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OFFICE OF ATMOSPHERIC PROTECTION

WASHINGTON, D.C. 20460

July 15, 2025

Mrs. Lauren Read
BKV dCarbon Ventures, LLC
10055 Morris Dido Newark Road
Fort Worth, Texas 76179

Re: Monitoring, Reporting and Verification (MRV) Plan for Cotton Cove CCS 1

Dear Mrs. Read:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted Cotton Cove CCS 1, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Cotton Cove CCS 1 on March 17, 2025, as the final MRV plan. The MRV Plan Approval Number is 1015181-1. This decision is effective five days after the signature date below and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

If you have any questions regarding this determination, please contact me or the Greenhouse Gas Reporting Program Helpdesk at ghgreporting@epa.gov.

Sincerely,

SHARYN LIE Digitally signed by SHARYN LIE Date: 2025.07.15 13:39:48 -04'00'

Sharyn Lie
Director, Climate Change Division

Technical Review of Subpart RR MRV Plan for Cotton Cove CCS #1

July 2025

Contents

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by BKV dCarbon Ventures, LLC (dCarbon) for its carbon dioxide (CO_2) capture and storage (CCS) project, the Cotton Cove CCS 1 injection well, located in Tarrant County, Texas. Note that this evaluation pertains only to the subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

The MRV plan states that BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV) is developing the Cotton Cove CCS 1 injection well (Cotton Cove) project in the northwest section of Tarrant County, Texas. The plan explains the project would receive a CO_2 stream produced by the nearby Cotton Cove Gas Plant operated by BKV Midstream, LLC which is a separate, pre-existing facility; and inject up to 75,000 metric tons of CO_2 annually over a 12-year period via an underground injection control (UIC) Class II well in secure geologic formations for safe and permanent storage. The plan states that the Cotton Cove injection well and the Cotton Cove Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category, making them separate and distinct facilities under 40 CFR 98.6. As part of the Cotton Cove project, dCarbon submitted this MRV plan.

The MRV plan states that dCarbon has secured a W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the Texas Railroad Commission (TRRC). dCarbon intends to dispose of CO_2 produced by the nearby Cotton Cove Gas Plant into the Cotton Cove CCS 1 injection well via a UIC Class II well (UIC number 000126822, API number 42-439-37356) and is authorized by the TRRC to inject up to 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr) of CO_2 into the CCS 1 injection well. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig). dCarbon plans to inject continuously for approximately 12 years. The plan states that although dCarbon intends to initiate injection with lower volumes, all calculations in the MRV plan conservatively assume close to the maximum injection amount allowed by the TRRC permit (75,744 MT/yr). dCarbon anticipates drilling the Cotton Cove CCS 1 injection well in Q1 of 2025 and completing and beginning injection operations in 2026. The well will inject a CO_2 stream that contains approximately 99.85% CO_2, although the composition of the gas may vary slightly over time.

Cotton Cove is located within the Fort Worth Basin, approximately four miles east-northeast of Azle, Texas. The Fort Worth Basin is a flexural basin covering an approximate 15,000 square miles in north central Texas in the United States. Section 3 of the MRV plan provides a detailed stratigraphic overview of the basin, identifying the Ellenburger Group as the primary injection target for the project. This unit directly overlies the crystalline basement rock. The MRV plan states that initial deposition consisted of locally abundant Cambrian clastics. These were followed by the deposition of Ordovician age Ellenburger platform carbonates, which formed a passive margin and are up to 4,000 feet thick. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting across several subunits. Ordovician Viola and Simpson Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group. Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). These regional relationships are illustrated in Figure 2 of the MRV plan.

Although there are multiple storage-confining unit systems that were evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett Shale and the Ellenburger Formation. At the proposed injection, the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch. The cross sections diagrams in the MRV plan indicate that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy. The MRV plan states that anticipated plume movement will be westward and southward, which is towards the Bend Arch.

The MRV plan states that the storage complex (i.e., storage reservoir and associated confining zones) will utilize the Ellenburger Formation for the injection and confining intervals. The Ellenburger group is divided into eight lithostratigraphic units (Subunits A through G). The MRV plan states that the project will utilize the Ellenburger Subunit E interval as the storage reservoir; the Ellenburger Subunit B-D intervals as the primary upper confining zone; and the Ellenburger Subunit F interval as the lower confining zone.

The MRV plan states that the Ellenburger Subunit E, located approximately 8,800 feet below ground surface (bgs), is a predominantly dolomitic, porous reservoir with an average thickness of 1,090 feet. Overlying this reservoir, the primary upper confining zone is composed of the Ellenburger Subunits B through D, which consist of interbedded limestone and dolostone layers situated between 7,000 and 8,700 feet bgs and average 500 feet in thickness. Beneath the storage reservoir, the Ellenburger Subunit F interval serves as the lower confining zone; it is composed of limestone, dolostone, and quartz, and lies at approximately 9,600 feet bgs with an average thickness of 136 feet.

The Simpson and Viola Groups are anticipated to serve as the secondary upper confining interval, as they lie between the Ellenburger Group and the active Barnett Shale reservoir that lies above it. A crystalline basement that lies beneath the Ellenburger Group is anticipated to serve as the secondary lower confining interval. The Ellenburger Subunit G interval was not seen on well logs consistently enough to confirm that it is present in the area but would provide an additional seal if present. dCarbon states in the MRV plan that the Cotton Cove injection well and target injection interval is located and designed in such a way to protect against migration of CO_2 into productive oil and gas formations.

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

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

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and the active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as "the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." Subpart RR defines active monitoring area as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the AMA is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5." See 40 CFR 98.449.

Section 4 of the MRV plan states that dCarbon calculated the required MMA and AMA according to the above stated regulatory definitions. For the variables (n) and (t), dCarbon used Year 1 of injection as the specific time interval from the first year of the period (n) and Year 12 (end of injection) as the last year in the period (t).

The MRV plan indicates that Schlumberger's Petrel software, a regional subsurface model, will be utilized for the project. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals, that contribute to overall higher fluid flow. As explained in detail in the MRV plan, for this project, a single porosity, single permeability distribution model was deemed appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E. The injection was modeled at 75,000 MT/year for 12 years of active injection followed by 100 years post-injection to determine when plume migration stops.

The MRV plan in Figure 17 illustrates the modeled bottom hole pressure (BHP) at the Cotton Cove CCS 1 well. The plan states that bottom hole pressure remained well under the bottom hole pressure constraint, with the maximum BHP reaching approximately 5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and 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, the flow transitions from capillary-driven to advection-driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

The MRV plan states that the MMA boundary will serve as the MMA and the AMA until facility closure. The plume boundary was defined by the weighted average gas saturation in the injection interval. A value of 5% gas saturation of CO_2 was used to determine the boundary of plume. The MRV plan states that the stabilized CO_2 plume associated with the Cotton Cove storage facility is anticipated to occur at or before Year 94 of post-injection, based upon the 100 years of post-injection modeling that dCarbon conducted. The MRV plan in Figure 16 indicates that the injected CO_2 flows generally west, which is the regional up dip direction and stabilizes in a position where the western end is under Eagle Mountain Lake. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation. The MMA boundary calculated utilizes the stabilized CO_2 plume area plus a one-half mile buffer. The area of the MMA was determined to be 3.07 square miles with the maximum distance to the boundary line reaching 1.5 miles southwest from the point of injection.

The MMA, as it is defined in the MRV plan, is consistent with subpart RR requirements because the defined MMA accounts for the expected free phase CO_2 plume, based on modeling results, and incorporates the additional 0.5-mile or greater buffer area. The rationale used to delineate the MMA, as described in dCarbon's MRV plan, accounts for the existing operational and subsurface conditions at the site, along with any potential changes in future operations

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

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). In Section 5 of their MRV plan, dCarbon identified the following potential leakage pathways that required consideration:

- Leakage from Surface Equipment
- Leakage from Approved, Not Yet Drilled Wells
- Leakage from Existing Wells
- Leakage from Fractures and Faults
- Leakage through Confining Layers
- Leakage from Natural or Induced Seismicity
- Leakage from Lateral Migration

A summary of the risk assessment for the potential leakage pathways is provided in Table 8 of the MRV plan and is recreated below.

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 12 hours of full permitted 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	**Unlikely**, 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 conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale 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 that reach shallow enough to serve as a conduit to the USDW or the surface.	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 2,000 feet 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 a couple 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 that extend shallow enough to reach the USDW or the surface.	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 5.8 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

3.1 Leakage Through Surface Equipment

Section 5.1 of the MRV plan states that the Cotton Cove facility is designed for injecting the CO_2 stream and is therefore, designed and operated to minimize leakage points and corrosion for pipes, valves, and flanges through design and construction by following industry standards and best practices, such as the American Society of Mechanical Engineers (ASME) standards and American Petroleum Institute (API) standards. The MRV plan states that there are designated locations that automatically detect CO_2 and a lack of O_2. All BKV and dCarbon field personnel are required to wear gas monitors that detect four or five gases, including H_2S and O_2. A shut-in valve is located at the wellhead in case of emergency.

Additional safety measures noted in the MRV plan include the compressor having emergency shut down switches that can be activated in case of unexpected standard operating conditions such as a loss of line pressure, and the area being subjected to monthly Auditory, Visual and Olfactory (AVO) inspections and CO_2 leak detection per BKV and dCarbon safety and operations standards. These recurring monthly inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will help detect any potential leaks that may occur. With these inspections, operations personnel can usually repair leaks immediately by tightening valves, flanges, or similar equipment. The plan states that BKV Midstream, LLC or dCarbon personnel are expected to visit the site daily.

The MRV plan states that with the level of monitoring at the Cotton Cove facility and the Cotton Cove CCS 1 injection well, any release of CO_2 would be quickly identified, and the safety systems would quickly minimize the volume of the release.

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

3.2 Leakage Through Wells within MMA

Leakage through Existing Wellbores

In Section 5.3 of the MRV plan, dCarbon states that historical oil and gas operations occurring within the MMA has mostly been in shallower formations, such as the Barnett Shale, and the targeted Ellenburger injection interval is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells present in the MMA were drilled shallower than the target Ellenburger Formation. The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to migrate vertically via faults in the Ellenburger Formation to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production and injected CO_2 could be produced in the gas stream of these wells, although it is considered improbable based upon the reservoir simulation modeling that dCarbon conducted.

The MRV plan also states that the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids, and each of these casing strings will be cemented and inspected to ensure wellbore integrity. All injection is set to occur through a steel tubing string that is secured in place with a permanent packer, and this design intends 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.

Leakage through Wells Not Yet Drilled

Section 5.2 of the MRV plan states that potential leakage caused by future drilling in the area are not expected to occur. The formations above the injection zone, such as the Barnett shale, have proven to be less productive in the area, and there are no approved, not yet drilled well permits within the MMA other than the Cotton Cove CCS 1 injection well.

Groundwater Wells

The MRV plan states that there are 107 freshwater wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well as shown in Figure 14 of the MRV plan. All of the identified groundwater wells in the area have total depths of less than 1,000 feet, as shown in Table 4 of the MRV plan. Additionally, dCarbon has a water well on the facility property that will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water intervals and plans to periodically sample the well to monitor for chemical composition. The MRV plan also states that the surface and intermediate casings of the injection well are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations. The wellbore casings and cements also serve to prevent CO_2 leakage to the surface along the borehole.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from both existing wellbores and not yet drilled wells.

3.3 Leakage Through Faults or Fractures

Section 5.4 of the MRV plan states that dynamic modeling at the Cotton Cove facility indicates that the migration of the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. The MRV plan states that existing faults terminate at the top of the Mississippian strata at roughly 6,000 feet TVDSS, leaving approximately 6,000 feet of unfaulted Pennsylvanian shales and sands to serve as yet another secondary confining system between the Ellenburger injection interval and the faults. Based on this modelling, it is considered highly improbable that injected CO_2 would migrate up faults to the Underground Source of Drinking Water (USDW) or to the surface through faults. The MRV plan does note that there is a presence of karsting in the Ellenburger Subunit A interval, but karsting does not appear to affect any subunit of the Ellenburger Formation below the Ellenburger Subunit A interval, therefore the upper primary confining seal composed of the Ellenburger Subunit B-D intervals will remain as a continuous upper seal.

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

3.4 Leakage Through Confining Layers

According to Section 5.5 of the MRV plan, the Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D intervals and below by the competent confining Ellenburger Subunit F interval. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA. Additionally, although the final CO_2 plume stabilizes in a position where the western end of the plume is located under Eagle Mountain Lake, the above mentioned upper confining seals should ensure that no CO_2 is able to reach the lake.

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

3.5 Leakage From Natural or Induced Seismicity

Section 5.6 of the MRV plan states that the location of the Cotton Cove CCS 1 injection well is in an area of the Fort Worth Basin that has experienced historic seismic activity, and the occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor. 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.

The MRV plan states that dCarbon installed new ground seismic monitoring stations 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 have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on 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. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

Before beginning injection, dCarbon will install surface pressure gauges to model and monitor reservoir pressure and injection pressure. dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 psi per foot gradient when measured from the top of the injection interval pursuant with TRRC guidelines and permit conditions. In conjunction with these measures, dCarbon will perform periodic pressure fall-off tests to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures will help prevent induced fracturing of the formation and reduce the likelihood of induced seismicity. The MRV plan states that if any unexpected increase in formation pressure is detected, dCarbon can perform fault slip potential analysis to evaluate the risk of induced seismicity on the closest mapped faults. The plan states that dCarbon plans to build this model based on geologic data collected during drilling the Cotton Cove CCS 1 well. It also states that if there is a concern about abnormal pressures or seismicity, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

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

3.6 Leakage From Lateral Migration

Section 5.7 of the MRV plan states that the structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection well is about two degrees up to the west and is displayed in Figure 21 of the MRV plan. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles. Conversely, dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west, therefore no leakage from lateral migration is expected. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 6 of the MRV plan discusses the strategies dCarbon will employ for monitoring and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(4). Section 7 of the MRV plan discusses the strategies that dCarbon will use for establishing expected baselines for CO_2 leakage. Monitoring will occur 1 year prior to injection, and during the 12-year injection phase of the project.

4.1 Detecting and Quantifying Leakage from Surface Equipment

Section 6.1 of the MRV plan states that the monitoring for surface leakage will occur during the planned 12-year injection period, or until the cessation of operations, and the likelihood for potential leakage from surface equipment is low due to the several mitigation measures. Additionally, dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes that may indicate leakage of CO_2, and leakage from surface equipment will be quickly detected and addressed upon identification.

The MRV plan states that field personnel at the compressor facility and the injection well will conduct periodic AVO inspections. These inspections will help address any issues, so corrective actions can be initiated in a timely manner.

Additionally, the CO_2 for injection will be metered with a Coriolis meter at the injection well site. Periodically, the injection stream will be sampled and analyzed with a gas chromatograph (that has been calibrated to industry standards) to determine final composition. 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. Gas samples will be taken and analyzed per the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate 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.

The MRV plan states that any leakage would be detected and managed per Texas regulations and dCarbon's safety and operations plans. Continuous monitoring systems would trigger an alarm upon a release, and 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.

The MRV plan provides adequate characterization of the Cotton Cove's facility approach to detect potential leakage from surface equipment and the injection wells as required by 40 CFR 98.448(a)(3).

4.2 Detecting and Quantifying Leakage from Existing and Future Wells

Section 6.2 of the MRV plan states that there are no wells within the MMA (current, existing, or pending) that penetrate as deep as the Ellenburger injection interval. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA on a quarterly basis, and dCarbon will investigate any future proposed wells within the area of the MMA to determine if any additional risks are introduced through the new well proposal.

The MRV plan states the injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead in addition to pressure sensors for each annulus of the well, and dCarbon will monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well, which will be reviewed and adjusted when data is outside the acceptable performance limits. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Additionally, dCarbon will conduct annual bottomhole pressure and temperature measurements to calibrate the surface readings to bottom hole, and mechanical integrity tests (MITs) will be performed annually to detect for the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

The MRV plan states that upon a detected leak into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells to take gas samples quarterly to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 that can be confidently attributed to injection volumes from the Cotton

Cove CCS 1 injection well would then be calculated using standard engineering procedures for estimating potential well leakage. These volumes would be documented and reflected in the annual monitoring report, and dCarbon would evaluate and execute any additional downhole remediations that could address leakage from the injection well to the existing and future wells in the monitoring area. Thus, the MRV plan provides adequate characterization of the Cotton Cove facility's approach to detect potential leakage through existing and future wells as required by 40 CFR 98.448(a)(3).

4.3 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Section 6.3 of the MRV states that no existing faults or fractures have been identified that would allow CO_2 to migrate vertically to intervals with USDWs or to the surface.

Section 6.5 of the MRV plan states that natural and induced seismicity is not uncommon for the Fort Worth basin area, therefore dCarbon is operating a proprietary seismic monitoring array in the general area of the Cotton Cove facility. This monitoring array augments the TexNet Seismic Monitoring system and if a seismic event of 3.0 magnitude or greater is detected, then dCarbon will review the injection volumes and pressures at the Cotton Cove CCS 1 injection well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, which is considered very unlikely because no faults or fractures have been identified through mapped faults and the extent of the modeled plume that would allow CO_2 to migrate vertically to intervals with USDWs or to the surface.

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

The MRV plan provides adequate characterization of dCarbon's approach to detect potential leakage from existing faults and fractures and natural or induced Seismicity as required by 40 CFR 98.448(a)(3).

4.4 Detecting and Quantifying of Leakage through Confining Layers or Lateral Migration

Section 6.4 of the MRV plan states that leakage through confining layers or from lateral migration will be monitored through periodic sampling of the produced gas stream from the Barnett Shale gas wells within the MMA to detect for CO_2 that has bypassed the primary confining sources. dCarbon plans to inject a small amount of chemical tracer with the CO_2 downstream of the volumetric flow meter, which will serve as confirmation that any increase in CO_2 detected in the produced gas stream from the Barnett Shale wells in the monitoring area is from the sequestration reservoir. Additionally, groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems, and dCarbon would utilize the same chemical tracer when sampling the deep groundwater monitoring well at the Cotton Cove Gas Plant. The groundwater monitoring well is deeper than any active groundwater wells in the area, and if dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, then the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Section 6.6 of the MRV plan also explains that leaking through lateral migration is unlikely since the distances to the closest penetration of the Ellenburger injection interval are more than four times the expected plume radius at the end of injection. Additionally, the only wells that penetrate the injection interval are saltwater disposal wells, which are expected to raise the reservoir pressure locally near the well, are expected to limit the ability of the CO_2 to access the saltwater injector well bore.

The MRV plan provides adequate characterization of the Cotton Cove facility's approach to detect potential leakage through the confining layers or lateral migration as required by 40 CFR 98.448(a)(3).

4.5 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that dCarbon will undertake to establish the expected baselines for CO_2 surface leakage per 40 CFR §98.448(a)(4). Prior to the start of continuous injection, the MRV plan identified the following data to compare with future data to detect surface leakage:

Groundwater Monitoring

The MRV plan states that baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells near the Cotton Cove CCS 1 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.

Gas Composition

The MRV plan states that baseline gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA that act as above-zone monitoring wells. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline Seismicity

The MRV plan states that baseline seismicity in the area near the Cotton Cove CCS 1 injection well has been determined through the historical data from USGS and TexNet seismic array data. This information has been supplemented by additional data from dCarbon's proprietary seismic monitoring array to determine a baseline.

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

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

Section 8 of the MRV plan provides the equations that dCarbon will use to calculate the mass of CO_2 sequestered annually.

5.1 Calculation of Mass of CO_2 Sequestered

According to Section 8.1 of the MRV plan, the CO_2 received for these injection wells will be wholly injected and not mixed with any other supplies of CO_2, thus the annual mass of CO_2 injected will equal the quantity of CO_2 received at the receiving flow meter. Therefore, in accordance with 40 CFR 98.444(a)(4), dCarbon has elected to use the mass of CO_2 injected as the mass of CO_2 received instead of using Equation RR-1 or RR-2.

dCarbon's approach to calculating the mass of CO_2 received is acceptable for the subpart RR requirements.

5.2 Calculation of Mass of CO_2 Injected

Section 8.2 of the MRV plan states that dCarbon will use a volumetric flow metering to measure the flow of the injected CO_2 stream and annually calculate the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

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

Where:

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

$Q_{p,u}$ = Quarterly volumetric flowrate measurement for flowmeter 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 (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year

u = Flow meter.

dCarbon provides an acceptable approach to calculation the mass of CO_2 injected in accordance with subpart RR requirements.

5.3 Calculation of Mass of CO_2 Produced/Recycled

Section 8.3 of the MRV plan states that there will be no production from the Cotton Cove CCS 1 injection well and that this injection well is not part of an enhanced oil recovery project. Therefore, dCarbon provides an acceptable approach for calculating the mass of CO_2 produced under subpart RR.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

Section 8.4 of the MRV plan states that dCarbon will not directly measure the annual mass of CO_2 emitted by equipment leaks and vented emissions. Any leakage would be detected and managed as a major upset event. Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 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 procedures outline in 40 CFR Part 98 subpart W.

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

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

Where:

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

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

X = Leakage pathway

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

5.5 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since the Cotton Cove facility does not actively produce oil, natural gas, or any other fluid, Section 8.5 of the MRV plan states that Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

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

where:

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

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

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO2 from equipment located on the surface between the mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of 40 CFR 98.

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

6 Summary of Findings

The subpart RR MRV plan for the Cotton Cove CCS 1 facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Cotton Cove MRV plan.

Subpart RR MRV Plan Requirement	Cotton Cove CCS 1 MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).	Section 4 of the MRV plan delineates and describes the MMA and AMA. dCarbon used geologic and numerical simulations for calculation of the projected CO_2 plume and key project boundaries. The MRV plan defines the active monitoring area as the same area as the MMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan

in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	identifies the following potential pathways: surface equipment, existing wells, wells not yet drilled, existing faults and fractures, natural or induced seismicity, confining layers, and lateral migration. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 6 of the MRV plan describes dCarbon's strategy for detecting and quantifying potential CO_2 leakage to the surface should it occur.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes dCarbon's strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. dCarbon will conduct CO_2 groundwater sampling, gas composition sampling, and seismic monitoring to establish baselines for CO_2 surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 8 of the MRV plan describes dCarbon's approach for determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including calculation of the total annual mass of CO_2 emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 2 of the MRV plan identify the well identification number used for the UIC permit and the UIC class for the Cotton Cove CCS 1 injection well. The well is permitted as Class II and regulated by Texas Railroad Commission.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 9 of the MRV plan states that dCarbon will be ready to begin CO_2 injection in 2026 and will begin to collect data for the total volume of CO_2 sequestered. Baseline monitoring data will be collected beginning in 2025, and the MRV plan will be implemented upon receiving EPA MRV plan approval.

Appendix A: Final MRV Plan

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

Cotton Cove CCS 1

NW Tarrant County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 3.0

February 19, 2025

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 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Cotton Cove CCS 1 injection well in Tarrant County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2, into the Cotton Cove CCS 1 injection well (CCS 1). produced by the nearby Cotton Cove Gas Plant (Gas Plant), operated by BKV Midstream, LLC (TCEQ CN604046912) which is a separate, pre-existing facility. The CCS 1 and the Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category, making them separate and distinct facilities under 40 CFR 98.6. The project site is located approximately four miles east-northeast of Azle, Texas, as shown in **Figure 1**. dCarbon anticipates drilling the Cotton Cove CCS 1 well in Q1 2025 and completing and beginning injection operations in 2026. The Cotton Cove CCS 1 has an approved W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the TRRC (UIC number 000126822, API number 42-439-37356). 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 close to the maximum injection amount allowed by the TRRC permit (75,744 MT/yr). dCarbon plans to inject for approximately 12 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 Cotton Cove CCS 1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 589741. All aspects of this MRV plan refer to this well and this GHGRP ID number.

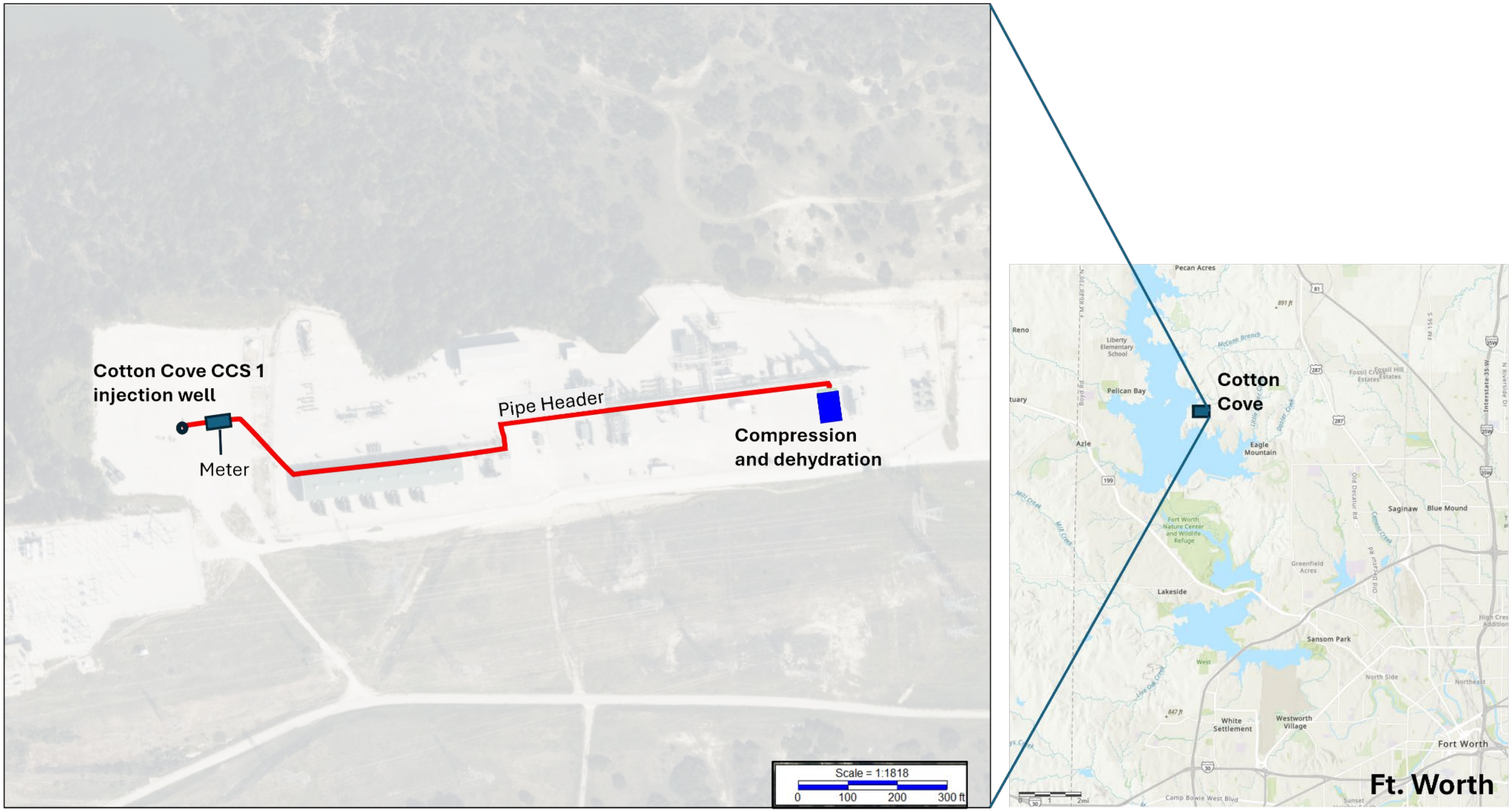


Figure 1. Location map for the Cotton Cove CCS 1 well in Tarrant County Texas. The well is planned to be drilled immediately west of the Cotton Cove Gas Plant that captures the CO_2 to be injected. North is up.

2 – FACILITY INFORMATION

<u>Facility Name</u>:

Cotton Cove Gas Plant (TCEQ CN604046912)

Address: 10055 Morris Dido Newark Road, Fort Worth, TX 76179

Latitude: 32.90927778

Longitude: -97.46976667

GHGRP ID number: 526203

FRS ID: 110040511256

NAICS Code: 211111

Reporting structure: Currently reporting under Subpart C, Subpart W, and Subpart RR.

<u>Underground Injection Control (UIC) Permit Class</u>:

The Oil and Gas Division of the Texas Railroad Commission (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 Cotton Cove CCS 1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

<u>Injection Well</u>:

Cotton Cove CCS 1

API number: 42-439-37356

UIC number: 000126822

Cotton Cove CCS 1, GHGRP ID: 589741

The Cotton Cove CCS 1 well will be disposing of CO_2 from the Cotton Cove Gas Plant. All aspects of this MRV plan refer to the Cotton Cove CCS 1 well and GHGRP 589741.

3.1 Overview of Geology

The proposed injection site lies in the northwestern part of Tarrant County, where the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. The north to south cross section of **Figure 2** shows the Ellenburger and overlying formations dipping down to the north. One inference from these cross sections is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward and southward, which is towards the Bend Arch. The dip direction is further represented in the structure contour map of the Ellenburger Group top (Pollastro, 2007) in **Figure 2**.

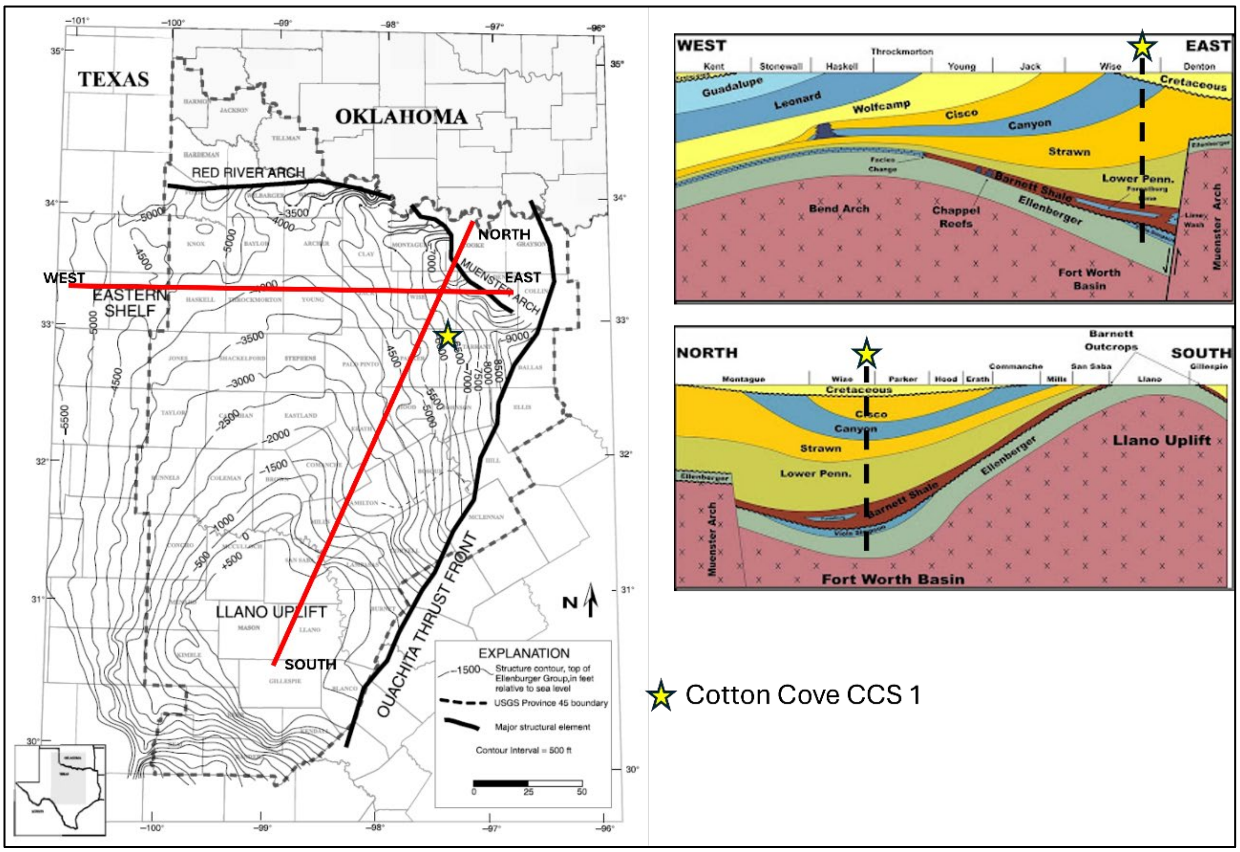


Figure 2. (*Left*) Ellenburger structure map modified from Jarvie *et al.* (2007) showing the regional structures within and bounding the Fort Worth Basin. The Ellenburger structural contours are depicted in feet True Vertical Depth Subsea (TVDSS) at an interval of 500 feet and the final Cotton Cove CCS 1 location is shown by a yellow star. (*Right*) Cross sections from W-E (top right) and N-S (middle right) show the regional dip of the sedimentary units in the Fort Worth Basin modified from Bruner *et. al.*, (2011), also with a yellow star and dashed black line indicating the position of the Cotton Cove CCS 1 well.

The Fort Worth Basin sedimentary succession began with the deposition of locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (**Table 1**). Ordovician age Ellenburger platform carbonates were deposited

next on a passive margin and are up to 4,000 feet thick 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 Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group (Gao, 2021). 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 Formation. The Ellenburger Group directly overlies the basement rock and is considered the main injection target.

Table 1. Regional Stratigraphy at Cotton Cove CCS 1 Site in North Texas.

SYSTEM	SERIES	STAGE	GROUP OR FORMATION	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian		Barnett	Upper Barnett Shale
				Forestburg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Upper		Viola Group	
			Simpson Group	
	Lower		Ellenburger Group	
Precambrian			Basement	

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, the planned injection and confining intervals or zones (terms interval and zone used interchangeably), the planned injection volumes and process, and the reservoir modeling performed for the proposed Cotton Cove CCS 1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Tarrant County, Texas.

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. 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 in 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 in the south.

3.2.2 Stratigraphy

The Ellenburger Group in the Fort Worth Basin contains alternating limestone and dolostone lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into eight subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.* (2019). The main target storage reservoir, Ellenburger Subunit E, was identified based on the dominant dolostone lithology, gross and net reservoir thicknesses, porosity values, and permeability values. The Ellenburger Subunit B and the stratigraphic top portion of Ellenburger Subunit C were identified as the caprock based on the dominant limestone lithology, thickness, porosity, and permeability values. Below this interval, there are layers of tighter limestone throughout Ellenburger Subunits C, C2, and D that would also act as sealing units to the underlying Ellenburger Subunit E storage interval.

The Barnett RDC 1 well (API number 42-497-38108), located approximately 27 miles northwest of the proposed Cotton Cove CCS 1 injection well, was used to calibrate well-log-based petrophysical properties since it has modern well logs and core data (**Figure 3**). The Tarrant North SWD 1 well (API number 42-439-31228), located approximately six miles to the northeast, was also used in well correlations and thickness calculations because of its closer proximity. Dominant lithologies were determined by comparing the photoelectric factor log curve and the separation of the density and neutron porosity curves in the Tarrant North SWD 1 well with the volume of clay, sand, lime, dolomite, gas, and free water calculated in the Barnett RDC 1 well. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

Figure 3 shows the correlation of the Barnett RDC 1 to the Cotton Cove CCS 1 site, including the Tarrant North SWD 1, as noted by the well names posted on the map and at the base of the well

logs in the cross section. Ellenburger Subunits A through F are present and appear to be contiguous in the project area. The thickness of Ellenburger Subunits B-D is approximately 2,000 feet while Ellenburger Subunit E thickness varies across the cross-sections. It is estimated there is at least 2,000 feet of Ellenburger Subunits B-D and 1,000 feet of Ellenburger Subunit E at the Cotton Cove CCS 1 proposed location.

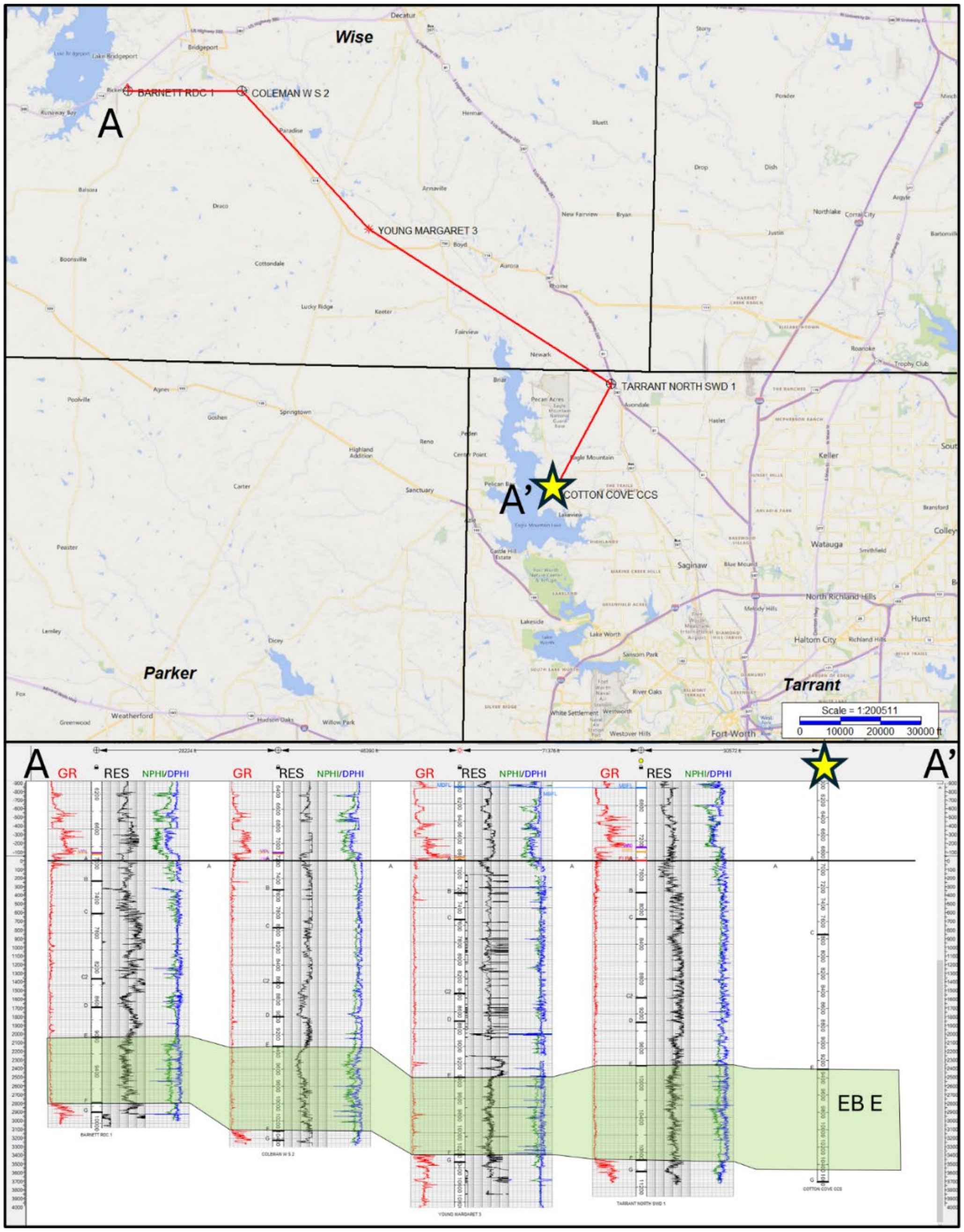


Figure 3. (*Top*) Map of north Texas, including Wise and Tarrant Counties, with the Cotton Cove CCS 1 (yellow star) and a NW-SE stratigraphic cross section (A-A'). North is up. (*Bottom*) Cross section, datumed on the top of the Ellenburger Subunit A, showing Gamma Ray (GR), Resistivity (RES), Neutron Porosity (NPHI), and Density Porosity (DPHI) from the Barnett RDC 1 well to the Tarrant North SWD 1 well. Ellenburger Subunit E (EB E) is the storage interval.

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 (**Figure 4**). A secondary set of east-west faults appear to connect these major trends. 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 present, suggesting that faults have not experienced significant movement since their formation (Wood, 2015). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Formation.

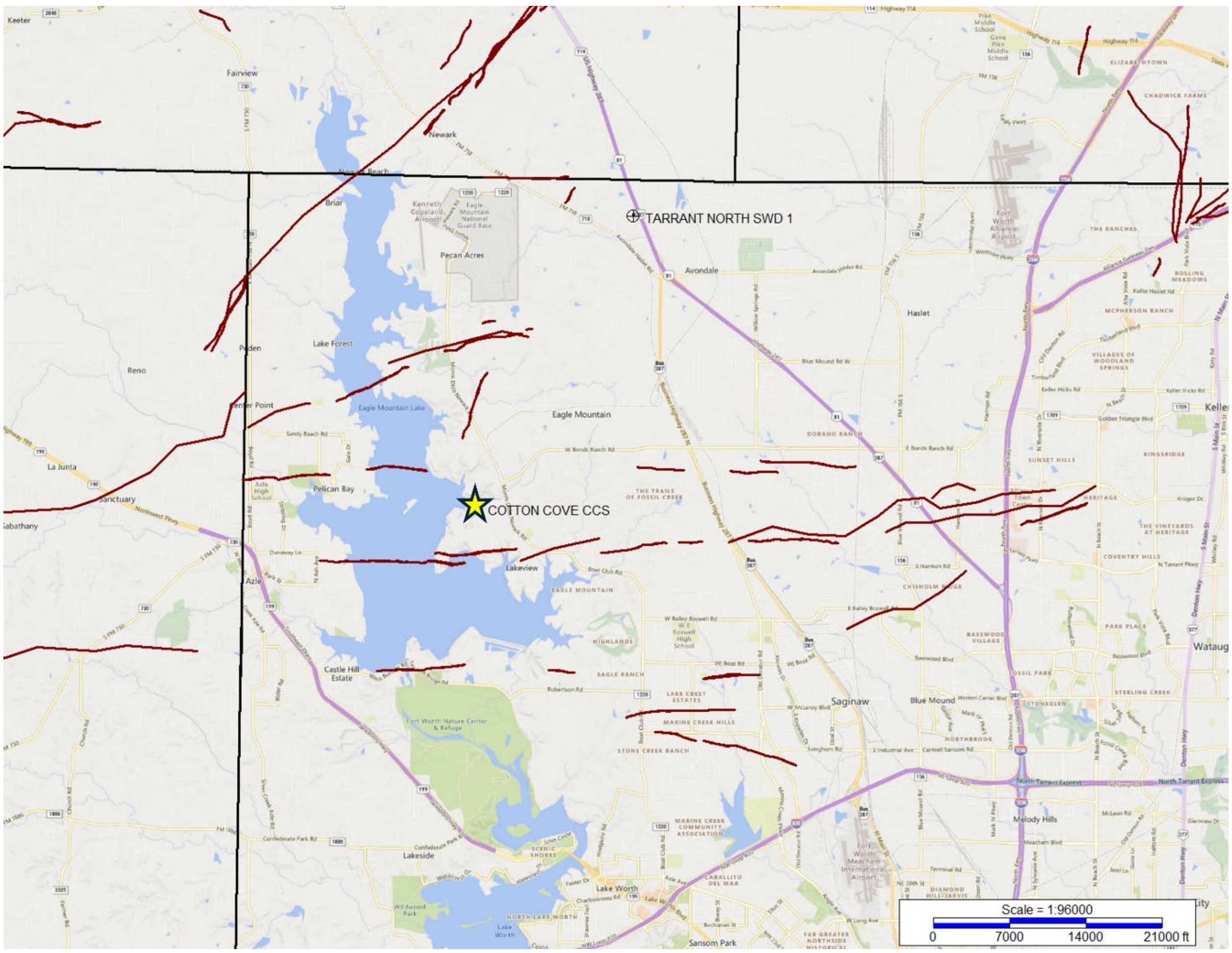


Figure 4. Mapped faults (brown lines) at the top Ellenburger level, near the proposed injection well, from Wood (2015) and internal mapping. North is up.

3.3 LITHOLOGICAL AND RESERVOIR CHARACTERIZATIONS

Smye *et al*. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Upper Cambrian to Ordovician. Prior to understanding the petrophysical 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. 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 strata highlighted by red dashed box in **Figure 5**. The Viola and Simpson Groups are expected to overlie Ellenburger Subunit A at the Cotton Cove CCS 1 site as depicted on the right side of the highlighted column.

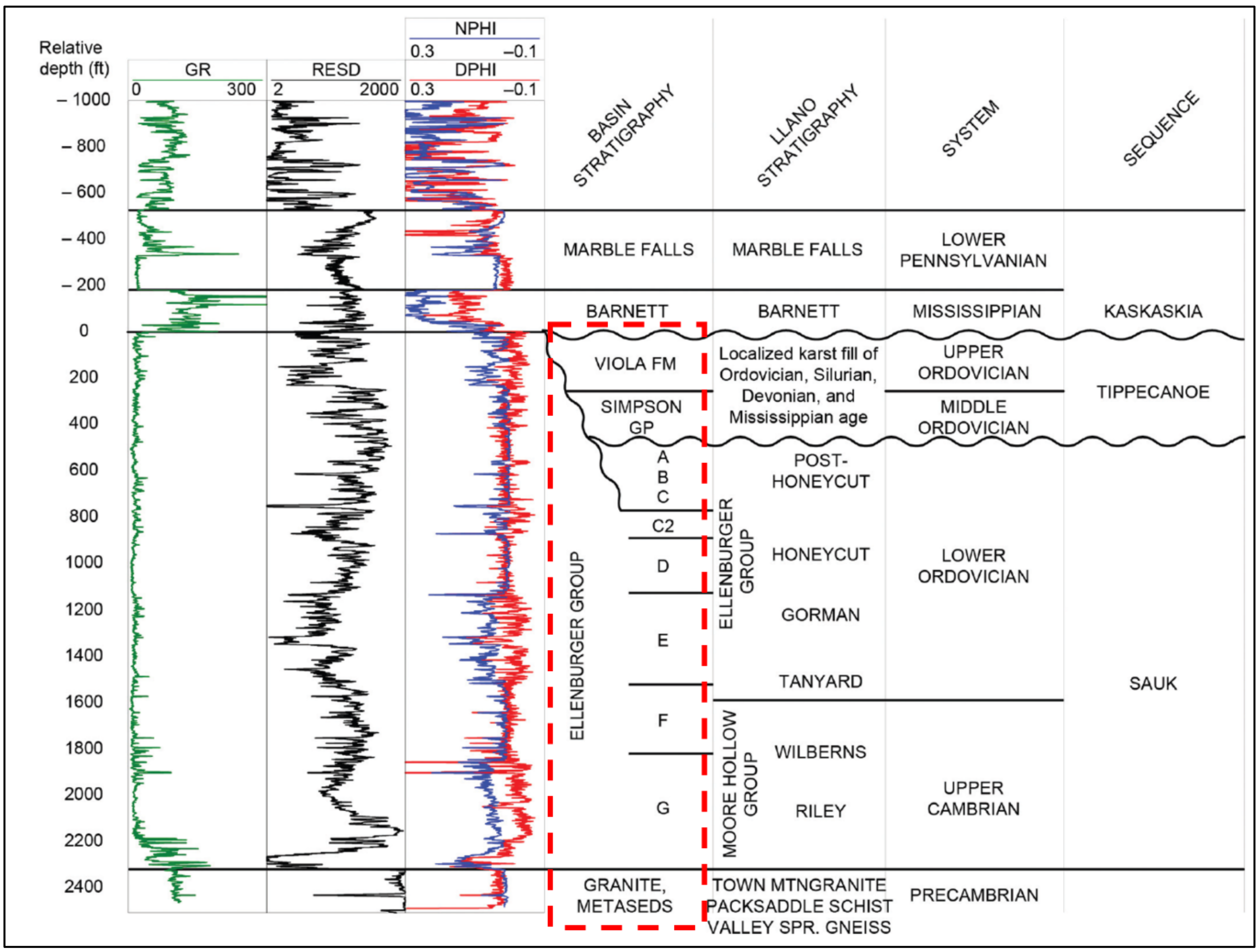


Figure 5. Regional stratigraphy at Cotton Cove CCS 1 site in north Texas (modified from Smye *et al.,* 2019). Red dashed box highlights the section of focus for the lithological characterization.

The Simpson and Viola Groups are anticipated to serve as the secondary confining interval at the Cotton Cove CCS 1 location. The Barnett Shale, located above the Viola Group, 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 range from 4-6% and 7-50 nanodarcies, respectively. These

low porosities and permeabilities are characteristic of conventional seals and, as such, the Barnett serves as an additional confining interval. The wells in the project area produce unconventional gas from the Barnett Shale.

Underlying the Viola and Simpson Groups are the informal Ellenburger lettered units defined by Smye *et al.*, 2019, which contains both the anticipated storage and confining intervals. The Ellenburger was divided into eight lithostratigraphic units starting with Ellenburger Subunit A at the top to Ellenburger Subunit G at the bottom which sits on top of the crystalline basement. Ellenburger Subunit G is not seen on well logs sufficiently to confirm that it is present in the area. Ellenburger Subunit F may sit on the crystalline basement in the area and serves as the lower seal for the reservoir. Core data from the Barnett RDC 1 showed Ellenburger Subunit F had porosities below 2% and permeabilities below 0.005 millidarcies (mD), making it an excellent lower seal. Ellenburger Subunit E will serve as the storage interval. It is characterized as a clean dolomitic reservoir with 49% dolomite by volume and approximately 4% matrix porosity. Ellenburger Subunits B and C were found to have lower matrix porosities compared to Ellenburger Subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger Subunit A has been proven to have reservoir characteristics with multiple saltwater disposal wells completed in Ellenburger Subunit A. Karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Ellenburger Subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger Subunits A-G.

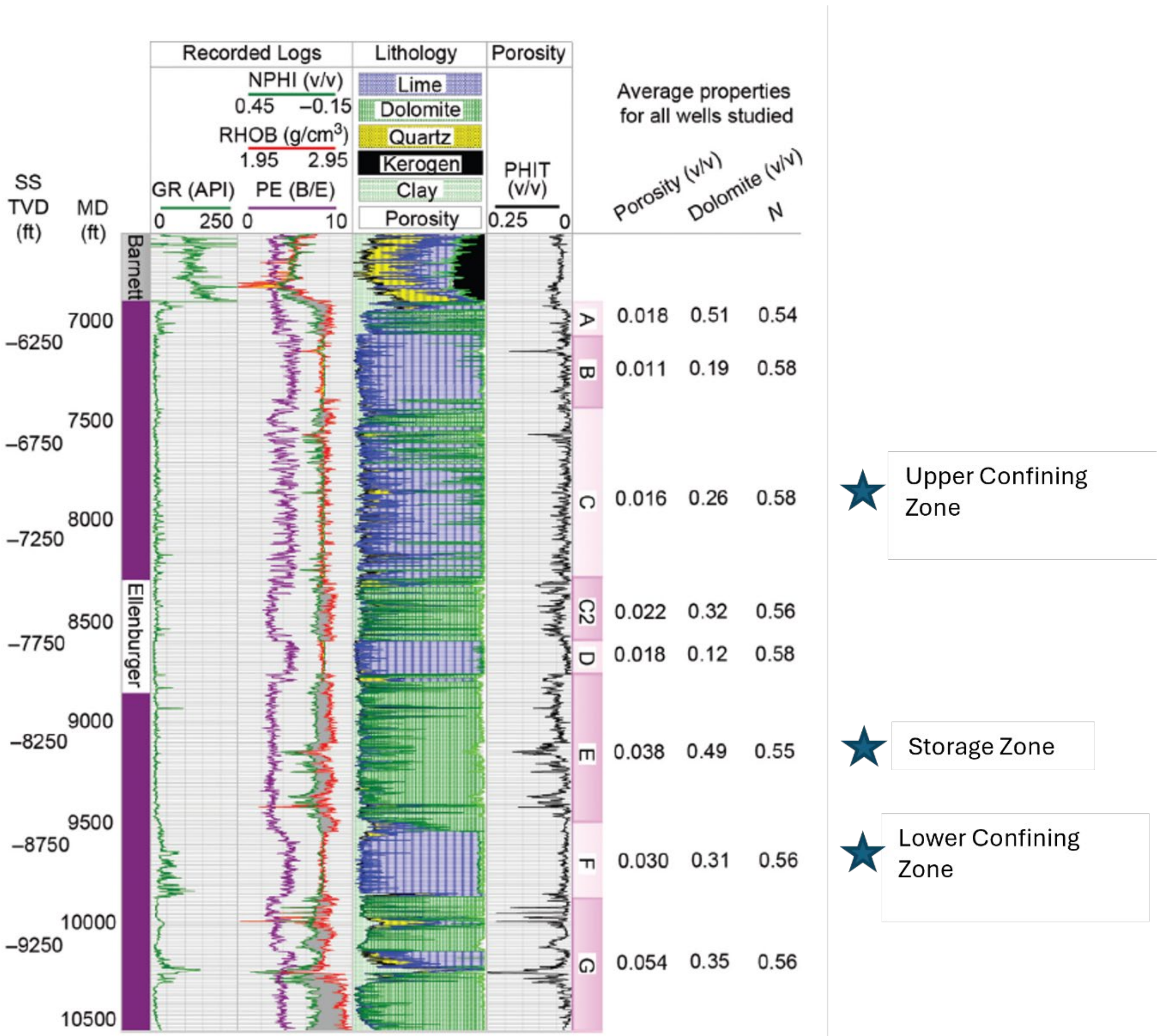


Figure 6. General properties of Ellenburger Subunits A-G in the project area (modified from Smye *et al.*, 2015).

The Barnett RDC 1 injection well located approximately 27 miles northwest of the proposed injection site also contains Ellenburger Subunits A through F, as shown below in **Figure 7**. Drilling at the proposed site should result in reservoir and seal intervals like those shown in both **Figures 6 and 7**.

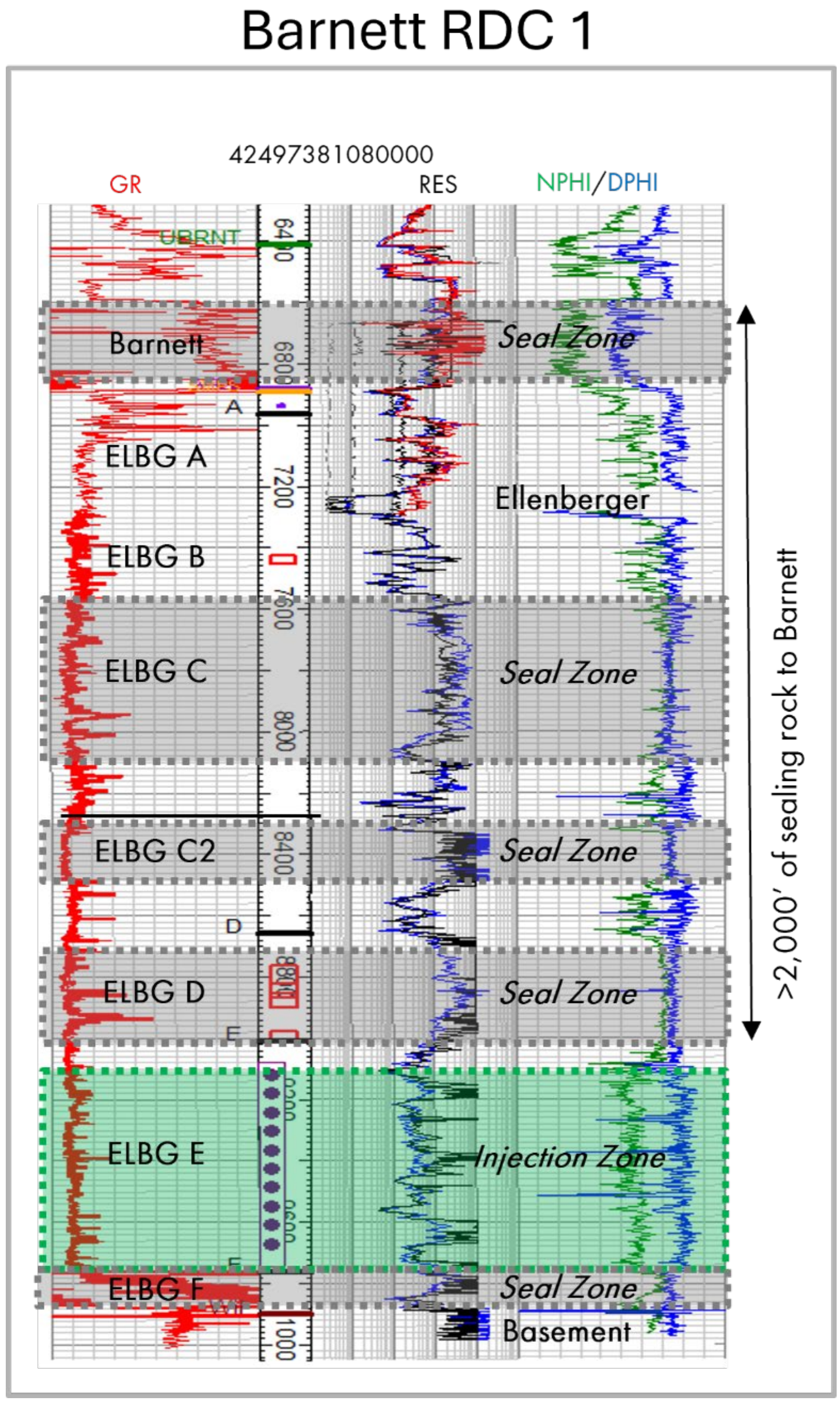


Figure 7. Barnett RDC 1 well log interpretation; Ellenburger Subunits A through F are shown on the log image.

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 as the cut-off because fractures greatly enhance

permeability and improve Ellenburger reservoir quality even in intervals with very low matrix porosity.

Saltwater disposal into analogous Ellenburger intervals with low porosity lend support to the premise that a low log porosity could still result in realizable CO_2 storage potential (*e.g.*, Tarrant North SWD 1). 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 interval properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger as seen in the Tarrant North SWD 1 well.

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

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHIA])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolostone	372	160	0.43	3.3	
B	Limestone	307	25	0.08	1.3	Upper Confining Interval
C	Limestone	906	284	0.31	2.4	
C2	Dolostone	281	88	0.31	2.5	
D	Limestone	502	288	0.57	3.5	
E	Dolostone	1087	700	0.64	4.2	Storage Interval
F	Limestone	136	4	0.03	1.1	Lower Confining Interval
G	Dolostone	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature and informed by the core data from the Barnett RDC 1 well. Regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.5 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.25°F per 100 feet using the well logs from the Tarrant North SWD 1.

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 v3.0, five wells within in the Fort Worth Basin were identified with water samples from the Ellenburger as shown in **Figure 8**.

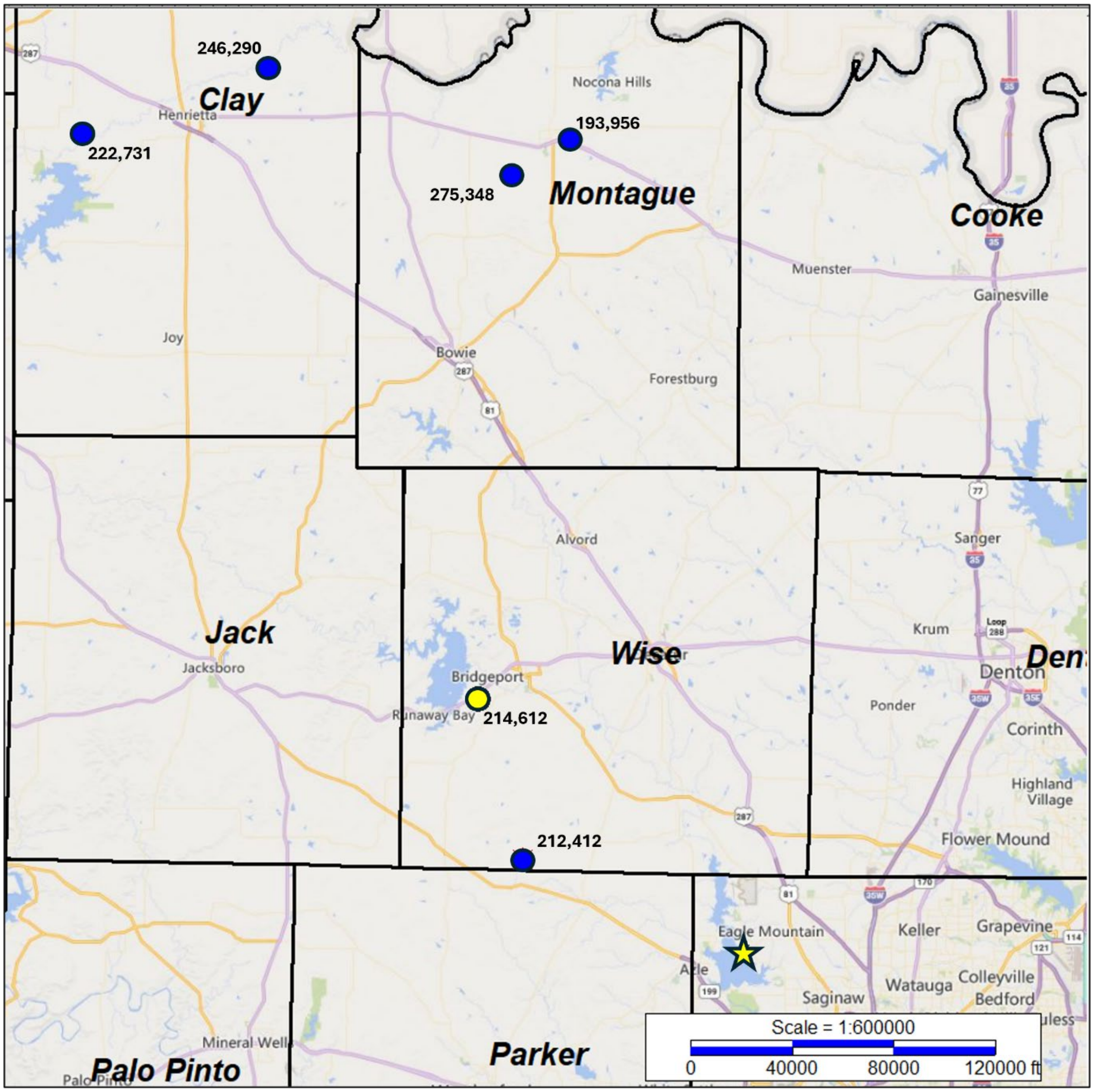


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis. The blue circles are wells from the USGS Produced Waters Database v3.0 while the yellow circle is the Barnett RDC 1. TDS values in mg/L are annotated. The Cotton Cove CCS 1 location is shown with the yellow star. North is up.

