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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

April 7, 2022

Mr. Tyler Mock
Red Trail Energy, LLC
3682 North Dakota HWY 8 S
PO Box 11
Richardton, ND 58652

Re: Monitoring, Reporting and Verification (MRV) Plan for Red Trail Energy, LLC

Dear Mr. Mock:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Red Trail Energy, LLC as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Red Trail Energy, LLC as the final MRV plan. The MRV Plan Approval Number is 1001157-1. This decision is effective April 12, 2022 and appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

If you have any questions regarding this determination, please write to ghgreporting@epa.gov and a member of the Greenhouse Gas Reporting Program will respond.

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Red Trail Energy

March 2022

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 Red Trail Energy (RTE) for the carbon dioxide (CO_2) capture and storage (CCS) project in the Broom Creek Formation.

1 Overview of Project

RTE indicates in section 1.1 of the MRV plan that it operates an investor-owned 64-million-gallon per year dry mill ethanol production plant located a mile east of Richardton, North Dakota that has been in operation since January 2007. This facility currently emits approximately 180,000 metric tons of high-purity CO_2 annually from the fermentation process during ethanol production. The RTE CCS project is currently constructing a CO_2 capture facility adjacent to this ethanol production plant to capture all CO_2 emitted during fermentation. RTE states that it plans to inject the captured 180,000 metric tons per year into the Broom Creek Formation via the RTE-10 injection well for permanent geologic storage (see Figure 1-1 of the MRV plan). This MRV plan was developed in accordance with 40 CFR §98.440-449 (Subpart RR) to provide for the monitoring, reporting, and verification of the quantity of CO_2 sequestered at the RTE CCS facility.

RTE received formal approval from the North Dakota Industrial Commission (NDIC) for its North Dakota CO_2 storage facility permit (SFP) in October 2021. This SFP approval authorizes geologic storage of CO_2 from the RTE ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation under the authority the North Dakota Underground Injection Control (UIC) Class VI Program. No other geologic storage project exists or is planned in the vicinity of the RTE CCS project.

The RTE CCS project site is on the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles. See Figure 1-2 of the MRV plan for the general location of the RTE CCS project site in relation to the western Williston Basin and the geographic distribution of oil fields in North Dakota. This figure indicates that there has been no exploration for, or development of, hydrocarbon resources within the Class VI Area of Review (AOR) for the RTE CCS project.

In Section 1 of the MRV plan, RTE describes the target CO_2 reservoir for the RTE CCS project, the Broom Creek Formation. This formation is a predominantly sandstone interval lying approximately 6,380 feet below the RTE facility. Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary upper confining zone, and the Amsden Formation (made up of dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, these three formations comprise the CO_2 storage complex. Additionally, the MRV plan states that there is approximately 1,200 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional 3,000 feet of impermeable intervals separates the Inyan Kara from the lowest underground source of drinking water (USDW), the Fox Hills Formation. See Figure 1-3 in the MRV plan for a generalized stratigraphic column of the area underlying the RTE CCS project site.

In section 1.3 of the MRV plan, RTE describes their CO_2 project facilities and proposed injection process. RTE plans to capture and store 180,000 metric tons of CO_2 per year over the course of 20 years followed by at least 10 years of post-injection site care. See Figure 1-4 in the MRV plan for a process flow diagram of the CCS process including the principal components. These CCS components are comprised of a capture-liquefaction facility following the scrubber that currently sends gas to stack emissions. This capture-liquefaction facility was designed to capture CO_2 produced during RTE's fermentation process, compress the gaseous CO_2 to approximately 350 pounds per square inch, dehydrate the stream, and then liquefy it through a closed-loop ammonia refrigeration process. A conventional distillation column would also distill the liquid CO_2 in order to remove non-condensable gases prior to sending the gas stream through an approximately 2-mile underground CO_2 flow line to the RTE-10 injection well for geologic storage in the Broom Creek Formation. This CO_2 flowline connecting the capture plant to the RTE-10 injection well has already been constructed.

The description of the project is determined to be acceptable and provides the necessary information to comply with 40 CFR 98.448(a)(6).

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

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

RTE has defined the AMA as the same AOR as determined for their Class VI well permit application (see Figure 2-1, Reference 1 Section 3, and Appendix A of the MRV plan). This AOR is defined as "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity" as defined by North Dakota Administrative Code (NDAC). The NDAC requires the project operator to develop an AOR based on a technical evaluation of the storage facility plus a minimum 1-mile buffer (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the aerial extent of the CO_2 plume plus a buffer area to allow operation to occur safely as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, RTE elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 3 and Appendix A of the MRV plan, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

Figure 2-2 in the MRV plan depicts a reservoir simulation of the extent of the stabilized CO_2 plume post-injection into the Broom Creek Formation along with a calculated AMA and MMA in compliance with 40 CFR 98.448(a)(1). The boundaries of the calculated AMA and MMA both fall within the boundary of the AOR. As such, RTE also proposes that the delineated AOR and proposed AMA from Figure 2-1 of the MRV plan serve as the MMA for the RTE CCS project, as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449.

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 RTE's MRV plan, accounts for the existing operational and subsurface conditions at the site along with any potential changes in future operations. Therefore, the designation of the AMA and MMA as the Class VI AOR is an acceptable approach.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly and explicitly 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). RTE identified the following as potential leakage pathways in their MRV plan that required consideration:

- Surface components
- Abandoned oil and gas wells
- Faults, fractures, bedding plane partings and seismicity
- Injection well and monitoring well
- Confining zone limitations
    - Lateral migration
    - Seal diffusivity
    - Drilling through the CO_2 plume

3.1 Leakage through Surface Components

RTE indicates that surface equipment may be subject to deterioration due to normal aging throughout its functional life, and that corrosion, lack of maintenance, and deviation from operational parameters may cause a loss in mechanical integrity of these components. Specific surface components identified in section 3.1 of the MRV plan include a 4-inch flowline buried a minimum of 6 feet used to transport CO_2 two miles from the capture facility to the storage site and the wellhead. RTE states that distributed temperature-sensing/acoustic-sensing fiber optics are installed along the flowline as part of their leak detection program. Flow meters and temperature/pressure transducers are installed at metering stations located at either end of the CO_2 flow line, and shutoff devices connected to the facility's automated monitoring system will be used to control any potential release of CO_2.

RTE affirms that surface components of the injection system, including the CO_2 flowline and wellhead, are continuously monitored via CO_2 leak detection equipment tracked through an automated system for alarm notification and process management, along with routine visual inspections. RTE's proposed efforts to mitigate the risk of surface leakage include adhering to regulatory requirements for the construction and operation of the site, implementing the highest standards on material selection and construction processes for the flowlines and wells, implementing best practices, operating procedures, a robust mechanical integrity program, and continuous monitoring via an automated system and integrated databases.

RTE asserts that the risk of leakage through surface equipment under normal operating conditions is unlikely, and the magnitude of potential leakage will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released over several hours, while a puncture in the CO_2 flowline could potentially represent several tons of CO_2 released underground until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply. RTE also notes that should a potential shutoff situation occur, the RTE facility will revert to current operations, emitting CO_2 under existing permits maintained through the North Dakota Department of Environmental Quality. Additionally, RTE states that the risk of leakage through surface equipment is almost zero during the post-injection period due to proper plugging and abandonment of the injection wells following NDIC protocols and decommissioning of facility equipment according to regulatory requirements. The only remaining potential leakage pathway through surface equipment will be the monitoring well, RTE-10.2, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

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

3.2 Leakage through Abandoned Oil and Gas Wells

Section 3.2 of the MRV plan asserts that the only abandoned oil or gas well within the AOR is the Rummel-State 1 (NDIC No. 6797), which was spudded in December 1978 to depth of 11,270 feet into the Red River Formation shortly before being plugged and abandoned in February 1979. RTE evaluated the well as part of the risk assessment for the RTE CCS project and determined that no corrective action was needed because the CO_2 plume is not predicted to come into contact with the well.

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

3.3 Leakage through Faults, Fractures, Bedding Plane Partings and Seismicity

In section 3.3 of the MRV plan, RTE states that there are no known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations within the AOR. This statement is supported through site-specific characterization activities, prior studies, and previous oil and gas exploration activities. See Reference 1, Section 2.5, which is attached to the MRV plan, for more information.

RTE identified one fault of interest, the Heart River Fault, in section 3.3.1 of the MRV plan. The Heart River Fault is located 3.2 miles southwest of the RTE CCS facility and 1.4 miles from the outer edge of the AOR for the project. RTE states that current seismic interpretations show it is a high-angle reverse fault that originates in the Precambrian basement with a total vertical footprint of less than 400 feet through the Stony Mountain, Stonewall, and lower Interlake formations, well below the injection zone of the Broom Creek formation (see Figure 1-3 in the MRV plan and Reference 1 Section 2.5.1 attached to the MRV plan for more information.)

RTE states in section 3.3.2 of the MRV plan that the history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (see Reference 1 Section 2.5.3 of the MRV plan). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin. The seismic event recorded closest to the RTE CCS project occurred 21.6 miles from Richardton, North Dakota, and had a magnitude of 2.3. RTE also notes that studies completed by the United States Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000 year period. Through this risk assessment process, RTE found that potential leakage from natural or induced seismicity was shown to be very unlikely.

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

3.4 Leakage through the Injection Well and Monitoring Well

Section 3.4 of the MRV plan provides characterization of the potential for leakage through the RTE CCS project injection well, RTE-10 (NDIC No. 37229), and monitoring well, RTE-10.2 (NDIC No. 37858). RTE states that the RTE-10 well will be monitored in real time with external downhole pressure and temperature gauges set in the injection and dissipation intervals to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable capable of collecting temperature and acoustic information will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Reference 1 section 3.1.1 of the MRV plan contains an evaluation performed by a professional engineer of the likelihood, magnitude, and timing of potential leakage through RTE-10 which determined that there is no significant risk of a potential leakage pathway to the surface. RTE also states that RTE-10 will be properly plugged and abandoned following NDIC protocols after the injection period ceases.

In section 3.4.2 of the MRV plan, RTE describes how RTE-10.2 was drilled as a stratigraphic test well and future monitoring well for the RTE CCS project. The RTE-10.2 well will monitor the Broom Creek formation (see Figure 1-3 for context) in real time with external downhole pressure and temperature gauges set in the injection and dissipation intervals along with fiber optic cable capable of collecting temperature and acoustic information from the top of the injection interval to the base of the confining layer, similar to the RTE-10 well. An evaluation of RTE-10.2 was also performed by a professional engineer and this evaluation determined that there is no significant risk of the well acting as a potential leakage pathway to the surface. Complete descriptions of the RTE-10 and RTE-10.2 wellbore construction can be found in Reference 1, Sections 4.5.1 and 4.5.2 of the MRV plan, respectively.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through the injection well or monitoring well.

3.5 Leakage through Lateral Migration

In section 3.5.1 of the MRV plan, RTE states that the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek formation will be the cap rock: the Opeche formation. The Opeche formation is a laterally extensive formation that is 6,726 feet below the surface and 103 feet thick at the RTE CCS project site (see reference 1, sections 2.3.2 and 2.4.1 of the MRV plan). RTE affirms that lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine).

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

3.6 Diffuse Leakage through the Seal

Section 3.5.2 of the MRV plan describes several additional formations that provide additional confinement above the Opeche Formation. These include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Combined with the Opeche Formation, these formations are 1,200 feet thick and RTE claims that it will isolate the Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. RTE then goes on to describe an additional 3,000 feet of impermeable rock that acts as an additional seal between the Inyan Kara Formation and the lowermost USDW, the Fox Hills Formation. These impermeable confining layers include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see figure 1-3 for reference). RTE asserts that the possibility of fluid migration through 1,200 and 3,000 feet of overlying confining layers presents very low risk to the RTE CCS project site, and that these thick, impermeable, and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

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

3.7 Drilling through the CO_2 Area

RTE states in section 3.5.3 of the MRV plan that there has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized CO_2 plume boundary. While they do note that there was historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial hydrocarbons in the AOR for the RTE CCS project (see reference 1, section 2.6 of the MRV plan). RTE asserts that with no commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. RTE also states that if there are any future endeavors to explore for or produce hydrocarbons in or around the project area horizontal drilling could be used to avoid the CO_2 plume.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage caused by drilling through the CO_2 storage area.

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 CO_2 surface leakage. Section 5 of the MRV plan details RTE's strategy for determining baselines for CO_2 monitoring and section 4 of the MRV plan details strategies for the detection of, response to, and quantification of CO_2 leakage. RTE's approach for detecting and quantifying surface leakage of CO_2 primarily includes monitoring of the RTE surface facilities, numerical model history-matching, mechanical integrity testing, geophysical surveys, and near-surface monitoring. Additionally, RTE states that data collected during monitoring will be used to calibrate a numerical model and improve the prediction for injectivity, CO_2 plume, and the resultant pressure front. See Table 4-1 and Table 4-2 of the MRV plan for a summary of RTE's approach to these activities. Table 4-3 of the MRV plan, which has been reproduced below, provides a summary of the potential leakage pathway(s) addressed by each of these activities.

Monitoring Strategy (target area) \ Potential Leakage Pathway	Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)	X			X	X		X
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	X			X	X	X	
Mass / Volume Flowmeters (RTE-10 and flowline)				X	X		
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	X			X	X	X	X
DTS/DAS Fiber (RTE-10, RTE-10.2, dedicated Fox Hills monitoring wells, and flowline)	X	X	X	X	X	X	X
Visual Inspections (flowline)	X			X	X		
Corrosion Coupons (flowline)				X	X		
SCADA Automated Remote System (surface facilities)			X	X	X		
Soil Gas Analysis (AOR)	X				X		X
Protected Groundwater Zone: Shallow Aquifers (AOR)		X			X		X
Protected Groundwater Zone: Lowest USDW (AOR)	X				X		X
Cement Bond Logs (RTE-10 and RTE-10.2)					X		
Annular Pressure Test (RTE-10 and RTE-10.2)				X	X		
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	X				X	X	X
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)					X		
Pressure Falloff Test (RTE-10)	X				X	X	
Time-Lapsed Seismic Surveys (AOR)	X	X		X	X	X	X
Surface Seismometers (AOR)		X	X				X
InSAR (AOR)*	X	X		X		X	X
Gravity Surveys (AOR)*						X	

* If feasible.

4.1 Detection of Leakage through Surface Components

As described in section 3.1 of the MRV plan, surface components of the RTE CCS project include the 4-inch flowline used to transport CO_2 two miles from the capture facility to the storage site and each wellhead. RTE's proposed strategy for detecting leakage from these surface components includes continuous analysis of the CO_2 stream, surface pressure gauges and temperature sensors, mass/volume flowmeters on the injection well and CO_2 flowline, downhole pressure gauges and temperature sensors in the injection and monitoring wells, distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber in each well and the flowline, visual inspections, corrosion coupons on the flowline, annular pressure testing of the injection and monitoring wells, time-lapsed seismic surveys, and interferometric synthetic aperture radar (InSAR) data collection (if feasible).

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through surface components as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Abandoned Oil and Gas Wells

As described in section 3.2 of the MRV plan, the only abandoned oil and gas well within the AOR is the Rummel-State 1 well. Additionally, RTE asserts that this well falls outside of the expected boundary of the CO_2 plume following the post-injection monitoring period. Despite this, RTE plans to monitor for potential CO_2 leaks via visual inspections, soil gas analysis throughout the AOR, monitoring of the lowest USDW, time-lapsed seismic surveys, and InSAR surveys.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through abandoned oil and gas wells as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults, Fractures, and Bedding Plane Partings

RTE's proposed strategy for quantifying potential CO_2 leakage through faults, fractures, and bedding plane partings includes DTS/DAS fiber in all injection and monitoring wells and along the CO_2 flowline, periodic monitoring of shallow aquifers with the AOR, time-lapsed seismic surveys, continuous monitoring via surface seismometers, and InSAR surveys.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through faults, fractures, and bedding plane partings as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through the Injection Well and Monitoring Well

As described in section 3.4 of the MRV plan, the RTE-10.1 and RTE-10.2 are the only injection well and monitoring well, respectively, for the RTE CCS project. RTE's proposed strategy for the detection of potential CO_2 leakage through these wells includes CO_2 stream analysis entering the injection wellhead, surface pressure gauges and temperature sensors, downhole pressure gauges and temperature sensors, DTS/DAS fiber in each well, visual inspections, soil gas analysis, monitoring of the lowest USDW, pulsed-neutron wellbore logs, pressure falloff testing on RTE-10.1, time-lapsed seismic surveys, and InSAR surveys.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through the injection well and monitoring well as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage through Lateral Migration of CO_2

RTE's proposed methodology for detecting leakage as a result of lateral migration of the CO_2 plume includes monitoring surface temperature and pressure gauges, monitoring downhole temperature and pressure gauges, continuous monitoring through DTS/DAS fiber along all RTE CCS project wells and the CO_2 flowline, annular pressure testing of the RTE-10.1 and RTE-10.2 wells, pressure falloff testing of the RTE-10.1 well, time-lapsed seismic surveys of the AOR, InSAR surveys of the AOR, and gravity surveys of the AOR. Additionally, RTE will compare history-matched data from initial numerical modeling efforts with continuously aggregated data and will initiate further investigation in the potential case that these values differ significantly.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through lateral migration of CO_2 as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage caused by Diffuse Leakage Through the Seal

RTE's proposed methodology for detecting potential CO_2 leakage through the seal includes CO_2 stream analysis; downhole pressure and temperature gauges in the RTE-10.1 and RTE-10.2 wells; DTS/DAS fiber monitoring in the RTE-10.1 well, RTE-10.2 well, and Fox Hills dedicated monitoring wells; soil gas analysis of the AOR; periodic monitoring of shallow aquifers in the AOR, monitoring of the lowest USDW in the

AOR, pulsed-neutron logs of RTE-10.1 and RTE-10.2, time-lapsed seismic surveys of the AOR, surface seismometers in the AOR, and InSAR surveys of the AOR.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage through diffuse leakage through the seal as required by 40 CFR 98.448(a)(3).

4.7 Drilling through the CO_2 Plume

In section 3.5.3 of the MRV plan, RTE notes that there has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized CO_2 plume boundary. Although there was some historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the AOR (see Reference 1, Section 2.6 of the MRV plan). RTE asserts that with no known commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. Additionally, RTE notes that any future endeavors to explore for, or produce, hydrocarbons could avoid the CO_2 plume using horizontal drilling techniques. Therefore, RTE does not propose any monitoring techniques specifically targeted at detecting leakage caused by drilling through the CO_2 plume.

Thus, the MRV plan provides adequate characterization of RTE's approach to detect potential leakage caused by drilling through the CO_2 plume as required by 40 CFR 98.448(a)(3).

4.8 Quantification of Potential CO_2 Leakage

As mentioned previously, RTE will monitor the injection well through continuous, automated pressure and temperature sensors in the injection zone, monitoring of the annular pressure in wellheads, distributed temperature sensing alongside the casing, and routine maintenance and inspection. RTE expands upon the usage of this data in section 4.1 of the MRV plan. History-matched data obtained from these monitoring systems will be used to compare the initial numerical model with the real development of the CO_2 plume and pressure front. This model will be continuously calibrated with the acquisition of real-time data, and a formal AOR review will be submitted every 5 years. If needed, RTE will submit a revised or modified monitoring plan.

RTE asserts that this model history match will allow the project operator to identify conditions which differ from those proposed by the numerical model and deviations from expected operating conditions. In the case that injection pressure, temperature, rate, or other measurements differ from expected values, then a data flag will be triggered by the automated system and field personnel will further investigate the excursion. RTE states that these excursions are not necessarily indicators of potential leaks, and that each excursion will be reviewed to determine if potential CO_2 leakage is occurring. RTE claims that in many cases, problems are straightforward and easy to fix (such as a meter in need of calibration) and there is no indication that potential CO_2 leakage has occurred. In the case that issues are not readily resolved, RTE plans to initiate a more detailed investigation. If further investigation reveals a potential leak has occurred, efforts will be made to quantity its magnitude.

RTE also states that because a potential CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, RTE will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the RTE CCS project. In the event of potential leakage, RTE states that it will address the event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery. If an event triggers cessation of injection and remedial actions, RTE affirms that it will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations, and these operations will only resume upon receipt of written authorization from the UIC program director.

RTE states in section 4.2 of the MRV plan that due to the uncertain nature and characteristics of any potential leaks, the most appropriate methods to quantify the volume of CO_2 leaked will be determined on a case-by-case basis, and any volume of CO_2 detected as potentially leaking to the surface will be quantified using acceptable emission factors, engineering estimates of potential leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. RTE will document, evaluate, and address these potential leaks in a timely manner, and records of potential leakage events will be retained in an electronic central database.

4.9 Determination of Baselines

Section 5 of the MRV plan outlines RTE's methodology for determining pre-injection baselines. RTE states that it will establish these pre-injection baselines by implementing a monitoring program during each of the four primary seasonal ranges prior to CO_2 injection with monitoring targeting the surface, near-surface, and deep subsurface. These baselines will contain information on the characteristics of a range of environmental media such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water. RTE states that these baselines will provide a basis for determining whether CO_2 leaks are occurring by providing a foundation against which these same characteristics can be compared and evaluated. A more detailed description of these baselines can be found in Reference 1, Section 4.4.6 of the MRV plan.

Surface baselines

RTE states that a baseline sampling program has been completed for the RTE CCS project. Baseline data were obtained from 11 soil gas sampling locations and three existing groundwater wells in the northwestern portion of the AOR. In addition, two dedicated monitoring wells were drilled in the Fox Hills Formation in close proximity to the RTE injection and monitoring wells. For additional information regarding surface baselines, see MRV plan Reference 1, Sections 4.4.5-4.4.7.

Subsurface baselines

RTE states in section 5.2 of the MRV plan that pre-operational baseline data will be collected from the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used by RTE as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir. RTE will also perform time-lapse geophysical surveys of the AOR in order to track the extent of the CO_2 plume within the reservoir. A 3D-seismic survey has already been conducted to establish baseline conditions in the storage reservoir.

Additionally, RTE plans to perform feasibility studies for monitoring surface deformation with InSAR and detecting changes in mass with gravity methods prior to injection in order to justify the application of these technologies at the RTE CCS project site. See Reference 1, Section 4.4.8 of the MRV plan for more information on what these technologies measure and how RTE plans to implement them.

In addition to periodic monitoring efforts, RTE states that it will also install seismometer stations sufficient to measure baseline seismicity confidently and passively from the injection area for 1 year prior to injection. See Reference 1, Section 4.4.8 of the MRV plan for more information regarding subsurface baselines.

The strategy for detecting and quantifying surface leakage of CO_2 and for establishing expected baselines for monitoring is acceptable per the requirements in 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4). The strategies described in the MRV plan are clearly and explicitly delineated and are consistent with Subpart RR requirements.

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

5.1 Calculation of Mass of CO_2 Stored

RTE proposes to use equation RR-12 per 40 CFR 98.443 to calculate the amount of CO_2 stored. The equation is:

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

Where:

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

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

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by potential surface leakage.

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

RTE provides an acceptable approach to calculating each of these variables in section 6.0 of the MRV plan.

5.2 Calculation of Total Annual Mass of CO_2 Injected (CO_{2I})

Section 6.0 of the MRV plan states that the mass of CO_2 injected into the subsurface at the RTE CCS project site will be calculated using equation RR-5. RTE indicates in the plan they will use a volumetric flow meter at the wellhead as the primary data source for this equation. The equation is:

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

Where:

$CO_{2,u}$ = Annual CO2 mass injected (metric tons) as measured by Flowmeter u.

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

D = Density of CO2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,u}$ = Quarterly CO2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

RTE provides an acceptable approach for calculating the total annual mass injected under the Subpart RR requirements.

5.3 Calculation of Total Annual Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

For reporting of the total annual CO_2 mass sequestered under Subpart RR, potential surface leaks must be accounted for in the mass balance equation. Pursuant to 40 CFR 98.448(a)(2), an MRV plan must describe the likelihood, magnitude, and timing of surface leakage of CO_2 through potential pathways. Subpart RR also requires that the MRV plan identify a strategy for establishing a baseline for monitoring CO_2 surface leakage, pursuant to 40 CFR 98.448(a)(4).

RTE has characterized, in detail, potential leakage pathways on the surface and subsurface, concluding that the probability is very low in each scenario (see section 3 of the MRV plan). Additionally, RTE has proposed a detailed monitoring and surveillance plan to detect any potential leak and have also defined a baseline for monitoring (see Reference 1, Section 4.4 of the MRV plan). RTE will utilize equation RR-10 to calculate and report the mass of CO_2 emitted from all potential leakage pathways in accordance with 40 CFR 98.448. The equation is:

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

Where:

CO_{2E} = Total annual CO2 mass emitted by potential surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO2 mass emitted (metric tons) at potential leakage pathway x in the reporting year.

x = Potential leakage pathway.

RTE's proposed approach for calculating the total annual mass emitted by surface leakage is acceptable for the Subpart RR requirements.

5.4 Calculation of Total Annual Mass of CO_2 Emitted by Potential Equipment Leaks and Vented Emissions (CO_{2FI})

RTE states that the annual mass of CO_2 emitted (in metric tons) from potential 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 (CO_{2FI}) 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 and surveillance plan proposed in Reference 1, Section 4.4 of the MRV plan.

RTE's proposed approach for calculating the total annual mass emitted by potential equipment leaks and vented emissions is acceptable for the Subpart RR requirements.

6 Summary of Findings

The Subpart RR MRV plan for the Red Trail Energy Broom Creek Formation injection facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the RTE MRV Plan.

Subpart RR MRV Plan Requirement	**RTE MRV Plan**
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 2 of the MRV plan describes the MMA and AMA. The MMA and AMA are both defined as the same region as the UIC Class VI Well Permit AOR. MMA and AMA delineations consider site characterization and reservoir modeling along with a 1-mile buffer.

40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 3 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage through surface components; leakage from abandoned oil and gas wells; leakage through faults, fractures, bedding plane partings, and seismicity; leakage through the injection well or monitoring well, and leakage through confining zone limitations. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. RTE determined that these leakage pathways are not likely at the RTE CCS facility, and that it is very unlikely that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 4.0 of the MRV plan describes a strategy for how the facility would detect CO_2 leakage to the surface, such as monitoring of existing wells, field inspections, and geophysical monitoring. Section 4.2 of the MRV plan describes a strategy for how surface leakage would be quantified.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 5 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential 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 6 of the MRV plan describes RTE's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted as 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.	Reference 1 in the MRV plan provides well identification numbers for each injection well. The MRV plan specifies that the RTE-10 injection well has been issued a UIC Class VI permit.
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.	The MRV plan states that the RTE CCS facility will begin implementation of this MRV plan starting in April 2022, or within 90 days of EPA approval, whichever occurs later.

Appendix A: Final MRV Plan

RED TRAIL ENERGY SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 530977

North Dakota Storage Facility Permit: Order No. 31453–31455

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STORAGE FACILITY PERMIT DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, the Red Trail Energy storage facility permit is designated as follows:

Reference 1: Red Trail Energy Carbon Dioxide Geologic Storage Facility Permit

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Area of Review
Section 4 – Supporting Permit Plans
Section 5 – Injection Well and Storage Operations
Appendix A – Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations
Appendix B – RTE-10 and RTE-10.2 Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Freshwater Well Fluid-Sampling Laboratory Analysis
Appendix D – Quality Assurance and Surveillance Plan
Appendix E – Storage Facility Permit Regulatory Compliance Table
Appendix F – Post-Hearing Supplement Filing: Financial Responsibility Demonstration Plan
Appendix G – Post-Hearing Supplemental Filing: Certification of Liability Insurance
Appendix H – Post-Hearing Supplemental Filing: Geologic Storage Agreement Summary of Surface Owners Who Have Ratified

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Red Trail Energy (RTE) facility is a North Dakota-based, investor-owned 64-million-gallon dry mill ethanol production plant, which has been in operation since January 2007. The RTE facility, located about a mile east of Richardton, North Dakota (Figure 1-1), emits an average of 180,000 metric tons annually of high-purity carbon dioxide (CO_2) (>99% CO_2 dry) from the fermentation process during ethanol production. The RTE carbon capture and storage (CCS) project is currently constructing a CO_2 capture facility (mainly dehydration and compression) adjacent to the RTE ethanol plant to capture all CO_2 from fermentation. RTE plans to inject the resulting 180,000-metric-ton-per-year CO_2 stream into the Broom Creek Formation via the RTE-10 injection well located on RTE property (Figure 1-1) for permanent geologic CO_2 storage.

RTE received formal approval of its North Dakota CO_2 storage facility permit (SFP) on October 19, 2021. This approval by the North Dakota Industrial Commission (NDIC) authorizes the geologic storage of CO_2 from the RTE ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation (NDIC Order Nos. 31453 and 31454). North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). No other geologic storage project exists or is planned at or near the RTE CCS project.

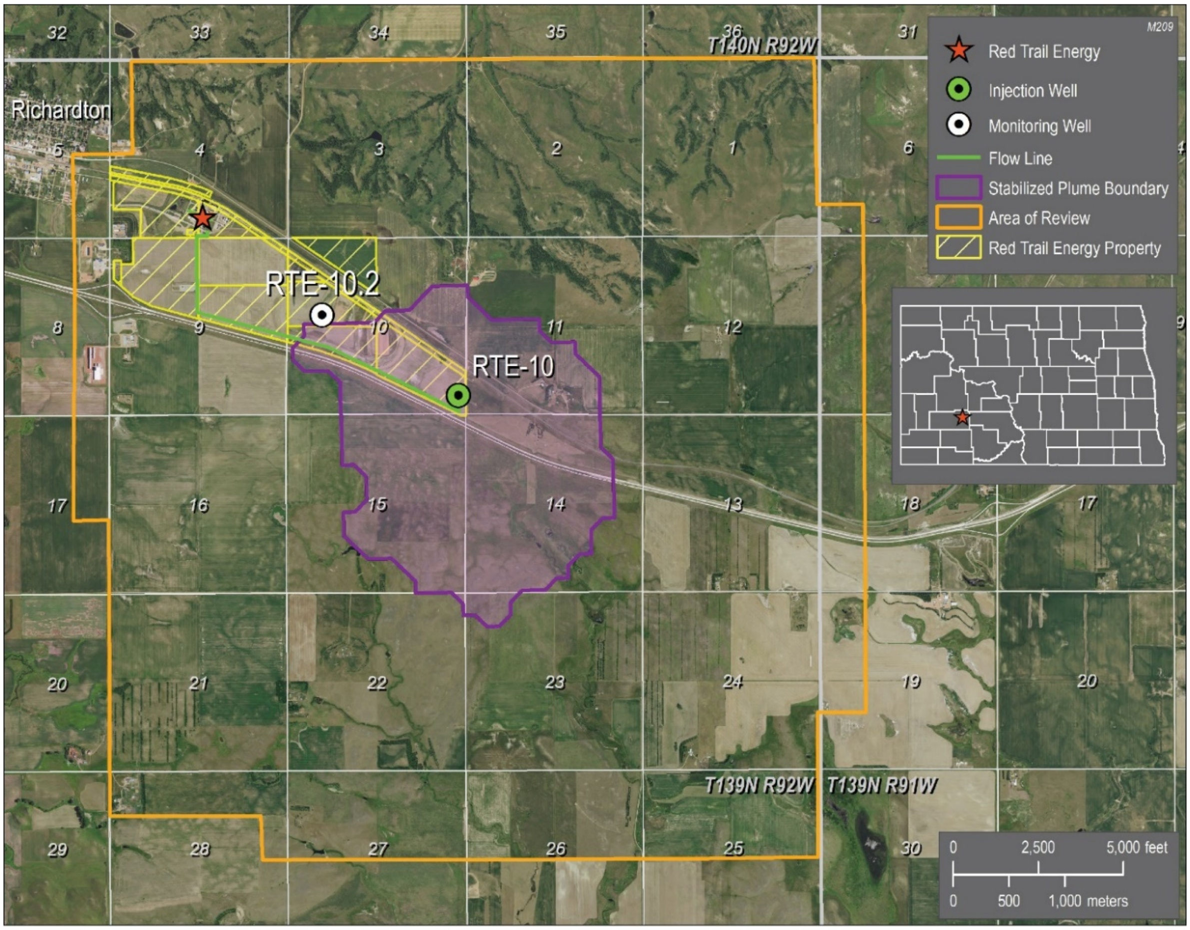

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Figure 1-1. Location of the RTE facility, RTE-10 injection well, RTE-10.2 monitoring well, and CO_2 flowline. Also shown is the town of Richardton, with a population of about 850 people, the stabilized plume boundary, and the area of review (AOR).

1.2 Environmental Setting

The RTE CCS project site is on the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota (i.e., western Williston Basin) and demonstrates there has been no exploration for, and development of, hydrocarbon resources within the stabilized plume boundary (Reference 1, Section 2.6). The Rummel-State 1 (NDIC No. 6797), a dry hole drilled to the Red River Formation (below the Broom Creek Formation) in 1978, is located within the southwestern edge of the AOR (see Section 3.2 of this MRV plan for more information on the Rummel-State 1).

A generalized stratigraphic column of the Williston Basin for the Richardton area is provided in Figure 1-3. The target CO_2 storage reservoir for the RTE CCS project is the Broom Creek Formation, a predominantly sandstone interval lying about 6,380 feet below the RTE facility

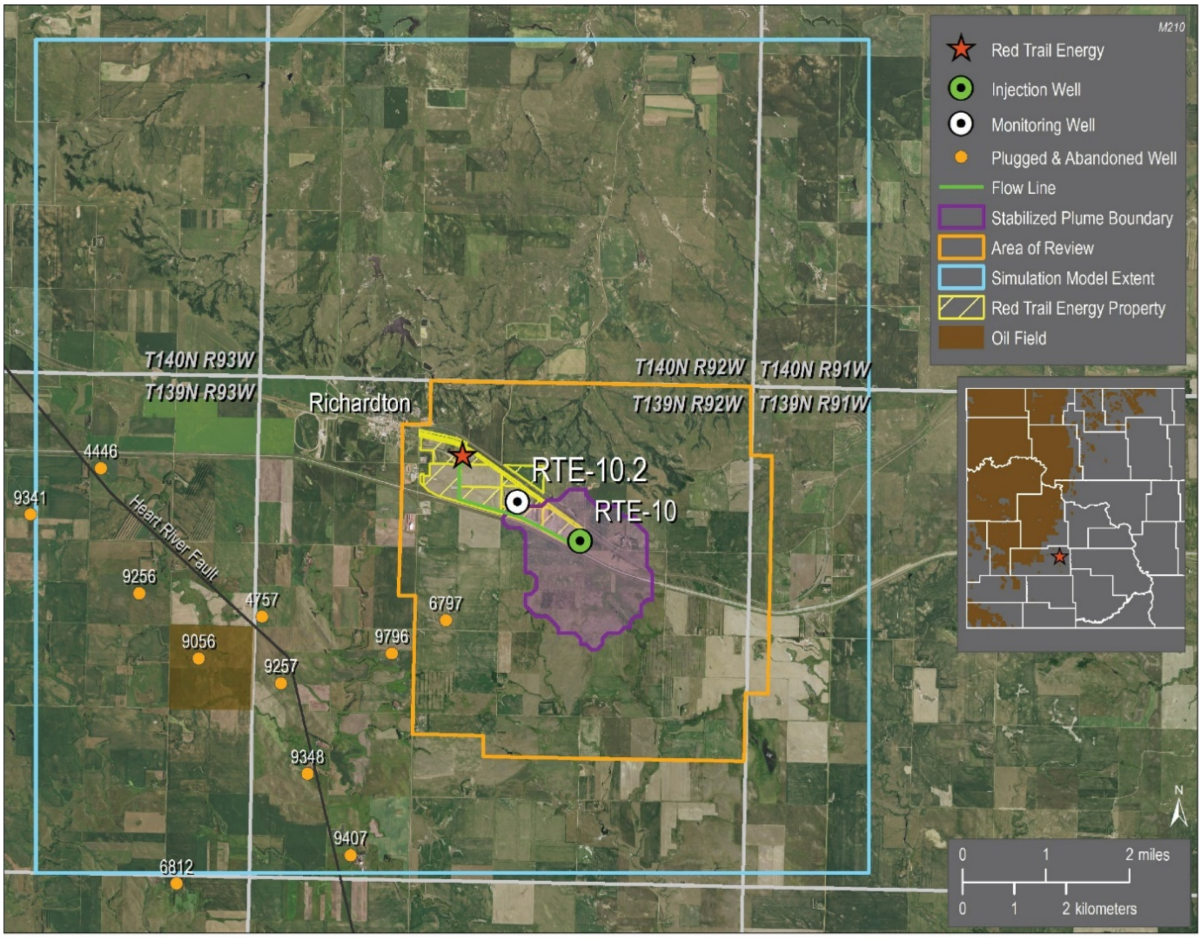

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Figure 1-2. Map showing the AOR, stabilized plume boundary, RTE ethanol facility, RTE-10 injection well, RTE-10.2 monitoring well, town of Richardton, and oil and gas wells immediately outside of or within the simulation model extents. Also shown is an inset map identifying the geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin) and the Heart River Fault. The oil field in T139N-R93W is the Taylor Field. Wells 9056 and 9341 produced some hydrocarbons from the Winnipeg Formation (see Figure 1-3 for stratigraphic reference), but all other wildcat wells shown on the map were classified as dry holes.

(Reference 1, Section 2.3). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Reference 1, Section 2.4.3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,200 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 3,000 feet of impermeable intervals separates the Inyan Kara and the lowest underground source of drinking water (USDW), the Fox Hills Formation.

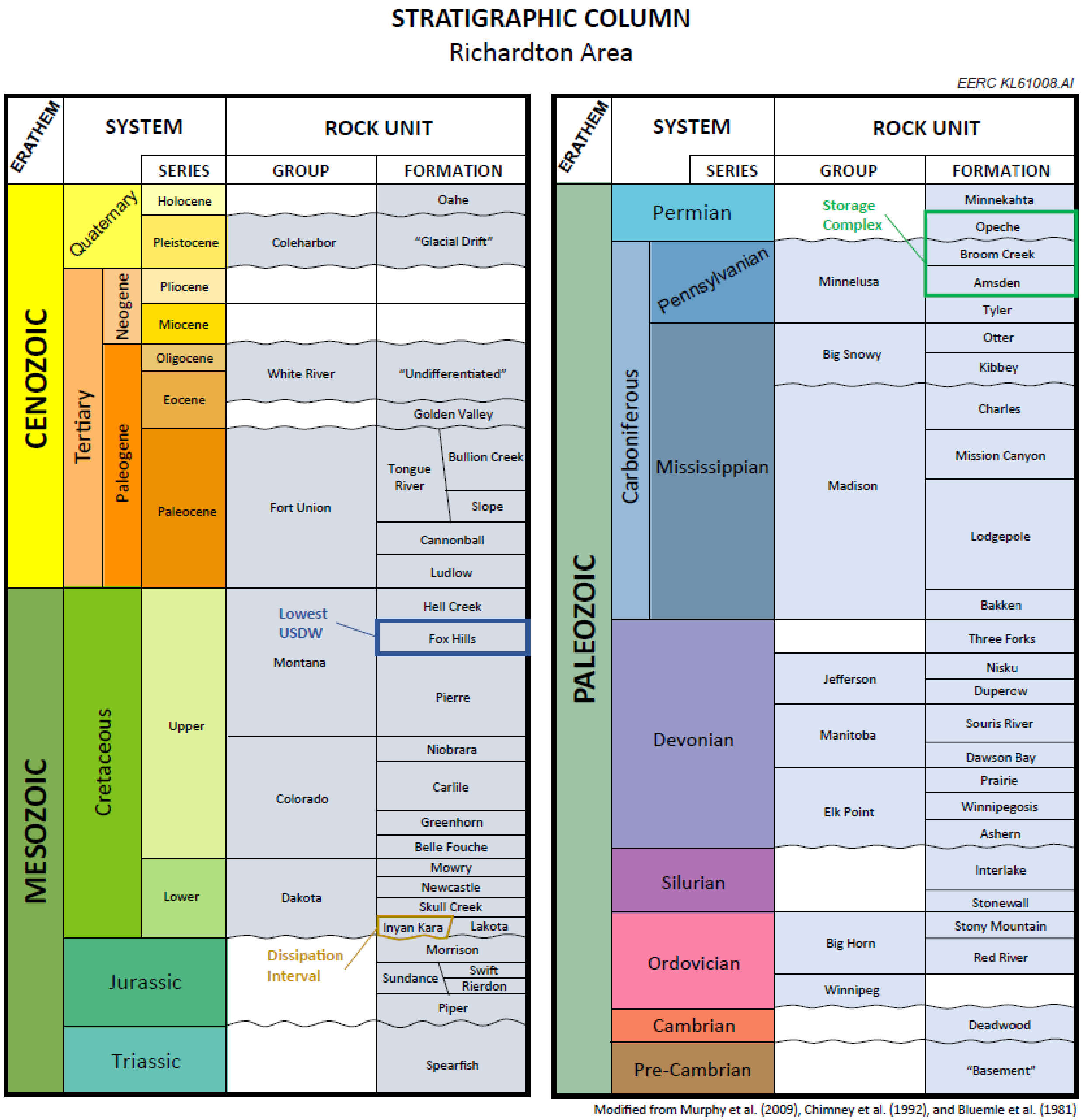

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Richardton area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the RTE CCS project site.

1.3 Description of CO_2 Project Facilities and Injection Process

RTE plans to capture and store 180,000 metric tons per year over the course of 20 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration of

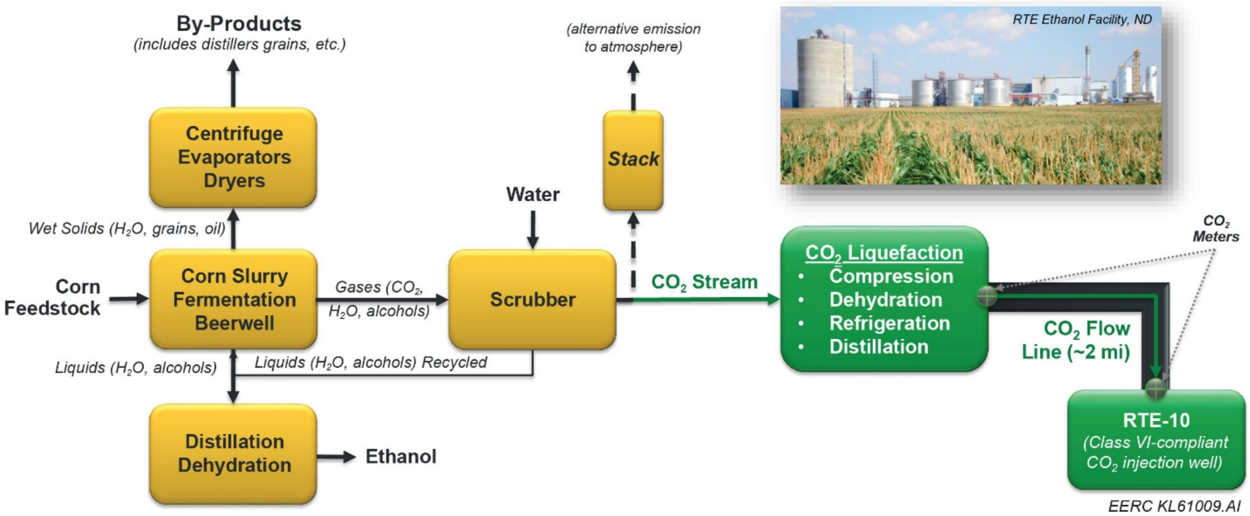

Figure 1-4. Flow diagram of the RTE CCS process, showing major CCS components and the path of the CO_2 stream from the capture facility to the RTE-10 injection well.

major CCS components with the existing RTE ethanol facility. The capture–liquefaction facility was designed to capture the CO_2 currently produced during RTE's fermentation process (following the scrubber prior to stack emission), compress the gaseous CO_2 stream to approximately 350 pounds per square inch, dehydrate the stream, and then liquefy the CO_2 using a closed-loop ammonia (NH_3) refrigeration process. A conventional distillation column would distill the liquid CO_2 to remove oxygen in addition to other noncondensable gases. The final liquid CO_2 stream would flow to the RTE-10 injection well for geologic storage into the Broom Creek Formation; an underground flowline is installed on RTE property to connect the capture plant to the RTE-10 injection well.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: RTE AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

RTE proposes that because the AOR, as delineated in Reference 1, Section 3 and Appendix A, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as AMA for the RTE CCS project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). The NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, RTE elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 3 and Appendix A, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

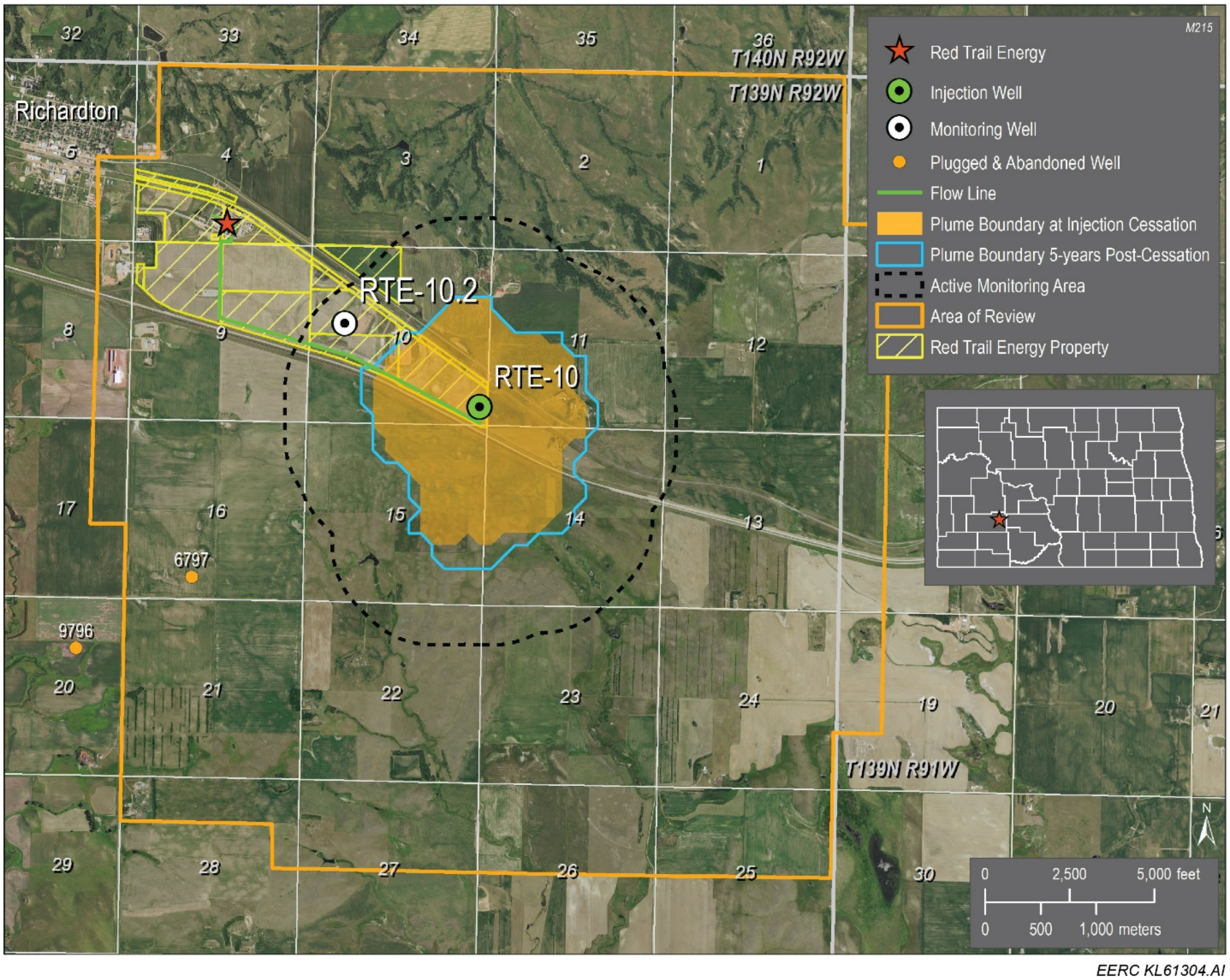

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (20 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the RTE CCS project.

