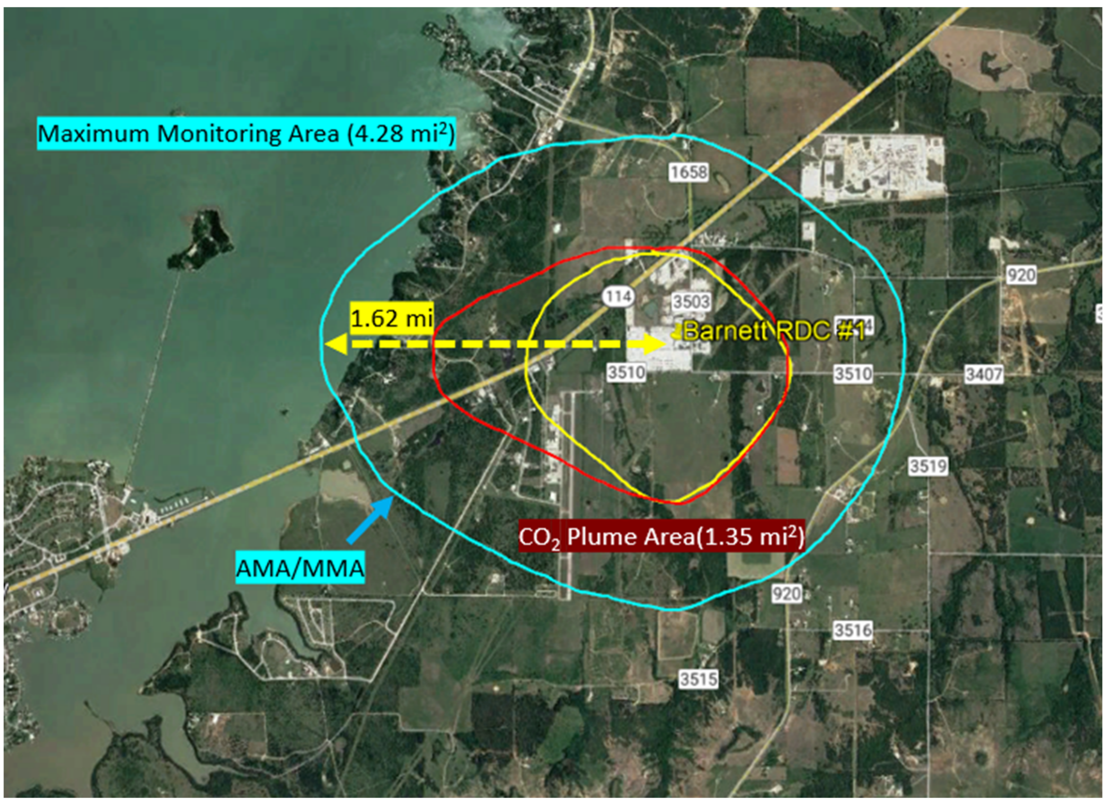

Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

dCarbon adhered to the definition of active monitoring area (AMA) provided in 40 CFR 98.449 to delineate the AMA for this project. As noted in Section 6, dCarbon proposes to monitor the injection site from year one through year 14, which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR § 98.449, the AMA must be delineated by superposition of:

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, dCarbon utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR § 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR § 98.449. **Figure 19** shows the MMA, which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil and/or gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 320 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