The Ellenburger Group is not productive of oil and gas 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. The USGS database indicates that Ellenburger fluids have greater than 190,000 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin as reported in **Table 3**. The average of the five samples available in the USGS database is similar to the TDS value that dCarbon obtained from the Barnett RDC 1 well. The Barnett RDC 1 well sample had 214,612 mg/L TDS, an Na concentration of 54,465 ppm, a Ca concentration of 22,269 ppm, and a Cl concentration of 128,819 ppm.

Table 3. Ellenburger Formation fluid chemistry. These values are derived from the five wells depicted in Figure 8.

	TDS (mg/L)	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	230,147	63,363	20,635	142,168
LOW	193,956	55,352	15,352	118,405
HIGH	275,348	77,094	23,443	169,720

3.5 Potential of Induced Seismicity – Ellenburger Formation

An analysis of historical seismic events within 100 square miles surrounding the proposed Class II well injection site shows seismic activity dating back to 1900, according to the U.S. Geological Survey (USGS) Earthquake Catalog (**Figure 9)**. Of the nine earthquakes above magnitude 3.0 shown on the map, three fall within the 100 square-mile area. All but one of the nine earthquakes appear to be part of the Azle-Reno earthquake swarm, documented by Hornbach, *et al*. (2015) (**Figure 10**). The Azle-Reno swarm earthquakes were mapped back to an NNE-SSW basement-rooted fault and its antithetic fault via data from a local earthquake network and advanced hypocenter location techniques. It is likely that the wide scatter in the mapped earthquake locations seen in the USGS catalog is a function of the location uncertainty due to the sparse recording array rather than actual separation of earthquake hypocenters.

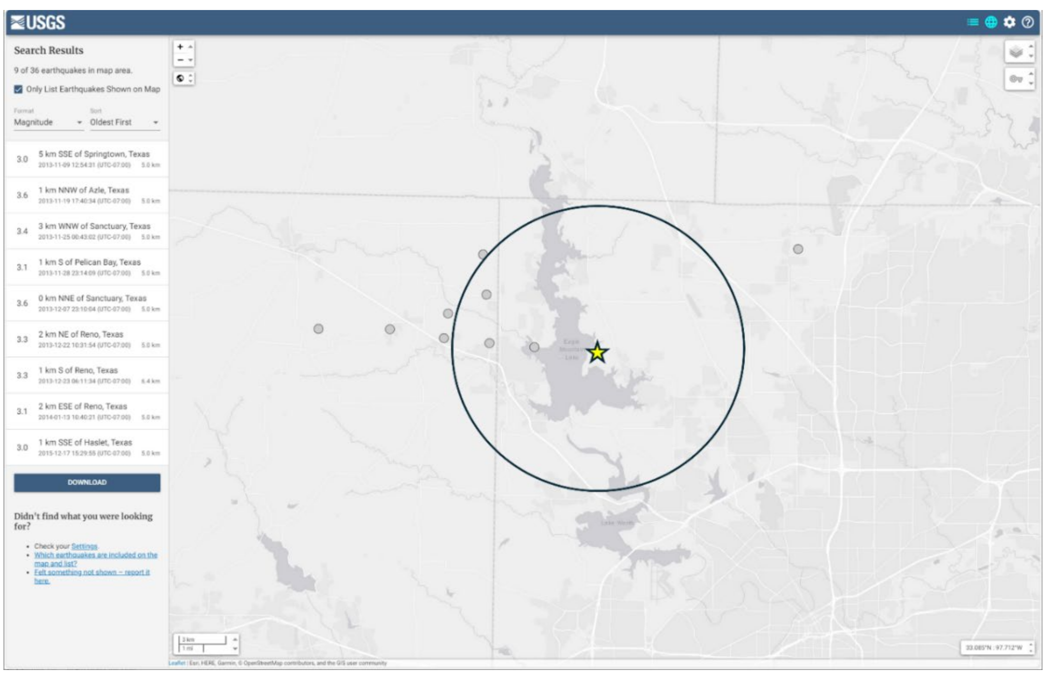
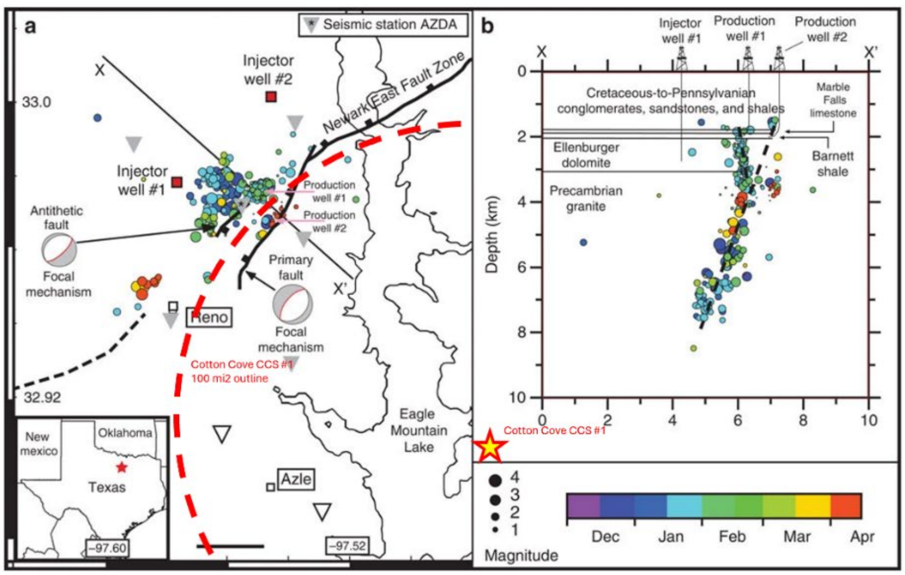


Figure 9. Screenshot from the USGS Earthquake Catalog showing historical seismic activity at or above Magnitude 3.0 in the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. Three seismic events meet these criteria in the USGS catalog. North is up.

Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey (Hennings, *et al.*, 2019). Current findings show that steeply dipping faults that strike north-northeast have the highest fault slip potential. These results are consistent with the orientation of the faults that produced the Azle-Reno swarm. No additional earthquakes have been reported since 2015 despite several saltwater disposal wells that inject in the Ellenburger Group continuing to operate in the area. Beginning in August 2023, BKV began operating a local earthquake network covering portions of Wise, Denton, Parker and Tarrant Counties in Texas (**Figure 11**). No earthquakes have been detected within the 100 square-mile area surrounding the Cotton Cove CCS 1 location with this array since it began recording.



Map showing the location of NEFZ (black) at the top of the Ellenburger formation, inferred faults (dashed) at the top of the Ellenburger formation, injection wells (red squares), two production wells (API 36734045 and 36734139) with significant brine production near the faults (pink arrows) and earthquake epicentres (coloured circles) recorded by the temporary seismic network (triangles) (**a**). The red star in the inset of **a** shows the map location. The black scale bar in **a** is 2 km. Grey (white) triangles indicate the locations of active (inactive) seismic stations. Line X–X′ in **a** shows the location of the cross-section shown in (**b**). We interpret two faults based on earthquake location and consistent with industry interpretations: a primary normal fault and a shallower antithetic normal fault.

Figure 10. Modified from a map from Hornbach *et.al.*, 2015. Earthquake hypocenters for the 2013-14 Azle-Reno swarm were located using a local array of seismometers resulting in reduced location uncertainty. Earthquakes were clustered along a northwest-dipping normal fault and it's southeast-dipping antithetic fault. These earthquakes cluster just outside of the line marking the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. North is up.

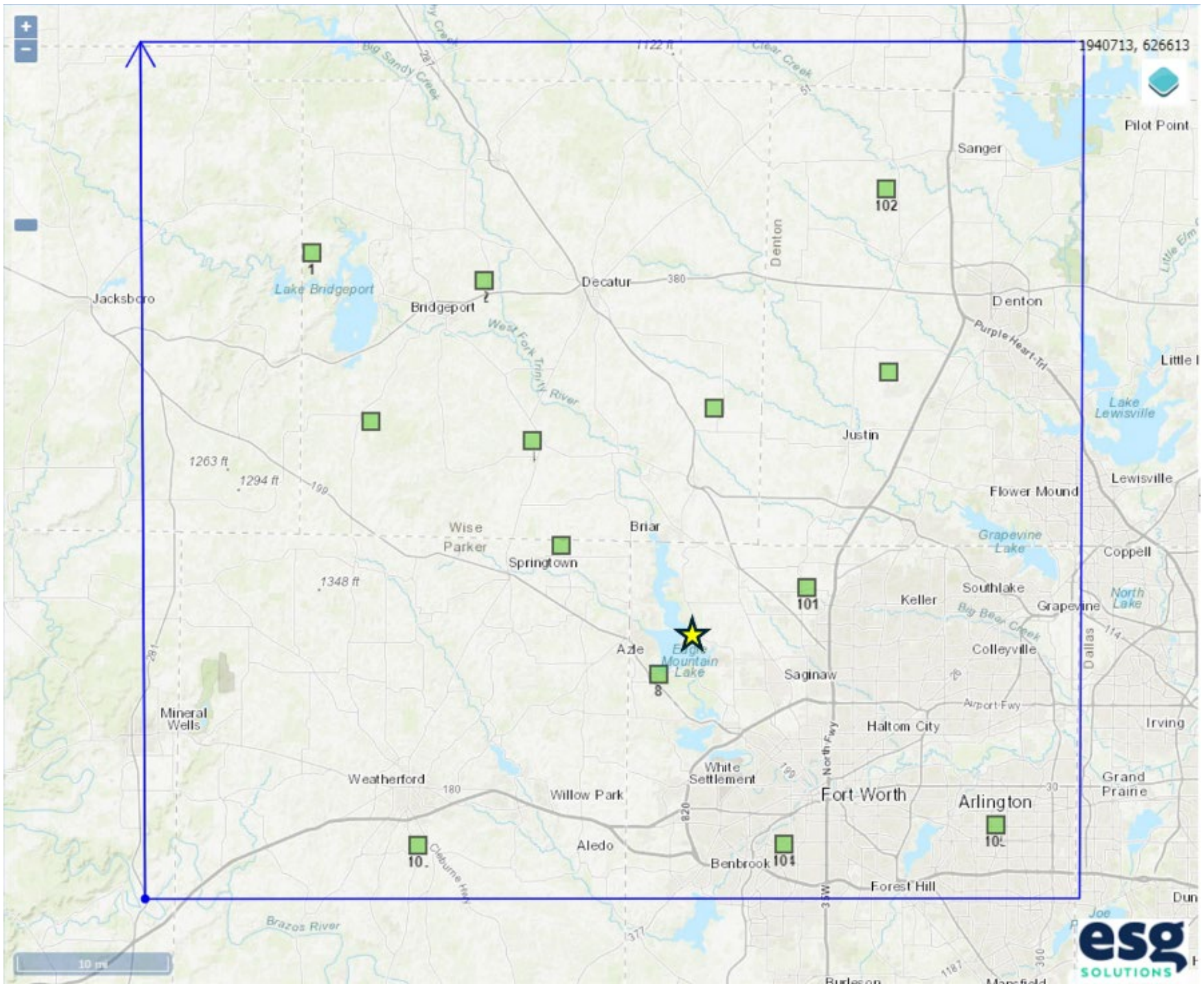


Figure 11. Map of the local seismic array monitoring the area of the Cotton Cove CCS 1. The yellow star marks the location of the Cotton Cove CCS 1. Seismic stations contributing data to the BKV seismic analysis are shown with the green squares. Stations 1-8 are operated by BKV while Stations 101-105 are operated by either TexNet or the USGS and their data are used in the hypocenter locations. North is up.

3.6 Groundwater Hydrology in MMA

Tarrant County falls within the Northern Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 12**). One aquifer is within the vicinity of the proposed injection site: the Trinity Group Aquifer. The Lower Cretaceous Trinity Group is classified as a major aquifer and serves as an important source of groundwater for a portion of northern Texas, including Tarrant County, Texas. The Trinity Group Aquifer outcrops at the Cotton Cove CCS 1 site and across a large swath of Wise and Parker Counties and the northwestern corner of Tarrant County.

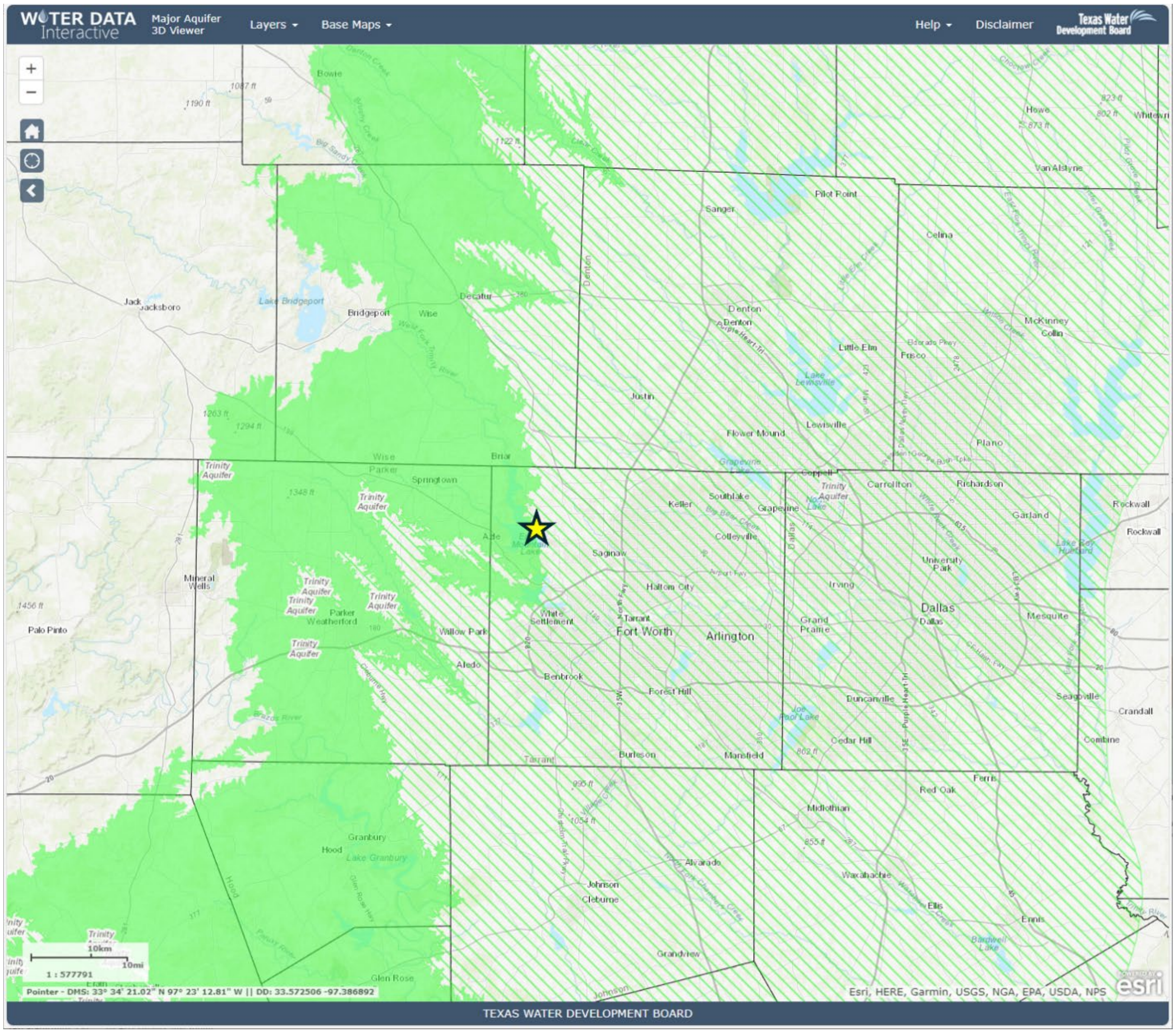


Figure 12. Map of the Trinity Major Aquifer extent within northcentral Texas, from the Texas Water Development Board Interactive Viewer. The location of the proposed Cotton Cove CCS 1 is shown with a yellow star. North is up.

The Trinty Group Aquifer is unconfined west of the project site and confined east of the site (**Figure 12**). Water in the Trinity Group Aquifer is considered fresh but hard, with TDS values in the project area of less than 1,000 mg/L. The overall stratigraphic column contains numerous barriers to vertical flow (or aquitards) that are expected to prevent CO_2 injected into the Ellenburger Subunit E from reaching the surface or near surface location of the Trinity Group Aquifer (**Figure 13**).

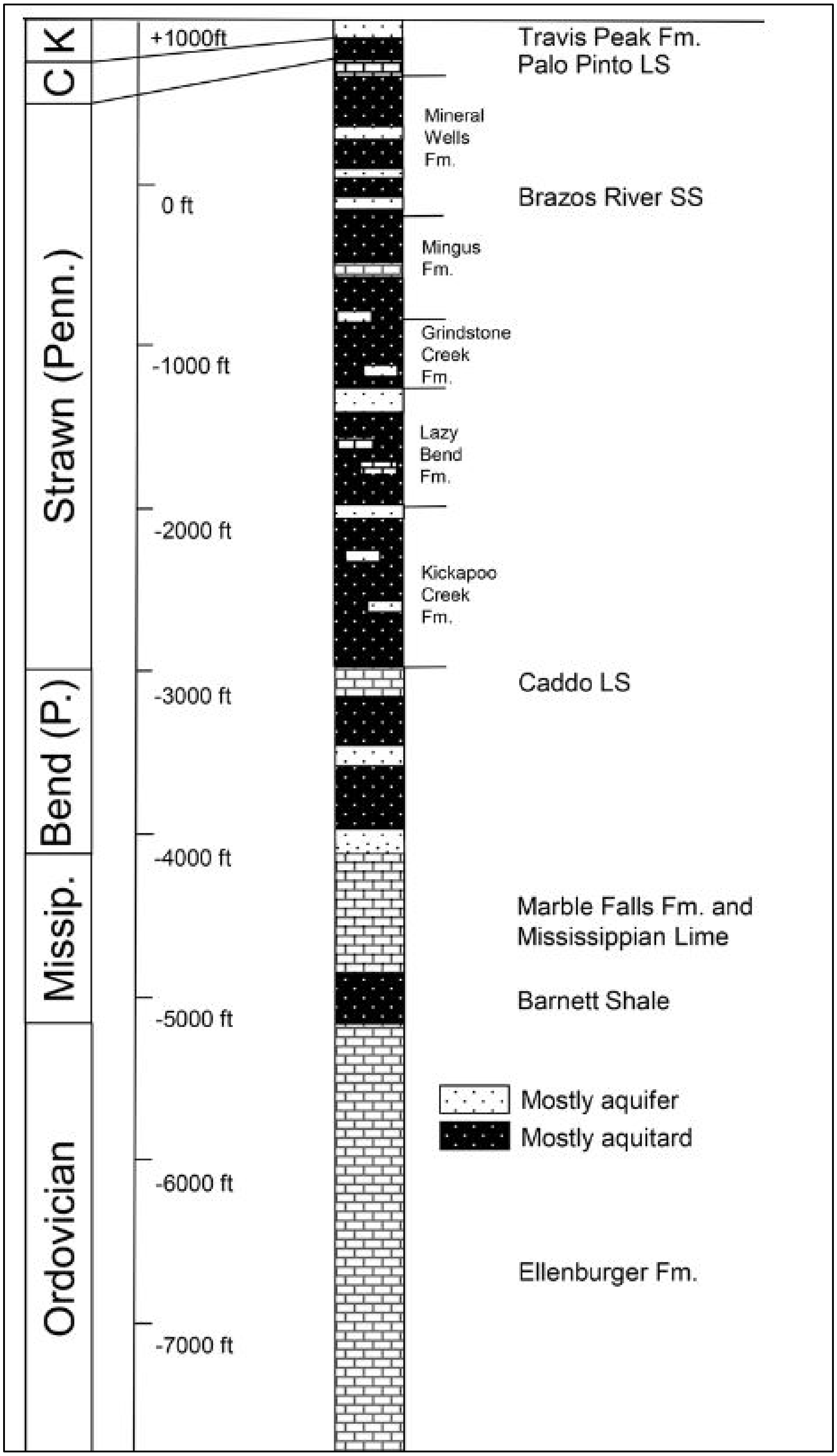


Figure 13. Stratigraphic column showing aquifers and aquitards, modified from Nicot *et al*., (2011)

There are 107 freshwater wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, as shown in **Figure 14** and listed in **Table 4**.

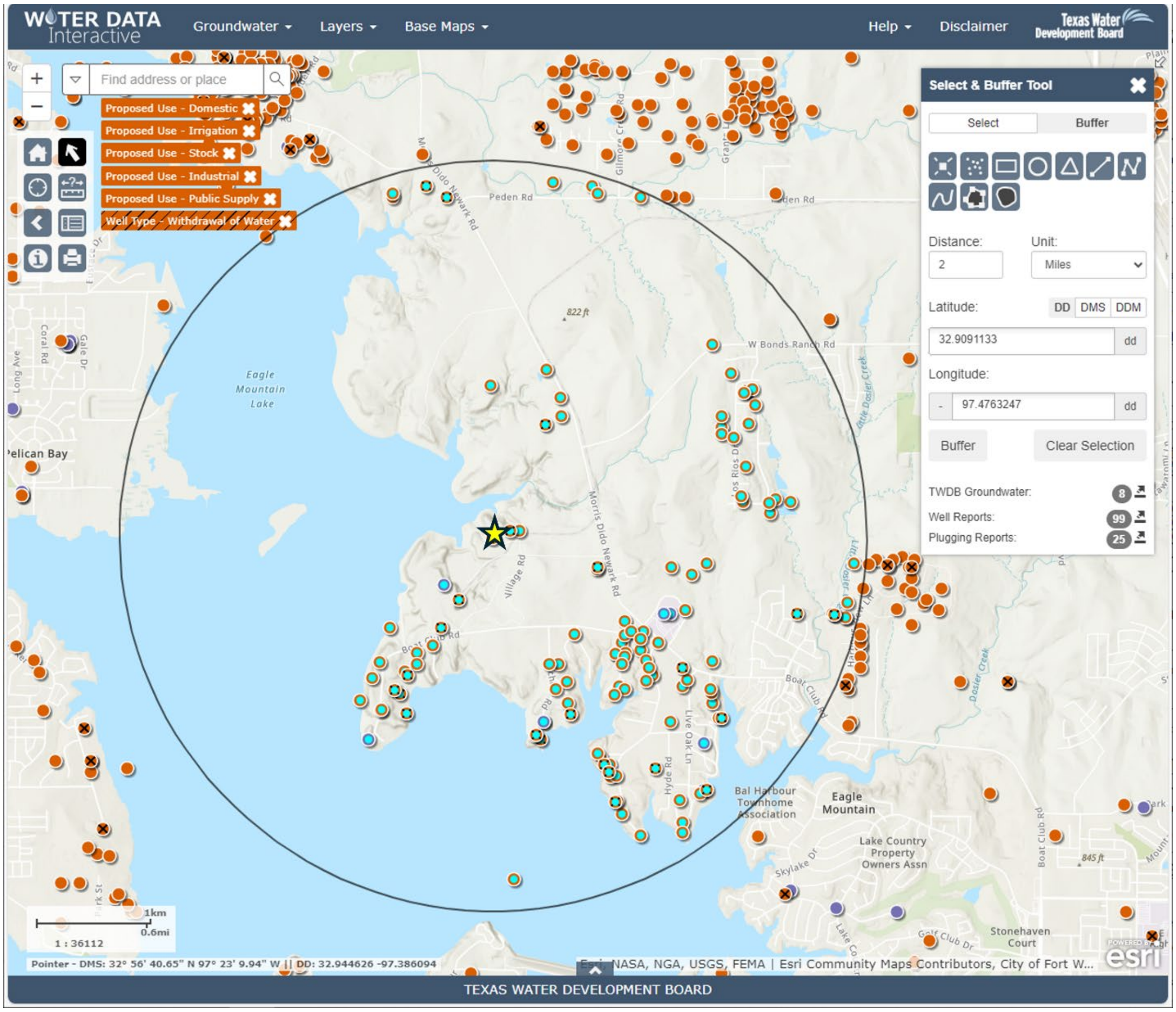


Figure 14. Water wells within two miles from the proposed injection site, data from the Texas Water Development Board Interactive Viewer. North is up.

Table 4. Groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
4945	32.8825	-97.474444	200
8105	32.886945	-97.458889	140
8162	32.888611	-97.459167	140
9201	32.899167	-97.483334	205
23976	32.896389	-97.488611	340
23981	32.916667	-97.454167	355

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
24611	32.902778	-97.443889	330
27215	32.921667	-97.454445	377
27217	32.9175	-97.455278	380
27266	32.914445	-97.453056	340
27268	32.916944	-97.455278	380
27269	32.918333	-97.455278	340
27270	32.920278	-97.453056	350
27271	32.920278	-97.453056	350
27273	32.917778	-97.452778	380
27274	32.919167	-97.452223	335
30454	32.936111	-97.467222	355
37395	32.891945	-97.466389	238
45494	32.902778	-97.443889	320
57105	32.935556	-97.466667	942
80342	32.923889	-97.456112	220
86272	32.889167	-97.457223	140
104755	32.908889	-97.476389	266
123923	32.900278	-97.462778	200
123929	32.899445	-97.462223	200
126757	32.901945	-97.485834	180
156542	32.898334	-97.461667	253
161948	32.901667	-97.462501	280
190665	32.892222	-97.466667	266
194317	32.903334	-97.458612	180
196988	32.900834	-97.464445	260
196990	32.899722	-97.464167	260
197152	32.935278	-97.462778	280
197159	32.936389	-97.470833	280
202905	32.909445	-97.473889	738
204320	32.902501	-97.464167	180
204322	32.900834	-97.461112	180
210501	32.901389	-97.464167	140
210511	32.906112	-97.458056	380
210912	32.896111	-97.469444	200
234675	32.894722	-97.460001	140
255591	32.899167	-97.464445	286
257427	32.901667	-97.463612	200
257473	32.901112	-97.462778	200
257476	32.898611	-97.484445	180
267624	32.898889	-97.461945	210

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
268343	32.899167	-97.470278	235
306601	32.899167	-97.471111	200
317205	32.896111	-97.456112	200
323205	32.921944	-97.471389	294
324408	32.895	-97.455556	180
330547	32.898056	-97.4875	172
364478	32.900001	-97.483334	224
365834	32.906945	-97.456667	260
367478	32.911667	-97.453334	297
373975	32.910834	-97.450834	297
377943	32.911667	-97.448889	320
386419	32.935278	-97.485556	240
387615	32.886111	-97.458889	200
389582	32.891389	-97.465556	280
392805	32.935556	-97.485556	220
395997	32.897222	-97.470555	200
396019	32.906945	-97.443056	300
403825	32.911945	-97.450278	297
407372	32.895556	-97.486667	320
407944	32.899286	-97.486792	210
412976	32.906531	-97.466806	802
415271	32.897861	-97.462194	260
438110	32.897417	-97.464733	160
458834	32.900585	-97.481922	320
463887	32.912167	-97.453444	347
469393	32.896937	-97.456209	200
508639	32.897211	-97.456264	200
513027	32.90004	-97.46411	200
520574	32.890422	-97.465485	220
527005	32.88756	-97.46444	140
532284	32.91165	-97.45088	322
534258	32.90395	-97.44367	372
535973	32.8994	-97.45613	180
545467	32.895599	-97.486566	281
550851	32.920408	-97.452453	400
557415	32.89743	-97.45887	260
562605	32.897185	-97.464191	200
573642	32.897149	-97.485324	200
579758	32.885889	-97.462765	180
583511	32.906633	-97.4599	220

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
585719	32.89795	-97.45848	220
587677	32.897767	-97.469483	240
634201	32.901472	-97.468833	160
641548	32.888573	-97.464852	222
644810	32.89678	-97.46515	278
648844	32.89053	-97.46497	280
649674	32.91975	-97.47009	170
654239	32.90302	-97.44504	360
662127	32.9183	-97.47005	335
667007	32.89999	-97.46504	265
667223	32.89999	-97.46504	265
677269	32.9207	-97.47656	313
677560	32.920123	-97.45321	420
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**
3205701	32.894722	-97.471667	273
3205702	32.894722	-97.471667	261
3205703	32.905278	-97.480833	196
3205704	32.893334	-97.487778	656
3205705	32.903056	-97.460001	194
3205706	32.903056	-97.460556	320
3205804	32.889445	-97.456945	233
3205805	32.893056	-97.456945	220

3.7 DESCRIPTION OF CO_2 PROJECT FACILITIES

dCarbon will accept CO_2 from by the Cotton Cove Gas Plant (**Figure 1**). 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 and transport it to the Cotton Cove CCS 1 injection site. The CO_2 stream will be metered to verify quantity. The CO_2 will then be injected into the Ellenburger Subunit E as previously described. 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 5**. Although the industry-standard sampling of the CO_2 stream is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly over time.

Table 5. CO_2 stream analysis for the Cotton Cove CCS 1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.007	0.011	0.007
Carbon Dioxide	99.8514	99.665	99.8514
Methane	0.095	0.261	0.095
Ethane	0.013	0.019	0.013
Propane	0.002	0.002	0.002
Isobutane	0.008	0.006	0.008
N-butane	0.001	0.001	0.001
Isopentane	0.003	0.002	0.003
N-pentane	0.000	0.000	0.000
Hexanes	0.006	0.003	0.006
Heptanes	0.000	0.000	0.000
Octanes	0.000	0.000	0.000
Nonanes	0.000	0.000	0.000
Decanes plus	0.000	0.000	0.000
BTEX	0.002	0.000	0.002
H_2S	0.000	0.000	0.000
H2O	0.012	0.030	0.012
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	3.15		
Density (lbs/gal)	4.09		
Molecular weight	43.93		
Specific gravity (Air=1)	1.5167		

3.8. Reservoir Characterization Modeling

A regional subsurface model was created in Schlumberger's Petrel software. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1, as discussed in previous sections) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals, that contribute to overall higher fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed

appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E. This assumption is supported by consistent saltwater disposal rates and injection volumes into the Ellenburger Group 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 Cotton Cove CCS 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
4. Quantify the increase in pore pressure dues to CO_2 injection spatially within the reservoir

The CO_2 storage complex is confined to the Ellenburger Group. The Ellenburger Subunit E is modeled as the reservoir interval and the Ellenburger Subunits B-D are modeled as the primary seal to impede vertical fluid flow. The lower confining interval for the reservoir is modeled as the Ellenburger Subunit F.

An SEM with the dimensions of 8.8 miles by 6.4 miles by 2.3 miles (X, Y, and Z) was constructed from elevation grids and faults derived from 3D seismic data and well log information (**Figure 15**) in Schlumberger's Petrel software. A 4-mile by 4-mile tartan grid was generated and then exported to Rock Fluid Dynamics's tNavigator simulator to account for fully implicit multiphase compositional fluid flow. This simulation was constructed to model other transport and mixing phenomena, i.e., relative permeability, diffusion, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be a completely saline aquifer. The salinity of the formation, estimated to be 200,000 ppm TDS, is typical of the Ellenburger Group in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 15** illustrates the vertical layering of the model with relationship to the simulated CO_2 saturation profile. The injection rate modeled was 75,000 MT/year for 12 years followed by 100 years of post-injection simulation to fully document the movement of CO_2. **Figure 15** also depicts the initial model conditions and a map view of permeability enhancements in the model due to mapped faults.

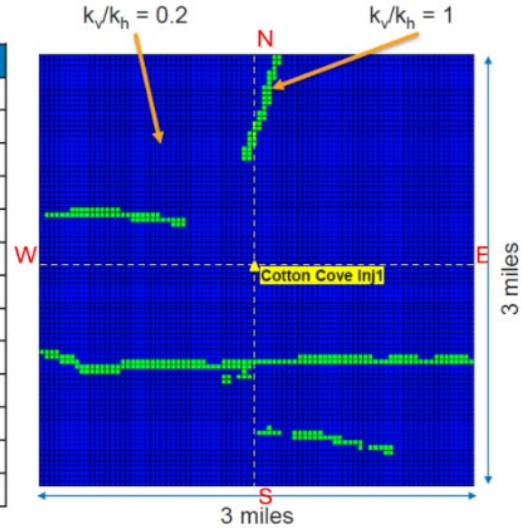
The methodologies employed for static and dynamic models were based on established techniques in literature. Specifically, the reservoir relative permeability model was calculated from capillary pressure data from the Barnett RDC 1 using the Brooks and Corey (1966) model. The relative permeability curves for sealing layers were obtained from Bennion and Bachu (2007). The initial reservoir conditions were developed using gradients derived from Barnett RDC 1 well data. Mapped and inferred faults were given enhanced permeability in the simulation model of 400 mD

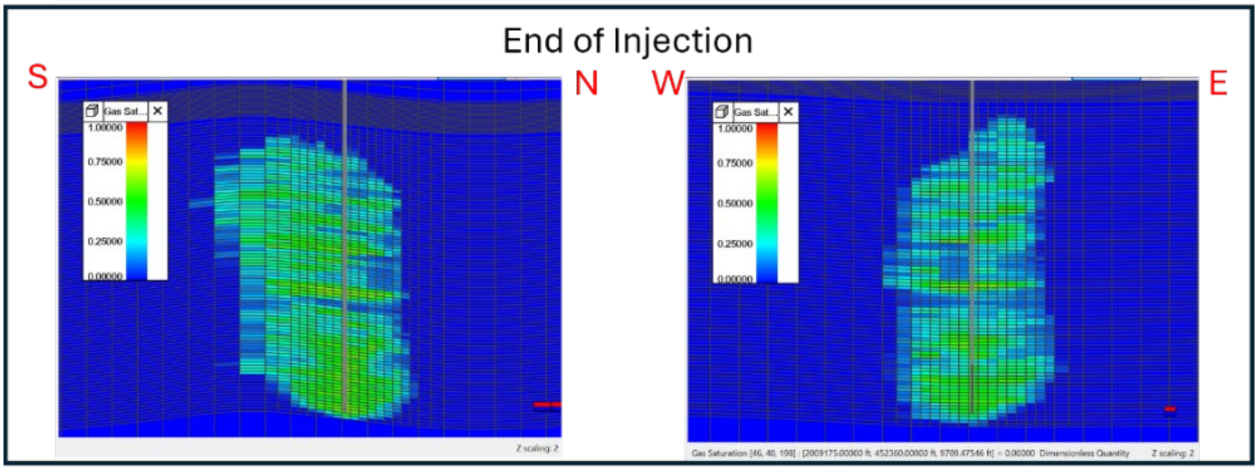
and a 1:1 vertical to horizontal permeability. Ellenburger Group interpreted as affected by karsting, primarily in the Ellenburger Subunit A, was given the same enhanced permeability in the simulation model as the mapped faults.

While the top of the Ellenburger Subunit E reservoir interval was modeled at 8,920 feet at the injection well, the top of the perforated interval was chosen to be at 10,140 feet to force the CO_2 to first migrate vertically in the reservoir before hitting the seal at the Ellenburger Subunit D.

Using the aforementioned methodology to develop model estimates, the pressure gradient was assumed to be 0.5 psi per foot, which resulted in an estimated reservoir pressure of 5,070 psi at the top of the injection interval. The temperature gradient was assumed to be 1.25°F per 100 feet, resulting in an estimated temperature of 200°F at the top of the injection interval. 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 6,388 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.

Input	Specifications
Total Number of Grid Blocks	1,732,470
N_x, N_y, N_z	64, 64, 199
D_x, D_y	250 ft * 250 ft
Injection Formation top	EB E ~ 8,180 ft TVDSS (8,920 ft MD)
k_v/k_h (matrix)	0.2
k_v/k_h (faults and karst)	1
Pressure Gradient	0.5 psi/ft
Temperature Gradient	1.25 deg F/100 ft + 70 deg F Surface
Injection rate	75 ktpa
Water saturation	100%
Fracture pressure Gradient	0.7 psi/ft
Maximum allowable pressure	90% of Fracture pressure
Salinity	200,000 ppm





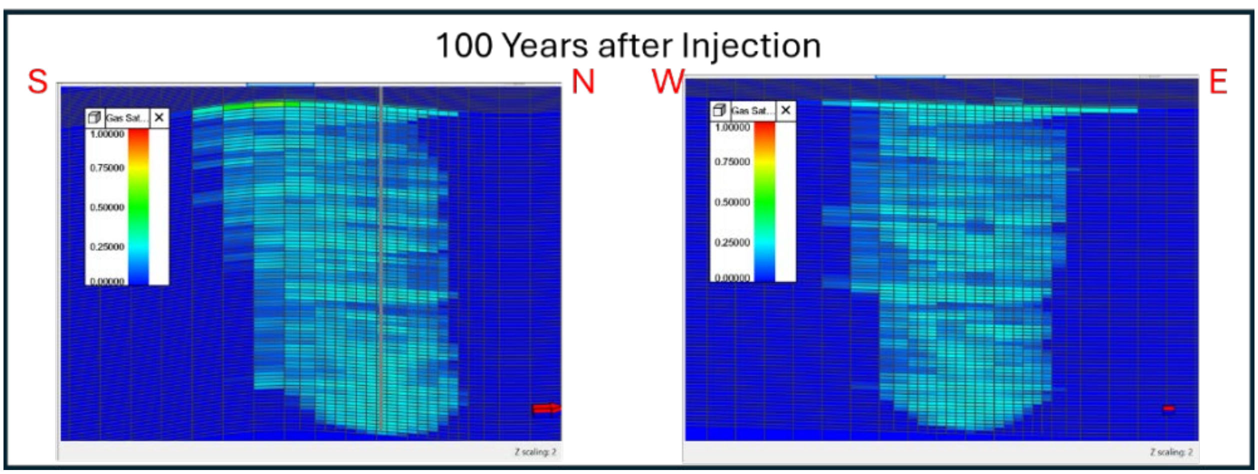


Figure 15. (Upper left table): Simulation conditions employed in the tNavigator model for the Cotton Cove CCS 1 well. (Middle and lower images): Depiction of the end of injection and 100 years after injection modeling results. The color bar in all images indicates modeled CO_2 gas saturation. (Upper right image): The map depicts the enhancement of permeability in certain areas of the model due to mapped faults.

As mentioned earlier, injection was modeled at 75,000 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 94 years post injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 16** shows the CO_2 plume at the end of injection (green) compared to 94 years post injection (cyan). Injected CO_2 flows generally west, which is the regional up dip direction. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation. While the final CO_2 plume stabilizes in a position where the western end is under Eagle Mountain Lake, there are no natural leak pathways that allow CO_2 to reach the lake. A more detailed discussion of potential leak pathways is presented in Section 5.

Figure 16. Simulation results showing CO_2 Plumes (end of injection = green and after 100 years of injection = cyan). Cotton Cove CCS 1 injection wells is shown by as the yellow star. North is up.

Figure 17 illustrates bottom hole pressure at the Cotton Cove CCS 1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is ~5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and 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, the flow transitions from capillary-driven to advection-driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

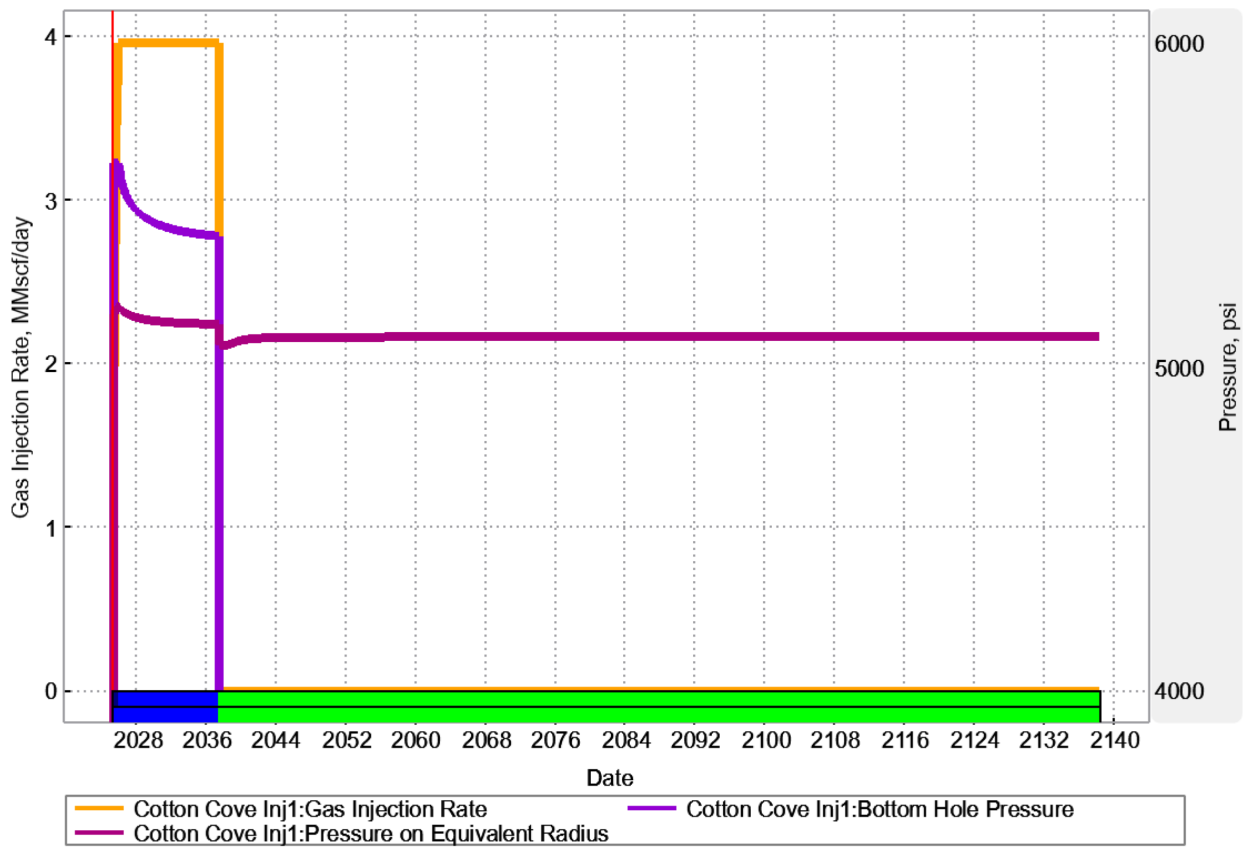


Figure 17. Modeled injection profile at Cotton Cove CCS 1 well. Gas injection rate shown in MMscf/day on the left Y axis and bottom hole pressure and pressure on equivalent radius shown in psi on the right Y axis. The blue bar along the X axis indicates the 12-year injection period and the green bar indicates the 100-year post-injection period.

4 – DELINEATION 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 of at least one-half mile. The numerical simulation using tNavigator as discussed above was used to estimate the size and migration of the CO_2 plume. We modeled injection of CO_2 into the Ellenburger Subunit E for 12 years followed by 100 years of post-injection modeling. Results indicated that the plume ceased to migrate after 94 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of gas saturation was used to determine the boundary of the CO_2 plume. The area of the MMA was determined to be 3.07 square miles with the greatest extent reaching 1.5 miles from the injector. **Figure 18** shows the End of Injection (EOI) plume (green), the 94-year post-injection plume (black solid), and the MMA using a 0.5 mi buffer (black dashed).

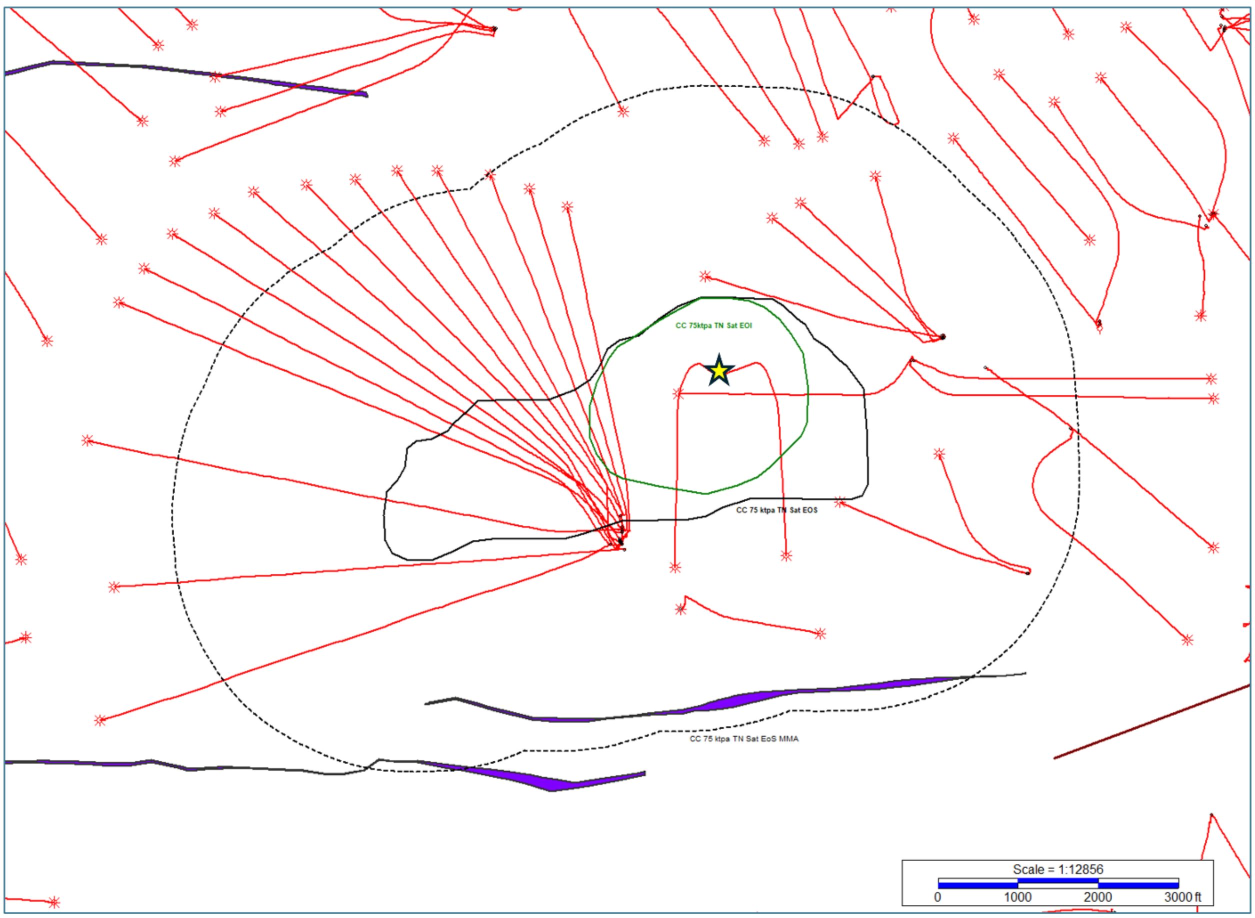


Figure 18. MMA (black dashed), EOI plume (green), and 100-year post injection plume outlines (black solid) as modeled at the Cotton Cove CCS 1 well (yellow star). Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. Thin purple polygons are faults at the top of the Ellenburger Group. North is up.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features mapped within the project area that could cause the unintended migration of the CO_2 plume through natural pathways to the USDW. The mapped faulting in the area does not extend shallower than the top of the Mississippian Marble Falls Formation, leaving more than 5,000 feet of mostly Pennsylvanian shales between the top of the faults and the USDW. 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 Sections 4 and 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 12, which is projected to be the EOI. Based on the definitions in 40 CFR § 98.449 and an initial time interval of t=12, we defined our AMA by superimposing the following:

(1) The area projected to contain the free phase CO_2 plume at the end of year 12, plus an all-around buffer 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 17.

As noted in Section 4.1, dCarbon utilized the plume area after 94 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 18** shows the MMA, which is the same as the AMA. **Figure 19** indicates the AMA/MMA (black dashed) and currently existing 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 802 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

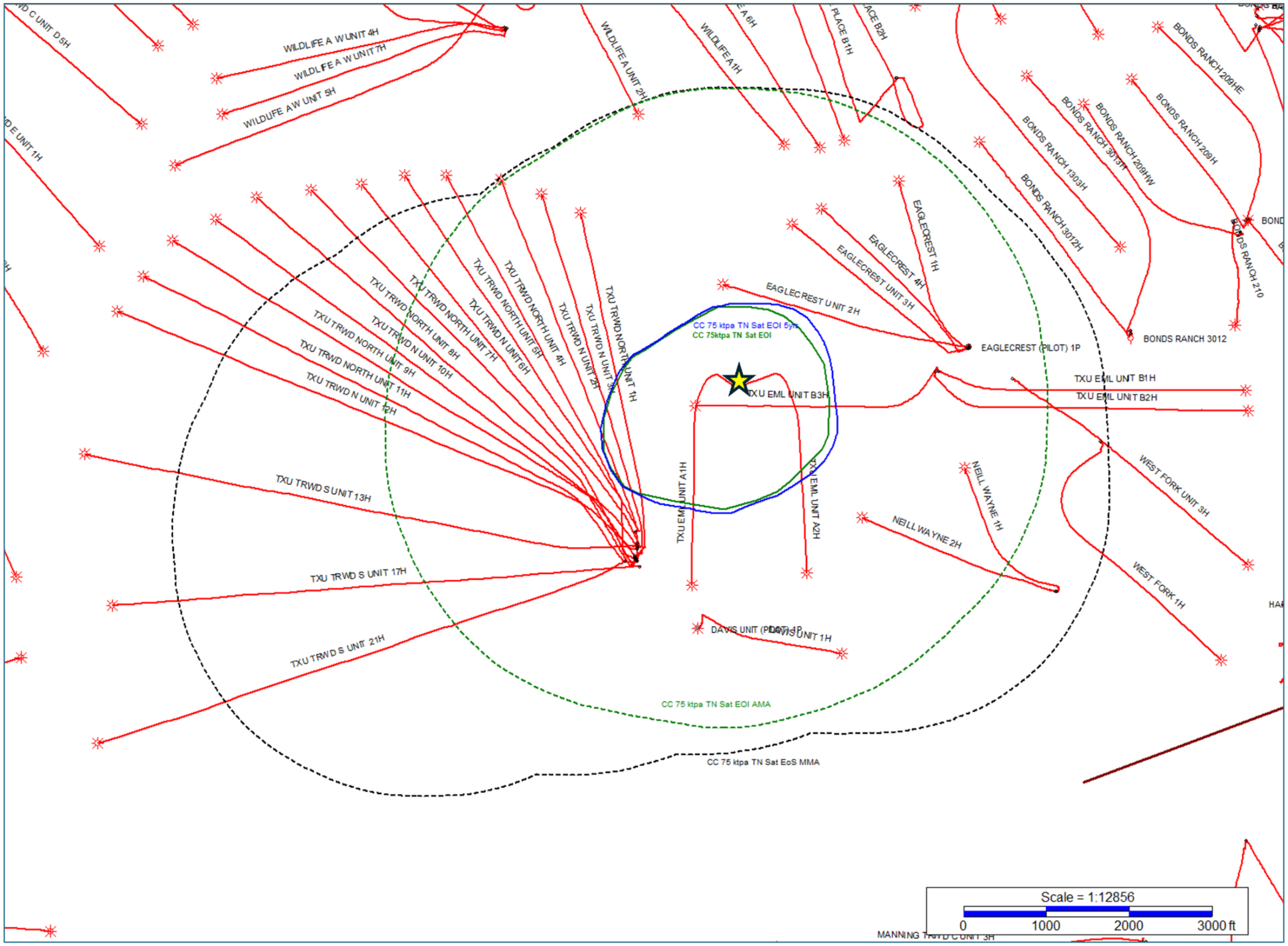


Figure 19. The calculated AMA (green dashed) and existing wells within the project AMA/MMA. The solid green and blue outlines show the extent of the CO_2 plume at EOI and five years post-injection respectively. The MMA is shown as the black dashed line for comparison. The Cotton Cove CCS 1 is shown as a yellow star. Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. North is up.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

dCarbon has assessed each of the 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 6** describes the basis for event likelihood and **Table 7** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 6. 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 7. 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 12 hours of full permitted 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	**Unlikely**, 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 conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale 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 that reach shallow enough to serve as a conduit to the USDW or the surface.	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 2,000 feet 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 a couple 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 that extend shallow enough to reach the USDW or the surface.	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 5.8 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

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at the Cotton Cove Gas Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 5**. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. This includes but is not limited to automatic detection of CO_2 and lack of O_2 detection in specifically designated locations. All BKV and dCarbon field personnel are required to wear gas monitors that detect four or five gases, including H_2S and O_2. 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 automatically in case of unexpected standard operating conditions such as a loss of line pressure.

Additionally, the compressor facility, pipe header, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and CO_2 leak detection per BKV and dCarbon safety and operations standards. These recurring monthly 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. BKV Midstream, LLC or dCarbon personnel are expected to visit the site daily.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no approved, not yet drilled well permits within the MMA other than the Cotton Cove CCS 1 well.

5.3 Leakage from Existing Wells

There are 34 existing wells within the MMA. Of these 34 wells, one had a pilot borehole for the subsequent horizontal well (**Table 8)**. The 34 wells all have active status. However, all these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 8,800 feet) is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells were drilled shallower than the target Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented over their entirety 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.

The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to travel via faults in the Ellenburger to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production. Injected CO_2 entering the Barnett Shale could be produced in the gas stream of these wells. While this is considered improbable due to the reservoir simulation modeling showing no CO_2 reaching the enhanced permeability areas of the model, dCarbon will consider this potential pathway specifically in its monitoring program. In addition, no wells in the AMA/MMA are located within Eagle Mountain Lake. No leak pathways are present that are expected to allow injected CO2 to reach the area of Eagle Mountain Lake.

Table 8. Existing oil and gas wells in MMA with TRRC records.

Well Name	Well Number	UWI	Latitude	Longitude	Operator Current	Operator Original	Total Depth(f)	Status
LAKE PLACE	B1H	424393102900	32.9191420	-97.4698666	BKV NORTH TEXAS LLC	ANTERO RESOURCES INC LP	8650	Gas Well
WILDLIFE	A1H	424393119200	32.9239294	-97.4838481	BKV NORTH TEXAS LLC	XTO ENERGY INC	10435	Gas Well
WILDLIFE A UNIT	2H	424393119600	32.9240571	-97.4837859	BKV NORTH TEXAS LLC	XTO ENERGY INC	8567	Gas Well
EAGLECREST	1H	424393124000	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	8641	Gas Well
EAGLECREST (PILOT)	1P	424393124077	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	6924	Location Only
EAGLECREST UNIT	2H	424393124400	32.9101730	-97.4670195	BKV NORTH TEXAS LLC	XTO ENERGY INC	9045	Gas Well
DAVIS UNIT	1H	424393137300	32.9008732	-97.4776844	BKV NORTH TEXAS LLC	XTO ENERGY INC	8227	Gas Well
DAVIS UNIT (PILOT)	1P	424393137377	32.9008732	-97.4776844	XTO ENERGY INC	XTO ENERGY INC	7158	Gas Well
NEILL WAYNE	1H	424393138400	32.9020862	-97.4635819	BKV NORTH TEXAS LLC	XTO ENERGY INC	8472	Gas Well
NEILL WAYNE	2H	424393138500	32.9020931	-97.4635666	BKV NORTH TEXAS LLC	XTO ENERGY INC	8889	Gas Well
WEST FORK	1H	424393162800	32.9070608	-97.4618388	BKV NORTH TEXAS LLC	SULLIVAN HOLLIS R INC	10163	Gas Well
LAKE PLACE	B2H	424393204200	32.9191465	-97.4698521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9088	Gas Well
TXU TRWD N UNIT	6H	424393221100	32.9035759	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	11683	Gas Well
TXU TRWD N UNIT	2H	424393221200	32.9040765	-97.4801342	BKV NORTH TEXAS LLC	XTO ENERGY INC	11025	Gas Well
TXU TRWD N UNIT	10H	424393223000	32.9035352	-97.4800689	BKV NORTH TEXAS LLC	XTO ENERGY INC	12585	Gas Well
TXU TRWD S UNIT	17H	424393223600	32.9029178	-97.4799856	BKV NORTH TEXAS LLC	XTO ENERGY INC	12845	Gas Well
TXU EML UNIT	A1H	424393245100	32.9089106	-97.4761473	BKV NORTH TEXAS LLC	XTO ENERGY INC	9164	Gas Well
TXU EML UNIT	A2H	424393262300	32.9089049	-97.4760521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9062	Gas Well
TXU TRWD S UNIT	13H	424393338100	32.9037054	-97.4800853	BKV NORTH TEXAS LLC	XTO ENERGY INC	13056	Gas Well

TXU TRWD S UNIT	21H	424393345100	32.9031007	-97.4805575	BKV NORTH TEXAS LLC	XTO ENERGY INC	13064	Gas Well
TXU TRWD N UNIT	12H	424393354600	32.9035061	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	13163	Gas Well
TXU EML UNIT	B1H	424393365600	32.9094039	-97.4683171	BKV NORTH TEXAS LLC	XTO ENERGY INC	10200	Gas Well
TXU EML UNIT	B2H	424393365800	32.9093921	-97.4683110	BKV NORTH TEXAS LLC	XTO ENERGY INC	10500	Gas Well
TXU EML UNIT	B3H	424393423300	32.9093969	-97.4682044	BKV NORTH TEXAS LLC	XTO ENERGY INC	9535	Gas Well
WEST FORK UNIT	3H	424393526800	32.9091561	-97.4652839	BKV NORTH TEXAS LLC	XTO ENERGY INC	9298	Gas Well
TXU TRWD NORTH UNIT	1H	424393598400	32.9032790	-97.4801794	BKV NORTH TEXAS LLC	XTO ENERGY INC	10350	Gas Well
TXU TRWD N UNIT	3H	424393598500	32.9032457	-97.4801754	BKV NORTH TEXAS LLC	XTO ENERGY INC	10694	Gas Well
TXU TRWD NORTH UNIT	5H	424393601000	32.9031750	-97.4801698	BKV NORTH TEXAS LLC	XTO ENERGY INC	11009	Gas Well
TXU TRWD NORTH UNIT	4H	424393603300	32.9032055	-97.4801726	BKV NORTH TEXAS LLC	XTO ENERGY INC	10765	Gas Well
TXU TRWD NORTH UNIT	7H	424393605300	32.9031776	-97.4801011	BKV NORTH TEXAS LLC	XTO ENERGY INC	11485	Gas Well
TXU TRWD NORTH UNIT	8H	424393605400	32.9031436	-97.4800911	BKV NORTH TEXAS LLC	XTO ENERGY INC	11846	Gas Well
TXU TRWD NORTH UNIT	9H	424393605500	32.9031212	-97.4800893	BKV NORTH TEXAS LLC	XTO ENERGY INC	12258	Gas Well
TXU TRWD NORTH UNIT	11H	424393605600	32.9030873	-97.4800851	BKV NORTH TEXAS LLC	XTO ENERGY INC	12522	Gas Well
LAKE PLACE	A7H	424393628200	32.9310611	-97.4774402	BKV NORTH TEXAS LLC	XTO ENERGY INC	11739	Gas Well
LAKE PLACE	A6H	424393628300	32.9310939	-97.4774460	BKV NORTH TEXAS LLC	XTO ENERGY INC	11470	Gas Well
EAGLECREST	4H	424393655400	32.9102140	-97.4670370	BKV NORTH TEXAS LLC	XTO ENERGY INC	8989	Gas Well
EAGLECREST UNIT	3H	424393655700	32.9101702	-97.4670211	BKV NORTH TEXAS LLC	XTO ENERGY INC	8975	Gas Well

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 such as the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita orogenic belt collision. These faults show displacement up into the base of the Pennsylvanian rocks. These larger, younger faults have greater displacement but are relatively sparce.