2.2 Maximum Monitoring Area

RTE proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the RTE CCS project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

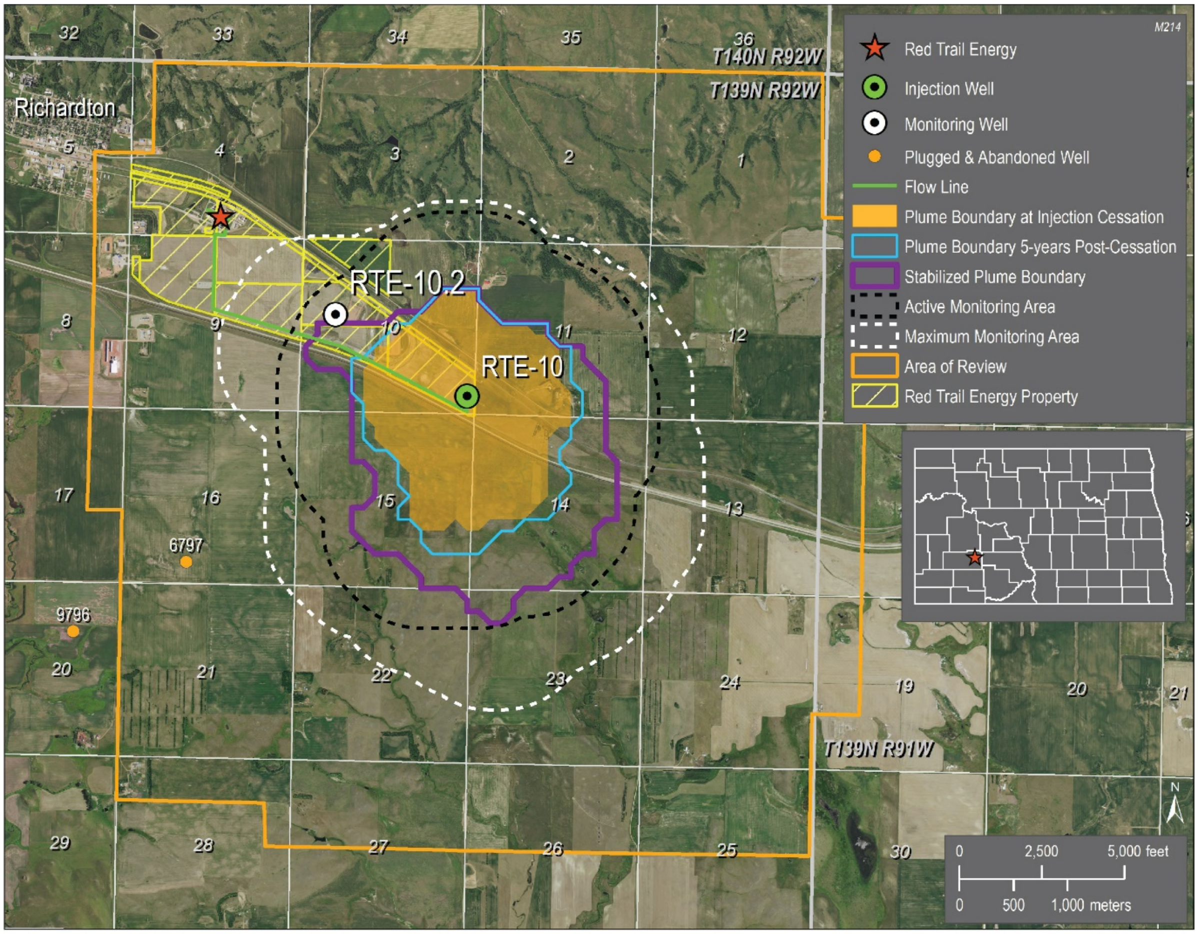

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Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the RTE CCS project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 4.4) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods therefore encompass the entire life cycle of the project. For purposes of this monitoring, reporting, and verification (MRV) plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 20 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

An evaluation of potential subsurface leakage pathways and surface equipment failures during implementation of the project was informed by a screening-level risk assessment (SLRA), which was performed in accordance with the International Organization for Standardization's (ISO's) risk management standard ISO 31000 (Leroux and others, 2017). The SLRA was conducted through a series of work group sessions involving Energy & Environmental Research Center subject matter experts. During these meetings, factors and equipment that could lead to potential leakage pathways were identified and evaluated for the following:

1. Surface components (flowline and wellhead)
2. Abandoned oil and gas wells
3. Faults, fractures, bedding plane partings, and seismicity
4. Injection well or monitoring well
5. Confining zone limitations

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 4.4 and summarized in Table 4-1, was developed to form the basis of this MRV plan.

3.1 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the RTE CCS project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The RTE CCS system includes a 4-inch flowline buried a minimum of 6 feet to transport CO_2 from the capture facility to the storage site (2 miles). The flowline will be connected to a metering station at the wellhead and located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics are installed along the flowline as part of the leak detection program and mechanical integrity protocol. Flowmeters and temperatureand pressure transducers will be installed at each metering station.

Shutoff devices will be installed at each end of the flowline to control any potential release and send alarms to the automated system. Pressure gauges will be installed on the wellhead to monitor annular pressure between tubing and casing.

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. Routine visual inspections will be conducted, and real-time operating parameters tracked through an automated system for alarm notification and process management.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing highest standards on material selection and construction processes for the flowline and wells.
- Implementing best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could potentially represent several tons of CO_2 released underground until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply. Note that should a potential shutoff situation occur, the RTE facility will revert to current operations, emitting CO_2 under existing permits maintained through the North Dakota Department of Environmental Quality.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injector wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, RTE-10.2, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.2 Abandoned Oil and Gas Wells

The Rummel-State 1 (NDIC No. 6797) well spudded in December 1978 to a depth of 11,270 feet into the Red River Formation and was plugged and abandoned in February 1979. Multiple drillstem tests were conducted in several stratigraphic intervals, but the well encountered no commercial accumulations of hydrocarbons. The Rummel-State 1 was evaluated as part of the risk assessment for the RTE CCS project and is the only oil and gas well within the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 3.1.2).

3.3 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.3.1 Heart River Fault

The Heart River Fault, located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AOR for the RTE project (Figure 1-2), is a high-angle reverse fault that originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 feet in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations, well below the Broom Creek Formation (Reference 1, Section 2.5.1). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset (see Figure 1-3 for stratigraphic reference).

3.3.2 Natural or Induced Seismicity

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (Reference 1 Section 2.5.3). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The seismic event recorded closest to the RTE CCS project occurred 21.6 miles from Richardton, North Dakota, with a magnitude of 3.2 (Reference 1, Section 2.5.3).

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year period (U.S. Geological Survey, 2019). Through the risk assessment process, potential leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.4 Injection Well and Monitoring Well

3.4.1 RTE-10 (NDIC No. 37229)

The RTE-10 well spudded in March 2020 as a stratigraphic test well to a depth of 6,900 feet into the Amsden Formation. This well was drilled specifically to gather geologic data to support the development of a CO_2 SFP and as the RTE CCS project's future injector well. The RTE-10 will be monitored in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, the RTE-10 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10 wellbore construction can be found in Reference 1, Section

4.5.1 (Well Casing and Cementing Program). An evaluation of RTE-10 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

3.4.2 RTE-10.2 (NDIC No. 37858)

The RTE-10.2 well spudded in October 2020 as a stratigraphic test well and future monitoring well for the injected CO_2 of the RTE project. The well was drilled to a depth of 6,770 feet into the Amsden Formation. The RTE-10.2 will monitor the Broom Creek Formation in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, RTE-10.2 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10.2 wellbore construction can be found in Reference 1, Section 4.5.2 (Well Casing and Cementing Program). An evaluation of RTE-10.2 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

3.5 Confining Zone Limitations

3.5.1 Lateral Migration

For the RTE CCS project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 6,276 feet below the surface and 103 feet thick at the RTE CCS project site (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine).

3.5.2 Seal Diffusivity

Several additional formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,200 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 3,000 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The possibility of fluid migration through 1,200 and 3,000 feet of overlying confining layers presents a very low risk to the RTE CCS project site. The thick impermeable layers and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

3.5.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized CO_2 plume boundary. Although there was some historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. Any future endeavors to explore for, or produce, hydrocarbons could avoid the CO_2 plume using horizontal drilling techniques.

3.6 Monitoring, Response, and Reporting Plan for CO_2 Loss

RTE proposes a detailed emergency remedial and response plan (Reference 1, Section 4.1) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk. RTE also proposes a robust monitoring program based on the detailed risk assessment performed during the application for the storage facility and UIC Class VI permit. The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 4.4.2); continuous, real-time surveillance of injection performance (Reference 1, Sections 4.4.3 and 4.4.4); monitoring of near-surface conditions (Reference 1, Sections 4.4.5–4.4.7); and direct and indirect monitoring of the CO_2 plume (Reference 1, Sections 4.4.8.1 and 4.4.8.2).

3.7 Summary

In an unlikely scenario of potential leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of CO_2 would require consideration of the potential leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING POTENTIAL SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring frequency for each of the three project periods, and Table 4-2 summarizes the potential leakage pathway covered by each technique. These methodologies target early detection of any potential abnormalities in operating parameters or deviations from the baseline and threshold established for the project. These methodologies will lead to a verification process to validate if a potential leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and pressure front.

Table 4-1. Summary of RTE's CCS Monitoring Strategy

Method (target area/structure)	Pre-Injection (Baseline – 1 year)	Injection Period (20 years)	Post-Injection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Real-time	NA[1]
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	NA	Real-time	NA
Mass/Volume Flowmeters (RTE-10 and flowline)	NA	Real-time	NA
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	NA	Real-time	Real-time until plume stabilization is demonstrated
DTS/DAS Fiber (RTE-10 and RTE 10.2, dedicated Fox Hills monitoring wells, and flowline)	NA	Real-time	Real-time DTS until well plugging and site reclamation
Visual Inspections (flowline)	Start-up	Quarterly	Quarterly
Corrosion Coupons (flowline)	NA	Quarterly	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (AOR)	Three to four seasonal samples adjacent to each RTE well	Three to four seasonal samples per year adjacent to each well	Three to four seasonal samples every 3 years adjacent to each well
Water Analysis: Shallow Aquifers (AOR)	Three to four seasonal sample events per water wells closest to RTE-10	Once per year during years 1 through 3 and 5, then every 5 years thereafter. Other water wells may be phased in based on CO_2 plume migration.	Three to four sample events at cessation of injection and before site closure
Water Analysis: Lowest USDW (AOR)	Three to four sample events per dedicated Fox Hills monitoring well adjacent to each RTE well	Once per year during years 1 through 3 and 5, then every 5 years thereafter	Three to four sample events at cessation of injection and before site closure
Cement Bond Logs (RTE-10 and RTE-10.2)	After cementing	If needed	Prior to P&A[3]

Continued . . .

Table 4-2. Summary of RTE's CCS Monitoring Strategy (continued)

Method (target area/structure)	Pre-Injection (Baseline – 1 year)	Injection Period (20 years)	Post-Injection (10 years)
Annular Pressure Test (RTE-10 and RTE-10.2)	Prior injection	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	Baseline	Every 5 years in RTE-10.2 and as needed in RTE-10	Every 5 years in RTE-10.2 and as needed in RTE-10
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pressure Falloff Test (RTE-10)	Prior to injection	Every 5 years	Prior to P&A
Time-Lapsed Seismic Surveys (AOR)	Baseline	Every 5 years	Every 5 years
Surface Seismometers (AOR)	Baseline	Real-time	Real-time
InSAR[4] (AOR)*	Baseline	Real-time	Real-time
Gravity Surveys (AOR)*	Baseline	TBD[5] – repeat survey at least once	TBD

* If feasible.
[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Plugged and abandoned.
[4] Interferometric synthetic aperture radar.
[5] To be determined.

Table 4-3. Monitoring Strategies for Detecting Changes in the Storage Reservoir Associated with CO_2 Injection

Monitoring Strategy (target area) \ Potential Leakage Pathway	Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)	X			X	X		X
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	X			X	X	X	
Mass / Volume Flowmeters (RTE-10 and flowline)				X	X		
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	X			X	X	X	X
DTS/DAS Fiber (RTE-10, RTE-10.2, dedicated Fox Hills monitoring wells, and flowline)	X	X	X	X	X	X	X
Visual Inspections (flowline)	X			X	X		
Corrosion Coupons (flowline)				X	X		
SCADA Automated Remote System (surface facilities)			X	X	X		
Soil Gas Analysis (AOR)	X				X		X
Protected Groundwater Zone: Shallow Aquifers (AOR)		X			X		X
Protected Groundwater Zone: Lowest USDW (AOR)	X				X		X
Cement Bond Logs (RTE-10 and RTE-10.2)					X		
Annular Pressure Test (RTE-10 and RTE-10.2)				X	X		
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	X				X	X	X
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)					X		
Pressure Falloff Test (RTE-10)	X				X	X	
Time-Lapsed Seismic Surveys (AOR)	X	X		X	X	X	X
Surface Seismometers (AOR)		X	X				X
InSAR (AOR)*	X	X		X		X	X
Gravity Surveys (AOR)*						X	

* If feasible.

4.1 Potential Leak Verification

RTE will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, DTS alongside the casing, and routine maintenance and inspection.

As part of the surveillance protocol, RTE will use reservoir simulation modeling, based on history-matched data obtained from the monitoring system, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR review will be submitted, and the monitoring plan revised and modified if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if potential CO_2 leakage is occurring. Excursions are not necessarily indicators of potential leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated) and there is no indication that potential CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a potential leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a potential CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, RTE will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the RTE CCS project.

Response plan actions and activities will depend upon the circumstances and severity of the event. RTE will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, RTE will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Potential Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any potential leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as potentially leaking to the surface will be quantified using acceptable emission factors, engineering estimates of potential leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Potential leaks will be documented, evaluated, and addressed in a timely manner. Records of potential leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

RTE will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if potential CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by potentially leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the RTE CCS project area is provided in Reference 1, Section 4.4.6.

5.1 Surface Baselines

A baseline sampling program has been completed for the RTE CCS project. Baseline data were obtained from 11 soil gas-sampling locations and three existing groundwater wells in the northwestern portion of the AOR. In addition, two dedicated monitoring wells were drilled in the Fox Hills Formation and placed near the RTE injection and monitoring wells. For additional information regarding surface baselines, refer to Reference 1, Sections 4.4.5–4.4.7.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir.

Feasibility studies for monitoring surface deformation with InSAR and detecting changes in mass with gravity methods will be performed prior to injection to justify application of the technologies at the RTE CCS site. For more information on what these technologies measure and how RTE plans to implement them, refer to Reference 1, Section 4.4.8 and Table 4-11 in Section 4.4.8.2, respectively.

For passive seismicity monitoring, the project will install seismometer stations sufficient to confidently measure baseline seismicity from the injection area 1 year prior to injection. For additional information regarding subsurface baselines, refer to Reference 1, Section 4.4.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The RTE CCS project area is a CO_2 storage site in a saline aquifer with no production associated from the storage complex. The proposed main metering station for mass balance calculation is identified as the first metering station placed at the wellhead, using the station at the flow line as a backup/duplicate.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

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

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

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by potential surface leakage.

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

Mass of CO_2 Injected (CO_{2I}):

RTE will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually 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 from 40 CFR Part 98-Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate 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 Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

Mass of CO_2 Emitted by Potential Surface Leakage (CO_{2E}):

RTE characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 4.4, to detect any potential leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of potential leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying potential leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the potential leak, and numerical and predictive models among others.

RTE will calculate the total annual mass of CO_2 emitted from all potential leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

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

x = Potential leakage pathway.

Mass of CO_2 Emitted by Potential Equipment Leaks and Vented Emissions (CO_{2FI})
Annual mass of CO_2 emitted (in metric tons) from potential 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 (CO_{2FI}) 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 and surveillance plan proposed in Reference 1, Section 4.4.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting April 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas (GHG) reports are filed on April 30 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect during the period of 30 years (20 years injection and 10 years post-injection) from April 2022 to April 2052, during which time the RTE CCS project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for RTE monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Section 4.4.9.

RTE will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at a receiving meter on the injection well pad.
- The quarterly CO_2 concentration will be reported from near-continuous measurement upstream of the receiving meter on the injection well pad.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).
- Operated in conformance with consensus-based standards organizations including, but not limited to, the American Society for Testing and Materials International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

RTE will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from potential equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

10.0 REFERENCES

Anderson, F.J., 2016, North Dakota earthquake catalog (1870–2015): North Dakota Geological Survey Miscellaneous Series No. 93.

Leroux, K.M., Klapperich, R.J., Azzolina, N.A., Jensen, M.D., Kalenze, N.S., Bosshart, N.W., Torres Rivero, J.A., Jacobson, L.L., Ayash, S.C., Nakles, D.V., Jiang, T., Oster, B.S., Feole, I.K., Fiala, N.J., Schlasner, S.M., Wilson IV, W.I., Doll, T.E., Hamling, J.A., Gorecki, C.D., Pekot, L.J., Peck, W.D., Harju, J.A., Burnison, S.A., Stevens, B.G., Smith, S.A., Butler, S.K., Glazewski, K.A., Piggott, B., and Vance, A.E., 2017, Integrated carbon capture and storage for North Dakota ethanol production: Final report (November 1, 2016 – May 31, 2017) for North Dakota Industrial Commission and Red Trail Energy, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

U.S. Geological Survey, 2019, Frequency of damaging earthquake shaking around the U.S. www.usgs.gov/media/images/frequency-damaging-earthquake-shaking-around-us (accessed October 2021).

Appendix B: Submissions and Responses to Requests for Additional Information

RED TRAIL ENERGY SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 530977

North Dakota Storage Facility Permit: Order No. 31453–31455

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STORAGE FACILITY PERMIT DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, the Red Trail Energy storage facility permit is designated as follows:

Reference 1: Red Trail Energy Carbon Dioxide Geologic Storage Facility Permit

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Area of Review
Section 4 – Supporting Permit Plans
Section 5 – Injection Well and Storage Operations
Appendix A – Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations
Appendix B – RTE-10 and RTE-10.2 Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Freshwater Well Fluid-Sampling Laboratory Analysis
Appendix D – Quality Assurance and Surveillance Plan
Appendix E – Storage Facility Permit Regulatory Compliance Table
Appendix F – Post-Hearing Supplement Filing: Financial Responsibility Demonstration Plan
Appendix G – Post-Hearing Supplemental Filing: Certification of Liability Insurance
Appendix H – Post-Hearing Supplemental Filing: Geologic Storage Agreement Summary of Surface Owners Who Have Ratified

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Red Trail Energy (RTE) facility is a North Dakota-based, investor-owned 64-million-gallon dry mill ethanol production plant, which has been in operation since January 2007. The RTE facility, located about a mile east of Richardton, North Dakota (Figure 1-1), emits an average of 180,000 metric tons annually of high-purity carbon dioxide (CO_2) (>99% CO_2 dry) from the fermentation process during ethanol production. The RTE carbon capture and storage (CCS) project is currently constructing a CO_2 capture facility (mainly dehydration and compression) adjacent to the RTE ethanol plant to capture all CO_2 from fermentation. RTE plans to inject the resulting 180,000-metric-ton-per-year CO_2 stream into the Broom Creek Formation via the RTE-10 injection well located on RTE property (Figure 1-1) for permanent geologic CO_2 storage.

RTE received formal approval of its North Dakota CO_2 storage facility permit (SFP) on October 19, 2021. This approval by the North Dakota Industrial Commission (NDIC) authorizes the geologic storage of CO_2 from the RTE ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation (NDIC Order Nos. 31453 and 31454). North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). No other geologic storage project exists or is planned at or near the RTE CCS project.

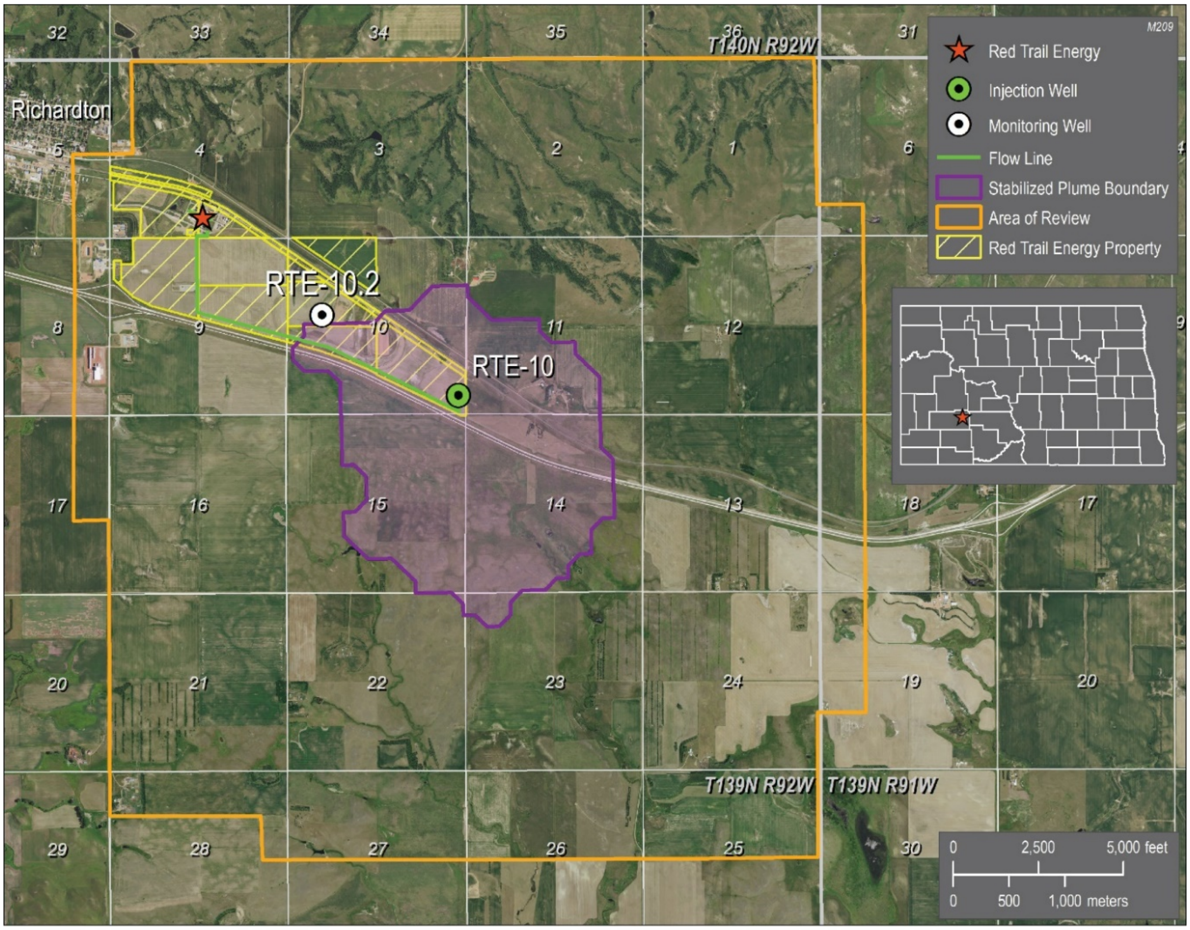

Figure 1-1. Location of the RTE facility, RTE-10 injection well, RTE-10.2 monitoring well, and CO_2 flowline. Also shown is the town of Richardton, with a population of about 850 people, the stabilized plume boundary, and the area of review (AOR).

1.2 Environmental Setting

The RTE CCS project site is on the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota (i.e., western Williston Basin) and demonstrates there has been no exploration for, and development of, hydrocarbon resources within the stabilized plume boundary (Reference 1, Section 2.6). The Rummel-State 1 (NDIC No. 6797), a dry hole drilled to the Red River Formation (below the Broom Creek Formation) in 1978, is located within the southwestern edge of the AOR (see Section 3.2 of this MRV plan for more information on the Rummel-State 1).

A generalized stratigraphic column of the Williston Basin for the Richardton area is provided in Figure 1-3. The target CO_2 storage reservoir for the RTE CCS project is the Broom Creek Formation, a predominantly sandstone interval lying about 6,380 feet below the RTE facility

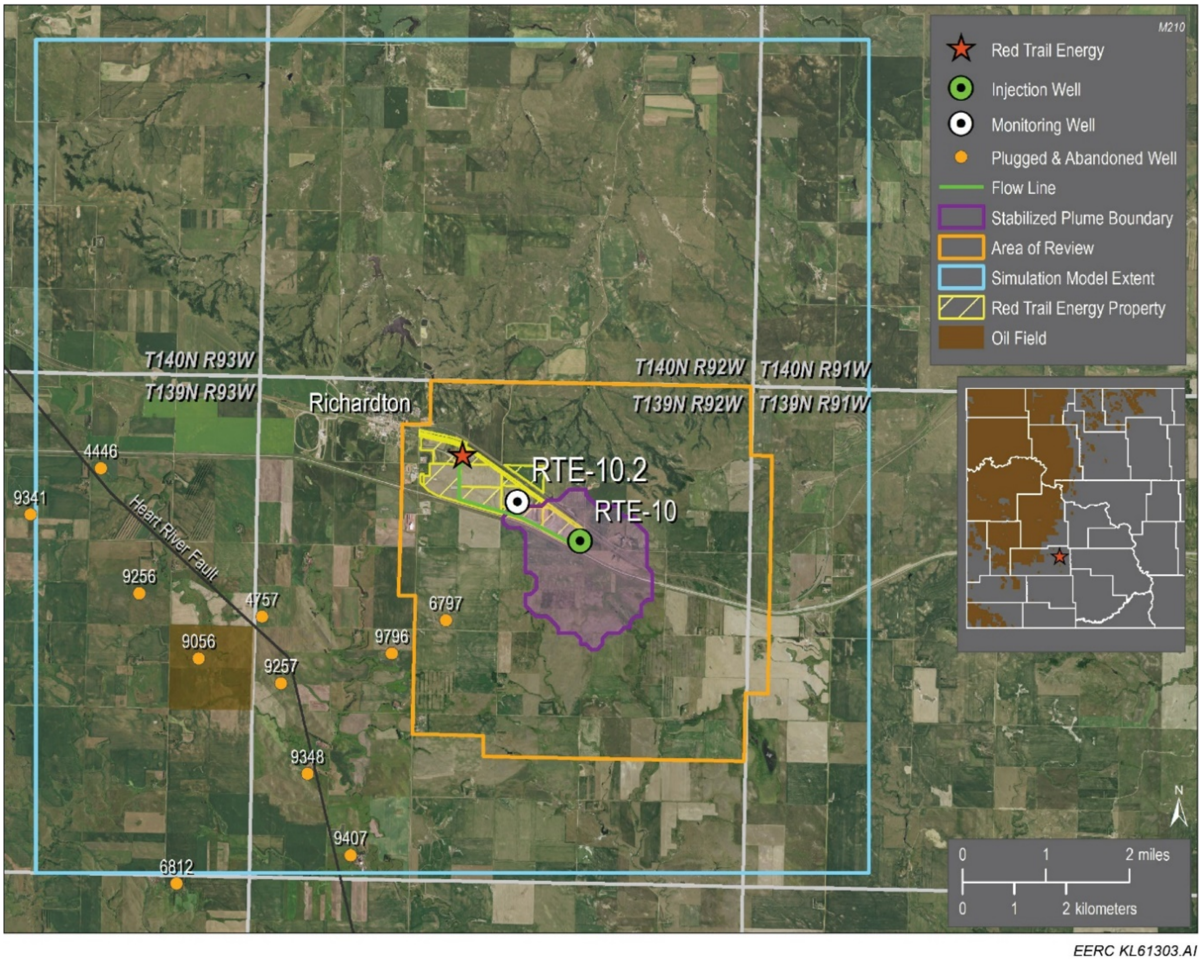

Figure 1-2. Map showing the AOR, stabilized plume boundary, RTE ethanol facility, RTE-10 injection well, RTE-10.2 monitoring well, town of Richardton, and oil and gas wells immediately outside of or within the simulation model extents. Also shown is an inset map identifying the geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin) and the Heart River Fault. The oil field in T139N-R93W is the Taylor Field. Wells 9056 and 9341 produced some hydrocarbons from the Winnipeg Formation (see Figure 1-3 for stratigraphic reference), but all other wildcat wells shown on the map were classified as dry holes.

(Reference 1, Section 2.3). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Reference 1, Section 2.4.3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1,200 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 3,000 feet of impermeable intervals separates the Inyan Kara and the lowest underground source of drinking water (USDW), the Fox Hills Formation.

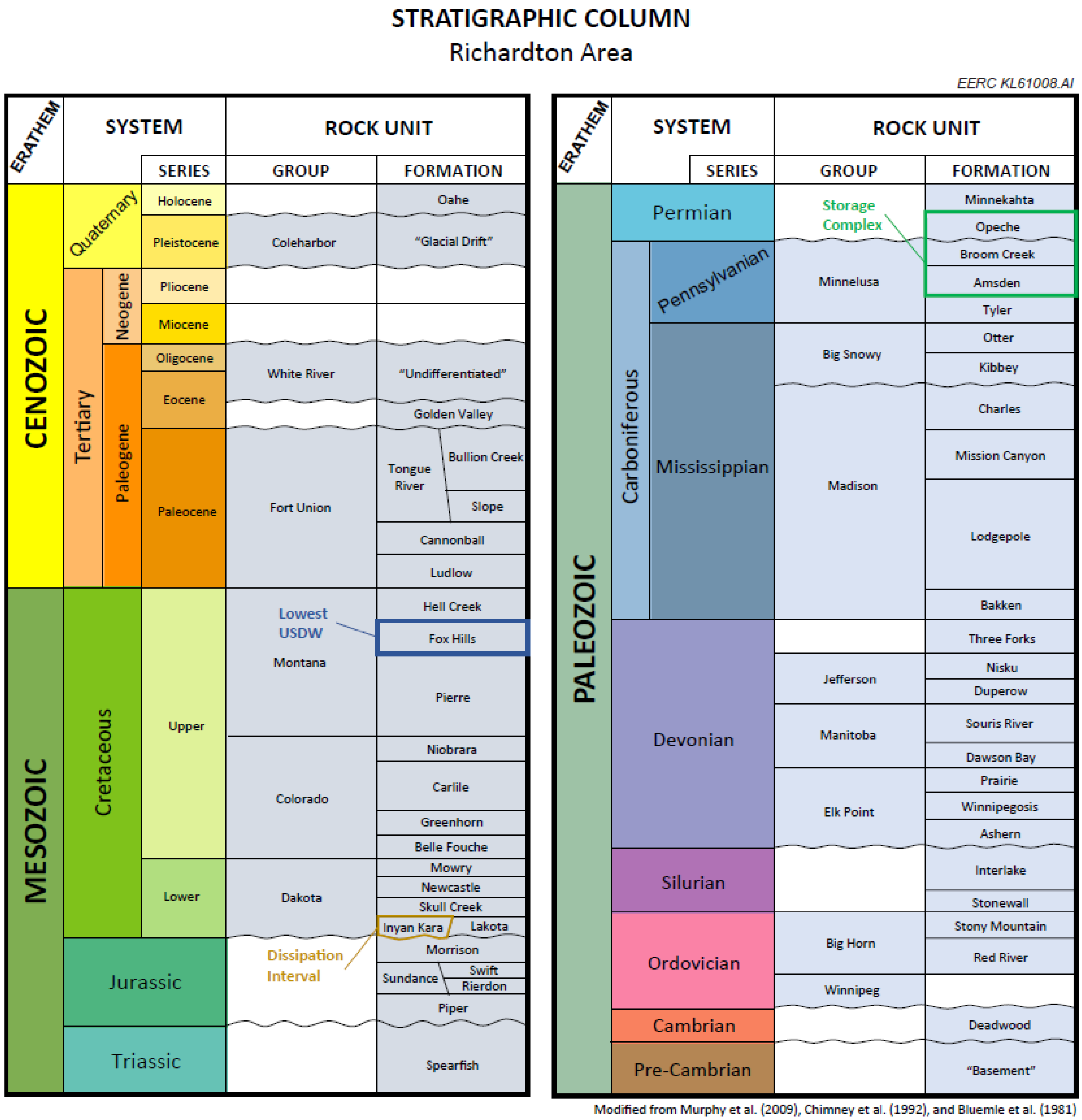

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Richardton area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the RTE CCS project site.

1.3 Description of CO_2 Project Facilities and Injection Process

RTE plans to capture and store 180,000 metric tons per year over the course of 20 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration of

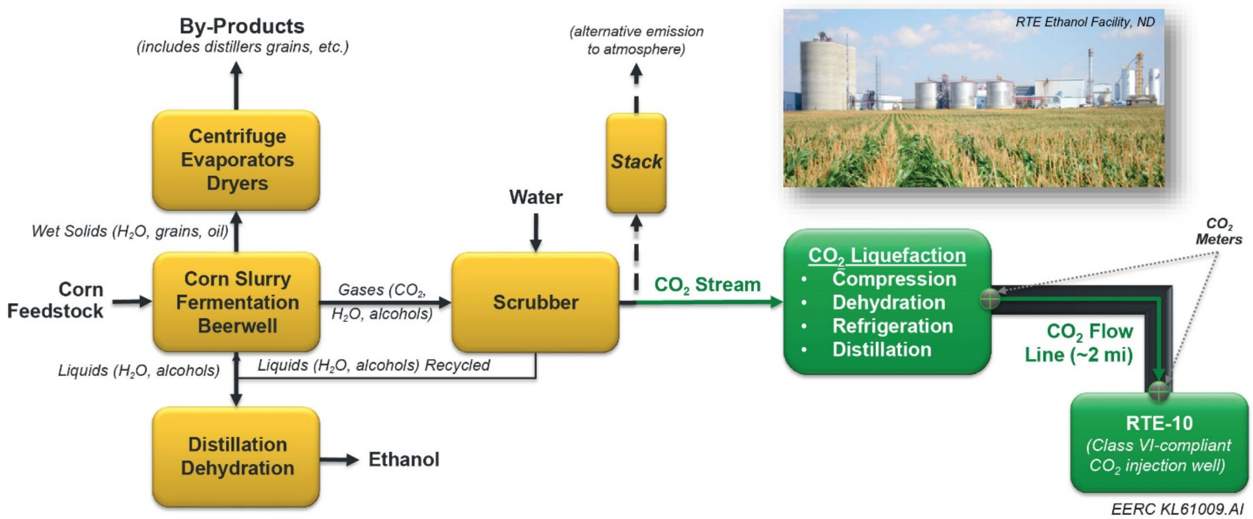

Figure 1-4. Flow diagram of the RTE CCS process, showing major CCS components and the path of the CO_2 stream from the capture facility to the RTE-10 injection well.

major CCS components with the existing RTE ethanol facility. The capture–liquefaction facility was designed to capture the CO_2 currently produced during RTE's fermentation process (following the scrubber prior to stack emission), compress the gaseous CO_2 stream to approximately 350 pounds per square inch, dehydrate the stream, and then liquefy the CO_2 using a closed-loop ammonia (NH_3) refrigeration process. A conventional distillation column would distill the liquid CO_2 to remove oxygen in addition to other noncondensable gases. The final liquid CO_2 stream would flow to the RTE-10 injection well for geologic storage into the Broom Creek Formation; an underground flowline is installed on RTE property to connect the capture plant to the RTE-10 injection well.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: RTE AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

RTE proposes that because the AOR, as delineated in Reference 1, Section 3 and Appendix A, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as AMA for the RTE CCS project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). The NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, RTE elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 3 and Appendix A, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

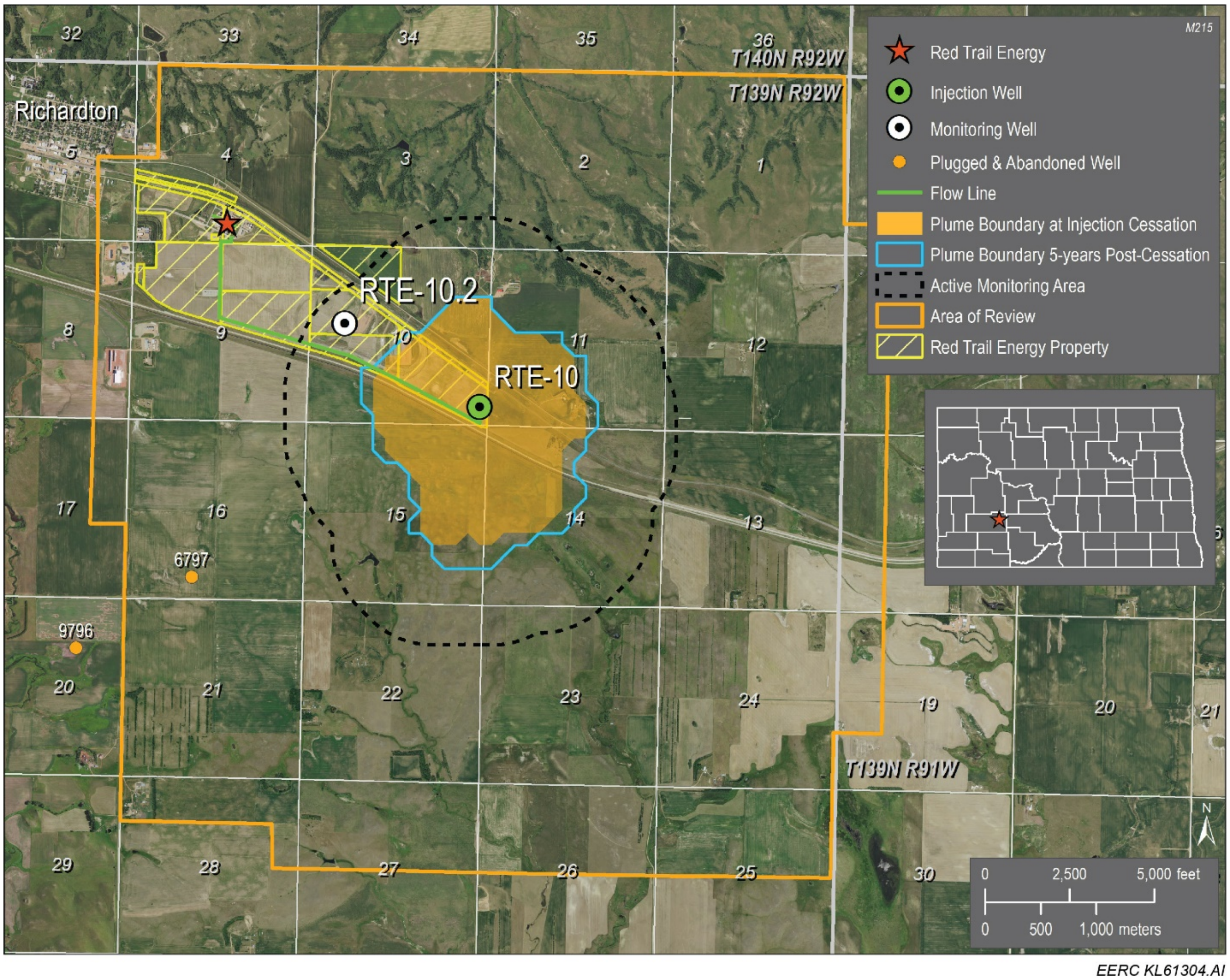

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (20 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the RTE CCS project.

2.2 Maximum Monitoring Area

RTE proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the RTE CCS project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

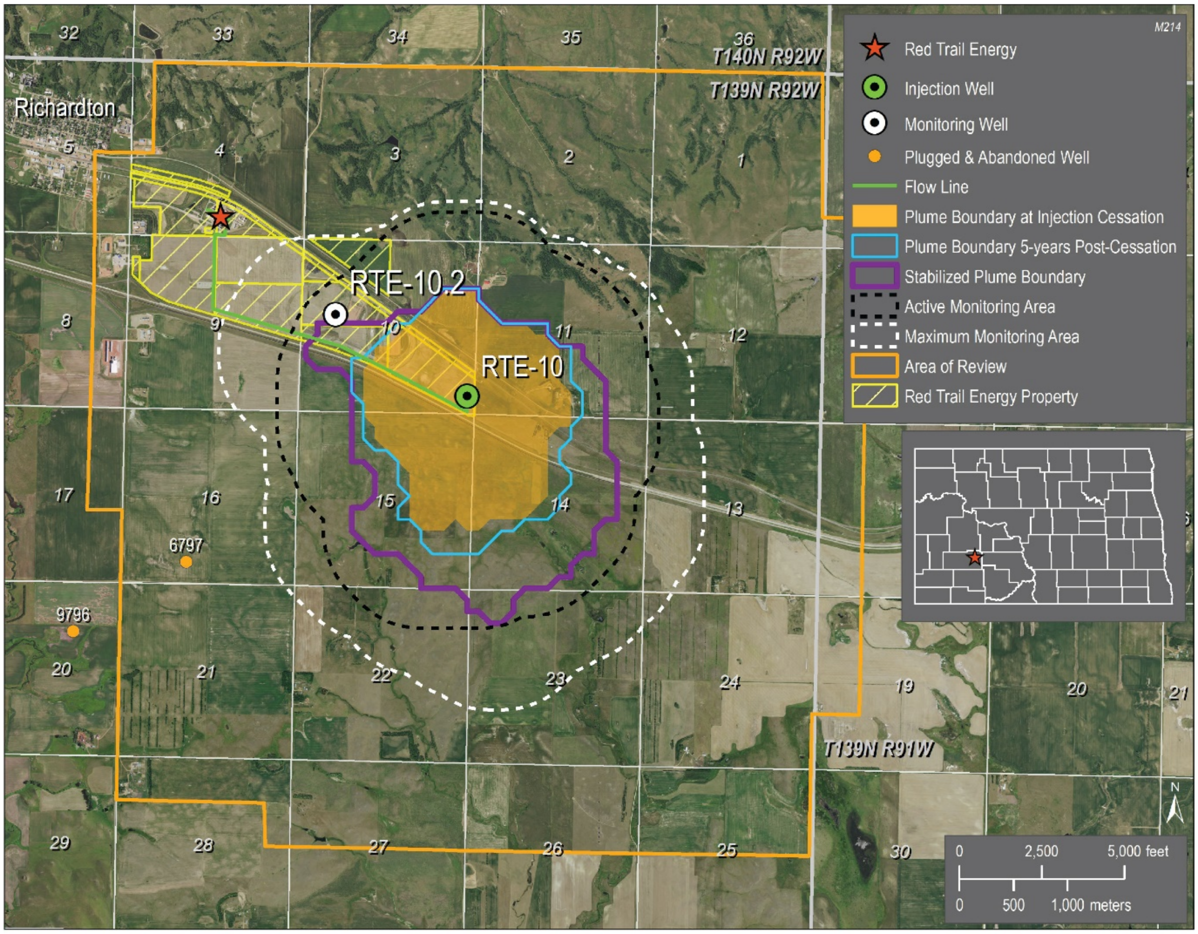

Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the RTE CCS project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 4.4) comprises three distinct periods: 1) pre-operational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. These monitoring periods therefore encompass the entire life cycle of the project. For purposes of this monitoring, reporting, and verification (MRV) plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 20 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

An evaluation of potential subsurface leakage pathways and surface equipment failures during implementation of the project was informed by a screening-level risk assessment (SLRA), which was performed in accordance with the International Organization for Standardization's (ISO's) risk management standard ISO 31000 (Leroux and others, 2017). The SLRA was conducted through a series of work group sessions involving Energy & Environmental Research Center subject matter experts. During these meetings, factors and equipment that could lead to potential leakage pathways were identified and evaluated for the following:

1. Surface components (flowline and wellhead)
2. Abandoned oil and gas wells
3. Faults, fractures, bedding plane partings, and seismicity
4. Injection well or monitoring well
5. Confining zone limitations

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 4.4 and summarized in Table 4-1, was developed to form the basis of this MRV plan.

3.1 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the RTE CCS project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The RTE CCS system includes a 4-inch flowline buried a minimum of 6 feet to transport CO_2 from the capture facility to the storage site (2 miles). The flowline will be connected to a metering station at the wellhead and located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics are installed along the flowline as part of the leak detection program and mechanical integrity protocol. Flowmeters and temperatureand pressure transducers will be installed at each metering station.

Shutoff devices will be installed at each end of the flowline to control any potential release and send alarms to the automated system. Pressure gauges will be installed on the wellhead to monitor annular pressure between tubing and casing.

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. Routine visual inspections will be conducted, and real-time operating parameters tracked through an automated system for alarm notification and process management.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing highest standards on material selection and construction processes for the flowline and wells.
- Implementing best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could potentially represent several tons of CO_2 released underground until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply. Note that should a potential shutoff situation occur, the RTE facility will revert to current operations, emitting CO_2 under existing permits maintained through the North Dakota Department of Environmental Quality.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injector wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, RTE-10.2, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.2 Abandoned Oil and Gas Wells

The Rummel-State 1 (NDIC No. 6797) well spudded in December 1978 to a depth of 11,270 feet into the Red River Formation and was plugged and abandoned in February 1979. Multiple drillstem tests were conducted in several stratigraphic intervals, but the well encountered no commercial accumulations of hydrocarbons. The Rummel-State 1 was evaluated as part of the risk assessment for the RTE CCS project and is the only oil and gas well within the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 3.1.2).