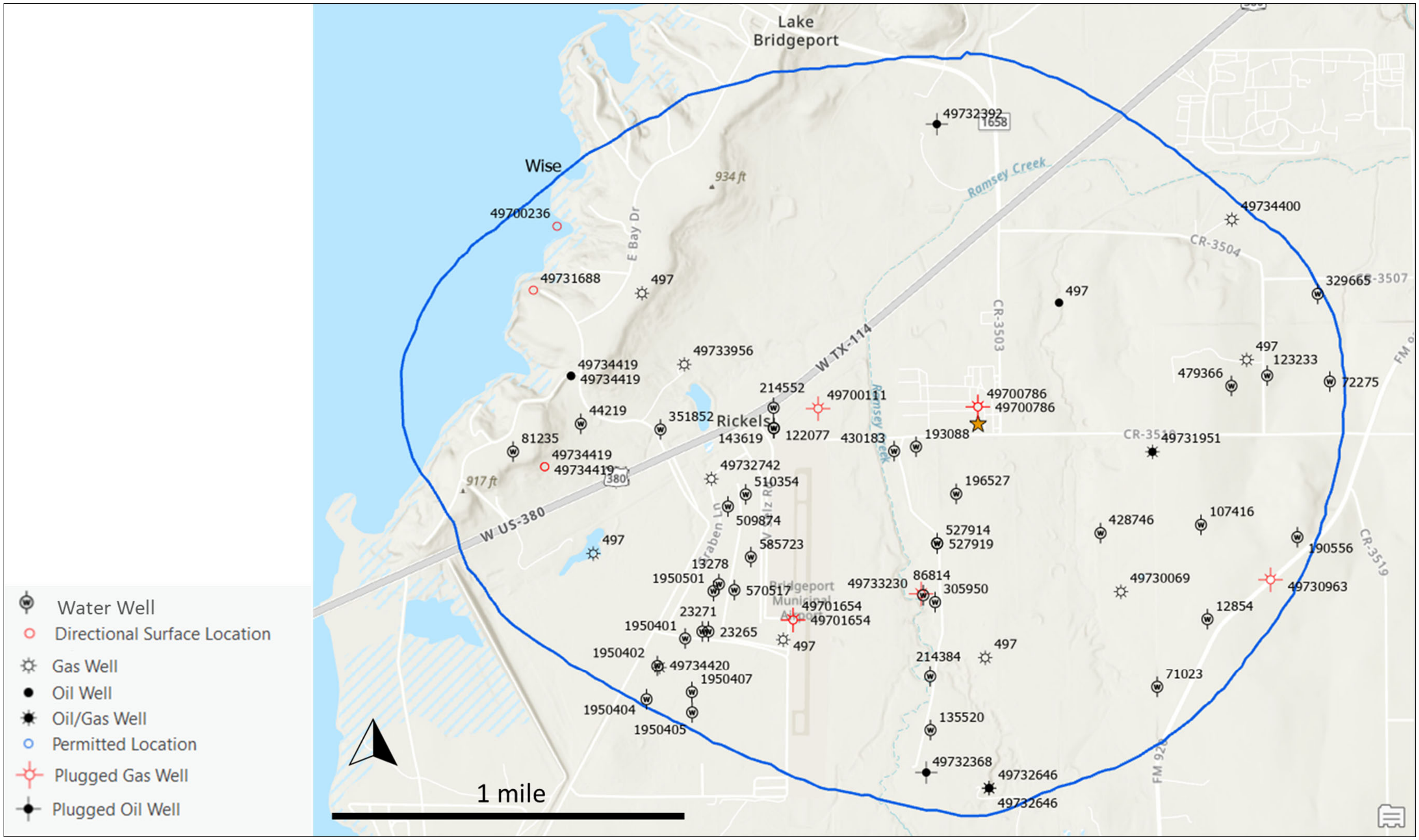

Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA. The Barnett RDC #1 is shown as a star.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 6**, including H_2S. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. All BKV and dCarbon field personnel are required to wear gas monitors that detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have emergency shut down switches that can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and Forward Looking InfraRed (FLIR) leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks that may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine the amount of CO_2 that may have leaked. These leakage quantities, if any exist, will be included in recurring reporting.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. However, there are multiple expired well permits within the MMA that would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3 Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website, as shown in **Table 6**. Six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable zones from the deepest existing well in the MMA (API number 42-497-34419, which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells that were drilled within the MMA, listed in **Table 7**, do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, and are attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet true vertical depth (TVD), several thousand feet shallower than the Ellenburger formation. Note that the well labeled as D in **Table 7** below is a dual completion but single wellbore. There is one additional well that was permitted but never drilled (labeled as B in **Table 7**)

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string that is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,027	Enserch Exploration, Inc.	9/27/1996
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999

Table 7. Existing Oil & Gas wells in MMA without digital TRRC records.