An east-west fault is interpreted at the south edge of the MMA, south of the Cotton Cove CCS 1 based on available subsurface data including 3D seismic data (**Figure 4**). A second, east-west fault may exist north of the MMA. These faults were included in the dynamic reservoir model as areas of enhanced permeability. Dynamic modeling indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. These faults terminate at the top of the Mississippian strata at roughly 6000 feet TVDSS, leaving roughly 6,000 feet of unfaulted Pennsylvanian shales and sands to serve as yet another secondary confining system. It is highly improbable that injected CO_2 would migrate up faults to the USDW or to the surface through faults. As there are no natural leak pathways that traverse this secondary confining system, we assess it as improbable that CO2 would reach the surface under Eagle Mountain Lake.

Karst development is present in some areas at the top of the Ellenburger. Karsting is often developed in the upper several hundred feet of an exposed carbonate (in this case, the Ellenburger Subunit A), where fresh water enters the shallow subsurface through fractures and dissolves the rock, creating underground caves with a thin roof (**Figure 20**). Subsequent loading of sediment can cause the thin cave roof to collapse, allowing the overlying sediment to fill the void (Zeng, 2011). These karsted sections of the Ellenburger were given enhanced permeability in the model as described earlier. We applied the enhanced permeability to the upper 500 feet of the Ellenburger, where karsted, as a conservative modeling assumption.

Karsting does not appear to affect any subunit of the Ellenburger below Ellenburger Subunit A, including Ellenburger Subunits B-D or the injection interval, Ellenburger Subunit E. This suggests that the Ellenburger Subunits B-D will remain a continuous upper seal for the injection interval even in karst areas. There are interpreted Ellenburger Subunit A karst features south and north of the Cotton Cove CCS 1, but the CO_2 plume does not intersect them, based on the dynamic modeling. Small karst features sitting at the northern edge of the MMA seem to have only impacted the upper 200 feet of the Ellenburger, leaving 2,000 feet of Ellenburger apparently unaffected as shown in the type log in **Figure 20**.

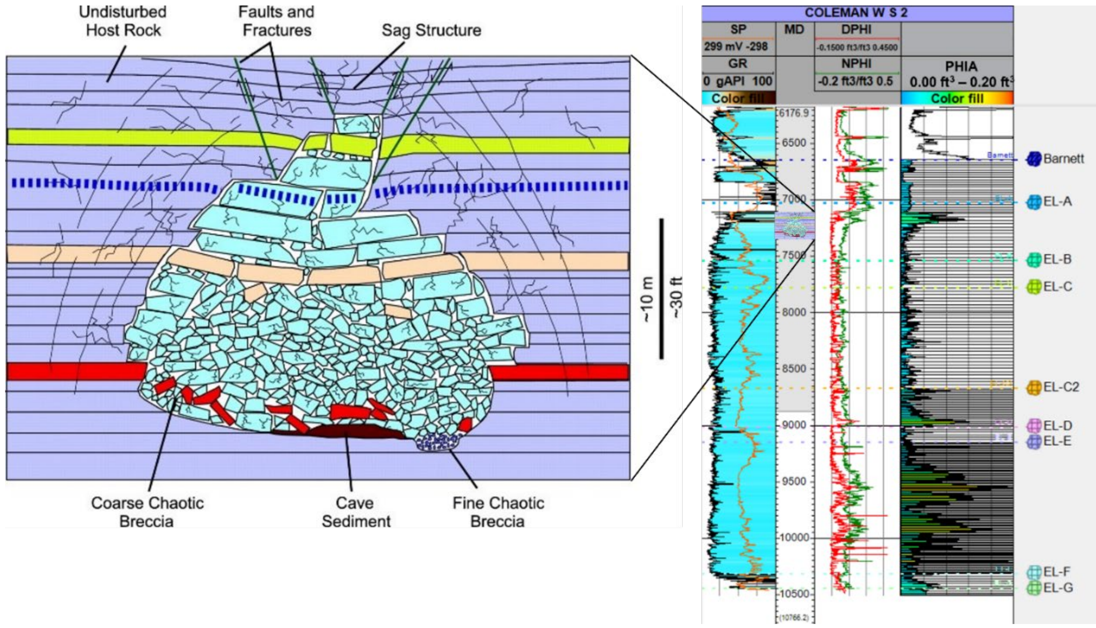


Figure 20. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al*., 2011). The typical scale of the karst features is shown on the right placing the feature on the Coleman 1 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining Ellenburger Subunits B-D and not in the modeled plume area.

5.5 Leakage Through Confining Layers

The Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D and below by the competent confining Ellenburger Subunit F. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA as described in Section 5.3.

5.6 Leakage from Natural or Induced Seismicity

The Cotton Cove CCS 1 well location is in an area of the Fort Worth Basin that has experienced seismic activity historically, as described in Section 3.5. The occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor.

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 surface pressure gauges, so that reservoir pressure and injection pressure can be modeled and monitored. Additionally, consistent with TRRC guidelines and

permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 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 and reduce the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis (Walsh, *et al.,* 2017) 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 Cotton Cove CCS 1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

Furthermore, dCarbon installed new ground seismic monitoring stations 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 have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on 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. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection site is about two degrees up to the west (200 feet/mile), shown in **Figure 21**. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles (Tarrant North SWD 1).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

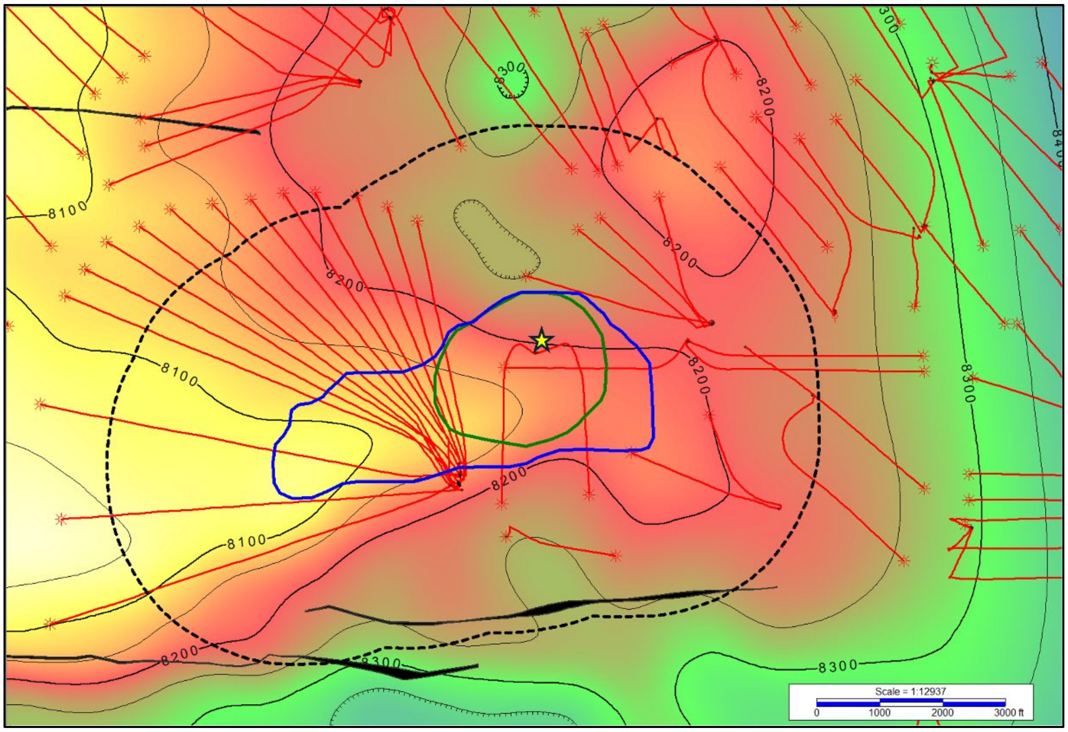


Figure 21. The Cotton Cove CCS 1 well location (yellow star) posted on a map of the top Ellenburger Subunit E depth structural contours in feet TVDSS with a contour interval of 500 feet from the simulation model. The CO_2 plume size at the end of injection (green) and 100 years post-injection and AMA/MMA are also shown as solid blue and dashed black outlines, respectively, from Figure 18. Mapped faults are shown in black.

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). This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur.

6.1 Leakage from Surface Equipment

Monitoring will occur during the planned 12-year injection period, or until the cessation of operations. 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. As the CO_2 compressor station, pipe header, and injection well are all designed to handle expected concentrations, temperatures, and pressures of 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.

Periodic 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 observations, corrective actions will be taken to address such issues.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. 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.

Additionally, CO_2 for injection will be metered with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself (**Figure 22**). The injection stream will also be sampled and analyzed periodically with a gas chromatograph to determine final composition. The meter will each be calibrated to industry standards. Any discrepancies in CO_2 throughput at the meter 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 the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate 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.

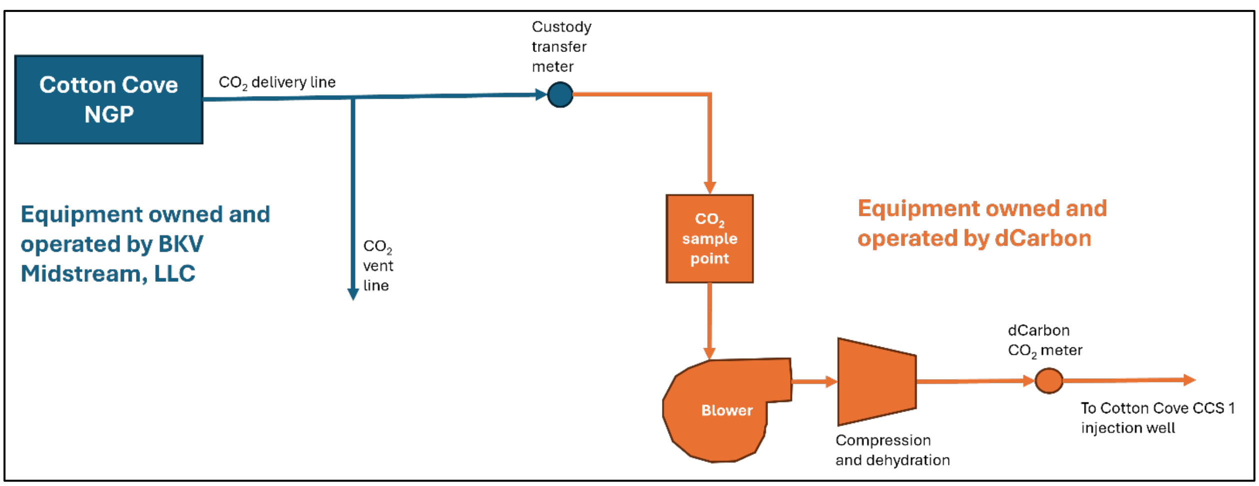


Figure 22. Project conceptual diagram with metering locations. Equipment and pipe headers in Blue are owned and operated by BKV Midstream, LLC while equipment and pipe headers in orange are owned and operated by dCarbon.

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 interval. 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, dCarbon will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will 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 in addition to pressure sensors for each annulus of the well. Annual bottomhole pressure and temperature measurements will be made to calibrate the surface readings to bottom hole. 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 gas samples quarterly 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 Cotton Cove CCS 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) 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 intervals 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 to the surface or to the USDW is improbable, given the number and thickness of competent layers between the injection interval and the USDW. Sampling of the produced gas stream from the Barnett Shale gas wells within the MMA is the primary tool for detecting CO_2 that has bypassed the primary confining system. These producing gas wells are not expected to produce any of the CO_2 injected into the Ellenburger Subunit E and will act as above

zone monitoring wells. dCarbon plans to inject a small amount of chemical tracer with the CO_2 downstream of the volumetric flow meter. Thie chemical tracer will serve as confirmation that any increase in CO_2 detected in the produced gas stream from the Barnett Shale wells in the AMA/MMA is from the sequestration reservoir.

Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems. The chemical tracer injected with the CO_2 can also be analyzed for in the groundwater sampling.

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 low, dCarbon operates a proprietary seismic monitoring array in the general area of the Cotton Cove CCS 1 well. This monitoring array augments 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 Cotton Cove CCS 1 well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, a situation that is very unlikely based on the location of mapped faults and the extent of the modeled plume.

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 four times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the only 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, like 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 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 sample the gas stream from the gas wells in the MMA. These wells should intercept CO_2 that might traverse the primary sealing interval before it bypasses the secondary seals. Noting the increase in CO_2 concentration in the produced gas stream along with the presence of the chemical tracer, will be a trigger for dCarbon to investigate and quantify possible leakage through the primary confining layers. dCarbon will document the methods used to calculate the volume of CO_2 leakage in its annual monitoring report.

dCarbon has access to a deep groundwater monitoring well at the Cotton Cove Gas Plant 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 intervals. 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. dCarbon will conduct baseline sampling of available water wells within the MMA prior to injection to establish a basis for comparison to later samples.

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 works with environmental services and data companies that specialize 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 may also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with high-fidelity CO_2 sensors 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 the X and Y axes (longitude + latitude) as well as the 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) (Korre, 2011). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. 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 (Chen, 2013).

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 Cotton Cove CCS 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.

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). There are three primary monitoring baselines that dCarbon will establish as part of this project.

Baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells 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 gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA that are acting as above-zone monitoring wells. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline seismicity in the area near the Cotton Cove CCS 1 has been determined through the historical data from USGS and TexNet seismic array data. This information is augmented by additional data from dCarbon's proprietary seismic monitoring array, operating since 2023.

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 Cotton Cove CCS 1 injection well will be 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
$C_{CO2,p,u}$	=	CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year

u = Flow meter

8.3 MASS OF CO_2 PRODUCED

The Cotton Cove CCS 1 injection well will receive CO_2 produced from the nearby Cotton Cove Gas Plant and will be used for injection only. No CO_2 will be produced from this well. Additionally, the injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

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. 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 CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 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 on 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 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
$CO_{2,E}$	=	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.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in 2026 and that will be the date that data to calculate the total volume of CO_2 sequestered will begin to be collected. Baseline monitoring data will be collected beginning in 2025 and the MRV plan will be implemented upon receiving EPA MRV plan approval. The exception to the monitoring baseline data is the seismicity baseline data which began in 2017 with the TexNet monitoring system.

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 reported 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, if employed, will be operated continuously, except for maintenance and calibration.
- Gas detectors, if employed, 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 most recent 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 five 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.

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Attachment A

Copies of W-14, W-1, Drilling Permit

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

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

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

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

PERMIT NO. 17534

BKV DCARBON VENTURES, LLC
4800 BLUE MOUND ROAD
FORT WORTH TX 76106

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated September 12, 2024, for the permitted interval(s) of the Ellenburger formation(s) and subject to the following terms and special conditions:

COTTON COVE CCS (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
TARRANT COUNTY
DISTRICT 05

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	43900000	000126822	Carbon Dioxide (CO_2)	8806	11150	4000	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	43900000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. (A) The operator shall notify the Commission within 24 hours of a discovery of any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; or any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Within 20 days of such a discovery, the operator shall file a report with the Commission documenting the event, findings, and response actions taken.** **(B) The permittee shall report the source(s) and the properties of injected acid gas as they are added. In no case may the volume of acid gas exceed the limit indicated in permit.** **(C) The well's construction and materials used must be resistant to corrosion per the proposed wellbore schematic that was submitted in the application.** **6. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.**

STANDARD CONDITIONS:

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

Note: This document will only be distributed electronically.

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

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

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

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

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

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

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

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

APPROVED AND ISSUED ON September 27, 2024.

for Ivan Salas, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

API No. 42-439-37356

Drilling Permit # 902971

SWR Exception

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No. 100589
2. Operator's Name (as shown on form P-5, Organization Report) BKV DCARBON VENTURES, LLC
3. Operator Address (include street, city, state, zip): 4800 BLUE MOUND ROAD FORT WORTH, TX 76106
4. Lease Name COTTON COVE CCS
5. Well No. 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No. 05
12. County TARRANT
13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4 miles in a NW direction from Alze which is the nearest town in the county of the well site.

15. Section
16. Block
17. Survey GARCIA, M
18. Abstract No. A-564
19. Distance to nearest lease line: ft.
20. Number of contiguous acres in lease, pooled unit, or unitized tract: 2.22

21. Lease Perpendiculars: 144 ft from the S line and 133 ft from the E line.

22. Survey Perpendiculars: 296 ft from the N line and 1131 ft from the E line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION **List all fields of anticipated completion including Wildcat. List one zone per line.**

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

Certificate:

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

Bill Spencer, Consultant
Name of filer

Sep 30, 2024
Date submitted

(512)9181062, x2
Phone

bill@spencerconsulting.org
E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Oct 1, 2024 2:05 PM(Current Version)

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director’s delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

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

PERMIT NUMBER 902971	DATE PERMIT ISSUED OR AMENDED Oct 01, 2024	DISTRICT 05
API NUMBER 42-439-37356	FORM W-1 RECEIVED Sep 30, 2024	COUNTY TARRANT
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 2.22

OPERATOR 100589 BKV DCARBON VENTURES, LLC 4800 BLUE MOUND ROAD FORT WORTH, TX 76106	NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (903) 984-3026
LEASE NAME COTTON COVE CCS	WELL NUMBER 1
LOCATION 4 miles NW direction from ALZE	TOTAL DEPTH 12000

Section, Block and/or Survey

SECTION BLOCK ABSTRACT 564

SURVEY GARCIA, M

DISTANCE TO SURVEY LINES 296 ft. N 1131 ft. E	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 144 ft. S 133 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE) COTTON COVE CCS	2.22	12,000	1 0	09

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

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

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

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

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION
SWR #13 Formation Data

TARRANT (439) County

Formation	Remarks	Geological Order	Effective Date
CADDO		1	12/17/2013
BARNETT SHALE	May be prorated into District 9	2	12/17/2013
ELLENBURGER		3	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

Appendix B: Submissions and Responses to Requests for Additional Information

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

Cotton Cove CCS 1

NW Tarrant County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 3.0

February 19, 2025

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 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Cotton Cove CCS 1 injection well in Tarrant County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2, into the Cotton Cove CCS 1 injection well (CCS 1). produced by the nearby Cotton Cove Gas Plant (Gas Plant), operated by BKV Midstream, LLC (TCEQ CN604046912) which is a separate, pre-existing facility. The CCS 1 and the Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category, making them separate and distinct facilities under 40 CFR 98.6. The project site is located approximately four miles east-northeast of Azle, Texas, as shown in **Figure 1**. dCarbon anticipates drilling the Cotton Cove CCS 1 well in Q1 2025 and completing and beginning injection operations in 2026. The Cotton Cove CCS 1 has an approved W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the TRRC (UIC number 000126822, API number 42-439-37356). 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 close to the maximum injection amount allowed by the TRRC permit (75,744 MT/yr). dCarbon plans to inject for approximately 12 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 Cotton Cove CCS 1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 589741. All aspects of this MRV plan refer to this well and this GHGRP ID number.

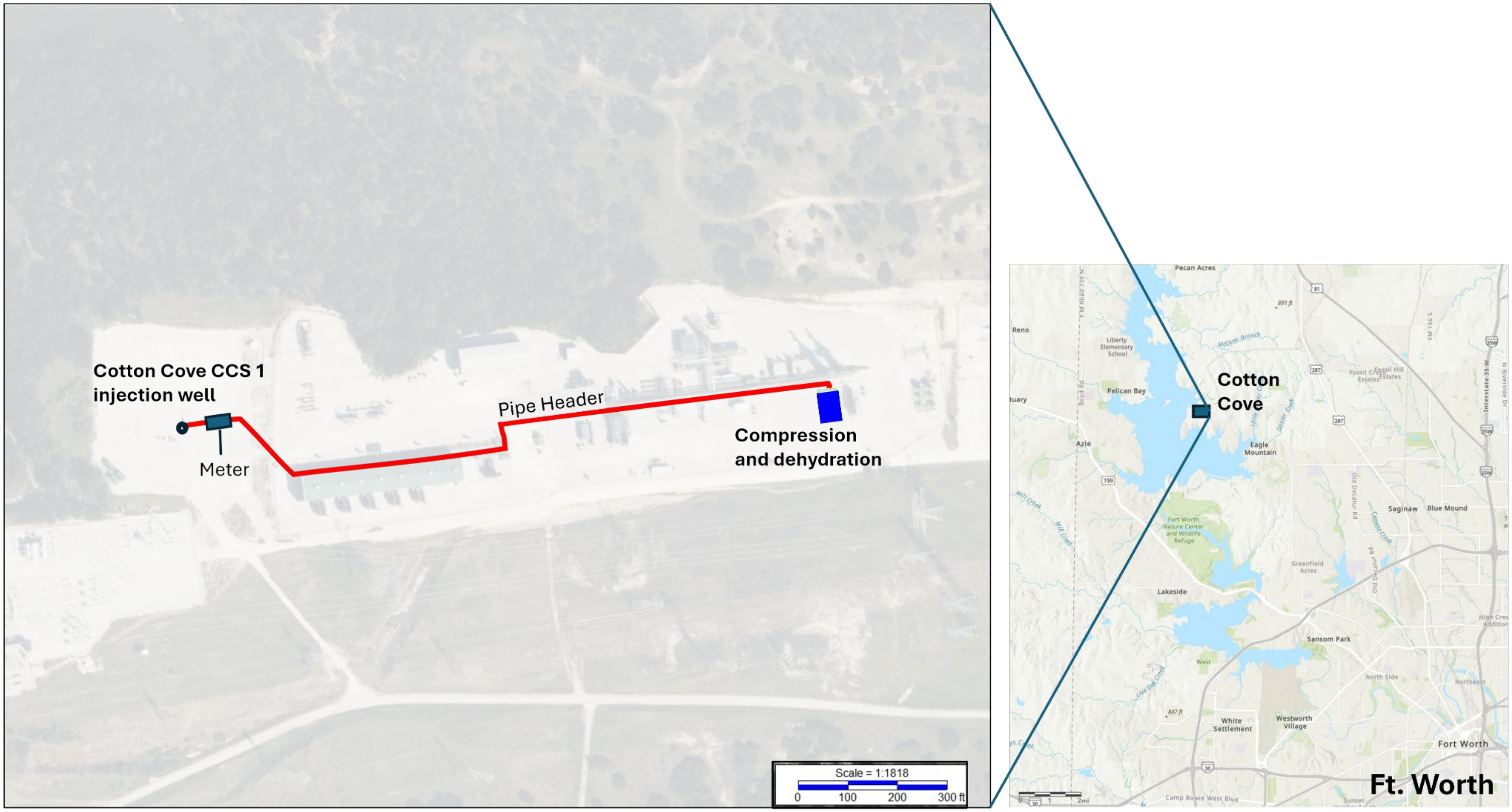


Figure 1. Location map for the Cotton Cove CCS 1 well in Tarrant County Texas. The well is planned to be drilled immediately west of the Cotton Cove Gas Plant that captures the CO_2 to be injected. North is up.

2 – FACILITY INFORMATION

Facility Name:

Cotton Cove Gas Plant (TCEQ CN604046912)

Address: 10055 Morris Dido Newark Road, Fort Worth, TX 76179

Latitude: 32.90927778

Longitude: -97.46976667

GHGRP ID number: 526203

FRS ID: 110040511256

NAICS Code: 211111

Reporting structure: Currently reporting under Subpart C, Subpart W, and Subpart RR.

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the Texas Railroad Commission (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 Cotton Cove CCS 1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Cotton Cove CCS 1

API number: 42-439-37356

UIC number: 000126822

Cotton Cove CCS 1, GHGRP ID: 589741

The Cotton Cove CCS 1 well will be disposing of CO_2 from the Cotton Cove Gas Plant. All aspects of this MRV plan refer to the Cotton Cove CCS 1 well and GHGRP 589741.

3.1 OVERVIEW OF GEOLOGY

The proposed injection site lies in the northwestern part of Tarrant County, where the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. The north to south cross section of **Figure 2** shows the Ellenburger and overlying formations dipping down to the north. One inference from these cross sections is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward and southward, which is towards the Bend Arch. The dip direction is further represented in the structure contour map of the Ellenburger Group top (Pollastro, 2007) in **Figure 2**.

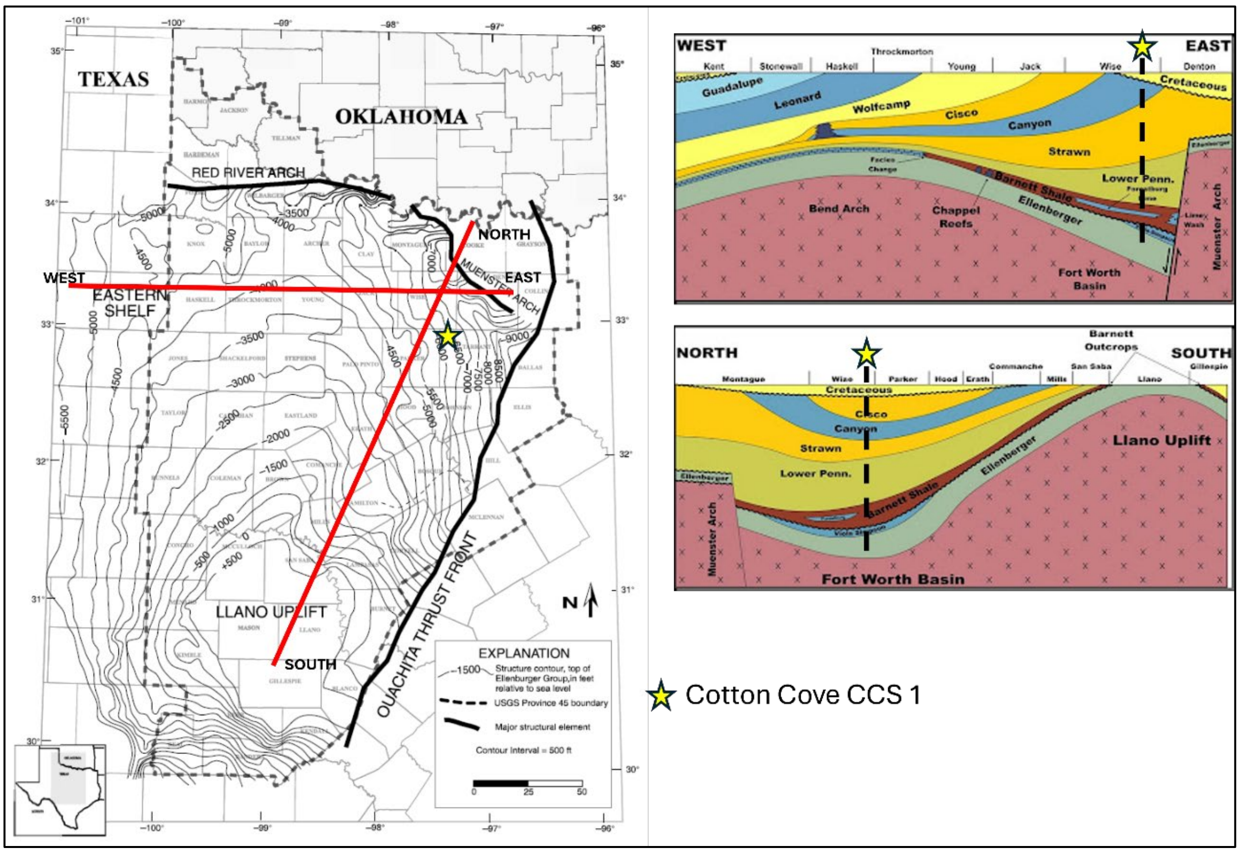


Figure 2. (*Left*) Ellenburger structure map modified from Jarvie *et al.* (2007) showing the regional structures within and bounding the Fort Worth Basin. The Ellenburger structural contours are depicted in feet True Vertical Depth Subsea (TVDSS) at an interval of 500 feet and the final Cotton Cove CCS 1 location is shown by a yellow star. (*Right*) Cross sections from W-E (top right) and N-S (middle right) show the regional dip of the sedimentary units in the Fort Worth Basin modified from Bruner *et. al.*, (2011), also with a yellow star and dashed black line indicating the position of the Cotton Cove CCS 1 well.

The Fort Worth Basin sedimentary succession began with the deposition of locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (**Table 1**). Ordovician age Ellenburger platform carbonates were deposited

next on a passive margin and are up to 4,000 feet thick 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 Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group (Gao, 2021). 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 Formation. The Ellenburger Group directly overlies the basement rock and is considered the main injection target.

Table 1. Regional Stratigraphy at Cotton Cove CCS 1 Site in North Texas.

SYSTEM	SERIES	STAGE	GROUP OR FORMATION	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian		Barnett	Upper Barnett Shale
				Forestburg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Upper		Viola Group	
			Simpson Group	
	Lower		Ellenburger Group	
Precambrian			Basement	

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, the planned injection and confining intervals or zones (terms interval and zone used interchangeably), the planned injection volumes and process, and the reservoir modeling performed for the proposed Cotton Cove CCS 1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Tarrant County, Texas.

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. 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 in 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 in the south.

3.2.2 Stratigraphy

The Ellenburger Group in the Fort Worth Basin contains alternating limestone and dolostone lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into eight subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.* (2019). The main target storage reservoir, Ellenburger Subunit E, was identified based on the dominant dolostone lithology, gross and net reservoir thicknesses, porosity values, and permeability values. The Ellenburger Subunit B and the stratigraphic top portion of Ellenburger Subunit C were identified as the caprock based on the dominant limestone lithology, thickness, porosity, and permeability values. Below this interval, there are layers of tighter limestone throughout Ellenburger Subunits C, C2, and D that would also act as sealing units to the underlying Ellenburger Subunit E storage interval.

The Barnett RDC 1 well (API number 42-497-38108), located approximately 27 miles northwest of the proposed Cotton Cove CCS 1 injection well, was used to calibrate well-log-based petrophysical properties since it has modern well logs and core data (**Figure 3**). The Tarrant North SWD 1 well (API number 42-439-31228), located approximately six miles to the northeast, was also used in well correlations and thickness calculations because of its closer proximity. Dominant lithologies were determined by comparing the photoelectric factor log curve and the separation of the density and neutron porosity curves in the Tarrant North SWD 1 well with the volume of clay, sand, lime, dolomite, gas, and free water calculated in the Barnett RDC 1 well. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

Figure 3 shows the correlation of the Barnett RDC 1 to the Cotton Cove CCS 1 site, including the Tarrant North SWD 1, as noted by the well names posted on the map and at the base of the well

logs in the cross section. Ellenburger Subunits A through F are present and appear to be contiguous in the project area. The thickness of Ellenburger Subunits B-D is approximately 2,000 feet while Ellenburger Subunit E thickness varies across the cross-sections. It is estimated there is at least 2,000 feet of Ellenburger Subunits B-D and 1,000 feet of Ellenburger Subunit E at the Cotton Cove CCS 1 proposed location.

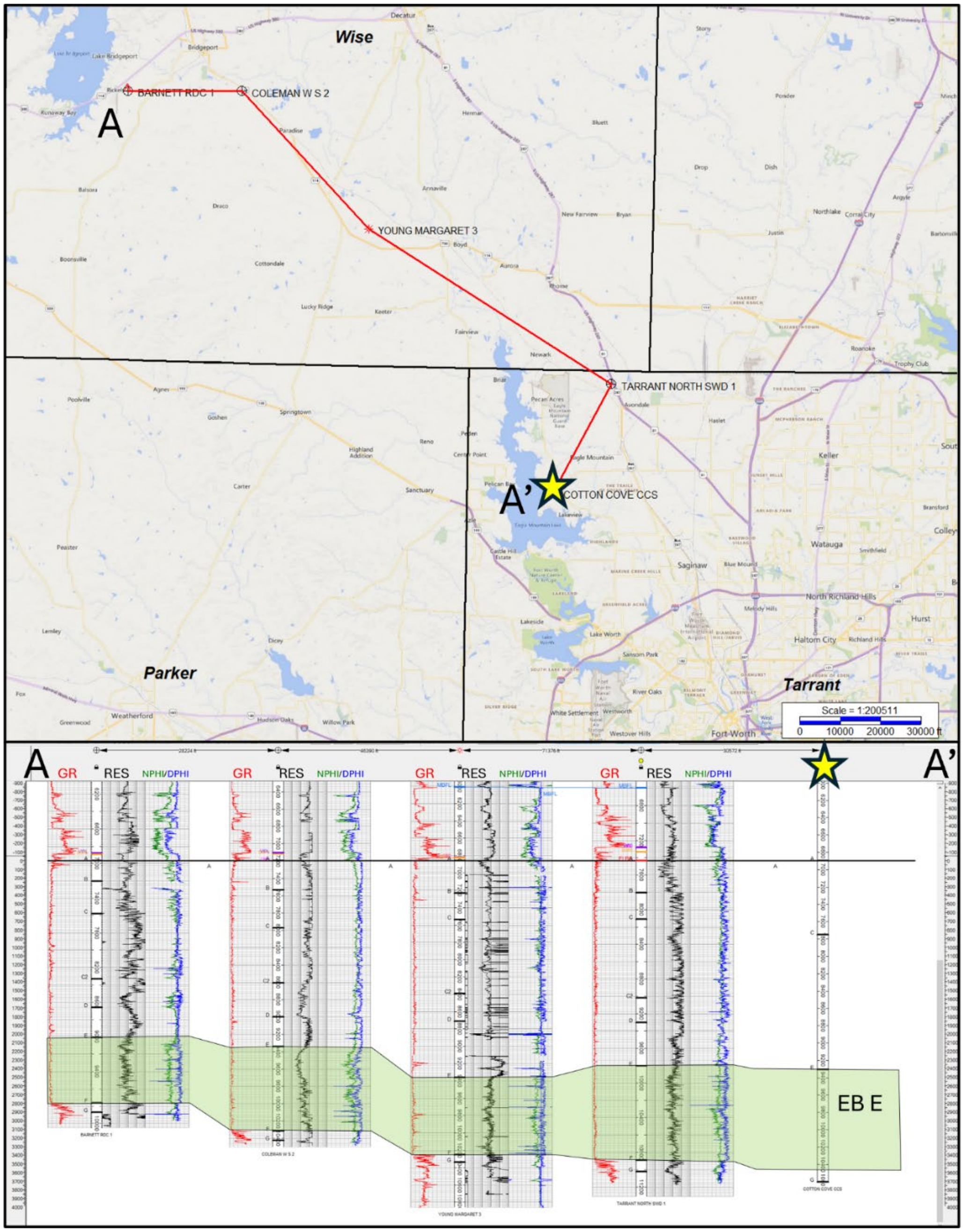


Figure 3. (*Top*) Map of north Texas, including Wise and Tarrant Counties, with the Cotton Cove CCS 1 (yellow star) and a NW-SE stratigraphic cross section (A-A'). North is up. (*Bottom*) Cross section, datumed on the top of the Ellenburger Subunit A, showing Gamma Ray (GR), Resistivity (RES), Neutron Porosity (NPHI), and Density Porosity (DPHI) from the Barnett RDC 1 well to the Tarrant North SWD 1 well. Ellenburger Subunit E (EB E) is the storage interval.

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 (**Figure 4**). A secondary set of east-west faults appear to connect these major trends. 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 present, suggesting that faults have not experienced significant movement since their formation (Wood, 2015). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Formation.

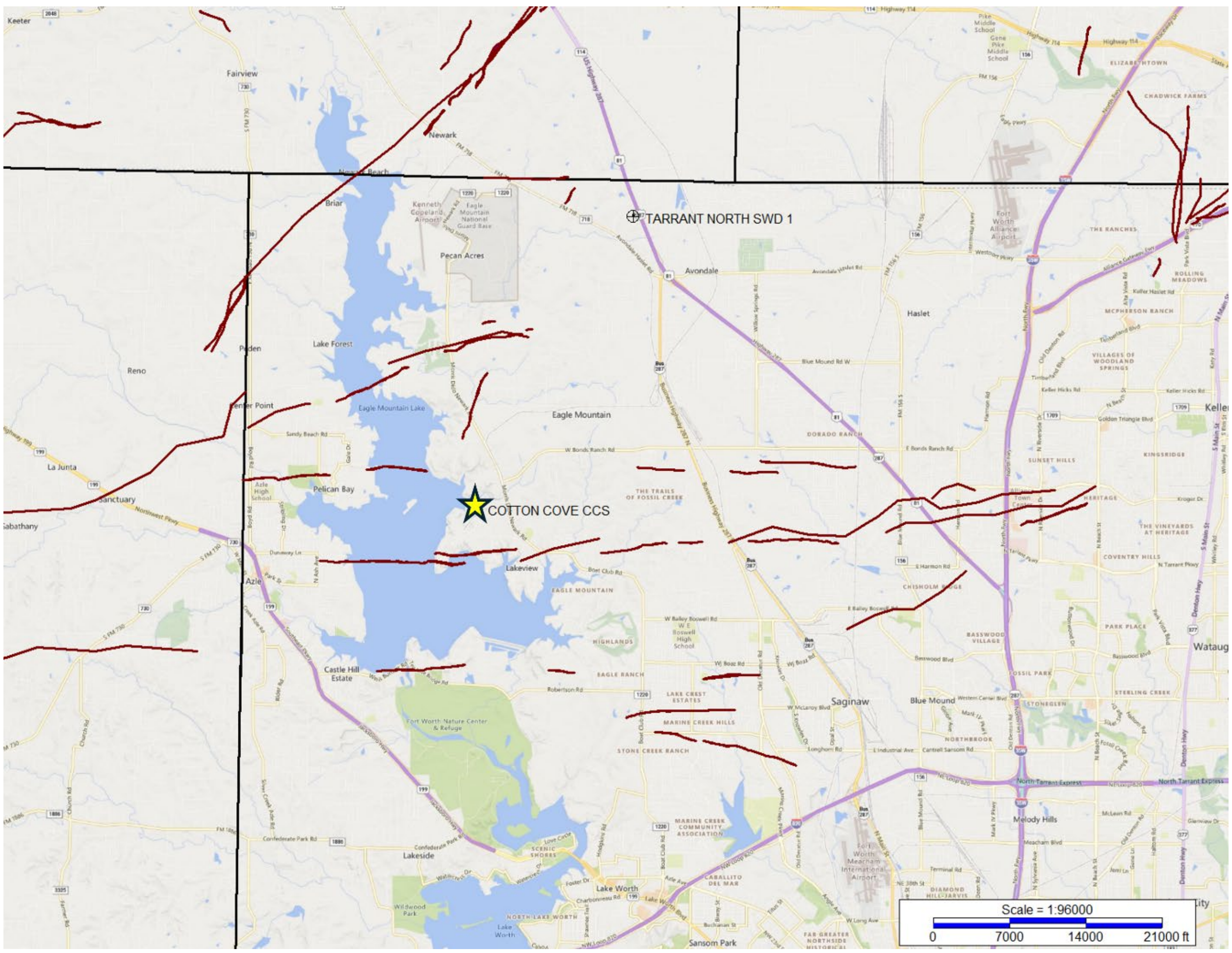


Figure 4. Mapped faults (brown lines) at the top Ellenburger level, near the proposed injection well, from Wood (2015) and internal mapping. North is up.

3.3 Lithological and Reservoir Characterizations

Smye *et al*. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Upper Cambrian to Ordovician. Prior to understanding the petrophysical 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. 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 strata highlighted by red dashed box in **Figure 5**. The Viola and Simpson Groups are expected to overlie Ellenburger Subunit A at the Cotton Cove CCS 1 site as depicted on the right side of the highlighted column.

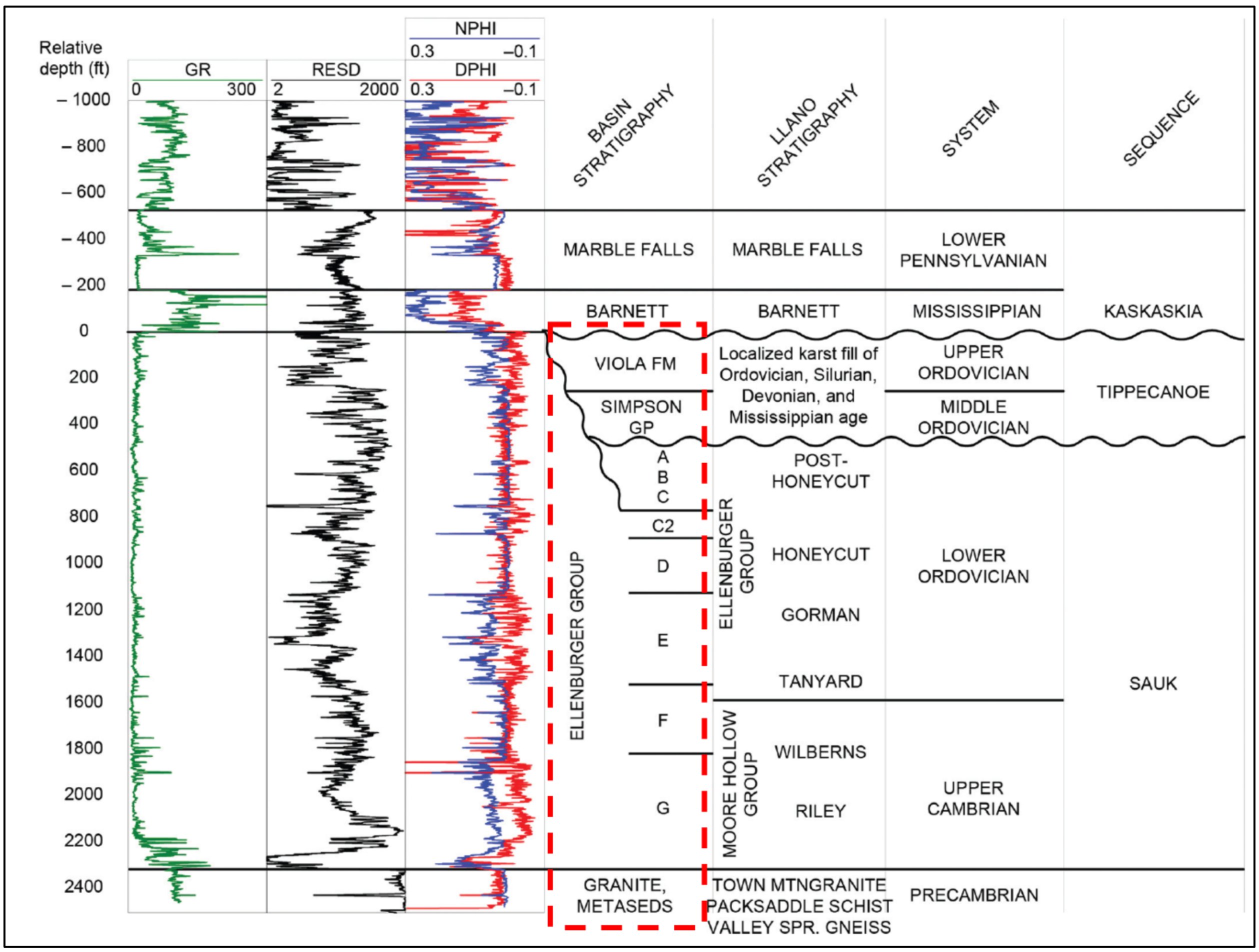


Figure 5. Regional stratigraphy at Cotton Cove CCS 1 site in north Texas (modified from Smye *et al.,* 2019). Red dashed box highlights the section of focus for the lithological characterization.

The Simpson and Viola Groups are anticipated to serve as the secondary confining interval at the Cotton Cove CCS 1 location. The Barnett Shale, located above the Viola Group, 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 range from 4-6% and 7-50 nanodarcies, respectively. These

low porosities and permeabilities are characteristic of conventional seals and, as such, the Barnett serves as an additional confining interval. The wells in the project area produce unconventional gas from the Barnett Shale.

Underlying the Viola and Simpson Groups are the informal Ellenburger lettered units defined by Smye *et al.*, 2019, which contains both the anticipated storage and confining intervals. The Ellenburger was divided into eight lithostratigraphic units starting with Ellenburger Subunit A at the top to Ellenburger Subunit G at the bottom which sits on top of the crystalline basement. Ellenburger Subunit G is not seen on well logs sufficiently to confirm that it is present in the area. Ellenburger Subunit F may sit on the crystalline basement in the area and serves as the lower seal for the reservoir. Core data from the Barnett RDC 1 showed Ellenburger Subunit F had porosities below 2% and permeabilities below 0.005 millidarcies (mD), making it an excellent lower seal. Ellenburger Subunit E will serve as the storage interval. It is characterized as a clean dolomitic reservoir with 49% dolomite by volume and approximately 4% matrix porosity. Ellenburger Subunits B and C were found to have lower matrix porosities compared to Ellenburger Subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger Subunit A has been proven to have reservoir characteristics with multiple saltwater disposal wells completed in Ellenburger Subunit A. Karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Ellenburger Subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger Subunits A-G.

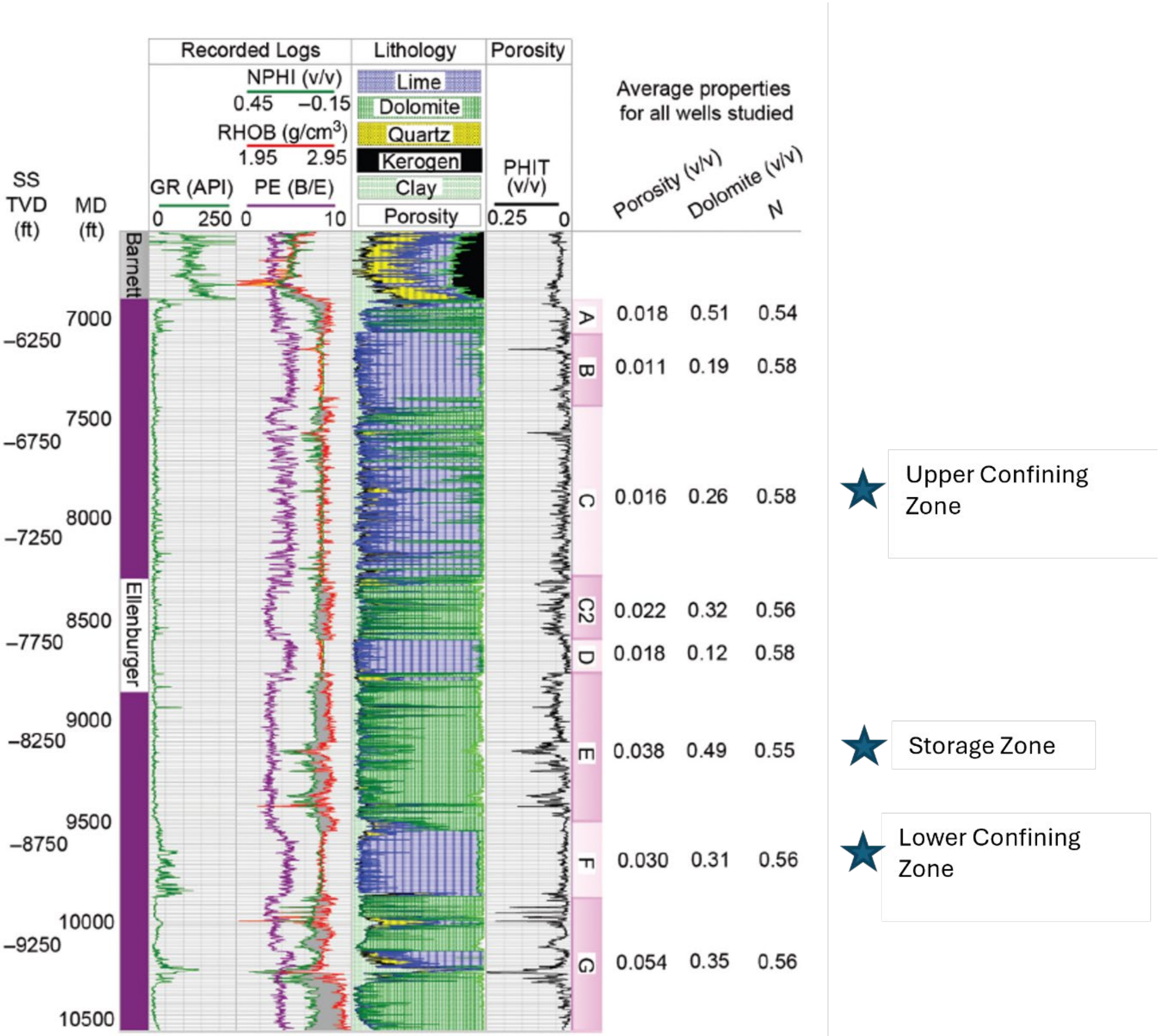


Figure 6. General properties of Ellenburger Subunits A-G in the project area (modified from Smye *et al.*, 2015).

The Barnett RDC 1 injection well located approximately 27 miles northwest of the proposed injection site also contains Ellenburger Subunits A through F, as shown below in **Figure 7**. Drilling at the proposed site should result in reservoir and seal intervals like those shown in both **Figures 6 and 7**.

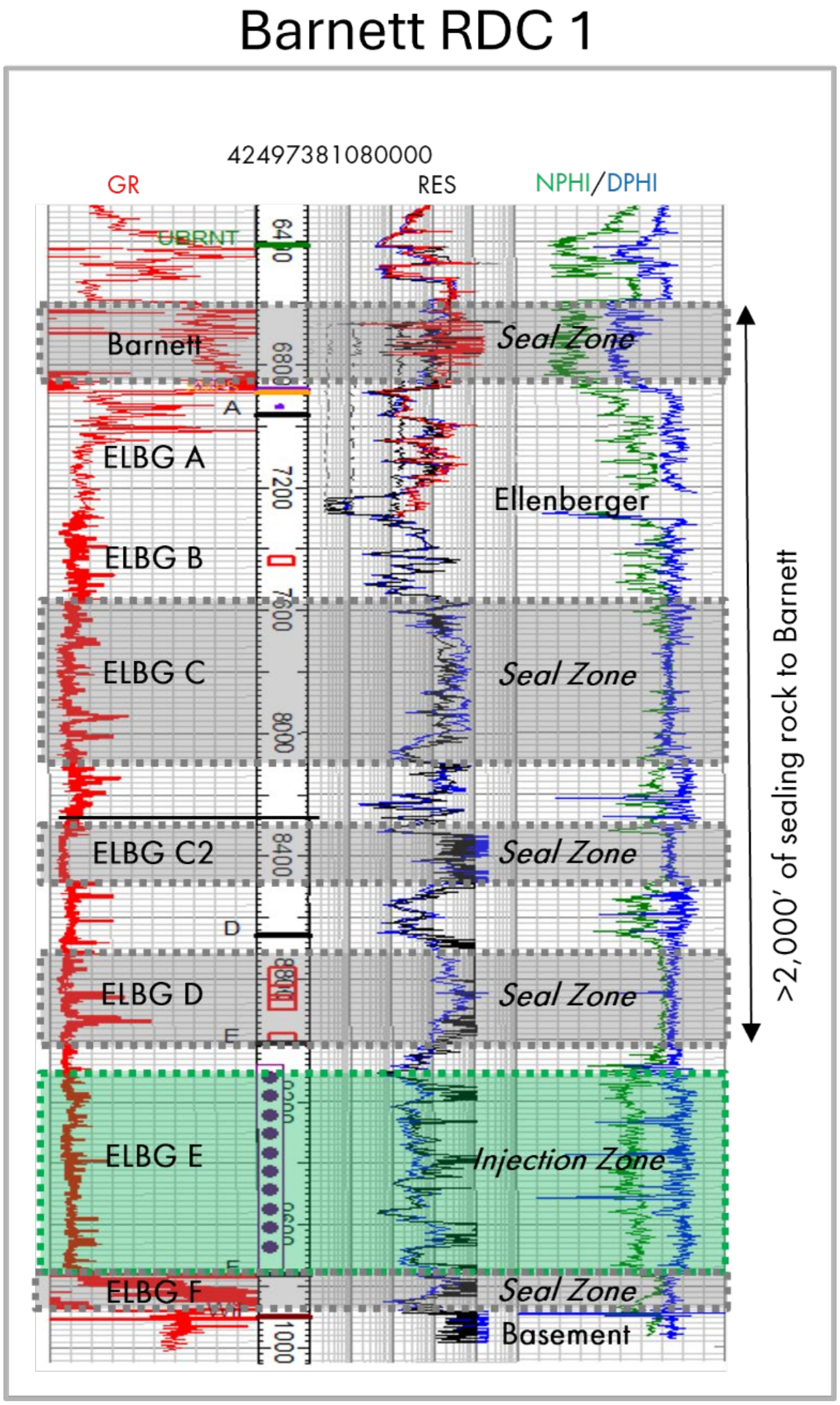


Figure 7. Barnett RDC 1 well log interpretation; Ellenburger Subunits A through F are shown on the log image.

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 as the cut-off because fractures greatly enhance

permeability and improve Ellenburger reservoir quality even in intervals with very low matrix porosity.

Saltwater disposal into analogous Ellenburger intervals with low porosity lend support to the premise that a low log porosity could still result in realizable CO_2 storage potential (*e.g.*, Tarrant North SWD 1). 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 interval properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger as seen in the Tarrant North SWD 1 well.

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

<table>
<tr><th>Ellenburger Subunit</th><th>Dominant Lithology</th><th>Gross Reservoir Thickness (feet)</th><th>Net Reservoir Thickness (feet [>2% PHIA])</th><th>Net-to-Gross Ratio</th><th>Average Reservoir Porosity (%)</th><th></th></tr>
<tr><td>A</td><td>Dolostone</td><td>372</td><td>160</td><td>0.43</td><td>3.3</td><td></td></tr>
<tr><td>B</td><td>Limestone</td><td>307</td><td>25</td><td>0.08</td><td>1.3</td><td rowspan="4">Upper Confining Interval</td></tr>
<tr><td>C</td><td>Limestone</td><td>906</td><td>284</td><td>0.31</td><td>2.4</td></tr>
<tr><td>C2</td><td>Dolostone</td><td>281</td><td>88</td><td>0.31</td><td>2.5</td></tr>
<tr><td>D</td><td>Limestone</td><td>502</td><td>288</td><td>0.57</td><td>3.5</td></tr>
<tr><td>E</td><td>Dolostone</td><td>1087</td><td>700</td><td>0.64</td><td>4.2</td><td>Storage Interval</td></tr>
<tr><td>F</td><td>Limestone</td><td>136</td><td>4</td><td>0.03</td><td>1.1</td><td>Lower Confining Interval</td></tr>
<tr><td>G</td><td>Dolostone</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td></td></tr>
</table>

Permeability data in individual Ellenburger subunits was obtained from literature and informed by the core data from the Barnett RDC 1 well. Regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.5 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.25°F per 100 feet using the well logs from the Tarrant North SWD 1.

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 v3.0, five wells within in the Fort Worth Basin were identified with water samples from the Ellenburger as shown in **Figure 8**.

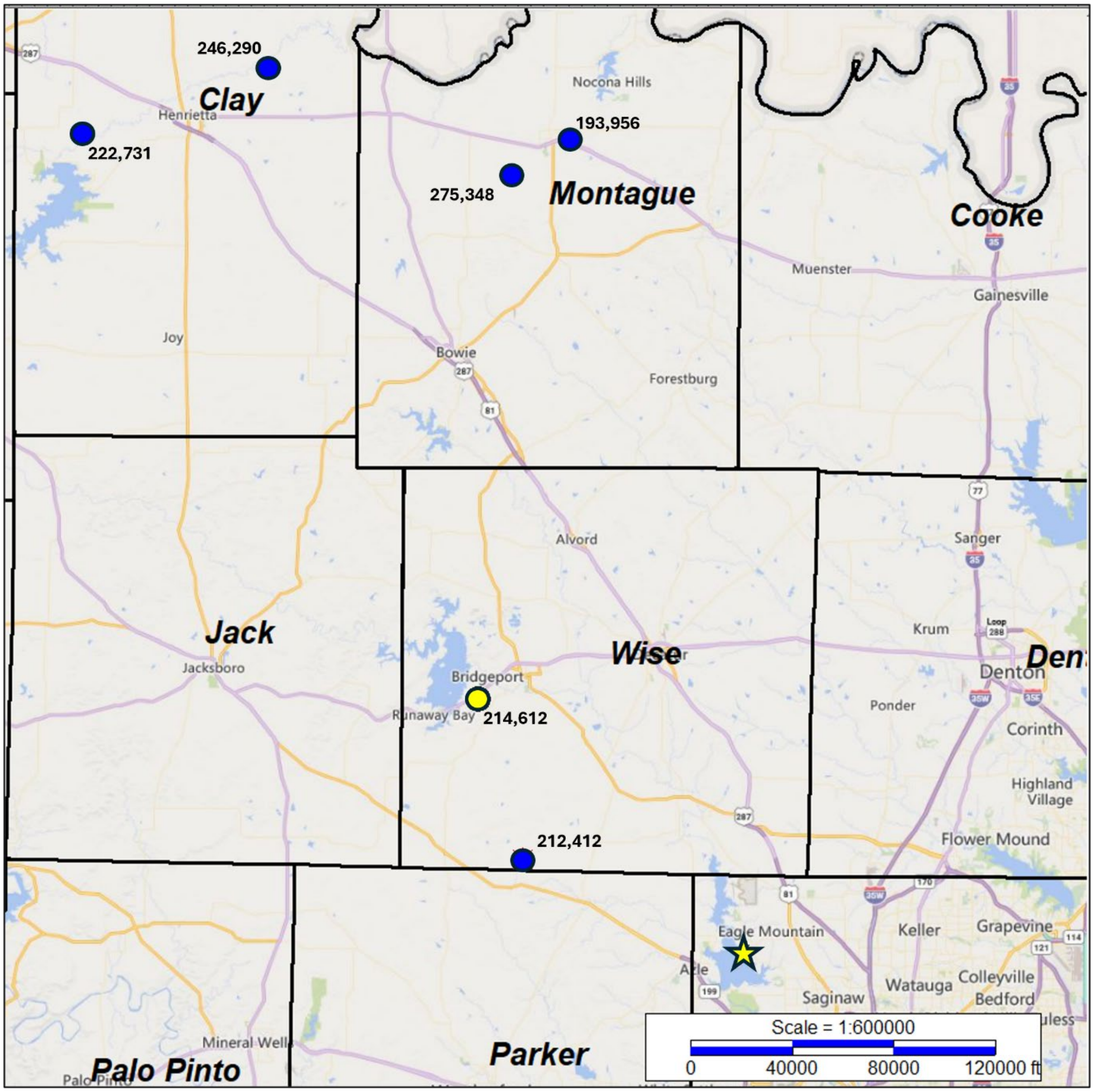


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis. The blue circles are wells from the USGS Produced Waters Database v3.0 while the yellow circle is the Barnett RDC 1. TDS values in mg/L are annotated. The Cotton Cove CCS 1 location is shown with the yellow star. North is up.

The Ellenburger Group is not productive of oil and gas 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. The USGS database indicates that Ellenburger fluids have greater than 190,000 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin as reported in **Table 3**. The average of the five samples available in the USGS database is similar to the TDS value that dCarbon obtained from the Barnett RDC 1 well. The Barnett RDC 1 well sample had 214,612 mg/L TDS, an Na concentration of 54,465 ppm, a Ca concentration of 22,269 ppm, and a Cl concentration of 128,819 ppm.

Table 3. Ellenburger Formation fluid chemistry. These values are derived from the five wells depicted in Figure 8.

	TDS (mg/L)	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	230,147	63,363	20,635	142,168
LOW	193,956	55,352	15,352	118,405
HIGH	275,348	77,094	23,443	169,720

3.5 Potential of Induced Seismicity – Ellenburger Formation

An analysis of historical seismic events within 100 square miles surrounding the proposed Class II well injection site shows seismic activity dating back to 1900, according to the U.S. Geological Survey (USGS) Earthquake Catalog (**Figure 9)**. Of the nine earthquakes above magnitude 3.0 shown on the map, three fall within the 100 square-mile area. All but one of the nine earthquakes appear to be part of the Azle-Reno earthquake swarm, documented by Hornbach, *et al*. (2015) (**Figure 10**). The Azle-Reno swarm earthquakes were mapped back to an NNE-SSW basement-rooted fault and its antithetic fault via data from a local earthquake network and advanced hypocenter location techniques. It is likely that the wide scatter in the mapped earthquake locations seen in the USGS catalog is a function of the location uncertainty due to the sparse recording array rather than actual separation of earthquake hypocenters.