3.3 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.3.1 Heart River Fault

The Heart River Fault, located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AOR for the RTE project (Figure 1-2), is a high-angle reverse fault that originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 feet in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations, well below the Broom Creek Formation (Reference 1, Section 2.5.1). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset (see Figure 1-3 for stratigraphic reference).

3.3.2 Natural or Induced Seismicity

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (Reference 1 Section 2.5.3). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The seismic event recorded closest to the RTE CCS project occurred 21.6 miles from Richardton, North Dakota, with a magnitude of 3.2 (Reference 1, Section 2.5.3).

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year period (U.S. Geological Survey, 2019). Through the risk assessment process, potential leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.4 Injection Well and Monitoring Well

3.4.1 RTE-10 (NDIC No. 37229)

The RTE-10 well spudded in March 2020 as a stratigraphic test well to a depth of 6,900 feet into the Amsden Formation. This well was drilled specifically to gather geologic data to support the development of a CO_2 SFP and as the RTE CCS project's future injector well. The RTE-10 will be monitored in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, the RTE-10 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10 wellbore construction can be found in Reference 1, Section

4.5.1 (Well Casing and Cementing Program). An evaluation of RTE-10 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

3.4.2 RTE-10.2 (NDIC No. 37858)

The RTE-10.2 well spudded in October 2020 as a stratigraphic test well and future monitoring well for the injected CO_2 of the RTE project. The well was drilled to a depth of 6,770 feet into the Amsden Formation. The RTE-10.2 will monitor the Broom Creek Formation in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, RTE-10.2 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10.2 wellbore construction can be found in Reference 1, Section 4.5.2 (Well Casing and Cementing Program). An evaluation of RTE-10.2 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

3.5 Confining Zone Limitations

3.5.1 Lateral Migration

For the RTE CCS project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 6,276 feet below the surface and 103 feet thick at the RTE CCS project site (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine).

3.5.2 Seal Diffusivity

Several additional formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,200 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 3,000 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The possibility of fluid migration through 1,200 and 3,000 feet of overlying confining layers presents a very low risk to the RTE CCS project site. The thick impermeable layers and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

3.5.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized CO_2 plume boundary. Although there was some historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. Any future endeavors to explore for, or produce, hydrocarbons could avoid the CO_2 plume using horizontal drilling techniques.

3.6 Monitoring, Response, and Reporting Plan for CO_2 Loss

RTE proposes a detailed emergency remedial and response plan (Reference 1, Section 4.1) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk. RTE also proposes a robust monitoring program based on the detailed risk assessment performed during the application for the storage facility and UIC Class VI permit. The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 4.4.2); continuous, real-time surveillance of injection performance (Reference 1, Sections 4.4.3 and 4.4.4); monitoring of near-surface conditions (Reference 1, Sections 4.4.5–4.4.7); and direct and indirect monitoring of the CO_2 plume (Reference 1, Sections 4.4.8.1 and 4.4.8.2).

3.7 Summary

In an unlikely scenario of potential leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of CO_2 would require consideration of the potential leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING POTENTIAL SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring frequency for each of the three project periods, and Table 4-2 summarizes the potential leakage pathway covered by each technique. These methodologies target early detection of any potential abnormalities in operating parameters or deviations from the baseline and threshold established for the project. These methodologies will lead to a verification process to validate if a potential leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and pressure front.

Table 4-1. Summary of RTE's CCS Monitoring Strategy

Method (target area/structure)	Pre-Injection (Baseline – 1 year)	Injection Period (20 years)	Post-Injection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Real-time	NA[1]
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	NA	Real-time	NA
Mass/Volume Flowmeters (RTE-10 and flowline)	NA	Real-time	NA
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	NA	Real-time	Real-time until plume stabilization is demonstrated
DTS/DAS Fiber (RTE-10 and RTE 10.2, dedicated Fox Hills monitoring wells, and flowline)	NA	Real-time	Real-time DTS until well plugging and site reclamation
Visual Inspections (flowline)	Start-up	Quarterly	Quarterly
Corrosion Coupons (flowline)	NA	Quarterly	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (AOR)	Three to four seasonal samples adjacent to each RTE well	Three to four seasonal samples per year adjacent to each well	Three to four seasonal samples every 3 years adjacent to each well
Water Analysis: Shallow Aquifers (AOR)	Three to four seasonal sample events per water wells closest to RTE-10	Once per year during years 1 through 3 and 5, then every 5 years thereafter. Other water wells may be phased in based on CO_2 plume migration.	Three to four sample events at cessation of injection and before site closure
Water Analysis: Lowest USDW (AOR)	Three to four sample events per dedicated Fox Hills monitoring well adjacent to each RTE well	Once per year during years 1 through 3 and 5, then every 5 years thereafter	Three to four sample events at cessation of injection and before site closure
Cement Bond Logs (RTE-10 and RTE-10.2)	After cementing	If needed	Prior to P&A[3]

Continued . . .

Table 4-2. Summary of RTE's CCS Monitoring Strategy (continued)

Method (target area/structure)	Pre-Injection (Baseline – 1 year)	Injection Period (20 years)	Post-Injection (10 years)
Annular Pressure Test (RTE-10 and RTE-10.2)	Prior injection	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	Baseline	Every 5 years in RTE-10.2 and as needed in RTE-10	Every 5 years in RTE-10.2 and as needed in RTE-10
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pressure Falloff Test (RTE-10)	Prior to injection	Every 5 years	Prior to P&A
Time-Lapsed Seismic Surveys (AOR)	Baseline	Every 5 years	Every 5 years
Surface Seismometers (AOR)	Baseline	Real-time	Real-time
InSAR[4] (AOR)*	Baseline	Real-time	Real-time
Gravity Surveys (AOR)*	Baseline	TBD[5] – repeat survey at least once	TBD

* If feasible.
[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Plugged and abandoned.
[4] Interferometric synthetic aperture radar.
[5] To be determined.

Table 4-3. Monitoring Strategies for Detecting Changes in the Storage Reservoir Associated with CO_2 Injection

Monitoring Strategy (target area) \ Potential Leakage Pathway	Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)	X			X	X		X
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	X			X	X	X	
Mass / Volume Flowmeters (RTE-10 and flowline)				X	X		
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	X			X	X	X	X
DTS/DAS Fiber (RTE-10, RTE-10.2, dedicated Fox Hills monitoring wells, and flowline)	X	X	X	X	X	X	X
Visual Inspections (flowline)	X			X	X		
Corrosion Coupons (flowline)				X	X		
SCADA Automated Remote System (surface facilities)			X	X	X		
Soil Gas Analysis (AOR)	X				X		X
Protected Groundwater Zone: Shallow Aquifers (AOR)		X			X		X
Protected Groundwater Zone: Lowest USDW (AOR)	X				X		X
Cement Bond Logs (RTE-10 and RTE-10.2)					X		
Annular Pressure Test (RTE-10 and RTE-10.2)				X	X		
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	X				X	X	X
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)					X		
Pressure Falloff Test (RTE-10)	X				X	X	
Time-Lapsed Seismic Surveys (AOR)	X	X		X	X	X	X
Surface Seismometers (AOR)		X	X				X
InSAR (AOR)*	X	X		X		X	X
Gravity Surveys (AOR)*						X	

* If feasible.

4.1 Potential Leak Verification

RTE will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, DTS alongside the casing, and routine maintenance and inspection.

As part of the surveillance protocol, RTE will use reservoir simulation modeling, based on history-matched data obtained from the monitoring system, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR review will be submitted, and the monitoring plan revised and modified if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if potential CO_2 leakage is occurring. Excursions are not necessarily indicators of potential leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated) and there is no indication that potential CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a potential leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a potential CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, RTE will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the RTE CCS project.

Response plan actions and activities will depend upon the circumstances and severity of the event. RTE will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, RTE will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Potential Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any potential leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as potentially leaking to the surface will be quantified using acceptable emission factors, engineering estimates of potential leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Potential leaks will be documented, evaluated, and addressed in a timely manner. Records of potential leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

RTE will establish pre-injection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if potential CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by potentially leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the RTE CCS project area is provided in Reference 1, Section 4.4.6.

5.1 Surface Baselines

A baseline sampling program has been completed for the RTE CCS project. Baseline data were obtained from 11 soil gas-sampling locations and three existing groundwater wells in the northwestern portion of the AOR. In addition, two dedicated monitoring wells were drilled in the Fox Hills Formation and placed near the RTE injection and monitoring wells. For additional information regarding surface baselines, refer to Reference 1, Sections 4.4.5–4.4.7.

5.2 Subsurface Baselines

Pre-operational baseline data will be collected in the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir.

Feasibility studies for monitoring surface deformation with InSAR and detecting changes in mass with gravity methods will be performed prior to injection to justify application of the technologies at the RTE CCS site. For more information on what these technologies measure and how RTE plans to implement them, refer to Reference 1, Section 4.4.8 and Table 4-11 in Section 4.4.8.2, respectively.

For passive seismicity monitoring, the project will install seismometer stations sufficient to confidently measure baseline seismicity from the injection area 1 year prior to injection. For additional information regarding subsurface baselines, refer to Reference 1, Section 4.4.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The RTE CCS project area is a CO_2 storage site in a saline aquifer with no production associated from the storage complex. The proposed main metering station for mass balance calculation is identified as the first metering station placed at the wellhead, using the station at the flow line as a backup/duplicate.

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

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

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

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by potential surface leakage.

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

Mass of CO_2 Injected (CO_{2I}):

RTE will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually 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 from 40 CFR Part 98-Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate 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 Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

Mass of CO_2 Emitted by Potential Surface Leakage (CO_{2E}):

RTE characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 4.4, to detect any potential leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of potential leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying potential leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the potential leak, and numerical and predictive models among others.

RTE will calculate the total annual mass of CO_2 emitted from all potential leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

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

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

x = Potential leakage pathway.

Mass of CO_2 Emitted by Potential Equipment Leaks and Vented Emissions (CO_{2FI})
Annual mass of CO_2 emitted (in metric tons) from potential 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 (CO_{2FI}) 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 and surveillance plan proposed in Reference 1, Section 4.4.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting April 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas (GHG) reports are filed on April 30 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect during the period of 30 years (20 years injection and 10 years post-injection) from April 2022 to April 2052, during which time the RTE CCS project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for RTE monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Section 4.4.9.

RTE will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:

- The quarterly flow rate of CO_2 will be reported from continuous measurement at a receiving meter on the injection well pad.
- The quarterly CO_2 concentration will be reported from near-continuous measurement upstream of the receiving meter on the injection well pad.

Flowmeter provision:

- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).
- Operated in conformance with consensus-based standards organizations including, but not limited to, the American Society for Testing and Materials International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

RTE will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from potential equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

10.0 REFERENCES

Anderson, F.J., 2016, North Dakota earthquake catalog (1870–2015): North Dakota Geological Survey Miscellaneous Series No. 93.

Leroux, K.M., Klapperich, R.J., Azzolina, N.A., Jensen, M.D., Kalenze, N.S., Bosshart, N.W., Torres Rivero, J.A., Jacobson, L.L., Ayash, S.C., Nakles, D.V., Jiang, T., Oster, B.S., Feole, I.K., Fiala, N.J., Schlasner, S.M., Wilson IV, W.I., Doll, T.E., Hamling, J.A., Gorecki, C.D., Pekot, L.J., Peck, W.D., Harju, J.A., Burnison, S.A., Stevens, B.G., Smith, S.A., Butler, S.K., Glazewski, K.A., Piggott, B., and Vance, A.E., 2017, Integrated carbon capture and storage for North Dakota ethanol production: Final report (November 1, 2016 – May 31, 2017) for North Dakota Industrial Commission and Red Trail Energy, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

U.S. Geological Survey, 2019, Frequency of damaging earthquake shaking around the U.S. www.usgs.gov/media/images/frequency-damaging-earthquake-shaking-around-us (accessed October 2021).

Request for Additional Information: Red Trail Energy
January 13, 2022

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.

	MRV Plan			
No.	**Section**	**Page**	**EPA Questions**	**Responses**
1.	N/A	N/A	Throughout the MRV plan there are several instances of missing thousands place separators in numeric integers. We recommend adding commas to numbers where appropriate to improve clarity.	The document has been reviewed in its entirety, and a total of ten instances were found and corrected in the MRV plan.
2.	N/A	N/A	The terms “preinjection”, “postinjection”, “preoperational”, and “postoperational” are used throughout the MRV plan, however, these are not words, or do not convey the intended meaning. We recommend editing these words for clarity and checking the entirety of the MRV plan for other hyphenation errors.	Hyphens were added to the four terms identified by EPA. The terms “preinjection,” “postinjection,” “preoperational,” and “postoperational” have been changed to read “pre-injection,” “post-injection,” “pre-operational,” and “post-operational” throughout the document.
3.	1.2	2	“…there has been no exploration for, and development of, hydrocarbon resources within the stabilized plume boundary.” While we recognize that Rummel State 1 was not drilled within the modeled plume boundary, we believe it is relevant to the characterization of the project’s setting due to its position in the AOR. Therefore, we recommend mentioning the well Rummel State 1 (NDIC No. 6797) in the Environmental Setting section.	Rummel-State 1 has been added to the “Environmental Setting” section as requested.
4.	1.2	3	“Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably **overly** the Broom Creek…” We believe there is a typo in the above phrase, specifically, the correct spelling of the bolded word is “overlie” in this context. Please correct this error.	This spelling error has been corrected in the MRV plan.

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
5.	1.2	4	We recommend updating Figure 1-3 to improve its resolution, if possible. Some of the labels, particularly those specific to this project (i.e., Dissipation Interval, Lowest USDW, and Storage Complex) are difficult to read.	Figure 1-3 has been updated for improved readability, including the labels called out in EPA's comments.
6.	3.0	9	"…which was performed in accordance with international standard **ISO** 31000…" The acronym 'ISO' is used in the above phrase before being defined. Please define it here for improved clarity.	The acronym ISO is now defined in the text to satisfy this request. Note: The **I**nternational **O**rganization for **S**tandardization intentionally chose to identify itself solely as ISO. More information is available on the website at https://www.iso.org/about-us.html.
7.	3.0, 3.3	9, 11	We recommend adding seismicity to subheading 3.3 so that it reads, "Faults, Fractures, Bedding Plane Partings, and Seismicity," in order to highlight RTE's characterization of risk from natural or induced seismicity. This would also necessitate an edit to the list of potential leakage pathways found on page 9 of the MRV plan.	The title of Section 3.3 and list on page 9 of the MRV plan have been updated to read as requested.
8.	3.1	9,10	The discussion of surface leakage includes CO_2 emitted from equipment leaks and vented emissions from equipment between the injection flow meter and the injection wellhead. 40 CFR 98.449 defines "surface leakage" as "the movement of the injected CO_2 stream from the injection zone to the surface, and into the atmosphere, indoor air, oceans, or surface water". The pathway for CO_2 emitted from equipment leaks and vented emissions from equipment between the injection flow meter and the injection wellhead should be discussed separately from pathways for emissions from potential surface leakage. They are separate and distinct inputs to Equation RR-12.	We believe this point is now rectified by our making the following changes to the MRV plan: 1) changing the title of Section 3.0 to have a more generic meaning and 2) stating in the first paragraph below that both "the potential leakage pathways for CO_2 arriving at the surface after injection or from potential surface equipment failures" were considered in the risk assessment. In this way, we believe that both the "CO_{2FI}" input from Equation RR-12 (i.e., the "potential equipment leaks and vented emissions" variable directly related to "potential surface equipment failures") and the "CO_{2E}" term from the same equation (i.e., the "potential surface leakage" input directly related to the "potential leakage pathways for CO_2 arriving at the surface after injection") are presented as separate ideas in the text and are further separated in Subsections 3.1 through 3.5.
9.	3.2, 3.4	10, 11	The term "spud" is used in the past tense throughout section 3 of the MRV plan. It is our understanding that the correct past tense form of spud is spudded; if this is the case then please correct it.	"Spud" was corrected to "spudded" in the MRV plan in all cases in which the word "spud" originally appeared in the document.

No.	MRV Plan Section	Page	EPA Questions	Responses
10.	3.3.1	10	"Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 feet in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations, well below the Broom Creek Formation (Reference 1, Section 2.5.1)." In reviewing the stratigraphic column on Section 1.2 (page 4), there is reference to the Stony Wash formation but not the Stony Mountain formation. Please clarify.	Figure 1-3 has been updated to reflect the correct nomenclature for the Stony Mountain Formation.
11.	3.4	12	The injection and monitoring wells are described in the MRV plan, but there is little detail presented about the wells' construction and the corresponding likelihood for leakage. Please elaborate on the wells and the likelihood, magnitude and timing of potential surface leakage.	Additional detail with the appropriate references has been added to the MRV plan in Sections 3.4.1 and 3.4.2 to address EPA's concern on this point.
12.	3.5.2	12	"Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1200 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation." In the stratigraphic column on Section 1.2 (page 4), there is reference to the Sundance formation but not the Swift formation. Please clarify.	The names "Sundance" and "Swift" are often used interchangeably by geologists, although technically the Swift is stratigraphically equivalent to just the upper part of the Sundance Formation. The stratigraphic column in the MRV plan (Figure 1-3) has been updated to incorporate the Swift and Rierdon Formation names as alternatives to Sundance for improved clarity.
13.	3.5.3	13	"Any future endeavors to explore for, or produce, hydrocarbons could avoid the CO_2 plume using horizontal drilling techniques." Is there a plan to address and review plans for oil and gas production that could impact the plume? Please describe the process for reviewing such plans for future drilling activity.	There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the storage facility area. Although there was some historical gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the storage facility area, and RTE is unaware of any future plans to explore for or produce hydrocarbons in the area.

No.	MRV Plan Section	MRV Plan Page	EPA Questions	Responses
14.	4.0	15	Table 4-2 lists monitoring strategies for different leakage pathways, one of which is "Wellbores". Do the listed strategies for wellbores also apply to the abandoned well that was identified in the leakage pathways discussion (Rummel-State 1 (NDIC No. 6797)? Which wellbores will be monitored?	The Rummel-State 1 and RTE-10.2 wells are the only wells that penetrate the deep stratigraphic section to the storage reservoir within the area of review. Both wells were evaluated to determine if corrective action was needed (Reference 1, Section 3.2). The results of the analysis demonstrated no corrective action was needed for either well; therefore, there are no current plans to monitor Rummel-State 1. Potential monitoring for Rummel-State 1 will be included in any reevaluation effort. Because RTE 10.2 is the monitoring well for the RTE CCS project, it will be monitored, along with RTE-10 (injection well) and two dedicated groundwater wells located near RTE-10.2 and RTE-10, as described in the Testing and Monitoring Plan (Reference 1, Section 4.4).
15.	5	17	"The baseline will contain information on a range of characteristics such as…..and **gas saturation/oil saturation**." We are of the understanding that this project is injecting into a saline aquifer. Can you please provide further characterization of the gas/oil saturation of the reservoir, or reason for its inclusion in the baseline?	This comment pointed to the well logging and testing program (Table 4-12 in Reference 1, Section 4.4.8) developed for the RTE CCS project, which confirmed the absence of any gas and oil in the storage formation via fluid sampling and the collection of certain well logs (e.g., pulsed-neutron, nuclear magnetic resonance, and resistivity logs). No gas or oil was expected to be encountered by any of the RTE project wells. Including them in the list of baseline characteristics probably overstated their importance to the reader and caused confusion. To simplify and avoid confusing the reader, the phrase "gas saturation/oil saturation" was deleted from the MRV plan.
16.	5.1	17	"For additional information regarding **subsurface baselines**, refer to Reference 1, Sections 4.4.5–4.4.7." Should this say, "surface baselines"? If so, please correct.	Correct. Subsurface baselines" is a type and has been changed to read "surface baselines" in the MRV plan.
17.	5.2	18	The acronym "InSAR" is used before it is defined. Please define it here.	The term "interferometric synthetic aperture radar" was first used in Table 4-1 on page 16 of the MRV plan; hence, the acronym InSAR was included there and used thereafter.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
18.	5.2	18	"….InSAR technology and gravity methods will be performed to determine application before injection…" Can you please further describe what is meant by, "to determine application before injection," in the phrase above?	This paragraph has been rewritten to clarify what is meant by "to determine application before injection." Please see MRV plan for details.
19.	6.0	18	"The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 flowline." Can you please provide further explanation behind RTE's decision to use the metering station at the start of the CO_2 flowline as the main metering station rather than the metering station at the wellhead?	This was a communication error on our part. The main metering station will be the one located at the RTE-10 wellhead. The metering station located at the start of the flowline will serve as a backup/duplicate. The text in the MRV plan has been updated to correct this error.
20.	6.0	19	"If the monitoring and surveillance plan detects a **deviation of the threshold** established for each method…." Is it the threshold that is deviating? We suggest editing the above bolded phrase to read, "deviation from the threshold," or similar to improve clarity.	Changed "of" to "from" as suggested by EPA.
21.	6.0	19	"Annual mass of CO2 emitted (in metric tons) from potential equipment leaks and vented emissions of CO2 from equipment located . . " We recommend adding an underlined title to this paragraph consistent with the underlined titles for other inputs into Equation RR-12. This will clarify that CO_2 emitted from equipment leaks and vented emissions from equipment located between the injection flow meter and the injection wells are differentiated from emissions resulting from surface leakage.	This paragraph has been given a title that is consistent with the other two underlined titles that describe the inputs for Equation RR-12.
22.	7.0	20	"It is anticipated that the MRV program will be in effect during the **specified period**…." The specified period is not defined in the MRV plan; please do so.	The anticipated period is now defined in the text.

	MRV Plan			
No.	**Section**	**Page**	**EPA Questions**	**Responses**
23.	8.0	20	Twice in this section the term “well path” is used. We believe this is a misspelling of the term “well pad”, please correct it if so.	Both occurrences of this spelling error have been corrected in the MRV plan.
24.	9.0	21	“In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years: . • Annual records of information used to calculate the CO2 emitted by potential surface leakage.” The rule language in § 98.447(a)(4) is more specific with respect to surface leakage stating, “Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.” We recommend that you include the language as it appears in the rule.	The recommended language has been adopted as requested.

RED TRAIL ENERGY SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Well

Reporting Number: 530977

North Dakota Storage Facility Permit: Order No. 31453–31455

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Continued . . .

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LIST OF FIGURES

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STORAGE FACILITY PERMIT DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, the Red Trail Energy storage facility permit is designated as follows:

Reference 1: Red Trail Energy Carbon Dioxide Geologic Storage Facility Permit

Section 1 – Pore Space Access
Section 2 – Geologic Exhibits
Section 3 – Area of Review
Section 4 – Supporting Permit Plans
Section 5 – Injection Well and Storage Operations
Appendix A – Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations
Appendix B – RTE-10 and RTE-10.2 Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Freshwater Well Fluid-Sampling Laboratory Analysis
Appendix D – Quality Assurance and Surveillance Plan
Appendix E – Storage Facility Permit Regulatory Compliance Table
Appendix F – Post-Hearing Supplement Filing: Financial Responsibility Demonstration Plan
Appendix G – Post-Hearing Supplemental Filing: Certification of Liability Insurance
Appendix H – Post-Hearing Supplemental Filing: Geologic Storage Agreement Summary of Surface Owners Who Have Ratified

1.0 PROJECT DESCRIPTION

1.1 Project Characteristics

The Red Trail Energy (RTE) facility is a North Dakota-based, investor-owned 64-million-gallon dry mill ethanol production plant, which has been in operation since January 2007. The RTE facility, located about a mile east of Richardton, North Dakota (Figure 1-1), emits an average of 180,000 metric tons annually of high-purity carbon dioxide (CO_2) (>99% CO_2 dry) from the fermentation process during ethanol production. The RTE carbon capture and storage (CCS) project is currently constructing a CO_2 capture facility (mainly dehydration and compression) adjacent to the RTE ethanol plant near Richardton, to capture all CO_2 from fermentation. RTE plans to inject the resulting 180,000-metric-ton-per-year CO_2 stream into the Broom Creek Formation via the RTE-10 injection well located on RTE property (Figure 1-1) for permanent geologic CO_2 storage.

RTE received formal approval of its North Dakota CO_2 storage facility permit (SFP) on October 19, 2021. This approval by the North Dakota Industrial Commission (NDIC) authorizes the geologic storage of CO_2 from the RTE ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation (NDIC Order Nos. 31453 and 31454). North Dakota has the authority to regulate the geologic storage of CO_2 and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). No other geologic storage project exists or is planned at or near the RTE CCS project.

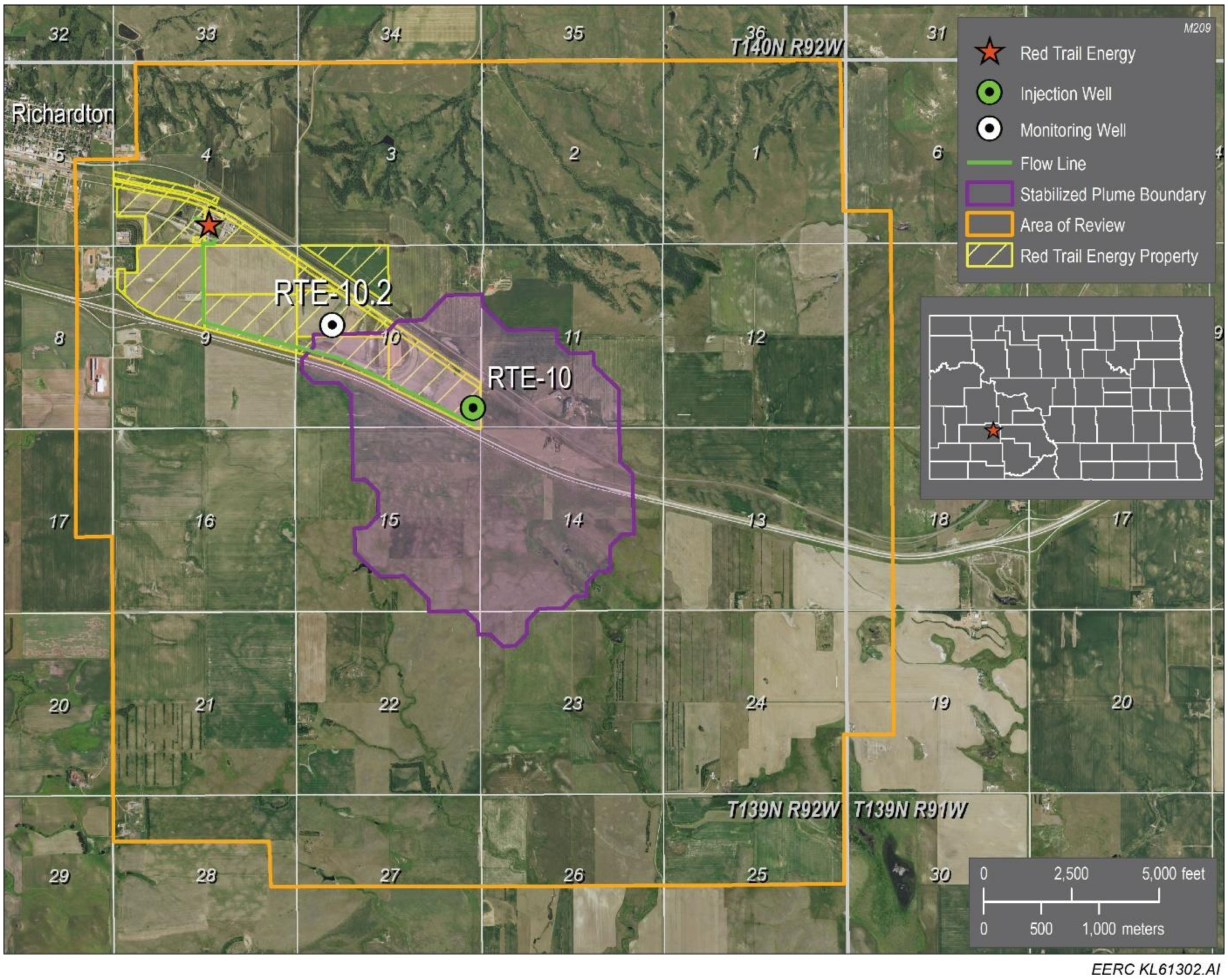

Figure 1-1. Location of the RTE facility, RTE-10 injection well, RTE-10.2 monitoring well, and CO_2 flowline. Also shown is the town of Richardton, with a population of ~850 people, the stabilized plume boundary, and the area of review (AOR).

1.2 Environmental Setting

The RTE CCS project site is on the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota (i.e., western Williston Basin) and demonstrates there has been no exploration for, and development of, hydrocarbon resources within the stabilized plume boundary (Reference 1, Section 2.6).

A generalized stratigraphic column of the Williston Basin for the Richardton area is provided in Figure 1-3. The target CO_2 storage reservoir for the RTE CCS project is the Broom Creek Formation, a predominantly sandstone interval lying about 6380 feet below the RTE facility (Reference 1, Section 2.3). Mudstones, siltstones, and interbedded evaporites of the Opeche

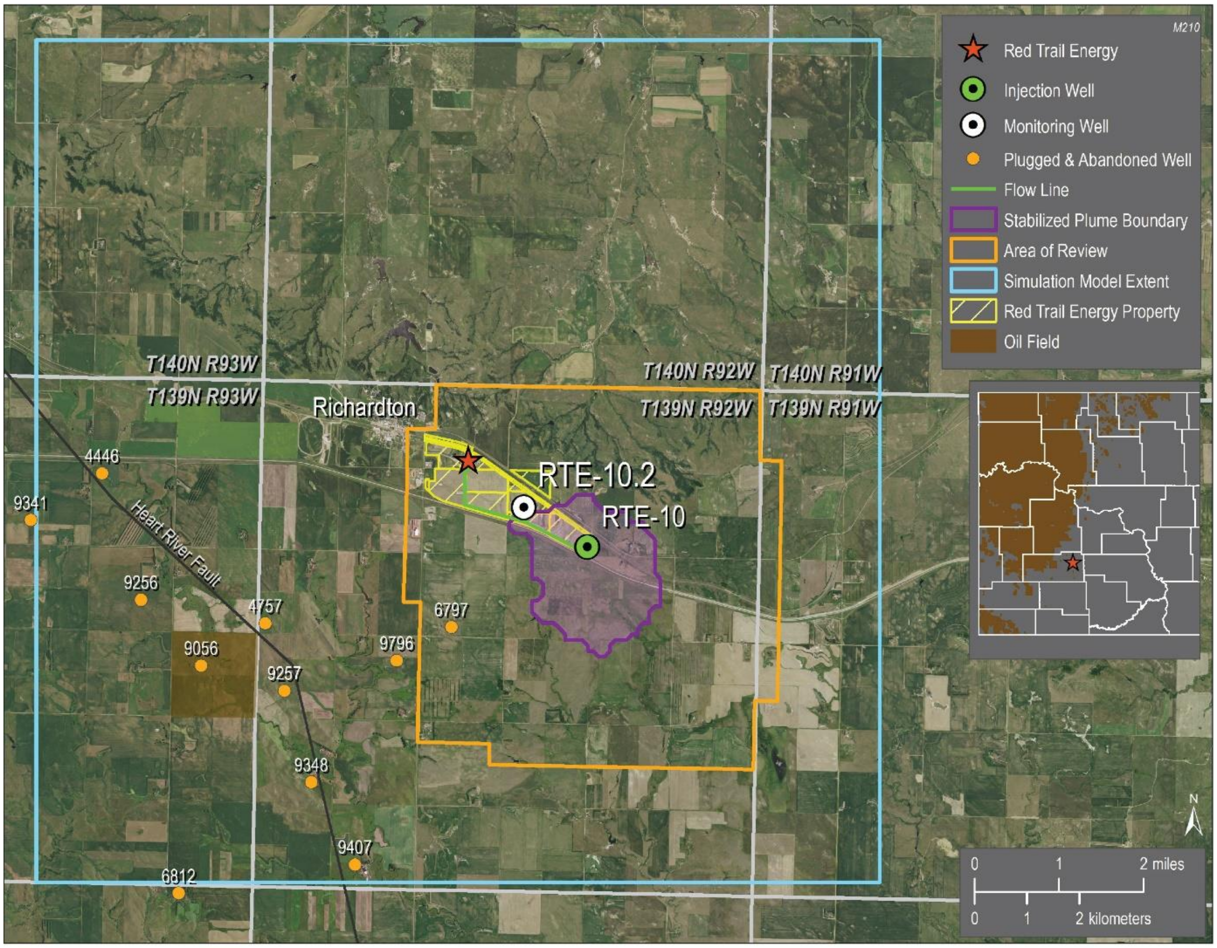

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Figure 1-2. Map showing the AOR, stabilized plume boundary, RTE ethanol facility, RTE-10 injection well, RTE-10.2 monitoring well, town of Richardton, and oil and gas wells immediately outside of or within the simulation model extents. Also shown is an inset map identifying the geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin) and the Heart River Fault. The oil field in T139N-R93W is the Taylor Field. Wells 9056 and 9341 produced some hydrocarbons from the Winnipeg Formation (see Figure 1-3 for stratigraphic reference), but all other wildcat wells shown on the map were classified as dry holes.

Formation unconformably overly the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Reference 1, Section 2.4.3). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex. In addition to the Opeche Formation, there is about 1200 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 3000 feet of impermeable intervals separates the Inyan Kara and the lowest underground source of drinking water (USDW), the Fox Hills Formation.

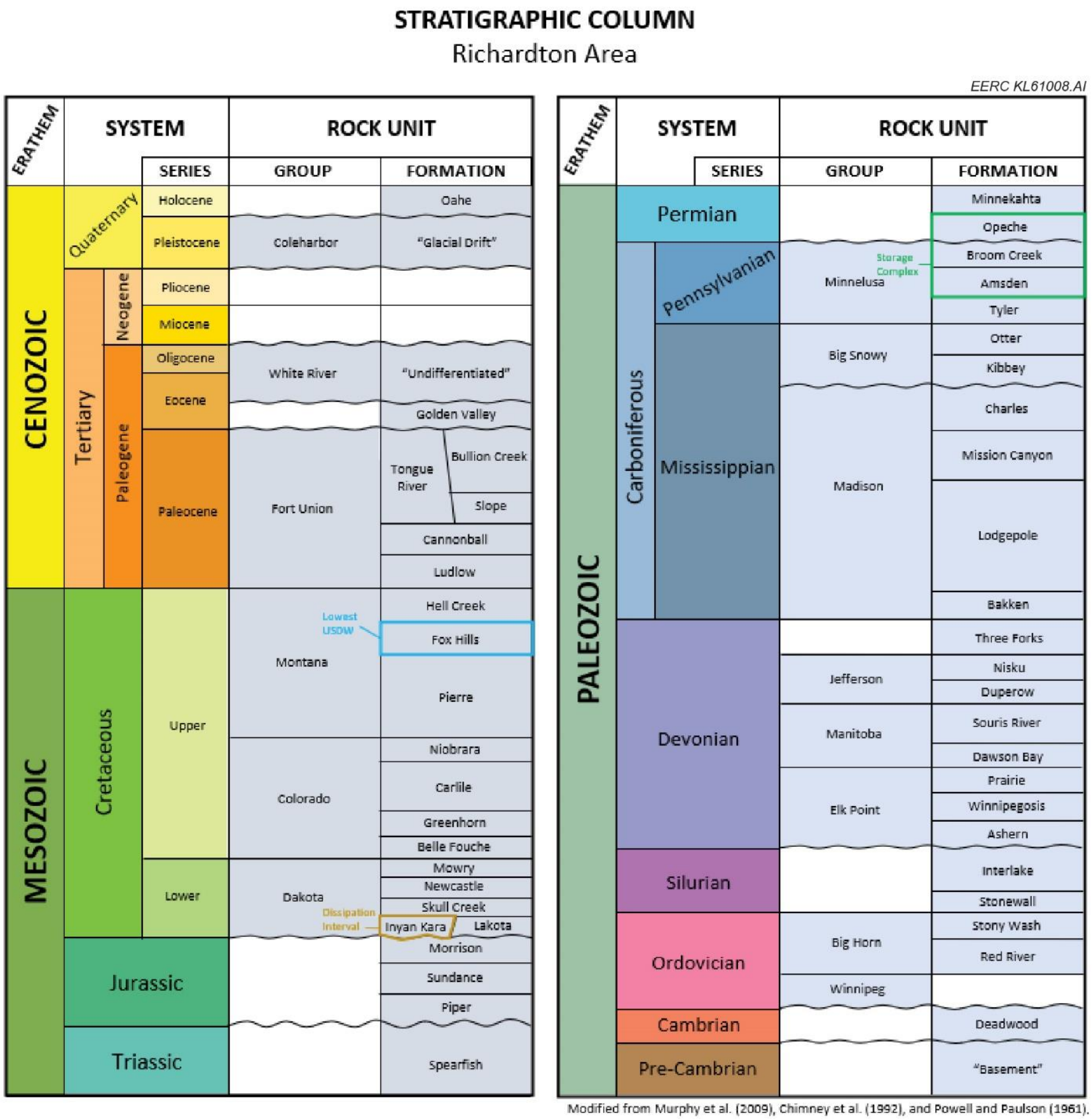

Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Richardton area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the RTE CCS project site.

1.3 Description of CO_2 Project Facilities and Injection Process

RTE plans to capture and store 180,000 metric tons per year over the course of 20 years of injection, followed by at least 10 years of postinjection site care. Figure 1-4 shows integration of major CCS components with the existing RTE ethanol facility. The capture–liquefaction facility was designed to capture the CO_2 currently produced during RTE's fermentation process (following

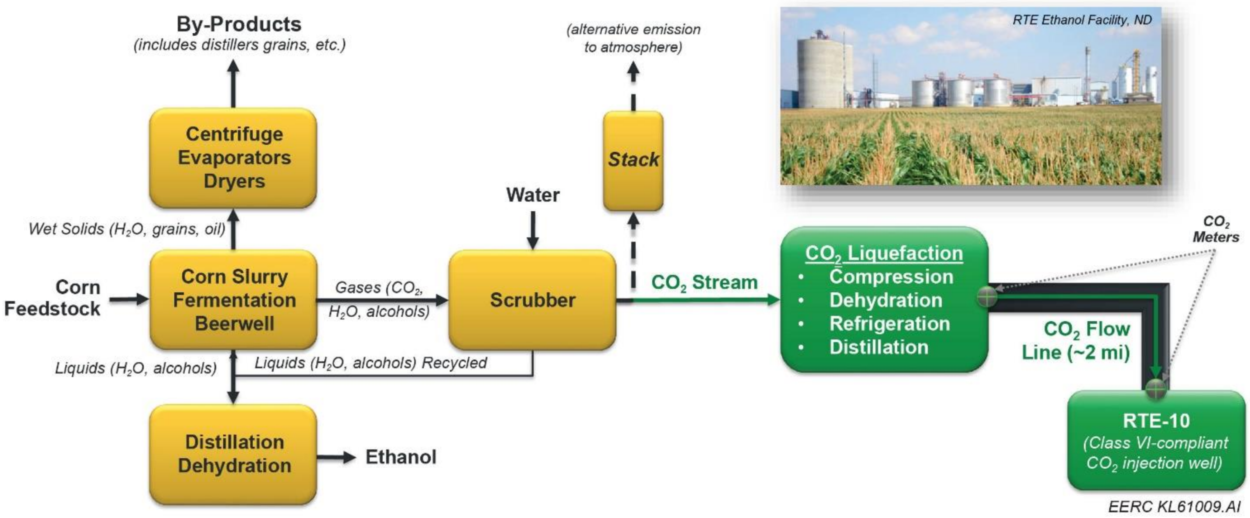

Figure 1-4. Flow diagram of the RTE CCS process, showing major CCS components and the path of the CO_2 stream from the capture facility to the RTE-10 injection well.

the scrubber prior to stack emission), compress the gaseous CO_2 stream to approximately 350 pounds per square inch, dehydrate the stream, and then liquefy the CO_2 using a closed-loop ammonia (NH_3) refrigeration process. A conventional distillation column would distill the liquid CO_2 to remove oxygen in addition to other noncondensable gases. The final liquid CO_2 stream would flow to the RTE-10 injection well for geologic storage into the Broom Creek Formation; an underground flowline is installed on RTE property to connect the capture plant to the RTE-10 injection well.

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area: RTE AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

RTE proposes that because the AOR, as delineated in Reference 1, Section 3 and Appendix A, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as AMA for the RTE CCS project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). The NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the CO_2 plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, RTE elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 3 and Appendix A, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

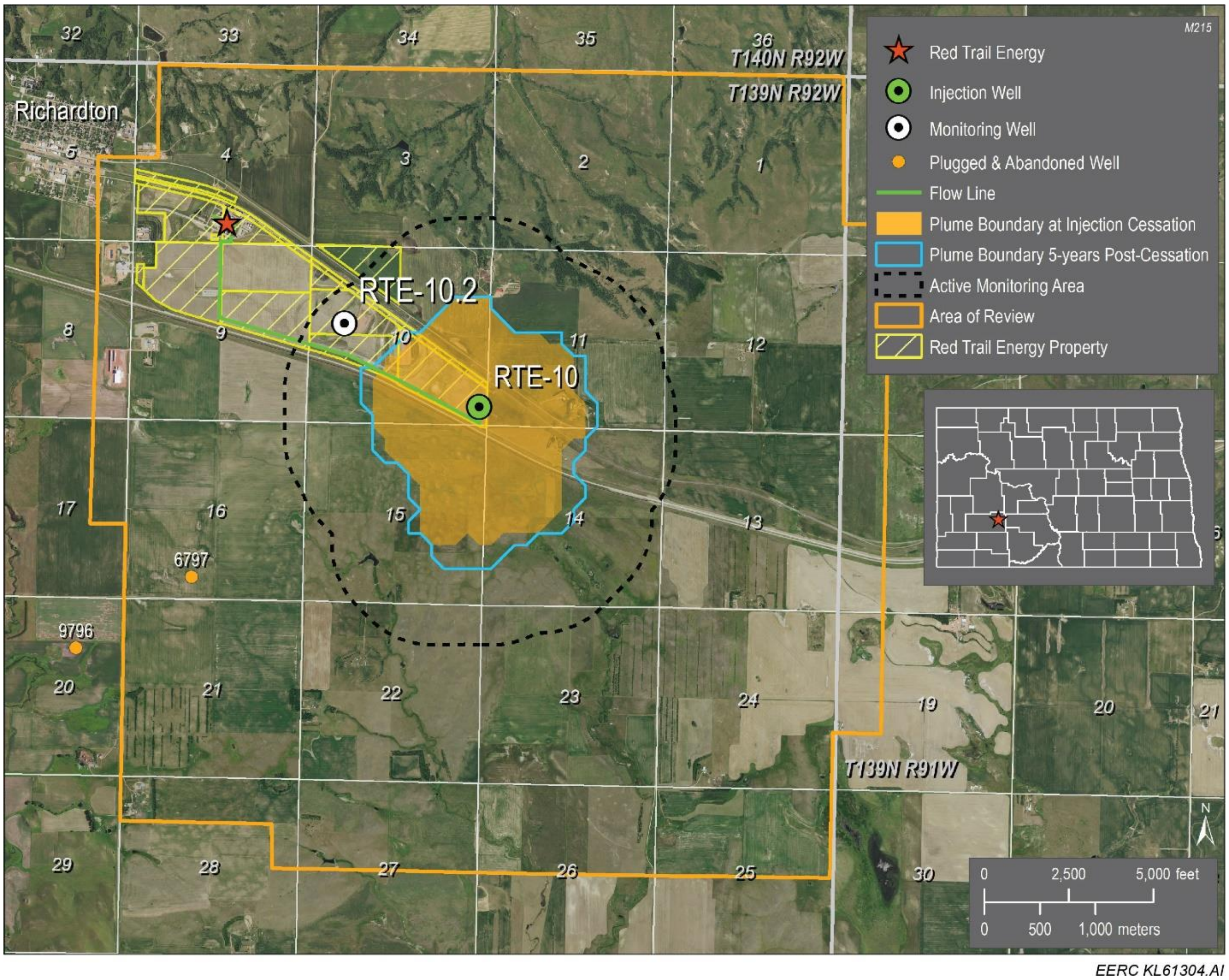

Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (20 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the RTE CCS project.

2.2 Maximum Monitoring Area

RTE proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the RTE CCS project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

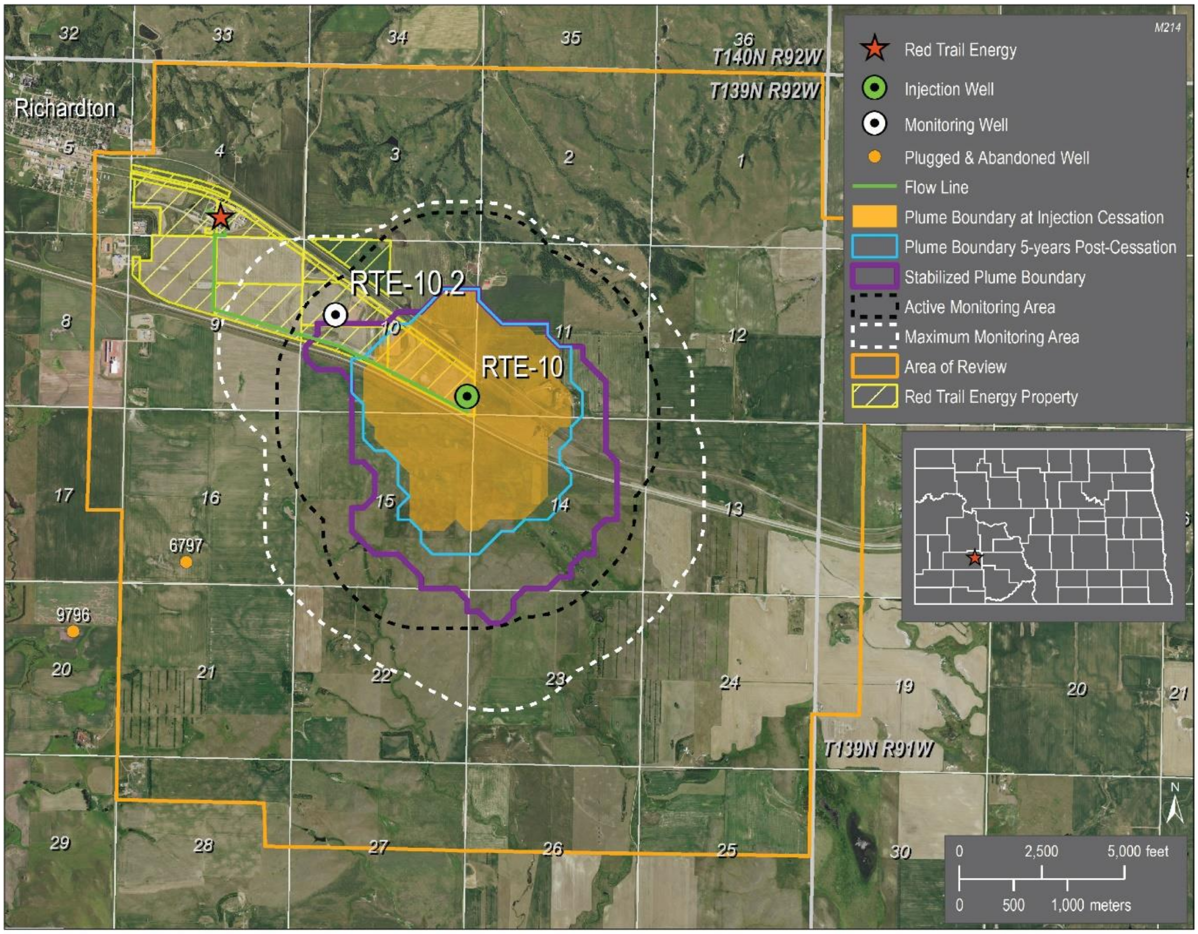

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Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the RTE CCS project.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2 (Reference 1, Section 4.4) comprises three distinct periods: 1) preoperational (preinjection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) postoperational (postinjection of CO_2) monitoring. These monitoring periods therefore encompass the entire life cycle of the project. For purposes of this monitoring, reporting, and verification (MRV) plan, it is expected that reporting will be initiated during the operational period and continue through the postinjection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of CO_2 that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the postoperational monitoring is to verify the stability of the CO_2 plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 20 and 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was informed by a screening-level risk assessment (SLRA) of the geologic storage project, which was performed in accordance with international standard ISO 31000 (Leroux and others, 2017). The SLRA was conducted through a series of work group sessions involving Energy & Environmental Research Center (EERC) subject matter experts (SMEs). During these meetings, factors and equipment that could lead to potential leakage pathways were identified and evaluated for the following:

1. Surface components (flowline and wellhead)
2. Abandoned oil and gas wells
3. Faults, fractures, and bedding plane partings
4. Injection well or monitoring well
5. Confining zone limitations

This leakage assessment determined that none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 4.4, and summarized in Table 4-1 forms the basis for this MRV plan.