API	Well Type	Latitude NAD27	Longitude NAD27	Status	Total Depth (feet)	Attachment B Label	Lease / Well Name	Operator
497-01653	Gas	33.188107	-97.83638	Open	5,602	A	Craft Water BD 19-1/ DW Harrison Lease	Lone Star Production
No API	N/A	33.184969	-97.827819	Expired Permit	N/A	B	McLanahan	N/A
497-00009	Oil	33.187529	-97.815993	Open	6,200	C	HH Wharton Gas Unit 1A	A'Mell Oil Properties
497-01686	Gas	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1	Lone Star Production
497-03093	Oil	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1A (dual completion of 497-01686)	Lone Star Production
497-30085	Gas	33.172971	-97.819788	Open	5,389	E	CR Upham JR #2 Shilling Harold Lease	Upham Oil & Gas
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F- Same as 497-01654	Craft Water Board Sampson #1	Lone Star Prod/Ensearch
497-01646	Gas	33.177438	-97.838912	Plugged	5,968	G	Craft Water Board 8-1	Lone Star Production

5.4 Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have greater displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. Karsting is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger subunit A) where fresh water is able to dissolve the rock (**Figure 21**). Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void.[15]

The injection interval, the Ellenburger subunit E appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger subunit C will remain a continuous upper seal even in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected (**Figure 22**).

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger subunit C upper seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