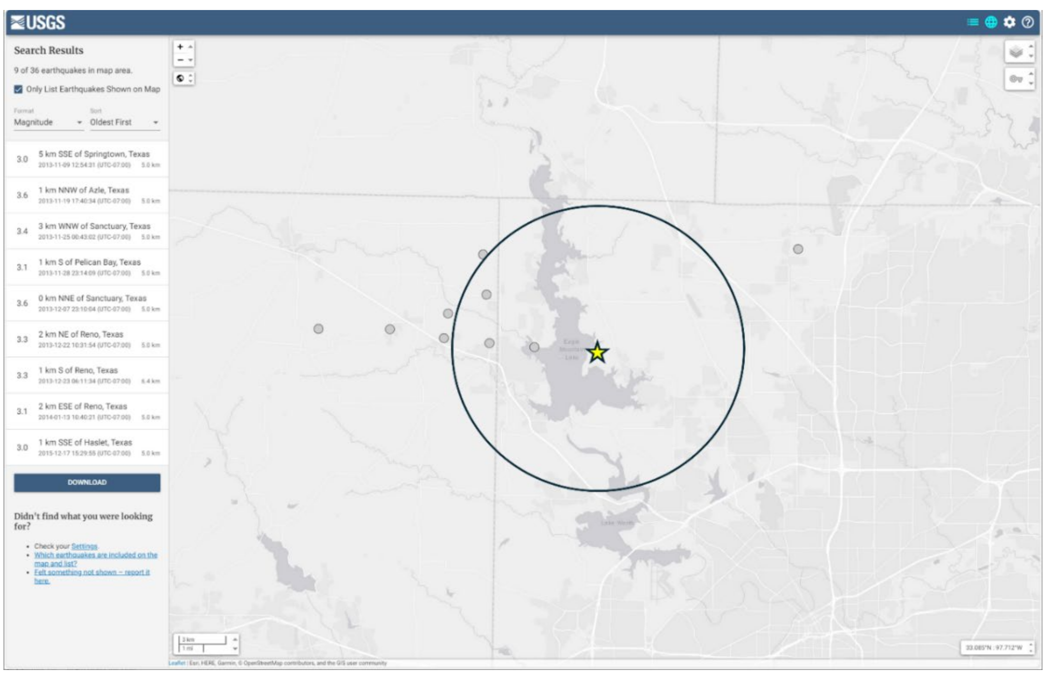
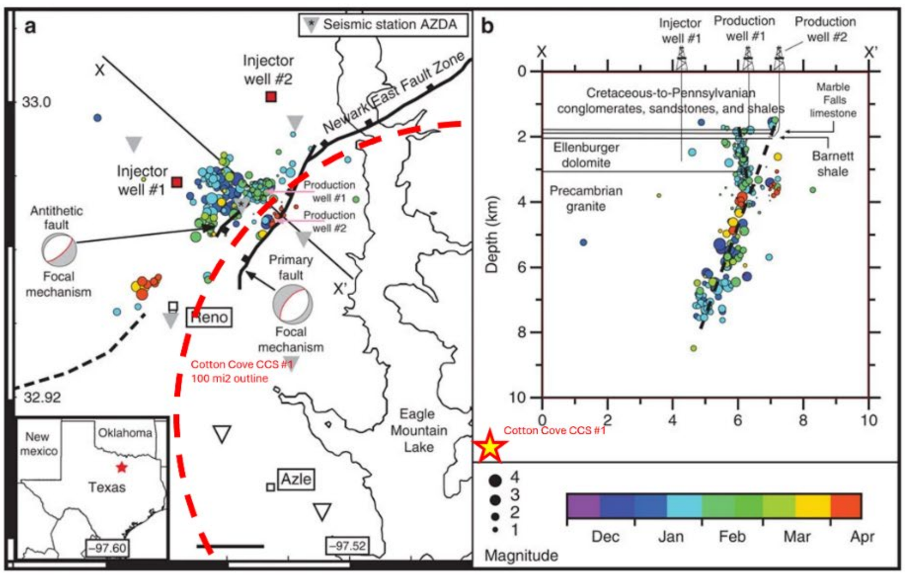


Figure 9. Screenshot from the USGS Earthquake Catalog showing historical seismic activity at or above Magnitude 3.0 in the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. Three seismic events meet these criteria in the USGS catalog. North is up.

Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey (Hennings, *et al.*, 2019). Current findings show that steeply dipping faults that strike north-northeast have the highest fault slip potential. These results are consistent with the orientation of the faults that produced the Azle-Reno swarm. No additional earthquakes have been reported since 2015 despite several saltwater disposal wells that inject in the Ellenburger Group continuing to operate in the area. Beginning in August 2023, BKV began operating a local earthquake network covering portions of Wise, Denton, Parker and Tarrant Counties in Texas (**Figure 11**). No earthquakes have been detected within the 100 square-mile area surrounding the Cotton Cove CCS 1 location with this array since it began recording.



Map showing the location of NEFZ (black) at the top of the Ellenburger formation, inferred faults (dashed) at the top of the Ellenburger formation, injection wells (red squares), two production wells (API 36734045 and 36734139) with significant brine production near the faults (pink arrows) and earthquake epicentres (coloured circles) recorded by the temporary seismic network (triangles) (**a**). The red star in the inset of **a** shows the map location. The black scale bar in **a** is 2 km. Grey (white) triangles indicate the locations of active (inactive) seismic stations. Line X–X′ in **a** shows the location of the cross-section shown in (**b**). We interpret two faults based on earthquake location and consistent with industry interpretations: a primary normal fault and a shallower antithetic normal fault.

Figure 10. Modified from a map from Hornbach *et.al.*, 2015. Earthquake hypocenters for the 2013-14 Azle-Reno swarm were located using a local array of seismometers resulting in reduced location uncertainty. Earthquakes were clustered along a northwest-dipping normal fault and it's southeast-dipping antithetic fault. These earthquakes cluster just outside of the line marking the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. North is up.

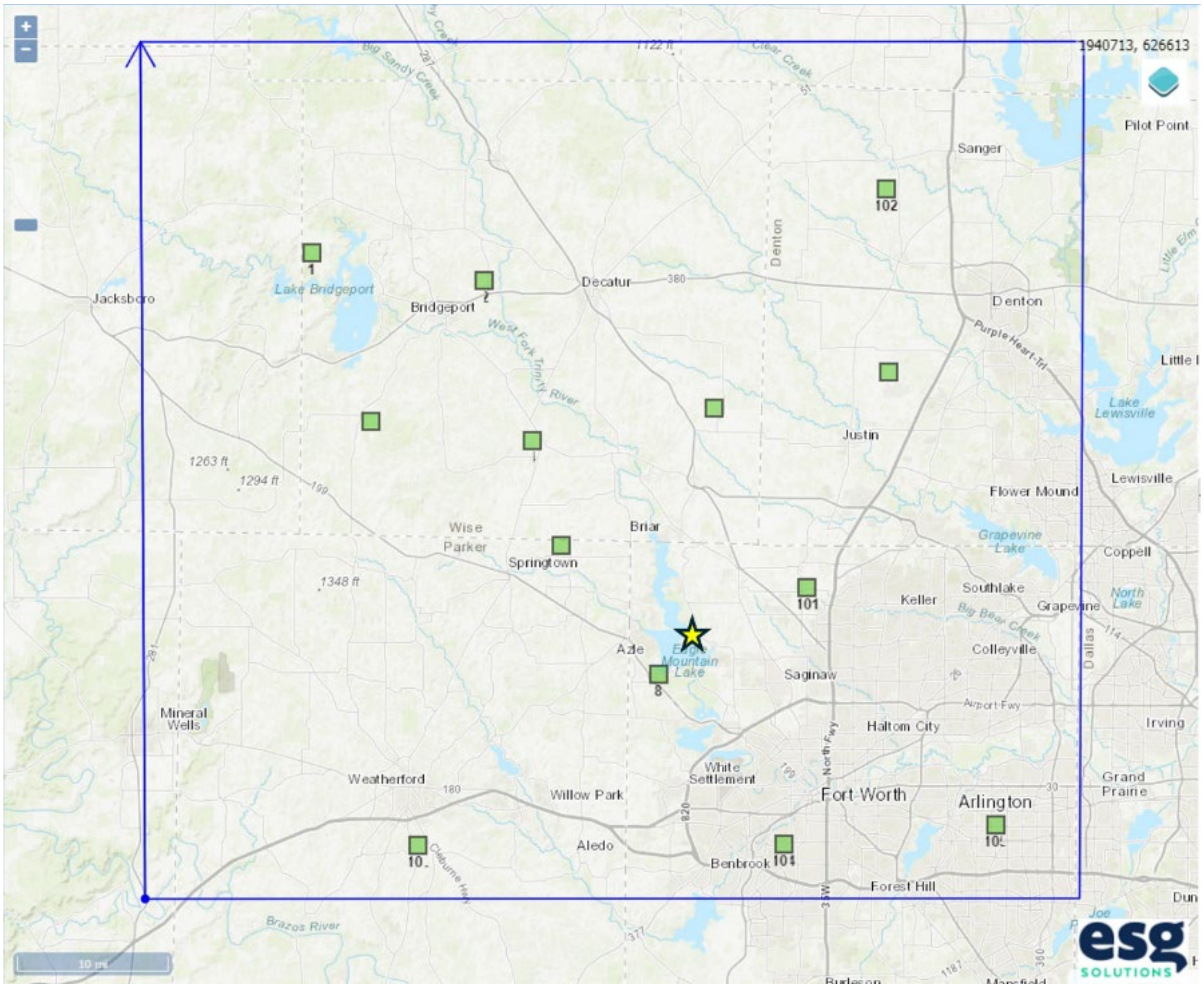


Figure 11. Map of the local seismic array monitoring the area of the Cotton Cove CCS 1. The yellow star marks the location of the Cotton Cove CCS 1. Seismic stations contributing data to the BKV seismic analysis are shown with the green squares. Stations 1-8 are operated by BKV while Stations 101-105 are operated by either TexNet or the USGS and their data are used in the hypocenter locations. North is up.

3.6 Groundwater Hydrology in MMA

Tarrant County falls within the Northern Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 12**). One aquifer is within the vicinity of the proposed injection site: the Trinity Group Aquifer. The Lower Cretaceous Trinity Group is classified as a major aquifer and serves as an important source of groundwater for a portion of northern Texas, including Tarrant County, Texas. The Trinity Group Aquifer outcrops at the Cotton Cove CCS 1 site and across a large swath of Wise and Parker Counties and the northwestern corner of Tarrant County.

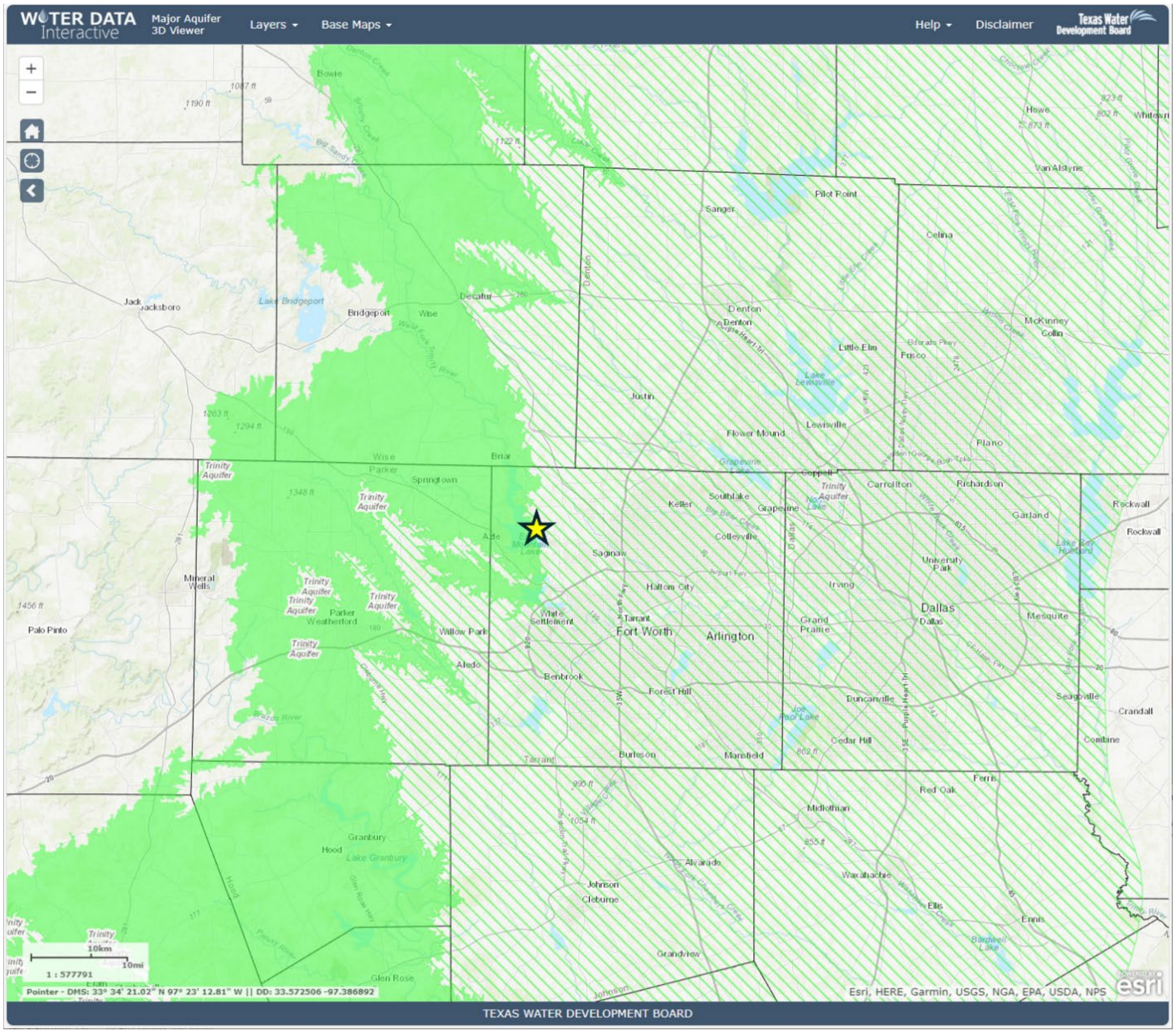


Figure 12. Map of the Trinity Major Aquifer extent within northcentral Texas, from the Texas Water Development Board Interactive Viewer. The location of the proposed Cotton Cove CCS 1 is shown with a yellow star. North is up.

The Trinty Group Aquifer is unconfined west of the project site and confined east of the site (**Figure 12**). Water in the Trinity Group Aquifer is considered fresh but hard, with TDS values in the project area of less than 1,000 mg/L. The overall stratigraphic column contains numerous barriers to vertical flow (or aquitards) that are expected to prevent CO_2 injected into the Ellenburger Subunit E from reaching the surface or near surface location of the Trinity Group Aquifer (**Figure 13**).

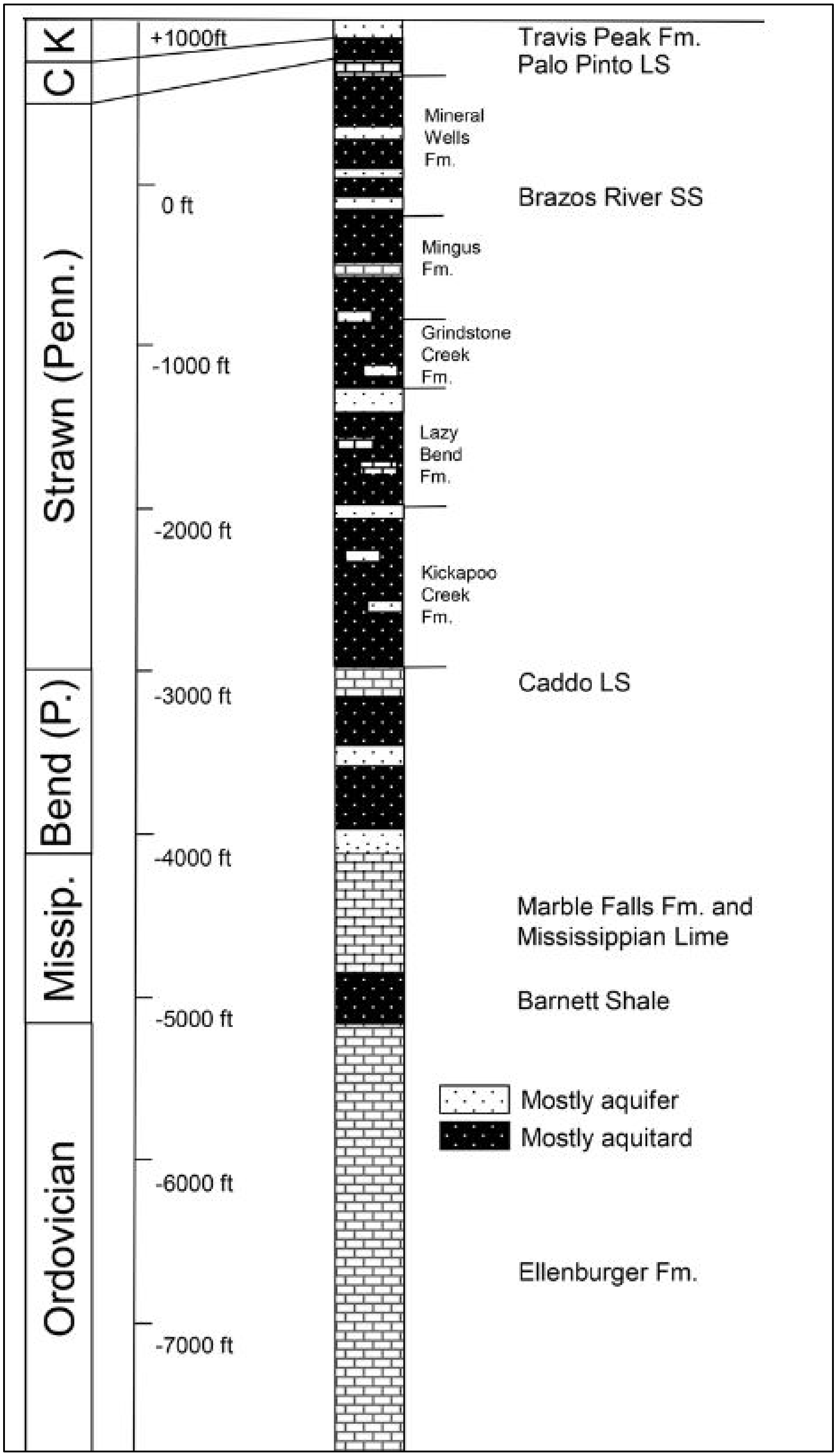


Figure 13. Stratigraphic column showing aquifers and aquitards, modified from Nicot *et al*., (2011)

There are 107 freshwater wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, as shown in **Figure 14** and listed in **Table 4**.

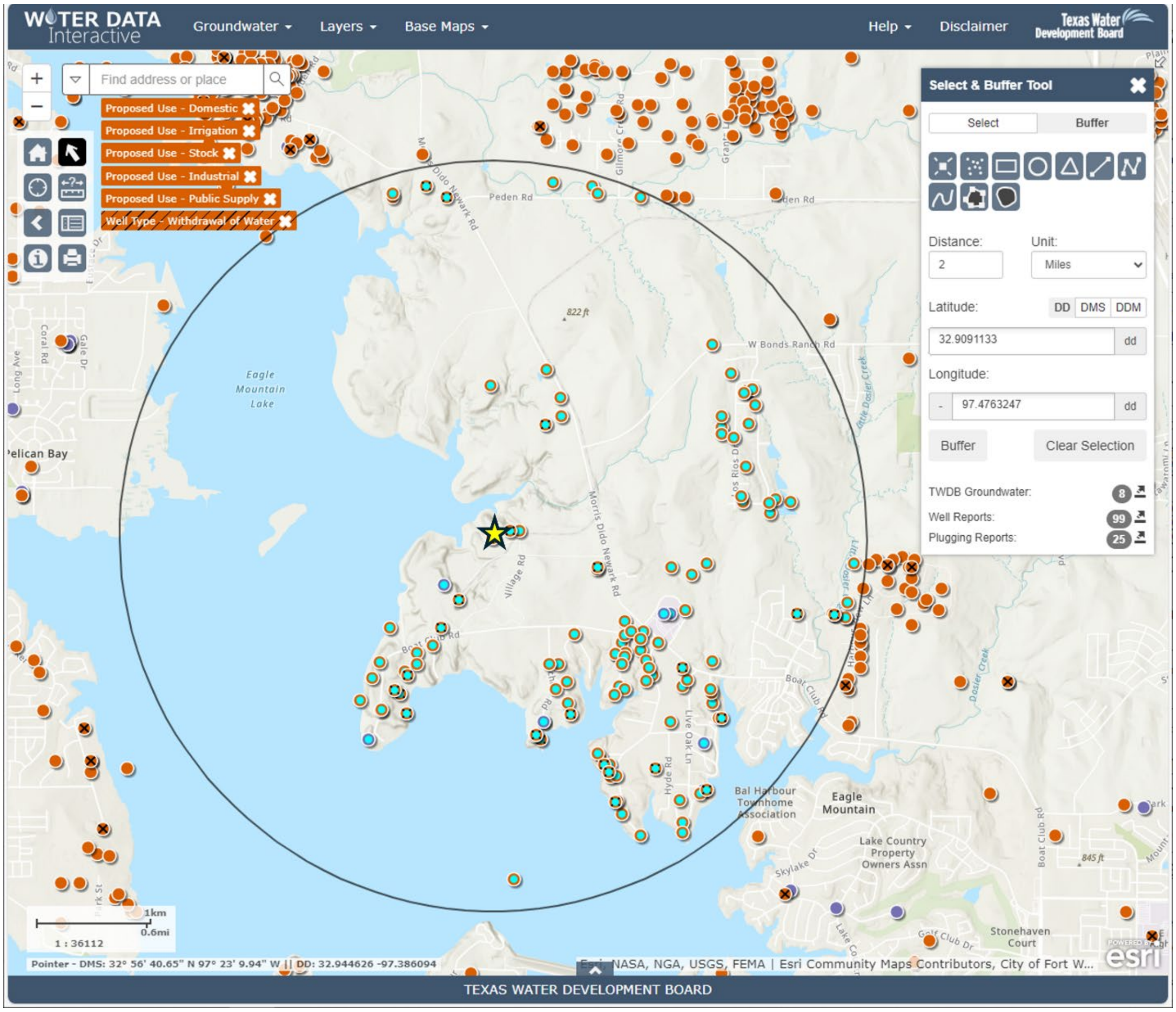


Figure 14. Water wells within two miles from the proposed injection site, data from the Texas Water Development Board Interactive Viewer. North is up.

Table 4. Groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
4945	32.8825	-97.474444	200
8105	32.886945	-97.458889	140
8162	32.888611	-97.459167	140
9201	32.899167	-97.483334	205
23976	32.896389	-97.488611	340
23981	32.916667	-97.454167	355

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
24611	32.902778	-97.443889	330
27215	32.921667	-97.454445	377
27217	32.9175	-97.455278	380
27266	32.914445	-97.453056	340
27268	32.916944	-97.455278	380
27269	32.918333	-97.455278	340
27270	32.920278	-97.453056	350
27271	32.920278	-97.453056	350
27273	32.917778	-97.452778	380
27274	32.919167	-97.452223	335
30454	32.936111	-97.467222	355
37395	32.891945	-97.466389	238
45494	32.902778	-97.443889	320
57105	32.935556	-97.466667	942
80342	32.923889	-97.456112	220
86272	32.889167	-97.457223	140
104755	32.908889	-97.476389	266
123923	32.900278	-97.462778	200
123929	32.899445	-97.462223	200
126757	32.901945	-97.485834	180
156542	32.898334	-97.461667	253
161948	32.901667	-97.462501	280
190665	32.892222	-97.466667	266
194317	32.903334	-97.458612	180
196988	32.900834	-97.464445	260
196990	32.899722	-97.464167	260
197152	32.935278	-97.462778	280
197159	32.936389	-97.470833	280
202905	32.909445	-97.473889	738
204320	32.902501	-97.464167	180
204322	32.900834	-97.461112	180
210501	32.901389	-97.464167	140
210511	32.906112	-97.458056	380
210912	32.896111	-97.469444	200
234675	32.894722	-97.460001	140
255591	32.899167	-97.464445	286
257427	32.901667	-97.463612	200
257473	32.901112	-97.462778	200
257476	32.898611	-97.484445	180
267624	32.898889	-97.461945	210

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
268343	32.899167	-97.470278	235
306601	32.899167	-97.471111	200
317205	32.896111	-97.456112	200
323205	32.921944	-97.471389	294
324408	32.895	-97.455556	180
330547	32.898056	-97.4875	172
364478	32.900001	-97.483334	224
365834	32.906945	-97.456667	260
367478	32.911667	-97.453334	297
373975	32.910834	-97.450834	297
377943	32.911667	-97.448889	320
386419	32.935278	-97.485556	240
387615	32.886111	-97.458889	200
389582	32.891389	-97.465556	280
392805	32.935556	-97.485556	220
395997	32.897222	-97.470555	200
396019	32.906945	-97.443056	300
403825	32.911945	-97.450278	297
407372	32.895556	-97.486667	320
407944	32.899286	-97.486792	210
412976	32.906531	-97.466806	802
415271	32.897861	-97.462194	260
438110	32.897417	-97.464733	160
458834	32.900585	-97.481922	320
463887	32.912167	-97.453444	347
469393	32.896937	-97.456209	200
508639	32.897211	-97.456264	200
513027	32.90004	-97.46411	200
520574	32.890422	-97.465485	220
527005	32.88756	-97.46444	140
532284	32.91165	-97.45088	322
534258	32.90395	-97.44367	372
535973	32.8994	-97.45613	180
545467	32.895599	-97.486566	281
550851	32.920408	-97.452453	400
557415	32.89743	-97.45887	260
562605	32.897185	-97.464191	200
573642	32.897149	-97.485324	200
579758	32.885889	-97.462765	180
583511	32.906633	-97.4599	220

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
585719	32.89795	-97.45848	220
587677	32.897767	-97.469483	240
634201	32.901472	-97.468833	160
641548	32.888573	-97.464852	222
644810	32.89678	-97.46515	278
648844	32.89053	-97.46497	280
649674	32.91975	-97.47009	170
654239	32.90302	-97.44504	360
662127	32.9183	-97.47005	335
667007	32.89999	-97.46504	265
667223	32.89999	-97.46504	265
677269	32.9207	-97.47656	313
677560	32.920123	-97.45321	420
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**
3205701	32.894722	-97.471667	273
3205702	32.894722	-97.471667	261
3205703	32.905278	-97.480833	196
3205704	32.893334	-97.487778	656
3205705	32.903056	-97.460001	194
3205706	32.903056	-97.460556	320
3205804	32.889445	-97.456945	233
3205805	32.893056	-97.456945	220

3.7 Description of CO_2 Project Facilities

dCarbon will accept CO_2 from by the Cotton Cove Gas Plant (**Figure 1**). 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 and transport it to the Cotton Cove CCS 1 injection site. The CO_2 stream will be metered to verify quantity. The CO_2 will then be injected into the Ellenburger Subunit E as previously described. 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 5**. Although the industry-standard sampling of the CO_2 stream is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly over time.

Table 5. CO_2 stream analysis for the Cotton Cove CCS 1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.007	0.011	0.007
Carbon Dioxide	99.8514	99.665	99.8514
Methane	0.095	0.261	0.095
Ethane	0.013	0.019	0.013
Propane	0.002	0.002	0.002
Isobutane	0.008	0.006	0.008
N-butane	0.001	0.001	0.001
Isopentane	0.003	0.002	0.003
N-pentane	0.000	0.000	0.000
Hexanes	0.006	0.003	0.006
Heptanes	0.000	0.000	0.000
Octanes	0.000	0.000	0.000
Nonanes	0.000	0.000	0.000
Decanes plus	0.000	0.000	0.000
BTEX	0.002	0.000	0.002
H_2S	0.000	0.000	0.000
H2O	0.012	0.030	0.012
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	3.15		
Density (lbs/gal)	4.09		
Molecular weight	43.93		
Specific gravity (Air=1)	1.5167		

3.8. Reservoir Characterization Modeling

A regional subsurface model was created in Schlumberger's Petrel software. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1, as discussed in previous sections) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals, that contribute to overall higher fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed

appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E. This assumption is supported by consistent saltwater disposal rates and injection volumes into the Ellenburger Group 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 Cotton Cove CCS 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
4. Quantify the increase in pore pressure dues to CO_2 injection spatially within the reservoir

The CO_2 storage complex is confined to the Ellenburger Group. The Ellenburger Subunit E is modeled as the reservoir interval and the Ellenburger Subunits B-D are modeled as the primary seal to impede vertical fluid flow. The lower confining interval for the reservoir is modeled as the Ellenburger Subunit F.

An SEM with the dimensions of 8.8 miles by 6.4 miles by 2.3 miles (X, Y, and Z) was constructed from elevation grids and faults derived from 3D seismic data and well log information (**Figure 15**) in Schlumberger's Petrel software. A 4-mile by 4-mile tartan grid was generated and then exported to Rock Fluid Dynamics's tNavigator simulator to account for fully implicit multiphase compositional fluid flow. This simulation was constructed to model other transport and mixing phenomena, i.e., relative permeability, diffusion, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be a completely saline aquifer. The salinity of the formation, estimated to be 200,000 ppm TDS, is typical of the Ellenburger Group in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 15** illustrates the vertical layering of the model with relationship to the simulated CO_2 saturation profile. The injection rate modeled was 75,000 MT/year for 12 years followed by 100 years of post-injection simulation to fully document the movement of CO_2. **Figure 15** also depicts the initial model conditions and a map view of permeability enhancements in the model due to mapped faults.

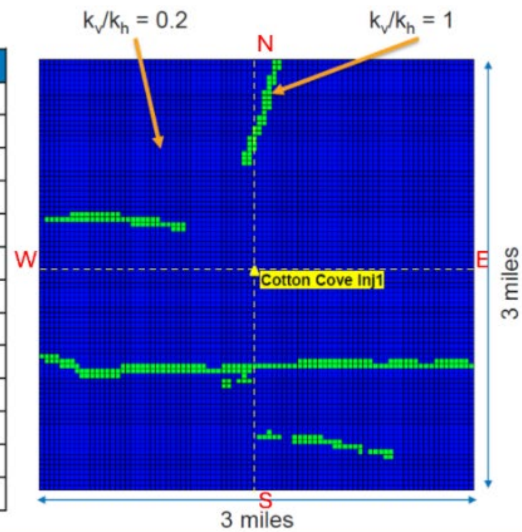
The methodologies employed for static and dynamic models were based on established techniques in literature. Specifically, the reservoir relative permeability model was calculated from capillary pressure data from the Barnett RDC 1 using the Brooks and Corey (1966) model. The relative permeability curves for sealing layers were obtained from Bennion and Bachu (2007). The initial reservoir conditions were developed using gradients derived from Barnett RDC 1 well data. Mapped and inferred faults were given enhanced permeability in the simulation model of 400 mD

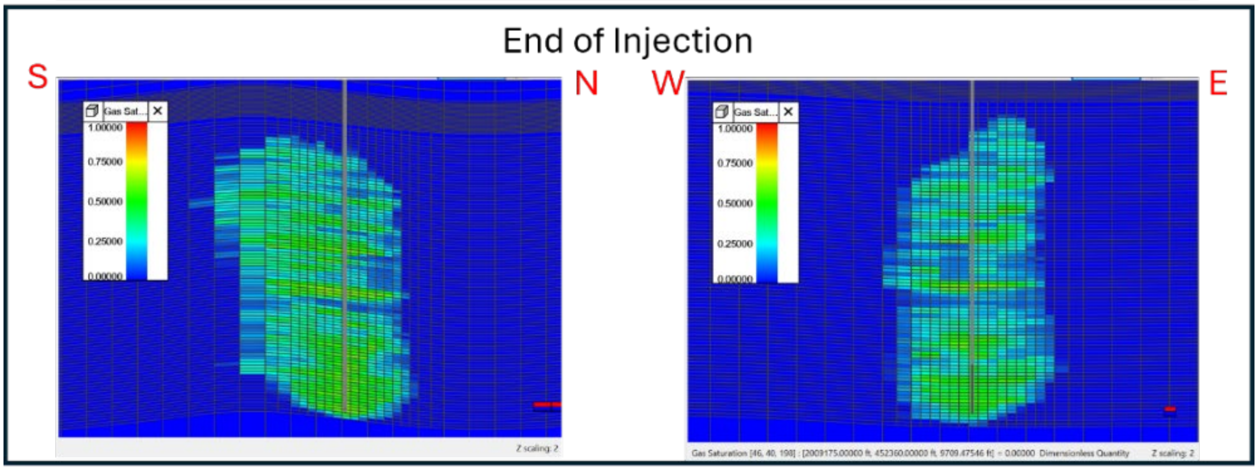
and a 1:1 vertical to horizontal permeability. Ellenburger Group interpreted as affected by karsting, primarily in the Ellenburger Subunit A, was given the same enhanced permeability in the simulation model as the mapped faults.

While the top of the Ellenburger Subunit E reservoir interval was modeled at 8,920 feet at the injection well, the top of the perforated interval was chosen to be at 10,140 feet to force the CO_2 to first migrate vertically in the reservoir before hitting the seal at the Ellenburger Subunit D.

Using the aforementioned methodology to develop model estimates, the pressure gradient was assumed to be 0.5 psi per foot, which resulted in an estimated reservoir pressure of 5,070 psi at the top of the injection interval. The temperature gradient was assumed to be 1.25^{o}F per 100 feet, resulting in an estimated temperature of 200^{o}F at the top of the injection interval. 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 6,388 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.

Input	Specifications
Total Number of Grid Blocks	1,732,470
N_x, N_y, N_z	64, 64, 199
D_x, D_y	250 ft * 250 ft
Injection Formation top	EB E ~ 8,180 ft TVDSS (8,920 ft MD)
k_v/k_h (matrix)	0.2
k_v/k_h (faults and karst)	1
Pressure Gradient	0.5 psi/ft
Temperature Gradient	1.25 deg F/100 ft + 70 deg F Surface
Injection rate	75 ktpa
Water saturation	100%
Fracture pressure Gradient	0.7 psi/ft
Maximum allowable pressure	90% of Fracture pressure
Salinity	200,000 ppm





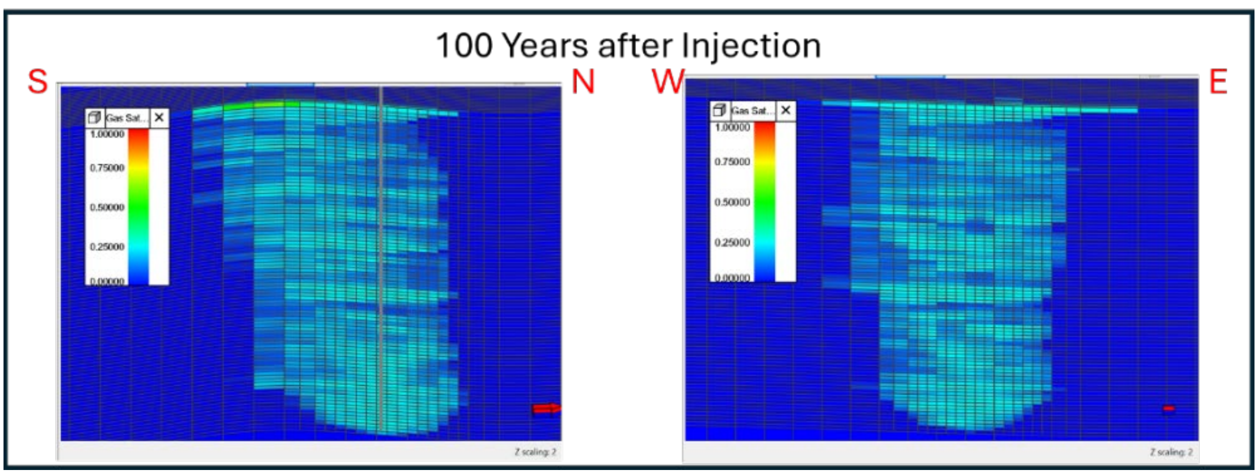


Figure 15. (Upper left table): Simulation conditions employed in the tNavigator model for the Cotton Cove CCS 1 well. (Middle and lower images): Depiction of the end of injection and 100 years after injection modeling results. The color bar in all images indicates modeled CO_2 gas saturation. (Upper right image): The map depicts the enhancement of permeability in certain areas of the model due to mapped faults.

As mentioned earlier, injection was modeled at 75,000 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 94 years post injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 16** shows the CO_2 plume at the end of injection (green) compared to 94 years post injection (cyan). Injected CO_2 flows generally west, which is the regional up dip direction. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation. While the final CO_2 plume stabilizes in a position where the western end is under Eagle Mountain Lake, there are no natural leak pathways that allow CO_2 to reach the lake. A more detailed discussion of potential leak pathways is presented in Section 5.

Figure 16. Simulation results showing CO_2 Plumes (end of injection = green and after 100 years of injection = cyan). Cotton Cove CCS 1 injection wells is shown by as the yellow star. North is up.

Figure 17 illustrates bottom hole pressure at the Cotton Cove CCS 1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is ~5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and 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, the flow transitions from capillary-driven to advection-driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

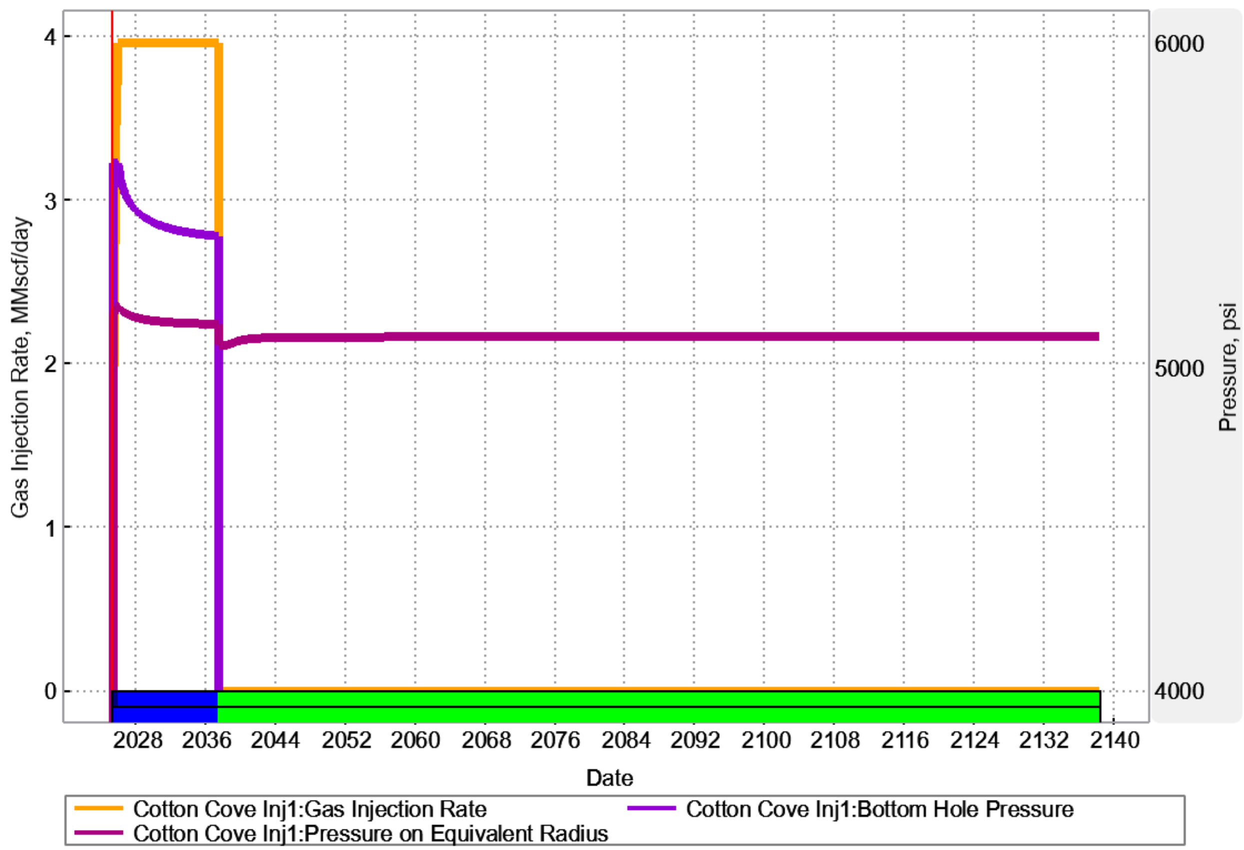


Figure 17. Modeled injection profile at Cotton Cove CCS 1 well. Gas injection rate shown in MMscf/day on the left Y axis and bottom hole pressure and pressure on equivalent radius shown in psi on the right Y axis. The blue bar along the X axis indicates the 12-year injection period and the green bar indicates the 100-year post-injection period.

4 – DELINEATION 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 of at least one-half mile. The numerical simulation using tNavigator as discussed above was used to estimate the size and migration of the CO_2 plume. We modeled injection of CO_2 into the Ellenburger Subunit E for 12 years followed by 100 years of post-injection modeling. Results indicated that the plume ceased to migrate after 94 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of gas saturation was used to determine the boundary of the CO_2 plume. The area of the MMA was determined to be 3.07 square miles with the greatest extent reaching 1.5 miles from the injector. **Figure 18** shows the End of Injection (EOI) plume (green), the 94-year post-injection plume (black solid), and the MMA using a 0.5 mi buffer (black dashed).

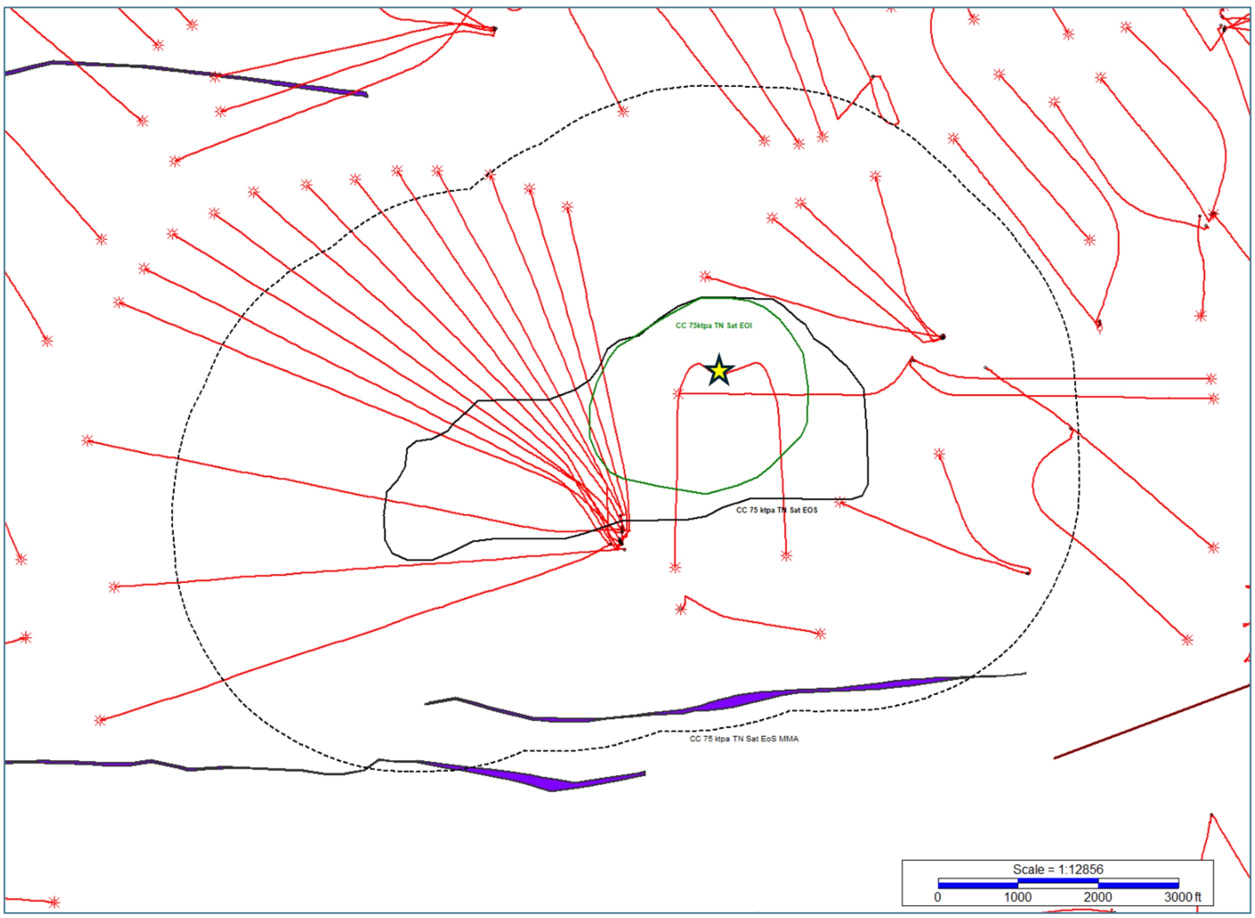


Figure 18. MMA (black dashed), EOI plume (green), and 100-year post injection plume outlines (black solid) as modeled at the Cotton Cove CCS 1 well (yellow star). Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. Thin purple polygons are faults at the top of the Ellenburger Group. North is up.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features mapped within the project area that could cause the unintended migration of the CO_2 plume through natural pathways to the USDW. The mapped faulting in the area does not extend shallower than the top of the Mississippian Marble Falls Formation, leaving more than 5,000 feet of mostly Pennsylvanian shales between the top of the faults and the USDW. 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 Sections 4 and 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 12, which is projected to be the EOI. Based on the definitions in 40 CFR § 98.449 and an initial time interval of t=12, we defined our AMA by superimposing the following:

(1) The area projected to contain the free phase CO_2 plume at the end of year 12, plus an all-around buffer 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 17.

As noted in Section 4.1, dCarbon utilized the plume area after 94 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 18** shows the MMA, which is the same as the AMA. **Figure 19** indicates the AMA/MMA (black dashed) and currently existing 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 802 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

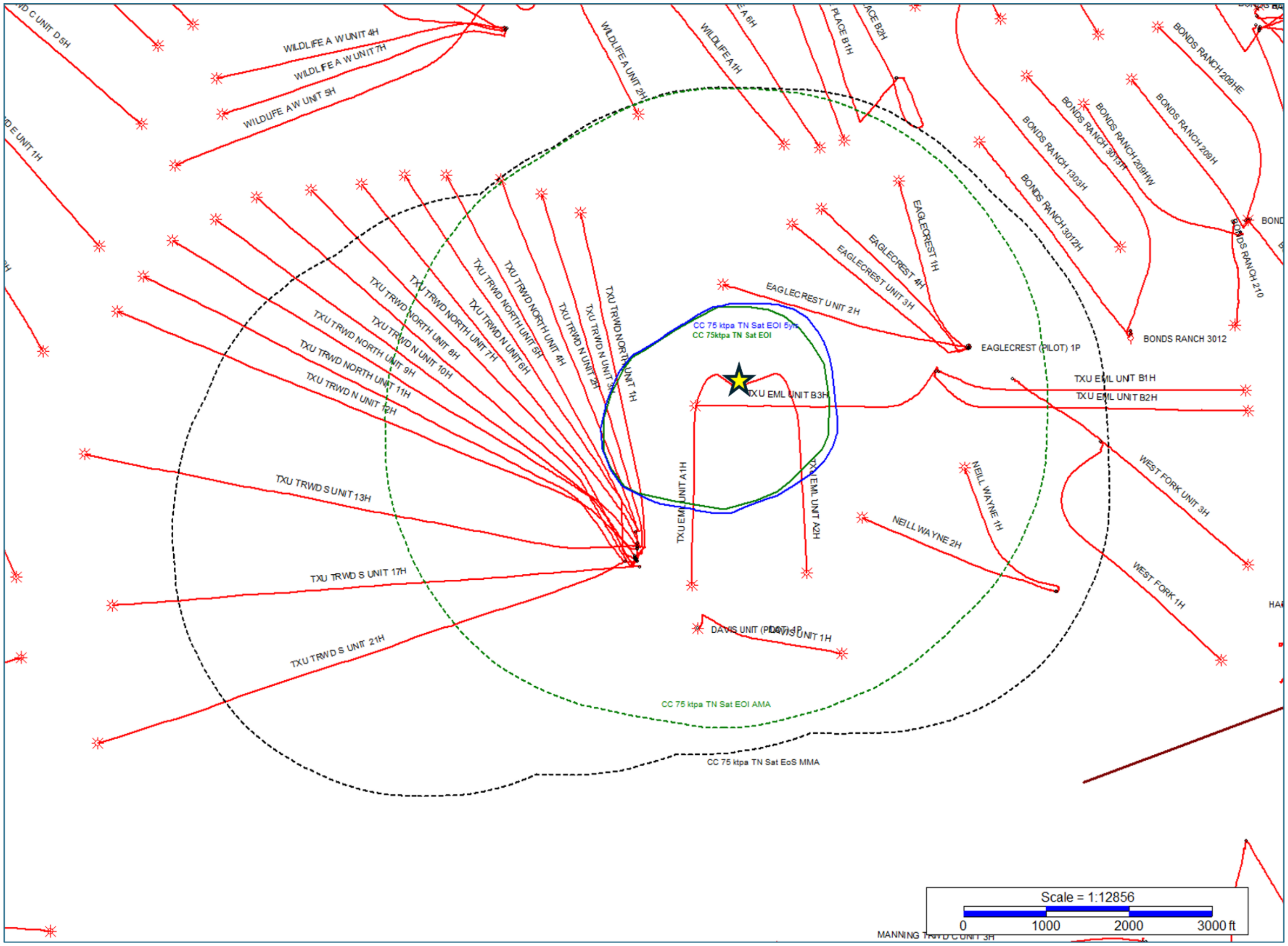


Figure 19. The calculated AMA (green dashed) and existing wells within the project AMA/MMA. The solid green and blue outlines show the extent of the CO_2 plume at EOI and five years post-injection respectively. The MMA is shown as the black dashed line for comparison. The Cotton Cove CCS 1 is shown as a yellow star. Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. North is up.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

dCarbon has assessed each of the 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 6** describes the basis for event likelihood and **Table 7** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 6. 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 7. 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 12 hours of full permitted 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	**Unlikely**, 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 conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale 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 that reach shallow enough to serve as a conduit to the USDW or the surface.	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 2,000 feet 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 a couple 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 that extend shallow enough to reach the USDW or the surface.	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 5.8 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

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at the Cotton Cove Gas Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 5**. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. This includes but is not limited to automatic detection of CO_2 and lack of O_2 detection in specifically designated locations. All BKV and dCarbon field personnel are required to wear gas monitors that detect four or five gases, including H_2S and O_2. 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 automatically in case of unexpected standard operating conditions such as a loss of line pressure.

Additionally, the compressor facility, pipe header, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and CO_2 leak detection per BKV and dCarbon safety and operations standards. These recurring monthly 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. BKV Midstream, LLC or dCarbon personnel are expected to visit the site daily.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no approved, not yet drilled well permits within the MMA other than the Cotton Cove CCS 1 well.

5.3 Leakage from Existing Wells

There are 34 existing wells within the MMA. Of these 34 wells, one had a pilot borehole for the subsequent horizontal well (**Table 8)**. The 34 wells all have active status. However, all these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 8,800 feet) is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells were drilled shallower than the target Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented over their entirety 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.

The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to travel via faults in the Ellenburger to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production. Injected CO_2 entering the Barnett Shale could be produced in the gas stream of these wells. While this is considered improbable due to the reservoir simulation modeling showing no CO_2 reaching the enhanced permeability areas of the model, dCarbon will consider this potential pathway specifically in its monitoring program. In addition, no wells in the AMA/MMA are located within Eagle Mountain Lake. No leak pathways are present that are expected to allow injected CO2 to reach the area of Eagle Mountain Lake.

Table 8. Existing oil and gas wells in MMA with TRRC records.

Well Name	Well Number	UWI	Latitude	Longitude	Operator Current	Operator Original	Total Depth(f)	Status
LAKE PLACE	B1H	424393102900	32.9191420	-97.4698666	BKV NORTH TEXAS LLC	ANTERO RESOURCES INC LP	8650	Gas Well
WILDLIFE	A1H	424393119200	32.9239294	-97.4838481	BKV NORTH TEXAS LLC	XTO ENERGY INC	10435	Gas Well
WILDLIFE A UNIT	2H	424393119600	32.9240571	-97.4837859	BKV NORTH TEXAS LLC	XTO ENERGY INC	8567	Gas Well
EAGLECREST	1H	424393124000	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	8641	Gas Well
EAGLECREST (PILOT)	1P	424393124077	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	6924	Location Only
EAGLECREST UNIT	2H	424393124400	32.9101730	-97.4670195	BKV NORTH TEXAS LLC	XTO ENERGY INC	9045	Gas Well
DAVIS UNIT	1H	424393137300	32.9008732	-97.4776844	BKV NORTH TEXAS LLC	XTO ENERGY INC	8227	Gas Well
DAVIS UNIT (PILOT)	1P	424393137377	32.9008732	-97.4776844	XTO ENERGY INC	XTO ENERGY INC	7158	Gas Well
NEILL WAYNE	1H	424393138400	32.9020862	-97.4635819	BKV NORTH TEXAS LLC	XTO ENERGY INC	8472	Gas Well
NEILL WAYNE	2H	424393138500	32.9020931	-97.4635666	BKV NORTH TEXAS LLC	XTO ENERGY INC	8889	Gas Well
WEST FORK	1H	424393162800	32.9070608	-97.4618388	BKV NORTH TEXAS LLC	SULLIVAN HOLLIS R INC	10163	Gas Well
LAKE PLACE	B2H	424393204200	32.9191465	-97.4698521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9088	Gas Well
TXU TRWD N UNIT	6H	424393221100	32.9035759	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	11683	Gas Well
TXU TRWD N UNIT	2H	424393221200	32.9040765	-97.4801342	BKV NORTH TEXAS LLC	XTO ENERGY INC	11025	Gas Well
TXU TRWD N UNIT	10H	424393223000	32.9035352	-97.4800689	BKV NORTH TEXAS LLC	XTO ENERGY INC	12585	Gas Well
TXU TRWD S UNIT	17H	424393223600	32.9029178	-97.4799856	BKV NORTH TEXAS LLC	XTO ENERGY INC	12845	Gas Well
TXU EML UNIT	A1H	424393245100	32.9089106	-97.4761473	BKV NORTH TEXAS LLC	XTO ENERGY INC	9164	Gas Well
TXU EML UNIT	A2H	424393262300	32.9089049	-97.4760521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9062	Gas Well
TXU TRWD S UNIT	13H	424393338100	32.9037054	-97.4800853	BKV NORTH TEXAS LLC	XTO ENERGY INC	13056	Gas Well

TXU TRWD S UNIT	21H	424393345100	32.9031007	-97.4805575	BKV NORTH TEXAS LLC	XTO ENERGY INC	13064	Gas Well
TXU TRWD N UNIT	12H	424393354600	32.9035061	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	13163	Gas Well
TXU EML UNIT	B1H	424393365600	32.9094039	-97.4683171	BKV NORTH TEXAS LLC	XTO ENERGY INC	10200	Gas Well
TXU EML UNIT	B2H	424393365800	32.9093921	-97.4683110	BKV NORTH TEXAS LLC	XTO ENERGY INC	10500	Gas Well
TXU EML UNIT	B3H	424393423300	32.9093969	-97.4682044	BKV NORTH TEXAS LLC	XTO ENERGY INC	9535	Gas Well
WEST FORK UNIT	3H	424393526800	32.9091561	-97.4652839	BKV NORTH TEXAS LLC	XTO ENERGY INC	9298	Gas Well
TXU TRWD NORTH UNIT	1H	424393598400	32.9032790	-97.4801794	BKV NORTH TEXAS LLC	XTO ENERGY INC	10350	Gas Well
TXU TRWD N UNIT	3H	424393598500	32.9032457	-97.4801754	BKV NORTH TEXAS LLC	XTO ENERGY INC	10694	Gas Well
TXU TRWD NORTH UNIT	5H	424393601000	32.9031750	-97.4801698	BKV NORTH TEXAS LLC	XTO ENERGY INC	11009	Gas Well
TXU TRWD NORTH UNIT	4H	424393603300	32.9032055	-97.4801726	BKV NORTH TEXAS LLC	XTO ENERGY INC	10765	Gas Well
TXU TRWD NORTH UNIT	7H	424393605300	32.9031776	-97.4801011	BKV NORTH TEXAS LLC	XTO ENERGY INC	11485	Gas Well
TXU TRWD NORTH UNIT	8H	424393605400	32.9031436	-97.4800911	BKV NORTH TEXAS LLC	XTO ENERGY INC	11846	Gas Well
TXU TRWD NORTH UNIT	9H	424393605500	32.9031212	-97.4800893	BKV NORTH TEXAS LLC	XTO ENERGY INC	12258	Gas Well
TXU TRWD NORTH UNIT	11H	424393605600	32.9030873	-97.4800851	BKV NORTH TEXAS LLC	XTO ENERGY INC	12522	Gas Well
LAKE PLACE	A7H	424393628200	32.9310611	-97.4774402	BKV NORTH TEXAS LLC	XTO ENERGY INC	11739	Gas Well
LAKE PLACE	A6H	424393628300	32.9310939	-97.4774460	BKV NORTH TEXAS LLC	XTO ENERGY INC	11470	Gas Well
EAGLECREST	4H	424393655400	32.9102140	-97.4670370	BKV NORTH TEXAS LLC	XTO ENERGY INC	8989	Gas Well
EAGLECREST UNIT	3H	424393655700	32.9101702	-97.4670211	BKV NORTH TEXAS LLC	XTO ENERGY INC	8975	Gas Well

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 such as the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita orogenic belt collision. These faults show displacement up into the base of the Pennsylvanian rocks. These larger, younger faults have greater displacement but are relatively sparce.

An east-west fault is interpreted at the south edge of the MMA, south of the Cotton Cove CCS 1 based on available subsurface data including 3D seismic data (**Figure 4**). A second, east-west fault may exist north of the MMA. These faults were included in the dynamic reservoir model as areas of enhanced permeability. Dynamic modeling indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. These faults terminate at the top of the Mississippian strata at roughly 6000 feet TVDSS, leaving roughly 6,000 feet of unfaulted Pennsylvanian shales and sands to serve as yet another secondary confining system. It is highly improbable that injected CO_2 would migrate up faults to the USDW or to the surface through faults. As there are no natural leak pathways that traverse this secondary confining system, we assess it as improbable that CO2 would reach the surface under Eagle Mountain Lake.

Karst development is present in some areas at the top of the Ellenburger. Karsting is often developed in the upper several hundred feet of an exposed carbonate (in this case, the Ellenburger Subunit A), where fresh water enters the shallow subsurface through fractures and dissolves the rock, creating underground caves with a thin roof (**Figure 20**). Subsequent loading of sediment can cause the thin cave roof to collapse, allowing the overlying sediment to fill the void (Zeng, 2011). These karsted sections of the Ellenburger were given enhanced permeability in the model as described earlier. We applied the enhanced permeability to the upper 500 feet of the Ellenburger, where karsted, as a conservative modeling assumption.

Karsting does not appear to affect any subunit of the Ellenburger below Ellenburger Subunit A, including Ellenburger Subunits B-D or the injection interval, Ellenburger Subunit E. This suggests that the Ellenburger Subunits B-D will remain a continuous upper seal for the injection interval even in karst areas. There are interpreted Ellenburger Subunit A karst features south and north of the Cotton Cove CCS 1, but the CO_2 plume does not intersect them, based on the dynamic modeling. Small karst features sitting at the northern edge of the MMA seem to have only impacted the upper 200 feet of the Ellenburger, leaving 2,000 feet of Ellenburger apparently unaffected as shown in the type log in **Figure 20**.

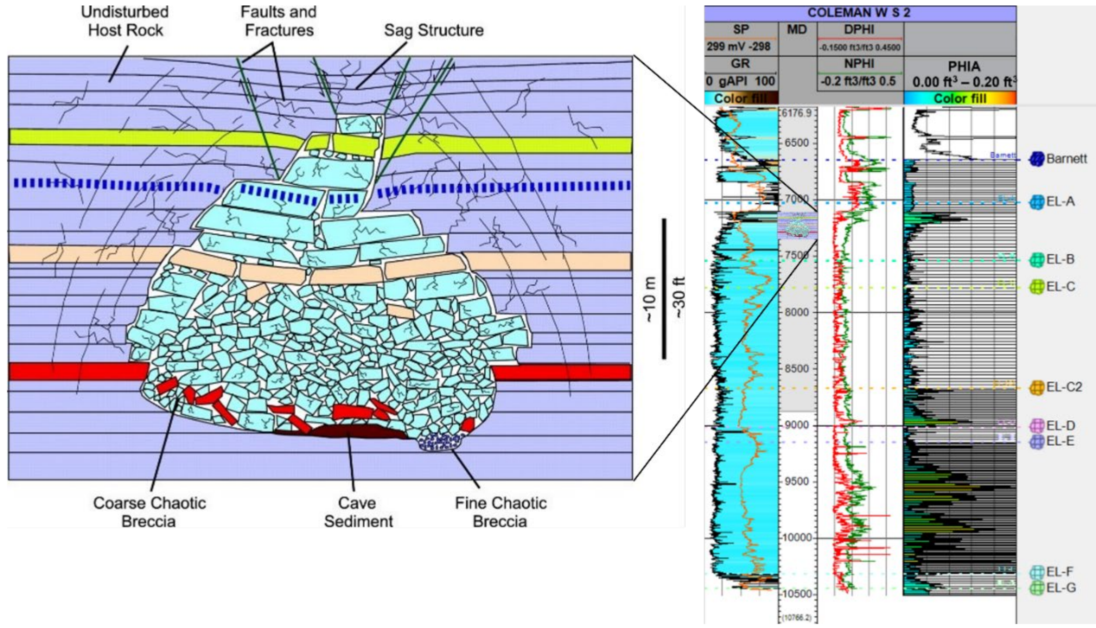


Figure 20. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al*., 2011). The typical scale of the karst features is shown on the right placing the feature on the Coleman 1 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining Ellenburger Subunits B-D and not in the modeled plume area.