3.1 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the RTE CCS project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The RTE CCS system includes a 4-inch flowline buried a minimum of 6 feet to transport CO_2 from the capture facility to the storage site (~2 miles). The flowline will be connected to a metering station and located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics are installed along the flowline as part of the leak detection program and mechanical integrity protocol. Flowmeters and temperature and pressure transducers will be installed at each metering station.

Shutoff devices will be installed at each end of the flowline to control any potential release and send alarms to the automated system. Pressure gauges will be installed on the wellhead to monitor annular pressure between tubing and casing.

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. Routine visual inspections will be conducted, and real-time operating parameters tracked through an automated system for alarm notification and process management.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing highest standards on material selection and construction processes for the flowline and wells.
- Implementing best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of CO_2 released during several hours, while a puncture in the flowline could potentially represent several tons of CO_2 released underground until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply. Note that should a potential shutoff situation occur, the RTE facility will revert to current operations, emitting CO_2 under existing permits maintained through the North Dakota Department of Environmental Quality.

This risk of leakage through surface equipment reduces to almost zero during the postinjection site care period. At cessation of the injection period, the injector wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, RTE-10.2, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.2 Abandoned Oil and Gas Wells

The Rummel-State 1 (NDIC No. 6797) well was spud in December 1978 to a depth of 11,270 feet into the Red River Formation and was plugged and abandoned in February 1979. Multiple drillstem tests were conducted in several stratigraphic intervals, but the well encountered no commercial accumulations of hydrocarbons. The Rummel-State 1 was evaluated as part of the risk assessment for the RTE CCS project and is the only oil and gas well within the AOR. It was determined that no corrective action was needed, as the CO_2 plume does not come into contact with the well (Reference 1, Section 3.1.2).

3.3 Faults, Fractures, and Bedding Plane Partings

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

3.3.1 Heart River Fault

The Heart River Fault, located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AOR for the RTE project (Figure 1-2), is a high-angle reverse fault that originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 feet in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations, well below the Broom Creek Formation (Reference 1, Section 2.5.1). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset (see Figure 1-3 for stratigraphic reference).

3.3.2 Natural or Induced Seismicity

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (Reference 1 Section 2.5.3). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The seismic event recorded closest to the RTE CCS project occurred 21.6 mi from Richardton, North Dakota, with a magnitude of 3.2 (Reference 1, Section 2.5.3).

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year period (U.S. Geological Survey, 2019). Through the risk assessment process, potential leakage resulting from natural or induced seismicity was shown to be very unlikely.

3.4 Injection Well and Monitoring Well

3.4.1 RTE-10 (NDIC No. 37229)

The RTE-10 well was spud in March 2020 as a stratigraphic test well to a depth of 6900 feet into the Amsden Formation. This well was drilled specifically to gather geologic data to support the development of a CO_2 SFP and as the RTE CCS project's future injector well. The RTE-10 will be monitored in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, the RTE-10 will be properly plugged and abandoned following NDIC protocols.

3.4.2 RTE-10.2 (NDIC No. 37858)

The RTE-10.2 well was spud in October 2020 as a stratigraphic test well and future monitoring well for the injected CO_2 of the RTE project. The well was drilled to a depth of 6770 feet into the Amsden Formation. The RTE-10.2 will monitor the Broom Creek Formation in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, RTE-10.2 will be properly plugged and abandoned following NDIC protocols.

3.5 Confining Zone Limitations

3.5.1 Lateral Migration

For the RTE CCS project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 6276 feet below the surface and 103 feet thick at the RTE CCS project site (Reference 1, Section 2.4.1). Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine).

3.5.2 Seal Diffusivity

Several additional formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1200 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 3000 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The possibility of fluid migration through 1200 and 3000 feet of overlying confining layers presents a very low risk to the RTE CCS project site. The thick impermeable layers and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

3.5.3 Drilling Through the CO_2 Area

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized CO_2 plume boundary. Although there was some historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. Any future endeavors to explore for, or produce, hydrocarbons could avoid the CO_2 plume using horizontal drilling techniques.

3.6 Monitoring, Response, and Reporting Plan for CO_2 Loss

RTE proposes a detailed emergency remedial and response plan (Reference 1, Section 4.1) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk. RTE also proposes a robust monitoring program based on the detailed risk assessment performed during the application for the storage facility and UIC Class VI permit. The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 4.4.2); continuous, real-time surveillance of injection performance (Reference 1, Sections 4.4.3 and 4.4.4); monitoring of near-surface conditions (Reference 1, Sections 4.4.5–4.4.7); and direct and indirect monitoring of the CO_2 plume (Reference 1, Sections 4.4.8.1 and 4.4.8.2).

3.7 Summary

In an unlikely scenario of potential leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of CO_2 would require consideration of the potential leakage event facts and circumstances, e.g., magnitude and timing of the CO_2 leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

4.0 STRATEGY FOR DETECTING AND QUANTIFYING POTENTIAL SURFACE LEAKAGE OF CO_2

Table 4-1 summarizes the monitoring frequency for each of the three project periods, and Table 4-2 summarizes the potential leakage pathway covered by each technique. These methodologies target early detection of any potential abnormalities in operating parameters or deviations from the baseline and threshold established for the project. These methodologies will lead to a verification process to validate if a potential leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, CO_2 plume, and pressure front.

Table 4-1. Summary of RTE's CCS Monitoring Strategy

Method (target area/structure)	Preinjection (Baseline – 1 year)	Injection Period (20 years)	Postinjection (10 years)
CO_2 Stream Analysis (capture)	Start-up	Real time	NA[1]
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	NA	Real time	NA
Mass/Volume Flowmeters (RTE-10 and flowline)	NA	Real time	NA
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	NA	Real time	Real time until plume stabilization is demonstrated
DTS/DAS Fiber (RTE-10 and RTE 10.2, dedicated Fox Hills monitoring wells, and flowline)	NA	Real time	Real time DTS until well plugging and site reclamation
Visual Inspections (flowline)	Start-up	Quarterly	Quarterly
Corrosion Coupons (flowline)	NA	Quarterly	NA
SCADA[2] Automated Remote System (surface facilities)	Start-up	Real time	NA
Soil Gas Analysis (AOR)	Three to four seasonal samples adjacent to each RTE well	Three to four seasonal samples per year adjacent to each well	Three to four seasonal samples every 3 years adjacent to each well
Water Analysis: Shallow Aquifers (AOR)	Three to four seasonal sample events per water wells closest to RTE-10	Once per year during years 1–3 and 5, then every 5 years thereafter. Other water wells may be phased in based on CO_2 plume migration.	Three to four sample events at cessation of injection and before site closure
Water Analysis: Lowest USDW (AOR)	Three to four sample events per dedicated Fox Hills monitoring well adjacent to each RTE well	Once per year during years 1–3 and 5, then every 5 years thereafter	Three to four sample events at cessation of injection and before site closure
Cement Bond Logs (RTE-10 and RTE-10.2)	After cementing	If needed	Prior to P&A[3]
Annular Pressure Test (RTE-10 and RTE-10.2)	Prior injection	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	Baseline	Every 5 years in RTE-10.2 and as needed in RTE-10	Every 5 years in RTE-10.2 and as needed in RTE-10
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)	Baseline	Perform during workovers but not more than once every 5 years	Perform during workovers but not more than once every 5 years
Pressure Falloff Test (RTE-10)	Prior injection	Every 5 years	Prior to P&A
Time-Lapsed Seismic Surveys (AOR)	Baseline	Every 5 years	Every 5 years
Surface Seismometers (AOR)	Baseline	Real time	Real time
Interferometric Synthetic Aperture Radar (AOR)*	Baseline	Real time	Real time
Gravity Surveys (AOR)*	Baseline	TBD[4] – repeat survey at least once	TBD

* If feasible.
[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Plugged and abandoned.
[4] To be determined.

Table 4-2. Monitoring Strategies for Detecting Changes in the Storage Reservoir Associated with CO_2 Injection

Monitoring Strategy (target area) \ Potential Leakage Pathway	Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis (capture)	X			X	X		X
Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline)	X			X	X	X	
Mass / Volume Flowmeters (RTE-10 and flowline)				X	X		
Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2)	X			X	X	X	X
DTS/DAS Fiber (RTE-10, RTE-10.2, dedicated Fox Hills monitoring wells, and flowline)	X	X	X	X	X	X	X
Visual Inspections (flowline)	X			X	X		
Corrosion Coupons (flowline)				X	X		
SCADA Automated Remote System (surface facilities)			X	X	X		
Soil Gas Analysis (AOR)	X				X		X
Protected Groundwater Zone: Shallow Aquifers (AOR)		X			X		X
Protected Groundwater Zone: Lowest USDW (AOR)	X				X		X
Cement Bond Logs (RTE-10 and RTE-10.2)					X		
Annular Pressure Test (RTE-10 and RTE-10.2)				X	X		
Pulsed-Neutron Logs (RTE-10 and RTE-10.2)	X				X	X	X
Ultrasonic Imager Logs (RTE-10 and RTE-10.2)					X		
Pressure Falloff Test (RTE-10)	X				X	X	
Time-Lapsed Seismic Surveys (AOR)	X	X		X	X	X	X
Surface Seismometers (AOR)		X	X				X
Interferometric Synthetic Aperture Radar (AOR)*	X	X		X		X	X
Gravity Surveys (AOR)*						X	

* If feasible.

4.1 Potential Leak Verification

RTE will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, DTS alongside the casing, and routine maintenance and inspection.

As part of the surveillance protocol, RTE will use reservoir simulation modeling, based on history-matched data obtained from the monitoring system, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR review will be submitted, and the monitoring plan revised and modified if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if potential CO_2 leakage is occurring. Excursions are not necessarily indicators of potential leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated) and there is no indication that potential CO_2 leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a potential leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in CO_2 concentration at the surface. Many variations of CO_2 concentration detected on the surface are the result of natural processes or external events not related to the CO_2 storage complex.

Because a potential CO_2 surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, RTE will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the RTE CCS project.

Response plan actions and activities will depend upon the circumstances and severity of the event. RTE will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, RTE will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

4.2 Quantification of Potential Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the CO_2 in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any potential leaks that may be encountered, the most appropriate methods to quantify the volume of CO_2 will be determined on a case-by-case basis. Any volume of CO_2 detected as potentially leaking to the surface will be quantified using acceptable emission factors, engineering estimates of potential leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Potential leaks will be documented, evaluated, and addressed in a timely manner. Records of potential leakage events will be retained in an electronic central database.

5.0 DETERMINATION OF BASELINES

RTE will establish preinjection baselines by implementing a monitoring program prior to any CO_2 injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media such as surface water, soil gas in the vadose zone, shallow groundwater, storage reservoir formation water, and gas saturation/oil saturation.

These baselines provide a basis for determining if potential CO_2 leaks are occurring by providing a foundation against which characteristics of these same media during CO_2 injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by potentially leaking CO_2.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the RTE CCS project area is provided in Reference 1, Section 4.4.6.

5.1 Surface Baselines

A baseline sampling program has been completed for the RTE CCS project. Baseline data were obtained from 11 soil gas-sampling locations and three existing groundwater wells in the northwestern portion of the AOR. In addition, two dedicated monitoring wells were drilled in the Fox Hills Formation and placed near the RTE injection and monitoring wells. For additional information regarding subsurface baselines, refer to Reference 1, Sections 4.4.5–4.4.7.

5.2 Subsurface Baselines

Preoperational baseline data will be collected in the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used as an assurance-monitoring technique for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval.

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir.

A feasibility study of surface deformation monitoring with InSAR technology and gravity methods will be performed to determine application before injection and would be performed to establish a baseline for the future application of this technology.

For passive seismicity monitoring, the project will install seismometer stations sufficient to confidently measure baseline seismicity from the injection area a year prior to injection. For additional information regarding subsurface baselines, refer to Reference 1, Section 4.4.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The RTE CCS project area is a CO_2 storage site in a saline aquifer with no production associated from the storage complex. The proposed main metering station for mass balance calculation is identified as the first metering station placed at the start of the CO_2 flowline (Figure 1-4).

To calculate the annual mass of CO_2 that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

CO_2 = Total annual CO_2 mass stored in subsurface geologic formations (metric tons) at the facility.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by potential surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from potential equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of CO_2 Injected (CO_{2I}):
RTE will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually 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 from 40 CFR Part 98-Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by Flowmeter u.
$Q_{p,u}$ = Quarterly volumetric flow rate 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 Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

<u>Annual Mass of CO_2 Emitted by Potential Surface Leakage (CO_{2E}):</u>
RTE characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 4.4, to detect any potential leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation of the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of potential leak to quantify the CO_2 volume to the best of its capabilities. The process for quantifying potential leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the potential leak, and numerical and predictive models among others.

RTE will calculate the total annual mass of CO_2 emitted from all potential leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by potential surface leakage (metric tons) in the reporting year.
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at potential leakage pathway x in the reporting year.
x = Potential leakage pathway.

Annual mass of CO_2 emitted (in metric tons) from potential 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 (CO_{2FI}) 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 and surveillance plan proposed in Reference 1, Section 4.4.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting February 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas (GHG) reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect during the specified period, during which time the RTE CCS project will be operated.

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for RTE monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Section 4.4.9.

RTE will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

CO_2 received:
- The quarterly flow rate of CO_2 will be reported from continuous measurement at a receiving meter on the injection well path.
- The quarterly CO_2 concentration will be reported from near-continuous measurement upstream of the receiving meter on the injection well path.

Flowmeter provision:
- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).
- Operated in conformance with consensus-based standards organizations including, but not limited to, ASTM International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

9.0 RECORDS RETENTION

RTE will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.

- Quarterly records of injected CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Annual records of information used to calculate the CO_2 emitted by potential surface leakage.
- Annual records of information used to calculate the CO_2 emitted from potential equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

10.0 REFERENCES

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RED TRAIL ENERGY – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO_2 Storage Facility Permit Application

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RED TRAIL ENERGY – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PERMIT APPLICATION SUMMARY

Red Trail Energy, LLC (RTE) is requesting consideration of this application for the geologic storage of carbon dioxide (CO_2) from the RTE ethanol facility located near Richardton, North Dakota (Figure PS-1). The RTE ethanol facility is a North Dakota-based, investor-owned 64-million-gallon dry mill ethanol production plant (Table PS-1), which has been in operation since January 2007. The RTE facility emits an average 180,000 metric tons of high-purity CO_2 (>99% CO_2 dry) annually from the fermentation process during ethanol production. RTE plans to commercially capture (dehydrate and compress) and inject the 180,000-metric-ton-per-year CO_2 stream into the Broom Creek Formation on RTE property for permanent geologic CO_2 storage.

Research efforts by RTE and the Energy & Environmental Research Center, with funding support from the North Dakota Industrial Commission Renewable Energy Program and the U.S. Department of Energy, began in 2016 to characterize the geology and determine site feasibility to develop the first carbon capture and storage (CCS) facility in North Dakota (Leroux and others, 2020). The geologic characterization work resulted in RTE conducting a 3D seismic survey over the project area in March 2019 and drilling a stratigraphic test well (RTE-10) in March–April 2020 to acquire the geologic data required for this North Dakota CO_2 Storage Facility Permit (SFP) application to implement commercial CCS at the RTE site. In addition, detailed capture process design has been conducted for a liquefaction system to capture the fermentation-generated CO_2 emissions at the RTE facility, providing the engineering support for the expected CO_2 output stream and thus injection conditions.

As shown in Figure PS-1, integration of CCS technology with the existing RTE ethanol facility will consist of a CO_2 liquefaction system pumping the CO_2 stream to the RTE-10 injection well for geologic storage into the Broom Creek Formation (a saline formation). An underground flow line will be installed on RTE property to connect the liquefaction system to the RTE-10 injection well. A monitoring well (RTE-10.2) was also installed on RTE property in October 2020 for compliance with the North Dakota CO_2 SFP requirements to directly monitor CO_2 injection in the Broom Creek Formation. Monitoring equipment currently installed in both RTE-10 and RTE-10.2 wells includes pressure–temperature gauges in the Broom Creek Formation and a fiber optic cable along the entire length of the well and flow line. Additional monitoring equipment to be added includes (but is not limited to) CO_2 flowmeters at the capture facility, along the flow line, and at the wellhead as well as related SCADA (supervisory control and data acquisition) systems.

The Broom Creek Formation is situated directly below RTE property with excellent geologic properties (high porosity/permeability, tight seals) for CO_2 injection and permanent storage (Sorensen and others, 2009; Glazewski and others, 2015; Leroux and others, 2020). Shales and salts of the Opeche, Piper, and Swift Formations overlying the Broom Creek Formation create a sealing barrier of over 1,000 ft, providing a secure, permanent geologic storage reservoir for the planned geologic CO_2 storage. Further above, the Pierre Formation is an impermeable shale approximately 2,000 ft thick, providing an additional seal for underground sources of drinking water in the area to be permitted.

Therefore, the following North Dakota CO_2 SFP application provides detailed geologic exhibits generated from the seismic survey, core collection with subsequent laboratory analyses and downhole testing from the RTE-10 and RTE 10.2 wells, and successive modeling and simulation for predictive CO_2 movement forecasting and pore space access determination. These lay the foundation for area of review determination, which is the basis for the required supporting permit plans: emergency and remedial response, financial assurance demonstration, worker safety, testing and monitoring, well casing and cementing, plugging, and postinjection site and facility closure. In conclusion, injection well and storage operations provide detailed descriptions of the RTE-10 and RTE-10.2 wells and planned injection and storage/monitoring operations, included for a proposed permit to inject. An RTE Storage Facility Permit Regulatory Compliance Table (Appendix E) has been generated to provide a crosswalk of the specific RTE application components addressing each permit requirement.

References

Glazewski, K.A., Grove, M.M., Peck, W.D., Gorecki, C.D., Steadman, E.N., and Harju, J.A., 2015, Characterization of the PCOR Partnership region: Plains CO_2 Reduction (PCOR) Partnership value-added report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2015-EERC-02-14, Grand Forks, North Dakota, Energy & Environmental Research Center, January.

Leroux, K.M., Klapperich, R.J., Ayash, S.C., Kalenze, N.S., Jensen, M.D., Jacobson, L.L., Crocker, C.R., Doll, T.E., Livers-Douglas, A.J., Azzolina, N.A., Crossland, J.L., Connors, K.C., Nakles, D.V., Hamling, J.A., Peck, W.D., Bosshart, N.W., Daly, D.J., Wilson IV, W.I., Gorecki, C.D., Brad D. Piggott Austyn E. Vance Piggott, B., and Vance, A.E., 2020, Subtask 1.3 – Integrated carbon capture and storage for North Dakota ethanol production: Final report (November 1, 2016 – May 31, 2020) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0024233, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

Sorensen, J., Bailey, T., Dobroskok, A., Gorecki, C., Smith, S., Fisher, D., Peck, W., Steadman, E., and Harju, J., 2009, Characterization and modeling of the Broom Creek Formation for potential storage of CO_2 from coal-fired power plants in North Dakota: Search and Discovery Article No. 80046.

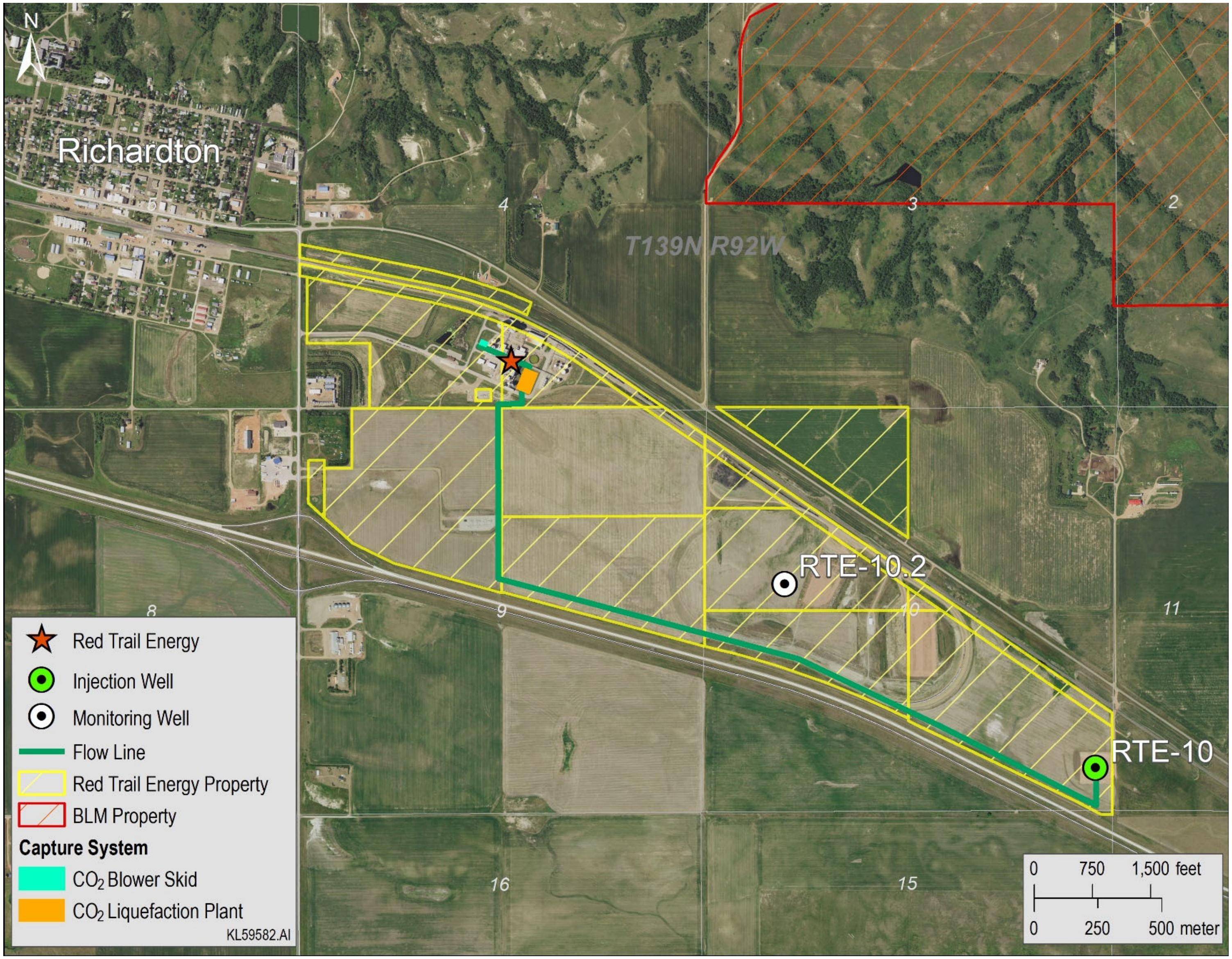

Figure PS-1. RTE geologic storage of CO_2 project map.

Table PS-1. RTE Operator and Ethanol Facility Information

Operator Information Pursuant to NDAC § 43-05-01-07.1 Subsection 3a, c, and f	
NDAC § 43-05-01-07.1 Subsection 3a The activities conducted by the applicant which require it to obtain a storage facility permit or other federal, state, or local permits.	RTE is proposing geologic storage of CO_2. Additional activities: drilling stratigraphic test wells RTE-10 (NDIC File No. 37229) and RTE-10.2 (NDIC File No. 37858), conversion of these wells to Class VI injection and monitoring wells (respectively), and the construction of a CO_2 liquefaction system and flow line.
NDAC § 43-05-01-07.1 Subsection 3c Up to four standard industrial classification codes which best reflect the principal products or services provided by the facility.	Products / Standard Industrial Classification (SIC) Code Ethanol: 2869 Corn Oil: 2046
NDAC § 43-05-01-07.1 Subsection 3f A listing of all environmental permits, construction approvals, or any other relevant permit received or applied for from the commission or any other federal, state, or local regulatory agency.	Permits to Drill (state) and Richardton Special Use Permits (local) for wells RTE-10 (NDIC File No. 37229) and RTE-10.2 (NDIC File No. 37858), construction permits (local) for the CO_2 liquefaction system, and storm water permit (state) for the CO_2 liquefaction system and wellsite location.

1.0 PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31-Subsurface Pore Space Policy). Prior to issuance of the Storage Facility Permit (SFP), the storage operator is mandated by North Dakota statute for geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC § 38-22-06(3) and -06(4) and North Dakota Administrative Code [NDAC] § 43-05-01-08(1) and -08(2)).

In connection herewith, Red Trail Energy (RTE) submits the form of storage agreement attached hereto as Attachment 1, which, upon final approval by NDIC, shall govern certain rights and obligations of the storage operator and the persons owning pore space within the amalgamated storage reservoir.

RTE has identified the owners (surface and mineral); in addition, no mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles of its outside boundary. RTE will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.

The identification of the owners, lessees, and operators that require notification was based on the following, recognizing that all surface owners also own the underlying pore space per North Dakota law, which vests the title to pore space in all strata underlying the surface of lands to the owner of the overlying surface estate (NDCC Chapter 47-31):

- A map showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record (Figure 1-1 and Figure 1-2).

- A table identifying all pore space (surface) owners, each owner's mailing address, and a legal description of pore space landownership (Table 1-1).

- A table identifying each owner of record of minerals and each mineral lessee of record (Table 1-2).

Note: All surface owners and pore space owners and lessees are the same owner of record, and there are no operators of mineral extraction activities within the storage facility area.

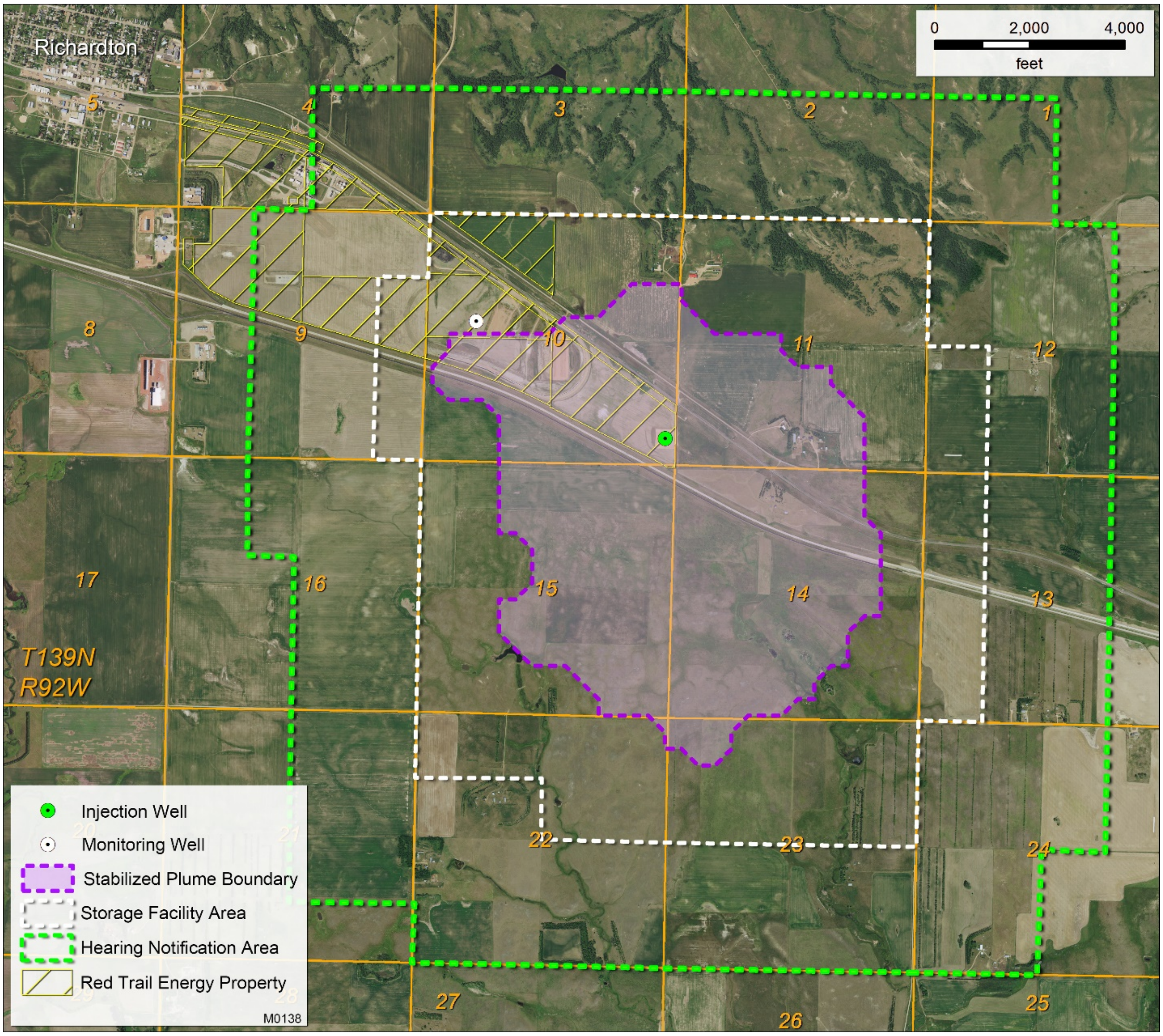

Figure 1-1. Storage facility area map.

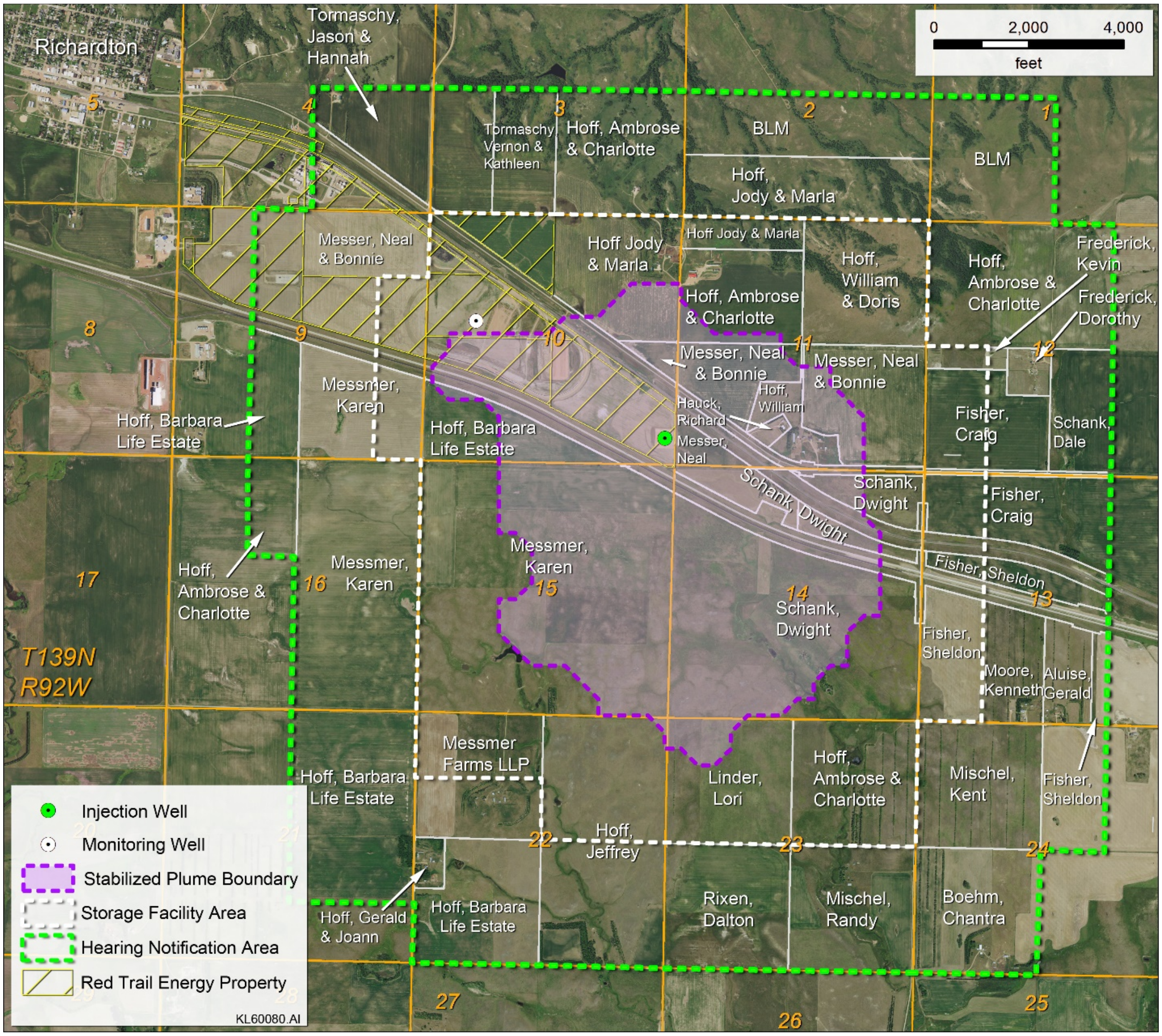

Figure 1-2. Hearing notification area for landowners within ½ mile of the storage facility area.

Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification

Owner, Lessee, or Operator Name	Addresses				Legal Description
	Street	City	State	Zip	
Jody Hoff and Marla Hoff	3729 86th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 2: S2S2
Ambrose R. Hoff and Charlotte Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 2: S2S2
Ambrose R. Hoff and Charlotte Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 3: SE4
Vernon J. Tormaschy and Kathleen M. Tormaschy	3549 86th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 3: E2SW4 and W2SW4
Karen Messmer	8860 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 9: SE4
Neal C. and Bonnie M. Messer Farm Properties LLLP	10339 Hwy 10	Dickinson	ND	58601	Township 139 North, Range 92 West Section 9: North Tract in E2 and Tract B in E2
Jody A. Hoff and Marla A. Hoff	3729 86th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: Tract in NE4NE4
Ambrose Hoff and Charlotte Hoff	8601 Hwy 10 E	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: Tract in NE4NE4
Jody A. Hoff and Marla A. Hoff	8601 Hwy 10 E	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: NE4 less tracts
Neal C. and Bonnie M. Messer Farm Properties LLLP	10339 Hwy 10	Dickinson	ND	58601	Township 139 North, Range 92 West Section 10: Tract in SE4 North of I-94
Gerald L. Hoff	422 1st Ave. W	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: 15.09-acre Tract in SE4 and 76.1-acre Tract in SW4

Continued . . .

Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification (continued)

Owner, Lessee, or Operator Name	Addresses				Legal Description
	Street	City	State	Zip	
Joann Hoselton	13877 145th St. SW	Red Lake Falls	MN	56750	Township 139 North, Range 92 West Section 10: 15.09-acre Tract in SE4 and 76.1-acre Tract in SW4
Barbara Hoff	3752 Hwy 8 S	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: 15.09-acre Tract in SE4 and 76.1-acre Tract in SW4
William S. Hoff and Doris Hoff	Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4
William S. Hoff and Doris Hoff	Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: Tracts in S2
Neal C. and Bonnie M. Messer Farm Properties LLLP	10339 Hwy 10	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: SE4 and SW4 less Tracts
Richard L. Hauck and Linda Hauck	8559 Hwy 10 East	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: 7.51-acre Tract in SE4SW4
Jody Hoff and Marla Hoff	3729 86th Ave. S	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: N2N2NW4
Ambrose R. Hoff and Charlotte Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 11: N2N2NW4
Ambrose Hoff and Charlotte Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 11: NW4 less N2N2NW4
Ambrose R. Hoff and Charlotte R. Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 12: NW4
Craig S. Fisher	8330 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 12: SW4 less tracts

Continued . . .

Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification (continued)

Owner, Lessee, or Operator Name	Addresses: Street	City	State	Zip	Legal Description
Kevin Frederick	1325 27th St. SE #900	Minot	ND	58701	Township 139 North, Range 92 West Section 12: 18.3-acre Tract in NW4SW4
Kenneth Moore	Box 56	Taylor	ND	58656	Township 139 North, Range 92 West Section 13: East 40 acres of SW4
Craig S. Fisher	8330 39th St SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: N2 lying north of Northern Pacific Railway ROW
Sheldon Fisher	8330 39th St SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: N2 lying south of Northern Pacific Railway ROW and S2 less tracts
Dwight F. Schank	3840 91st Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 14: All
Karen L. Messmer	1990 Mesquite Lp	Bismarck	ND	58503	Township 139 North, Range 92 West Section 15: All
Karen L. Messmer	1990 Mesquite Lp	Bismarck	ND	58503	Township 139 North, Range 92 West Section 16: E2
Gerald L. Hoff and JoAnn Hoselton	422 1st Ave. West	Richardton	ND	58652	Township 139 North, Range 92 West Section 21: NE4
Jeffrey R. Hoff	3960 87th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 22: E2
Messmer Farms LLP	10844 East Queensborough Ave.	Mesa	AZ	85212	Township 139 North, Range 92 West Section 22: NW4
Lori Linder	613 Rose Ave.	Wheatland	CA	95692	Township 139 North, Range 92 West Section 23: E2NW4 and W2NW4

Continued . . .

Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification (continued)

Owner, Lessee, or Operator Name	Addresses				Legal Description
	Street	City	State	Zip	
Randy Mischel	7410 Keystone Dr.	Bismarck	ND	58503	Township 139 North, Range 92 West Section 23: N2SE4
Gary Mischel	1036 SE 6th St.	Cape Coral	FL	33990	Township 139 North, Range 92 West Section 23: S2SE4
Dalton Rixen	201 Linden Ave.	Taylor	ND	58656	Township 139 North, Range 92 West Section 23: N2SW4
Ambrose Hoff and Charlotte Hoff	3713 36th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 23: W2NE4 and E2NE4
Kent Mischel	5411 Trace Bd	Bryan	TX	77807	Township 139 North, Range 92 West Section 24: W2NW4