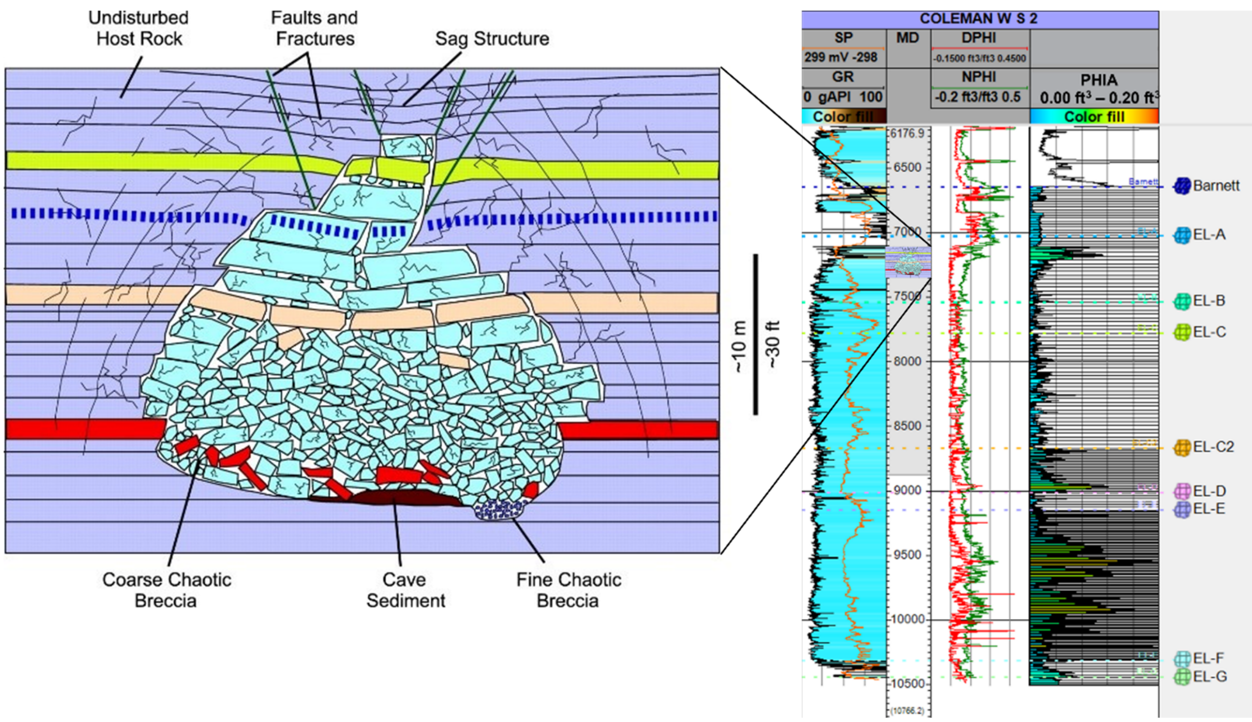

Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*[16]). The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger subunit C.

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[15] Zeng, H., 2011. Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei Uplift, Tarim Basin, Western China. *Geophysics* 76 (4), 2011.

[16] Zeng, H., *et al*., 2011. Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the Central Tabei Uplift, Northern Tarim Basin, Western China. *American Association of Petroleum Geologists Bulletin* 95 (12), pgs. 2061–2083. 2011.