5.5 Leakage Through Confining Layers

The Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D and below by the competent confining Ellenburger Subunit F. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA as described in Section 5.3.

5.6 Leakage from Natural or Induced Seismicity

The Cotton Cove CCS 1 well location is in an area of the Fort Worth Basin that has experienced seismic activity historically, as described in Section 3.5. The occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor.

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 surface pressure gauges, so that reservoir pressure and injection pressure can be modeled and monitored. Additionally, consistent with TRRC guidelines and

permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 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 and reduce the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis (Walsh, *et al.,* 2017) 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 Cotton Cove CCS 1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

Furthermore, dCarbon installed new ground seismic monitoring stations 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 have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on 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. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection site is about two degrees up to the west (200 feet/mile), shown in **Figure 21**. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles (Tarrant North SWD 1).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

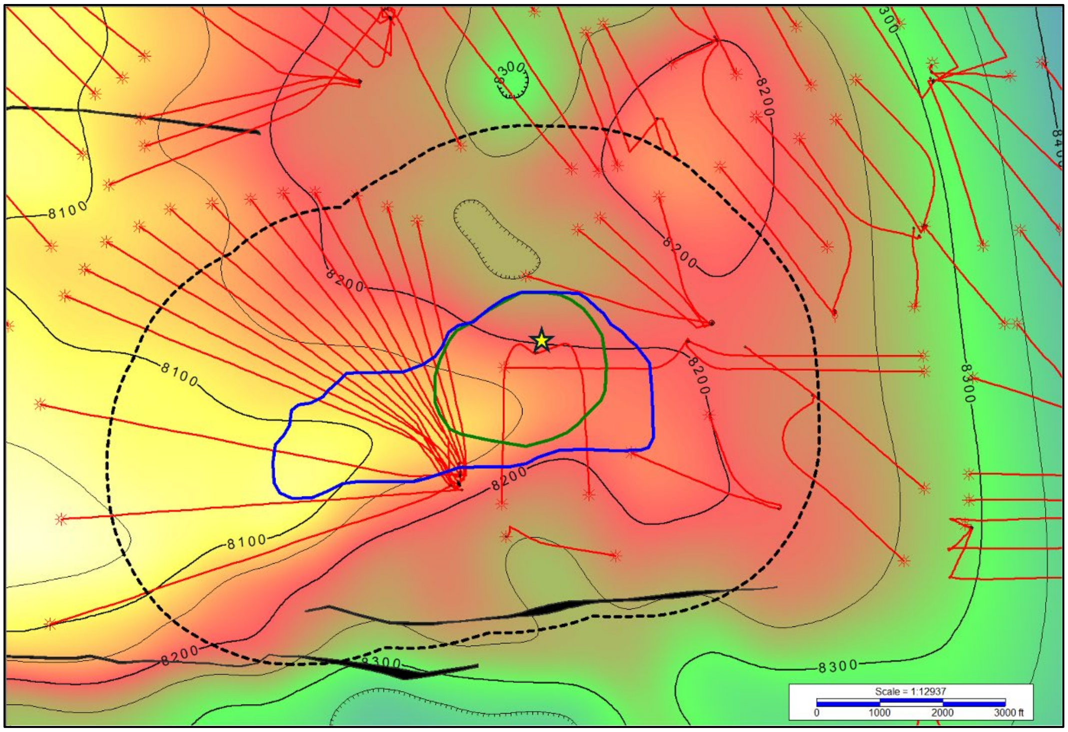


Figure 21. The Cotton Cove CCS 1 well location (yellow star) posted on a map of the top Ellenburger Subunit E depth structural contours in feet TVDSS with a contour interval of 500 feet from the simulation model. The CO_2 plume size at the end of injection (green) and 100 years post-injection and AMA/MMA are also shown as solid blue and dashed black outlines, respectively, from Figure 18. Mapped faults are shown in black.

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). This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur.

6.1 Leakage from Surface Equipment

Monitoring will occur during the planned 12-year injection period, or until the cessation of operations. 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. As the CO_2 compressor station, pipe header, and injection well are all designed to handle expected concentrations, temperatures, and pressures of 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.

Periodic 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 observations, corrective actions will be taken to address such issues.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. 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.

Additionally, CO_2 for injection will be metered with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself (**Figure 22**). The injection stream will also be sampled and analyzed periodically with a gas chromatograph to determine final composition. The meter will each be calibrated to industry standards. Any discrepancies in CO_2 throughput at the meter 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 the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate 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.

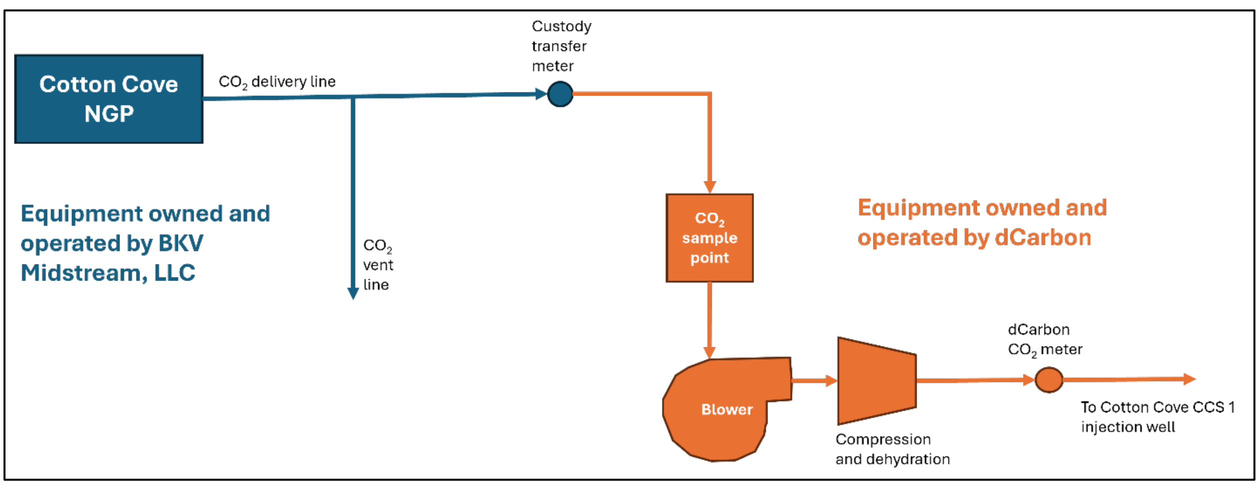


Figure 22. Project conceptual diagram with metering locations. Equipment and pipe headers in Blue are owned and operated by BKV Midstream, LLC while equipment and pipe headers in orange are owned and operated by dCarbon.

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 interval. 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, dCarbon will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will 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 in addition to pressure sensors for each annulus of the well. Annual bottomhole pressure and temperature measurements will be made to calibrate the surface readings to bottom hole. 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 gas samples quarterly 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 Cotton Cove CCS 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) 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 intervals 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 to the surface or to the USDW is improbable, given the number and thickness of competent layers between the injection interval and the USDW. Sampling of the produced gas stream from the Barnett Shale gas wells within the MMA is the primary tool for detecting CO_2 that has bypassed the primary confining system. These producing gas wells are not expected to produce any of the CO_2 injected into the Ellenburger Subunit E and will act as above

zone monitoring wells. dCarbon plans to inject a small amount of chemical tracer with the CO_2 downstream of the volumetric flow meter. Thie chemical tracer will serve as confirmation that any increase in CO_2 detected in the produced gas stream from the Barnett Shale wells in the AMA/MMA is from the sequestration reservoir.

Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems. The chemical tracer injected with the CO_2 can also be analyzed for in the groundwater sampling.

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 low, dCarbon operates a proprietary seismic monitoring array in the general area of the Cotton Cove CCS 1 well. This monitoring array augments 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 Cotton Cove CCS 1 well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, a situation that is very unlikely based on the location of mapped faults and the extent of the modeled plume.

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 four times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the only 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, like 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 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 sample the gas stream from the gas wells in the MMA. These wells should intercept CO_2 that might traverse the primary sealing interval before it bypasses the secondary seals. Noting the increase in CO_2 concentration in the produced gas stream along with the presence of the chemical tracer, will be a trigger for dCarbon to investigate and quantify possible leakage through the primary confining layers. dCarbon will document the methods used to calculate the volume of CO_2 leakage in its annual monitoring report.

dCarbon has access to a deep groundwater monitoring well at the Cotton Cove Gas Plant 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 intervals. 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. dCarbon will conduct baseline sampling of available water wells within the MMA prior to injection to establish a basis for comparison to later samples.

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 works with environmental services and data companies that specialize 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 may also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with high-fidelity CO_2 sensors 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 the X and Y axes (longitude + latitude) as well as the 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) (Korre, 2011). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. 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 (Chen, 2013).

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 Cotton Cove CCS 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.

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). There are three primary monitoring baselines that dCarbon will establish as part of this project.

Baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells 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 gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA that are acting as above-zone monitoring wells. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline seismicity in the area near the Cotton Cove CCS 1 has been determined through the historical data from USGS and TexNet seismic array data. This information is augmented by additional data from dCarbon's proprietary seismic monitoring array, operating since 2023.

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 Cotton Cove CCS 1 injection well will be 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
$C_{CO2,p,u}$	=	CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year

u = Flow meter

8.3 Mass of CO_2 Produced

The Cotton Cove CCS 1 injection well will receive CO_2 produced from the nearby Cotton Cove Gas Plant and will be used for injection only. No CO_2 will be produced from this well. Additionally, the injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

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. 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 CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 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 on 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 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
$CO_{2,E}$	=	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.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in 2026 and that will be the date that data to calculate the total volume of CO_2 sequestered will begin to be collected. Baseline monitoring data will be collected beginning in 2025 and the MRV plan will be implemented upon receiving EPA MRV plan approval. The exception to the monitoring baseline data is the seismicity baseline data which began in 2017 with the TexNet monitoring system.

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 reported 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, if employed, will be operated continuously, except for maintenance and calibration.
- Gas detectors, if employed, 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 most recent 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 five 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.

12 – REFERENCES

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Attachment A

Copies of W-14, W-1, Drilling Permit

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

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

PERMIT NO. 17534

BKV DCARBON VENTURES, LLC
4800 BLUE MOUND ROAD
FORT WORTH TX 76106

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated September 12, 2024, for the permitted interval(s) of the Ellenburger formation(s) and subject to the following terms and special conditions:

COTTON COVE CCS (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
TARRANT COUNTY
DISTRICT 05

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	43900000	000126822	Carbon Dioxide (CO_2)	8806	11150	4000	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	43900000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval. 2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation. 3. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata. 4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW. 5. (A) The operator shall notify the Commission within 24 hours of a discovery of any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; or any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Within 20 days of such a discovery, the operator shall file a report with the Commission documenting the event, findings, and response actions taken. (B) The permittee shall report the source(s) and the properties of injected acid gas as they are added. In no case may the volume of acid gas exceed the limit indicated in permit. (C) The well's construction and materials used must be resistant to corrosion per the proposed wellbore schematic that was submitted in the application. 6. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.**

STANDARD CONDITIONS:

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

Note: This document will only be distributed electronically.

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

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

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

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

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

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

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

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

APPROVED AND ISSUED ON September 27, 2024.

for Ivan Salas, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

API No. 42-439-37356

Drilling Permit # 902971

SWR Exception

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No.: 100589
2. Operator's Name (as shown on form P-5, Organization Report): BKV DCARBON VENTURES, LLC
3. Operator Address (include street, city, state, zip): 4800 BLUE MOUND ROAD, FORT WORTH, TX 76106
4. Lease Name: COTTON COVE CCS
5. Well No.: 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth: 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No.: 05
12. County: TARRANT
13. Surface Location: [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4 miles in a NW direction from Alze which is the nearest town in the county of the well site.

15. Section:
16. Block:
17. Survey: GARCIA, M
18. Abstract No.: A-564
19. Distance to nearest lease line: ft.
20. Number of contiguous acres in lease, pooled unit, or unitized tract: 2.22

21. Lease Perpendiculars: 144 ft from the S line and 133 ft from the E line.

22. Survey Perpendiculars: 296 ft from the N line and 1131 ft from the E line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION — List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

Certificate:

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

Bill Spencer, Consultant — Name of filer

Sep 30, 2024 — Date submitted

(512)9181062, x2 — Phone

bill@spencerconsulting.org — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Oct 1, 2024 2:05 PM(Current Version)

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director's delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

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

PERMIT NUMBER 902971	DATE PERMIT ISSUED OR AMENDED Oct 01, 2024	DISTRICT 05
API NUMBER 42-439-37356	FORM W-1 RECEIVED Sep 30, 2024	COUNTY TARRANT
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 2.22
OPERATOR 100589 BKV DCARBON VENTURES, LLC 4800 BLUE MOUND ROAD FORT WORTH, TX 76106		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (903) 984-3026
LEASE NAME COTTON COVE CCS		WELL NUMBER 1
LOCATION 4 miles NW direction from ALZE		TOTAL DEPTH 12000

Section, Block and/or Survey
SECTION BLOCK ABSTRACT 564
SURVEY GARCIA, M

DISTANCE TO SURVEY LINES 296 ft. N 1131 ft. E	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 144 ft. S 133 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE) COTTON COVE CCS	2.22 0	12,000	1	09

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

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

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

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

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION
SWR #13 Formation Data

TARRANT (439) County

Formation	Remarks	Geological Order	Effective Date
CADDO		1	12/17/2013
BARNETT SHALE	May be prorated into District 9	2	12/17/2013
ELLENBURGER		3	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

Request for Additional Information: Cotton Cove CCS 1
February 18, 2025

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.4	14	We recommend revising Figure 8 to ensure that it is legible. E.g., the injection wells and the units for fluid chemistry are difficult to interpret.	Revised Figure 8 to make it legible, updated Table 3 and Figure 8 to exclude one well outside of the Fort Worth Basin that had been classified by the USGS as in the basin.
2.	4.2	31	"As defined in 40 CFR § 98.449, the AMA must be delineated by superposition of: (1) The area projected to contain the free phase CO2 plume at the end of year 12, plus an all-around buffer 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 CO2 plume at the end of year 17." Because MRV plans cannot modify the definitions in 40 CFR Part 98, we recommend changing the phrasing of this first sentence to something akin to: "Based on the definitions in 40 CFR § 98.449 and an initial time interval of t=12, we defined our AMA by superimposing the following:"	We have modified the language in Section 4.2 as suggested.
3.	5	33	"Table 6 describes the basis for event likelihood and Table 6 provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk." Please review this sentence to determine whether Table 7 should be referenced here.	Changed the second reference to "Table 6" to "Table 7" in Section 5

4.	5.2	35	"There are no active well permits within the MMA other than the Cotton Cove CCS 1 well." There are numerous references to the producing Barnett Shale wells on pages 10, 34, 36, 39, 43, 44, 46, and 49. Please clarify this statement in the MRV plan.	Changed the sentence to "There are no active approved, not yet drilled well permits within the MMA other than the Cotton Cove CCS 1 well." to align the section to the heading.
5.	8.3, 8.5	49	"Should it be determined that CO2 has bypassed the primary confining system and Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO2 sequestered at the facility." We recommend adding a similar statement in section 8.3 regarding calculating CO2 produced from wells.	Modified the statement in 8.5 and added it also into 8.3: "Should it be determined that CO2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO2 sequestered at the facility."

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

Cotton Cove CCS 1

NW Tarrant County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 2.0

January 16, 2025

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 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Cotton Cove CCS 1 injection well in Tarrant County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2, into the Cotton Cove CCS 1 injection well (CCS 1). produced by the nearby Cotton Cove Gas Plant (Gas Plant), operated by BKV Midstream, LLC (TCEQ CN604046912) which is a separate, pre-existing facility. The CCS 1 and the Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category, making them separate and distinct facilities under 40 CFR 98.6. The project site is located approximately four miles east-northeast of Azle, Texas, as shown in **Figure 1**. dCarbon anticipates drilling the Cotton Cove CCS 1 well in Q1 2025 and completing and beginning injection operations in 2026. The Cotton Cove CCS 1 has an approved W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the TRRC (UIC number 000126822, API number 42-439-37356). 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 close to the maximum injection amount allowed by the TRRC permit (75,744 MT/yr). dCarbon plans to inject for approximately 12 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 Cotton Cove CCS 1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 589741. All aspects of this MRV plan refer to this well and this GHGRP ID number.

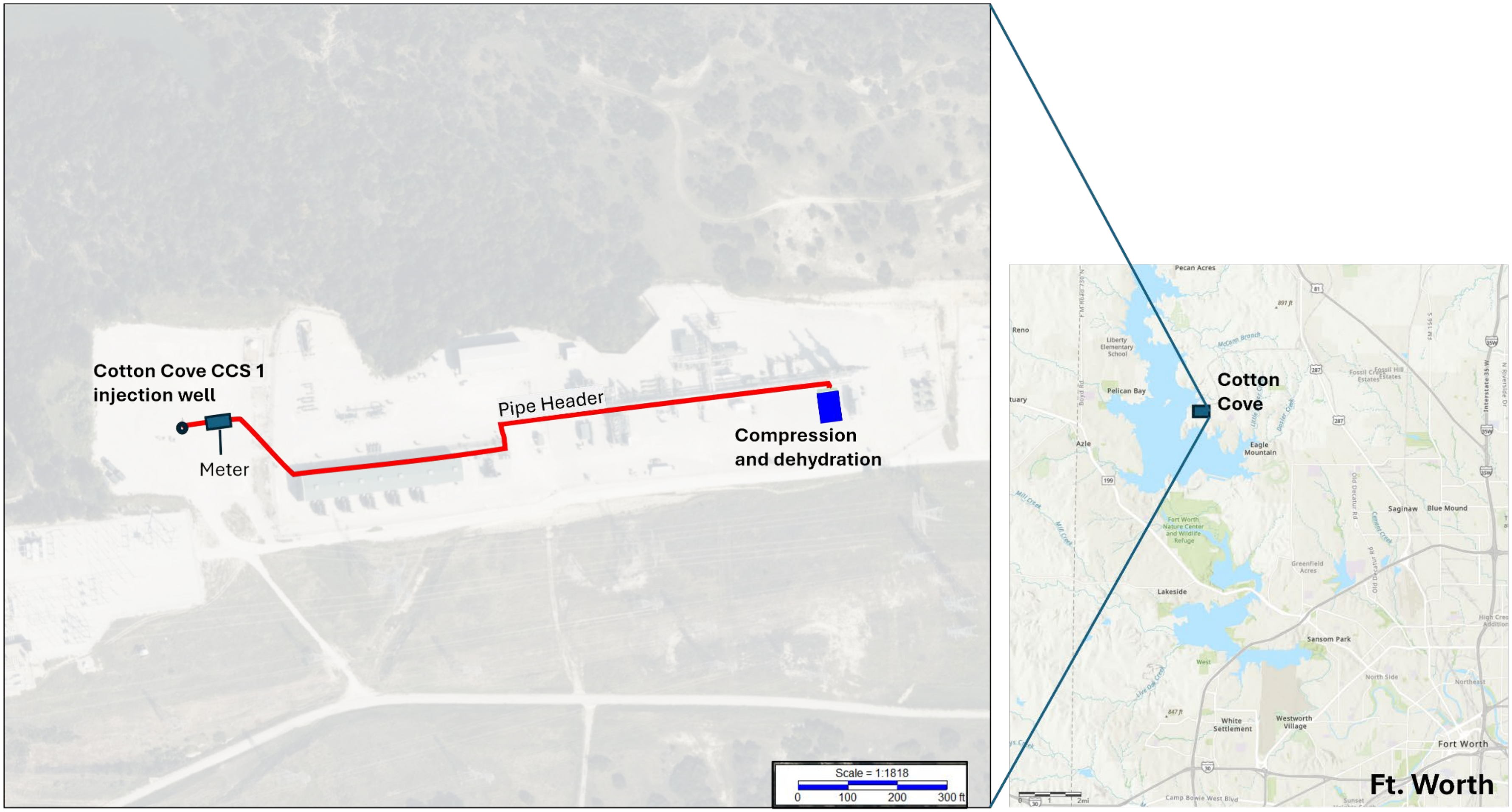


Figure 1. Location map for the Cotton Cove CCS 1 well in Tarrant County Texas. The well is planned to be drilled immediately west of the Cotton Cove Gas Plant that captures the CO_2 to be injected. North is up.

2 – FACILITY INFORMATION

Facility Name:

Cotton Cove Gas Plant (TCEQ CN604046912)

Address: 10055 Morris Dido Newark Road, Fort Worth, TX 76179

Latitude: 32.90927778

Longitude: -97.46976667

GHGRP ID number: 526203

FRS ID: 110040511256

NAICS Code: 211111

Reporting structure: Currently reporting under Subpart C, Subpart W, and Subpart RR.

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the Texas Railroad Commission (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 Cotton Cove CCS 1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Cotton Cove CCS 1

API number: 42-439-37356

UIC number: 000126822

Cotton Cove CCS 1, GHGRP ID: 589741

The Cotton Cove CCS 1 well will be disposing of CO_2 from the Cotton Cove Gas Plant. All aspects of this MRV plan refer to the Cotton Cove CCS 1 well and GHGRP 589741.

3.1 OVERVIEW OF GEOLOGY

The proposed injection site lies in the northwestern part of Tarrant County, where the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. The north to south cross section of **Figure 2** shows the Ellenburger and overlying formations dipping down to the north. One inference from these cross sections is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward and southward, which is towards the Bend Arch. The dip direction is further represented in the structure contour map of the Ellenburger Group top (Pollastro, 2007) in **Figure 2**.

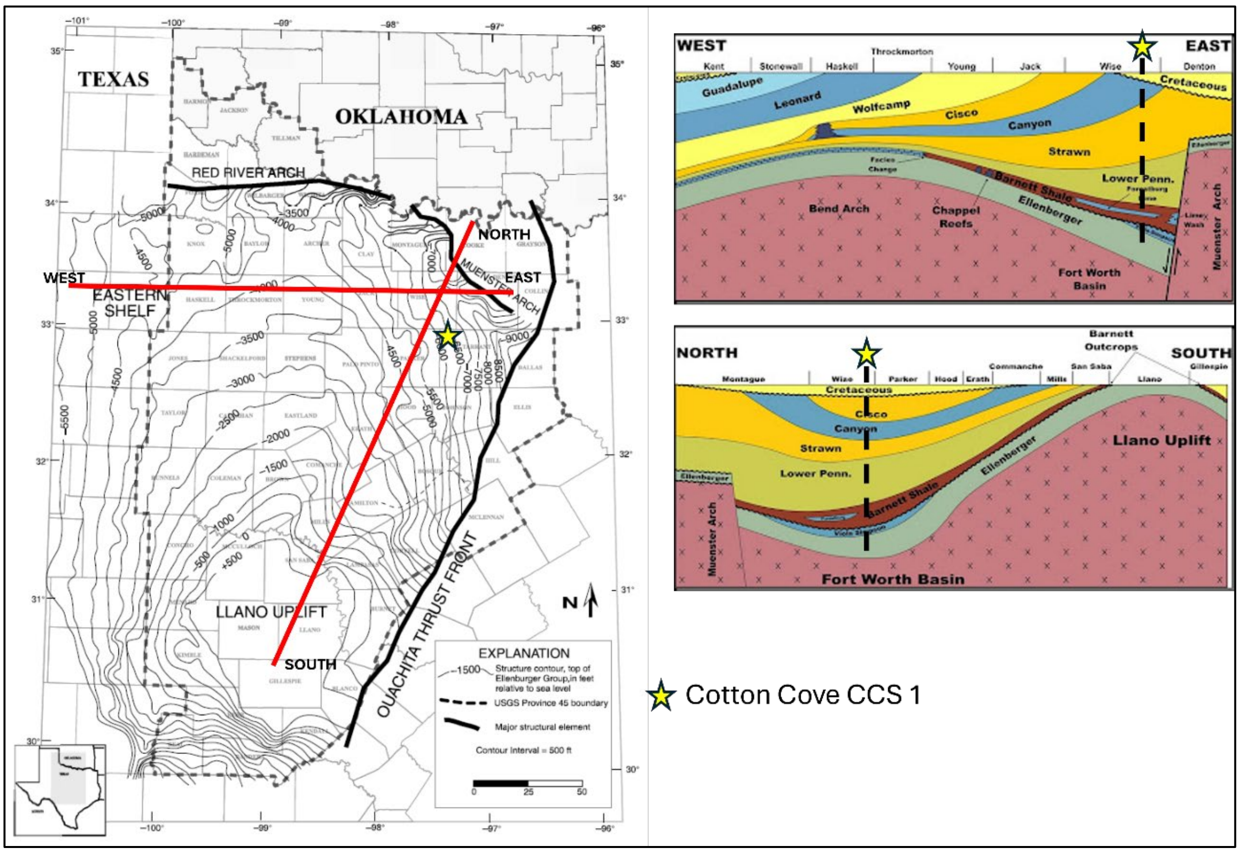


Figure 2. (*Left*) Ellenburger structure map modified from Jarvie *et al.* (2007) showing the regional structures within and bounding the Fort Worth Basin. The Ellenburger structural contours are depicted in feet True Vertical Depth Subsea (TVDSS) at an interval of 500 feet and the final Cotton Cove CCS 1 location is shown by a yellow star. (*Right*) Cross sections from W-E (top right) and N-S (middle right) show the regional dip of the sedimentary units in the Fort Worth Basin modified from Bruner *et. al.*, (2011), also with a yellow star and dashed black line indicating the position of the Cotton Cove CCS 1 well.

The Fort Worth Basin sedimentary succession began with the deposition of locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (**Table 1**). Ordovician age Ellenburger platform carbonates were deposited

next on a passive margin and are up to 4,000 feet thick 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 Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group (Gao, 2021). 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 Formation. The Ellenburger Group directly overlies the basement rock and is considered the main injection target.

Table 1. Regional Stratigraphy at Cotton Cove CCS 1 Site in North Texas.

SYSTEM	SERIES	STAGE	GROUP OR FORMATION	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian		Barnett	Upper Barnett Shale
				Forestburg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Upper		Viola Group	
			Simpson Group	
	Lower		Ellenburger Group	
Precambrian			Basement	

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, the planned injection and confining intervals or zones (terms interval and zone used interchangeably), the planned injection volumes and process, and the reservoir modeling performed for the proposed Cotton Cove CCS 1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Tarrant County, Texas.

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. 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 in 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 in the south.

3.2.2 Stratigraphy

The Ellenburger Group in the Fort Worth Basin contains alternating limestone and dolostone lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into eight subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.* (2019). The main target storage reservoir, Ellenburger Subunit E, was identified based on the dominant dolostone lithology, gross and net reservoir thicknesses, porosity values, and permeability values. The Ellenburger Subunit B and the stratigraphic top portion of Ellenburger Subunit C were identified as the caprock based on the dominant limestone lithology, thickness, porosity, and permeability values. Below this interval, there are layers of tighter limestone throughout Ellenburger Subunits C, C2, and D that would also act as sealing units to the underlying Ellenburger Subunit E storage interval.

The Barnett RDC 1 well (API number 42-497-38108), located approximately 27 miles northwest of the proposed Cotton Cove CCS 1 injection well, was used to calibrate well-log-based petrophysical properties since it has modern well logs and core data (**Figure 3**). The Tarrant North SWD 1 well (API number 42-439-31228), located approximately six miles to the northeast, was also used in well correlations and thickness calculations because of its closer proximity. Dominant lithologies were determined by comparing the photoelectric factor log curve and the separation of the density and neutron porosity curves in the Tarrant North SWD 1 well with the volume of clay, sand, lime, dolomite, gas, and free water calculated in the Barnett RDC 1 well. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

Figure 3 shows the correlation of the Barnett RDC 1 to the Cotton Cove CCS 1 site, including the Tarrant North SWD 1, as noted by the well names posted on the map and at the base of the well

logs in the cross section. Ellenburger Subunits A through F are present and appear to be contiguous in the project area. The thickness of Ellenburger Subunits B-D is approximately 2,000 feet while Ellenburger Subunit E thickness varies across the cross-sections. It is estimated there is at least 2,000 feet of Ellenburger Subunits B-D and 1,000 feet of Ellenburger Subunit E at the Cotton Cove CCS 1 proposed location.

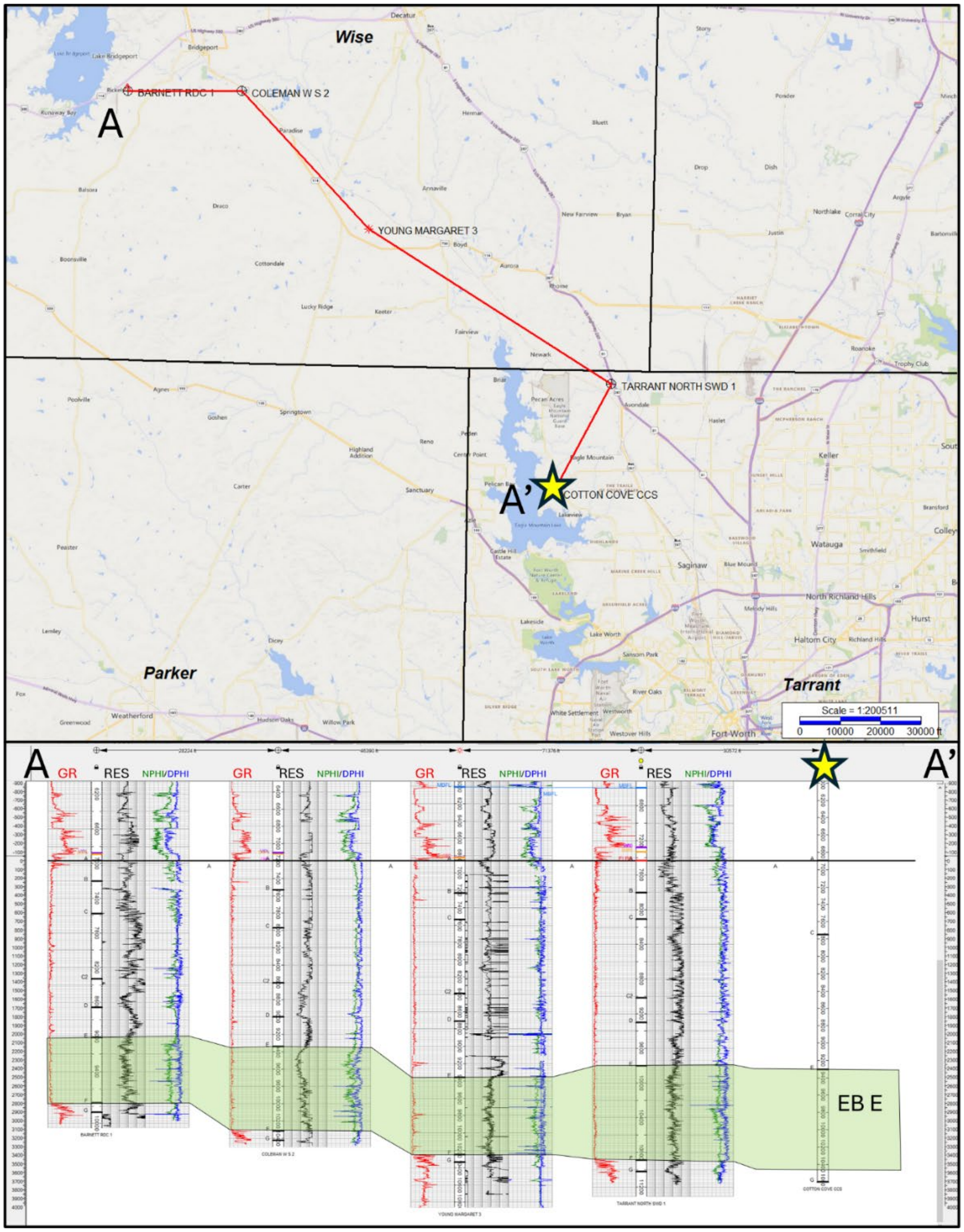


Figure 3. (*Top*) Map of north Texas, including Wise and Tarrant Counties, with the Cotton Cove CCS 1 (yellow star) and a NW-SE stratigraphic cross section (A-A'). North is up. (*Bottom*) Cross section, datumed on the top of the Ellenburger Subunit A, showing Gamma Ray (GR), Resistivity (RES), Neutron Porosity (NPHI), and Density Porosity (DPHI) from the Barnett RDC 1 well to the Tarrant North SWD 1 well. Ellenburger Subunit E (EB E) is the storage interval.

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 (**Figure 4**). A secondary set of east-west faults appear to connect these major trends. 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 present, suggesting that faults have not experienced significant movement since their formation (Wood, 2015). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Formation.

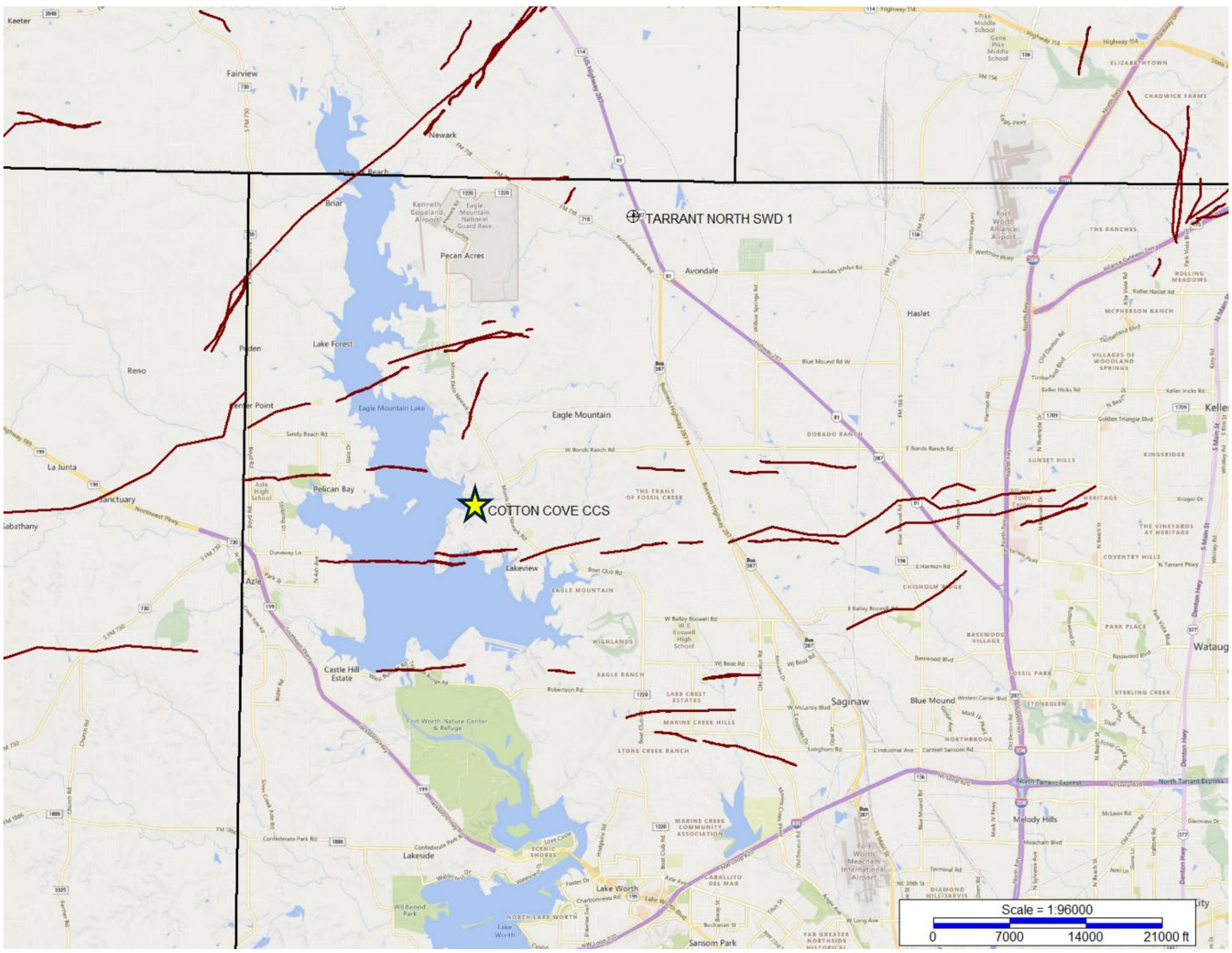


Figure 4. Mapped faults (brown lines) at the top Ellenburger level, near the proposed injection well, from Wood (2015) and internal mapping. North is up.

3.3 LITHOLOGICAL AND RESERVOIR CHARACTERIZATIONS

Smye *et al*. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Upper Cambrian to Ordovician. Prior to understanding the petrophysical 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. 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 strata highlighted by red dashed box in **Figure 5**. The Viola and Simpson Groups are expected to overlie Ellenburger Subunit A at the Cotton Cove CCS 1 site as depicted on the right side of the highlighted column.

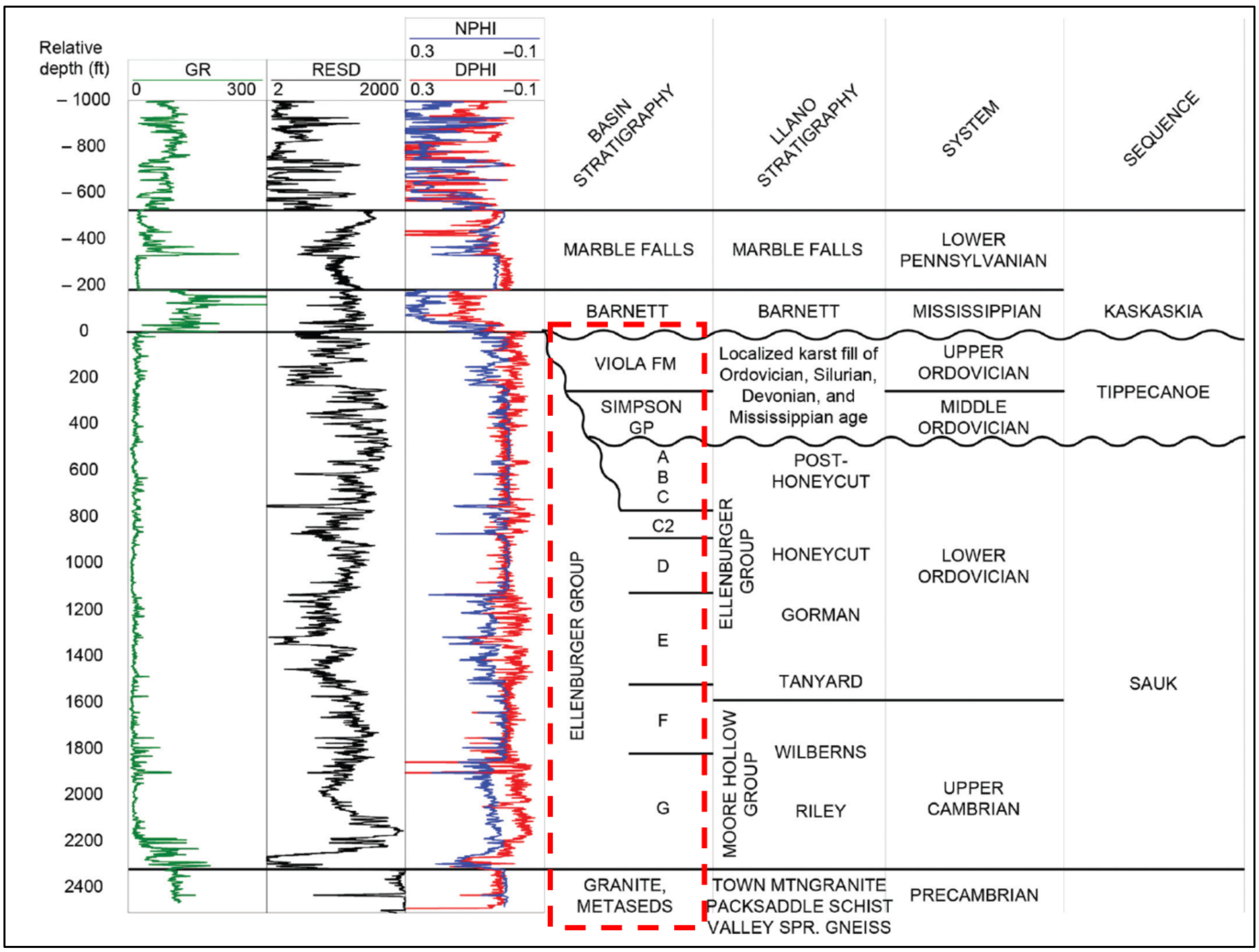


Figure 5. Regional stratigraphy at Cotton Cove CCS 1 site in north Texas (modified from Smye *et al.,* 2019). Red dashed box highlights the section of focus for the lithological characterization.

The Simpson and Viola Groups are anticipated to serve as the secondary confining interval at the Cotton Cove CCS 1 location. The Barnett Shale, located above the Viola Group, 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 range from 4-6% and 7-50 nanodarcies, respectively. These

low porosities and permeabilities are characteristic of conventional seals and, as such, the Barnett serves as an additional confining interval. The wells in the project area produce unconventional gas from the Barnett Shale.

Underlying the Viola and Simpson Groups are the informal Ellenburger lettered units defined by Smye *et al.*, 2019, which contains both the anticipated storage and confining intervals. The Ellenburger was divided into eight lithostratigraphic units starting with Ellenburger Subunit A at the top to Ellenburger Subunit G at the bottom which sits on top of the crystalline basement. Ellenburger Subunit G is not seen on well logs sufficiently to confirm that it is present in the area. Ellenburger Subunit F may sit on the crystalline basement in the area and serves as the lower seal for the reservoir. Core data from the Barnett RDC 1 showed Ellenburger Subunit F had porosities below 2% and permeabilities below 0.005 millidarcies, making it an excellent lower seal. Ellenburger Subunit E will serve as the storage interval. It is characterized as a clean dolomitic reservoir with 49% dolomite by volume and approximately 4% matrix porosity. Ellenburger Subunits B and C were found to have lower matrix porosities compared to Ellenburger Subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger Subunit A has been proven to have reservoir characteristics with multiple saltwater disposal wells completed in Ellenburger Subunit A. Karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Ellenburger Subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger Subunits A-G.

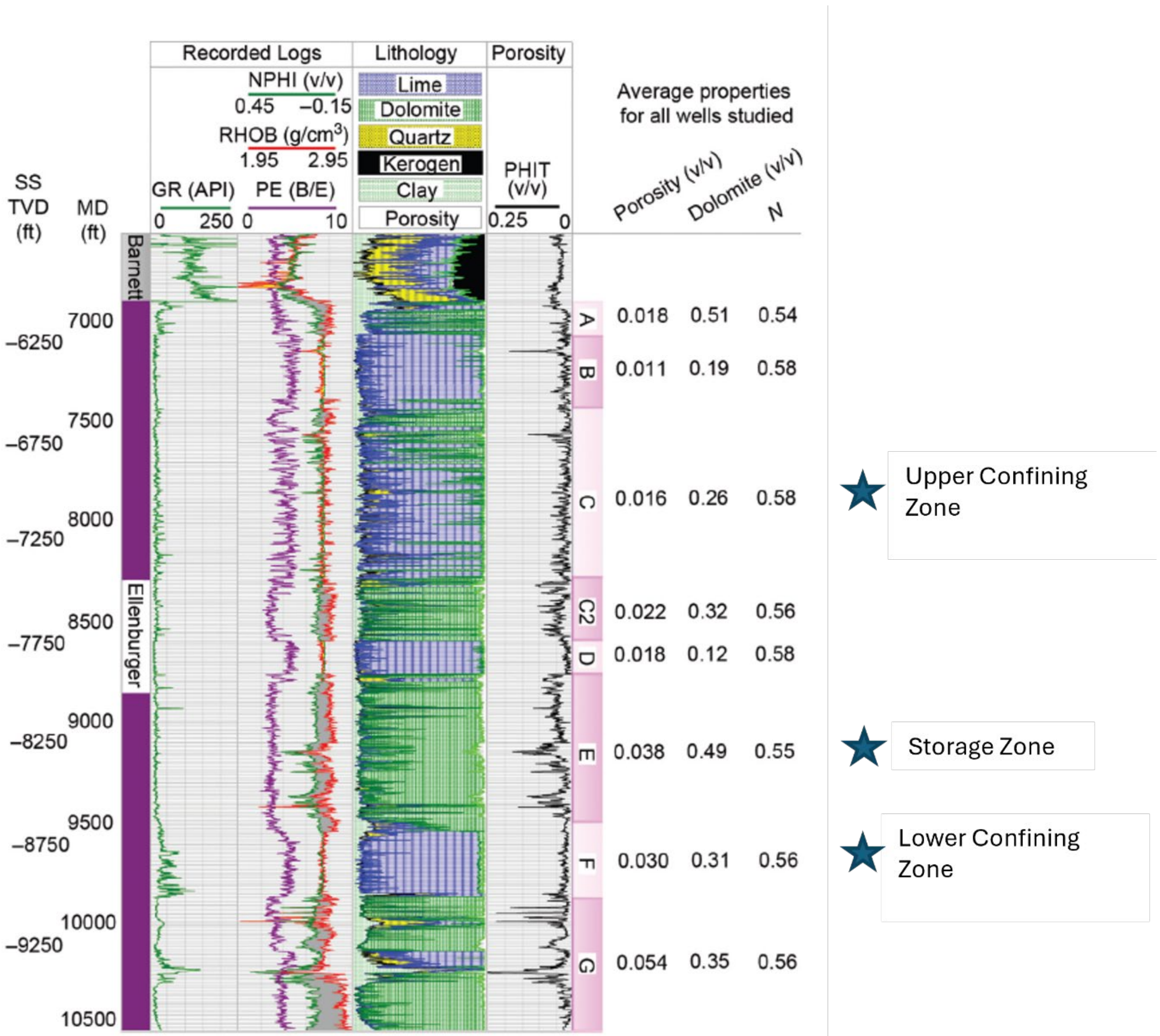


Figure 6. General properties of Ellenburger Subunits A-G in the project area (modified from Smye *et al.*, 2015).

The Barnett RDC 1 injection well located approximately 27 miles northwest of the proposed injection site also contains Ellenburger Subunits A through F, as shown below in **Figure 7**. Drilling at the proposed site should result in reservoir and seal intervals like those shown in both **Figures 6 and 7**.

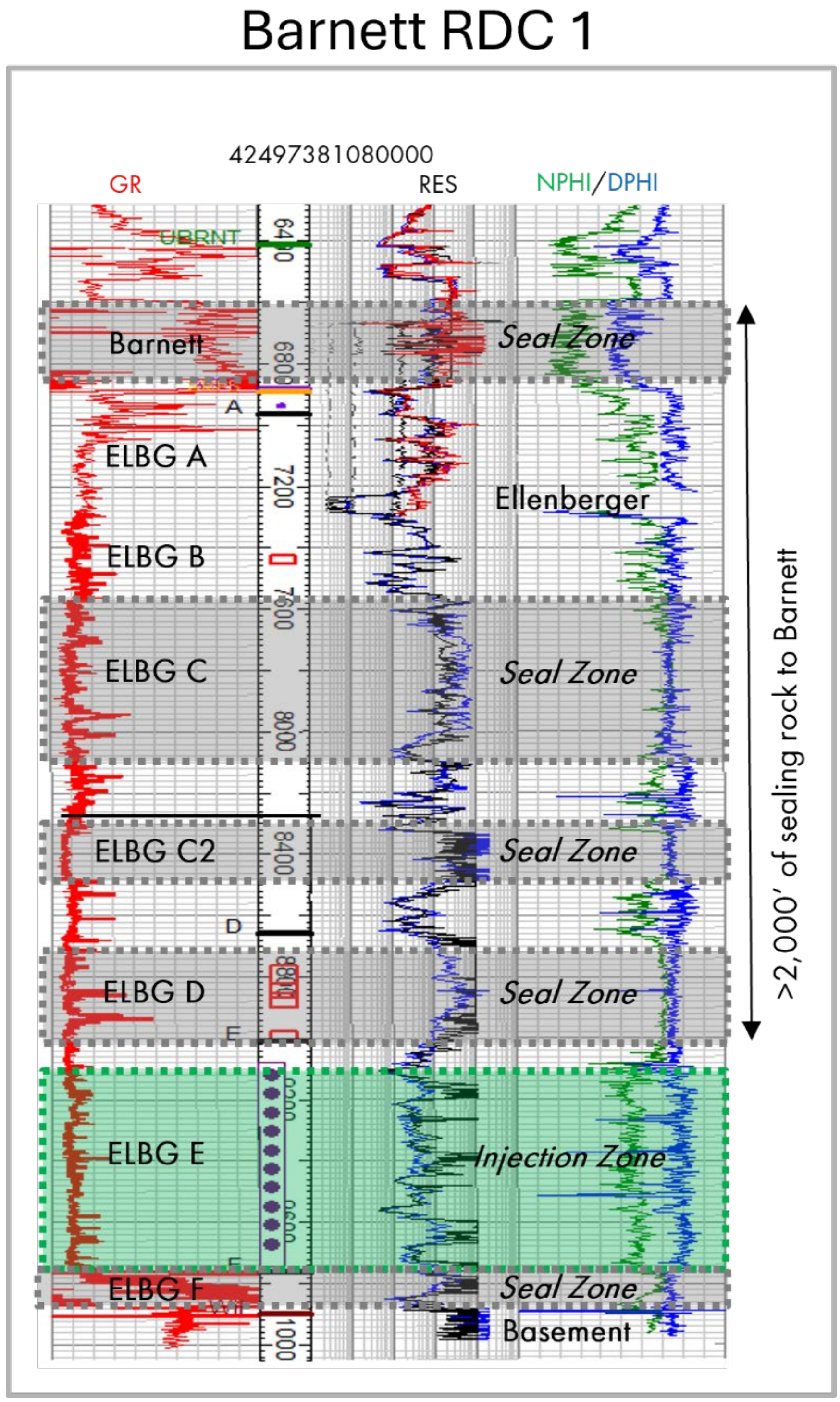


Figure 7. Barnett RDC 1 well log interpretation; Ellenburger Subunits A through F are shown on the log image.

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 as the cut-off because fractures greatly enhance

permeability and improve Ellenburger reservoir quality even in intervals with very low matrix porosity.

Saltwater disposal into analogous Ellenburger intervals with low porosity lend support to the premise that a low log porosity could still result in realizable CO_2 storage potential (*e.g.*, Tarrant North SWD 1). 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 interval properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger as seen in the Tarrant North SWD 1 well.

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

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHIA])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolostone	372	160	0.43	3.3	
B	Limestone	307	25	0.08	1.3	Upper Confining Interval
C	Limestone	906	284	0.31	2.4	
C2	Dolostone	281	88	0.31	2.5	
D	Limestone	502	288	0.57	3.5	
E	Dolostone	1087	700	0.64	4.2	Storage Interval
F	Limestone	136	4	0.03	1.1	Lower Confining Interval
G	Dolostone	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature and informed by the core data from the Barnett RDC 1 well. Regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.5 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.25°F per 100 feet using the well logs from the Tarrant North SWD 1.

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 v3.0, six wells within in the Fort Worth Basin were identified with water samples from the Ellenburger as shown in **Figure 8**.

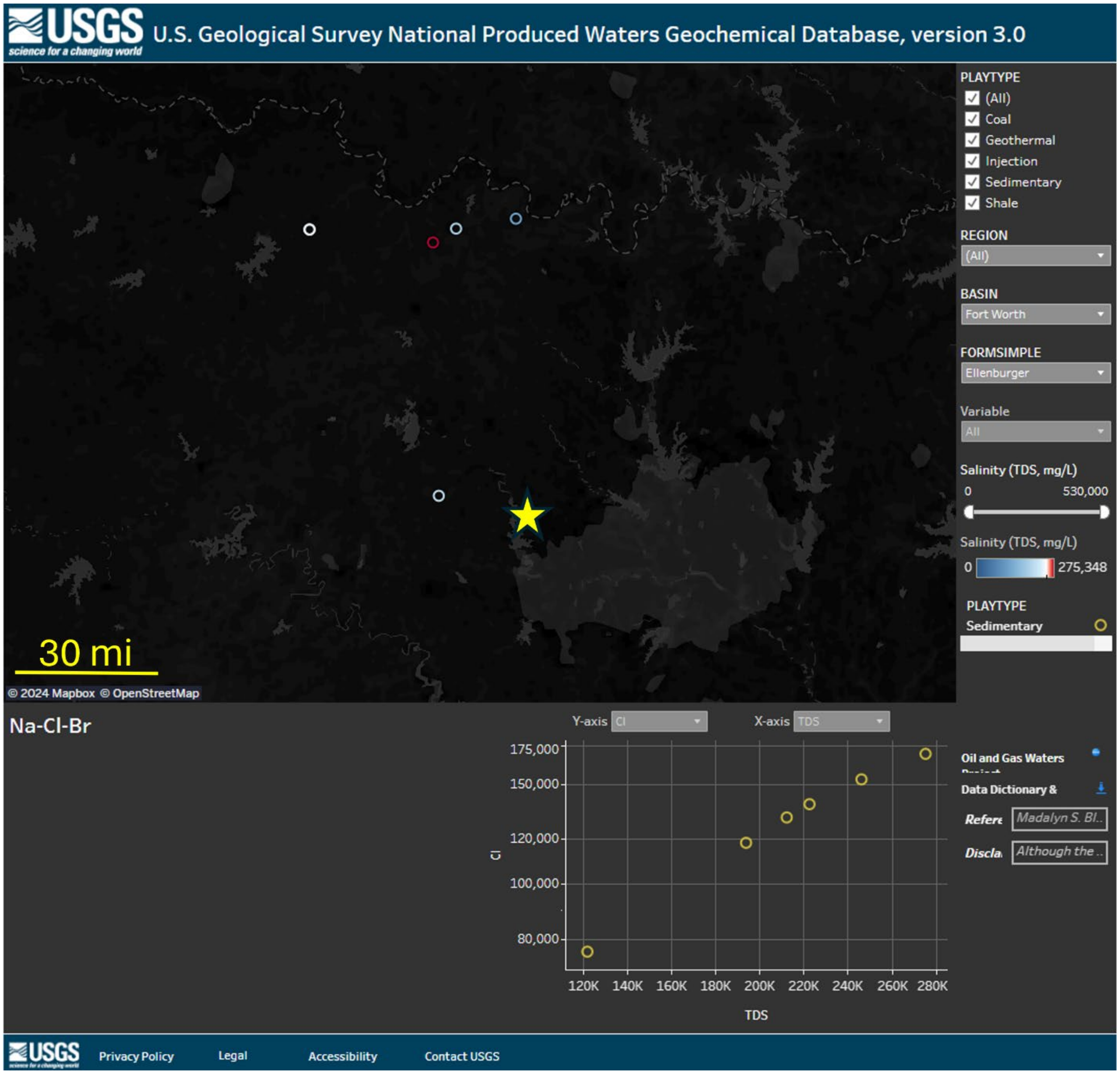


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis. The Cotton Cove CCS 1 location is shown with the yellow star. North is up.

The Ellenburger Group is not productive of oil and gas 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. The USGS database indicates that Ellenburger fluids have greater than 190,000 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin as reported in **Table 3**. The average of the six samples available in the USGS database is very close to the TDS value that dCarbon obtained from the Barnett RDC 1 well. The well sample had 214,612 ppm TDS, a pH of 7.4, an Na concentration of 54,465 ppm, a Ca concentration of 22,269 ppm, and a Cl concentration of 128,819 ppm.

Table 3. Ellenburger Formation fluid chemistry. These values are derived from the six wells depicted in Figure 8.

	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 Formation

An analysis of historical seismic events within 100 square miles surrounding the proposed Class II well injection site shows seismic activity dating back to 1900, according to the U.S. Geological Survey (USGS) Earthquake Catalog (**Figure 9**). Of the nine earthquakes above magnitude 3.0 shown on the map, three fall within the 100 square-mile area. All but one of the nine earthquakes appear to be part of the Azle-Reno earthquake swarm, documented by Hornbach, *et al*. (2015) (**Figure 10**). The Azle-Reno swarm earthquakes were mapped back to an NNE-SSW basement-rooted fault and its antithetic fault via data from a local earthquake network and advanced hypocenter location techniques. It is likely that the wide scatter in the mapped earthquake locations seen in the USGS catalog is a function of the location uncertainty due to the sparse recording array rather than actual separation of earthquake hypocenters.

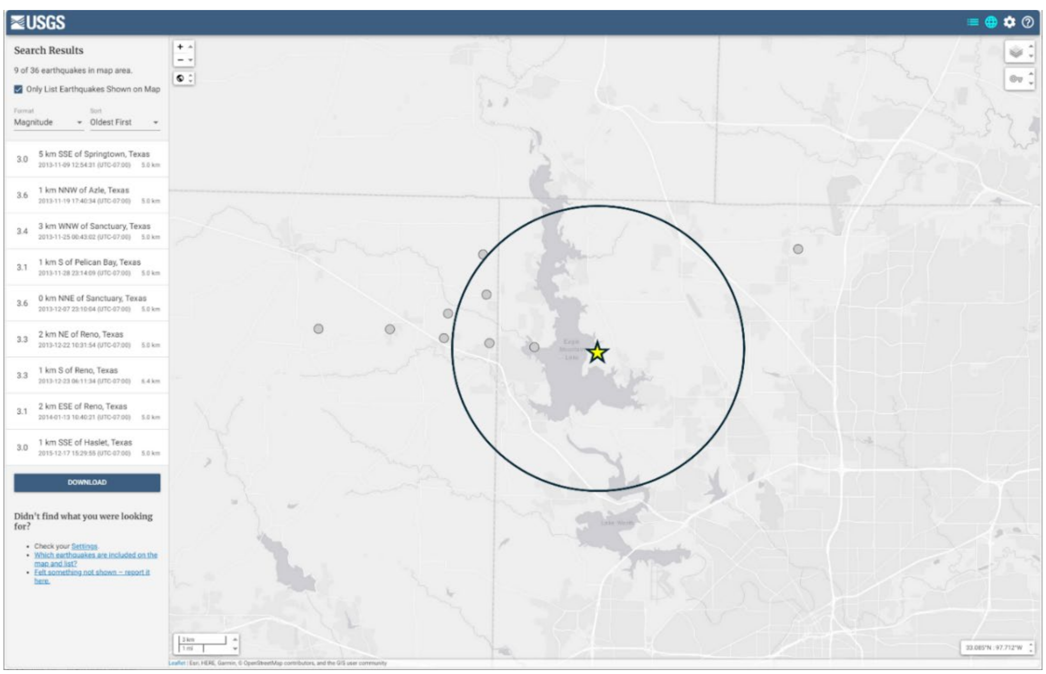
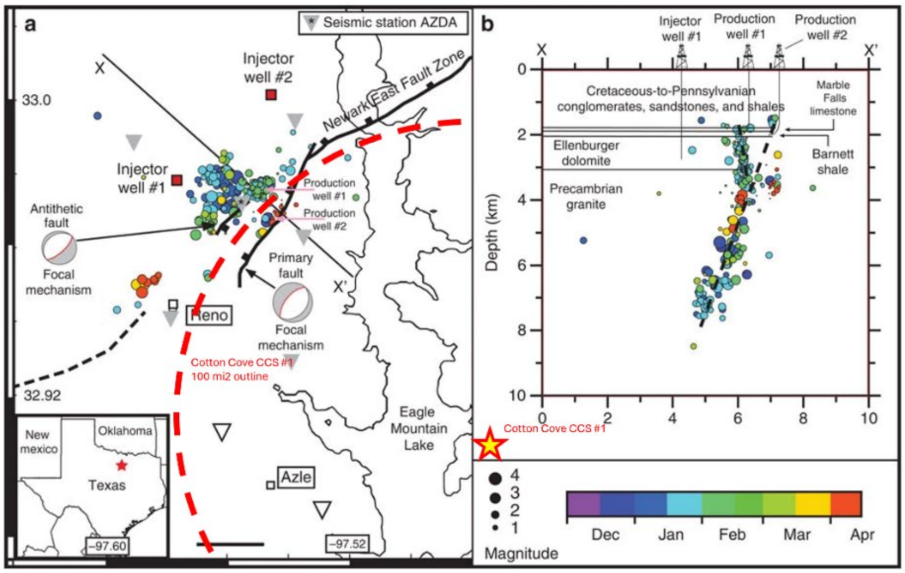


Figure 9. Screenshot from the USGS Earthquake Catalog showing historical seismic activity at or above Magnitude 3.0 in the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. Three seismic events meet these criteria in the USGS catalog. North is up.

Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey (Hennings, *et al.*, 2019). Current findings show that steeply dipping faults that strike north-northeast have the highest fault slip potential. These results are consistent with the orientation of the faults that produced the Azle-Reno swarm. No additional earthquakes have been reported since 2015 despite several saltwater disposal wells that inject in the Ellenburger Group continuing to operate in the area. Beginning in August 2023, BKV began operating a local earthquake network covering portions of Wise, Denton, Parker and Tarrant Counties in Texas (**Figure 11**). No earthquakes have been detected within the 100 square-mile area surrounding the Cotton Cove CCS 1 location with this array since it began recording.



Map showing the location of NEFZ (black) at the top of the Ellenburger formation, inferred faults (dashed) at the top of the Ellenburger formation, injection wells (red squares), two production wells (API 36734045 and 36734139) with significant brine production near the faults (pink arrows) and earthquake epicentres (coloured circles) recorded by the temporary seismic network (triangles) (**a**). The red star in the inset of **a** shows the map location. The black scale bar in **a** is 2 km. Grey (white) triangles indicate the locations of active (inactive) seismic stations. Line X–X′ in **a** shows the location of the cross-section shown in (**b**). We interpret two faults based on earthquake location and consistent with industry interpretations: a primary normal fault and a shallower antithetic normal fault.

Figure 10. Modified from a map from Hornbach *et.al.*, 2015. Earthquake hypocenters for the 2013-14 Azle-Reno swarm were located using a local array of seismometers resulting in reduced location uncertainty. Earthquakes were clustered along a northwest-dipping normal fault and it's southeast-dipping antithetic fault. These earthquakes cluster just outside of the line marking the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. North is up.

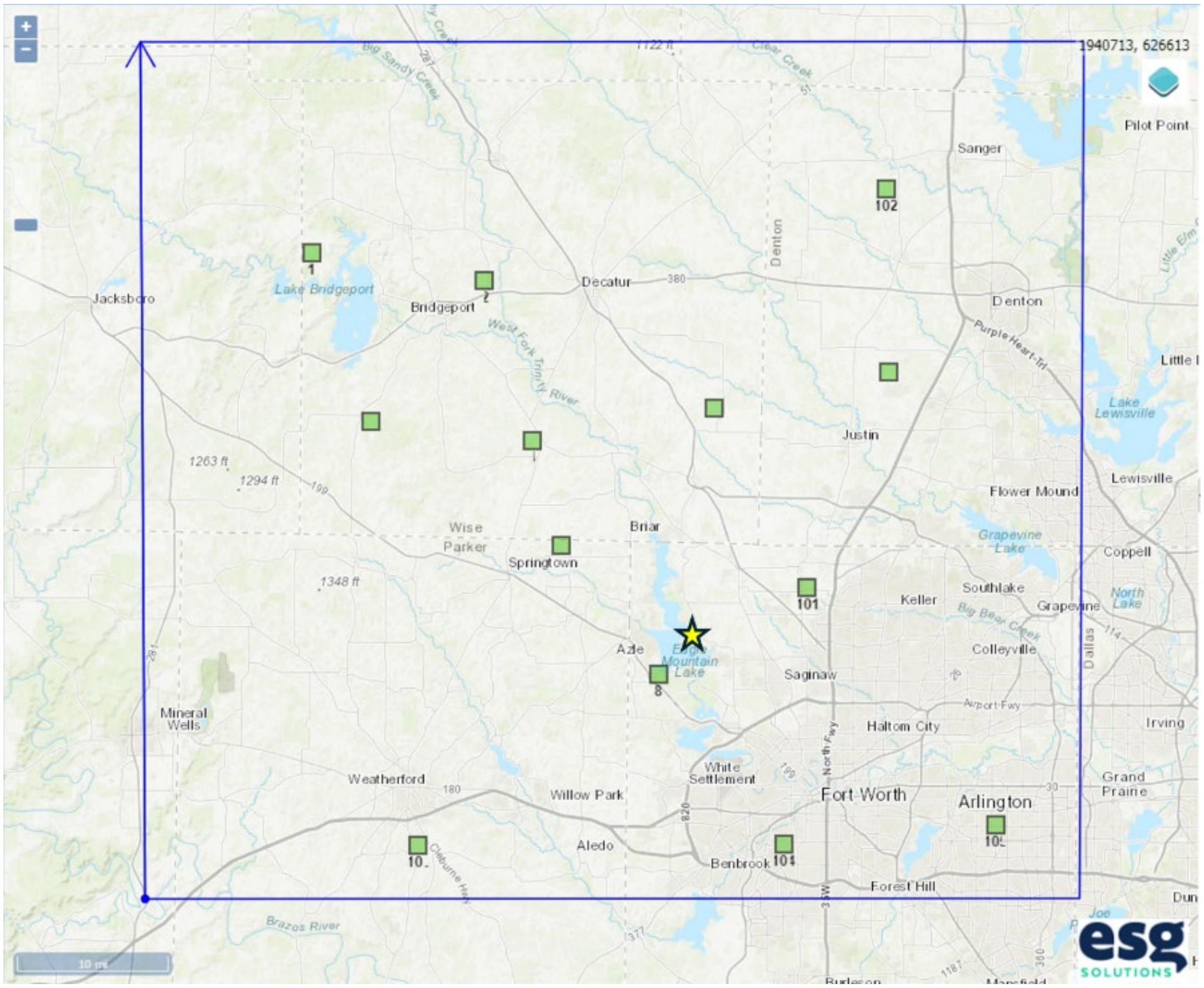


Figure 11. Map of the local seismic array monitoring the area of the Cotton Cove CCS 1. The yellow star marks the location of the Cotton Cove CCS 1. Seismic stations contributing data to the BKV seismic analysis are shown with the green squares. Stations 1-8 are operated by BKV while Stations 101-105 are operated by either TexNet or the USGS and their data are used in the hypocenter locations. North is up.

3.6 Groundwater Hydrology in MMA

Tarrant County falls within the Northern Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 12**). One aquifer is within the vicinity of the proposed injection site: the Trinity Group Aquifer. The Lower Cretaceous Trinity Group is classified as a major aquifer and serves as an important source of groundwater for a portion of northern Texas, including Tarrant County, Texas. The Trinity Group Aquifer outcrops at the Cotton Cove CCS 1 site and across a large swath of Wise and Parker Counties and the northwestern corner of Tarrant County.

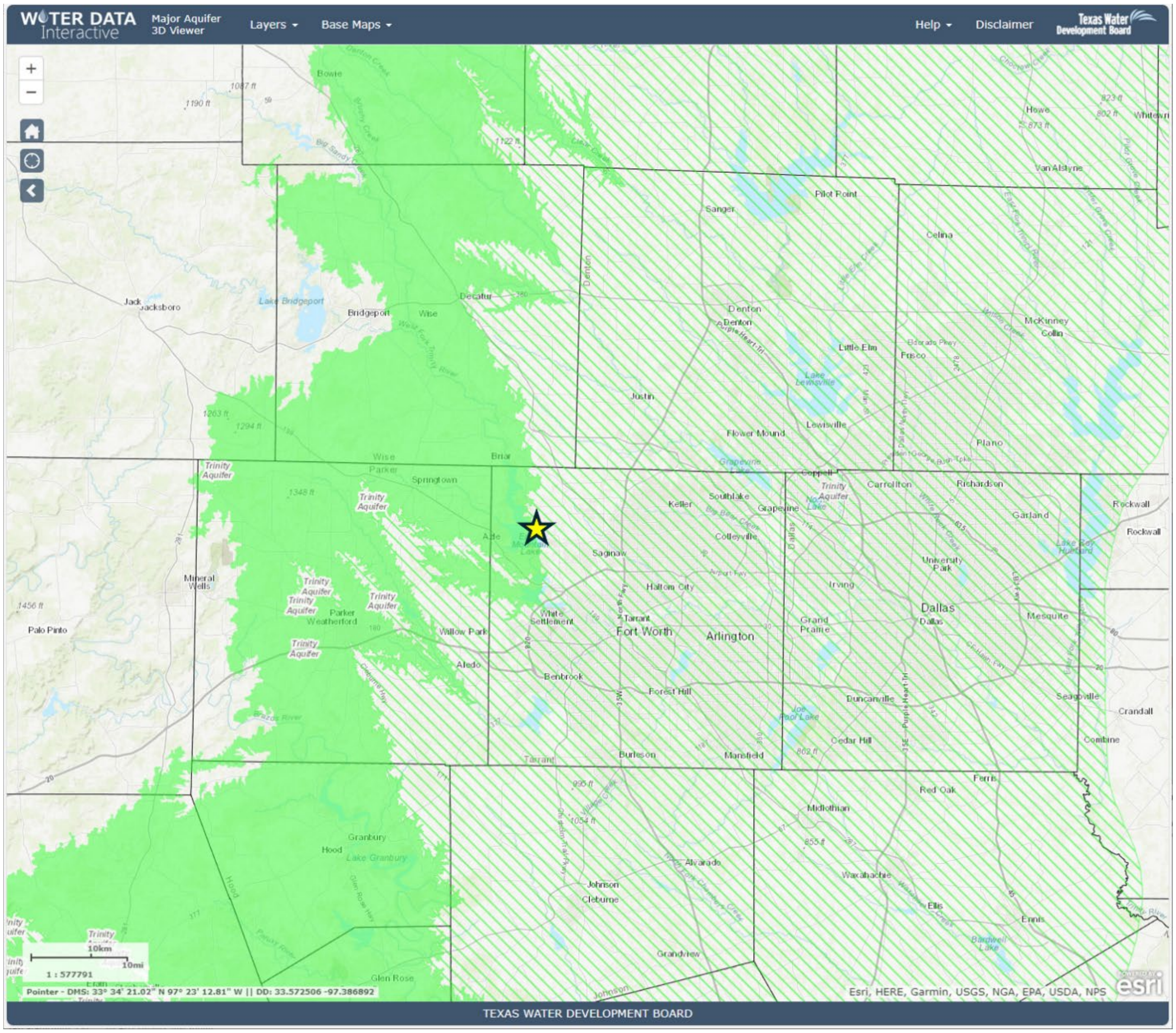


Figure 12. Map of the Trinity Major Aquifer extent within northcentral Texas, from the Texas Water Development Board Interactive Viewer. The location of the proposed Cotton Cove CCS 1 is shown with a yellow star. North is up.

The Trinty Group Aquifer is unconfined west of the project site and confined east of the site (**Figure 12**). Water in the Trinity Group Aquifer is considered fresh but hard, with TDS values in the project area of less than 1,000 mg/L. The overall stratigraphic column contains numerous barriers to vertical flow (or aquitards) that are expected to prevent CO_2 injected into the Ellenburger Subunit E from reaching the surface or near surface location of the Trinity Group Aquifer (**Figure 13**).

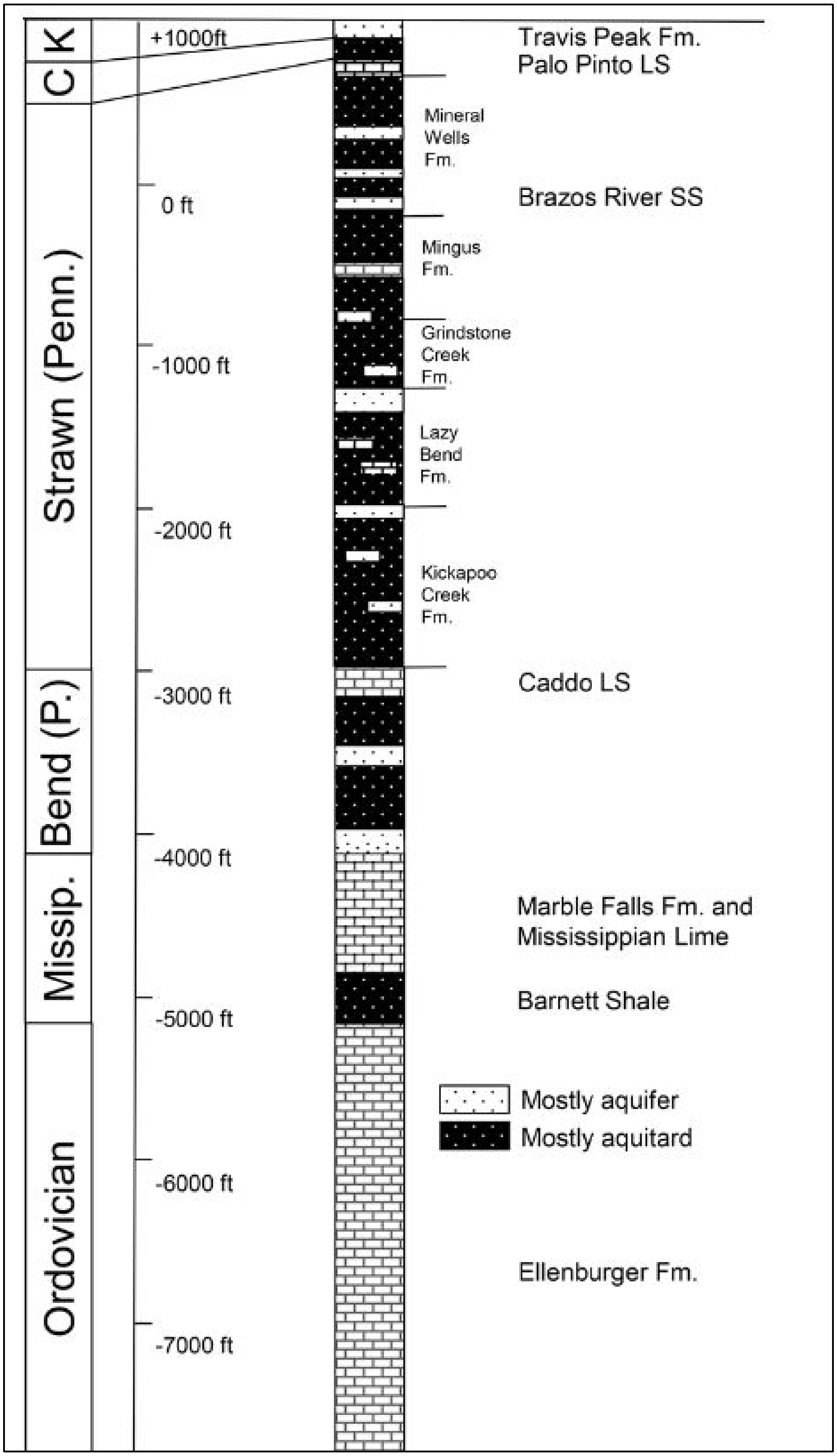


Figure 13. Stratigraphic column showing aquifers and aquitards, modified from Nicot *et al*., (2011)

There are 107 freshwater wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, as shown in **Figure 14** and listed in **Table 4**.

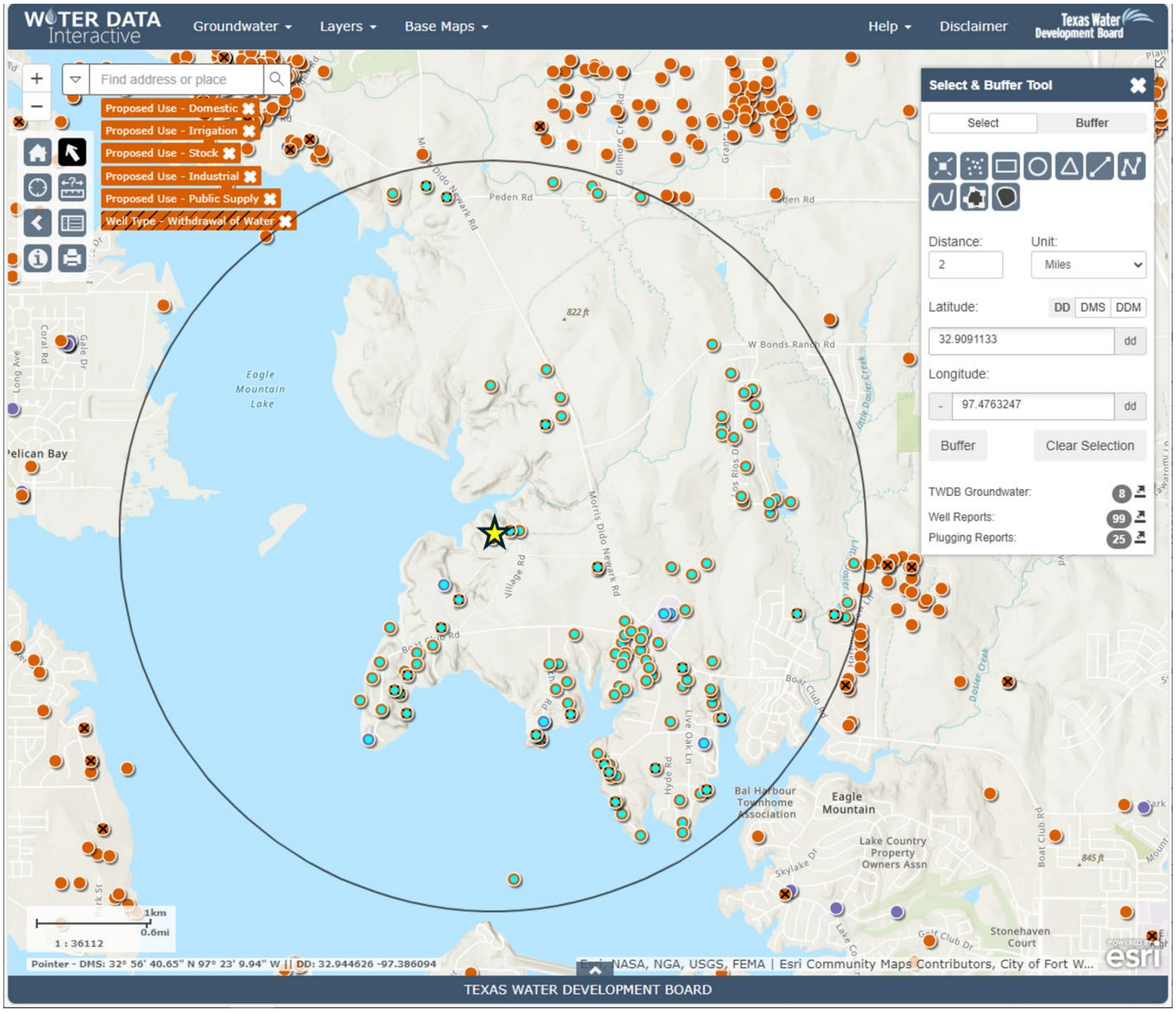


Figure 14. Water wells within two miles from the proposed injection site, data from the Texas Water Development Board Interactive Viewer. North is up.

Table 4. Groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
4945	32.8825	-97.474444	200
8105	32.886945	-97.458889	140
8162	32.888611	-97.459167	140
9201	32.899167	-97.483334	205
23976	32.896389	-97.488611	340
23981	32.916667	-97.454167	355

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
24611	32.902778	-97.443889	330
27215	32.921667	-97.454445	377
27217	32.9175	-97.455278	380
27266	32.914445	-97.453056	340
27268	32.916944	-97.455278	380
27269	32.918333	-97.455278	340
27270	32.920278	-97.453056	350
27271	32.920278	-97.453056	350
27273	32.917778	-97.452778	380
27274	32.919167	-97.452223	335
30454	32.936111	-97.467222	355
37395	32.891945	-97.466389	238
45494	32.902778	-97.443889	320
57105	32.935556	-97.466667	942
80342	32.923889	-97.456112	220
86272	32.889167	-97.457223	140
104755	32.908889	-97.476389	266
123923	32.900278	-97.462778	200
123929	32.899445	-97.462223	200
126757	32.901945	-97.485834	180
156542	32.898334	-97.461667	253
161948	32.901667	-97.462501	280
190665	32.892222	-97.466667	266
194317	32.903334	-97.458612	180
196988	32.900834	-97.464445	260
196990	32.899722	-97.464167	260
197152	32.935278	-97.462778	280
197159	32.936389	-97.470833	280
202905	32.909445	-97.473889	738
204320	32.902501	-97.464167	180
204322	32.900834	-97.461112	180
210501	32.901389	-97.464167	140
210511	32.906112	-97.458056	380
210912	32.896111	-97.469444	200
234675	32.894722	-97.460001	140
255591	32.899167	-97.464445	286
257427	32.901667	-97.463612	200
257473	32.901112	-97.462778	200
257476	32.898611	-97.484445	180
267624	32.898889	-97.461945	210

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
268343	32.899167	-97.470278	235
306601	32.899167	-97.471111	200
317205	32.896111	-97.456112	200
323205	32.921944	-97.471389	294
324408	32.895	-97.455556	180
330547	32.898056	-97.4875	172
364478	32.900001	-97.483334	224
365834	32.906945	-97.456667	260
367478	32.911667	-97.453334	297
373975	32.910834	-97.450834	297
377943	32.911667	-97.448889	320
386419	32.935278	-97.485556	240
387615	32.886111	-97.458889	200
389582	32.891389	-97.465556	280
392805	32.935556	-97.485556	220
395997	32.897222	-97.470555	200
396019	32.906945	-97.443056	300
403825	32.911945	-97.450278	297
407372	32.895556	-97.486667	320
407944	32.899286	-97.486792	210
412976	32.906531	-97.466806	802
415271	32.897861	-97.462194	260
438110	32.897417	-97.464733	160
458834	32.900585	-97.481922	320
463887	32.912167	-97.453444	347
469393	32.896937	-97.456209	200
508639	32.897211	-97.456264	200
513027	32.90004	-97.46411	200
520574	32.890422	-97.465485	220
527005	32.88756	-97.46444	140
532284	32.91165	-97.45088	322
534258	32.90395	-97.44367	372
535973	32.8994	-97.45613	180
545467	32.895599	-97.486566	281
550851	32.920408	-97.452453	400
557415	32.89743	-97.45887	260
562605	32.897185	-97.464191	200
573642	32.897149	-97.485324	200
579758	32.885889	-97.462765	180
583511	32.906633	-97.4599	220

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
585719	32.89795	-97.45848	220
587677	32.897767	-97.469483	240
634201	32.901472	-97.468833	160
641548	32.888573	-97.464852	222
644810	32.89678	-97.46515	278
648844	32.89053	-97.46497	280
649674	32.91975	-97.47009	170
654239	32.90302	-97.44504	360
662127	32.9183	-97.47005	335
667007	32.89999	-97.46504	265
667223	32.89999	-97.46504	265
677269	32.9207	-97.47656	313
677560	32.920123	-97.45321	420
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**
3205701	32.894722	-97.471667	273
3205702	32.894722	-97.471667	261
3205703	32.905278	-97.480833	196
3205704	32.893334	-97.487778	656
3205705	32.903056	-97.460001	194
3205706	32.903056	-97.460556	320
3205804	32.889445	-97.456945	233
3205805	32.893056	-97.456945	220

3.7 DESCRIPTION OF CO_2 PROJECT FACILITIES

dCarbon will accept CO_2 from by the Cotton Cove Gas Plant (**Figure 1**). 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 and transport it to the Cotton Cove CCS 1 injection site. The CO_2 stream will be metered to verify quantity. The CO_2 will then be injected into the Ellenburger Subunit E as previously described. 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 5**. Although the industry-standard sampling of the CO_2 stream is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly over time.

Table 5. CO_2 stream analysis for the Cotton Cove CCS 1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.007	0.011	0.007
Carbon Dioxide	99.8514	99.665	99.8514
Methane	0.095	0.261	0.095
Ethane	0.013	0.019	0.013
Propane	0.002	0.002	0.002
Isobutane	0.008	0.006	0.008
N-butane	0.001	0.001	0.001
Isopentane	0.003	0.002	0.003
N-pentane	0.000	0.000	0.000
Hexanes	0.006	0.003	0.006
Heptanes	0.000	0.000	0.000
Octanes	0.000	0.000	0.000
Nonanes	0.000	0.000	0.000
Decanes plus	0.000	0.000	0.000
BTEX	0.002	0.000	0.002
H_2S	0.000	0.000	0.000
H2O	0.012	0.030	0.012
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	3.15		
Density (lbs/gal)	4.09		
Molecular weight	43.93		
Specific gravity (Air=1)	1.5167		

3.8. Reservoir Characterization Modeling

A regional subsurface model was created in Schlumberger's Petrel software. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1, as discussed in previous sections) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals, that contribute to overall higher fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed

appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E. This assumption is supported by consistent saltwater disposal rates and injection volumes into the Ellenburger Group 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 Cotton Cove CCS 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
4. Quantify the increase in pore pressure dues to CO_2 injection spatially within the reservoir

The CO_2 storage complex is confined to the Ellenburger Group. The Ellenburger Subunit E is modeled as the reservoir interval and the Ellenburger Subunits B-D are modeled as the primary seal to impede vertical fluid flow. The lower confining interval for the reservoir is modeled as the Ellenburger Subunit F.

An SEM with the dimensions of 8.8 miles by 6.4 miles by 2.3 miles (X, Y, and Z) was constructed from elevation grids and faults derived from 3D seismic data and well log information (**Figure 15**) in Schlumberger's Petrel software. A 4-mile by 4-mile tartan grid was generated and then exported to Rock Fluid Dynamics's tNavigator simulator to account for fully implicit multiphase compositional fluid flow. This simulation was constructed to model other transport and mixing phenomena, i.e., relative permeability, diffusion, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be a completely saline aquifer. The salinity of the formation, estimated to be 200,000 ppm TDS, is typical of the Ellenburger Group in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 15** illustrates the vertical layering of the model with relationship to the simulated CO_2 saturation profile. The injection rate modeled was 75,000 MT/year for 12 years followed by 100 years of post-injection simulation to fully document the movement of CO_2. **Figure 15** also depicts the initial model conditions and a map view of permeability enhancements in the model due to mapped faults.

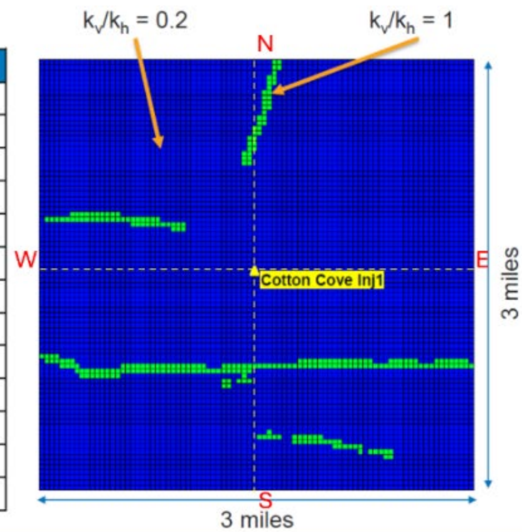
The methodologies employed for static and dynamic models were based on established techniques in literature. Specifically, the reservoir relative permeability model was calculated from capillary pressure data from the Barnett RDC 1 using the Brooks and Corey (1966) model. The relative permeability curves for sealing layers were obtained from Bennion and Bachu (2007). The initial reservoir conditions were developed using gradients derived from Barnett RDC 1 well data. Mapped and inferred faults were given enhanced permeability in the simulation model of 400 mD

and a 1:1 vertical to horizontal permeability. Ellenburger Group interpreted as affected by karsting, primarily in the Ellenburger Subunit A, was given the same enhanced permeability in the simulation model as the mapped faults.

While the top of the Ellenburger Subunit E reservoir interval was modeled at 8,920 feet at the injection well, the top of the perforated interval was chosen to be at 10,140 feet to force the CO_2 to first migrate vertically in the reservoir before hitting the seal at the Ellenburger Subunit D.

Using the aforementioned methodology to develop model estimates, the pressure gradient was assumed to be 0.5 psi per foot, which resulted in an estimated reservoir pressure of 5,070 psi at the top of the injection interval. The temperature gradient was assumed to be 1.25°F per 100 feet, resulting in an estimated temperature of 200°F at the top of the injection interval. 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 6,388 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.

Input	Specifications
Total Number of Grid Blocks	1,732,470
N_x, N_y, N_z	64, 64, 199
D_x, D_y	250 ft * 250 ft
Injection Formation top	EB E ~ 8,180 ft TVDSS (8,920 ft MD)
k_v/k_h (matrix)	0.2
k_v/k_h (faults and karst)	1
Pressure Gradient	0.5 psi/ft
Temperature Gradient	1.25 deg F/100 ft + 70 deg F Surface
Injection rate	75 ktpa
Water saturation	100%
Fracture pressure Gradient	0.7 psi/ft
Maximum allowable pressure	90% of Fracture pressure
Salinity	200,000 ppm



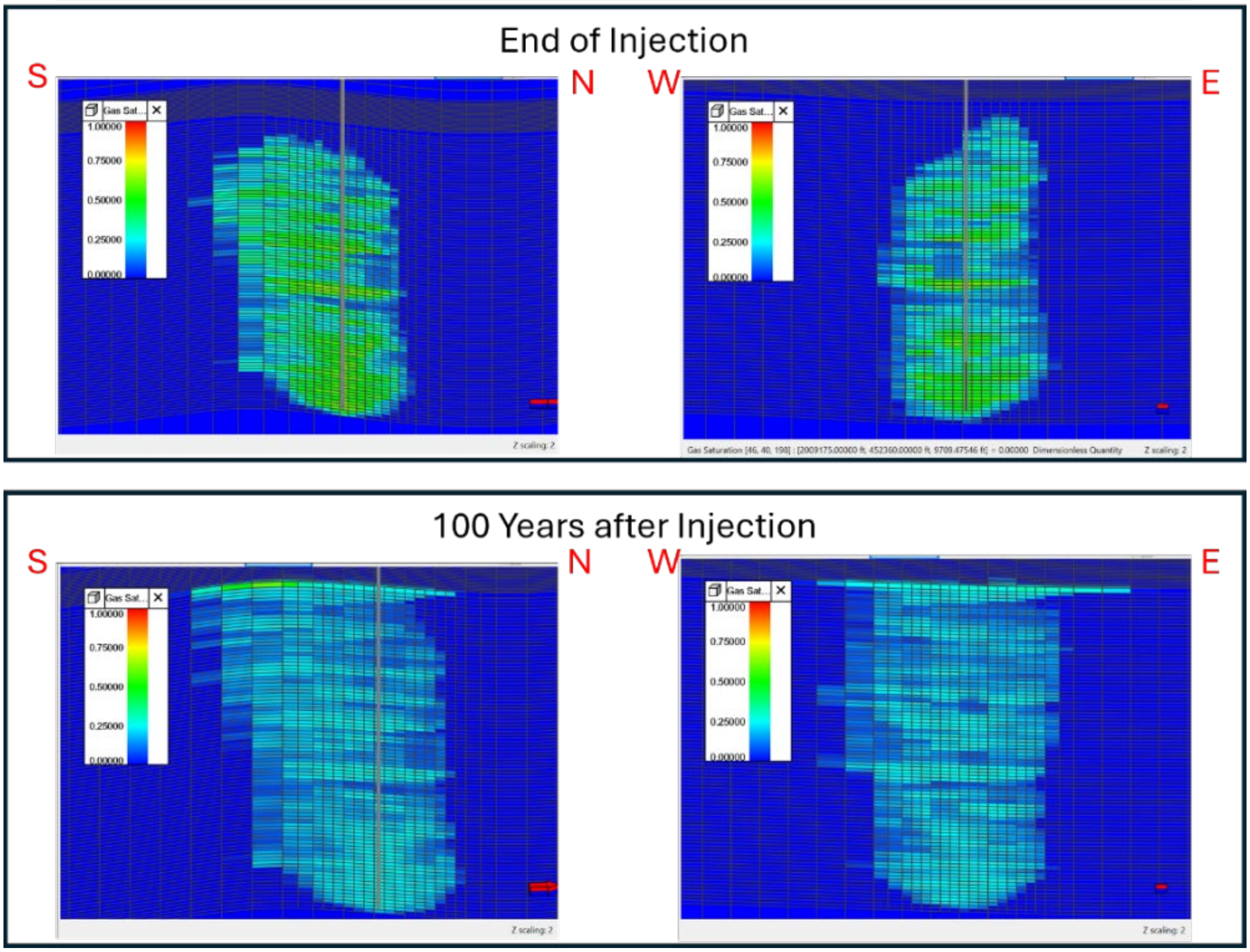


Figure 15. (Upper left table): Simulation conditions employed in the tNavigator model for the Cotton Cove CCS 1 well. (Middle and lower images): Depiction of the end of injection and 100 years after injection modeling results. The color bar in all images indicates modeled CO_2 gas saturation. (Upper right image): The map depicts the enhancement of permeability in certain areas of the model due to mapped faults.

As mentioned earlier, injection was modeled at 75,000 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 94 years post injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 16** shows the CO_2 plume at the end of injection (green) compared to 94 years post injection (cyan). Injected CO_2 flows generally west, which is the regional up dip direction. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation. While the final CO_2 plume stabilizes in a position where the western end is under Eagle Mountain Lake, there are no natural leak pathways that allow CO_2 to reach the lake. A more detailed discussion of potential leak pathways is presented in Section 5.

Figure 16. Simulation results showing CO_2 Plumes (end of injection = green and after 100 years of injection = cyan). Cotton Cove CCS 1 injection wells is shown by as the yellow star. North is up.

Figure 17 illustrates bottom hole pressure at the Cotton Cove CCS 1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is ~5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and 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, the flow transitions from capillary-driven to advection-driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

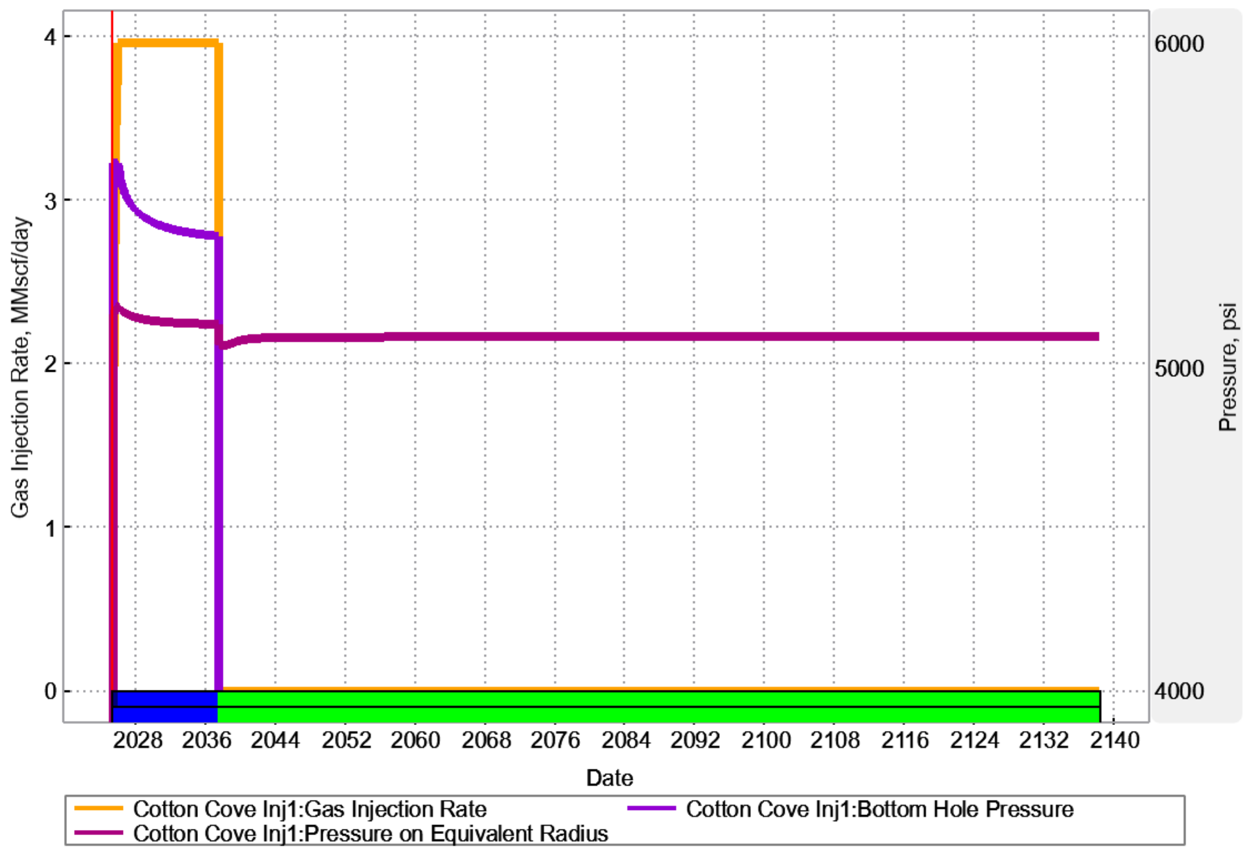


Figure 17. Modeled injection profile at Cotton Cove CCS 1 well. Gas injection rate shown in MMscf/day on the left Y axis and bottom hole pressure and pressure on equivalent radius shown in psi on the right Y axis. The blue bar along the X axis indicates the 12-year injection period and the green bar indicates the 100-year post-injection period.

4 – DELINEATION 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 of at least one-half mile. The numerical simulation using tNavigator as discussed above was used to estimate the size and migration of the CO_2 plume. We modeled injection of CO_2 into the Ellenburger Subunit E for 12 years followed by 100 years of post-injection modeling. Results indicated that the plume ceased to migrate after 94 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of gas saturation was used to determine the boundary of the CO_2 plume. The area of the MMA was determined to be 3.07 square miles with the greatest extent reaching 1.5 miles from the injector. **Figure 18** shows the End of Injection (EOI) plume (green), the 94-year post-injection plume (black solid), and the MMA using a 0.5 mi buffer (black dashed).

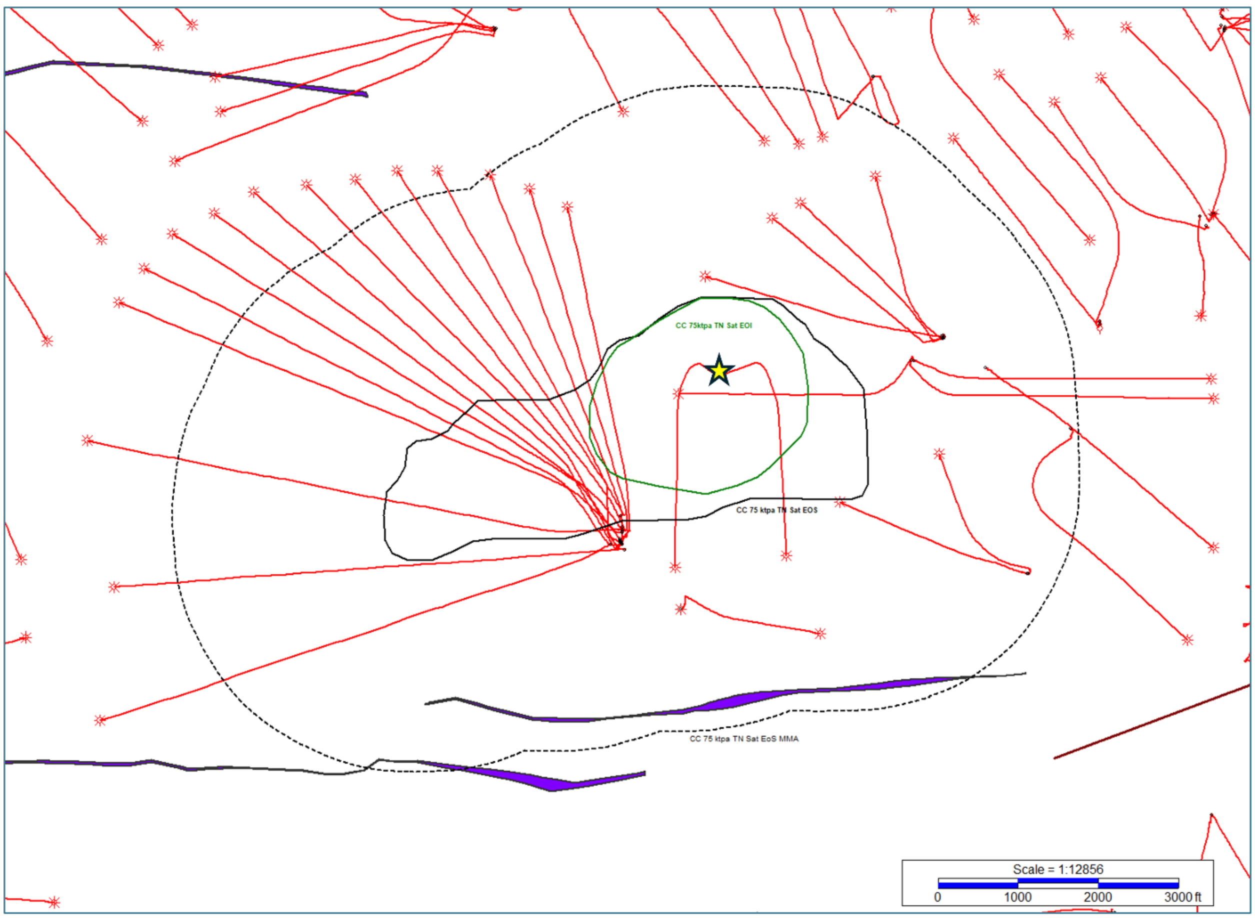


Figure 18. MMA (black dashed), EOI plume (green), and 100-year post injection plume outlines (black solid) as modeled at the Cotton Cove CCS 1 well (yellow star). Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. Thin purple polygons are faults at the top of the Ellenburger Group. North is up.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features mapped within the project area that could cause the unintended migration of the CO_2 plume through natural pathways to the USDW. The mapped faulting in the area does not extend shallower than the top of the Mississippian Marble Falls Formation, leaving more than 5,000 feet of mostly Pennsylvanian shales between the top of the faults and the USDW. 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 Sections 4 and 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 12, which is projected to be the EOI. 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 12, plus an all-around buffer 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 17.

As noted in Section 4.1, dCarbon utilized the plume area after 94 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 18** shows the MMA, which is the same as the AMA. **Figure 19** indicates the AMA/MMA (black dashed) and currently existing 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 802 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

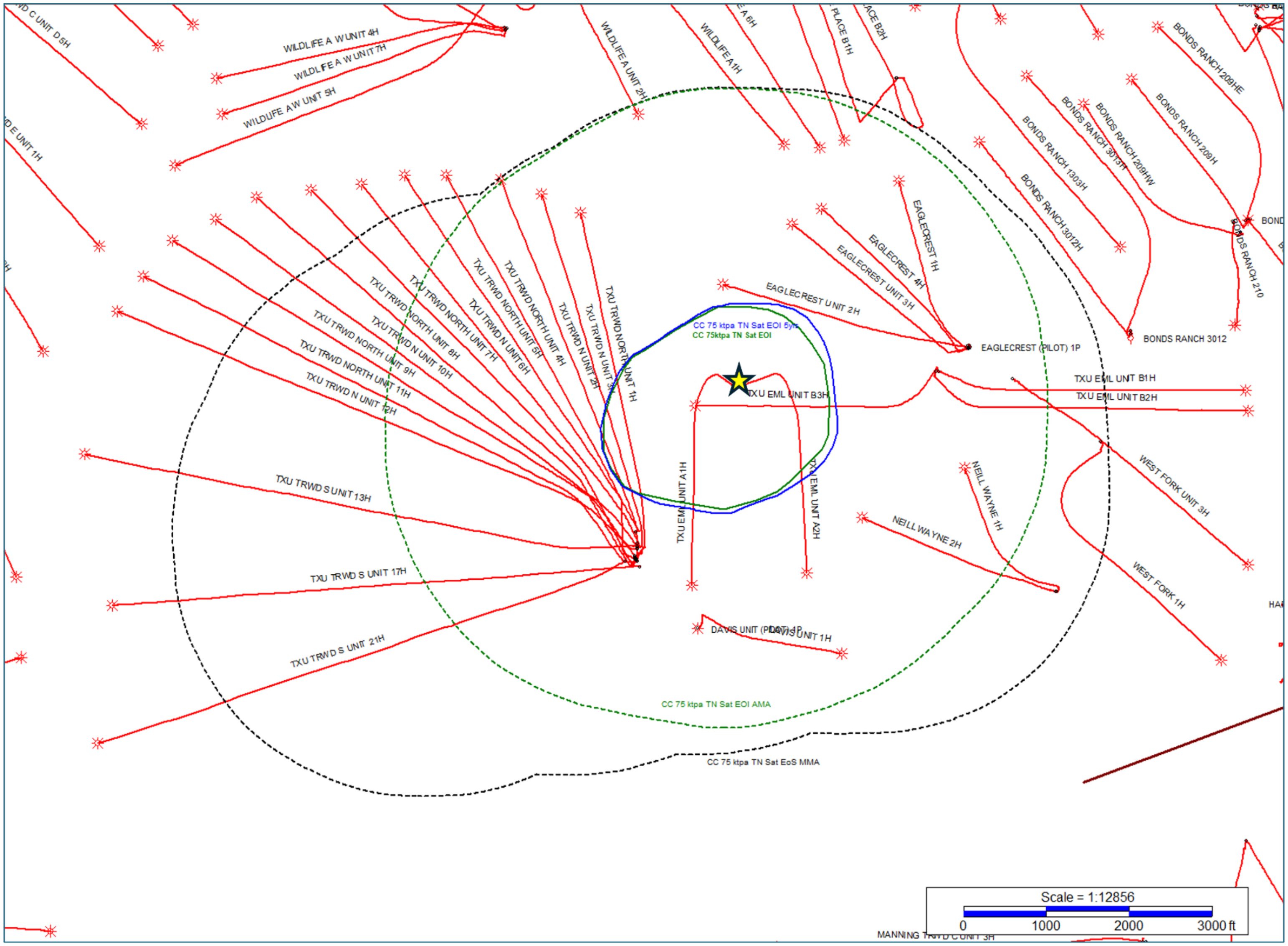


Figure 19. The calculated AMA (green dashed) and existing wells within the project AMA/MMA. The solid green and blue outlines show the extent of the CO_2 plume at EOI and five years post-injection respectively. The MMA is shown as the black dashed line for comparison. The Cotton Cove CCS 1 is shown as a yellow star. Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. North is up.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

dCarbon has assessed each of the 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 6** describes the basis for event likelihood and **Table 6** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 6. 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 7. 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 12 hours of full permitted 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	**Unlikely**, 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 conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale 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 that reach shallow enough to serve as a conduit to the USDW or the surface.	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 2,000 feet 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 a couple 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 that extend shallow enough to reach the USDW or the surface.	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 5.8 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

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at the Cotton Cove Gas Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 5**. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. This includes but is not limited to automatic detection of CO_2 and lack of O_2 detection in specifically designated locations. All BKV and dCarbon field personnel are required to wear gas monitors that detect four or five gases, including H_2S and O_2. 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 automatically in case of unexpected standard operating conditions such as a loss of line pressure.

Additionally, the compressor facility, pipe header, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and CO_2 leak detection per BKV and dCarbon safety and operations standards. These recurring monthly 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. BKV Midstream, LLC or dCarbon personnel are expected to visit the site daily.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA other than the Cotton Cove CCS 1 well.

5.3 Leakage from Existing Wells

There are 34 existing wells within the MMA. Of these 34 wells, one had a pilot borehole for the subsequent horizontal well (**Table 8**). The 34 wells all have active status. However, all these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 8,800 feet) is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells were drilled shallower than the target Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented over their entirety 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.

The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to travel via faults in the Ellenburger to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production. Injected CO_2 entering the Barnett Shale could be produced in the gas stream of these wells. While this is considered improbable due to the reservoir simulation modeling showing no CO_2 reaching the enhanced permeability areas of the model, dCarbon will consider this potential pathway specifically in its monitoring program. In addition, no wells in the AMA/MMA are located within Eagle Mountain Lake. No leak pathways are present that are expected to allow injected CO2 to reach the area of Eagle Mountain Lake.

Table 8. Existing oil and gas wells in MMA with TRRC records.

Well Name	Well Number	UWI	Latitude	Longitude	Operator Current	Operator Original	Total Depth(f)	Status
LAKE PLACE	B1H	424393102900	32.9191420	-97.4698666	BKV NORTH TEXAS LLC	ANTERO RESOURCES INC LP	8650	Gas Well
WILDLIFE	A1H	424393119200	32.9239294	-97.4838481	BKV NORTH TEXAS LLC	XTO ENERGY INC	10435	Gas Well
WILDLIFE A UNIT	2H	424393119600	32.9240571	-97.4837859	BKV NORTH TEXAS LLC	XTO ENERGY INC	8567	Gas Well
EAGLECREST	1H	424393124000	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	8641	Gas Well
EAGLECREST (PILOT)	1P	424393124077	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	6924	Location Only
EAGLECREST UNIT	2H	424393124400	32.9101730	-97.4670195	BKV NORTH TEXAS LLC	XTO ENERGY INC	9045	Gas Well
DAVIS UNIT	1H	424393137300	32.9008732	-97.4776844	BKV NORTH TEXAS LLC	XTO ENERGY INC	8227	Gas Well
DAVIS UNIT (PILOT)	1P	424393137377	32.9008732	-97.4776844	XTO ENERGY INC	XTO ENERGY INC	7158	Gas Well
NEILL WAYNE	1H	424393138400	32.9020862	-97.4635819	BKV NORTH TEXAS LLC	XTO ENERGY INC	8472	Gas Well
NEILL WAYNE	2H	424393138500	32.9020931	-97.4635666	BKV NORTH TEXAS LLC	XTO ENERGY INC	8889	Gas Well
WEST FORK	1H	424393162800	32.9070608	-97.4618388	BKV NORTH TEXAS LLC	SULLIVAN HOLLIS R INC	10163	Gas Well
LAKE PLACE	B2H	424393204200	32.9191465	-97.4698521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9088	Gas Well
TXU TRWD N UNIT	6H	424393221100	32.9035759	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	11683	Gas Well
TXU TRWD N UNIT	2H	424393221200	32.9040765	-97.4801342	BKV NORTH TEXAS LLC	XTO ENERGY INC	11025	Gas Well
TXU TRWD N UNIT	10H	424393223000	32.9035352	-97.4800689	BKV NORTH TEXAS LLC	XTO ENERGY INC	12585	Gas Well
TXU TRWD S UNIT	17H	424393223600	32.9029178	-97.4799856	BKV NORTH TEXAS LLC	XTO ENERGY INC	12845	Gas Well
TXU EML UNIT	A1H	424393245100	32.9089106	-97.4761473	BKV NORTH TEXAS LLC	XTO ENERGY INC	9164	Gas Well
TXU EML UNIT	A2H	424393262300	32.9089049	-97.4760521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9062	Gas Well
TXU TRWD S UNIT	13H	424393338100	32.9037054	-97.4800853	BKV NORTH TEXAS LLC	XTO ENERGY INC	13056	Gas Well

TXU TRWD S UNIT	21H	424393345100	32.9031007	-97.4805575	BKV NORTH TEXAS LLC	XTO ENERGY INC	13064	Gas Well
TXU TRWD N UNIT	12H	424393354600	32.9035061	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	13163	Gas Well
TXU EML UNIT	B1H	424393365600	32.9094039	-97.4683171	BKV NORTH TEXAS LLC	XTO ENERGY INC	10200	Gas Well
TXU EML UNIT	B2H	424393365800	32.9093921	-97.4683110	BKV NORTH TEXAS LLC	XTO ENERGY INC	10500	Gas Well
TXU EML UNIT	B3H	424393423300	32.9093969	-97.4682044	BKV NORTH TEXAS LLC	XTO ENERGY INC	9535	Gas Well
WEST FORK UNIT	3H	424393526800	32.9091561	-97.4652839	BKV NORTH TEXAS LLC	XTO ENERGY INC	9298	Gas Well
TXU TRWD NORTH UNIT	1H	424393598400	32.9032790	-97.4801794	BKV NORTH TEXAS LLC	XTO ENERGY INC	10350	Gas Well
TXU TRWD N UNIT	3H	424393598500	32.9032457	-97.4801754	BKV NORTH TEXAS LLC	XTO ENERGY INC	10694	Gas Well
TXU TRWD NORTH UNIT	5H	424393601000	32.9031750	-97.4801698	BKV NORTH TEXAS LLC	XTO ENERGY INC	11009	Gas Well
TXU TRWD NORTH UNIT	4H	424393603300	32.9032055	-97.4801726	BKV NORTH TEXAS LLC	XTO ENERGY INC	10765	Gas Well
TXU TRWD NORTH UNIT	7H	424393605300	32.9031776	-97.4801011	BKV NORTH TEXAS LLC	XTO ENERGY INC	11485	Gas Well
TXU TRWD NORTH UNIT	8H	424393605400	32.9031436	-97.4800911	BKV NORTH TEXAS LLC	XTO ENERGY INC	11846	Gas Well
TXU TRWD NORTH UNIT	9H	424393605500	32.9031212	-97.4800893	BKV NORTH TEXAS LLC	XTO ENERGY INC	12258	Gas Well
TXU TRWD NORTH UNIT	11H	424393605600	32.9030873	-97.4800851	BKV NORTH TEXAS LLC	XTO ENERGY INC	12522	Gas Well
LAKE PLACE	A7H	424393628200	32.9310611	-97.4774402	BKV NORTH TEXAS LLC	XTO ENERGY INC	11739	Gas Well
LAKE PLACE	A6H	424393628300	32.9310939	-97.4774460	BKV NORTH TEXAS LLC	XTO ENERGY INC	11470	Gas Well
EAGLECREST	4H	424393655400	32.9102140	-97.4670370	BKV NORTH TEXAS LLC	XTO ENERGY INC	8989	Gas Well
EAGLECREST UNIT	3H	424393655700	32.9101702	-97.4670211	BKV NORTH TEXAS LLC	XTO ENERGY INC	8975	Gas Well

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 such as the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita orogenic belt collision. These faults show displacement up into the base of the Pennsylvanian rocks. These larger, younger faults have greater displacement but are relatively sparce.

An east-west fault is interpreted at the south edge of the MMA, south of the Cotton Cove CCS 1 based on available subsurface data including 3D seismic data (**Figure 4**). A second, east-west fault may exist north of the MMA. These faults were included in the dynamic reservoir model as areas of enhanced permeability. Dynamic modeling indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. These faults terminate at the top of the Mississippian strata at roughly 6000 feet TVDSS, leaving roughly 6,000 feet of unfaulted Pennsylvanian shales and sands to serve as yet another secondary confining system. It is highly improbable that injected CO_2 would migrate up faults to the USDW or to the surface through faults. As there are no natural leak pathways that traverse this secondary confining system, we assess it as improbable that CO2 would reach the surface under Eagle Mountain Lake.

Karst development is present in some areas at the top of the Ellenburger. Karsting is often developed in the upper several hundred feet of an exposed carbonate (in this case, the Ellenburger Subunit A), where fresh water enters the shallow subsurface through fractures and dissolves the rock, creating underground caves with a thin roof (**Figure 20**). Subsequent loading of sediment can cause the thin cave roof to collapse, allowing the overlying sediment to fill the void (Zeng, 2011). These karsted sections of the Ellenburger were given enhanced permeability in the model as described earlier. We applied the enhanced permeability to the upper 500 feet of the Ellenburger, where karsted, as a conservative modeling assumption.

Karsting does not appear to affect any subunit of the Ellenburger below Ellenburger Subunit A, including Ellenburger Subunits B-D or the injection interval, Ellenburger Subunit E. This suggests that the Ellenburger Subunits B-D will remain a continuous upper seal for the injection interval even in karst areas. There are interpreted Ellenburger Subunit A karst features south and north of the Cotton Cove CCS 1, but the CO_2 plume does not intersect them, based on the dynamic modeling. Small karst features sitting at the northern edge of the MMA seem to have only impacted the upper 200 feet of the Ellenburger, leaving 2,000 feet of Ellenburger apparently unaffected as shown in the type log in **Figure 20**.

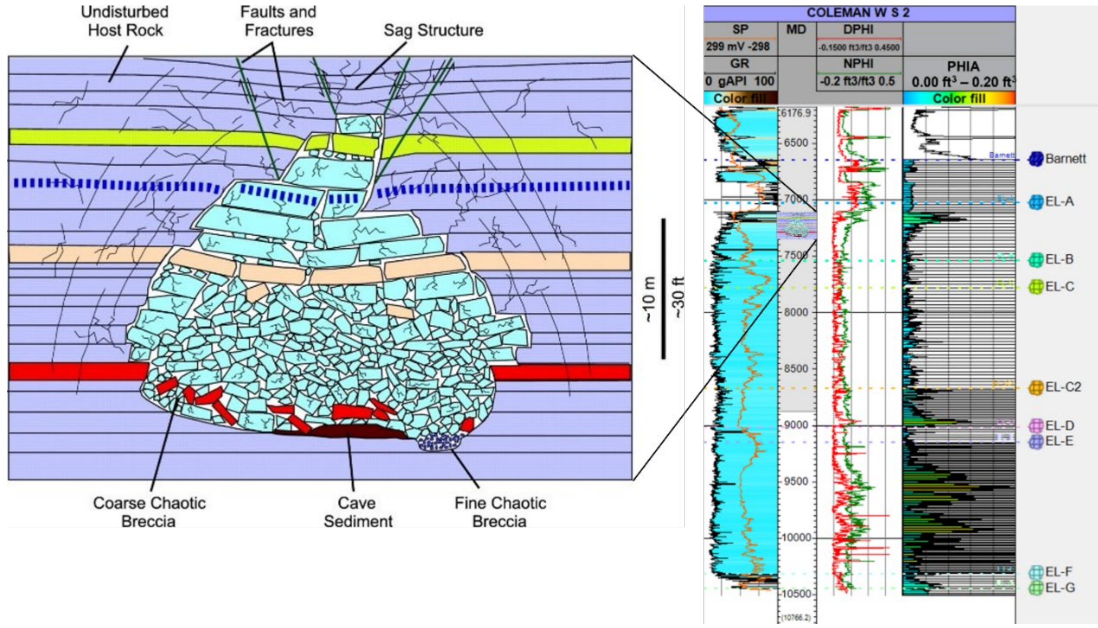


Figure 20. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al*., 2011). The typical scale of the karst features is shown on the right placing the feature on the Coleman 1 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining Ellenburger Subunits B-D and not in the modeled plume area.

5.5 Leakage Through Confining Layers

The Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D and below by the competent confining Ellenburger Subunit F. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA as described in Section 5.3.

5.6 Leakage from Natural or Induced Seismicity

The Cotton Cove CCS 1 well location is in an area of the Fort Worth Basin that has experienced seismic activity historically, as described in Section 3.5. The occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor.

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 surface pressure gauges, so that reservoir pressure and injection pressure can be modeled and monitored. Additionally, consistent with TRRC guidelines and

permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 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 and reduce the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis (Walsh, *et al.,* 2017) 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 Cotton Cove CCS 1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

Furthermore, dCarbon installed new ground seismic monitoring stations 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 have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on 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. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection site is about two degrees up to the west (200 feet/mile), shown in **Figure 21**. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles (Tarrant North SWD 1).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

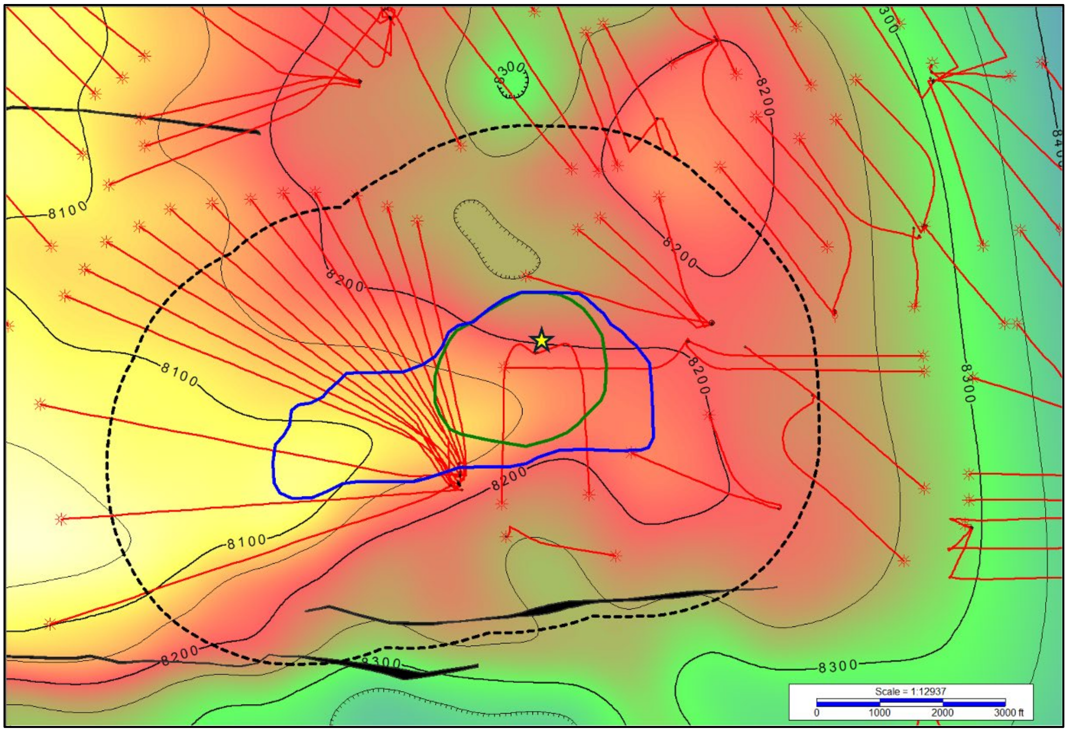


Figure 21. The Cotton Cove CCS 1 well location (yellow star) posted on a map of the top Ellenburger Subunit E depth structural contours in feet TVDSS with a contour interval of 500 feet from the simulation model. The CO_2 plume size at the end of injection (green) and 100 years post-injection and AMA/MMA are also shown as solid blue and dashed black outlines, respectively, from Figure 18. Mapped faults are shown in black.