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Lee Gress					Township 139 North, Range 92 West Section 10: A tract in the SW4
Lucille C. Gress					Township 139 North, Range 92 West Section 10: A tract in the SW4
Althea Prible	12015 SW Rose Vista Dr.	Portland	OR	97223	Township 139 North, Range 92 West Section 10: A tract in the SW4
Carole Gress					Township 139 North, Range 92 West Section 10: A tract in the SW4
Rose Schnell	7536 SE 141st Ave.	Portland	OR	97236	Township 139 North, Range 92 West Section 10: A tract in the SW4
Aloys Gress	7526 East Maple Ave.	Vancouver	WA	98664	Township 139 North, Range 92 West Section 10: A tract in the SW4
Anton Gress	941 NE 113 Ave.	Portland	OR	97200	Township 139 North, Range 92 West Section 10: A tract in the SW4
George Gress	10657 South Ave. 9-E, Space A-6	Yuma	AZ	85365	Township 139 North, Range 92 West Section 10: A tract in the SW4
John Gress	3140 Hwy 8	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: A tract in the SW4
John Gress Family Trust					Township 139 North, Range 92 West Section 10: A tract in the SW4
Gerald Gress	3112 La Tierra Dr.	Roswell	NM	88201	Township 139 North, Range 92 West Section 10: A tract in the SW4
Francis Gress	825 Elm Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 10: A tract in the SW4
Victor Gress	488 NW 6th Ave. Apt. 12	Gresham	OR	97013	Township 139 North, Range 92 West Section 10: A tract in the SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Barbara E. Hoff	3752 Hwy 8 South	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: A tract in the SW4
Donald Roy Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 10: A tract in the SW4
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 10: A tract in the SW4
Donald Roy Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 10: NE4
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 10: NE4
Lee Gress					Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Lucille C. Gress					Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Althea Prible	12015 SW Rose Vista Dr.	Portland	OR	97223	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Carole Gress					Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Rose Schnell	7536 SE 141st Ave.	Portland	OR	97236	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Aloys Gress					Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Eleanor Gaman	7526 East Maple Ave.	Vancouver	WA	98664	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Anton Gress	836 S Curry St Unit 304	Portland	OR	97239	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
George Gress	10657 South Ave. 9-E, Space A-6	Yuma	AZ	85368	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
John Gress	3140 Hwy 8	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
John Gress Family Trust					Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Gerald Gress	3112 La Tierra Dr.	Roswell	MN	88201	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Francis Gress	825 Elm Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Victor Gress	488 NW 6th Ave. Apt. 12	Gresham	OR	97013	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Donald Roy Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 10: SW4 less a 76.10-acre tract
Kathleen McVay	14530 Westchester Dr.	Colorado Springs	CO	80921	Township 139 North, Range 92 West Section 10: A tract in the SE4
Curtis Hoff	4817 Cheyenne Dr.	Larkspur	CO	80921	Township 139 North, Range 92 West Section 10: A tract in the SE4
Joyce Kastner	4720 Ignacio Ave.	Loveland	CO	80118	Township 139 North, Range 92 West Section 10: A tract in the SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Jane Will	1222 Richmond Dr.	Bismarck	ND	50538	Township 139 North, Range 92 West Section 10: A tract in the SE4
Joel Hoff	1141 Clark	Billings	MT	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Theodore Hoff	Box 7268	Bozeman	MT	49102	Township 139 North, Range 92 West Section 10: A tract in the SE4
Emily Knopik	903 13th St. West	Billings	MT	49771	Township 139 North, Range 92 West Section 10: A tract in the SE4
Regina Pfeifer	1111 N 1st St. Apt. 1	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Rose Mary Hoff	21138 Saddleback Circle	Parker	CO	80138	Township 139 North, Range 92 West Section 10: A tract in the SE4
Barbara E. Hoff	3752 Hwy 8 South	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: A tract in the SE4
Sarah Jane Wolf	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: A tract in the SE4
Ann Geck	716 East Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: A tract in the SE4
Kathryn Geck	1121 West Highland Acres Rd.	Bismarck	MD	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Clemens Geck	668 Knollwood Dr.	Woodland	CA	95695	Township 139 North, Range 92 West Section 10: A tract in the SE4
Sarah Surry	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: A tract in the SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: A tract in the SE4
Ann Kilzer	716 E. Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Kathryn Dorgan	1121 West Highland Acres Rd.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: A tract in the SE4
Paul Hoff and Eleanor Hoff, as Trustees of the Paul Hoff Family Mineral Trust, dated 01/04/1982	Box 371	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: A tract in the SE4
James L. Hoff	606 Dakota St. N	Elgin	ND	58533	Township 139 North, Range 92 West Section 10: A tract in the SE4
Lee Ann Hoff	78 Stratford St.	West Roxbury	MA	02132	Township 139 North, Range 92 West Section 10: A tract in the SE4
Kenneth Hoff	6165 Paisley Dr. North	Olmstead	OH	44070	Township 139 North, Range 92 West Section 10: A tract in the SE4
Marie Hoff	4262 Shaw, Apt 1 East	St. Louis	MO	63100	Township 139 North, Range 92 West Section 10: A tract in the SE4
Lee R. Hoff	2618 South Willow Wood	Mesa	AZ	85209	Township 139 North, Range 92 West Section 10: A tract in the SE4
Bernadine Hoff	7202 Lake Shore Rd	Derby	NY	14047	Township 139 North, Range 92 West Section 10: A tract in the SE4
Judith Lee Dinyer	318 Bluffview Dr.	Brownwood	TX	76801	Township 139 North, Range 92 West Section 10: A tract in the SE4
Raymond Hoff, Trustee of the Hoff Family Revocable Trust, dated 06/29/2012	340 North Ave. East	Missoula	MT	59801	Township 139 North, Range 92 West Section 10: A tract in the SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Kathleen McVay	14530 Westchester Dr.	Colorado Springs	CO	80921	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Curtis Hoff	4817 Cheyenne Dr.	Larkspur	CO	80921	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Joyce Kastner	4720 Ignacio Ave.	Loveland	CO	80118	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Jane Will	1222 Richmond Dr.	Bismarck	ND	50538	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Joel Hoff	1141 Clark	Billings	MT	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Theodore Hoff	Box 7268	Bozeman	MT	49102	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Emily Knopik	903 13th St. West	Billings	MT	49771	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Regina Pfeifer	1111 N 1st St. Apt. 1	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Rose Mary Hoff	21138 Saddleback Circle	Parker	CO	80138	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Sarah Jane Wolf	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Ann Geck	716 East Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Kathryn Geck	1121 West Highland Acres Rd.	Bismarck	MD	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Clemens Geck	668 Knollwood Dr.	Woodland	CA	95695	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Sarah Surry	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Ann Kilzer	716 East Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Kathryn Dorgan	1121 West Highland Acres Rd.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Paul Hoff and Eleanor Hoff, as Trustees of the Paul Hoff Family Mineral Trust, dated 01/04/1982	Box 371	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
James L. Hoff	606 Dakota St. North	Elgin	ND	58533	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Lee Ann Hoff	78 Stratford St.	West Roxbury	MA	02132	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Kenneth Hoff	6165 Paisley Dr. North	Olmstead	OH	44070	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Marie Hoff	4262 Shaw, Apt 1 East	St. Louis	MO	63100	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Lee R. Hoff	2618 South Willow Wood	Mesa	AZ	85209	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Bernadine Hoff	7202 Lake Shore Rd	Derby	NY	14047	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Judith Lee Dinyer	318 Bluffview Dr.	Brownwood	TX	76801	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Raymond Hoff, Trustee of the Hoff Family Revocable Trust, dated 06/29/2012	340 North Ave. East	Missoula	MT	59801	Township 139 North, Range 92 West Section 10: SE4 less 15.09-acre tract and less a 98.19-acre tract
Kathleen McVay	14530 Westchester Dr.	Colorado Springs	CO	80921	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Curtis Hoff	4817 Cheyenne Dr.	Larkspur	CO	80921	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Joyce Kastner	4720 Ignacio Ave.	Loveland	CO	80118	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Jane Will	1222 Richmond Dr.	Bismarck	ND	50538	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Joel Hoff	1141 Clark	Billings	MT	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Theodore Hoff	Box 7268	Bozeman	MT	49102	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Emily Knopik	903 13th St. West	Billings	MT	49771	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Regina Pfeifer	1111 N 1st St. Apt. 1	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Rose Mary Hoff	21138 Saddleback Circle	Parker	CO	80138	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Sarah Jane Wolf	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Ann Geck	716 East Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Kathryn Geck	1121 West Highland Acres Rd.	Bismarck	MD	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Clemens Geck	668 Knollwood Dr.	Woodland	CA	95695	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Sarah Surry	1780 NW 7th Pl	Gresham	OR	97030	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Timothy R. Geck	4560 Lake Ave.	Saint Paul	MN	55110	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Ann Kilzer	716 E. Turnpike Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Kathryn Dorgan	1121 West Highland Acres Rd.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Paul Hoff and Eleanor Hoff, as Trustees of the Paul Hoff Family Mineral Trust, dated 01/04/1982	Box 371	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
James L. Hoff	606 Dakota St. North	Elgin	ND	58533	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Lee Ann Hoff	78 Stratford St.	West Roxbury	MA	02132	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Kenneth Hoff	6165 Paisley Dr. North	Olmstead	OH	44070	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Marie Hoff	4262 Shaw, Apt 1 East	St. Louis	MO	63100	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Lee R. Hoff	2618 South Willow Wood	Mesa	AZ	85209	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Bernadine Hoff	7202 Lake Shore Rd	Derby	NY	14047	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Judith Lee Dinyer	318 Bluffview Dr.	Brownwood	TX	76801	Township 139 North, Range 92 West Section 10: SE4, excepting the mainline ROW of the TT and ROW of a county road
Raymond Hoff, Trustee of the Hoff Family Revocable Trust, dated 06/29/2012	340 N Ave. East	Missoula	MT	59801	Township 139 North, Range 92 West Section 10: S4, excepting the mainline ROW of the TT and ROW of a county road
Magdalena Hauck					Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Carolyn Jurgens	PO Box 204	Taylor	ND	58656	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Robert Bosch	7032 57th Dr. NE	Marysville	WA	98270	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Patty Bosch	2013 Hewitt Dr.	Billings	MT	59102	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Kaire Bosch	3170 121st Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Richard Hauck	8559 Hwy 10 East	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Marilyn Marx	3129 Lakeview Dr.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Gladys Schwehr	1716 West 40th Ave.	Kennewick	WA	99337	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Dwight Hauck	41625 228th Ave. SE	Enumclaw	WA	98022-9079	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Glenn Hauck	947 – 24th St. West	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
David Hauck	2233 Hwy 8	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Bryan Hauck	PO Box 154	Smoot	WY	83126	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Frank Hoff, Jr.					Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Alvin Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Juanita Baesler	409 Ashbrook Ln	Russellville	AR	72802	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Robert Hoff	PO Box 5063	Nikolaeysk	AK	99556	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
William Hoff	PO Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Harold Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Faye Stockie King	2117 Debra Dr.	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
James Baesler	4018 Maple Dr. 5009	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Mark Stockie	West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Audrey Baesler Gund	852 Cliff Rd	Russellville	AR	72801	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Earl Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Heather Moff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
James Hart	PO Box 110266	Campbell	CA	95011	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Kay Lynn Hoff McGarva	2718 N 153rd Dr.	Goodyear	AZ	85395	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Ann Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Tristan Hoff	1 Michele Ln	Kennebunk	ME	04043	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Daniel Hoff	12040 SW Fairfield St.	Beaverton	OR	97005	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Jane Hoff Hutz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Edward Wehri	2639 Camino Lenada	Oakland	CA	94611	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Katelyn Elaine Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Samantha Michelle Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Madalyn Jacqueline Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Earl E. Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
James E. Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Ann Clara Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: A 7.51-acre tract in the SE4SW4
Lee Gress					Township 139 North, Range 92 West Section 11: S2NW4
Lucille C. Gress					Township 139 North, Range 92 West Section 11: S2NW4
Althea Prible	12015 SW Rose Vista Dr.	Portland	OR	97223	Township 139 North, Range 92 West Section 11: S2NW4
Rose Schnell	7536 SE 141st Ave.	Portland	OR	97236	Township 139 North, Range 92 West Section 11: S2NW4
Aloys Gress	7526 East Maple Ave.	Vancouver	WA	98664	Township 139 North, Range 92 West Section 11: S2NW4
Eleanor Gaman					Township 139 North, Range 92 West Section 11: S2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Anton Gress	836 South Curry St. Unit 304	Portland	OR	97239	Township 139 North, Range 92 West Section 11: S2NW4
George Gress	10657 South Ave. 9-E, Space A-6	Yuma	AZ	85365	Township 139 North, Range 92 West Section 11: S2NW4
John Gress	3140 Hwy 8	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: S2NW4
Gerald Gress, as Co-Trustee of the John Gress Family Trust Dated May 6, 1992	3112 La Tierra Dr.	Rosewell	NM	88201	Township 139 North, Range 92 West Section 11: S2NW4
Francis Gress, as Co-Trustee of the John Gress Family Trust Dated May 6, 1992	825 Elm Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: S2NW4
Victor Gress	488 NW 6th Ave. Apt. 12	Gresham	OR	97013	Township 139 North, Range 92 West Section 11: S2NW4
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 11: S2NW4
Donald Roy Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 11: S2NW4
William S. Hoff and Doris Hoff	PO Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: SE4
Frank Hoff, Jr.					Township 139 North, Range 92 West Section 11: SE4
Alvin Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 11: SE4
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: SE4
Juanita Baesler	409 Ashbrook Ln	Russellville	AR	72802	Township 139 North, Range 92 West Section 11: SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Robert Hoff	PO Box 5063	Nikolaevsk	AK	99556	Township 139 North, Range 92 West Section 11: SE4
William Hoff	PO Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: SE4
Harold Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: SE4
Faye Stockie King	2117 Debra Dr.	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: SE4
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 11: SE4
James Baesler	4018 Maple Dr.	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 11: SE4
Mark Stockie	5009 West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 11: SE4
Audrey Baesler Gund	852 Cliff Rd	Russellville	AR	72801	Township 139 North, Range 92 West Section 11: SE4
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 11: SE4
Earl Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SE4
Heather Moff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 11: SE4
James Hart	PO Box 110266	Campbell	CA	95011	Township 139 North, Range 92 West Section 11: SE4
Kay Lynn Hoff McGarva	2718 N 153rd Dr.	Goodyear	AZ	85395	Township 139 North, Range 92 West Section 11: SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Ann Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: SE4
Tristan Hoff	1 Michele Ln	Kennebunk	ME	04043	Township 139 North, Range 92 West Section 11: SE4
Daniel Hoff	12040 SW Fairfield St.	Beaverton	OR	97005	Township 139 North, Range 92 West Section 11: SE4
Jane Hoff Hutz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: SE4
Edward Wehri	2639 Camino Lenada	Oakland	CA	94611	Township 139 North, Range 92 West Section 11: SE4
Katelyn Elaine Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SE4
Samantha Michelle Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SE4
Madalyn Jacqueline Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SE4
Earl E. Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SE4
James E. Hart	PO Box 110266	Campbell	CA	95011	Township 139 North, Range 92 West Section 11: SE4
Ann Clara Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: SE4
William S. Hoff and Doris Hoff	PO Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Frank Hoff, Jr.					Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Alvin Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Juanita Baesler	409 Ashbrook Ln	Russellville	AR	72802	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Robert Hoff	PO Box 5063	Nikolaevsk	AK	99556	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
William Hoff	PO Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Harold Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Faye Stockie King	2117 Debra Dr.	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
James Baesler	4018 Maple Dr.	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Mark Stockie	5009 West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Audrey Baesler Gund	852 Cliff Rd	Russellville	AR	72801	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Earl Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Heather Moff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
James Hart	PO Box 110266	Campbell	CA	95011	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Kay Lynn Hoff McGarva	2718 N 153rd Dr.	Goodyear	AZ	85395	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Ann Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Tristan Hoff	1 Michele Ln	Kennebunk	ME	04043	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Daniel Hoff	12040 SW Fairfield St.	Beaverton	OR	97005	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Jane Hoff Hutz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Edward Wehri	2639 Camino Lenada	Oakland	CA	94611	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Katelyn Elaine Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Samantha Michelle Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Madalyn Jacqueline Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Earl E. Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
James E. Hart	PO Box 110266	Campbell	CA	95011	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
Ann Clara Hart	178 Echo Ave.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: SW4, less a 7.51-acre tract in the SE4SW4
State Treasurer, as Trustee for the State of North Dakota	1707 N 9th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: NE4
Robert D. Barth	PO Box 270	Dickinson	ND	58562	Township 139 North, Range 92 West Section 14: NE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Lorraine Thompson	5990 Tanforan Ct.	Fair Oaks	CA	95628-2634	Township 139 North, Range 92 West Section 14: NE4
Lucille Wendt	PO Box 788	Medical Lake	WA	99022	Township 139 North, Range 92 West Section 14: NE4
Delnita Messer	3052 Lakeview Dr.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 14: NE4
Kim Glasser	1228 Richmond Dr.	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: NE4
Randy Barth	581 Cottonwood Loop	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: NE4
Larry Meyer	252 7th Ln SW	Fairfield	MT	59436	Township 139 North, Range 92 West Section 14: NE4
Steve Meyer	205 7th Ave. NW	Watford City	ND		Township 139 North, Range 92 West Section 14: NE4
Nancy Bishop	22860 Sky St.	Rapid City	SD	57703	Township 139 North, Range 92 West Section 14: NE4
Gerald R. Barth and Mary Ann Barth as Trustees of the Gerald and Mary Barth Trust Dated January 13, 2015	1900 West Camino Granada	Yuma	AZ	85364	Township 139 North, Range 92 West Section 14: NE4
John D. Barth and Edith A. Barth, as Co-Trustees of the John and Edith Barth Family Mineral Trust Dated August 10, 2015	1307 N 18th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: NE4
Luann Woeste	1014 1st Ave. NW	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: NE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Pamela Meissner	650 52-1/2 Ave. SW #12	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: NE4
Alicia Holum	5512 64th Ave. NW	Gig Harbor	WA		Township 139 North, Range 92 West Section 14: NE4
Kathleen Mangan	3053 N 19th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: NE4
Cynthia Martin	5110 99th Ave. SW	Lefor	ND	58641	Township 139 North, Range 92 West Section 14: NE4
Wayne Pechtl	3001 Ohio St. Apt. 13	Bismarck	ND	58503	Township 139 North, Range 92 West Section 14: NE4
Jeanne Betlaf	8075 Haas Ln	Blackhawk	SD		Township 139 North, Range 92 West Section 14: NE4
AgriBank, FCB	30 East 7th St. Suite 1600	St. Paul	MN		Township 139 North, Range 92 West Section 14: NW4
Robert D. Barth	PO Box 270	Dickinson	ND	58562	Township 139 North, Range 92 West Section 14: NW4
Lorraine Thompson	5990 Tanforan Ct.	Fair Oaks	CA	95628-2634	Township 139 North, Range 92 West Section 14: NW4
Lucille Wendt	PO Box 788	Medical Lake	WA	99022	Township 139 North, Range 92 West Section 14: NW4
Delnita Messer	3052 Lakeview Dr.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 14: NW4
Kim Glasser	1228 Richmond Dr.	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: NW4
Randy Barth	581 Cottonwood Loop	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Larry Meyer	252 7th Ln SW	Fairfield	MT	59436	Township 139 North, Range 92 West Section 14: NW4
Steve Meyer	205 7th Ave. NW	Watford City	ND		Township 139 North, Range 92 West Section 14: NW4
Nancy Bishop	22860 Sky St.	Rapid City	SD	57703	Township 139 North, Range 92 West Section 14: NW4
Gerald R. Barth and Mary Ann Barth as Trustees of the Gerald and Mary Barth Trust Dated January 13, 2015	1900 West Camino Granada	Yuma	AZ	85364	Township 139 North, Range 92 West Section 14: NW4
John D. Barth and Edith A. Barth, as Co-Trustees of the John and Edith Barth Family Mineral Trust Dated August 10, 2015	1307 N 18th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: NW4
Luann Woeste	1014 1st Ave. NW	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: NW4
Pamela Meissner	650 52-1/2 Ave. SW #12	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: NW4
Alicia Holum	5512 64th Ave. NW	Gig Harbor	WA		Township 139 North, Range 92 West Section 14: NW4
Kathleen Mangan	3053 N 19th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: NW4
Cynthia Martin	5110 99th Ave. SW	Lefor	ND	58641	Township 139 North, Range 92 West Section 14: NW4
Wayne Pechtl	3001 Ohio St. Apt. 13	Bismarck	ND	58503	Township 139 North, Range 92 West Section 14: NW4
Jeanne Betlaf	8075 Haas Ln	Blackhawk	SD		Township 139 North, Range 92 West Section 14: NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
State Treasurer, as Trustee for the State of North Dakota	1707 N 9th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: S2
Robert D. Barth	PO Box 270	Dickinson	ND	58562	Township 139 North, Range 92 West Section 14: S2
Lorraine Thompson	5990 Tanforan Ct.	Fair Oaks	CA	95628-2634	Township 139 North, Range 92 West Section 14: S2
Lucille Wendt	PO Box 788	Medical Lake	WA	99022	Township 139 North, Range 92 West Section 14: S2
Delnita Messer	3052 Lakeview Dr.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 14: S2
Kim Glasser	1228 Richmond Dr.	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: S2
Randy Barth	581 Cottonwood Loop	Bismarck	ND	58504	Township 139 North, Range 92 West Section 14: S2
Larry Meyer	252 7th Ln SW	Fairfield	MT	59436	Township 139 North, Range 92 West Section 14: S2
Steve Meyer	205 7th Ave. NW	Watford City	ND		Township 139 North, Range 92 West Section 14: S2
Nancy Bishop	22860 Sky St.	Rapid City	SD	57703	Township 139 North, Range 92 West Section 14: S2
Gerald R. Barth and Mary Ann Barth as Trustees of the Gerald and Mary Barth Trust Dated January 13, 2015	1900 West Camino Granada	Yuma	AZ	85364	Township 139 North, Range 92 West Section 14: S2
John D. Barth and Edith A. Barth, as Co-Trustees of the John and Edith Barth Family Mineral Trust Dated August 10, 2015	1307 N 18th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: S2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Luann Woeste	1014 1st Ave. NW	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: S2
Pamela Meissner	650 52-1/2 Ave. SW #12	Hazen	ND	58545	Township 139 North, Range 92 West Section 14: S2
Alicia Holum	5512 64th Ave. NW	Gig Harbor	WA		Township 139 North, Range 92 West Section 14: S2
Kathleen Mangan	3053 N 19th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 14: S2
Cynthia Martin	5110 99th Ave. SW	Lefor	ND	58641	Township 139 North, Range 92 West Section 14: S2
Wayne Pechtl	3001 Ohio St. Apt. 13	Bismarck	ND	58503	Township 139 North, Range 92 West Section 14: S2
Jeanne Betlaf	8075 Haas Ln	Blackhawk	SD		Township 139 North, Range 92 West Section 14: S2
John Messmer					Township 139 North, Range 92 West Section 15: ALL
Regina V. Messmer	145 Wilson St.	Bordulac	ND	58421	Township 139 North, Range 92 West Section 15: ALL
Amalia Amann	N 1818 Cook St.	Spokane	WA	99207	Township 139 North, Range 92 West Section 15: ALL
Joe Messmer	4478 Essex St. SE	Salem	OR	97301	Township 139 North, Range 92 West Section 15: ALL
Rose Steiner		Reeder	ND	58649	Township 139 North, Range 92 West Section 15: ALL
Beatrice Zimmerman	620 112th St. SE #316	Everett	WA	98208	Township 139 North, Range 92 West Section 15: ALL

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Jack Messmer					Township 139 North, Range 92 West Section 15: ALL
Ida Stergios	4043 Lucille Ave. SE	Salem	OR	97302	Township 139 North, Range 92 West Section 15: ALL
Anna Grasseth	3016 Oak Crest Dr. NW	Salem	OR	97306	Township 139 North, Range 92 West Section 15: ALL
Francis Messmer	4825 Yellowstone Court NE	Salem	OR	97301	Township 139 North, Range 92 West Section 15: ALL
Linus Messmer	4121 Markins Dr.	Corpus Christi	TX	78411	Township 139 North, Range 92 West Section 15: ALL
Albert Messmer	Rt. 3, Box 16	Mott	ND	58646	Township 139 North, Range 92 West Section 15: ALL
Ernest Messmer					Township 139 North, Range 92 West Section 15: ALL
Kathy L. Hoyt, as Trustee of the Pauline E. Messmer Family Trust dated August 10, 2011	1013 Fir Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 15: ALL
Donald J. Blatz and Venita F. Blatz, Trustees of the Blatz Revocable Trust, under Trust Agreement dated June 27, 1995	7718 Mustang Ln	Lina Lakes	MN	55014	Township 139 North, Range 92 West Section 15: ALL
Bob Morland, Trustee of the Roy J. Messmer Living Trust	PO Box 13	Bowman	ND	58623	Township 139 North, Range 92 West Section 15: ALL
Victor Messmer and Clara Messmer	3515 N 19th St., Apt. 4	Bismarck	ND	58501	Township 139 North, Range 92 West Section 15: ALL
Karen Messmer, as Trustee of T K Messmer Mineral Trust	1990 Mesquite Loop	Bismarck	ND	58503	Township 139 North, Range 92 West Section 15: ALL

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
James Walby and Mary Ann Walby	502 2nd St. SW	Bowman	ND	58623	Township 139 North, Range 92 West Section 15: ALL
William R. Messmer and Jennifer Lynne Messmer	11303 Halma Ln	Woodstock	IL	60098	Township 139 North, Range 92 West Section 15: ALL
Jennifer Anne Hischer	445 31st Ave. East	West Fargo	ND	58078	Township 139 North, Range 92 West Section 15: ALL
Paul Robert Helten	3147 Morgan Circle	Bismarck	ND	58503	Township 139 North, Range 92 West Section 15: ALL
Gerald T. Rixen	PO Box 9583	Fargo	ND	58109	Township 139 North, Range 92 West Section 22: NE4
Patricia M. Meyer	1902 East Beck Ln	Phoenix	AZ	85022-3341	Township 139 North, Range 92 West Section 22: NE4
Linda M. Reisenauer	PO Box 116	New England	ND	58647	Township 139 North, Range 92 West Section 22: NE4
Dennis J. Rixen	508 5th St. NE	Jamestown	ND	58401	Township 139 North, Range 92 West Section 22: NE4
Leroy A. Rixen, Jr.	37 - 29th Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: NE4
Wayne M. Rixen	1301 4th St. NE	Jamestown	ND	58401	Township 139 North, Range 92 West Section 22: NE4
Bonnie J. Saetz	3030 115th Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: NE4
Dennis Mischel	Box 6	Horace	ND	58049	Township 139 North, Range 92 West Section 23: E2NE4
Lori Linder	613 Rose Ave.	Wheatland	CA	95692	Township 139 North, Range 92 West Section 23: E2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Donald Mischel	608 Lynn Dr.	Argusville	ND	58005	Township 139 North, Range 92 West Section 23: W2NE4
Diane Mischel	5212 Meadow Ln Court	Rapid City	SD	57703-6581	Township 139 North, Range 92 West Section 23: W2NW4
United States of America Bureau of Land Management	5001 Southgate Dr.	Billings	MT	59101	Township 139 North, Range 92 West Section 1: SW4
Garrett BTF Minerals, LLC	9701 North Broadway	Oklahoma City	OK	73114	Township 139 North, Range 92 West Section 1: SW4
The Pfanenstiel Company, LLC	PO Box 12928	Oklahoma City	OK	73157	Township 139 North, Range 92 West Section 1: SW4
Somerset Development, Inc.	15660 North Dallas Parkway, Suite 700	Dallas	TX	75248	Township 139 North, Range 92 West Section 1: SW4
Youngblood LTD	3826 N. Versailles Ave.	Dallas	TX	75209	Township 139 North, Range 92 West Section 1: SW4
J. Lee Youngblood, Trustee	128 West Denver Dr.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 1: SW4
Donald Roy Gress	12881 Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 1: SW4
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 1: SW4
Estate of Jerry Schnell	2522 West Meredith Dr. (1993)	Vienna	VA	22181	Township 139 North, Range 92 West Section 1: SW4
Carla Schnell	2522 West Meredith Dr. (1993)	Vienna	VA	22181	Township 139 North, Range 92 West Section 1: SW4
Gordon W. Schnell and Sandra Y. Schnell	801 9th Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 1: SW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Tom Schnell	1437 South Washington Ave	Royal Oaks	MI	48067	Township 139 North, Range 92 West Section 1: SW4
Courtney Moody	27680 Spring Valley Rd	Farmington Hills	MI	48336	Township 139 North, Range 92 West Section 1: SW4
Brian Schnell	6016 Erin Terrace	Edina	MN	55439	Township 139 North, Range 92 West Section 1: SW4
MAP2006-OK	101 N. Robinson, Suite 100	Oklahoma City	OK	73102	Township 139 North, Range 92 West Section 1: SW4
Dennis L. Roossien, Jr., as the duly appointed Chapter 11 Trustee for Provident Royalties, LLC, and its affiliate debtors					Township 139 North, Range 92 West Section 1: SW4
Assumption Abbey	418 3rd Ave. West	Richardton	ND	58652	Township 139 North, Range 92 West Section 1: SW4
United States of America Bureau of Land Management	5001 Southgate Dr.	Billings	MT	59101	Township 139 North, Range 92 West Section 2: S2
Donald Roy Gress	12881 Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 2: S2
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 2: S2
Estate of Jerry Schnell	2522 West Meredith Dr.	Vienna	VA	22181	Township 139 North, Range 92 West Section 2: S2
Carla Schnell	2522 West Meredith Dr.	Vienna	VA	22181	Township 139 North, Range 92 West Section 2: S2
Gordon W. Schnell Sandra Y. Schnell	801 9th Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 2: S2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Tom Schnell	1437 South Washington Ave.	Royal Oaks	MI	48067	Township 139 North, Range 92 West Section 2: S2
Courtney Moody	27680 Spring Valley Rd	Farmington Hills	MI	48336	Township 139 North, Range 92 West Section 2: S2
Brian Schnell	6016 Erin Terrace	Edina	MN	55439	Township 139 North, Range 92 West Section 2: S2
Ambrose R. Hoff and Chalotte Hoff	3713 86th Ave. SW	Richardton	ND	59652	Township 139 North, Range 92 West Section 3: S2
Vernon J. and Kathleen M. Tomaschy	3549 86th Ave. SW	Richardton	ND	59652	Township 139 North, Range 92 West Section 3: S2
Great Northern Properties LP	PO Box 1745	Miles City	MT	59301	Township 139 North, Range 92 West Section 3: S2
Donald R. Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 3: S2
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97128	Township 139 North, Range 92 West Section 3: S2
Patrick M. Carroll	306 2nd Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 3: S2
Bonnie M. Carroll	306 2nd Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 3: S2
Gene Lacher and Joyce Lacher	616 S. Anderson St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 3: S2
St. John's Lutheran Church	PO Box 126	Taylor	ND	58656	Township 139 North, Range 92 West Section 3: S2
William Robinson	Christian Colony	Ripon	WI		Township 139 North, Range 92 West Section 3: S2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Farmer's Loom & Trust Co.		New York	NY		Township 139 North, Range 92 West Section 3: S2
Edwin H. McHenry		St. Paul	MN		Township 139 North, Range 92 West Section 3: S2
United States of America	306 2nd Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 4: SE4
Patrick M. Carroll and Bonnie M. Carroll	PO Box 126	Taylor	ND	58656	Township 139 North, Range 92 West Section 4: SE4
St. John's Lutheran Church	Rt. 1, Box 41	Sentinel Butte	ND	58654	Township 139 North, Range 92 West Section 4: SE4
Home of the Range	8749 Hwy. 10	Richardton	ND	58652	Township 139 North, Range 92 West Section 4: SE4
Jason R. Tormaschy and Hannah Tormaschy	PO Box 11	Richardton	ND	58652	Township 139 North, Range 92 West Section 4: SE4
Red Trail Energy, LLC	306 2nd Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 4: SE4
BNSF Railroad Co.	2500 Lou Menk Dr.	Fort Worth	TX	76131-2830	Township 139 North, Range 92 West Section 9: E2, E2W2
Assumption Abby, Inc.	PO Box A	Richardton	ND	58652	Township 139 North, Range 92 West Section 9: E2, E2W2
State of North Dakota	608 East Boulevard Ave.	Bismarck	ND	58505-0700	Township 139 North, Range 92 West Section 9: E2, E2W2
James L. Hoff	Route 1	Leith	ND	58551	Township 139 North, Range 92 West Section 10: NW4
Lee Ann Hoff	71A Appleton	Boston	MA	2116	Township 139 North, Range 92 West Section 10: NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Kenneth Hoff	6165 Paisley Dr. N	Olmstead	OH	44070	Township 139 North, Range 92 West Section 10: NW4
Marie Hoff	4262 Shaw, Apt. 1	East St. Louis	MO	63100	Township 139 North, Range 92 West Section 10: NW4
Lee R. Hoff	Box 143	Leith	ND	58551	Township 139 North, Range 92 West Section 10: NW4
Bernadine Hoff	7200 Old Lake Shore Rd	Derby	NY	14047-0266	Township 139 North, Range 92 West Section 10: NW4
Paul Hoff and Eleanor Hoff, Trustees of the Paul Hoff Family Mineral Trust	Box 371	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: NW4
Regina Pfeifer	708 8th Ave. NW	Mandan	ND	58554	Township 139 North, Range 92 West Section 10: NW4
Clemens Geck	668 Knollwood Dr.	Woodland	CA	95695	Township 139 North, Range 92 West Section 10: NW4
Rose Mary Hoff	7939 Pecos	Denver	CO	80221	Township 139 North, Range 92 West Section 10: NW4
Judith Lee Dinyer	221 East Owens Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: NW4
Raymond J. Hoff, Trustee of the Hoff Family Revocable Trust	340 E North Ave.	Missoula	MT	59801	Township 139 North, Range 92 West Section 10: NW4
Emil M. Hoff	1023 Alderson	Billings	MT	59102	Township 139 North, Range 92 West Section 10: NW4
Emily Knopik	1023 Alderson	Billings	MT	59102	Township 139 North, Range 92 West Section 10: NW4
Joel Hoff	712 Kirkland Circle #A303	Kirkland	WA	98033	Township 139 North, Range 92 West Section 10: NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Curtis Hoff	17780 Canterbury Dr.	Monument	CO	80132	Township 139 North, Range 92 West Section 10: NW4
Theodore Hoff	3380 Penwell Bridge Rd.	Belgrade	MT	59714	Township 139 North, Range 92 West Section 10: NW4
Joyce Kastner	1802 W. 37th	Loveland	CO	80537	Township 139 North, Range 92 West Section 10: NW4
Jane Will	1222 Richmond Dr.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 10: NW4
Kathleen McVay	14530 Westchester Dr.	Colorado Springs	CO	80921	Township 139 North, Range 92 West Section 10: NW4
Red Trail Energy, LLC	PO Box 11	Richardton	ND	58652	Township 139 North, Range 92 West Section 10: NW4
Adam Dale Schank	4809 Southbay Dr.	Mandan	ND	58554	Township 139 North, Range 92 West Section 10: NW4
Great Northern Properties Limited Partnership	1107 N. 27th St., Suite 201	Billings	MT	59101	Township 139 North, Range 92 West Section 11: NE4, N2NW4
William S. Hoff & Doris Hoff	8547 Hwy 10 E	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Alvin Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Edward Wehri	7901 Winthrope St.	Oakland	CA	94605	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Juanita Baesler	509 Scenic Dr.	Ville Platte	LA	70586	Township 139 North, Range 92 West Section 11: NE4, N2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Robert Hoff	PO Box 5063	Nikolaevsk	AK	99556	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Frances Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Earl E. Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: NE4, N2NW4
James E. Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Ann Clara Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Earl Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: NE4, N2NW4
James Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Ann Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 11: NE4, N2NW4
William Hoff	8547 Hwy 10 East	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Harlan Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Katelyn Elaine Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Samantha Michelle Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Madalyn Jacqueline Hart	629 N. 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 11: NE4, N2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Bremer Bank, NA	128 North B St., PO Box 352	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Faye Stockie King	1043 Cinnamon Ave.	Eugene	OR	97404	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Mark Stockie	5009 West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 11: NE4, N2NW4
James Baesler	4018 Maple Dr.	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Audrey Baesler Gund	852 Cliff Rd	Russellvile	AR	72801	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Heather Hoff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Kay Lynn Hoff McGarva	1252 First Street West	Dickinson	ND	58601	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Tristan Hoff	PO Box 10947	Jackson	WY	83002	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Daniel Hoff	426 - RD 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Jane Hoff Hotz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Ambrose R. Hoff and Charlotte Hoff	3713 86th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Jody Hoff and Marla Hoff	3729 86th Ave. .	Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Lee Gress	941 NE 113 Ave.	Portland	OR	97200	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Rose Schnell	941 NE 113 Ave.	Portland	OR	97200	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Charles F. Gress	483 SW Pemberly Loop	McMinnville	OR	97218	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Donald Roy Gress	12881 NW Bayonne Ln	Portland	OR	97229	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Aloys Gress	5100 NE 19th Ave.	Vancouver	WA	98660	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Anton Gress	941 N.E. 113 Ave.	Portland	OR	97200	Township 139 North, Range 92 West Section 11: NE4, N2NW4
George Gress	Doby Lou's Trailer Park, 1980 Colorado St.	Yuma	AZ	85364	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Victor Gress	3250 SE Hillyard Rd	Gresham	OR	97030	Township 139 North, Range 92 West Section 11: NE4, N2NW4
John Gress		Richardton	ND	58652	Township 139 North, Range 92 West Section 11: NE4, N2NW4
Ambrose R. Hoff and Chalotte Hoff	3713 86th Ave. SW	Richardton	ND	59652	Township 139 North, Range 92 West Section 12: W2E2, W2
AgriBank	30 E. 7th St., #1600	St. Paul	MN	55101	Township 139 North, Range 92 West Section 12: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Joel and Linda Zimmerman, Trustees of the Zimmerman Living Trust	44236 N 12th St.	New River	AZ	85087	Township 139 North, Range 92 West Section 12: W2E2, W2
R.A. Couse and Darlene Couse, Trustees of the Robert and Darlene Couse Trust	493 Avenida Dr.	Arroyo Grande	CA	93420	Township 139 North, Range 92 West Section 12: W2E2, W2
Marie Wehri	17 South Merriam Ave.	Miles City	MT	59301	Township 139 North, Range 92 West Section 12: W2E2, W2
Alvin Hoff	426 - RD - 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 12: W2E2, W2
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 12: W2E2, W2
Juanita Baesler	409 Ashbrook Ln	Russellville	AR	72801	Township 139 North, Range 92 West Section 12: W2E2, W2
Robert Hoff	PO Box 5063	Nikolaevsk	AK	99556	Township 139 North, Range 92 West Section 12: W2E2, W2
Frances Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Earl E. Hart III	629 N St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 12: W2E2, W2
James E. Hart,	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Ann Clara Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
William Hoff	8547 Hwy 10 East	Richardton	ND	58652	Township 139 North, Range 92 West Section 12: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Harold Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 12: W2E2, W2
Mitch Erdle	8160 35th St.	Hebron	ND	58638	Township 139 North, Range 92 West Section 12: W2E2, W2
Faye Stockie King	1043 Cinnamon Ave.	Eugene	OR	97404	Township 139 North, Range 92 West Section 12: W2E2, W2
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 12: W2E2, W2
Mark Stockie	5009 West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 12: W2E2, W2
Earl Hart III	629 N 18th St.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
James Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Ann Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
William J. Jones, Earl E. Hart and Denise M. Drye, Co-Trustees of the Residual Trust under the Jones Family Living Trust Dated January 14, 1992	1507 Shaw Dr.	San Jose	CA	95118	Township 139 North, Range 92 West Section 12: W2E2, W2
Edward Wehri	7901 Winthrope St.	Oakland	CA	94605	Township 139 North, Range 92 West Section 12: W2E2, W2
James Baesler	4018 Maple Dr.	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 12: W2E2, W2
Audrey Baesler Gund	852 Cliff Rd	Russellville	AR	72801	Township 139 North, Range 92 West Section 12: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 12: W2E2, W2
Heather Hoff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 12: W2E2, W2
Kay Lynn Hoff McGarva	1252 First St. West	Dickinson	ND	58601	Township 139 North, Range 92 West Section 12: W2E2, W2
Tristan Hoff	PO Box 10947	Jackson	WY	83002	Township 139 North, Range 92 West Section 12: W2E2, W2
Daniel Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 12: W2E2, W2
Jane Hoff Hotz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 12: W2E2, W2
Katelyn Elaine Hart	629 N 18th St.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Samantha Mitchell Hart	629 N 18th St.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Madalyn Jacqueline Hart	629 N 18th St.	Campbell	CA	95008	Township 139 North, Range 92 West Section 12: W2E2, W2
Dakota Community Bank and Trust	609 Main St. PO Box 431	Hebron	ND	58638-0431	Township 139 North, Range 92 West Section 12: W2E2, W2
Rocky Mountain Exploration, Inc.	5441 Preserve Parkway S	Greenwood Village	CO	80121	Township 139 North, Range 92 West Section 12: W2E2, W2
Tracker Resources Development II, LLC	1050 17th St., Suite 975	Denver	CO	80265	Township 139 North, Range 92 West Section 12: W2E2, W2
BNSF Railway Company	2500 Lou Menk Dr.	Fort Worth	TX	76131-2830	Township 139 North, Range 92 West Section 13: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Great Northern Properties Limited Partnership	1101 N 27th St., Suite 201	Billings	MT	59101	Township 139 North, Range 92 West Section 13: W2E2, W2
State of North Dakota	608 East Boulevard Ave.	Bismarck	ND	58505-0700	Township 139 North, Range 92 West Section 13: W2E2, W2
Kenneth E. Moore	8465 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: W2E2, W2
Gerald R. Aluise & Valerie A. Aluise	8441 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: W2E2, W2
Sheldon Fisher	8330 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: W2E2, W2
Naomi Elkins	131 Boise	Bismarck	ND	58501	Township 139 North, Range 92 West Section 13: W2E2, W2
Janice Faye Wahlers	44628 308 St.	Mission Hill	SD	57046	Township 139 North, Range 92 West Section 13: W2E2, W2
Cheryl Harriet Keenan	15922 Dunmoor	Houston	TX	77059	Township 139 North, Range 92 West Section 13: W2E2, W2
Joy Beth Mische	1335 Hwy 30	Pipestone	MN	56164	Township 139 North, Range 92 West Section 13: W2E2, W2
Melodie Joy Alt	7015 County Rd 4	Grafton	ND	58237	Township 139 North, Range 92 West Section 13: W2E2, W2
William S. Hoffand Doris Hoff	Box 204	Richardton	ND	58652	Township 139 North, Range 92 West Section 13: W2E2, W2
Frank Hoff, Jr.					Township 139 North, Range 92 West Section 13: W2E2, W2
Edward Wehri	7901 Winthrope St.	Oakland	CA	94605	Township 139 North, Range 92 West Section 13: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Alvin Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 13: W2E2, W2
Donna Stockie	795 Montview Way	Springfield	OR	97477	Township 139 North, Range 92 West Section 13: W2E2, W2
Juanita Baesler	5009 Scenic Dr.	Ville Platte	LA	70586	Township 139 North, Range 92 West Section 13: W2E2, W2
Robert Hoff	PO Box 5063	Nikolaevsk	AK	99556	Township 139 North, Range 92 West Section 13: W2E2, W2
Harold Hoff	733 Chaffee Row	Beulah	ND	58523	Township 139 North, Range 92 West Section 13: W2E2, W2
Frances Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 13: W2E2, W2
Earl E. Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 13: W2E2, W2
James E. Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 13: W2E2, W2
Ann Clara Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 13: W2E2, W2
Faye Stockie King	1043 Cinnamon Ave..	Eugene	OR	97404	Township 139 North, Range 92 West Section 13: W2E2, W2
Guy Stockie	5720 125th St. SE	Snohomish	WA	98296	Township 139 North, Range 92 West Section 13: W2E2, W2
Mark Stockie	5009 West Rosewood Ave.	Glendale	AZ	85304	Township 139 North, Range 92 West Section 13: W2E2, W2
Katelyn Elaine Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 13: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Samantha Michelle Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 13: W2E2, W2
Madalyn Jacqueline Hart	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 13: W2E2, W2
Earl Hart III	629 N 18th St.	San Jose	CA	95112	Township 139 North, Range 92 West Section 13: W2E2, W2
James Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 13: W2E2, W2
Ann Hart	1138 Nadine Dr.	Campbell	CA	95008	Township 139 North, Range 92 West Section 13: W2E2, W2
James Baesler	4018 Maple Dr.	Chesapeake	VA	23321	Township 139 North, Range 92 West Section 13: W2E2, W2
Audrey Baesler Gund	852 Cliff Rd	Russellville	AR	72801	Township 139 North, Range 92 West Section 13: W2E2, W2
Leland Baesler	PO Box 80751	San Diego	CA	92138	Township 139 North, Range 92 West Section 13: W2E2, W2
Heather Hoff	2702 N 191st Ave.	Buckeye	AZ	85326	Township 139 North, Range 92 West Section 13: W2E2, W2
Kay Lynn Hoff McGarva	1252 First St. West	Dickinson	ND	58601	Township 139 North, Range 92 West Section 13: W2E2, W2
Tristan Hoff	PO Box 10947	Jackson	WY	83002	Township 139 North, Range 92 West Section 13: W2E2, W2
Daniel Hoff	426 Rd 261	Glendive	MT	59330	Township 139 North, Range 92 West Section 13: W2E2, W2
Jane Hoff Hotz	1407 First Ave. NE	Beulah	ND	58523	Township 139 North, Range 92 West Section 13: W2E2, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Wells Fargo Bank, N.A.	101 N Phillips Ave.	Sioux Falls	SD	57104	Township 139 North, Range 92 West Section 13: W2E2, W2
State of North Dakota	1707 N 9th St.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 16: E2, E2NW4
James Erdle	8840 37th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 16: E2, E2NW4
Mary Mooer	192 Hwy 200 South	Glendive	MT	59330	Township 139 North, Range 92 West Section 16: E2, E2NW4
Kathleen Heimbuch	9748 122nd Ave. SE	Cogswell	ND	58017	Township 139 North, Range 92 West Section 16: E2, E2NW4
Lucille Trotman	2701 Berkshire Dr.	Bismarck	ND	58503	Township 139 North, Range 92 West Section 16: E2, E2NW4
Teresa Hoff	128 West Denver Dr.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 16: E2, E2NW4
Karen Elstoen	505 Halyard Dr.	Allen	TX	75013	Township 139 North, Range 92 West Section 16: E2, E2NW4
Jerome Erdle	21051 Gresham St.; Apt 201	Canoga Park	CA	91304	Township 139 North, Range 92 West Section 16: E2, E2NW4
Tim Erdle	16901 Northridge Ave. N	Marine On St. Croix	MN	55047	Township 139 North, Range 92 West Section 16: E2, E2NW4
Assumption Abbey	PO Box A	Richardton	ND	58652	Township 139 North, Range 92 West Section 16: E2, E2NW4
Carey D. Rummel	534 10th St. West	West Fargo	ND	58078	Township 139 North, Range 92 West Section 16: E2, E2NW4
Darcie M. Rummel	2327 Hoover Ave.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 16: E2, E2NW4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Peggy A. Rummel	7735 Hwy 9 SE	Carrington	ND	58421	Township 139 North, Range 92 West Section 16: E2, E2NW4
Peggy A. Rummel	7735 Hwy 9 SE	Carrington	ND	58421	Township 139 North, Range 92 West Section 16: E2, E2NW4
Anthony Messmer and Karen Messmer, as Trustees of the TK Messmer Mineral Trust	8860 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 16: E2, E2NW4
Barbara E. Hoff	3752 Hwy 8 South	Richardton	ND	58652	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Gerald L. Hoff	422 1st Ave. West	Richardton	ND	58652	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Joann Hoselton	13877 145th St. SW	Red Lake Falls	MN	56750	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Sharon Schaefer	12012 NW 35th Ave.	Vancouver	WA	98685	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Ambrose Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Rita Schaefer	5415 N 179 Dr.	Litchfield Park	AZ	85340	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Jeffrey Hoff	3960 87th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Lucas Hoff	8969 31st St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Fred J. Williams III, as Trustee of the Fred J. Williams III 2017 GST Trust under agreement dated January 27, 2010, as amended	4437 Beach Ln South	Fargo	ND	58104	Township 139 North, Range 92 West Section 21: NE4, N2SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Fred J. Williams III and Jennifer G. Williams, collectively, as Trustees of the Jennifer G. Williams GST Trust under agreement, effective August 6, 2020	6119 East Osborn Rd	Scottsdale	AZ	85251	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Bruce C. Fjelde, as Trustee of the Bruce C. Fjelde Revocable Trust, dated the 13th day of July, 2015	1200 Harwood Dr. South, #127	Fargo	ND	58104	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Williams Mineral Investments, LLC	1042 Morningside Court	Casselton	ND	58012	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Frederick W. Burgum	Box 206	Arthur	ND	58006	Township 139 North, Range 92 West Section 21: NE4, N2SE4
A. C. Johnson	Box 2643, 1736-8 St. S	Fargo	ND	58108	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Black Stone Minerals Company, L.P.	1001 Fannin, Suite 2020	Houston	TX	77002-6709	Township 139 North, Range 92 West Section 21: NE4, N2SE4
Bonnie J. Saetz	3030 115th Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Jolene F. Gress	746 8th Ave. SW	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Jerilyn L. Haberstroh	6608 80th Ave. SW	Mott	ND	58646	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Michelle L. Kuhn	1201 Prairie View Dr.	Bismarck	ND	58501	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Gerald T. Rixen	PO Box 9583	Fargo	ND	58106-9583	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Patricia M. Meyer	7821 Arroyo Dr.	Paradise Valley	AZ	85253-3006	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Linda M. Reisenauer	Rt. 2, Box 87	New England	ND	58647	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Wayne M. Rixen	3421 East Acoma Dr.	Phoenix	AZ	85032-5165	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Dennis J. Rixen	117 2nd Ave. East	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
LeRoy A. Rixen, Jr.	RR 1, Box 60	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Barabra E. Hoff	3752 Hwy 8 South	Richardton	ND	58652	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Joann Hoselton	13877 145th St. SW	Red Lake Falls	MN	56750	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Sharon Schaefer	12012 NW 35th Ave.	Vancouver	WA	98685	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Gerald L. Hoff	422 1st Ave. West	Richardton	ND	58625	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Ambrose Hoff	2461 81st Ave. SW	Hebron	ND	58638	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Rita Schaefer	5415 N 179 Dr.	Litchfield Park	AZ	85340	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Jeffery Hoff	3960 87th Ave. SW	Richardton	ND	58625	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Lucas Hoff	8969 31st St. SW	Richardton	ND	58625	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

	Addresses				
Mineral Owner Name	**Street**	**City**	**State**	**Zip**	**Legal Description**
JRH Enterprises	3960 87th Ave. SW	Richardton	ND	58625	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Jennifer Anne Hischer	445 31st Ave. East	West Fargo	ND	58078-8301	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Paul Robert Helten	3147 Morgan Circle	Bismarck	ND	58503-0154	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Betty L. Zacher	261 Boothill Rd.	Custer	SD	57730-6223	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Kathleen A. Porubensky	6305 Mountain Meadow Dr.	Blackhawk	SD	57718	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
John J. Zacher	2221 Merlot Cr.	Fort Collins	CO	80528	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Lynn M. Groh	16147 Harvard Ln.	Lakeville	MN	55044	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Richard A. Zacher	105 Buckboard Ct.	Custer	SD	57730	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
William R. and Jennifer Lynne Messmer	11303 Halma Ln	Woodstock	IL	60098-7537	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
James and Mary Ann Walby	502 2nd St. SW	Bowman	ND	58623-4533	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Todd Walby	PO Box 784	Bowman	ND	58623	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Scott Walby	P.O. Box 109	Bowman	ND	58623	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Daniel Walby	1486 13th St. W	Dickinson	ND	58623	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Jason Walby	2403 Benders Place	Mandan	ND	58554	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Eric Walby	207 9th Ave. NW	Bowman	ND	58623	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Karen Messmer, as Trustee of the T.K. Messmer Mineral Trust	8860 39th St. W	Richardton	ND	58625	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Terry Messmer	220 Buckingham Dr	Providence	UT	84332-9669	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Timothy Messmer	1245 Holly St.	Denver	CO	80220	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Victoria Jessop	PO Box 265	Mott	ND	58646	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Carrie Gerving	4245 62nd Ave.	Glen Ullin	ND	58631	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Victor Messmer and Clara Messmer	3515 N 19th St., Apt. 4	Bismarck	ND	58503-5395	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Kathy L Hoyt, as Trustee of the Pauline E. Messmer Family Trust	1031 Fir Ave.	Dickinson	ND	58601	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Bob Morland, Trustee of the Roy J. Messmer Living Trust	15 S Main St.	Bowman	ND	58623	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Donald and Venita F. Blatz, Trustees of the Blatz Revocable Trust	216 Capitol Dr.	Appleton	WI	54911-1204	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Albert Messmer		Mott	ND	58646	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Russell James Messmer, as Trustee of the Magdaline E. Messmer Family Mineral Trust	10695 Annette Ct.	Portland	OR	97229-8801	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Rocky Mountain Exploration, Inc.	5441 Preserve Parkway S	Greenwood Village	CO	80121-2148	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Tracker Resources Development II, LLC	1050 17th St., Suite 975	Denver	CO	80265-1001	Township 139 North, Range 92 West Section 22: S2NE4, W2, SE4
Great Northern Properties Limited Partnership	1107 N 27th St., Suite 201	Billings	MT	59101	Township 139 North, Range 92 West Section 23: S2
Dalton John Rixen	201 Linden Ave.	Taylor	ND	58656	Township 139 North, Range 92 West Section 23: S2
Tracy John Rixen and Debbie Ann Rixen	8429 44th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 23: S2
Grace Rixen-Handford	4496 85th Ave. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 23: S2
Gary Mischel	1036 South E 6th St.	Cape Coral	FL	33990	Township 139 North, Range 92 West Section 23: S2
Randy Mischel	7410 Keystone Dr.	Bismarck	ND	58503	Township 139 North, Range 92 West Section 23: S2
Farm Credit Services of Mandan, FLCA	1600 Old Red Trail	Mandan	ND	58554	Township 139 North, Range 92 West Section 23: S2
Joy Beth Mische	1335 State Hwy 30	Pipestone	MN	56164	Township 139 North, Range 92 West Section 24: W2NE4, W2
Melodie Joy Alt	7015 County Rd 4	Grafton	ND	58237	Township 139 North, Range 92 West Section 24: W2NE4, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Cheryl H. Keenan	15922 Dunmoor	Houston	TX	77059	Township 139 North, Range 92 West Section 24: W2NE4, W2
Janice Faye Wahlers	44628 308th St.	Mission Hill	SD	57046	Township 139 North, Range 92 West Section 24: W2NE4, W2
Naomi Elkins	131 Boise	Bismarck	ND	58501	Township 139 North, Range 92 West Section 24: W2NE4, W2
Sheldon Fisher	8330 39th St. SW	Richardton	ND	58652	Township 139 North, Range 92 West Section 24: W2NE4, W2
Dorothy Palm Monte	12420 SE Steele	Portland	OR	97236	Township 139 North, Range 92 West Section 24: W2NE4, W2
Angela Palm Brouillette	24335 S. Brockway Rd	Oregon City	OR	97045	Township 139 North, Range 92 West Section 24: W2NE4, W2
Mary Teresa Palm Miller	11272 SE 64th Ave.	Milwaukee	OR	97222	Township 139 North, Range 92 West Section 24: W2NE4, W2
Geriann Palm Courtney	10485 SW Kiowa St.	Tualatin	OR	97062	Township 139 North, Range 92 West Section 24: W2NE4, W2
Michael Palm	6627 SE Mabel Ave.	Milwaukee	OR	97267	Township 139 North, Range 92 West Section 24: W2NE4, W2
Chantra Boehm	2120 South 12th St.; Apt. 112	Bismarck	ND	58504	Township 139 North, Range 92 West Section 24: W2NE4, W2
Kent Mischel	5411 Trace Bend	Bryan	TX	77807	Township 139 North, Range 92 West Section 24: W2NE4, W2
Nancy Schmidt	533 South 17th St.	Bismarck	ND	58504	Township 139 North, Range 92 West Section 24: W2NE4, W2
Benjamin B. Saunders, Frances Fohs Sohn and Fred Sohn	1116 SE Terrace St.	Roseburg	OR	97470	Township 139 North, Range 92 West Section 24: W2NE4, W2

Continued . . .