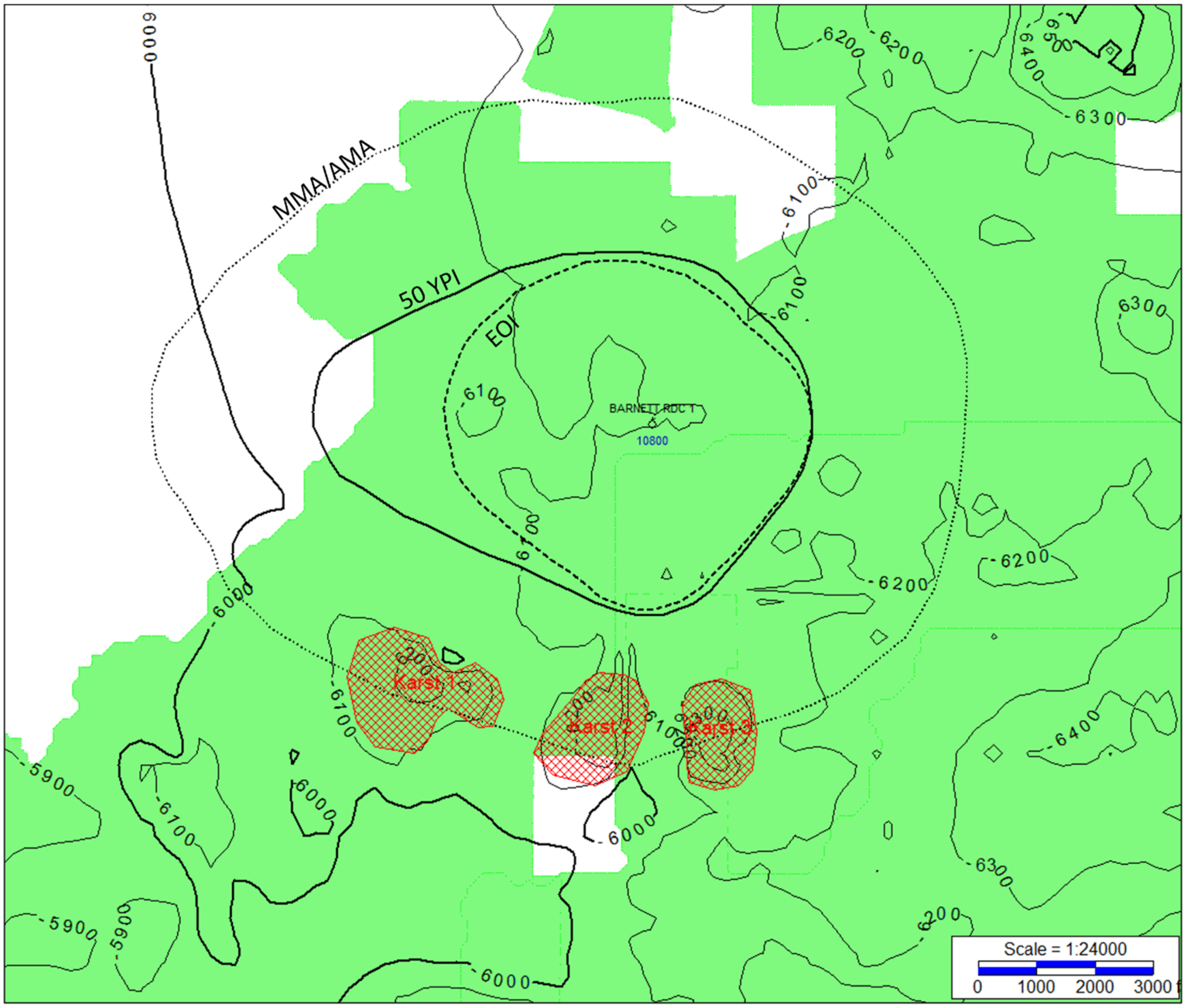

Figure 22. The Barnett RDC #1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger subunit E injection zone is bound by competent confining zones above the injection interval by the Ellenburger subunit C and below the injection interval in the Ellenburger subunit F. Secondary seals above the injection zone include the Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F serves as the lower confining zone. Overall, there is an excess of 3,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining zones unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, consistent with RRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 psi per foot gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation or increase the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis[17] to evaluate the risk of induced seismicity on the closest mapped faults. dCarbon plans to build this model based on geologic data collected during drilling the Barnett RDC #1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will shut-in the well and investigate further.

Furthermore, dCarbon plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be located in the subsurface and analyzed to determine their origin and if they may have potential impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

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[17] Walsh, F.R.I., Zoback, M.D., Pais, D., Weingartern, M., and Tyrell, T. (2017). FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile), shown in **Figure 23**. The closest well that penetrates the Ellenburger subunit E injection interval up dip from the injection site is more than ten miles to the west-southwest. The closest well that penetrates the injection interval is down dip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order ten times the distance the plume is expected to travel, no leakage from lateral migration is expected.