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). This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur.

6.1 Leakage from Surface Equipment

Monitoring will occur during the planned 12-year injection period, or until the cessation of operations. 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. As the CO_2 compressor station, pipe header, and injection well are all designed to handle expected concentrations, temperatures, and pressures of 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.

Periodic 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 observations, corrective actions will be taken to address such issues.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. 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.

Additionally, CO_2 for injection will be metered with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself (**Figure 22**). The injection stream will also be sampled and analyzed periodically with a gas chromatograph to determine final composition. The meter will each be calibrated to industry standards. Any discrepancies in CO_2 throughput at the meter 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 the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate 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.

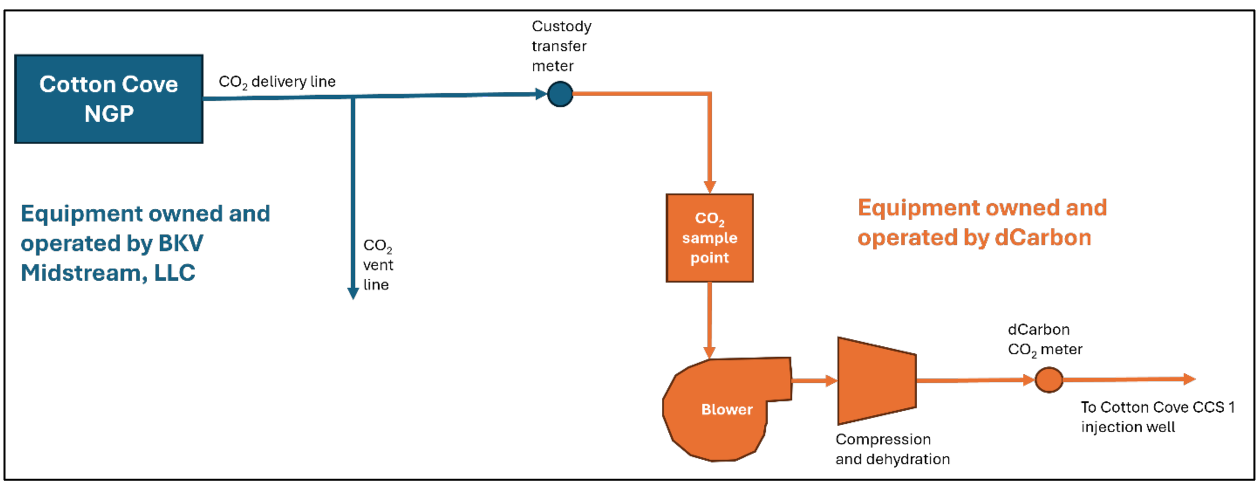


Figure 22. Project conceptual diagram with metering locations. Equipment and pipe headers in Blue are owned and operated by BKV Midstream, LLC while equipment and pipe headers in orange are owned and operated by dCarbon.

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 interval. 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, dCarbon will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will 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 in addition to pressure sensors for each annulus of the well. Annual bottomhole pressure and temperature measurements will be made to calibrate the surface readings to bottom hole. 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 gas samples quarterly 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 Cotton Cove CCS 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) 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 intervals 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 to the surface or to the USDW is improbable, given the number and thickness of competent layers between the injection interval and the USDW. Sampling of the produced gas stream from the Barnett Shale gas wells within the MMA is the primary tool for detecting CO_2 that has bypassed the primary confining system. These producing gas wells are not expected to produce any of the CO_2 injected into the Ellenburger Subunit E and will act as above

zone monitoring wells. dCarbon plans to inject a small amount of chemical tracer with the CO_2 downstream of the volumetric flow meter. Thie chemical tracer will serve as confirmation that any increase in CO_2 detected in the produced gas stream from the Barnett Shale wells in the AMA/MMA is from the sequestration reservoir.

Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems. The chemical tracer injected with the CO_2 can also be analyzed for in the groundwater sampling.

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 low, dCarbon operates a proprietary seismic monitoring array in the general area of the Cotton Cove CCS 1 well. This monitoring array augments 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 Cotton Cove CCS 1 well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, a situation that is very unlikely based on the location of mapped faults and the extent of the modeled plume.

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 four times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the only 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, like 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 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 sample the gas stream from the gas wells in the MMA. These wells should intercept CO_2 that might traverse the primary sealing interval before it bypasses the secondary seals. Noting the increase in CO_2 concentration in the produced gas stream along with the presence of the chemical tracer, will be a trigger for dCarbon to investigate and quantify possible leakage through the primary confining layers. dCarbon will document the methods used to calculate the volume of CO_2 leakage in its annual monitoring report.

dCarbon has access to a deep groundwater monitoring well at the Cotton Cove Gas Plant 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 intervals. 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. dCarbon will conduct baseline sampling of available water wells within the MMA prior to injection to establish a basis for comparison to later samples.

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 works with environmental services and data companies that specialize 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 may also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with high-fidelity CO_2 sensors 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 the X and Y axes (longitude + latitude) as well as the 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) (Korre, 2011). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. 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 (Chen, 2013).

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 Cotton Cove CCS 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.

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). There are three primary monitoring baselines that dCarbon will establish as part of this project.

Baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells 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 gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA that are acting as above-zone monitoring wells. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline seismicity in the area near the Cotton Cove CCS 1 has been determined through the historical data from USGS and TexNet seismic array data. This information is augmented by additional data from dCarbon's proprietary seismic monitoring array, operating since 2023.

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 Cotton Cove CCS 1 injection well will be 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
$C_{CO2,p,u}$	=	CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year

u = Flow meter

8.3 Mass of CO_2 Produced

The Cotton Cove CCS 1 injection well will receive CO_2 produced from the nearby Cotton Cove Gas Plant and will be used for injection only. No CO_2 will be produced from this well. Additionally, 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. 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 CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 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 on 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 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
$CO_{2,E}$	=	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.

Should it be determined that CO_2 has bypassed the primary confining system and Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in 2026 and that will be the date that data to calculate the total volume of CO_2 sequestered will begin to be collected. Baseline monitoring data will be collected beginning in 2025 and the MRV plan will be implemented upon receiving EPA MRV plan approval. The exception to the monitoring baseline data is the seismicity baseline data which began in 2017 with the TexNet monitoring system.

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 reported 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, if employed, will be operated continuously, except for maintenance and calibration.
- Gas detectors, if employed, 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 most recent 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 five 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.

12 – REFERENCES

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Attachment A

Copies of W-14, W-1, Drilling Permit

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

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

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

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

PERMIT NO. 17534

BKV DCARBON VENTURES, LLC
4800 BLUE MOUND ROAD
FORT WORTH TX 76106

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated September 12, 2024, for the permitted interval(s) of the Ellenburger formation(s) and subject to the following terms and special conditions:

COTTON COVE CCS (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
TARRANT COUNTY
DISTRICT 05

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	43900000	000126822	Carbon Dioxide (CO_2)	8806	11150	4000	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	43900000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. (A) The operator shall notify the Commission within 24 hours of a discovery of any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; or any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Within 20 days of such a discovery, the operator shall file a report with the Commission documenting the event, findings, and response actions taken.** **(B) The permittee shall report the source(s) and the properties of injected acid gas as they are added. In no case may the volume of acid gas exceed the limit indicated in permit.** **(C) The well's construction and materials used must be resistant to corrosion per the proposed wellbore schematic that was submitted in the application.** **6. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.**

STANDARD CONDITIONS:

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

Note: This document will only be distributed electronically.

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

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

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

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

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

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

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

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

APPROVED AND ISSUED ON September 27, 2024.

for Ivan Salas, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

API No. 42-439-37356

Drilling Permit # 902971

SWR Exception

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No. 100589

2. Operator's Name (as shown on form P-5, Organization Report) BKV DCARBON VENTURES, LLC

3. Operator Address (include street, city, state, zip): 4800 BLUE MOUND ROAD FORT WORTH, TX 76106

4. Lease Name COTTON COVE CCS

5. Well No. 1

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

11. RRC District No. 05

12. County TARRANT

13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4 miles in a NW direction from Alze which is the nearest town in the county of the well site.

15. Section

16. Block

17. Survey GARCIA, M

18. Abstract No. A-564

19. Distance to nearest lease line: ft.

20. Number of contiguous acres in lease, pooled unit, or unitized tract: 2.22

21. Lease Perpendiculars: 144 ft from the S line and 133 ft from the E line.

22. Survey Perpendiculars: 296 ft from the N line and 1131 ft from the E line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	12000	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

Certificate:

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

Bill Spencer, Consultant
Name of filer

Sep 30, 2024
Date submitted

(512)9181062, x2
Phone

bill@spencerconsulting.org
E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Oct 1, 2024 2:05 PM(Current Version)

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director’s delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

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

PERMIT NUMBER 902971	DATE PERMIT ISSUED OR AMENDED Oct 01, 2024	DISTRICT 05
API NUMBER 42-439-37356	FORM W-1 RECEIVED Sep 30, 2024	COUNTY TARRANT
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 2.22

OPERATOR 100589

BKV DCARBON VENTURES, LLC

4800 BLUE MOUND ROAD
FORT WORTH, TX 76106

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(903) 984-3026

LEASE NAME COTTON COVE CCS	WELL NUMBER 1
LOCATION 4 miles NW direction from ALZE	TOTAL DEPTH 12000

Section, Block and/or Survey

SECTION BLOCK ABSTRACT 564

SURVEY GARCIA, M

DISTANCE TO SURVEY LINES 296 ft. N 1131 ft. E	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 144 ft. S 133 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL # / NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE)	2.22	12,000	1	09
COTTON COVE CCS			0	

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

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

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

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

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION
SWR #13 Formation Data

TARRANT (439) County

Formation	Remarks	Geological Order	Effective Date
CADDO		1	12/17/2013
BARNETT SHALE	May be prorated into District 9	2	12/17/2013
ELLENBURGER		3	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

Request for Additional Information: Cotton Cove CCS 1
December 20, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Please review the Figures and the Figure Descriptions included in the MRV plan to ensure that all text is legible, scale bars and legends are scaled appropriately, etc. For example, Figures 1, 5, 16, and 22 are low resolution and difficult to read. Furthermore, we recommend doing an additional review for spelling, grammar, etc. One example noted was on page 6, where the facility is referred to as "Cotton Cover CCS", rather than Cotton Cove CCS.	"Cover" on page 6 replaced with "Cove" Figures 1, 5, 16, and 22 have been updated with better quality graphics. Figures have been renumbered above Figure 15.
2.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, "TVDSS" is not defined within the text.	TVDSS defined in first use (Fig. 2)
3.	3.8	27	"As mentioned earlier, injection was modeled at 75 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops." The previously mentioned injection rates are listed as 75,000 MT/year. Please revise for clarity.	Text has been corrected to 75,000 MT/yr
4.	5.1	33	Figure 17 shows that the projected CO_2 plume at the end of injection and the end of migration settles below a body of water. Please include additional discussion regarding whether this would affect leakage pathways and corresponding monitoring strategies.	Modified text in Sections 3.8, 5.3, 5.4, 6.4. There are no leak pathways (faults, fractures, and existing well bores) that provide a pathway for leaking CO_2 to the lake. The lake has no impact on the monitoring strategies needed for this project.
5.	5 .1	33	"dCarbon's surface facilities at the Cotton Cove Processing Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in Table 5. The	Added wording around Automatic detections and AVO inspection frequency in section 5.1.

			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 four or five gases, including 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 CO_2 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." These paragraphs do not mention automatic detection in the case of a leak from surface equipment. Please provide an estimated frequency of the personnel visits/AVO inspections that are set to occur.	
6.	8.2	47	"$C_{CO2,p,u}$ = Quarterly CO2 concentration measurement in flow for flow meter u in quarter p (weight percent CO2, expressed as a decimal fraction)" In equation RR-5, the variable per subpart RR is defined as "$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO2, expressed as a decimal fraction)." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Equations and variables in section 8.2 have been updated to conform with the text in 40 CFR 98.443.

7.	8.3	47	"The injection well is not part of an enhanced oil recovery project, and therefore, no CO2 will be produced." In this section and/or others, please provide additional explanation of why the facility is making the determination that there is no production associated with this facility and why it is proposing to use RR-12 instead of RR-11. For example, please explain the relationship between the capture and injection facilities (are they one facility or separate per the definition at 40 CFR 98.6 "Facility") and explain whether the injected CO2 plume could be projected to reach or interact with the production wells. Please explain whether the MRV plan and applicable equations would be revised/resubmitted in the event that injected CO_2 does reach the production wells.	I have made modifications to Sections 1, 6.4, 7, 8.1, 8.2, 8.3, 8.4, and 8.5. dCarbon currently intends to dispose of CO2, into the Cotton Cove CCS 1 injection well (CCS 1). produced by the nearby Cotton Cove Gas Plant (Gas Plant), operated by BKV Midstream, LLC (TCEQ CN604046912) which is a separate, pre-existing facility. The CCS 1 and the Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category making them separate and distinct facilities under 40 CFR 98.6. Should it be determined that CO2 has bypassed the primary confining system and Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO2 sequestered at the facility
8.	8.4	47	"Mass of CO2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H2S, 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 CO2 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 Table 5, the referenced injectant stream analysis shows that the normalized percentages of H_2S is 0.000%. Please clarify and/or revise the table or discussion in section 8.4 for consistency.	Removed wording around H2S in section 8.4. Does not apply here. Will not measure leaks directly. Will calculate.

9.	8.5	48	"$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$ Where: CO2 = Total annual CO2 mass sequestered in subsurface geologic formations (metric tons) at the Cotton Cove CCS 1 facility in the reporting year. CO2,I = Total annual CO2 mass injected (metric tons) in the Cotton Cove CCS 1 well in the reporting year." In Equation RR-12, these variables are identified as: "CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year. CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Modified the variable definitions in Section 8.5 to conform with the text in 40 CFR 98.443.
10.	9	48	"The injection well is expected to begin operation in 2025. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA MRV plan approval." 40 CFR 98.448(a)(7) requires a "Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial	The start date for injection has been revised to 2026 and the start date will be the date that data to calculate the total volume of CO2 sequestered will begin to be collected. Seismicity baseline data began collection in 2017 with the TexNet seismic array and augmented in 2023 with the local seismic array operated by dCarbon. Groundwater and natural gas stream sampling proposed by the MRV plan will begin in 2025.

			AMA." Please clarify whether such a date is included in the MRV plan.	
11.	7	49	The baseline determination discussion utilizes three strategies for monitoring CO_2 surface leakage per §98.448(a)(4), including groundwater sampling, baseline gas composition, and seismicity. Would the facility also monitor operational data such as injection pressures?	Language in Section 6.1 documents the use of operating data such as SCADA concentrations, pressures and temperatures to identify leaks rapidly, should they occur. Section 7 is geared towards the monitoring measurements that require long-term baseline data to recognize deviations from the background trends. Operational data will not be available prior to first injection and, therefore, will not be part of the baseline determinations.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Cotton Cove CCS 1

NW Tarrant County, Texas

Prepared by
BKV dCarbon Ventures, LLC

Version 1.2
November 8, 2024

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 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Cotton Cove CCS 1 injection well in Tarrant County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2 from the nearby Cotton Cove Gas Plant, operated by BKV Midstream, LLC (TCEQ CN604046912), into the Cotton Cove CCS 1 well. The project site is located approximately four miles east-northeast of Azle, Texas, as shown in **Figure 1**.

dCarbon anticipates drilling the Cotton Cove CCS 1 well in Q1 2025 and completing and beginning injection operations in 2025. The Cotton Cove CCS 1 has an approved W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the TRRC (UIC number 000126822, API number 42-439-37356). 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 (75,744 MT/yr). dCarbon plans to inject for approximately 12 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 Cotton Cove CCS 1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 589741. All aspects of this MRV plan refer to this well and this GHGRP ID number.

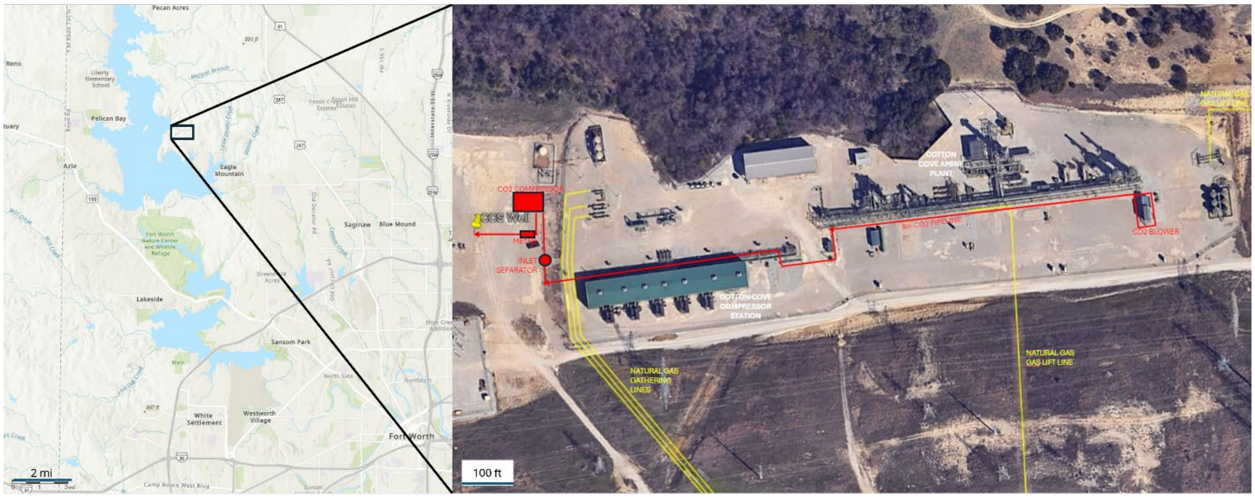


Figure 1. Location map for the Cotton Cove CCUS 1 well in Tarrant County Texas. The well is planned to be drilled immediately west of the Cotton Cove Gas Plant that captures the CO_2 to be injected. North is up.

2 – FACILITY INFORMATION

Facility Name:

Cotton Cove Gas Plant (TCEQ CN604046912)

Address: 10055 Morris Dido Newark Road, Fort Worth, TX 76179

Latitude: 32.90927778

Longitude: -97.46976667

GHGRP ID number: 526203

FRS ID: 110040511256

NAICS Code: 211111

Reporting structure: Currently reporting under Subpart C, Subpart W, and Subpart RR.

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the Texas Railroad Commission (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 Cotton Cove CCS 1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Cotton Cove CCS 1

API number: 42-439-37356

UIC number: 000126822

Cotton Cove CCS 1, GHGRP ID: 589741

The Cotton Cove CCS 1 well will be disposing of CO_2 from the Cotton Cove Gas Plant. All aspects of this MRV plan refer to the Cotton Cove CCS 1 well and GHGRP 589741.

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, the planned injection and confining intervals or zones (terms interval and zone used interchangeably), the planned injection volumes and process, and the reservoir modeling performed for the proposed Cotton Cove CCS 1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Tarrant County, Texas.

3.1 Overview of Geology

The proposed injection site lies in the northwestern part of Tarrant County, where the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. The north to south cross section of **Figure 2** shows the Ellenburger and overlying formations dipping to the north. One inference from these cross sections is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward and southward, which is towards the Bend Arch. The dip direction is further represented in the structure contour map of the Ellenburger Group top (Pollastro, 2007) in **Figure 2**.

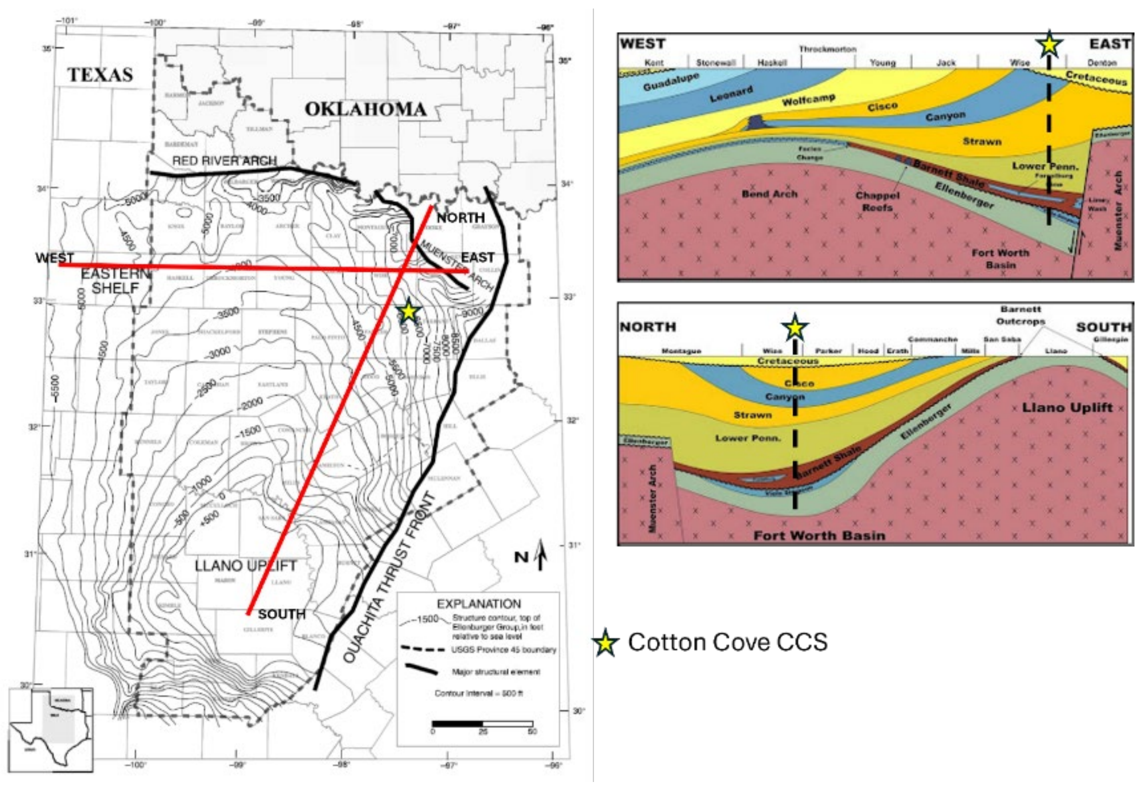


Figure 2. (*Left*) Ellenburger structure map modified from Jarvie *et al.* (2007) showing the regional structures within and bounding the Fort Worth Basin. The Ellenburger structural contours are depicted in feet TVDSS at an interval of 500 feet and the final dCarbon area of interest is denoted by a yellow star. (*Right*) Cross sections from W-E (top right) and N-S (middle right) show the regional dip of the sedimentary units in the Fort Worth Basin modified from Bruner et. al., (2011), also with a yellow star and dashed black line indicating the position of the Cotton Cove CCS 1 well.

The Fort Worth Basin sedimentary succession began with the deposition of locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (**Table 1**). Ordovician age Ellenburger platform carbonates were deposited next on a passive margin and are up to 4,000 feet thick 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 Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group (Gao, 2021). 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 Formation. The Ellenburger Group directly overlies the basement rock and is considered the main injection target.

Table 1. Regional Stratigraphy at Cotton Cove CCS 1 Site in North Texas.

SYSTEM	SERIES	STAGE	GROUP OR FORMATION	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian		Barnett	Upper Barnett Shale
				Forestburg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Upper		Viola Group	
			Simpson Group	
	Lower		Ellenburger Group	
Precambrian			Basement	

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. 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 in 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 in the south.

3.2.2 Stratigraphy

The Ellenburger Group in the Fort Worth Basin contains alternating limestone and dolostone lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into eight subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.* (2019). The main target storage reservoir, Ellenburger Subunit E, was identified based on the dominant dolostone lithology, gross and net reservoir thicknesses, porosity values, and permeability values. The Ellenburger Subunit B and the stratigraphic top portion of Ellenburger Subunit C were identified as the caprock based on the dominant limestone lithology, thickness, porosity, and permeability values. Below this interval, there are layers of tighter limestone throughout Ellenburger Subunits C, C2, and D that would also act as sealing units to the underlying Ellenburger Subunit E storage interval.

The Barnett RDC 1 well (API number 42-497-38108), located approximately 27 miles northwest of the proposed Cotton Cove CCS 1 injection well, was used to calibrate well-log-based petrophysical properties since it has modern well logs and core data (**Figure 3**). The Tarrant North SWD 1 well (API number 42-439-31228), located approximately six miles to the northeast, was also used in well correlations and thickness calculations because of its closer proximity. Dominant lithologies were determined by comparing the photoelectric factor log curve and the separation of the density and neutron porosity curves in the Tarrant North SWD 1 well with the volume of clay, sand, lime, dolomite, gas, and free water calculated in the Barnett RDC 1 well. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

Figure 3 shows the correlation of the Barnett RDC 1 to the Cotton Cover CCS 1 site, including the Tarrant North SWD 1, as noted by the well names posted on the map and at the base of the well logs in the cross section. Ellenburger Subunits A through F are present and appear to be contiguous in the project area. The thickness of Ellenburger Subunits B-D is approximately 2,000 feet while Ellenburger Subunit E thickness varies across the cross-sections. It is estimated there is at least 2,000 feet of Ellenburger Subunits B-D and 1,000 feet of Ellenburger Subunit E at the Cotton Cove CCS 1 proposed location.

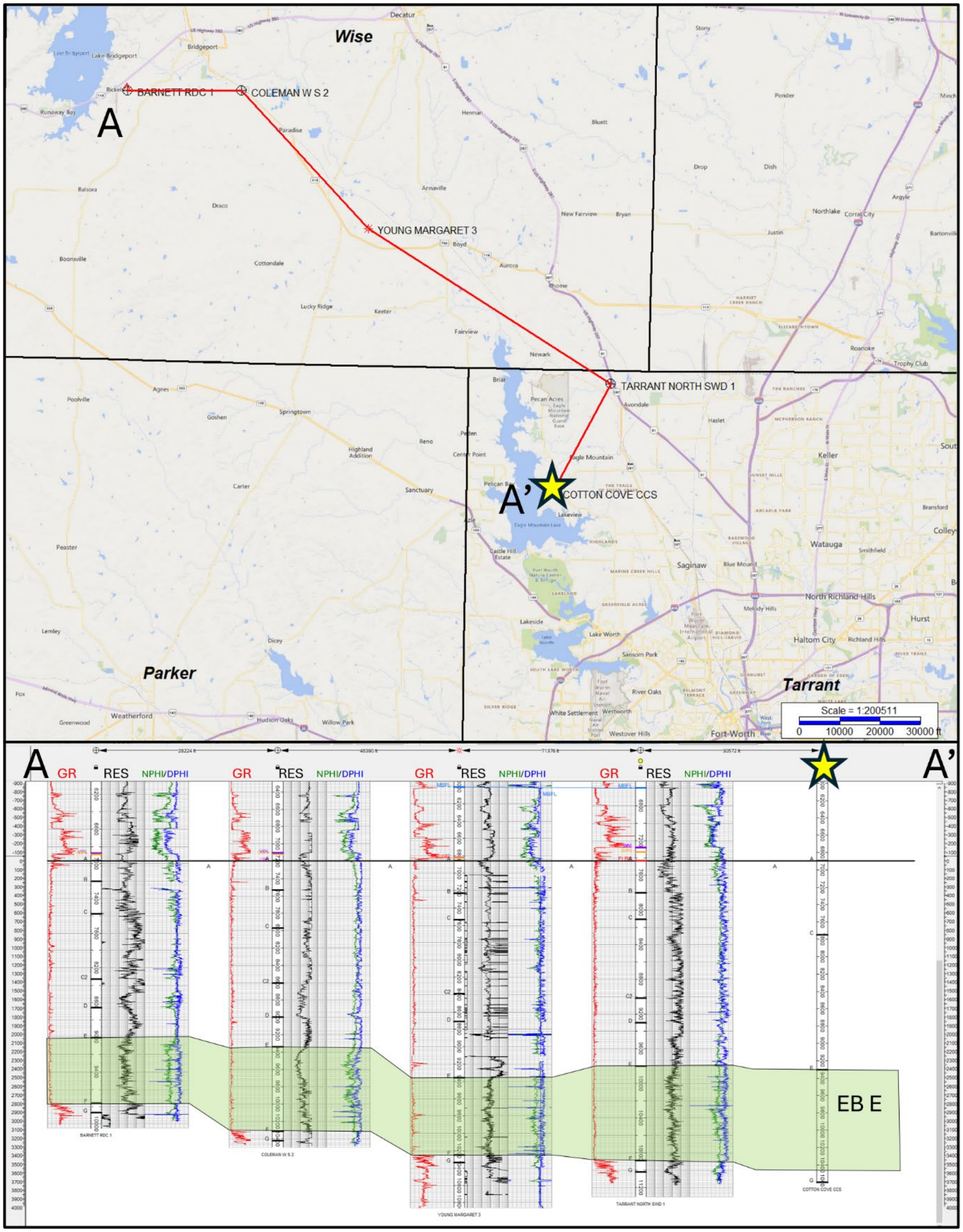


Figure 3. (*Top*) Map of north Texas, including Wise and Tarrant Counties, with the Cotton Cove CCS 1 (yellow star) and a NW-SE stratigraphic cross section (A-A'), datumed on the top of the Ellenburger Subunit A. North is up. (*Bottom*) Cross section showing Gamma Ray (GR), Resistivity (RES), Neutron Porosity (NPHI), and Density Porosity (DPHI) from the Barnett RDC 1 well to the Tarrant North SWD 1 well. Ellenburger Subunit E (EB E) is the storage interval.

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 (**Figure 4**). A secondary set of east-west faults appear to connect these major trends. 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 present, suggesting that faults have not experienced significant movement since their formation (Wood, 2015). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Formation.

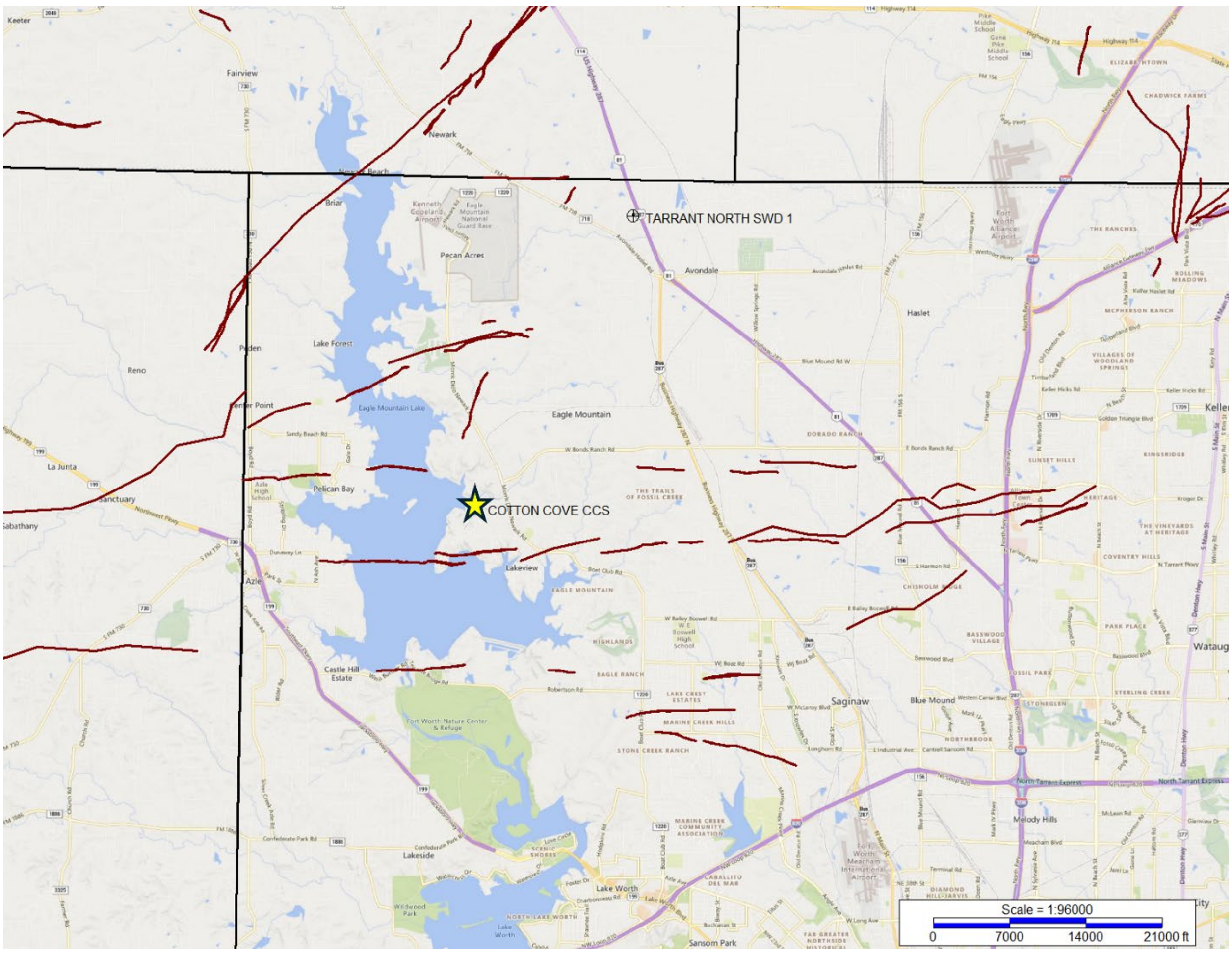


Figure 4. Mapped faults (brown lines) at the top Ellenburger level, near the proposed injection well from Wood (2015) and internal mapping. North is up.

3.3 Lithological and Reservoir Characterizations

Smye *et al*. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Upper Cambrian to Ordovician. Prior to understanding the petrophysical 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. 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 strata highlighted by red dashed box in **Figure 5**. The Viola and Simpson Groups are expected to overlie Ellenburger Subunit A at the Cotton Cove CCS 1 site as depicted on the right side of the highlighted column.

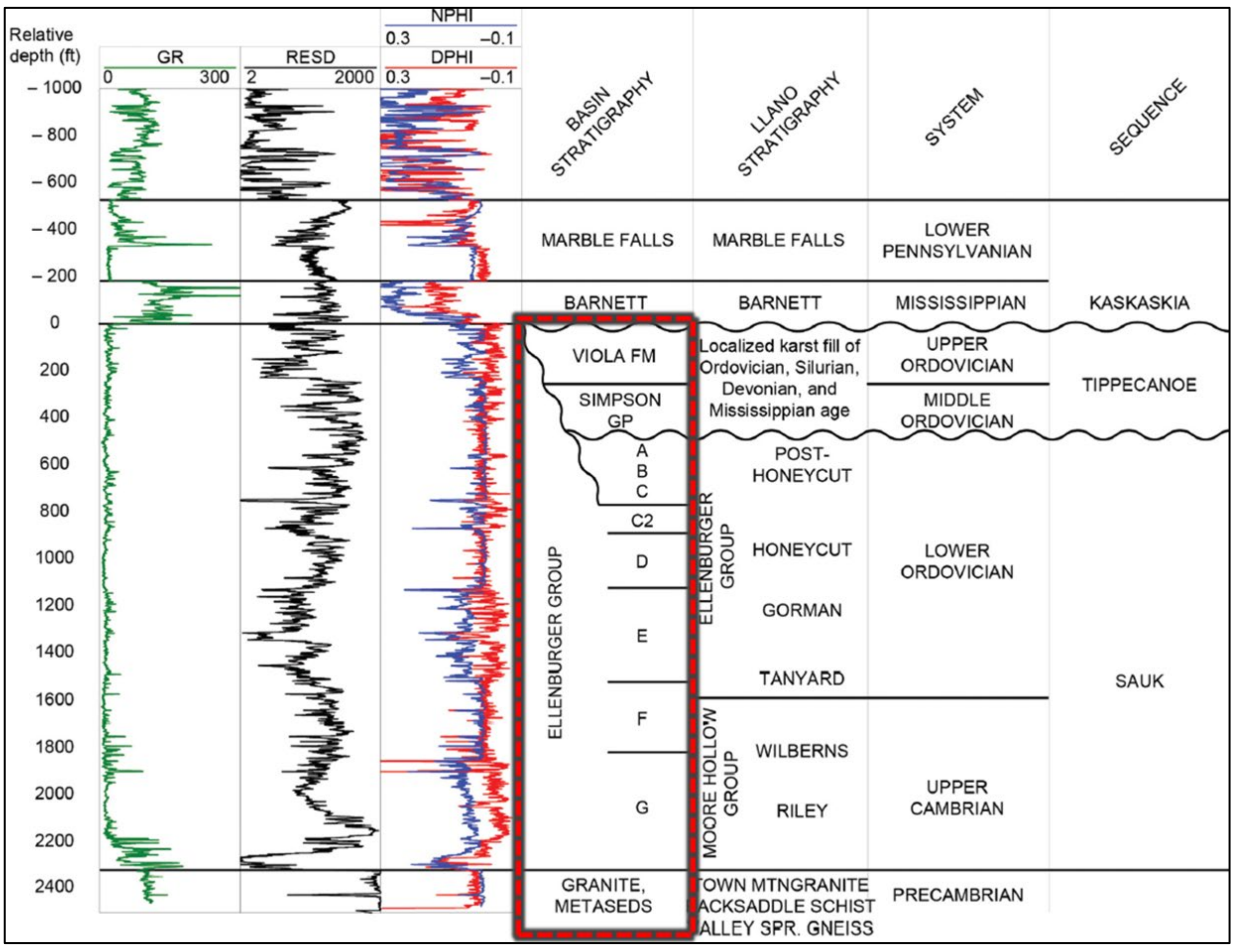


Figure 5. Regional stratigraphy at dCarbon site in North Texas (modified from Smye *et al.*, 2019). Red dashed box denotes the section of focus for the lithological characterization.

The Simpson and Viola Groups are anticipated to serve as the secondary confining interval at the Cotton Cove CCS 1 location. The Barnett Shale, located above the Viola Group, 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 range from 4-6% and 7-50 nanodarcies, respectively. These low porosities and permeabilities are characteristic of conventional seals and, as such, the Barnett serves as an additional confining interval. The wells in the project area produce unconventional gas from the Barnett Shale.

Underlying the Viola and Simpson Groups are the informal Ellenburger lettered units defined by Smye *et al.*, 2019, which contains both the anticipated storage and confining intervals. The Ellenburger was divided into eight lithostratigraphic units starting with Ellenburger Subunit A at the top to Ellenburger Subunit G at the bottom which sits on top of the crystalline basement. Ellenburger Subunit G is not seen on well logs sufficiently to confirm that it is present in the area. Ellenburger Subunit F may sit on the crystalline basement in the area and serves as the lower seal for the reservoir. Core data from the Barnett RDC 1 showed Ellenburger Subunit F had porosities below 2% and permeabilities below 0.005 millidarcies, making it an excellent lower seal. Ellenburger Subunit E will serve as the storage interval. It is characterized as a clean dolomitic reservoir with 49% dolomite by volume and approximately 4% matrix porosity. interval. Ellenburger Subunits B and C were found to have lower matrix porosities compared to Ellenburger Subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger Subunit A has been proven to have reservoir characteristics with multiple saltwater disposal wells completed in Ellenburger Subunit A. Karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Ellenburger Subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger Subunits A-G.

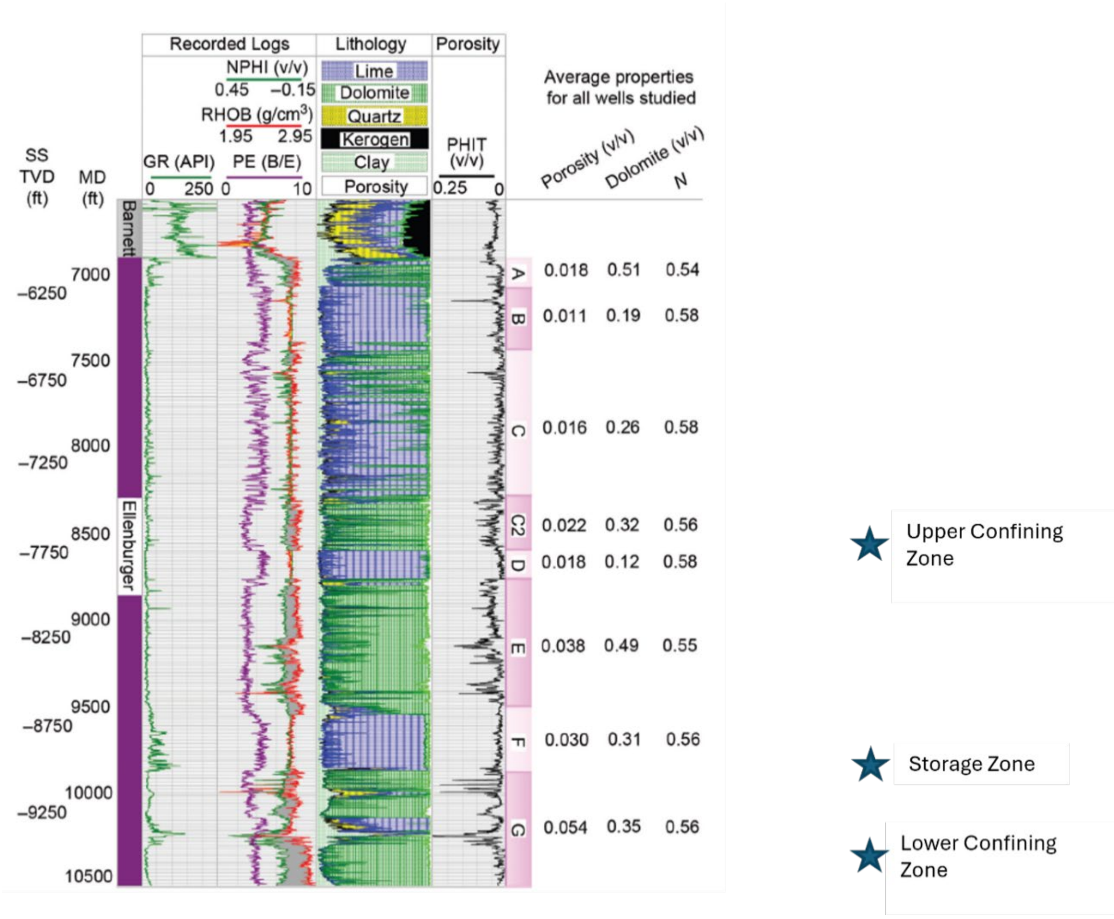


Figure 6. General properties of Ellenburger Subunits A-G in the project area (modified from Smye *et al.*, 2015).

The Barnett RDC 1 injection well located approximately 27 miles northwest of the proposed injection site also contains Ellenburger Subunits A through F, as shown below in **Figure 7**. Drilling at the proposed site should result in reservoir and seal intervals like those shown in both **Figures 6 and 7**.

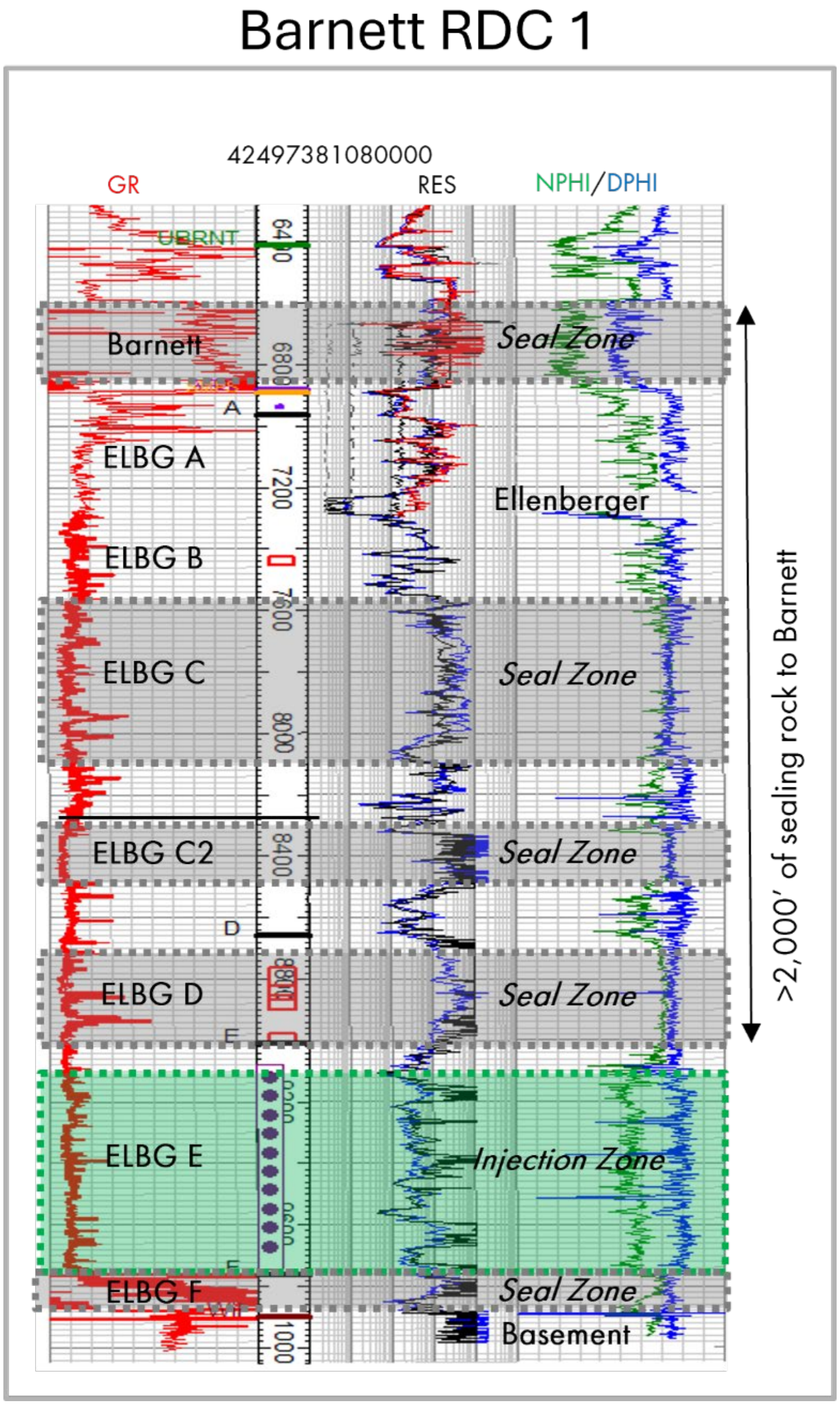


Figure 7. Barnett RDC 1 well log interpretation; Ellenburger Subunits A through F are denoted on the log image.

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 as the cut-off because fractures greatly enhance

permeability and improve Ellenburger reservoir quality even in intervals with very low matrix porosity.

Saltwater disposal into analogous Ellenburger intervals with low porosity lend support to the premise that a low log porosity could still result in realizable CO_2 storage potential (*e.g.*, Tarrant North SWD 1). 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 interval properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger as seen in the Tarrant North SWD 1 well.

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

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHIA])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolostone	372	160	0.43	3.3	
B	Limestone	307	25	0.08	1.3	Upper Confining Interval
C	Limestone	906	284	0.31	2.4	
C2	Dolostone	281	88	0.31	2.5	
D	Limestone	502	288	0.57	3.5	
E	Dolostone	1087	700	0.64	4.2	Storage Interval
F	Limestone	136	4	0.03	1.1	Lower Confining Interval
G	Dolostone	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature and informed by the core data from the Barnett RDC 1 well. Regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.5 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.25°F per 100 feet using the well logs from the Tarrant North SWD 1.

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 v3.0, six wells within in the Fort Worth Basin were identified with water samples from the Ellenburger as shown in **Figure 8**.

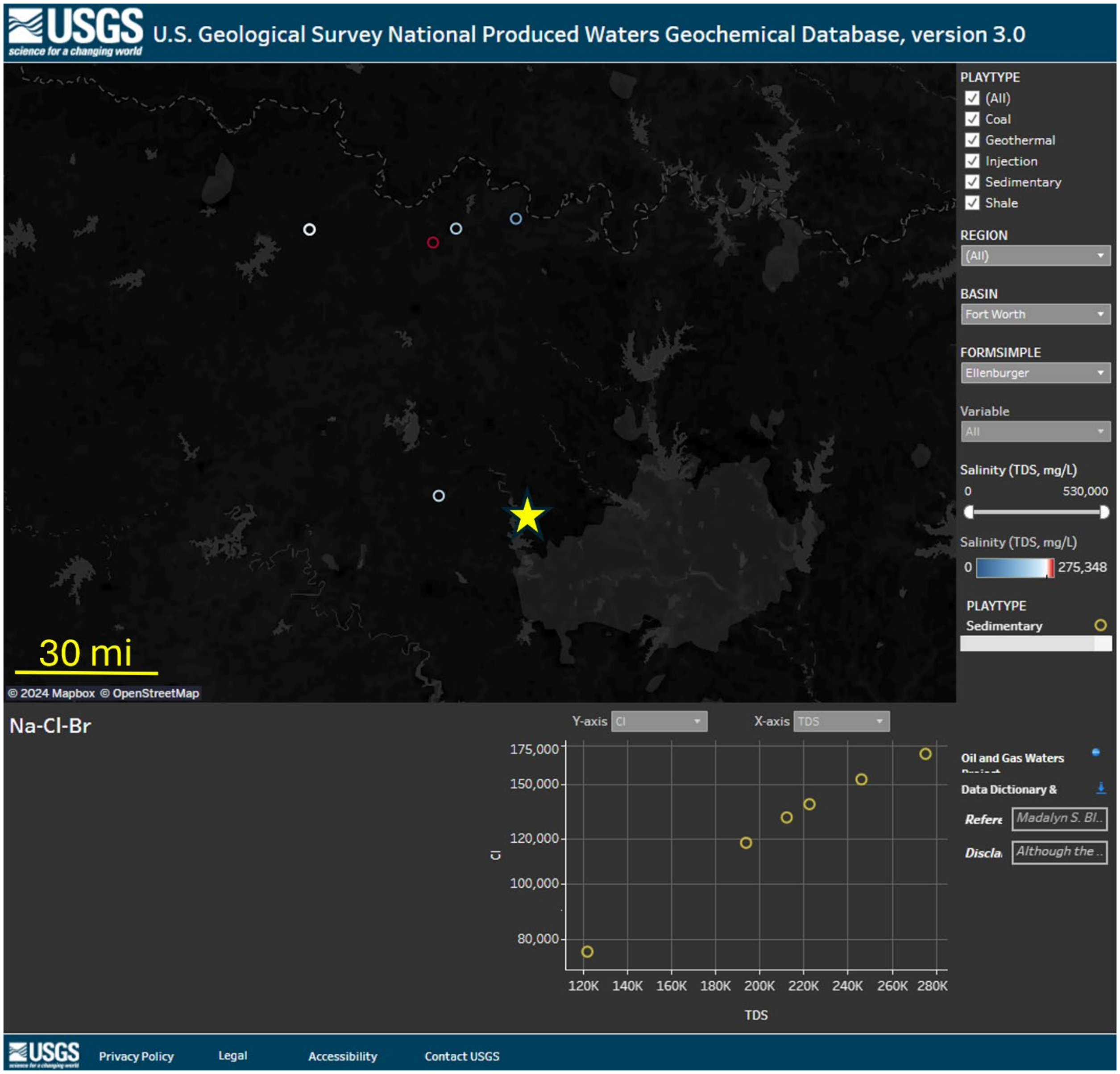


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis. The Cotton Cove CCS 1 location is shown with the yellow star. North is up.

The Ellenburger Group is not productive of oil and gas 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. The USGS database indicates that Ellenburger fluids have greater than 190,000 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin as reported in **Table 3**. The average of the six samples available in the USGS database is very close to the TDS value that dCarbon obtained from the Barnett RDC 1 well. The well sample had 214,612 ppm TDS, a pH of 7.4, an Na concentration of 54,465 ppm, a Ca concentration of 22,269 ppm, and a Cl concentration of 128,819 ppm.

Table 3. Ellenburger Formation fluid chemistry. These values are derived from the six wells depicted in Figure 8.

	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 Formation

An analysis of historical seismic events within 100 square miles surrounding the proposed Class II well injection site shows seismic activity dating back to 1900, according to the U.S. Geological Survey (USGS) Earthquake Catalog (**Figure 9**). Of the nine earthquakes above magnitude 3.0 shown on the map, three fall within the 100 square-mile area. All but one of the nine earthquakes appear to be part of the Azle-Reno earthquake swarm, documented by Hornbach, *et al*. (2015) (**Figure 10**). The Azle-Reno swarm earthquakes were mapped back to an NNE-SSW basement-rooted fault and its antithetic fault via data from a local earthquake network and advanced hypocenter location techniques. It is likely that the wide scatter in the mapped earthquake locations seen in the USGS catalog is a function of the location uncertainty due to the sparse recording array rather than actual separation of earthquake hypocenters.

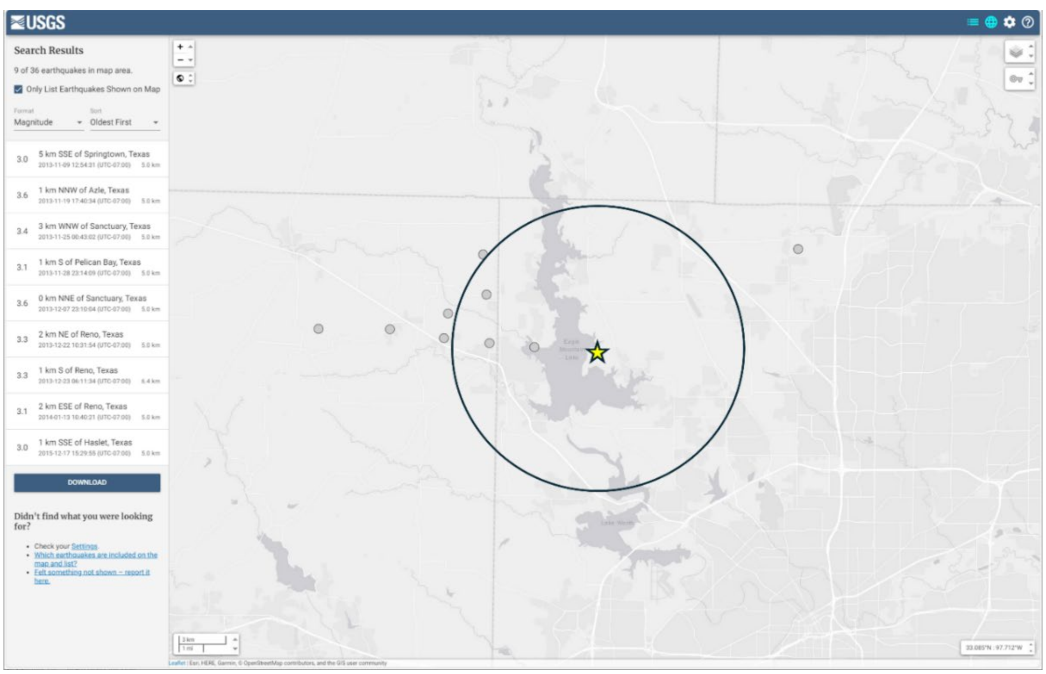
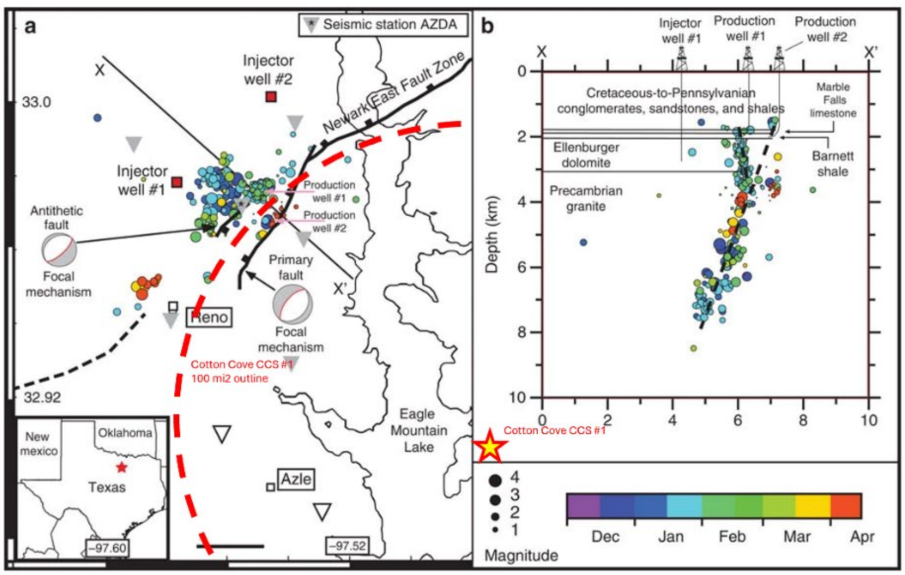


Figure 9. Screenshot from the USGS Earthquake Catalog showing historical seismic activity at or above Magnitude 3.0 in the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. Three seismic events meet these criteria in the USGS catalog. North is up.

Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey (Hennings, *et al.*, 2019). Current findings show that steeply dipping faults that strike north-northeast have the highest fault slip potential. These results are consistent with the orientation of the faults that produced the Azle-Reno swarm. No additional earthquakes have been reported since 2015 despite several saltwater disposal wells that inject in the Ellenburger Group continuing to operate in the area. Beginning in August 2023, BKV began operating a local earthquake network covering portions of Wise, Denton, Parker and Tarrant Counties in Texas (**Figure 11**). No earthquakes have been detected within the 100 square-mile area surrounding the Cotton Cove CCS 1 location with this array since it began recording.



Map showing the location of NEFZ (black) at the top of the Ellenburger formation, inferred faults (dashed) at the top of the Ellenburger formation, injection wells (red squares), two production wells (API 36734045 and 36734139) with significant brine production near the faults (pink arrows) and earthquake epicentres (coloured circles) recorded by the temporary seismic network (triangles) (**a**). The red star in the inset of **a** shows the map location. The black scale bar in **a** is 2 km. Grey (white) triangles indicate the locations of active (inactive) seismic stations. Line X–X′ in **a** shows the location of the cross-section shown in (**b**). We interpret two faults based on earthquake location and consistent with industry interpretations: a primary normal fault and a shallower antithetic normal fault.

Figure 10. Modified from a map from Hornbach *et.al.*, 2015. Earthquake hypocenters for the 2013-14 Azle-Reno swarm were located using a local array of seismometers resulting in reduced location uncertainty. Earthquakes were clustered along a northwest-dipping normal fault and it's southeast-dipping antithetic fault. These earthquakes cluster just outside of the line marking the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. North is up.

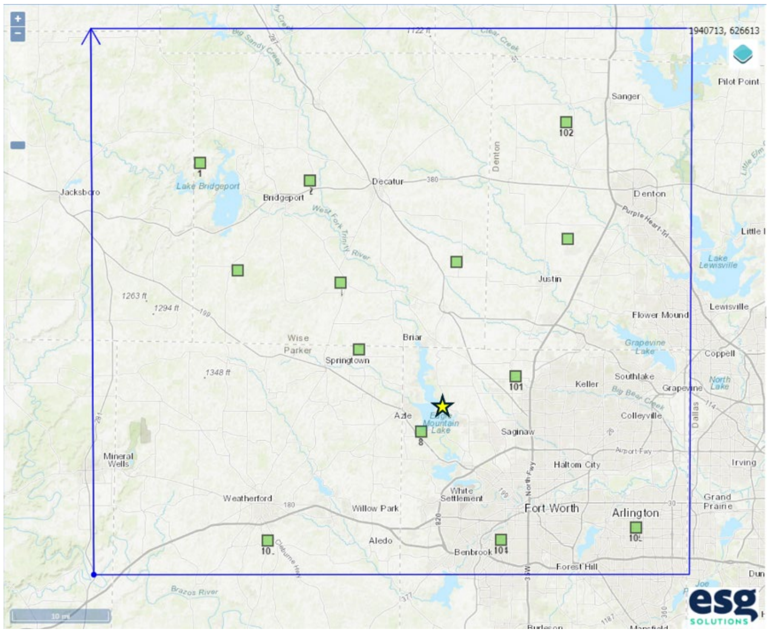


Figure 11. The yellow star marks the location of the Cotton Cove CCS 1. Seismic stations contributing data to the BKV seismic analysis are shown with the green squares. Stations 1-8 are operated by BKV while Stations 101-105 are operated by either TexNet or the USGS and their data are used in the hypocenter locations. North is up.