Table 1-2. Mineral Owners and Lessees Requiring Hearing Notification (continued)

Mineral Owner Name	Addresses				Legal Description
	Street	City	State	Zip	
Charlotte R. Richards, Trustee, Fohs Sohn Oil and Gas Trust	PO Box 1001	Roseburg	OR	97470	Township 139 North, Range 92 West Section 24: W2NE4, W2
Adobe Oil Company	Petroleum Life Building	Midland	TX	79701	Township 139 North, Range 92 West Section 24: W2NE4, W2
SFER Properties - A, Inc.	1616 S Voss; Suite 1000	Houston	TX	77057	Township 139 North, Range 92 West Section 24: W2NE4, W2
Assumption Abbey	PO Box A	Richardton	ND	58652	Township 139 North, Range 92 West Section 24: W2NE4, W2

ATTACHMENT 1

GEOLOGIC STORAGE AGREEMENT

GEOLOGIC STORAGE AGREEMENT
BROOM CREEK FORMATION
STARK COUNTY, NORTH DAKOTA

THIS AGREEMENT (“Agreement”) is entered into as of the 1st day of __________ 20__, by the parties who have signed the original of this instrument, a counterpart thereof, ratification and joinder or other instrument agreeing to become a Party hereto.

WITNESSETH:

WHEREAS, it is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's ethanol industry, to the economic benefit of North Dakota and its citizens;

WHEREAS, to further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

WHEREAS, for geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

NOW, THEREFORE, in consideration of the premise and of the mutual agreements herein contained, it is agreed as follows:

ARTICLE 1
DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article

1.4 **Facility Area** is the land described by Tracts in Exhibit “B” and shown on Exhibit “A” containing ______ acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as **[stratigraphic limits].**

1.12 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.13 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.14 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.15 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances and fluids.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

ARTICLE 2
EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Storage Facility area and the tracts therein;

2.1.2 Exhibit “B” is a schedule that describes the acres of each Tract in the Storage Facility area;

2.1.3 Exhibit “C” is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit “D” is the Form of Surface Use and Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits “A,” “B,” “C” and “D” shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

ARTICLE 3
CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Form of Surface Use and Pore Space Lease attached hereto as Exhibit “D”.

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Form of Surface Use and Pore Space Lease attached hereto as

Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

ARTICLE 4
STORAGE OPERATIONS

4.1 **Storage Operator.** Red Trail Energy, LLC is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators**. The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** Nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

ARTICLE 5
TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

ARTICLE 6
ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space

Interest in such Tract in accordance with the Pore Space Owners' Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

ARTICLE 7
TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

ARTICLE 8
EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Owner shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

ARTICLE 9
ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

ARTICLE 10
TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

ARTICLE 11
RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

ARTICLE 12
LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

ARTICLE 13
FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

ARTICLE 14
EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before ____________, 20__ this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space

Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

ARTICLE 15
TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with Section 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "C" or other agreement.

15.4 **Salvaging Equipment Upon Termination.** If not otherwise granted by Exhibit "C" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination.** Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 16
APPROVAL

16.1 **Original, Counterpart or Other Instrument.** A Pore Space Owner may approve this Agreement by signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity.** Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission.**
Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

ARTICLE 17
GENERAL

17.1 **Amendments Affecting Pore Space Owners.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction.** This agreement shall be construed according to the laws of the State of North Dakota.

ARTICLE 18
SUCCESSORS AND ASSIGNS

18.1 **Successors and Assigns.** This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows*.]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

Dated: ___________, 20___ **STORAGE OPERATOR**

RED TRAIL ENERGY, LLC

By:___________________________________

[NAME]

Its:________________________________

EXHIBIT A

Tract Map

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

EXHIBIT B

Tract Summary

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

EXHIBIT D

Form of Surface Use and Pore Space Lease

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

2.0 GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed Red Trail Energy (RTE) carbon dioxide (CO_2) storage project will be situated near Richardton, North Dakota (Figure 2-1). This project site is on the southern flank of the Williston Basin. The Williston Basin is a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota.

Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO_2 storage due, in part, to the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability.

The target CO_2 storage reservoir for the RTE project is the Broom Creek Formation, a predominantly sandstone horizon lying about 6,380 ft below the RTE facility. Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overly the Broom Creek and serve as the primary confining zone (Figure 2-2). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche, Broom Creek, and Amsden comprise the CO_2 storage complex for the RTE project (Table 2-1).

In addition to the Opeche Formation, there is ~1,200 ft of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation. An additional ~3,000 ft of impermeable intervals separates the Inyan Kara and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO_2. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, private data from brokers) and site-specific data acquired specifically to characterize the storage complex.

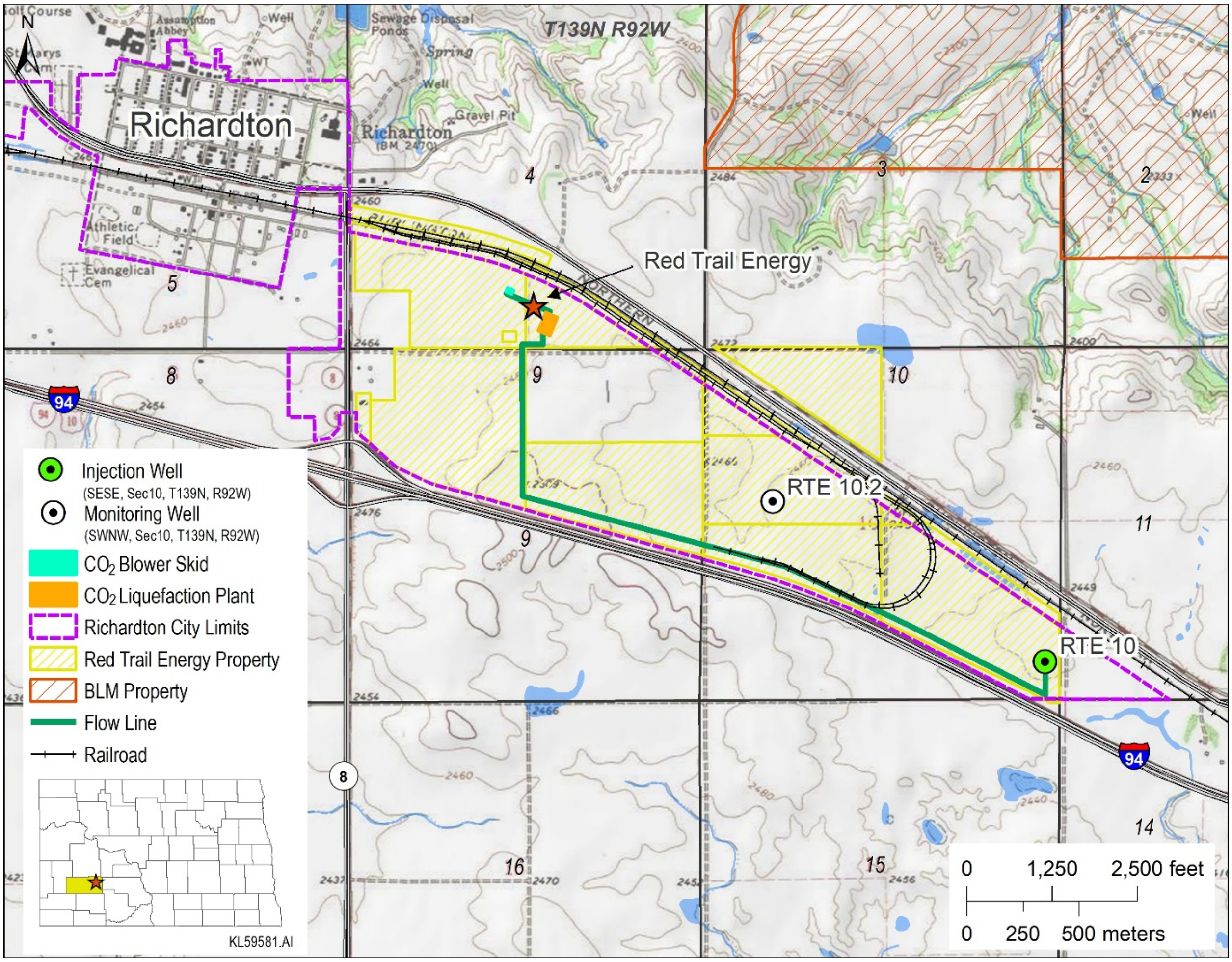

Figure 2-1. Topographic map of the RTE project area showing well locations, RTE, the proposed CO_2 flow line, and property lines.

2.2.1 Existing Data

Existing data used to characterize the geology beneath the RTE site included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission's (NDIC's) online database. Well log data and interpreted formation top depths were acquired for 47 wellbores within a 25-mile radius of the proposed storage site (Figure 2-3). These data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Existing laboratory measurements from Broom Creek Formation core samples were available from three wells: Flemmer 1 (NDIC File No. 34243), BNI 1 (NDIC File No. 34244), and ANG 1 (North Dakota Department of Health [NDDH] No. 11308) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data. Ten square miles of legacy 3D seismic data from Mercer County, encompassing the Flemmer 1 wellsite, was examined to understand heterogeneity and geologic structure of the Broom Creek Formation interval.

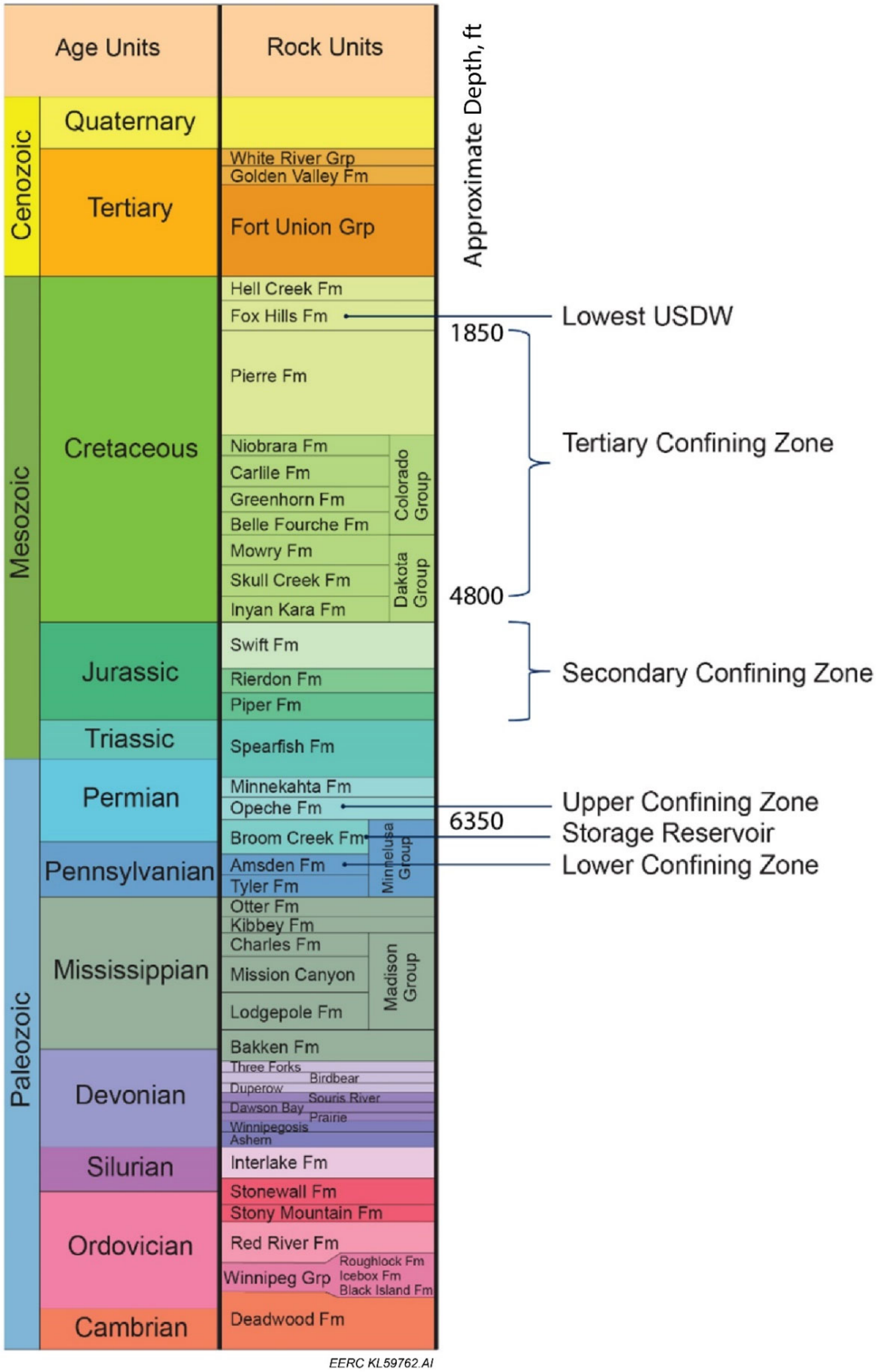

Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones for the geology underlying the RTE project area.

Table 2-1. Formations Comprising the RTE CO_2 Storage Complex

	Formation	Purpose	Average Thickness at RTE Site, ft	Average Depth at RTE Site, SSTVD ft	Lithology
Storage Complex	Opeche	Upper confining zone	103	3,871	Mudstone/siltstone
	Broom Creek	Storage reservoir (i.e., injection zone)	313	3,974	Sandstone, dolomite
	Amsden	Lower confining zone	329	4,285	Dolomite/shaly sand

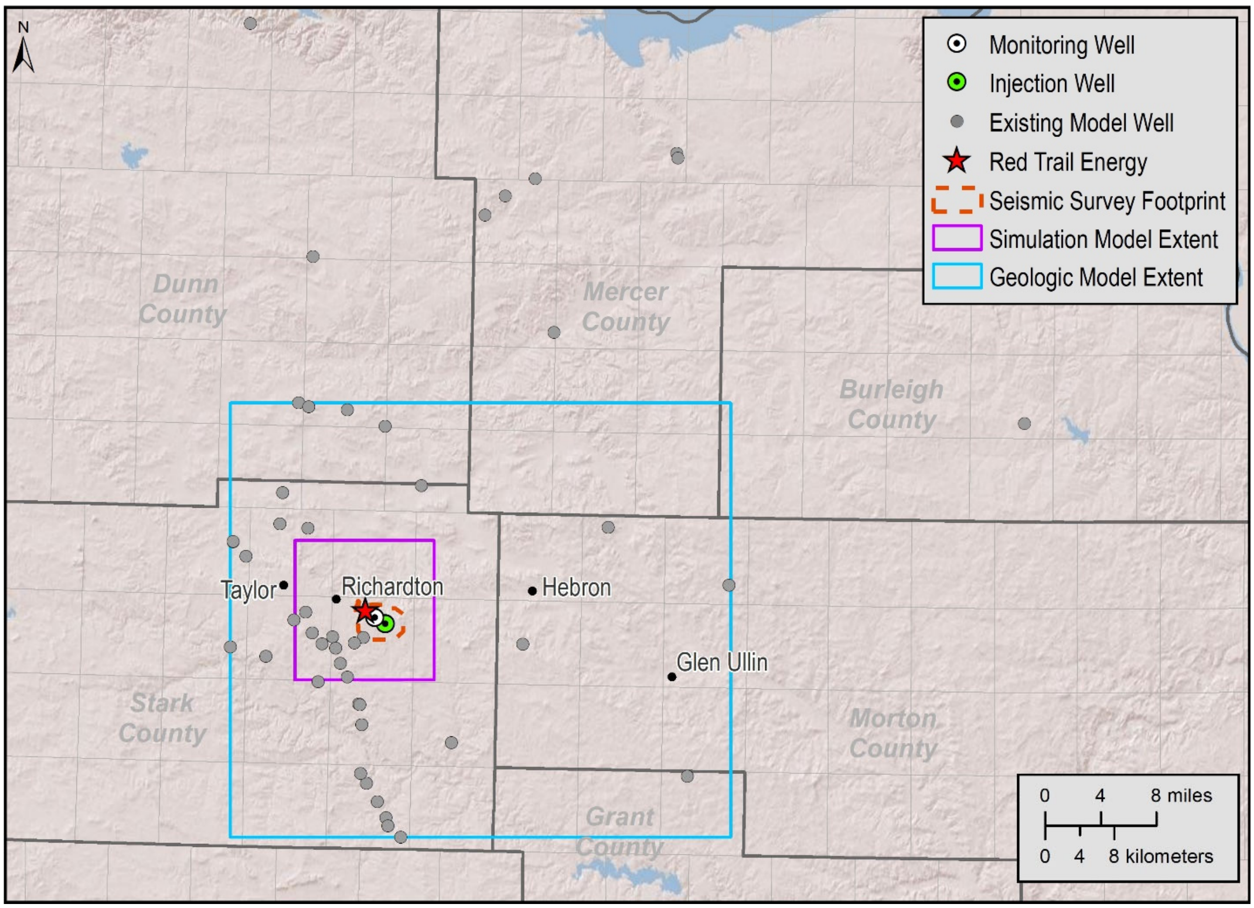

Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

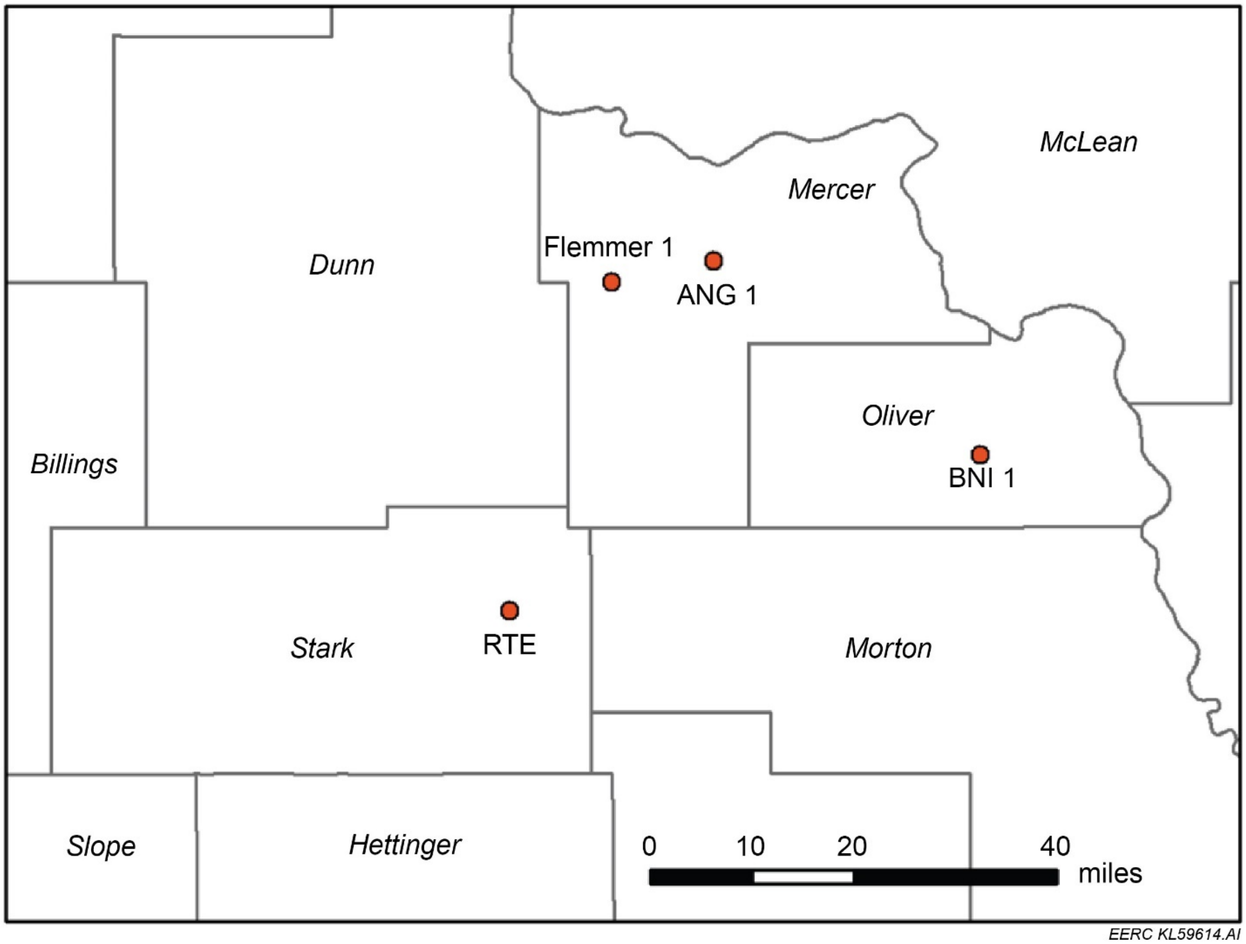

Figure 2-4. Map showing the spatial relationship between the RTE project area and wells where Broom Creek Formation core samples were collected.

2.2.2 Site-Specific Data

Site-specific efforts to characterize the proposed storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, and 3D seismic data. In 2019, the RTE-10 well was drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit and serve as the future CO_2 injection well. RTE-10 was drilled to a depth of 6,900 ft, 223 ft into the Amsden Formation. A downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche, Broom Creek, and Amsden Formations [Figure 2-5a]). Additional characterization efforts focused on the Inyan Kara Formation interval as a potential alternate CO_2 storage reservoir (Figure 2-5b).

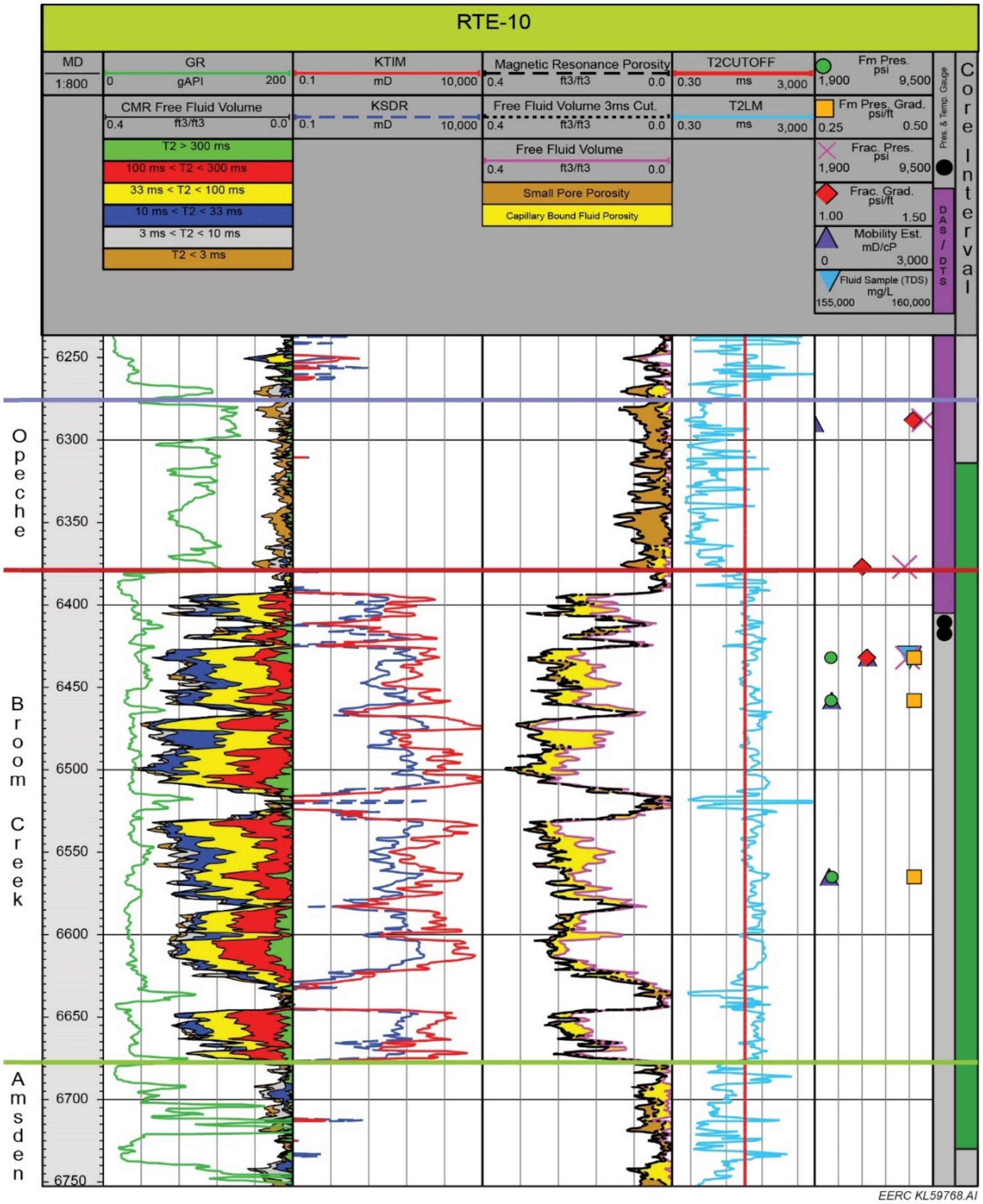

Figure 2-5a. Schematic showing vertical relationship of coring, combinable magnetic resonance (CMR) logging, and testing intervals in the Opeche, Broom Creek, and Amsden Formations in the RTE-10 well. Note: Small pore and capillary-bound fluid porosities represent porosity containing immobile formation fluid. Fluid within the small pores cannot escape because of pore size, while capillary-bound fluids cannot escape pores because of pressure constraints. Higher recorded T2 relaxation times (ms) of hydrogen atoms in the first track indicate the presence of larger pores within the near well-bore environment, which are filled with water and, therefore, more pore space (Kenyon and others, 1995; Schlumberger, 2002). T2 values that are greater than the T2 cutoff, as seen in the fourth track, indicate higher pore space and permeabilities.

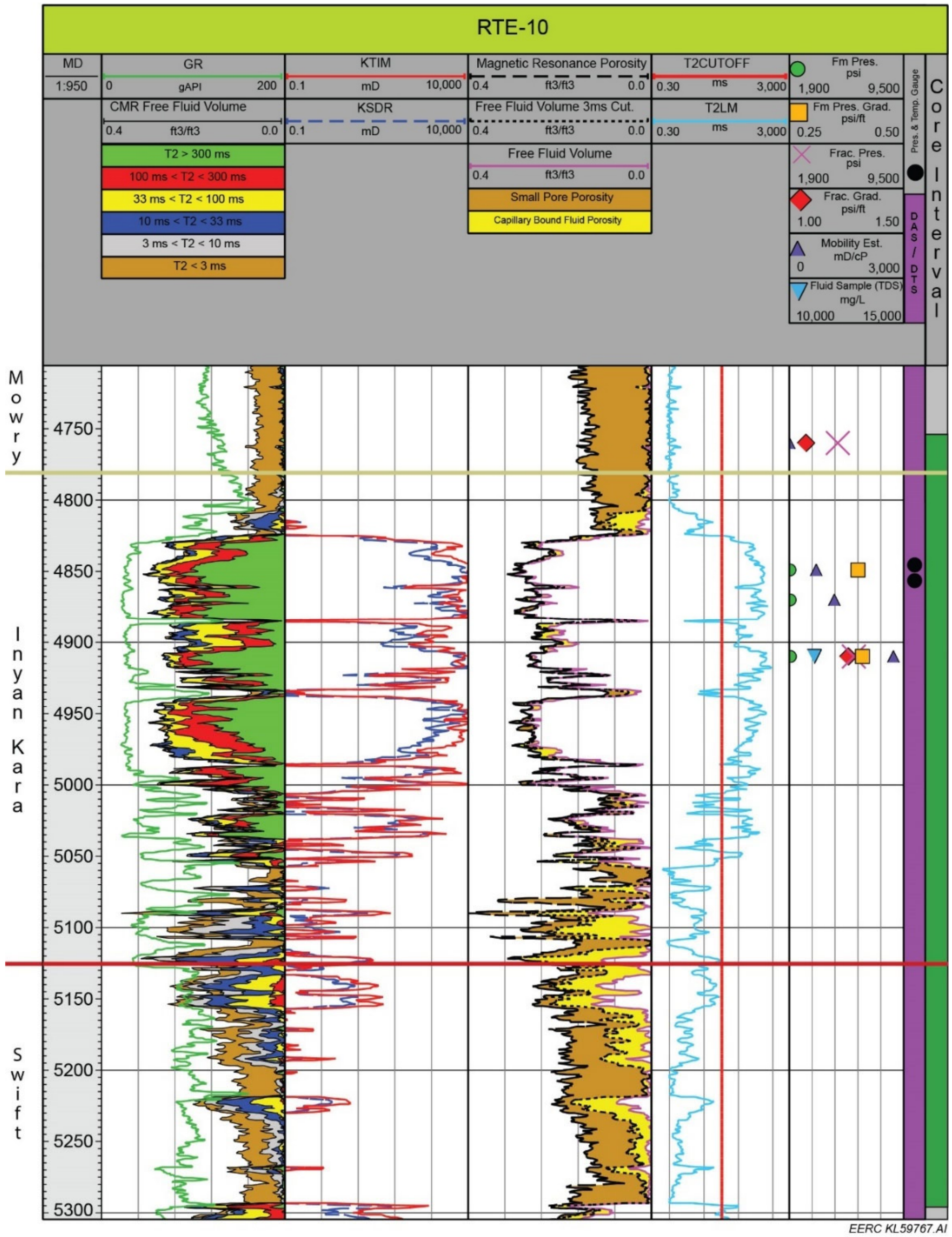

Figure 2-5b. Schematic showing vertical relationship of coring, CMR logging, and testing intervals in the Mowry, Inyan Kara, and Swift Formations in the RTE-10 well. Note: Small pore and capillary-bound fluid porosities represent porosity containing immobile formation fluid. Fluid within the small pores cannot escape because of pore size, while capillary-bound fluids cannot escape pores because of pressure constraints. Higher recorded T2 relaxation times (ms) of hydrogen atoms in the first track indicate the presence of larger pores within the near wellbore environment, which are filled with water and, therefore, more pore space (Kenyon and others, 1995; Schlumberger, 2002). T2 values that are greater than the T2 cutoff, as seen in the fourth track, indicate higher pore space and permeabilities.

Site-specific data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific data were used as inputs for geologic model construction (Appendix A), numerical simulations of CO_2 injection (Appendix A), geochemical simulation (Sections 2.3.3 and 2.4.1.2), and geomechanical analysis (Section 2.4.4). The improved understanding of the subsurface provided by the site-specific data directly informed the selection of monitoring technologies, development of the timing and frequency of monitoring data collection, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data provide important information for guiding the design and operation of site equipment and infrastructure.

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the RTE-10 well along the entire open section of the wellbore. The logging suite included caliper, spontaneous potential (SP), gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, a CMR log, and a full-bore formation microimager (FMI) log.

The acquired well logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The site-specific formation top depths were added to the existing data of the 47 wellbores within a 25-mile radius of the study area to understand the geologic extent, depth, and thickness of the subsurface geologic strata. Formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

Nearly 420 ft of core was collected from the Broom Creek storage complex in RTE-10. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the RTE-10 wellbore were used to derive a temperature gradient for the proposed injection site (Table 2-2). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the study area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

Formation pressure testing at RTE-10 was performed with the Schlumberger MDT* Modular Formation Dynamics Tester tool. A wireline conveyed tool assembly incorporated a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pumpout module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection (Appendix D, “Schlumberger, MDT Modular Formation Dynamics Tester”).

Table 2-2. Description of RTE-10 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Mowry	4,760.18	129.18
Inyan Kara	4,849.66	125.26
	4,869.73	125.94
	4,910.08	126.62
Mean Inyan Kara Temp.	125.94	
Inyan Kara Temperature Gradient, °F/ft	0.017	
Opeche	6,290.08	142.29
Broom Creek	6,432.17	143.70
	6,458.91	143.98
	6,565.09	144.65
Mean Broom Creek Temp.	144.11	
Broom Creek Temperature Gradient, °F/ft	0.016	

The MDT tool formation pressure measurements from the Inyan Kara and Broom Creek Formations are included in Table 2-3. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-3. Description of RTE-10 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Inyan Kara	4,849.66	1,947.97
Inyan Kara	4,869.73	1,956.62
Inyan Kara	4,910.08	1,974.03
Mean Inyan Kara Pressure	1,959.51	
Inyan Kara Formation Pressure Gradient, psi/ft	0.40	
Broom Creek	6,432.17	2,935.16
Broom Creek	6,458.91	2,947.73
Broom Creek	6,565.09	2,997.91
Mean Broom Creek Pressure	2,960.14	
Broom Creek Pressure Gradient, psi/ft	0.45	

2.2.2.4 Microfracture Tests

Using the Schlumberger MDT* Modular Formation Dynamics Tester tool, Appendix D, "SLB-MDT brochure," microfracture tests were performed at RTE-10. In situ reservoir stress testing measurements provided real-time formation temperatures, formation fracture breakdown, formation fracture propagation, and formation fracture closure pressures.

Microfracture tests were performed in the Mowry, Inyan Kara, Opeche, and Broom Creek Formations (Table 2-4). The use of the dual-packer module on the MDT tool assembly to isolate the designated intervals tested a 1.5-foot section of the zone of interest.

Two of the three tests attempted in the Opeche Formation were unsuccessful. One predominant reason included Schlumberger's dual-packer mechanical specifications, with a maximum differential pressure between the upper packer and the hydrostatic pressure of 5,500 psi. See Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Opeche Formation at the two depths indicated that the upper confining formation is very tight and exhibits sufficient geologic integrity to contain the injected carbon dioxide stream. The first microfracture test attempted in the Broom Creek Formation was unable to achieve injection zone formation breakdown pressure because of the Broom Creek's high permeability, requiring additional injection volumes, which then led to the successful breakdown of the second test, Appendix D, "SPE Paper 127233."

Fracture propagation pressures determined from the microfracture test were used to calculate pressure constraints related to the maximum allowable bottomhole pressure.

Table 2-4. Description of RTE-10 Microfracture Tests

Formation		**Test Depth, ft**	**Breakdown Pressure**		**Propagation Pressure**	**Closure Pressure**		**Initial Shut-In Pressure**	
		psi	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**
Mowry	4,760.49	5,122.00	1.08	4,027.31	0.85	3,910.53	0.82	3,993.20	0.84
Inyan Kara	4,910.35	6,192.76	1.26	4,901.44	1.00	4,819.42	0.98	4,741.64	0.97
Opeche	6,288.91	* Unable to break down; max. inj. pressure = 8,912 psi, gradient = 1.41 psi/ft							
	6,291.49	* Unable to break down; max. inj. pressure = 8,908 psi, gradient = 1.41 psi/ft							
	6,376.89	7,676.76	1.20	4,878.68	0.77	4,623.94	0.73	4,900.51	0.77
Broom Creek	6,432.18	7,863.00	1.22	4,594.73	0.71	3,762.17	0.58	4,649.10	0.72
	6,432.69	* Unable to break down; max. inj. pressure = 7,890 psi, gradient = 1.23 psi/ft.							

2.2.2.5 Fluid Samples

Fluid samples from the Broom Creek and Inyan Kara Formations were collected from the RTE-10 wellbore via an MDT tool (Table 2-5), Appendix D, "Schlumberger Saturn 3D Radial Probe. Results were analyzed by a state-certified laboratory and confirmed by the Energy & Environmental Research Center (EERC). Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations. Fluid sample analysis reports can be found in Appendix B.

Table 2-5. Description of RTE-10 Fluid Sample Tests and Corresponding Total Dissolved Solids (TDS) Values for Each Sample

Formation	Test Depth, ft	TDS, mg/L
Inyan Kara	4,910.08	11,100
Broom Creek	6,432.04	159,000

In situ fluid pressure testing was performed in the upper confining zone, the Opeche Formation, with the MDT tool. This test utilized the tools large-diameter probe to test both mobility and reservoir pressure (Appendix D). The probe (MDT) was unable to draw down reservoir fluid in order to give the reservoir pressure or in situ fluid sample, and the formation was unable to rebound (build pressure) because of low to almost zero permeability. The nonmobile fluid can be confirmed with the CMR log showing low to almost zero permeability (Figure 2-5a). The testing results provide further evidence of the confining properties of the Opeche Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

2.2.2.6 Seismic Survey

A 7.8-square-mile 3D seismic survey was acquired in early 2019 (Figure 2-6). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The seismic data were used for assessment of geologic structure, interpretation of interwell heterogeneity, and to inform well placement. Additionally, data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model.

The 3D seismic data and RTE-10 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the RTE-10 sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the RTE project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity were observed in the seismic data. Section 2.5.2 describes interpretation of the seismic data in more detail.

The 3D seismic data were also used to gain a better understanding of interwell heterogeneity across the study area for petrophysical property distributions. The 3D seismic data suggest the interbedded dolomite and anhydrite intervals within the Broom Creek Formation seen in RTE-10 are laterally discontinuous in the RTE project area; however, the data do not suggest that these lower-permeability intervals compartmentalize the storage reservoir in the RTE project area. A compressional wave (P-wave) velocity volume was created using the 3D seismic data and RTE-10 sonic and density log data (Figure 2-7). The velocity volume was used to classify sandstone and dolostone lithofacies of the Broom Creek Formation and distribute lithofacies through the geologic model as well as inform petrophysical property distribution in the geologic model.

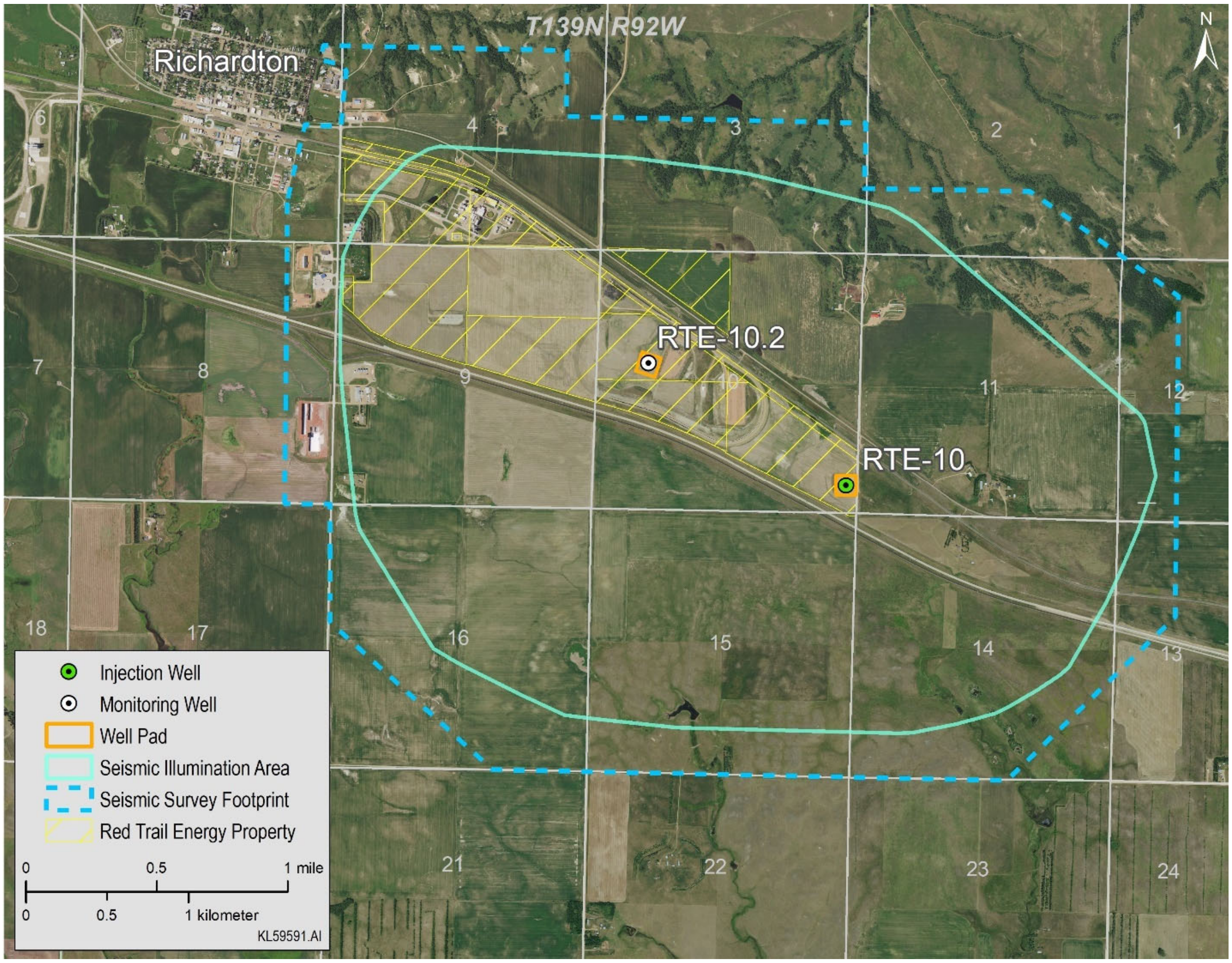

Figure 2-6. Map showing the extent of the 7.8-square-mile 3D seismic survey in the RTE project area.

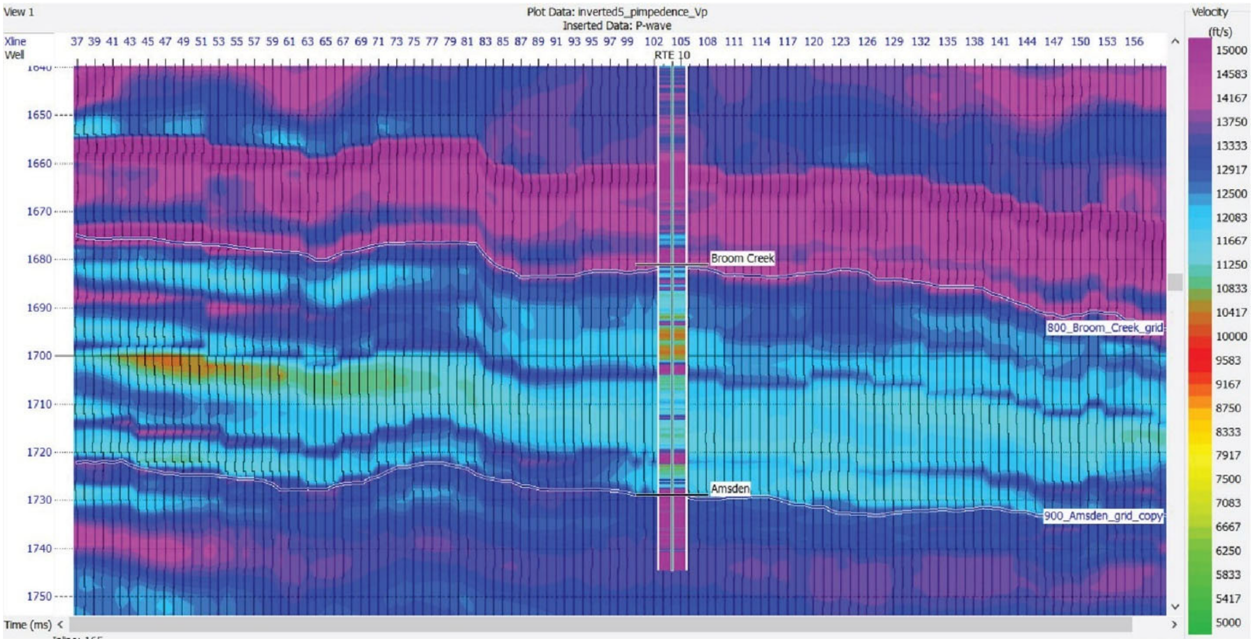

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Figure 2-7. Cross section of the inverted compressional wave velocity volume that transects the RTE-10 well. The compressional wave velocities from the RTE-10 sonic log are shown on the inset panel.

2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2).