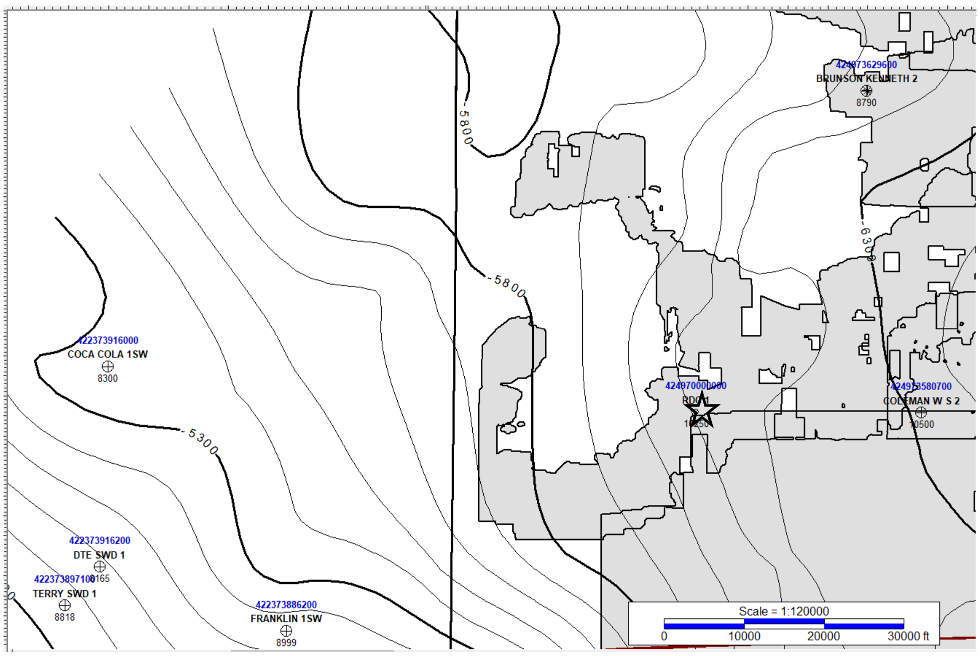

Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Furthermore, dCarbon has assessed each of the previously discussed potential leakage pathways for likelihood, potential timing, and magnitude. The framework of this assessment is based upon the California Air and Resources Board's CCS Protocol Section C.2.2(d).

Table 8 describes the basis for event likelihood and **Table 9** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 8. Risk likelihood matrix (developed based on comparable projects).

Risk Factor for Probability		Description
1	Improbable	<1% chance of occurring*
2	Unlikely	1-5% chance of occurring*
3	Possible	> 5% chance of occurring*
*During the life of the project or 100 years after project closure, whichever is shorter		

Table 9. Description of leakage likelihood, timing, and magnitude.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 3 hours of full flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells	When the CO_2 plume expands to the lateral locations of existing wells	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 1,000' thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration five miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E and continuity / thickness of upper confining zone

6 – PLAN OF ACTION FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR § 98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or until the cessation of operations, plus a proposed two-year post-injection period.

6.1 Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment will be quickly detected and addressed. The facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, American Petroleum Institute (API) standards, and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and CO_2 concentration increases. This monitoring equipment will be set with a high alarm setpoint for H_2S that automatically alerts field personnel of abnormalities. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically one ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, will allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR § 98.448(a)(5).

Additionally, CO_2 for injection will be metered in three locations for redundancy and precision. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Plant and dCarbon's compression facility. This location will meter the CO_2 in gas phase and is depicted in **Figure 24a** and **Figure 24b**. Once the CO_2 is compressed to supercritical, it will pass through a Coriolis meter for measurement and then be transported approximately 6,815 feet via pipeline (see **Figure 15**) to the injection well site. The CO_2 will then be measured again with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself. The injection stream will also be analyzed with a gas chromatograph at the well site to determine final composition. The meters will each be calibrated to industry standards. Any discrepancies in CO_2

throughput between the meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR § 98.448(a)(5), and subtracted from reported injection volumes. Gas samples will be taken and analyzed per manufacturer's recommendations to confirm stream composition and calibrate or re-calibrate meters, if necessary. At a minimum, these samples will be taken quarterly. Minimal variation of concentration and composition are expected but will be included in regulatory filings as appropriate.

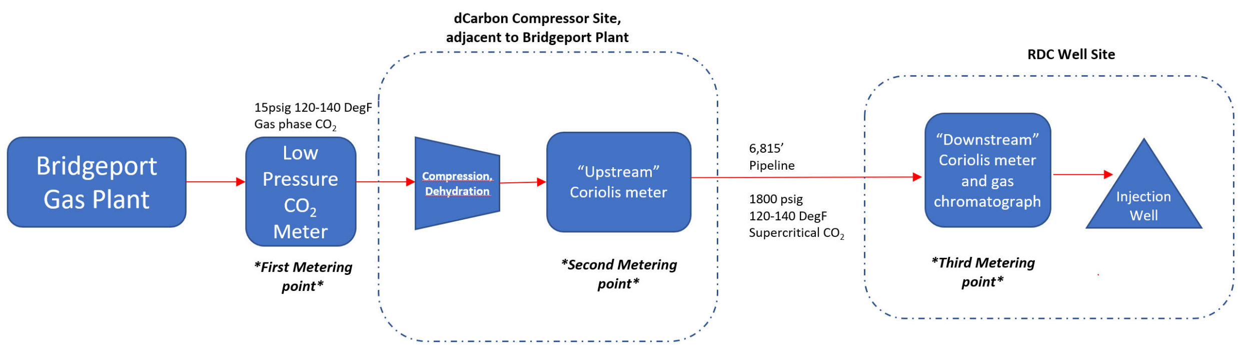

Figure 24a. Project conceptual diagram and metering locations.