3.6 Groundwater Hydrology in MMA

Tarrant County falls within the Northern Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 12**). One aquifer is within the vicinity of the proposed injection site: the Trinity Group Aquifer. The Lower Cretaceous Trinity Group is classified as a major aquifer and serves as an important source of groundwater for a portion of northern Texas, including Tarrant County, Texas. The Trinity Group Aquifer outcrops at the Cotton Cove CCS 1 site and across a large swath of Wise and Parker Counties and the northwestern corner of Tarrant County.

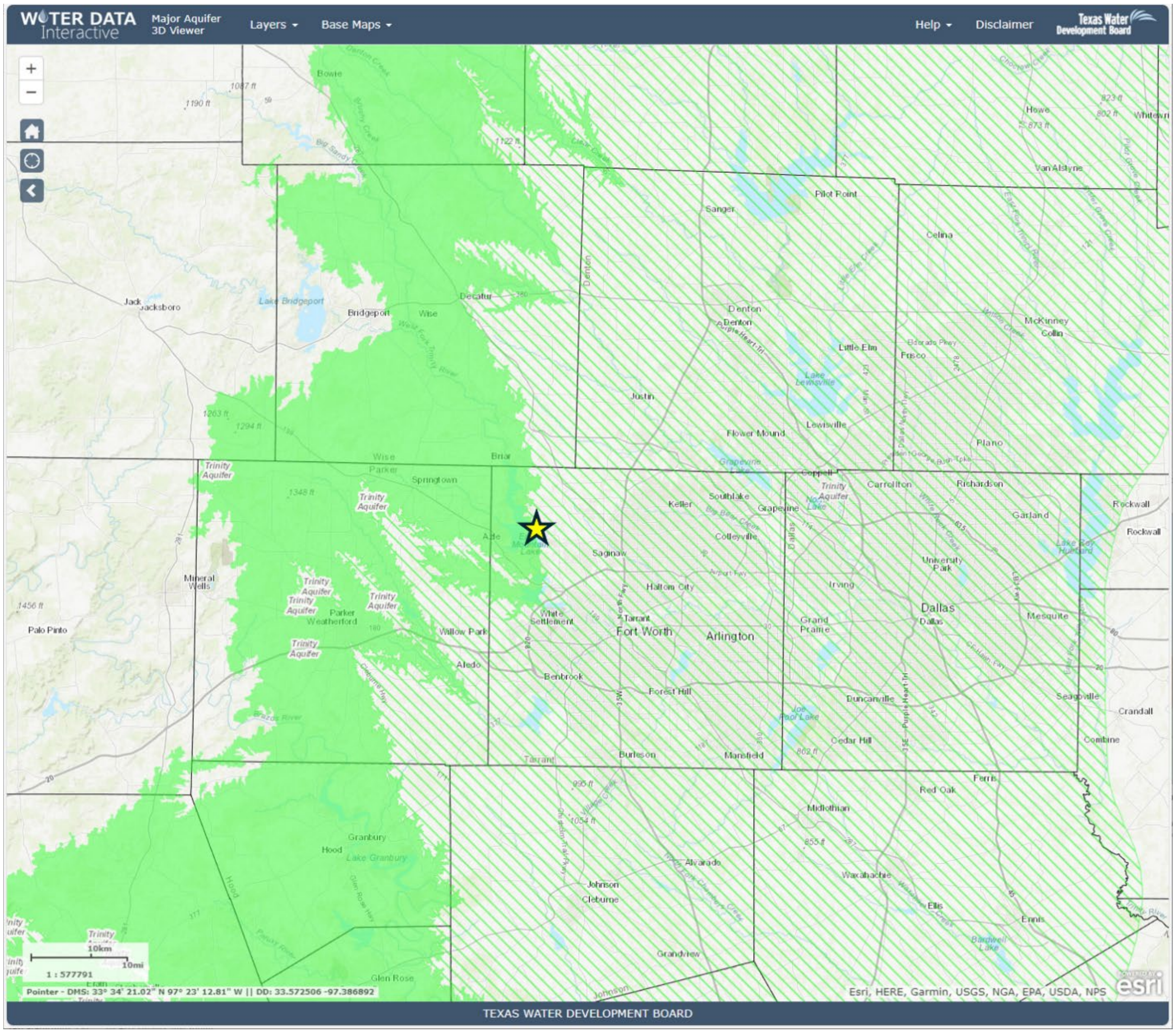


Figure 12. Map of the Trinity Major Aquifer extent within North Central Texas, from the Texas Water Development Board Interactive Viewer. The location of the proposed Cotton Cove CCS 1 is shown with a yellow star. North is up.

The Trinty Group Aquifer is unconfined west of the project site and confined east of the site (**Figure 12**). Water in the Trinity Group Aquifer is considered fresh but hard, with TDS values in the project area of less than 1,000 mg/L. The overall stratigraphic column contains numerous barriers to vertical flow (or aquitards) that are expected to prevent CO_2 injected into the Ellenburger Subunit E from reaching the surface or near surface location of the Trinity Group Aquifer (**Figure 13**).

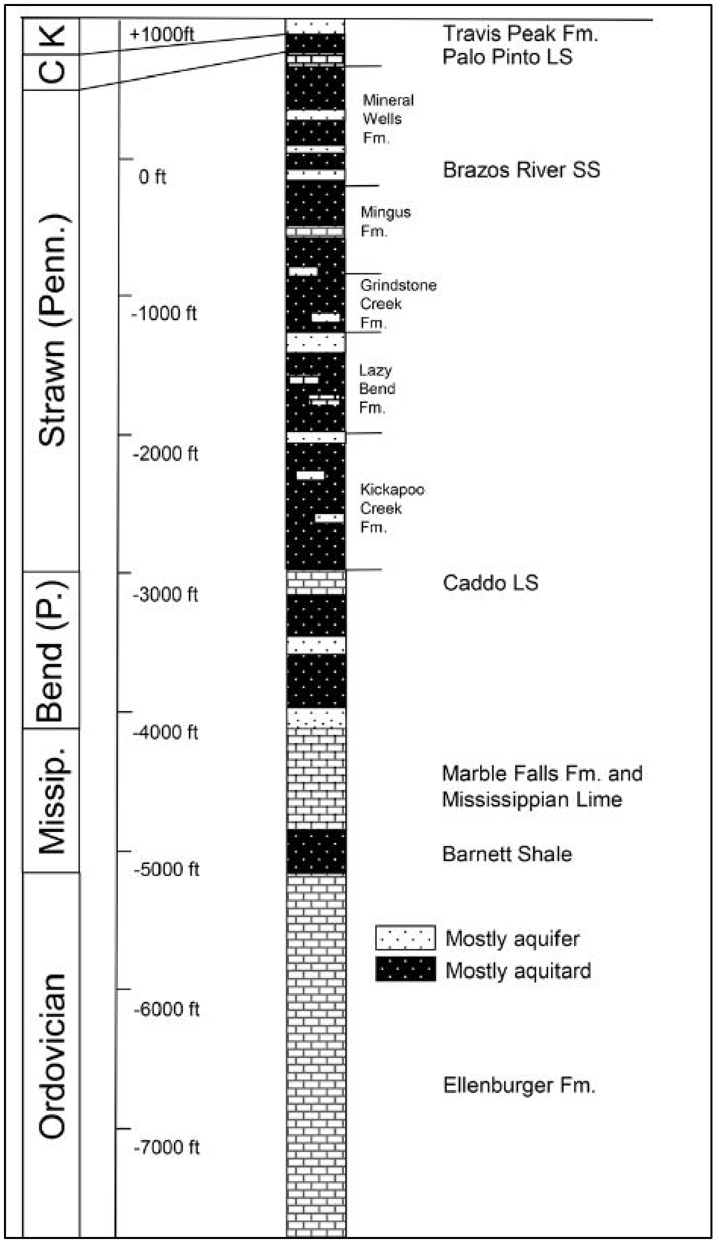


Figure 13. Stratigraphic column denoting aquifers and aquitards, modified from Nicot *et al.*, (2011)

There are 107 freshwater and wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, as shown in **Figure 14** and listed in **Table 4**.

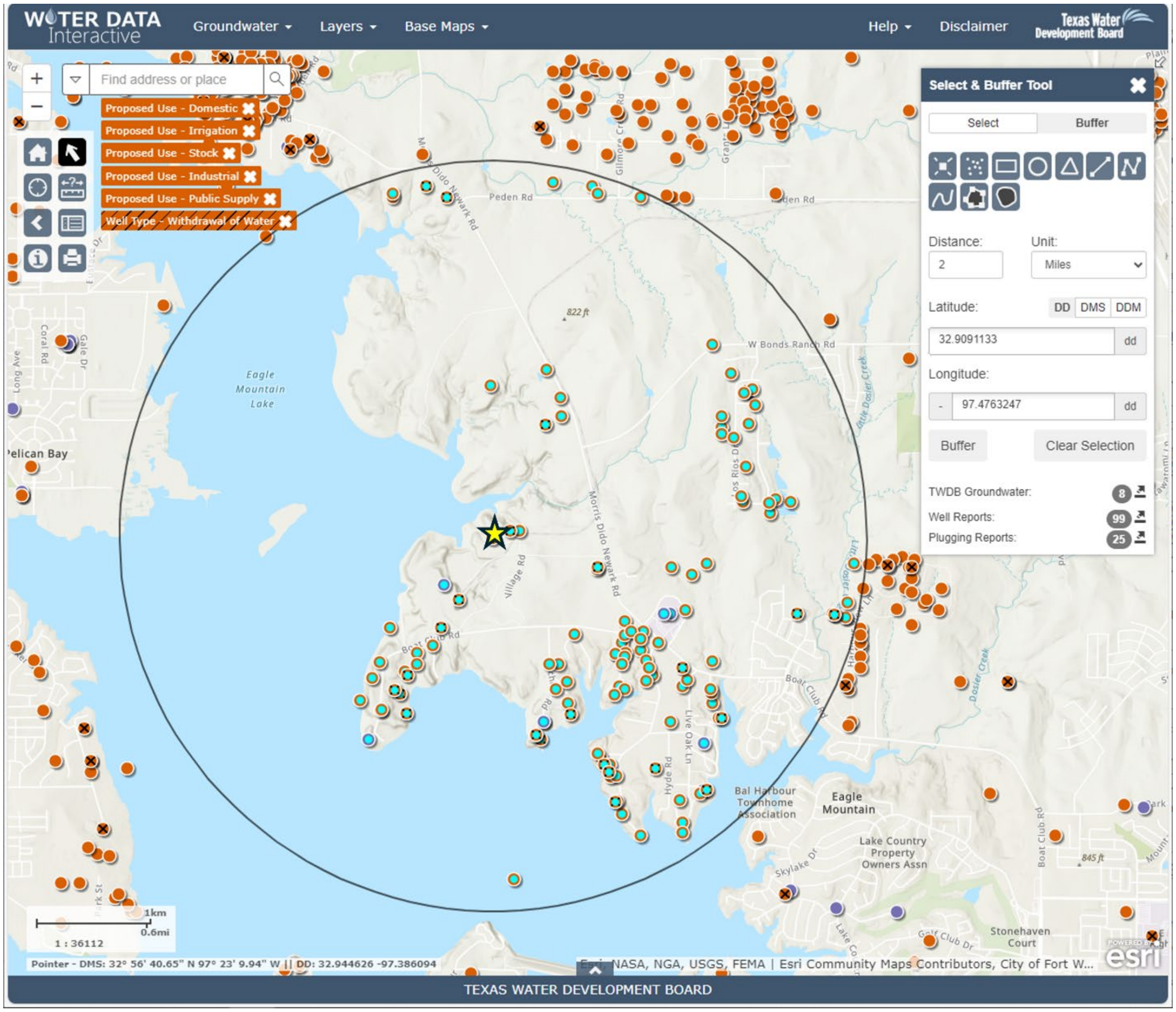


Figure 14. Water wells within two miles from the proposed injection site, data from the Texas Water Development Board Interactive Viewer. North is up.

Table 4. Groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
4945	32.8825	-97.474444	200
8105	32.886945	-97.458889	140
8162	32.888611	-97.459167	140
9201	32.899167	-97.483334	205
23976	32.896389	-97.488611	340
23981	32.916667	-97.454167	355
24611	32.902778	-97.443889	330
27215	32.921667	-97.454445	377
27217	32.9175	-97.455278	380
27266	32.914445	-97.453056	340

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
27268	32.916944	-97.455278	380
27269	32.918333	-97.455278	340
27270	32.920278	-97.453056	350
27271	32.920278	-97.453056	350
27273	32.917778	-97.452778	380
27274	32.919167	-97.452223	335
30454	32.936111	-97.467222	355
37395	32.891945	-97.466389	238
45494	32.902778	-97.443889	320
57105	32.935556	-97.466667	942
80342	32.923889	-97.456112	220
86272	32.889167	-97.457223	140
104755	32.908889	-97.476389	266
123923	32.900278	-97.462778	200
123929	32.899445	-97.462223	200
126757	32.901945	-97.485834	180
156542	32.898334	-97.461667	253
161948	32.901667	-97.462501	280
190665	32.892222	-97.466667	266
194317	32.903334	-97.458612	180
196988	32.900834	-97.464445	260
196990	32.899722	-97.464167	260
197152	32.935278	-97.462778	280
197159	32.936389	-97.470833	280
202905	32.909445	-97.473889	738
204320	32.902501	-97.464167	180
204322	32.900834	-97.461112	180
210501	32.901389	-97.464167	140
210511	32.906112	-97.458056	380
210912	32.896111	-97.469444	200
234675	32.894722	-97.460001	140
255591	32.899167	-97.464445	286
257427	32.901667	-97.463612	200
257473	32.901112	-97.462778	200
257476	32.898611	-97.484445	180
267624	32.898889	-97.461945	210
268343	32.899167	-97.470278	235
306601	32.899167	-97.471111	200
317205	32.896111	-97.456112	200
323205	32.921944	-97.471389	294

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
324408	32.895	-97.455556	180
330547	32.898056	-97.4875	172
364478	32.900001	-97.483334	224
365834	32.906945	-97.456667	260
367478	32.911667	-97.453334	297
373975	32.910834	-97.450834	297
377943	32.911667	-97.448889	320
386419	32.935278	-97.485556	240
387615	32.886111	-97.458889	200
389582	32.891389	-97.465556	280
392805	32.935556	-97.485556	220
395997	32.897222	-97.470555	200
396019	32.906945	-97.443056	300
403825	32.911945	-97.450278	297
407372	32.895556	-97.486667	320
407944	32.899286	-97.486792	210
412976	32.906531	-97.466806	802
415271	32.897861	-97.462194	260
438110	32.897417	-97.464733	160
458834	32.900585	-97.481922	320
463887	32.912167	-97.453444	347
469393	32.896937	-97.456209	200
508639	32.897211	-97.456264	200
513027	32.90004	-97.46411	200
520574	32.890422	-97.465485	220
527005	32.88756	-97.46444	140
532284	32.91165	-97.45088	322
534258	32.90395	-97.44367	372
535973	32.8994	-97.45613	180
545467	32.895599	-97.486566	281
550851	32.920408	-97.452453	400
557415	32.89743	-97.45887	260
562605	32.897185	-97.464191	200
573642	32.897149	-97.485324	200
579758	32.885889	-97.462765	180
583511	32.906633	-97.4599	220
585719	32.89795	-97.45848	220
587677	32.897767	-97.469483	240
634201	32.901472	-97.468833	160
641548	32.888573	-97.464852	222

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
644810	32.89678	-97.46515	278
648844	32.89053	-97.46497	280
649674	32.91975	-97.47009	170
654239	32.90302	-97.44504	360
662127	32.9183	-97.47005	335
667007	32.89999	-97.46504	265
667223	32.89999	-97.46504	265
677269	32.9207	-97.47656	313
677560	32.920123	-97.45321	420
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**
3205701	32.894722	-97.471667	273
3205702	32.894722	-97.471667	261
3205703	32.905278	-97.480833	196
3205704	32.893334	-97.487778	656
3205705	32.903056	-97.460001	194
3205706	32.903056	-97.460556	320
3205804	32.889445	-97.456945	233
3205805	32.893056	-97.456945	220

3.7 Description of CO_2 Project Facilities

dCarbon will accept CO_2 from by the Cotton Cove Processing Facility (**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 Cotton Cove CCS 1 injection site. The CO_2 stream will be metered to verify quantity. The CO_2 will then be injected into the Ellenburger Subunit E as previously described. 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 5**. Although the aforementioned industry-standard sampling of the CO_2 stream is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly over time.

Figure 15. Proposed CO_2 transport and processing layout. North is up.

Table 5. CO_2 stream analysis for the Cotton Cove CCS 1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.007	0.011	0.007
Carbon Dioxide	99.8514	99.665	99.8514
Methane	0.095	0.261	0.095
Ethane	0.013	0.019	0.013
Propane	0.002	0.002	0.002
Isobutane	0.008	0.006	0.008
N-butane	0.001	0.001	0.001
Isopentane	0.003	0.002	0.003
N-pentane	0.000	0.000	0.000
Hexanes	0.006	0.003	0.006
Heptanes	0.000	0.000	0.000
Octanes	0.000	0.000	0.000
Nonanes	0.000	0.000	0.000
Decanes plus	0.000	0.000	0.000
BTEX	0.002	0.000	0.002
H_2S	0.000	0.000	0.000
H2O	0.012	0.030	0.012
Total	100	100	100

Total Sample Properties			
Property	Value		
BTU (Gross)	3.15		
Density (lbs/gal)	4.09		
Molecular weight	43.93		
Specific gravity (Air=1)	1.5167		

3.8. Reservoir Characterization Modeling

A regional subsurface model was created in Schlumberger's Petrel software. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1, as discussed in previous sections) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals to contribute to overall higher fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E, This assumption is supported by consistent saltwater disposal rates and injection volumes into the Ellenburger Group 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 Cotton Cove CCS 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.

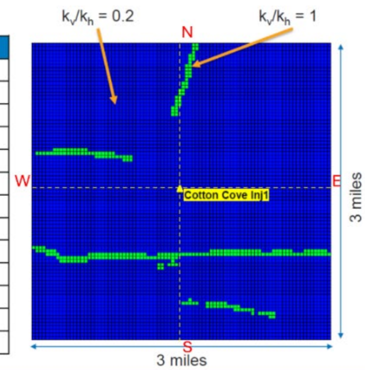
The primary objectives of the simulation model were to:

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
4. Quantify the increase in pore pressure dues to CO_2 injection spatially within the reservoir

The CO_2 storage complex is confined to the Ellenburger Group. The Ellenburger Subunit E is modeled as the reservoir interval and the Ellenburger Subunits B-D are modeled as the primary seal to impede vertical fluid flow. The lower confining interval for the reservoir is modeled as the Ellenburger Subunit F.

An SEM with the dimensions of 8.8 miles by 6.4 miles by 2.3 miles (X, Y, and Z) was constructed from elevation grids and faults derived from 3D seismic data and well log information (**Figure 16**) in Schlumberger's Petrel software. A 4-mile by 4-mile tartan grid was generated and then exported to Rock Fluid Dynamics's tNavigator simulator to account for fully implicit multiphase compositional fluid flow. This simulation was constructed to model other transport and mixing phenomena, i.e., relative permeability, diffusion, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be a completely saline aquifer. The salinity of the formation is estimated to be 200,000 ppm TDS, is typical of the Ellenburger Group in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering of the model with relationship to the simulated CO_2 saturation profile. The injection rate modeled was 75,000 MT/year for 12 years followed by 100 years of post-injection simulation to fully document the movement of CO_2. **Figure 16** also depicts the initial model conditions and a map view of permeability enhancements in the model due to mapped faults.

Input	Specifications
Total Number of Grid Blocks	1,732,470
N_x, N_y, N_z	64, 64, 199
D_x, D_y	250 ft * 250 ft
Injection Formation top	EB E ~ 8,180 ft TVDSS (8,920 ft MD)
k_v/k_h (matrix)	0.2
k_v/k_h (faults and karst)	1
Pressure Gradient	0.5 psi/ft
Temperature Gradient	1.25 deg F/100 ft + 70 deg F Surface
Injection rate	75 ktpa
Water saturation	100%
Fracture pressure Gradient	0.7 psi/ft
Maximum allowable pressure	90% of Fracture pressure
Salinity	200,000 ppm



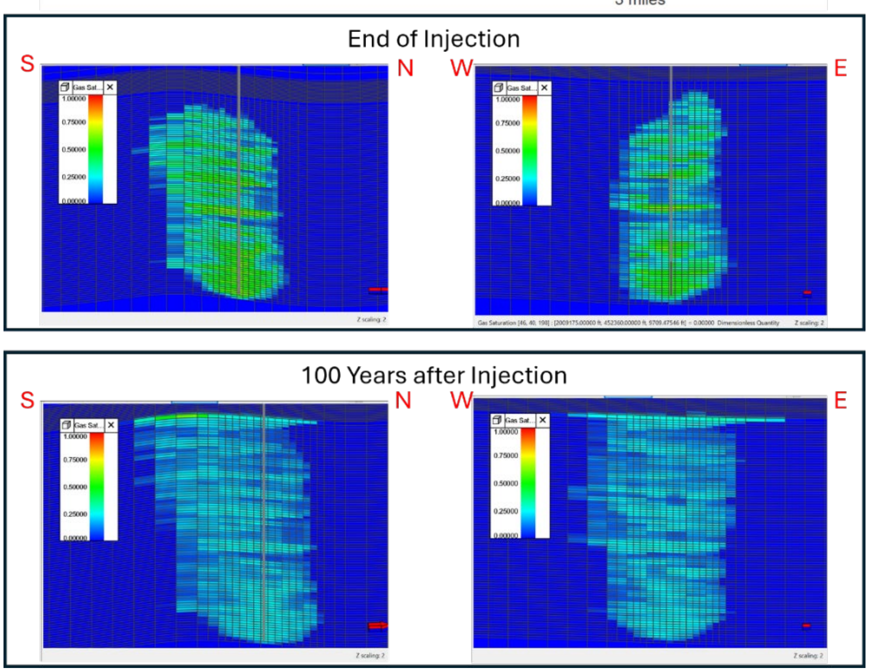


Figure 16. (Upper left table): Simulation conditions employed in the tNavigator model for the Cotton Cove CCS 1 well. (Middle and lower images): Depiction of the end of injection and 100 years after injection modeling results. The color bar in all images indicates modeled CO_2 gas saturation. (Upper right image): The map depicts the enhancement of permeability in certain areas of the model due to mapped faults.

The methodologies employed for static and dynamic models were based on established techniques in literature. Specifically, the reservoir relative permeability model was calculated from capillary pressure data from the Barnett RDC 1 using the Brooks and Corey (1966) model. The relative permeability curves for sealing layers were obtained from Bennion and Bachu (2007). The initial reservoir conditions were developed using gradients derived from Barnett RDC 1 well data. Mapped and inferred faults were given enhanced permeability in the simulation model of 400 mD and a 1:1 vertical to horizontal permeability. Ellenburger Group interpreted as affected by karsting, primarily in the Ellenburger Subunit A, was given the same enhanced permeability in the simulation model as the mapped faults.

While the top of the Ellenburger Subunit E reservoir interval was modeled at 8,920 feet at the injection well, the top of the perforated interval was chosen to be at 10,140 feet to force the CO_2 to first migrate vertically in the reservoir before hitting the seal at the Ellenburger Subunit D.

Using the aforementioned methodology to develop model estimates, the pressure gradient was assumed to be 0.5 psi per foot, which resulted in an estimated reservoir pressure of 5,070 psi at the top of the injection interval. The temperature gradient was assumed to be 1.25°F per 100 feet, resulting in an estimated temperature of 200°F at the top of the injection interval. 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 6,388 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 75 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 94 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 (green) compared to 94 years post injection (cyan). Injected CO_2 flows generally west, which is the regional up dip direction. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation.

Figure 17. Simulation results showing CO_2 Plumes (end of injection = green and after 100 years of injection = cyan). North is up.

Figure 18 illustrates bottom hole pressure at the Cotton Cove CCS 1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is ~5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and 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, the flow transitions from capillary driven to advection driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

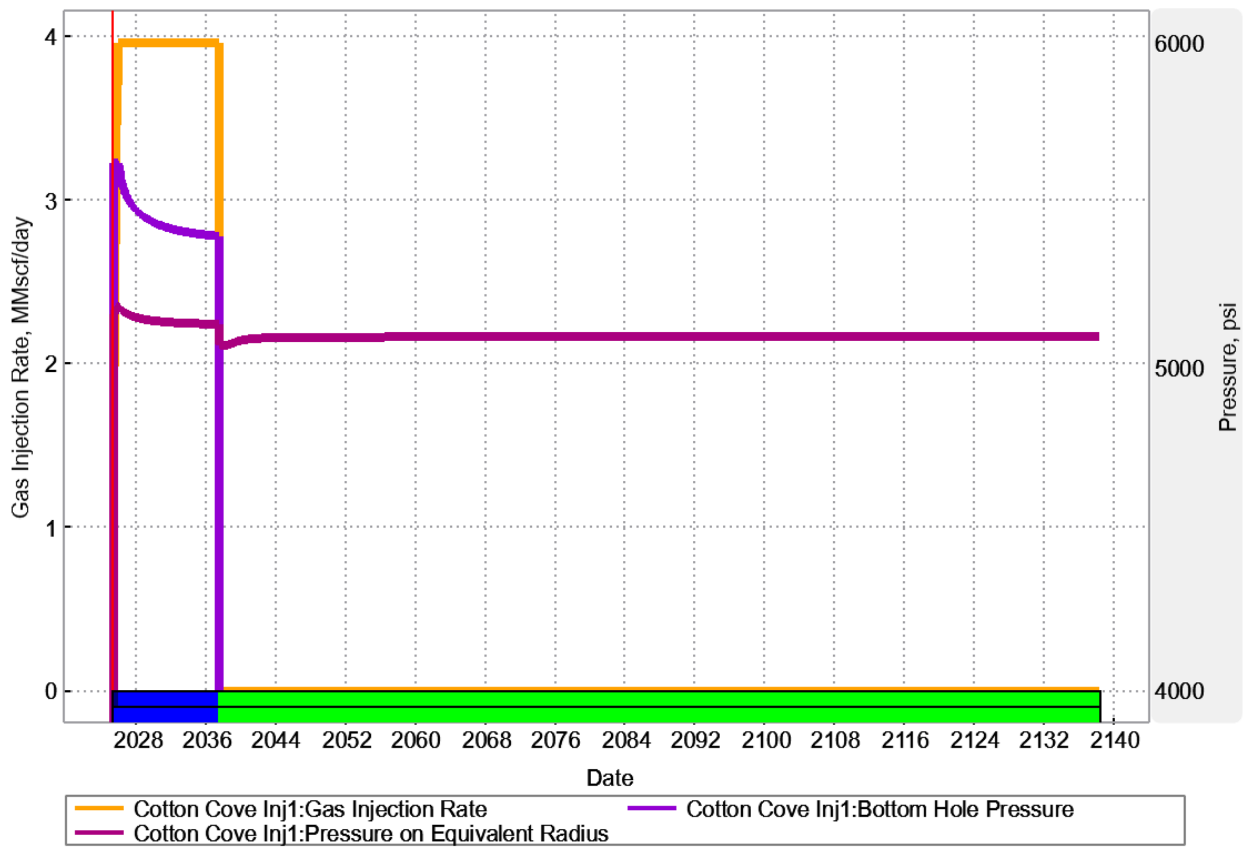


Figure 18. Modeled injection profile at Cotton Cove CCS 1 well. Gas injection rate shown in MMscf/day on the left Y axis and bottom hole pressure and pressure on equivalent radius shown in psi on the right Y axis. The blue bar along the X axis indicates the 12-year injection period and the green bar indicates the 100-year post-injection period.

4 – DELINEATION 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 of at least one-half mile. The numerical simulation using tNavigator as discussed above was used to estimate the size and migration of the CO_2 plume. We modeled injection of CO_2 into the Ellenburger Subunit E for 12 years followed by 100 years of post-injection modeling. Results indicated that the plume ceased to migrate after 94 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of gas saturation was used to determine the boundary of the CO_2 plume. The area of the MMA was determined to be 3.07 square miles with the greatest extent reaching 1.5 miles from the injector. **Figure 19** shows the End Of Injection (EOI) plume (green), the 94-year post-injection plume (black solid), and the MMA using a 0.5 mi buffer (black dashed).

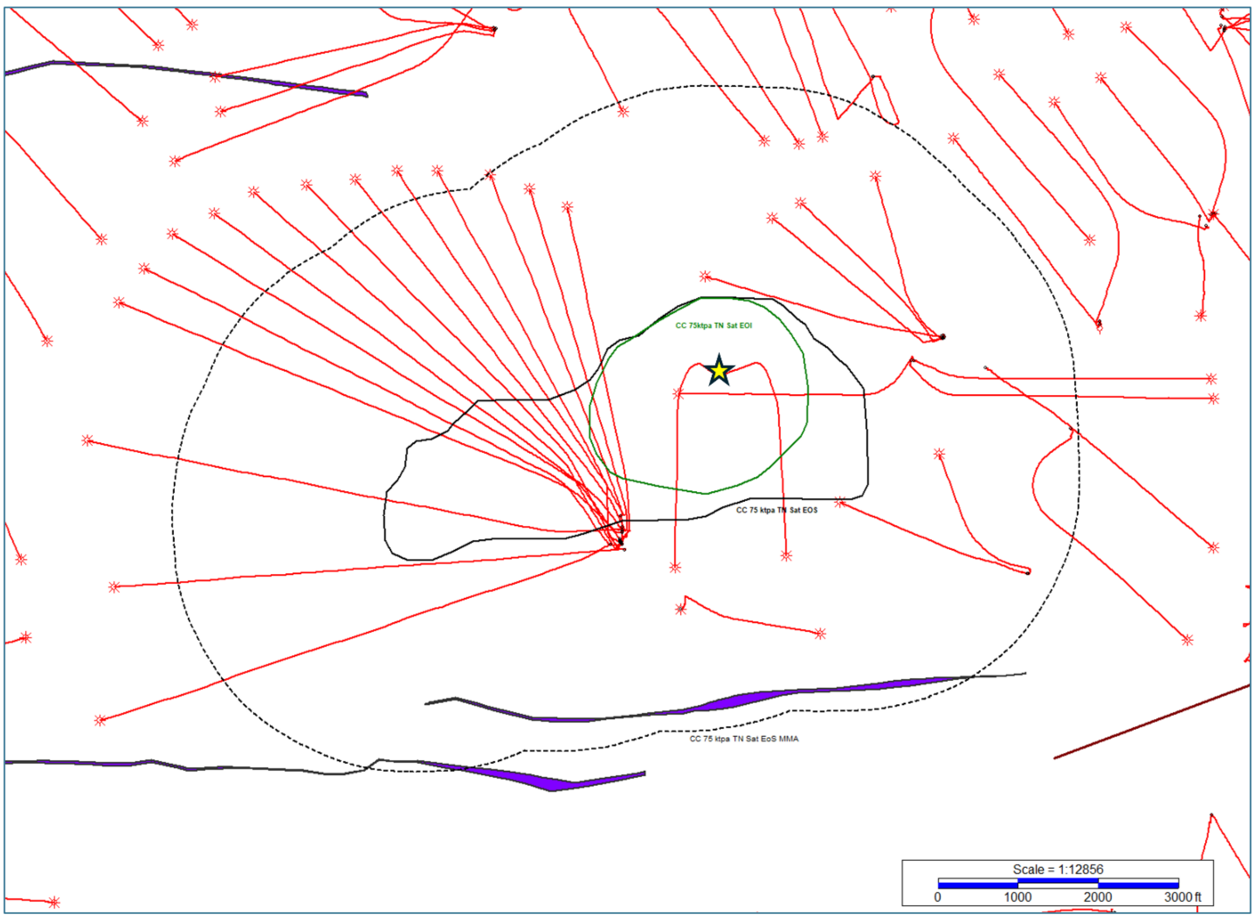


Figure 19. MMA (black dashed), EOI plume (green), and 100-year post injection plume outlines (black solid) as modeled at the Cotton Cove CCS 1 well (yellow star). Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. Thin purple polygons are fault polygons at the top of the Ellenburger Group. North is up.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features mapped within the project area that could cause the unintended migration of the CO_2 plume through natural pathways to the USDW. The mapped faulting in the area does not extend shallower than the top of the Mississippian Marble Falls Formation, leaving more than 5,000 feet of mostly Pennsylvanian shales between the top of the faults and the USDW. 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 Sections 4 and 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 12, which is projected to be the EOI. 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 12, plus an all-around buffer 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 17.

As noted in Section 4.1, dCarbon utilized the plume area after 94 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 (black dashed) and currently existing 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 802 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

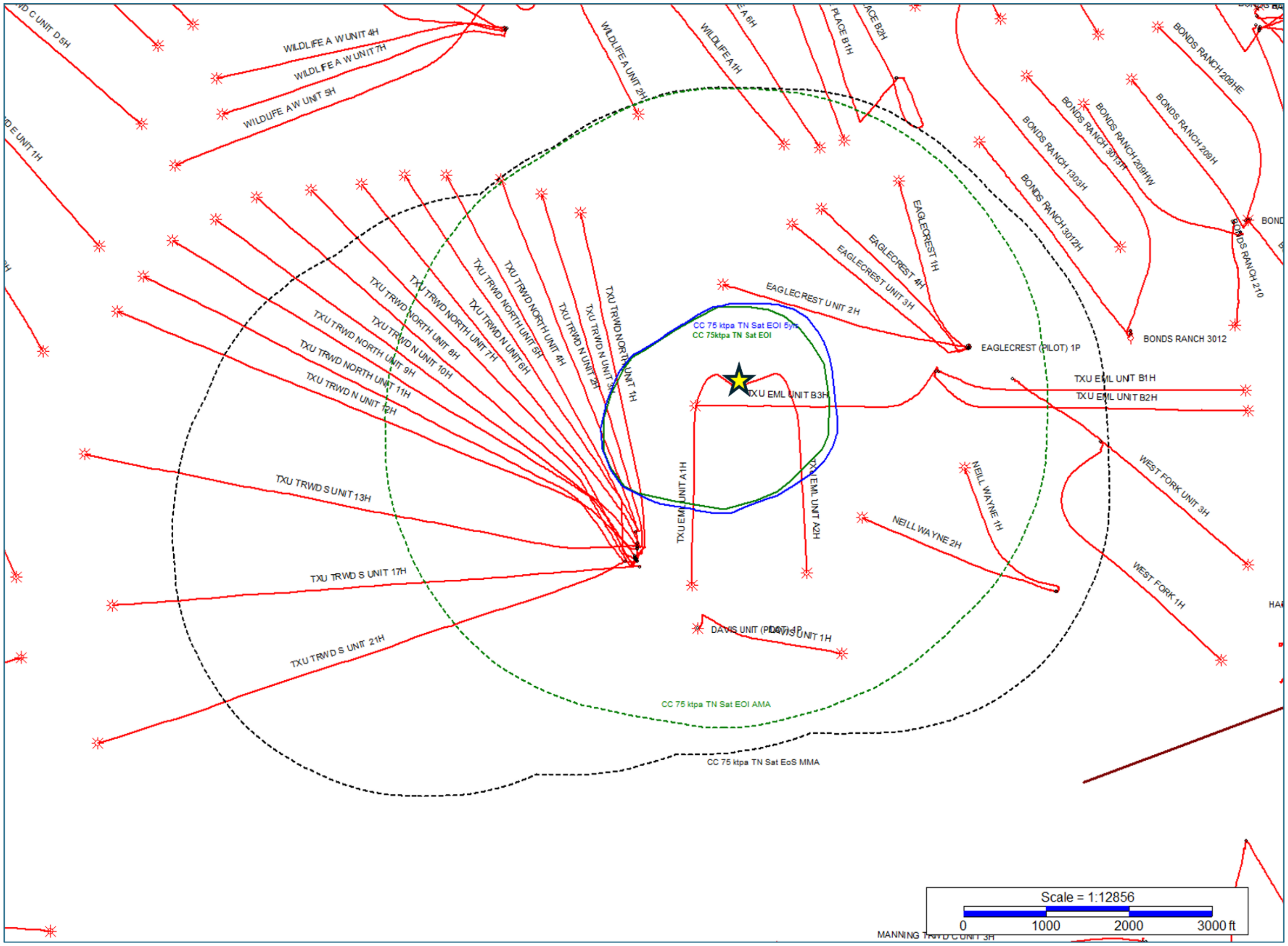


Figure 20. The calculated AMA (green dashed) and existing wells within the project AMA/MMA. The solid green and blue outlines show the extent of the CO_2 plume at EOI and five years post-injection respectively. The MMA is shown as the black dashed line for comparison. The Cotton Cove CCS 1 is shown as a yellow star. Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. North is up.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at the Cotton Cove Processing Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 5**. 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 four or five gases, including 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 CO_2 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 other than the Cotton Cove CCS 1 well.

5.3 Leakage from Existing Wells

There are 34 existing wells within the MMA. Of these 34 wells, one had a pilot borehole for the subsequent horizontal well (**Table 6)**. The 34 wells all have active status. However, all these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 8,800 feet) is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells were drilled shallower than the target Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented over their entirety 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 CO2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to travel via faults in the Ellenburger to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production. Injected CO_2 entering the Barnett Shale could be produced in the gas stream of these wells. While this is considered improbable due to the modeling showing no CO_2 reaching the enhanced permeability areas of the model, dCarbon will consider this potential pathway specifically in its monitoring program.

Table 6. Existing oil and gas wells in MMA with TRRC records.

Well Name	Well Number	UWI	Latitude	Longitude	Operator Current	Operator Original	Total Depth(f)	Status
LAKE PLACE	B1H	424393102900	32.9191420	-97.4698666	BKV NORTH TEXAS LLC	ANTERO RESOURCES INC LP	8650	Gas Well
WILDLIFE	A1H	424393119200	32.9239294	-97.4838481	BKV NORTH TEXAS LLC	XTO ENERGY INC	10435	Gas Well
WILDLIFE A UNIT	2H	424393119600	32.9240571	-97.4837859	BKV NORTH TEXAS LLC	XTO ENERGY INC	8567	Gas Well
EAGLECREST	1H	424393124000	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	8641	Gas Well
EAGLECREST (PILOT)	1P	424393124077	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	6924	Location Only
EAGLECREST UNIT	2H	424393124400	32.9101730	-97.4670195	BKV NORTH TEXAS LLC	XTO ENERGY INC	9045	Gas Well
DAVIS UNIT	1H	424393137300	32.9008732	-97.4776844	BKV NORTH TEXAS LLC	XTO ENERGY INC	8227	Gas Well
DAVIS UNIT (PILOT)	1P	424393137377	32.9008732	-97.4776844	XTO ENERGY INC	XTO ENERGY INC	7158	Gas Well
NEILL WAYNE	1H	424393138400	32.9020862	-97.4635819	BKV NORTH TEXAS LLC	XTO ENERGY INC	8472	Gas Well
NEILL WAYNE	2H	424393138500	32.9020931	-97.4635666	BKV NORTH TEXAS LLC	XTO ENERGY INC	8889	Gas Well
WEST FORK	1H	424393162800	32.9070608	-97.4618388	BKV NORTH TEXAS LLC	SULLIVAN HOLLIS R INC	10163	Gas Well
LAKE PLACE	B2H	424393204200	32.9191465	-97.4698521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9088	Gas Well
TXU TRWD N UNIT	6H	424393221100	32.9035759	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	11683	Gas Well
TXU TRWD N UNIT	2H	424393221200	32.9040765	-97.4801342	BKV NORTH TEXAS LLC	XTO ENERGY INC	11025	Gas Well
TXU TRWD N UNIT	10H	424393223000	32.9035352	-97.4800689	BKV NORTH TEXAS LLC	XTO ENERGY INC	12585	Gas Well
TXU TRWD S UNIT	17H	424393223600	32.9029178	-97.4799856	BKV NORTH TEXAS LLC	XTO ENERGY INC	12845	Gas Well
TXU EML UNIT	A1H	424393245100	32.9089106	-97.4761473	BKV NORTH TEXAS LLC	XTO ENERGY INC	9164	Gas Well
TXU EML UNIT	A2H	424393262300	32.9089049	-97.4760521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9062	Gas Well
TXU TRWD S UNIT	13H	424393338100	32.9037054	-97.4800853	BKV NORTH TEXAS LLC	XTO ENERGY INC	13056	Gas Well
TXU TRWD S UNIT	21H	424393345100	32.9031007	-97.4805575	BKV NORTH TEXAS LLC	XTO ENERGY INC	13064	Gas Well
TXU TRWD N UNIT	12H	424393354600	32.9035061	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	13163	Gas Well

TXU EML UNIT	B1H	424393365600	32.9094039	-97.4683171	BKV NORTH TEXAS LLC	XTO ENERGY INC	10200	Gas Well
TXU EML UNIT	B2H	424393365800	32.9093921	-97.4683110	BKV NORTH TEXAS LLC	XTO ENERGY INC	10500	Gas Well
TXU EML UNIT	B3H	424393423300	32.9093969	-97.4682044	BKV NORTH TEXAS LLC	XTO ENERGY INC	9535	Gas Well
WEST FORK UNIT	3H	424393526800	32.9091561	-97.4652839	BKV NORTH TEXAS LLC	XTO ENERGY INC	9298	Gas Well
TXU TRWD NORTH UNIT	1H	424393598400	32.9032790	-97.4801794	BKV NORTH TEXAS LLC	XTO ENERGY INC	10350	Gas Well
TXU TRWD N UNIT	3H	424393598500	32.9032457	-97.4801754	BKV NORTH TEXAS LLC	XTO ENERGY INC	10694	Gas Well
TXU TRWD NORTH UNIT	5H	424393601000	32.9031750	-97.4801698	BKV NORTH TEXAS LLC	XTO ENERGY INC	11009	Gas Well
TXU TRWD NORTH UNIT	4H	424393603300	32.9032055	-97.4801726	BKV NORTH TEXAS LLC	XTO ENERGY INC	10765	Gas Well
TXU TRWD NORTH UNIT	7H	424393605300	32.9031776	-97.4801011	BKV NORTH TEXAS LLC	XTO ENERGY INC	11485	Gas Well
TXU TRWD NORTH UNIT	8H	424393605400	32.9031436	-97.4800911	BKV NORTH TEXAS LLC	XTO ENERGY INC	11846	Gas Well
TXU TRWD NORTH UNIT	9H	424393605500	32.9031212	-97.4800893	BKV NORTH TEXAS LLC	XTO ENERGY INC	12258	Gas Well
TXU TRWD NORTH UNIT	11H	424393605600	32.9030873	-97.4800851	BKV NORTH TEXAS LLC	XTO ENERGY INC	12522	Gas Well
LAKE PLACE	A7H	424393628200	32.9310611	-97.4774402	BKV NORTH TEXAS LLC	XTO ENERGY INC	11739	Gas Well
LAKE PLACE	A6H	424393628300	32.9310939	-97.4774460	BKV NORTH TEXAS LLC	XTO ENERGY INC	11470	Gas Well
EAGLECREST	4H	424393655400	32.9102140	-97.4670370	BKV NORTH TEXAS LLC	XTO ENERGY INC	8989	Gas Well
EAGLECREST UNIT	3H	424393655700	32.9101702	-97.4670211	BKV NORTH TEXAS LLC	XTO ENERGY INC	8975	Gas Well

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 such as the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita orogenic belt collision. These faults show displacement up into the base of the Pennsylvanian rocks. These larger, younger faults have greater displacement but are relatively sparce.

An east-west fault is interpreted at the south edge of the MMA, south of the Cotton Cove CCS 1 based on available subsurface data including 3D seismic data (**Figure 4**). A second, east-west fault may exist north of the MMA. These faults were included in the dynamic reservoir model as areas of enhanced permeability. Dynamic modeling indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. These faults terminate at the top of the Mississippian strata. It is highly improbable that injected CO_2 would migrate up faults to the USDW or to the surface through faults.

Karst development is present in some areas at the top of the Ellenburger. Karsting is often developed in the upper several hundred feet of an exposed carbonate (in this case, the Ellenburger Subunit A), where fresh water enters the shallow subsurface through fractures and dissolves the rock, creating underground caves with a thin roof (**Figure 21**). Subsequent loading of sediment can cause the thin cave roof to collapse, allowing the overlying sediment to fill the void (Zeng, 2011). These karsted sections of the Ellenburger were given enhanced permeability in the model as described earlier. We applied the enhanced permeability to the upper 500 feet of the Ellenburger, where karsted, as a conservative modeling assumption.

Karsting does not appear to affect any subunit of the Ellenburger below Ellenburger Subunit A, including Ellenburger Subunits B-D or the injection interval, Ellenburger Subunit E. This suggests that the Ellenburger Subunits B-D will remain a continuous upper seal for the injection interval even in karst areas. There are interpreted Ellenburger Subunit A karst features south and north of the Cotton Cove CCS 1, but the CO_2 plume does not intersect them, based on the dynamic modeling. Small karst features sitting at the northern edge of the MMA seem to have only impacted the upper 200 feet of the Ellenburger, leaving 2,000 feet of Ellenburger apparently unaffected as shown in the type log in **Figure 21**.

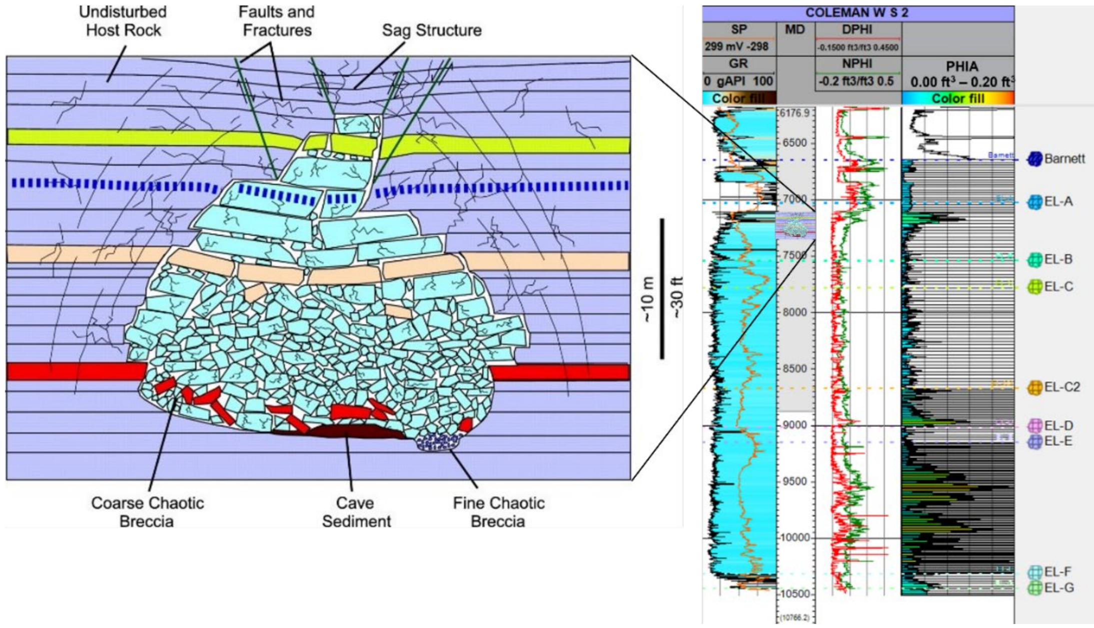


Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al*., 2011). The typical scale of the karst features is shown on the right placing the feature on the Coleman 1 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining Ellenburger Subunits B-D and not in the modeled plume area.

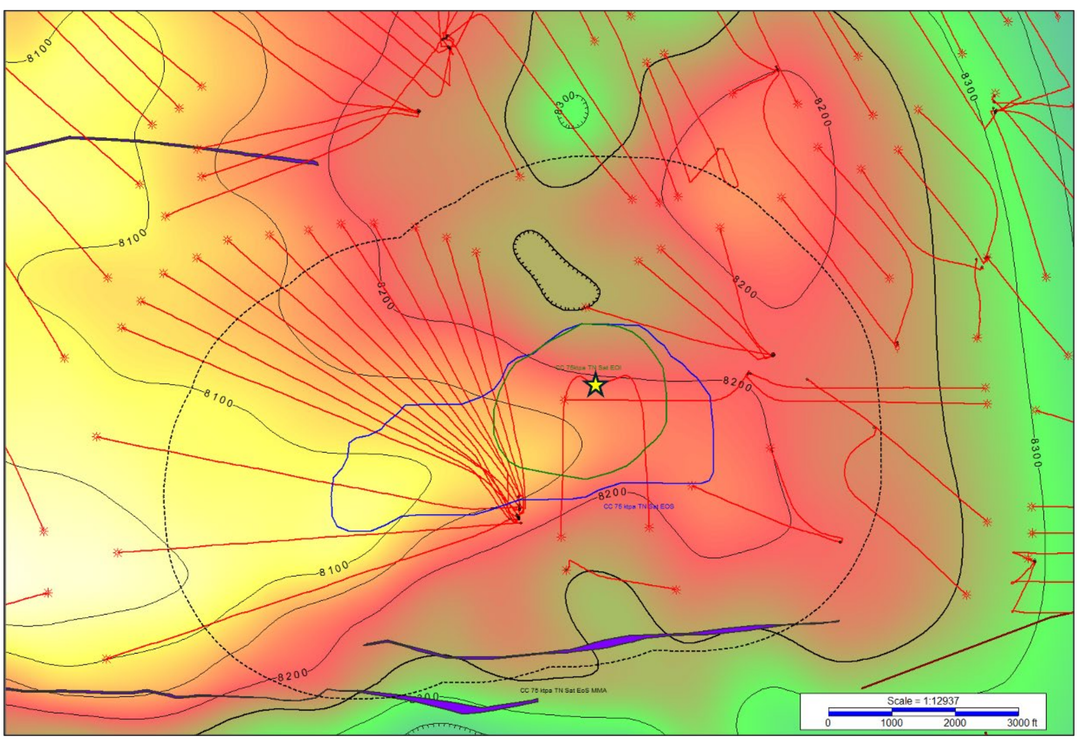


Figure 22. The Cotton Cove CCS 1 well location (yellow star) posted on a map of the top Ellenburger Subunit E depth structural contours in feet TVDSS with a contour interval of 500 feet from the simulation model. The CO_2 plume size at the end of injection (green) and 100 years post-injection are also shown as blue and dashed black outlines, respectively, from Figure 19.

5.5 LEAKAGE THROUGH CONFINING LAYERS

The Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D and below by the competent confining Ellenburger Subunit F. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA as described in Section 5.3.

5.6 LEAKAGE FROM NATURAL OR INDUCED SEISMICITY

The Cotton Cove CCS 1 well location is in an area of the Fort Worth Basin that has experienced seismic activity historically, as described in Section 3.5. The occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor.

The closest earthquake locations are more than five miles to the northwest of the Cotton Cove injection site 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 TRRC held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The TRRC 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 surface pressure gauges, so that reservoir pressure and injection pressure can be modeled and monitored. Additionally, consistent with TRRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 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 and reduce the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis (Walsh, *et al.,* 2017) 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 Cotton Cove CCS 1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

Furthermore, dCarbon installed new ground seismic monitoring stations 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 have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on 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. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection site is about two degrees up to the west (200 feet/mile), shown in **Figure 22**. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles (Tarrant North SWD 1).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

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

Table 7. 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 8. 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 12 hours of full permitted 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	**Unlikely**, 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 conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale 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 that reach shallow enough to serve as a conduit to the USDW or the surface.	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 2,000 feet 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 a couple 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 that extend shallow enough to reach the USDW or the surface.	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 5.8 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). This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur.

6.1 LEAKAGE FROM SURFACE EQUIPMENT

Monitoring will occur during the planned 12-year injection period, or until the cessation of operations. 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. As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of 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.

Periodic 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 observations, corrective actions will be taken to address such issues.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. 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.

Additionally, CO_2 for injection will be metered with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself (**Figure 23**). The injection stream will also be sampled and analyzed periodically with a gas chromatograph to determine final composition. The meter will each be calibrated to industry standards. Any discrepancies in CO_2 throughput at the meter 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 the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate 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.

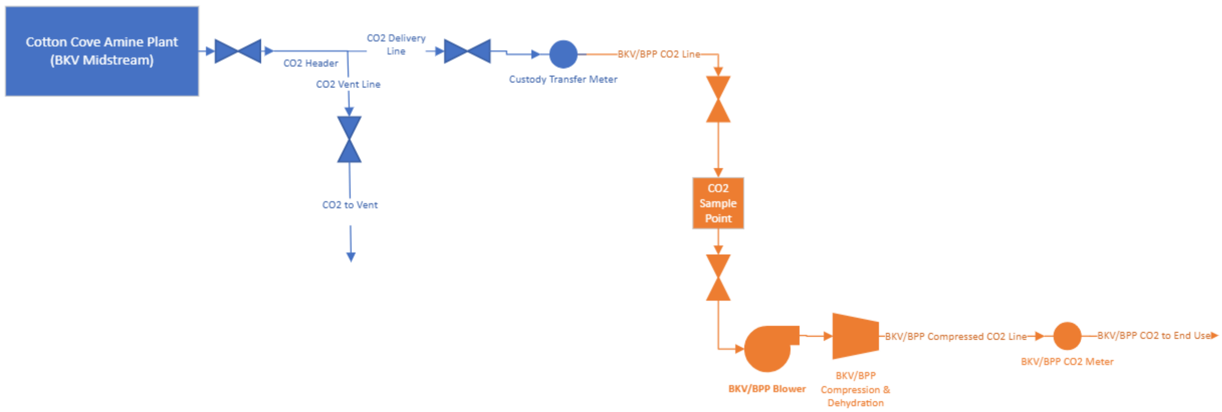


Figure 23. Project conceptual diagram and metering locations.

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 interval. 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, dCarbon will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will 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 in addition to pressure sensors for each annulus of the well. Annual bottomhole pressure and temperature measurements will be made to calibrate the surface readings to bottom hole. 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 gas samples quarterly 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 Cotton Cove CCS 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) 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 intervals 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 to the surface or to the USDW is improbable, given the number and thickness of competent layers between the injection interval and potable groundwater. Sampling of the produced gas stream from the gas wells within the MMA is the primary tool for detecting CO_2 that has bypassed the primary confining system. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems. 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 low, dCarbon operates a proprietary seismic monitoring array in the general area of the Cotton Cove CCS 1 well. This monitoring array augments 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 Cotton Cove CCS 1 well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, a situation that is very unlikely based on the location of mapped faults and the extent of the modeled plume.

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 four times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the only 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, like 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 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 sample the gas stream from the gas wells in the MMA. These wells should intercept CO_2 that might traverse the primary sealing interval before it bypasses the secondary seals. Noting the increase in CO_2 concentration in the produced gas stream will be a trigger for dCarbon to investigate and quantify possible leakage through the primary confining layers. dCarbon will document the methods used to calculate the volume of CO_2 leakage in its annual monitoring report.

dCarbon has access to a deep groundwater monitoring well at the Cotton Cove Gas Plant 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 intervals. 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. dCarbon will conduct baseline sampling of available water wells within the MMA prior to injection to establish a basis for comparison to later samples.

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 works with environmental services and data companies that specialize 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 may also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with high-fidelity CO_2 sensors 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 the X and Y axes (longitude + latitude) as well as the 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) (Korre, 2011). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. 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 (Chen, 2013).

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 Cotton Cove CCS 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.

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). There are three primary monitoring baselines that dCarbon will establish as part of this project.

Baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells 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 gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline seismicity in the area near the Cotton Cove CCS 1 has been determined through the historical data from USGS and TexNet seismic array data. This information is augmented by additional data from dCarbon's proprietary seismic monitoring array, operating since 2023.

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 Cotton Cove CCS 1 injection well will be 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 CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 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 on 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 Cotton Cove CCS 1 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the Cotton Cove CCS 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 2025. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA MRV plan 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 reported 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, if employed, will be operated continuously, except for maintenance and calibration.
- Gas detectors, if employed, 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 most recent 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 five 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.

12 – REFERENCES

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Attachment A

Copies of W-14, W-1, Drilling Permit

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

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

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

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

PERMIT NO. 17534

BKV DCARBON VENTURES, LLC
4800 BLUE MOUND ROAD
FORT WORTH TX 76106

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated September 12, 2024, for the permitted interval(s) of the Ellenburger formation(s) and subject to the following terms and special conditions:

COTTON COVE CCS (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
TARRANT COUNTY
DISTRICT 05

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC No.	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Gas (PSIG)
1	43900000	000126822	Carbon Dioxide (CO_2)	8806	11150	4000	2500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	43900000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO_2. Geologic sequestration of CO_2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. (A) The operator shall notify the Commission within 24 hours of a discovery of any monitoring or other information which indicates that any contaminant may cause an endangerment to a USDW; or any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs. Within 20 days of such a discovery, the operator shall file a report with the Commission documenting the event, findings, and response actions taken.** **(B) The permittee shall report the source(s) and the properties of injected acid gas as they are added. In no case may the volume of acid gas exceed the limit indicated in permit.** **(C) The well's construction and materials used must be resistant to corrosion per the proposed wellbore schematic that was submitted in the application.** **6. One or more seismic events have been recorded within the review area of this well. In addition to the standard H-10 Annual Disposal/Injection Well Monitoring Report, the operator shall collect and maintain daily records of injected volumes and maximum injection pressure. The operator shall make this data available to the Commission upon request.**

STANDARD CONDITIONS:

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

Note: This document will only be distributed electronically.

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

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

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

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

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

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

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

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

APPROVED AND ISSUED ON September 27, 2024.

for Ivan Salas, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

API No. 42-439-37356

Drilling Permit # 902971

SWR Exception

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No.: 100589

2. Operator's Name (as shown on form P-5, Organization Report): BKV DCARBON VENTURES, LLC

3. Operator Address (include street, city, state, zip): 4800 BLUE MOUND ROAD FORT WORTH, TX 76106

4. Lease Name: COTTON COVE CCS

5. Well No.: 1

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth: 12000

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

11. RRC District No.: 05

12. County: TARRANT

13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4 miles in a NW direction from Alze which is the nearest town in the county of the well site.

15. Section:

16. Block:

17. Survey: GARCIA, M

18. Abstract No.: A-564

19. Distance to nearest lease line: ft.

20. Number of contiguous acres in lease, pooled unit, or unitized tract: 2.22

21. Lease Perpendiculars: 144 ft from the S line and 133 ft from the E line.

22. Survey Perpendiculars: 296 ft from the N line and 1131 ft from the E line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	12000	0.00	1

Remarks

Certificate:

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

Bill Spencer, Consultant — Name of filer

Sep 30, 2024 — Date submitted

(512)9181062, x2 — Phone

bill@spencerconsulting.org — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Oct 1, 2024 2:05 PM(Current Version)

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*<u>other than diesel fuels</u>*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director’s delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

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

PERMIT NUMBER	DATE PERMIT ISSUED OR AMENDED	DISTRICT
902971	Oct 01, 2024	05
API NUMBER 42-439-37356	FORM W-1 RECEIVED Sep 30, 2024	COUNTY TARRANT
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 2.22

OPERATOR 100589

BKV DCARBON VENTURES, LLC

4800 BLUE MOUND ROAD
FORT WORTH, TX 76106

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(903) 984-3026

LEASE NAME	WELL NUMBER
COTTON COVE CCS	1
LOCATION 4 miles NW direction from ALZE	TOTAL DEPTH 12000

Section, Block and/or Survey
SECTION BLOCK ABSTRACT 564
SURVEY GARCIA, M

DISTANCE TO SURVEY LINES	DISTANCE TO NEAREST LEASE LINE
296 ft. N 1131 ft. E	ft.
DISTANCE TO LEASE LINES 144 ft. S 133 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME / LEASE NAME	ACRES / NEAREST LEASE	DEPTH	WELL # / NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE)	2.22	12,000	1	09
COTTON COVE CCS			0	

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

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

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

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

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION
SWR #13 Formation Data

TARRANT (439) County

Formation	Remarks	Geological Order	Effective Date
CADDO		1	12/17/2013
BARNETT SHALE	May be prorated into District 9	2	12/17/2013
ELLENBURGER		3	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info