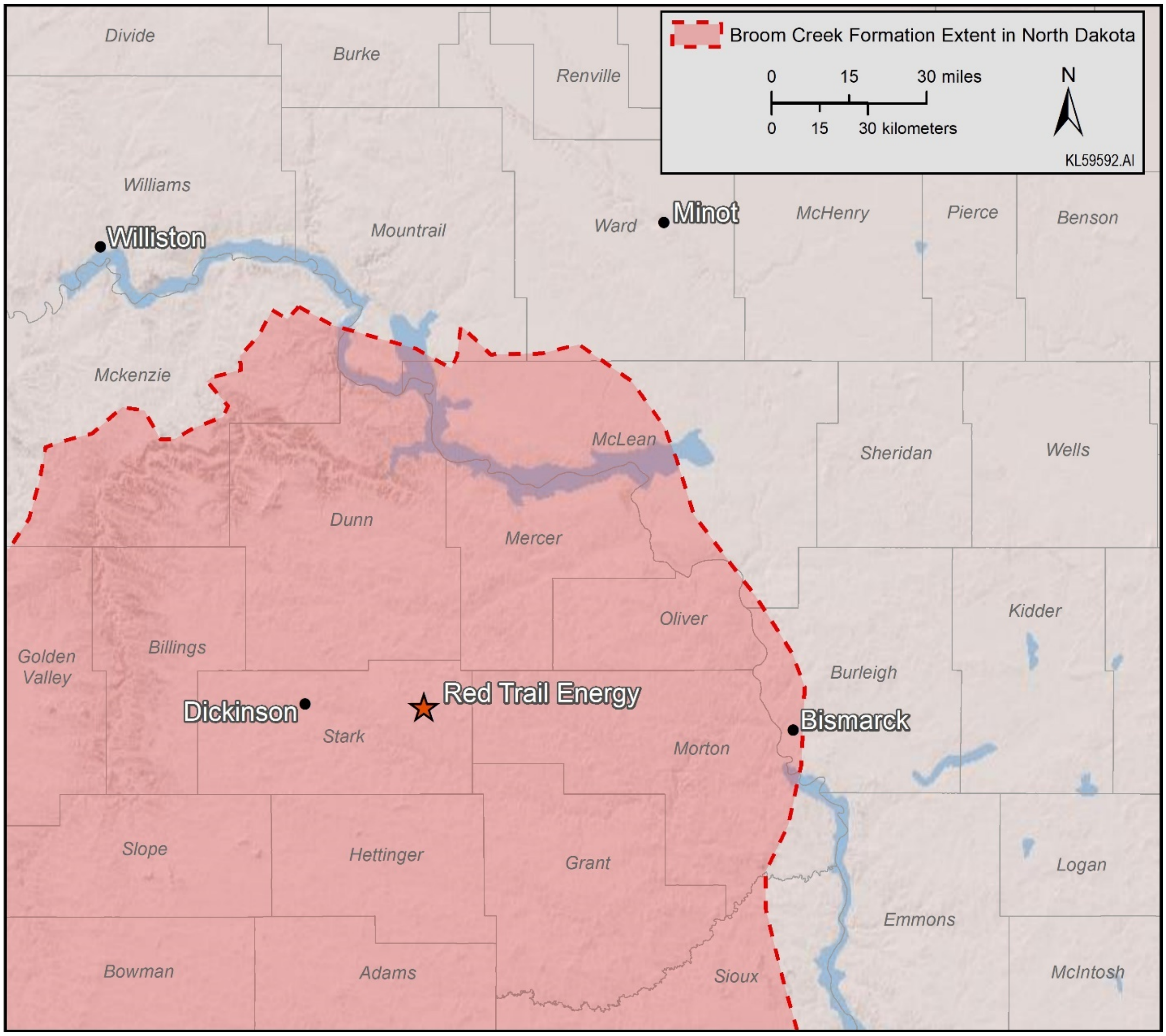

Figure 2-8. Areal extent of the Broom Creek Formation in North Dakota.

At RTE-10, the Broom Creek Formation is made up of 201 ft of sandstone and 97 ft of dolostone and is located at a depth of 6,379 ft. Across the project area, the Broom Creek Formation varies in thickness from 210 to 406 ft (Figure 2-9), with an average thickness of 313 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the project area ranges from 48 to 324 ft, with an average of 192 ft.

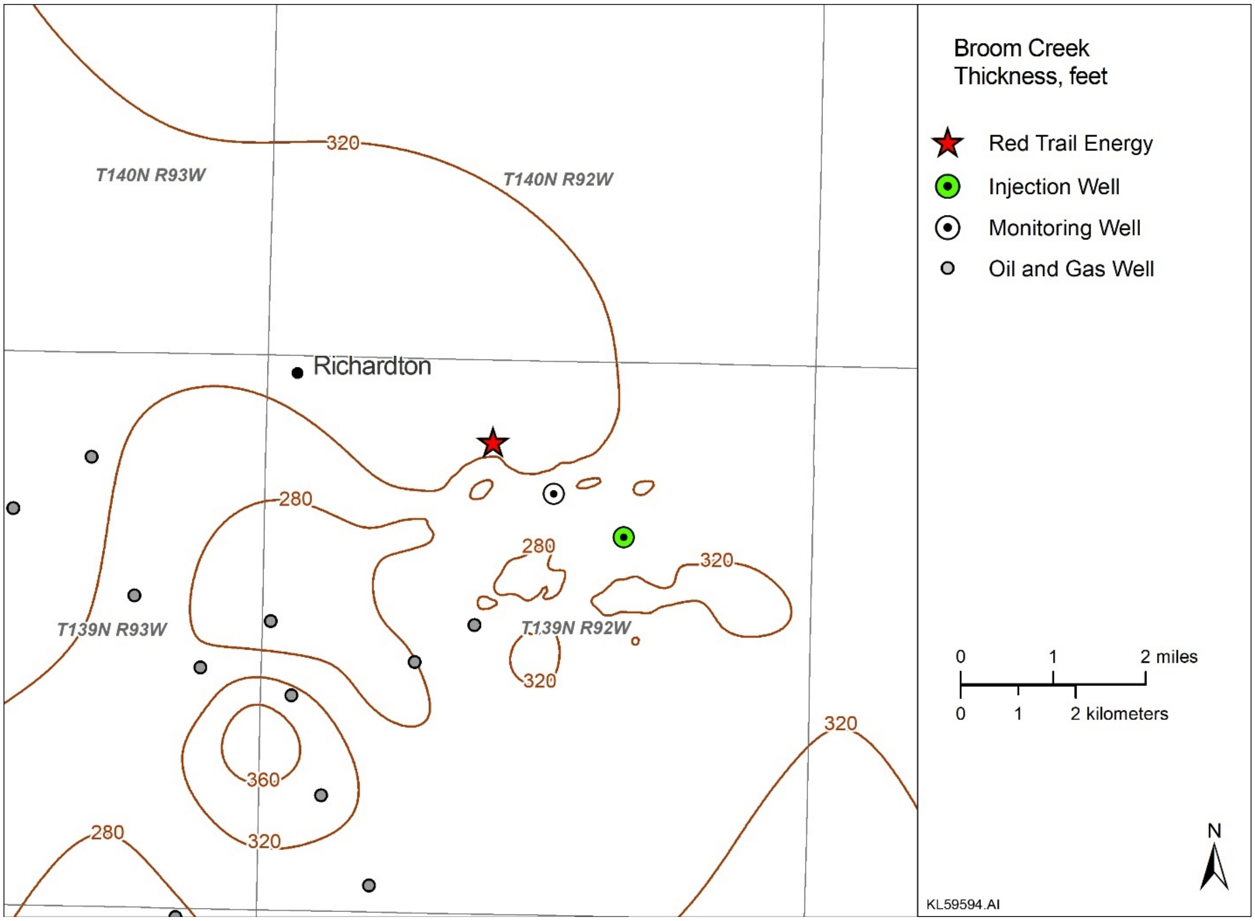

Figure 2-9. Isopach map of the Broom Creek Formation in the RTE project area.

The top of the Broom Creek Formation was picked across the project area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek (Figure 2-10). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that could be correlated across the project area. Seismic data collected as part of site characterization efforts (Figure 2-6) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near RTE-10 (Figures 2-11a and 2-11b). The 3D seismic data suggest the interbedded dolomite and anhydrite intervals in the RTE-10 well are laterally discontinuous and do not compartmentalize the storage reservoir in the RTE project area. A structure map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figures 2-12 and 2-13).

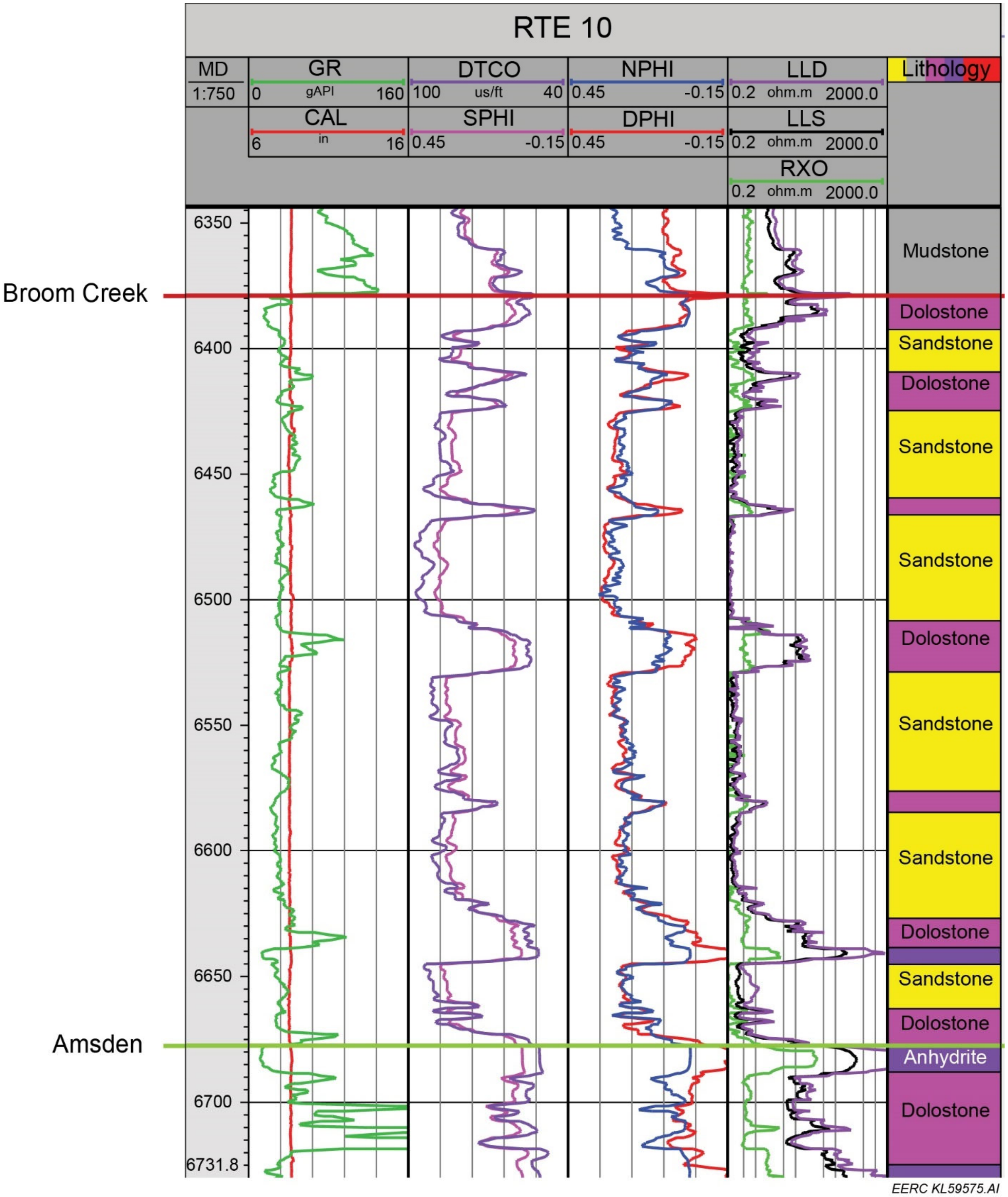

Figure 2-10. Well log display of the interpreted lithologies of the lower Opeche, Broom Creek, and upper Amsden Formation in RTE-10.

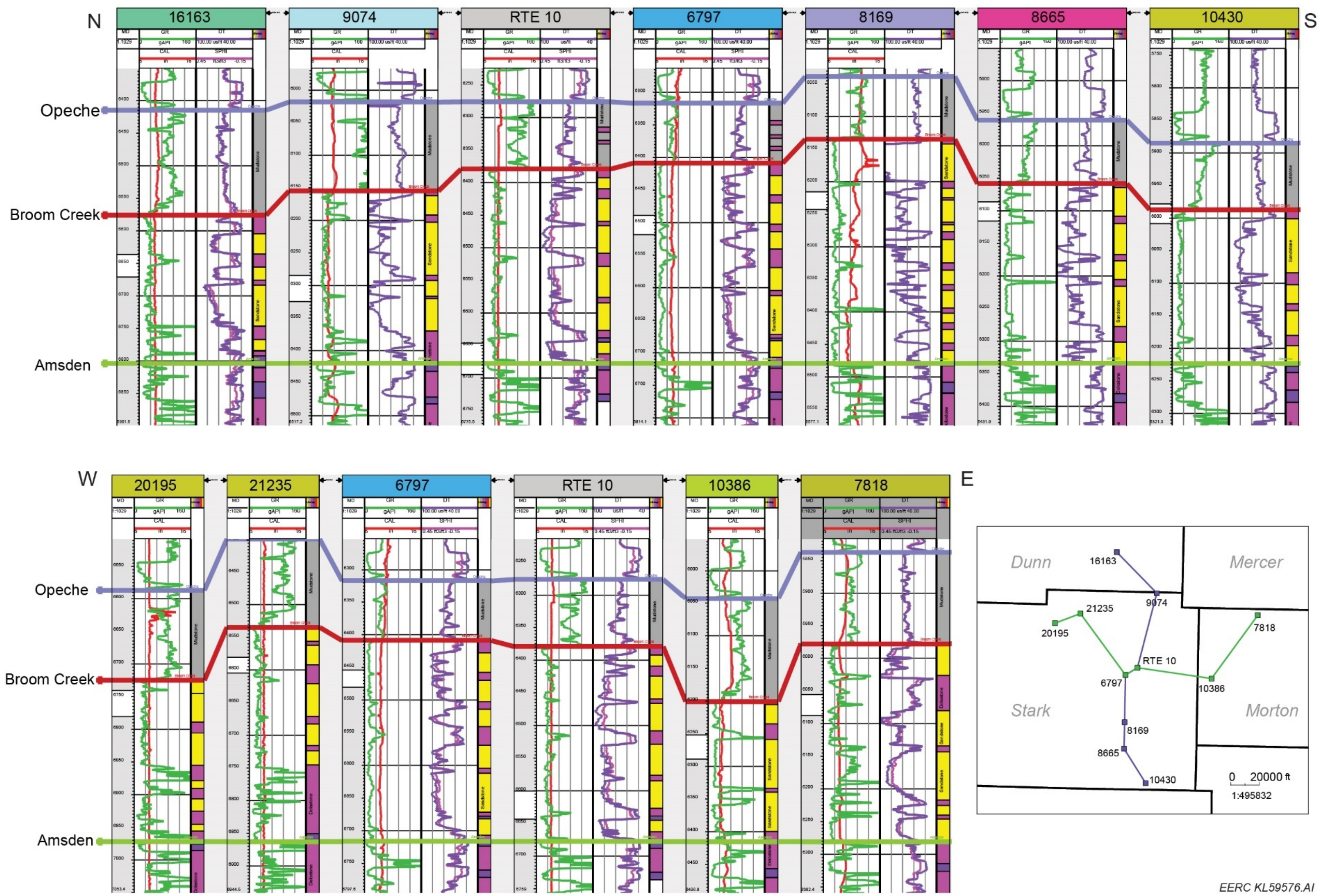

Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (purple), and 3) interpreted lithology log.

Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is.

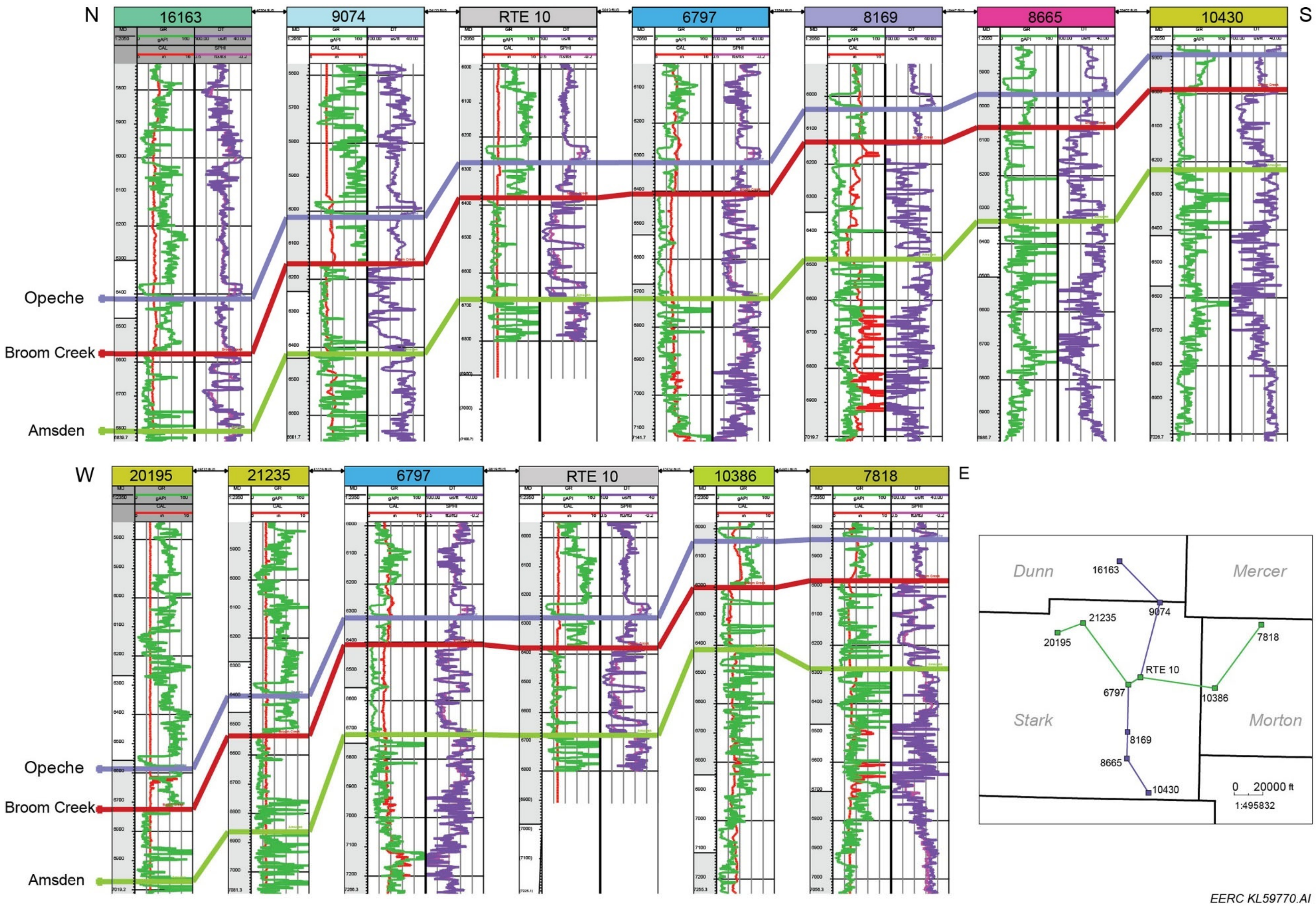

Figure 2-11b. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (purple).

Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is.

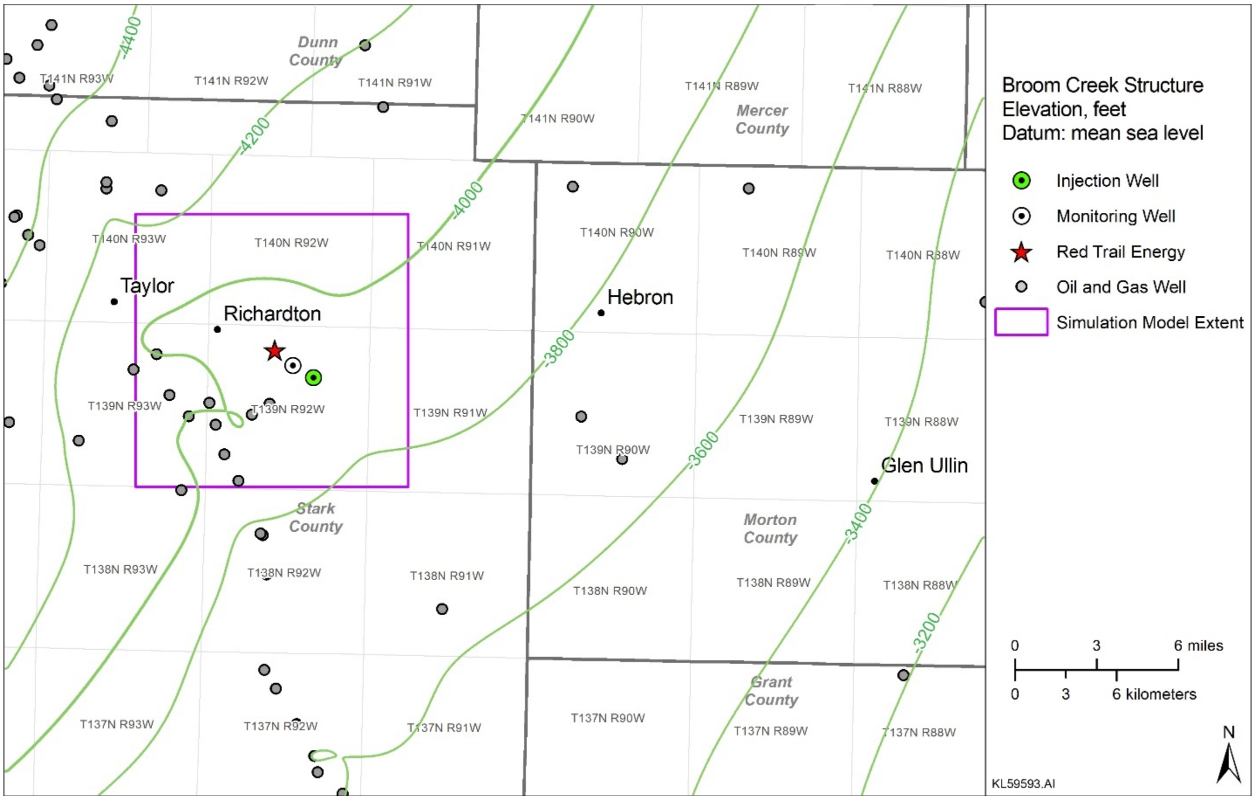

Figure 2-12. Structure map of the Broom Creek Formation across the greater RTE project area.

Forty-three 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of Broom Creek core retrieved from the RTE-10 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the RTE-10 Broom Creek core samples have porosity values ranging from 2.91% to 33.7% and permeabilities ranging from <0.001 to 5,120 mD (Table 2-6). The wide range in porosity and permeability reflects the differences between the sandstone and dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek core revealed unconsolidated or poorly consolidated sandstone.

Analysis of 21 core samples from the sandstone portion of the Broom Creek core from RTE-10 showed porosity values ranging from 12% to 34%, with an average of 22%. Permeability of the sandstone samples ranged from 25 to 5,120 mD, with a geometric average of 419 mD. Porosity values of dolostone samples from the Broom Creek core ranged from 3% to 9%, with an average of 6%. Dolostone permeability values ranged from 0.004 to 1.12 mD, with a geometric average of 0.08 mD (Table 2-6 and Figure 2-14).

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The core sample measurements showed good agreement with the wireline logs collected from RTE-10. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially

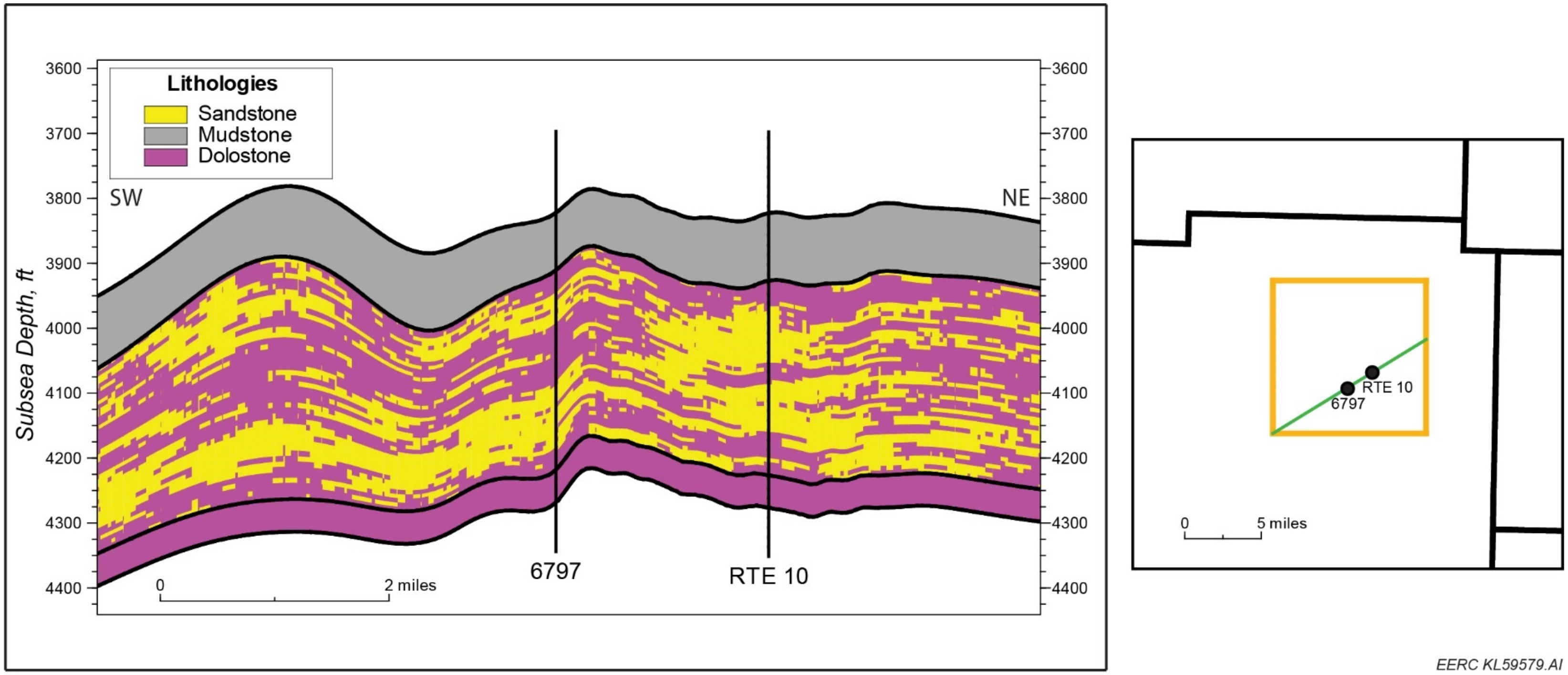

Figure 2-13. Cross section of the RTE CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced to mean sea level.

and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-6 are derived from a combination of the core analysis and the larger data set derived from offset well logs.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity due to high porosity and brine salinity, and high sonic velocity measurements. The dolostone intervals in the formation are associated with an increase in GR measurements compared to the sandstone intervals, in addition to high density, low porosity (neutron, density, and sonic), high resistivity, and low sonic velocity measurements.

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the RTE-10 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	Broom Creek		
Formation Top Depth, ft	6,379		
Capillary Entry Pressure (GW), psi	1.1		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Broom Creek (sandstone)	Porosity, %	21.68 (12.18–33.65)*	25.26 (1.01 – 32.14)*
	Permeability, mD	419.1 (25.35–5,120)**	277.45 (20.20 – 2,483.64)**
Broom Creek (dolomite)	Porosity, %	6 (2.91–8.54)*	15.24 (1.01 – 32.14)*
	Permeability, mD	0.08 (0.004–1.12)**	8.65 (0.01– 2,261.53)**

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses.
** Permeability values are reported as the geometric mean followed by the range of values in parentheses.

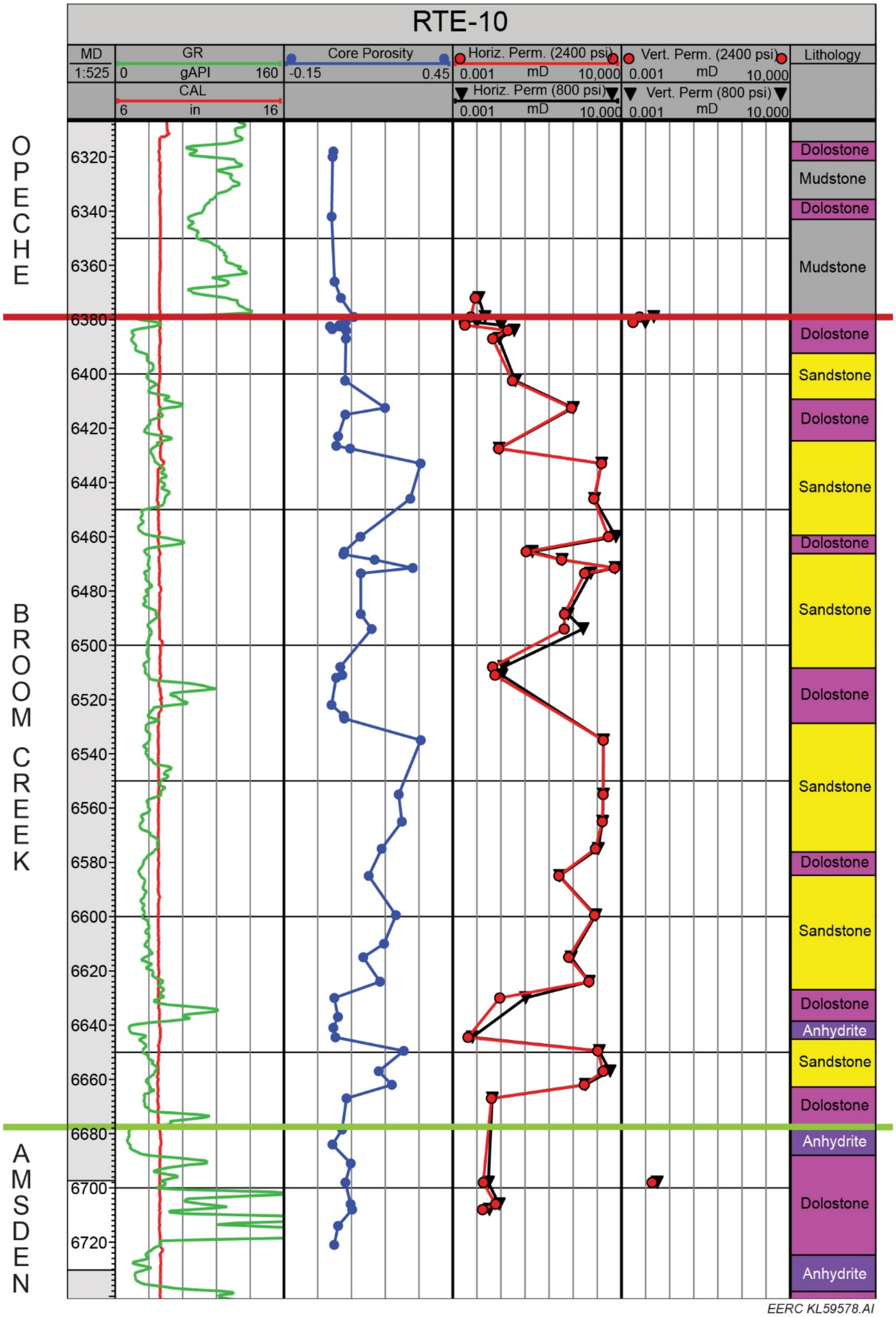

Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the RTE CO_2 storage complex.

Pressure testing in the Broom Creek Formation included three formation pressure measurements via an MDT tool at RTE-10. All tests resulted in good agreement, with reservoir pressures recorded that ranged from 2,935 to 2,998 psi. These pressures were used to derive a pressure gradient of 0.45 psi/ft. The pressure gradient was used to calculate a formation pressure profile for use in the numerical simulations of CO_2 injection.

A microfracture test was performed via an MDT tool in the RTE-10 well within the Broom Creek Formation. The test was conducted 53 ft below the top of the formation. The results of this test are shown in Table 2-7.

Table 2-7. Broom Creek Microfracture Results from RTE-10

Depth, ft	6,432	
Pressure/Gradient	psi	psi/ft
Breakdown	7,863	1.22
Fracture Propagation	4,594	0.717
Closure	3,762	0.584

The measured temperature of the Broom Creek Formation in RTE-10 was 144°F at a depth of 6,432 ft. Using an average surface temperature of 40°F, the resulting temperature gradient for the Broom Creek Formation is 0.016°F/ft.

$$\frac{144°\text{F}-40°\text{F}}{6{,}460\ \text{ft}} = 0.016°\text{F/ft} \qquad \text{[Eq. 1]}$$

Fluid samples collected via an MDT tool in RTE-10 from the Broom Creek Formation were analyzed by a state-certified lab and confirmed by the EERC.

2.3.1 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation is dominated by fine- to medium-grained sandstone with lesser amounts of carbonates and anhydrites. Forty-three depth intervals representing nearly 300 ft of the Broom Creek Formation were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment below, thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals show that quartz (80%) is the dominant mineral. Throughout these intervals are minor occurrence of feldspar (3%), dolomite (5%), and anhydrite as cement (10%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The contact between grains is long (straight) to tangential. The porosity ranges between 20% to 25%.

Two distinct carbonate intervals are notable. First is the presence of a very fine- to fine-grained dolostone (80%), with quartz of variable size and shape (5%) and iron oxides (10%)

present. The porosity is intercrystalline and not well-developed, averaging 5%. Diagenesis is expressed by dolomitization of the original calcite grains. Fossils are not present in this interval. In the second occurrence of carbonate, the texture becomes coarse and more fossil-rich, comprising fine-grained dolomite (35%), dolomitized fossils (25%), quartz (15%), and silicified fossils (25%). Diagenesis is expressed by the dissolution of dolomite, resulting in shelter and vuggy porosity. The presence of quartz crystallized inside fossils shows several episodes of crystallization partially obstructing the vuggy porosity. The porosity averages 20%. The anhydrite intervals are expressed as thin beds that separate different sand bodies and as cement. The porosity is almost null.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, dolomite, anhydrite, clay, and iron oxides (Figure 2-15).

XRF data are shown in Figure 2-16 for the Broom Creek Formation. As shown, the majority of the sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (70%–90%), CaO (5%–10%), and MgO (5%–10%). The high percentage of CaO and SO_3 at 6,640 ft indicates a presence of a thin layer of anhydrite. The formation shows very little clay, with a range of 0.0.5% to 3% being the highest detected.

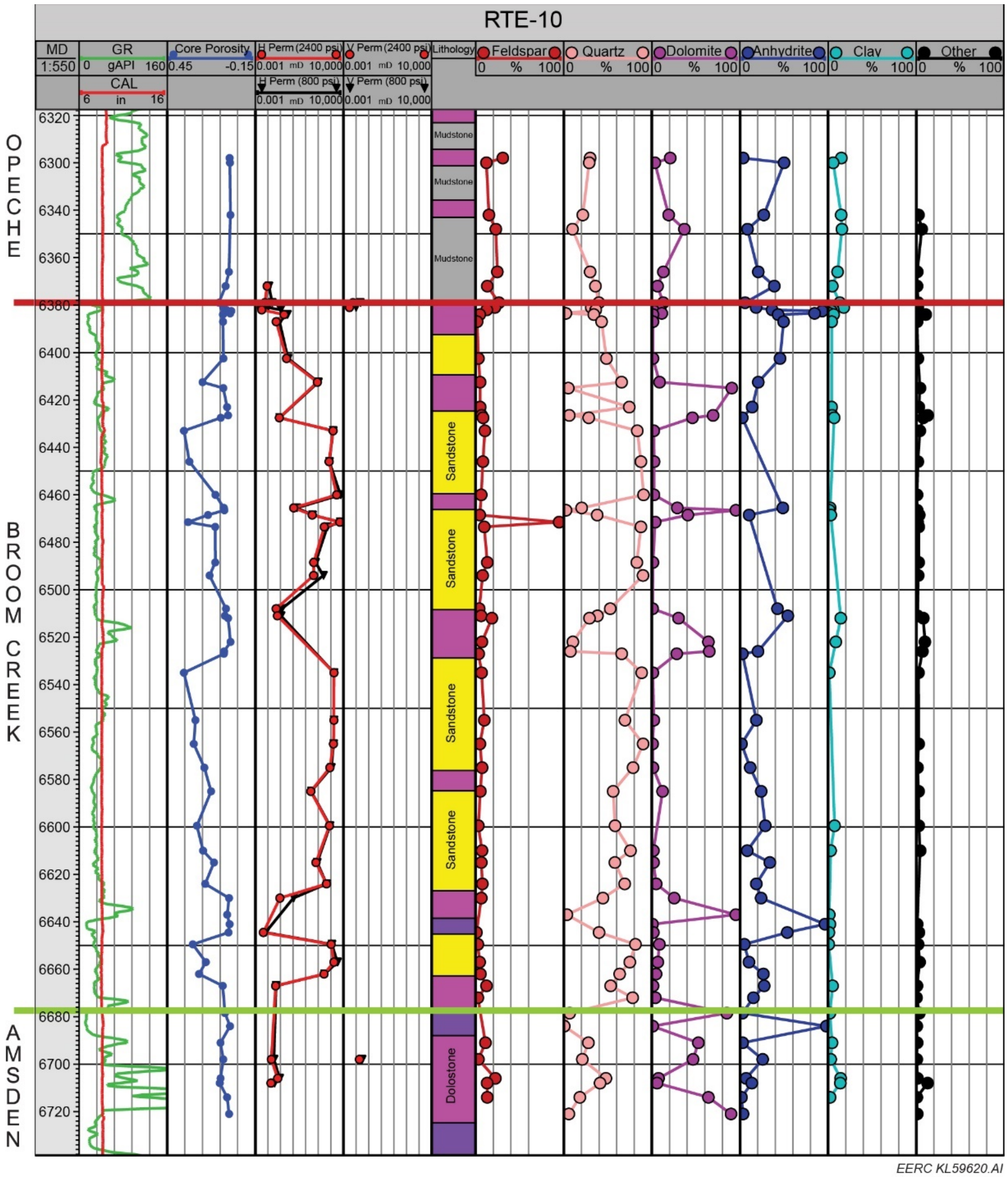

Figure 2-15. Laboratory-derived mineralogic characteristics of the Broom Creek Formation.

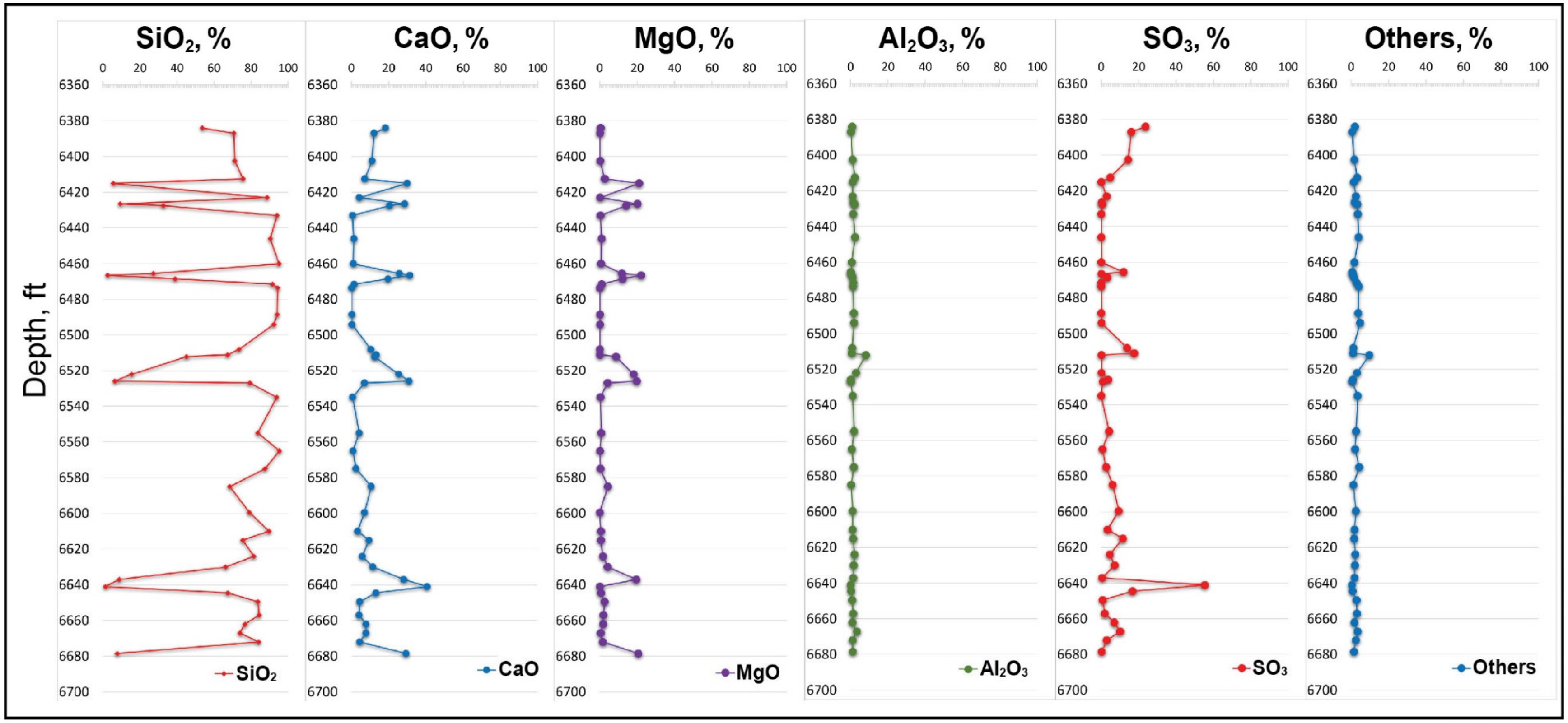

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Figure 2-16. XRF data from the Broom Creek from RTE-10.

2.3.2 Mechanism of Geologic Confinement

For the RTE project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.3.3 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone. The effects have been found to be minimal and not threatening to the geologic integrity of the storage system.

The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. The project's base case simulation (base case) was rerun with the geochemical analysis option included (geochemistry case), and results from the two cases were compared. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause observable change to storage reservoir performance or to mechanical integrity of the storage formation.

The geochemistry case was constructed using the base case simulation inputs and assumptions as well as honoring the average mineralogical composition of the Broom Creek rock materials (80% of bulk reservoir volume) and the average formation brine composition (20% of bulk reservoir volume). XRD data from the RTE 10 core samples were used to inform the mineralogical composition of the Broom Creek used in the geochemical modeling (Table 2-8). CO_2 injection stream composition remained the same as the base case, as described by RTE (Table 2-9). The geochemistry case was run for the 20-year injection period followed by 25 years of postinjection shutdown and monitoring.

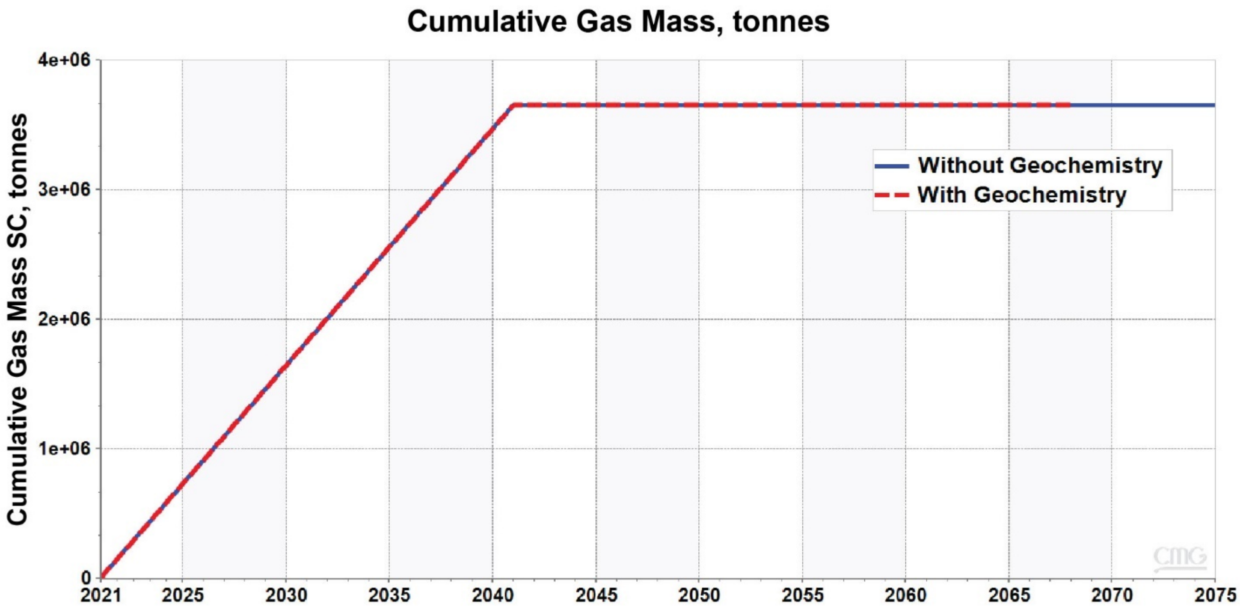
Table 2-8. XRD Results for RTE-10 Broom Creek Core Samples

Depth 6,599.5 ft		Depth 6,667 ft	
Mineral Data	**%**	**Mineral Data**	**%**
Kaolinite	2	Illite/muscovite	3.9
Illite/Muscovite	5.3	Chlorite	1.1
K-Feldspar	3	K-feldspar	12.3
Quartz	58.2	Quartz	53.2
Rutile	0.8	Calcite	0.8
Aphthitalite	1.1	Dolomite	1.3
Halite	0.9	Anhydrite	27.4
Anhydrite	28.7		

Table 2-9. Expected CO_2 Stream Composition for the RTE Project

Component Flows	ppmv	mol%
Carbon Dioxide, CO_2	998,700	99.87
Oxygen, O_2	10	1.00E-03
Nitrogen, N_2	610	6.10E-02
Total Hydrocarbons, (as CH_4)	92	9.20E-03
Total Sulfur, as S	2.6	2.60E-04
Water, H_2O	633	6.33E-02

Figure 2-17 shows that reservoir performance results for the two cases are essentially identical. There is no observable change in injection rate or pressure as a result of geochemical reactions in the reservoir. However, the pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-18a and 2-18b. It should be noted that the area affected by pH change extends approximately 300 feet beyond the area of CO_2 saturation.