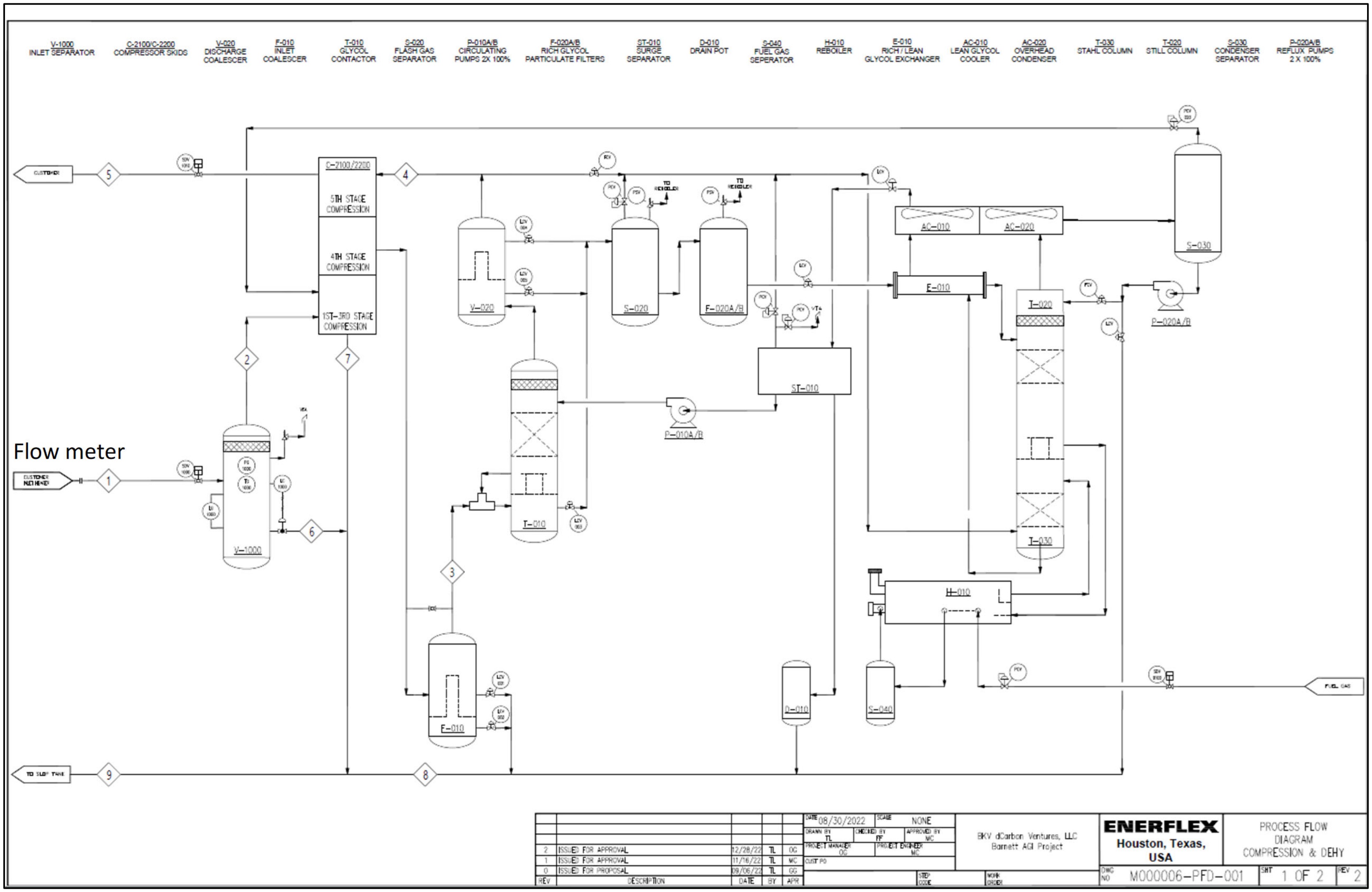

Figure 24b. Compression facility process flow diagram.

6.2 Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending that penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The downhole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon will evaluate and execute any additional downhole remediations (*e.g.*, well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface. In the unlikely event that such leakage from faults or fractures occurs, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4 Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs because of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring array in the general area of the Barnett RDC #1 well. This monitoring array will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occurred that would indicate potential leakage. To suspect leakage due to natural or induced seismicity, the evidence would need to suggest that the earthquakes are activating faults that penetrate through the confining zones.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6 Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7 Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize to quantify leakage depending on the nature and severity of the leak. dCarbon has designed a monitoring network suited to detect CO_2 leaks before they interact with local resources, infrastructure, or USDW. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon's methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to install a deep groundwater monitoring well in the MMA that will be used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water zones. dCarbon also plans to periodically sample the well to monitor for chemical composition. If dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of the distance from potential leak sources can then be coupled with temporally matched meteorological data to semi-quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon is working with a leading environmental services and data company that specializes in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both X and Y axis (longitude + latitude) as well as Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified, provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM).[18] This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to

[18] Korre, A., *et al.*, 2011. Quantification techniques for potential CO_2 leakage from geologic sites. Energy Procedia 4 (2011), pgs. 3143-3420.

detect smaller leaks may be limited.[19] Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (*e.g.*, gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. dCarbon may also evaluate other emerging technologies for quantifying CO_2 leakage such as non-dispersive infra-red (NDIR) CO_2 sensors and soil flux detectors. dCarbon may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA.[19]

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Barnett RDC #1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

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[19] Chen, M., *et al.*, 2013. Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA. *Hydrogeology* 21, pgs. 1429–1445. 2013.

7 – BASELINE DETERMINATIONS

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per § 98.448(a)(4). dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. If any issues are identified, such as vapor clouds, ice formations, or abnormal AVO or FLIR observations, corrective actions will be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at approximately 1 ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

8 – SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

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

8.1 Mass of CO_2 Received

Per 40 CFR § 98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR § 98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received by dCarbon for injection into the Barnett RDC #1 injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams will be metered separately before being combined into the calculated stream.

8.2 Mass of CO_2 Injected

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

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

Where:

$CO_{2,u}$	=	Annual CO_2 mass injected (metric tons) as measured by flow meter u
$Q_{p,u}$	=	Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)
D	=	Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO2,p,u}$	=	Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (weight percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year
u	=	Flow meter

8.3 Mass of CO_2 Produced

The injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

8.4 MASS OF CO_2 EMITTED BY SURFACE LEAKAGE

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S, which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using 40 CFR Part 98-Subpart RR Equation 10 as follows:

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

Where:

$CO_{2,E}$	=	Total annual 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

Annual mass of CO2 emitted (in metric tons) from any equipment leaks and vented emissions of CO2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan

8.5 MASS OF CO_2 SEQUESTERED

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off from 40 CFR Part 98, Subpart RR Equation 12 , as this well will not actively produce any oil or natural gas or any other fluids, as follows:

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

Where:

CO_2	=	Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.
$CO_{2,E}$	=	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 Part 98.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA MRV approval.

10 – QUALITY ASSURANCE

10.1 CO_2 INJECTED

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications.

10.2 CO_2 EMISSIONS FROM LEAKS AND VENTED EMISSIONS

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3 MEASUREMENT DEVICES

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR § 98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4 MISSING DATA

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR § 98.

11 – RECORDS RETENTION

dCarbon will retain records as required by 40 CFR § 98.3(g). These records will be retained for at least three years and include:

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