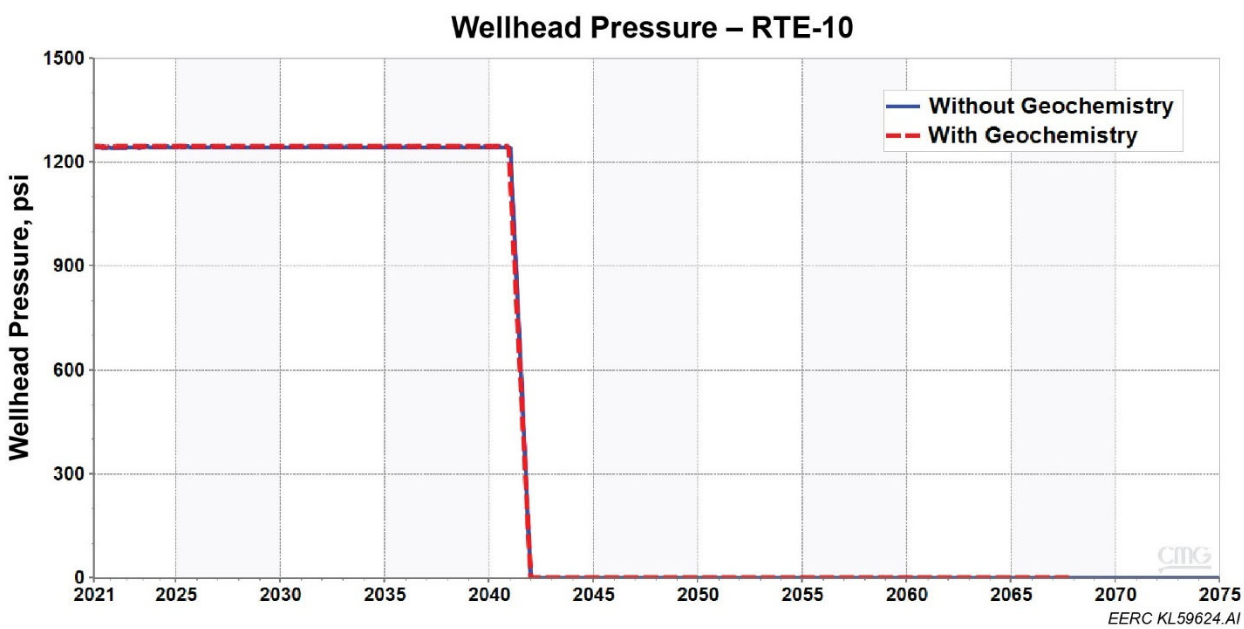


Figure 2-17. Upper graph shows cumulative injection vs. time. The two cases overlay each other. Lower graph shows wellhead injection pressure for the two cases. There is no observable change in injection performance.

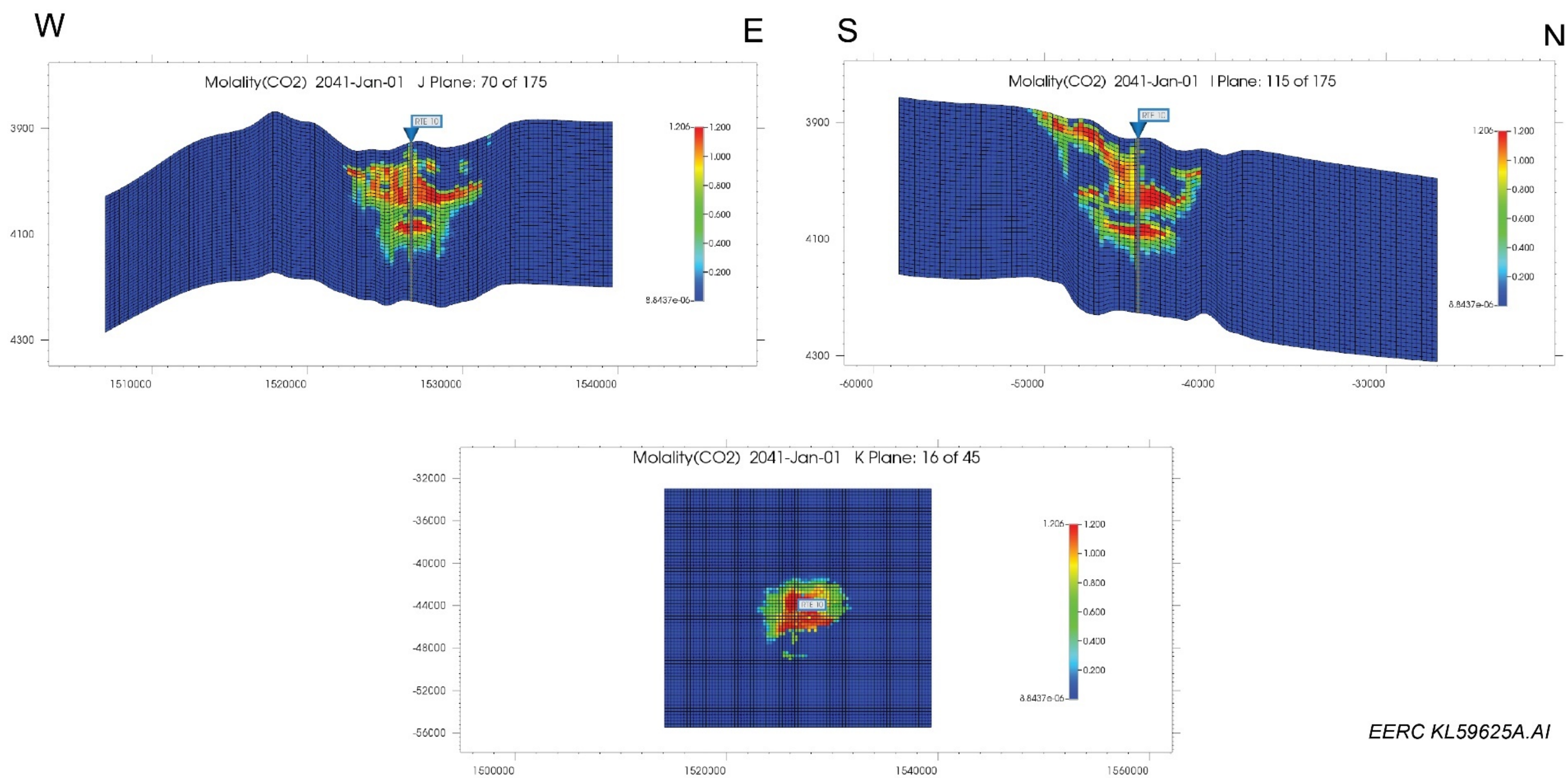


Figure 2-18a. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality.

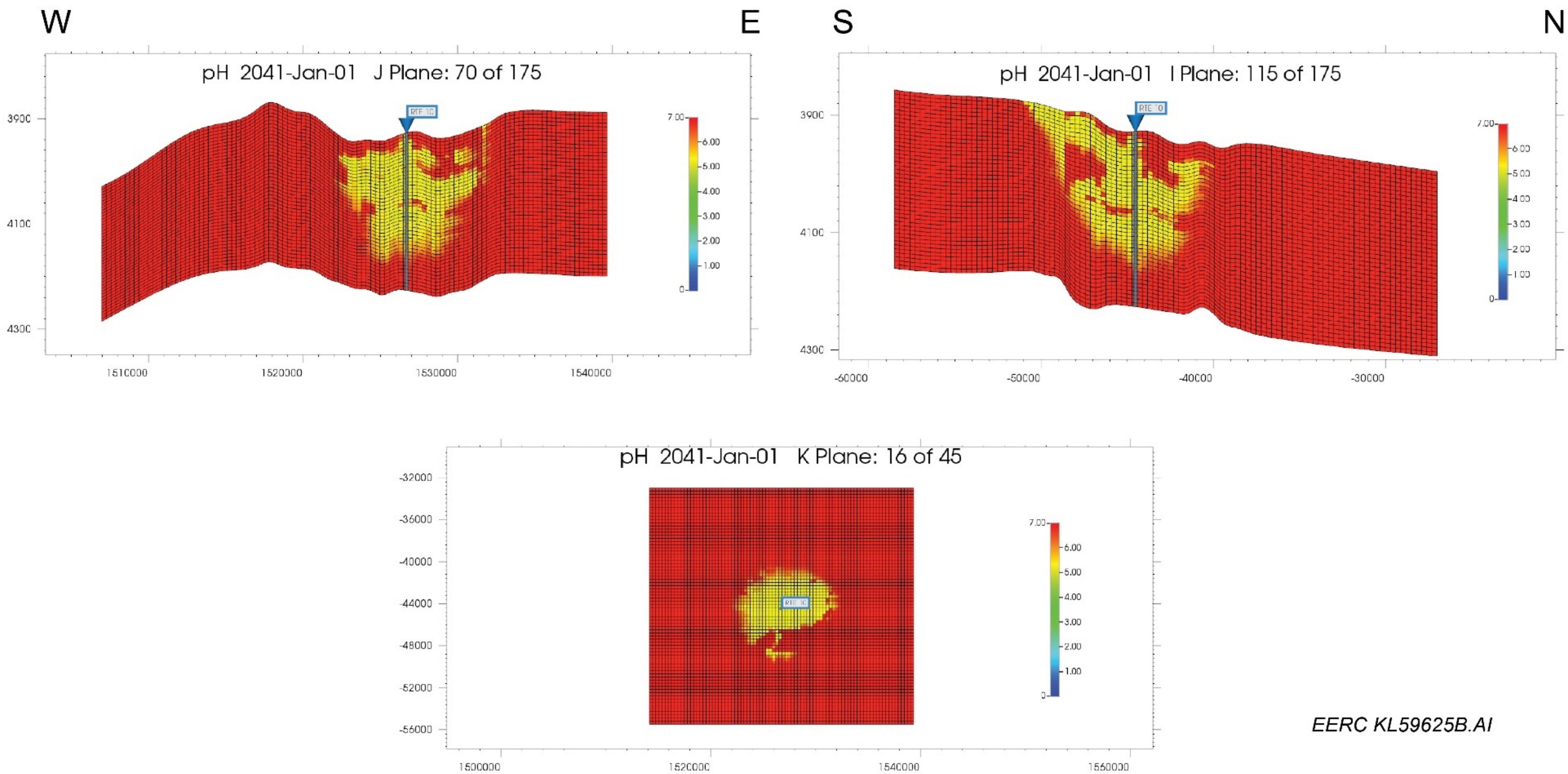


Figure 2-18b. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine. The extent of the pH-affected area is slightly larger (~300 feet) than the extent of the CO_2 accumulation.

Figure 2-19 shows the mass of mineral dissolution and precipitation due to geochemical reactions in the Broom Creek. Dissolution of halite far exceeds the quantities of the other minerals. Halite, calcite, and dolomite dissolution appreciably slows after Year 2041, the year in which injection ends. There is net dissolution during the simulation period as larger quantities of minerals are dissolved than precipitated. Figure 2-20a and 2-20b provides an indication of the distribution of the mineral that has the most dissolution, halite, and the mineral that has the most precipitation, illite, at the end of the injection period. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-19, the affected area has an associated increase in porosity (Figure 2-21). However, the porosity change is small, up to 1.5 porosity units, equating to a maximum increase in average porosity from 20% to 21.5% after the 20-year injection period.

Results of the simulation show that geochemical processes will be at work in the Broom Creek during and after CO_2 injection. Mineral dissolution and some reprecipitation are expected to occur during the simulated time span of 45 years. Fluid pH will decrease in the area of the CO_2 accumulation, and there will be a slight net increase in system porosity. However, these changes are not significant enough to create observable change in reservoir performance parameters such as injection rate or wellhead injection pressure.

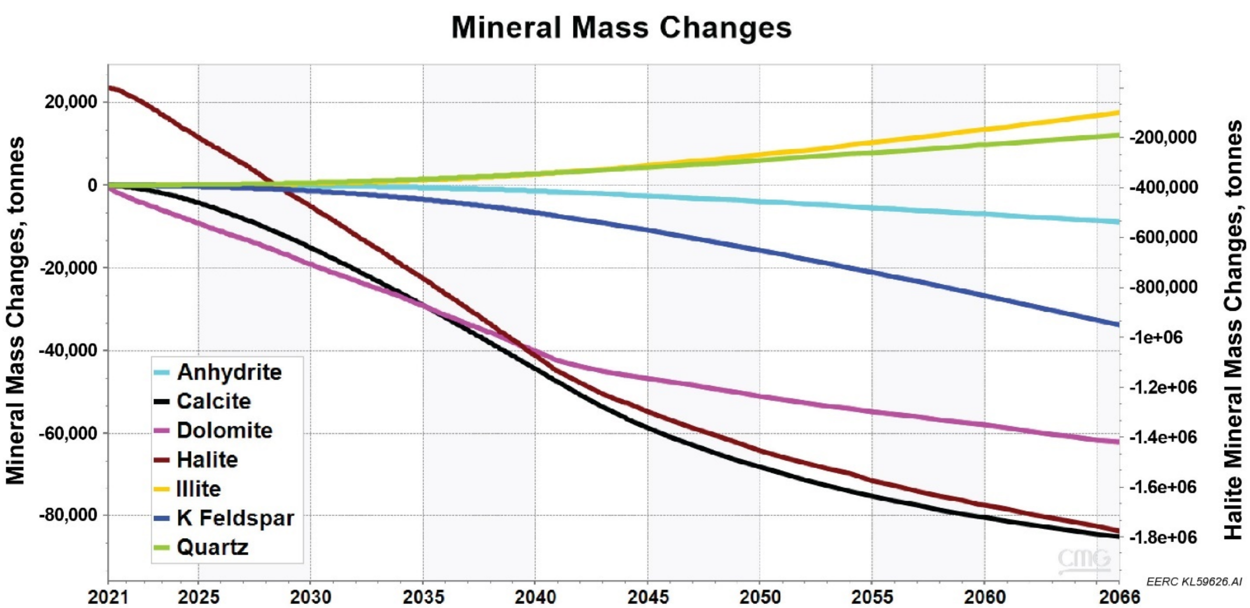


Figure 2-19. Dissolution and precipitation quantities of reservoir minerals due to CO_2 injection.

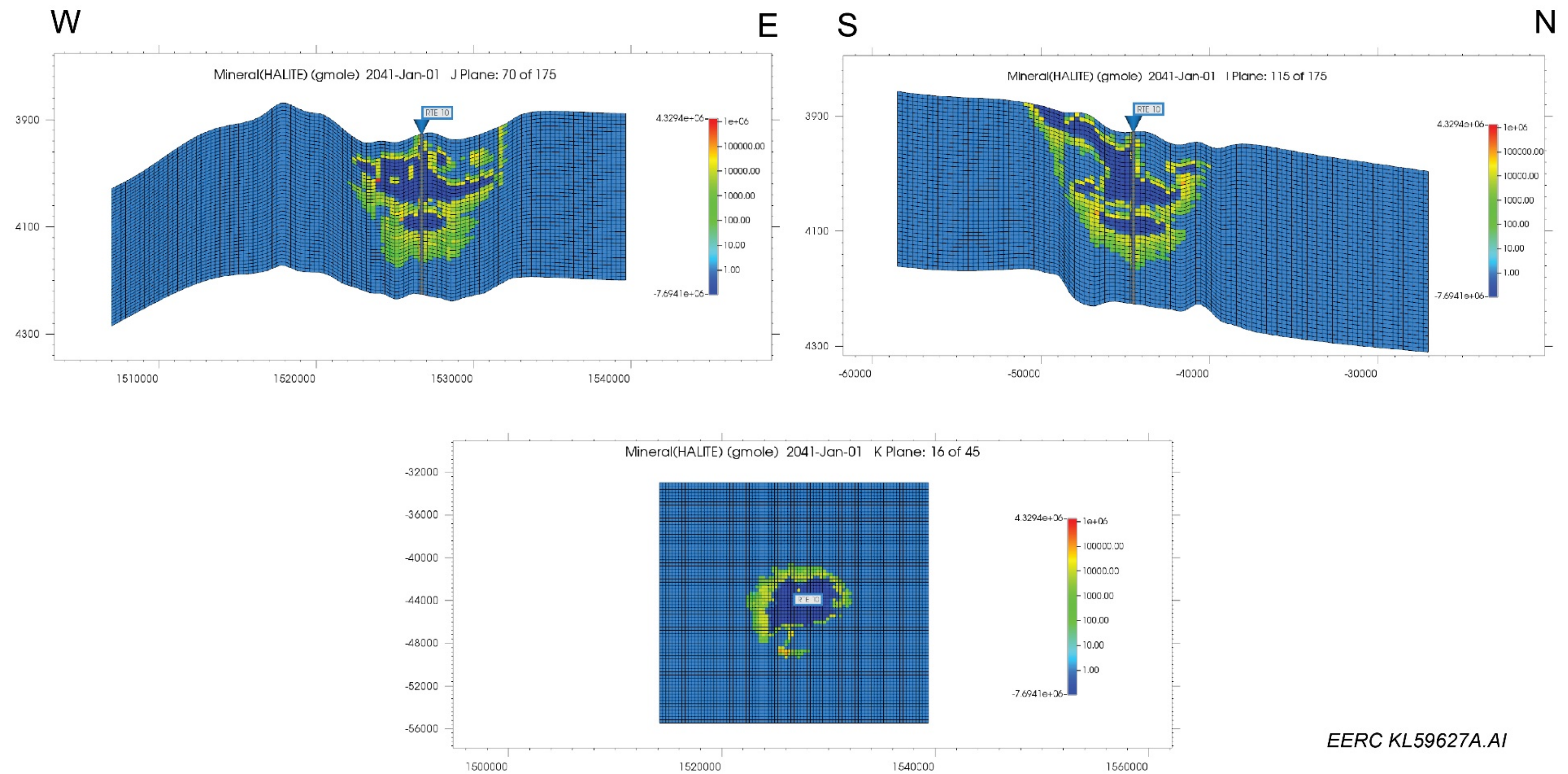


Figure 2-20a. Molar distribution of key dissolved and precipitated minerals at the end of the injection period. Dissolution of halite is shown by the dark blue color. Compare to the molar CO_2 distribution in the left side of Figure 2-18a. Some reprecipitation of halite is indicated in lower and peripheral areas of the reservoir, as shown by areas of green and yellow color.

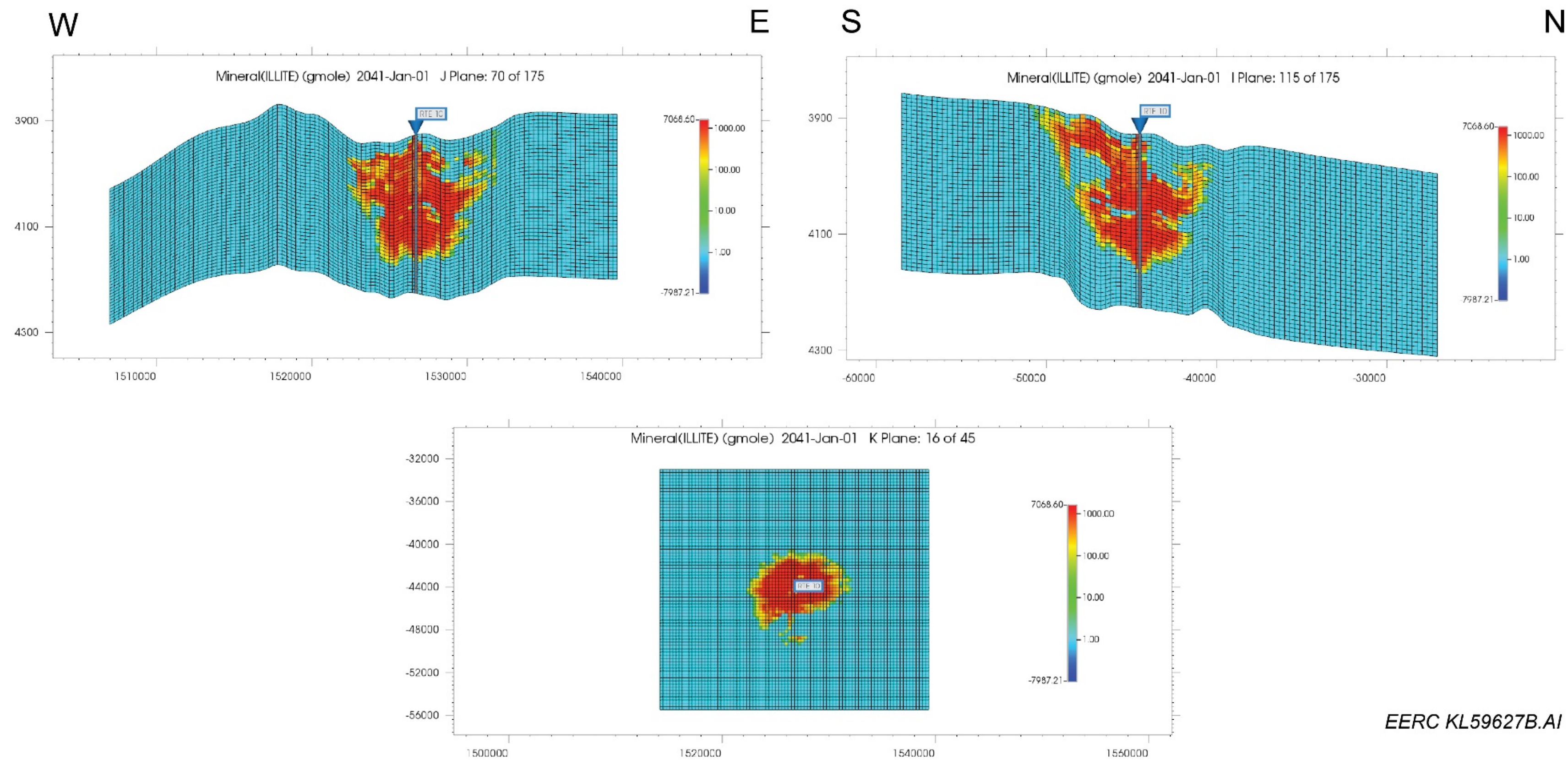


Figure 2-20b. Molar distribution of key dissolved and precipitated minerals at the end of the injection period. Illite precipitation is indicated throughout the affected area of the reservoir.

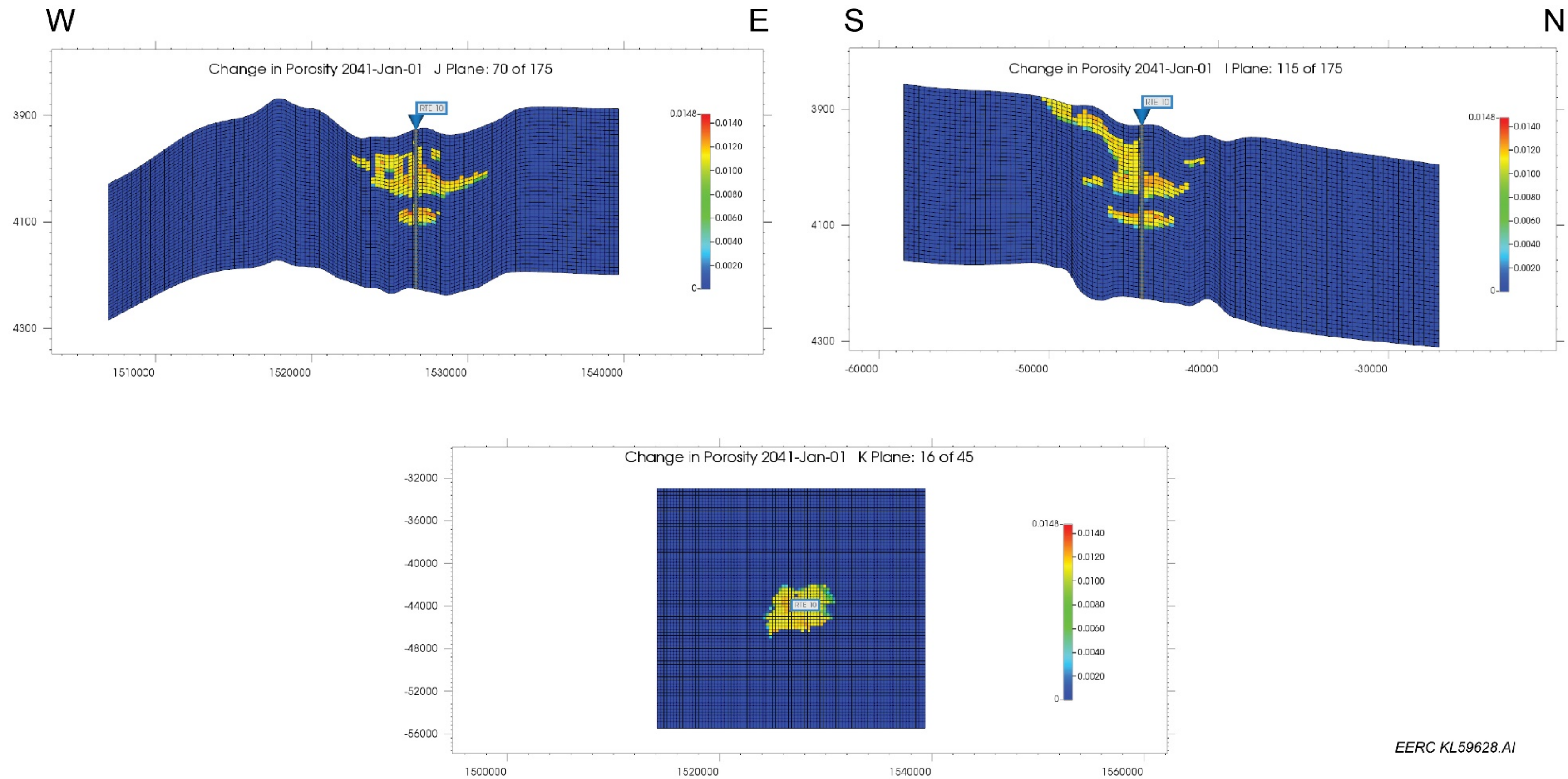


Figure 2-21. Change in porosity due to geochemical dissolution after the 20-year injection period (compare to the molar CO_2 distribution in the left side of Figure 2-18).

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Opeche Formation and underlying Amsden Formation (Figure 2-2, Table 2-10). Both the Amsden and the Opeche Formations consist of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	
Formation Top Depth, ft	6,276	
Thickness, ft	103	329
Porosity, % (core data)	4.01 (1.36–9.89)*	6.13 (2.25–9.24)*
Permeability, mD (core data)	0.0046 (0.0029–0.0056)**	0.0267 (0.017–0.059)**
Capillary Entry Pressure (GW), psi	27.1	23.8
Depth below Lowest Identified USDW, ft	4307	4708

* Porosity values are reported as the arithmetic mean followed by the range of values in parenthesis.
** Permeability values are reported as the geometric mean followed by the range of values in parenthesis.

2.4.1 Upper Confining Zone

In the RTE project area, the Opeche Formation consists of silty mudstone with interbedded fine sandstone and anhydrite. The Opeche is laterally extensive across the project area (Figures 2-22 and 2-23) and is 6276 ft below the land surface and 103 ft thick at the RTE site (Table 2-10 and Figure 22-24a). The contact between the underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-25).

This document includes the requested supplemental thickness maps for the Opeche Formation. Figure 2-24a displays the estimated thickness of the Opeche Formation in the RTE project area. The interpolated Opeche Formation surface used to generate this map was based on formation top data (NDIC and site-specific), while the Broom Creek Formation horizon was based upon seismic data and formation top data. Figure 2-24b illustrates the thickness of the Opeche Formation using only interpreted seismic horizons. Convergent interpolation with Schlumberger's Petrel software was used to interpolate the surfaces used in Figures 2-24a and 2-24b.

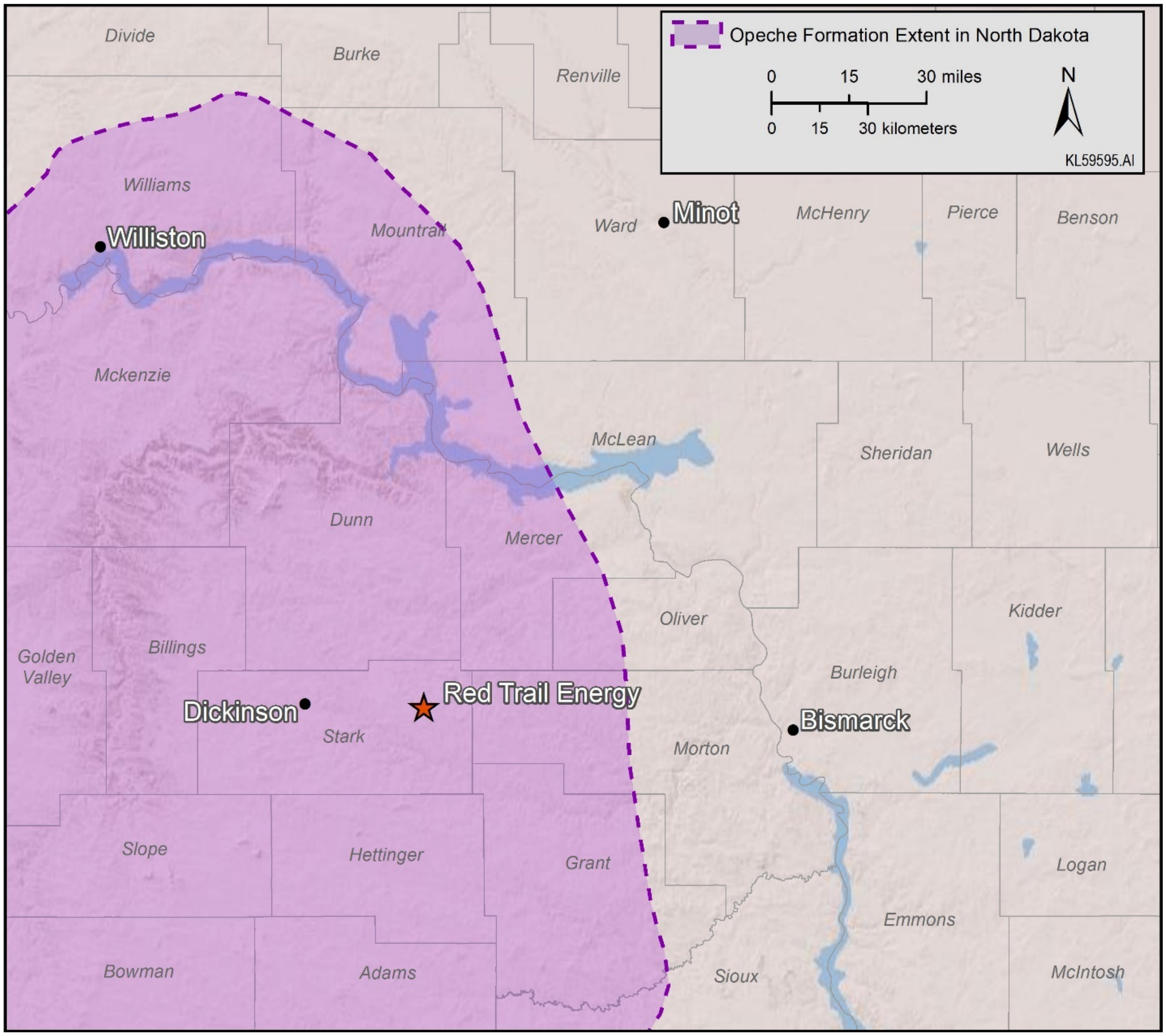


Figure 2-22. Areal extent of the Opeche Formation in western North Dakota. Extent is derived from Carlson (1993).

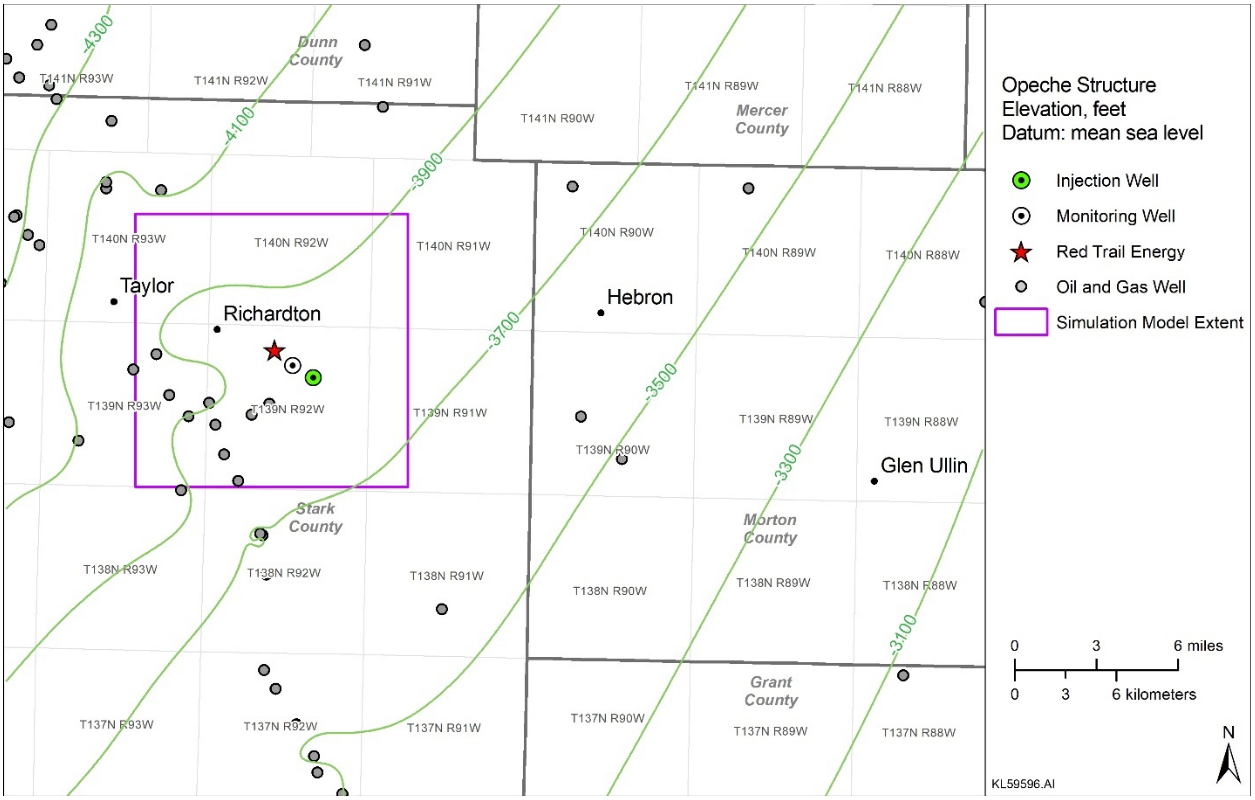


Figure 2-23. Structure map of the Opeche Formation across the greater RTE project area.

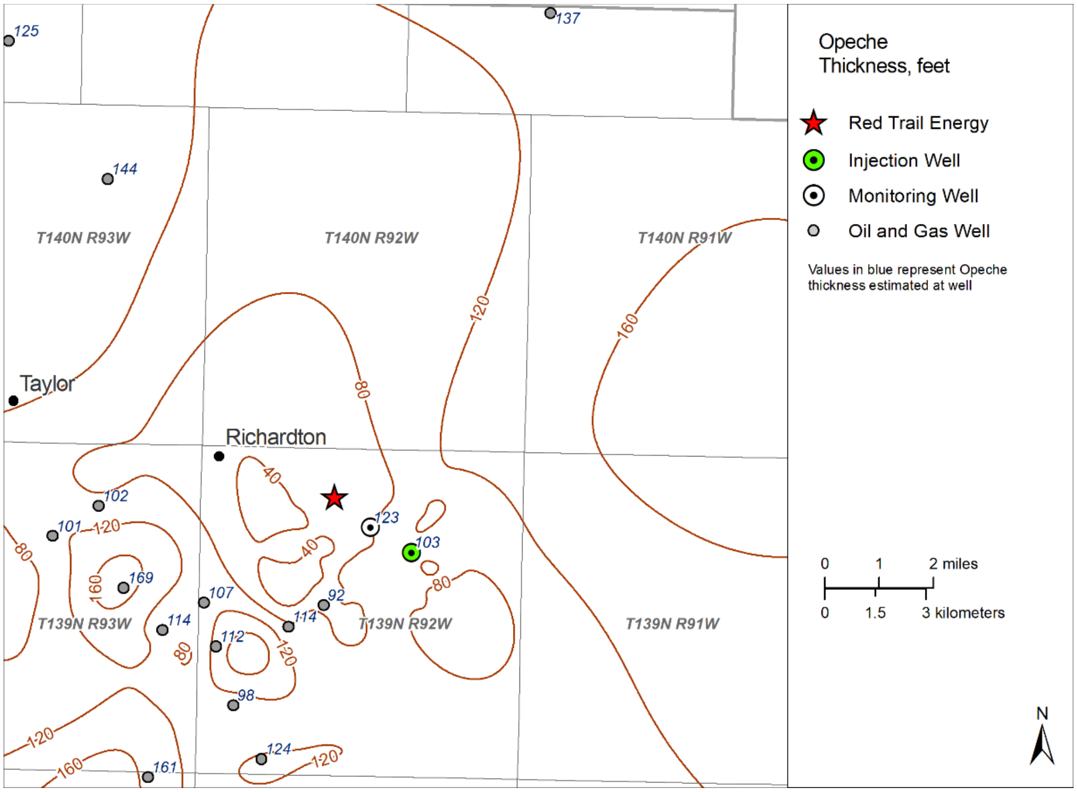


Figure 2-24a. Thickness map of the Opeche Formation in the RTE project area. Estimated thickness for each well is shown in blue text.

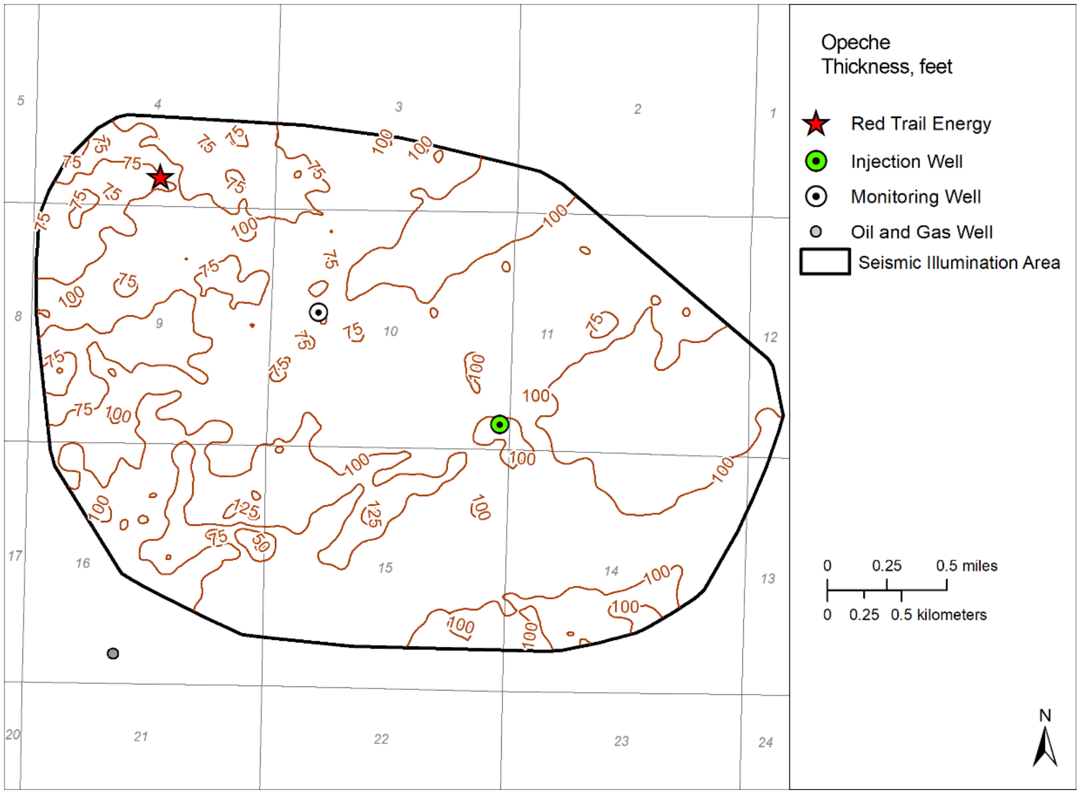


Figure 2-24b. Thickness map of the Opeche Formation in the RTE area. Thicknesses were calculated using interpreted seismic horizons.

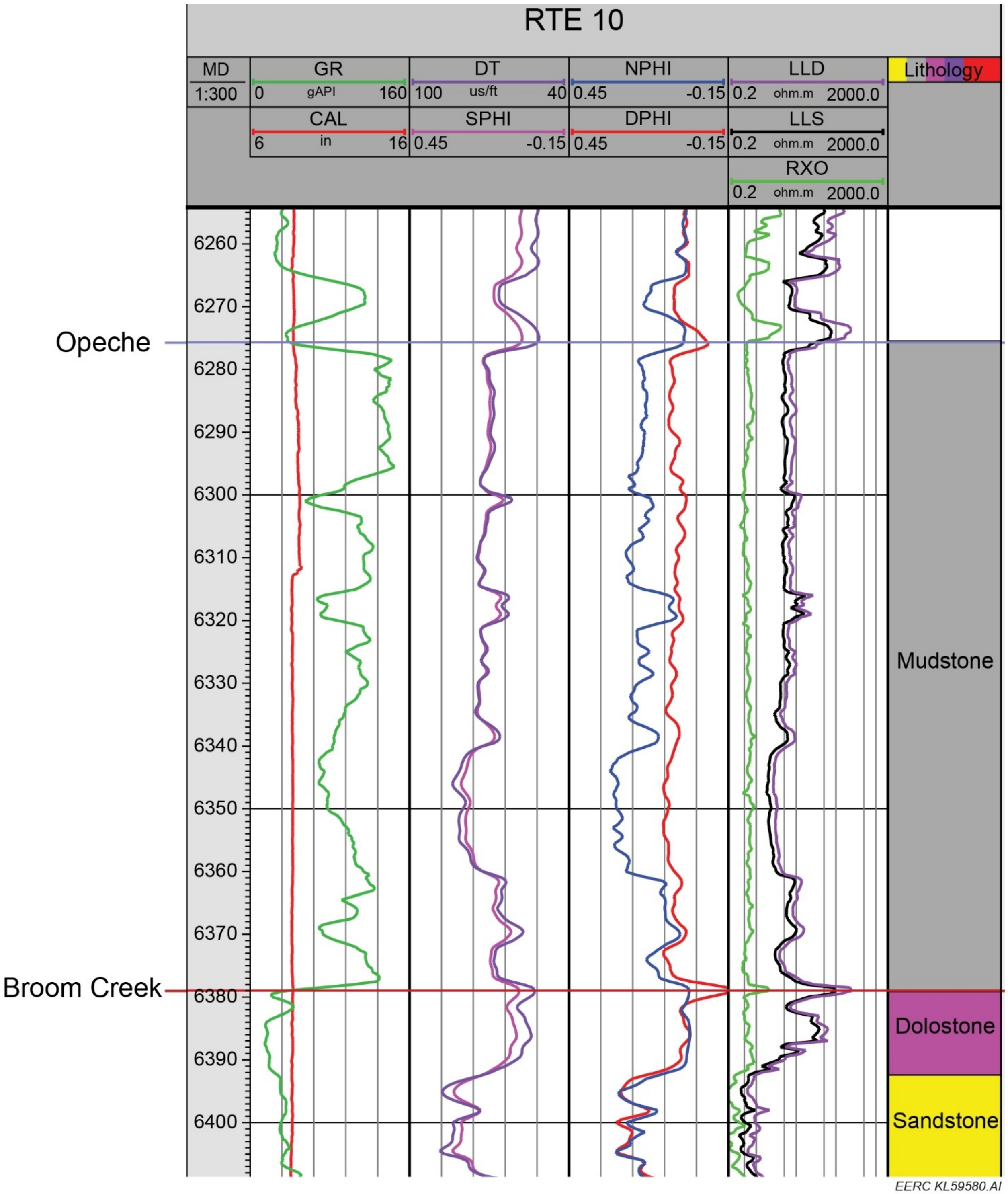


Figure 2-24. Well log display of the Opeche Formation at the RTE-10 well.

Microfracture tests were performed via an MDT tool in RTE-10 near the base of the Opeche Formation (Table 2-11). The MDT test results showed a fracture initiation pressure of 7,677 psi at a depth of 6,376 ft in the Opeche Formation. Two other microfracture tests in the Opeche were attempted at depths of 6,288 and 6,291 ft. The instruments recorded a pump pressure of 8,900 psi without generating a fracture. The tests were discontinued at this pressure because of concerns maintaining the seals of the confining packers. Section 2.2.2.4 discusses this in more detail.

Table 2-11. Opeche Microfracture Results from RTE-10

Depth, ft	6,376	
Pressure/Gradient	psi	psi/ft
Initiation/Breakdown	7,677	1.20
Propagation	4,874	0.77
Closure	4,624	0.73

Laboratory measurements from 11 Opeche Formation core samples taken from the RTE-10 well have porosity values ranging from 1.36% to 9.89% and permeability values from <0.001 to 0.0086 mD (Table 2-12). The lithology of the cored sections of the Opeche is primarily silty mudstone with interbedded fine sandstone and anhydrite.

Table 2-12. Opeche Core Sample Porosity and Permeability from RTE-10

Sample Depth, ft	Porosity, %	Permeability, mD
6,318	2.55	<0.001
6,320	2.3	<0.01
6,342	1.96	<0.001
6,366	3	<0.001
6,372	5.25	0.0086
6,379	9.89	0.0056
6,381	6.89	0.0030
6,382	4.79	0.0032
6,382.5	1.36	<0.001
6,383.5	2.15	<0.001
Range	1.36–9.89	<0.001–0.0086

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche Formation comprises alternating intervals of silty mudstone, argillaceous siltstone, mudstone, and anhydrite. In all, 11 thin sections were created covering greater than 60 ft of the Opeche. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The grains are almost always surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. The porosity ranges between 1% and 3%.

XRD data from 11 samples from the RTE-10 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, dolomite, and anhydrite.

XRF analysis of the Opeche Formation shown in Figure 2-26 identifies the major chemical constituents to be dominated by SiO_2 (30%–60%), Al_2O_3 (3%–10%), CaO (5%–40%), and MgO (1%–16%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by XRD. Two samples toward the base of the Opeche show high percentages of CaO and SO_3 attributed to an interval of anhydrite separating the two formation. This correlates with XRD, core description, and thin-section analysis.

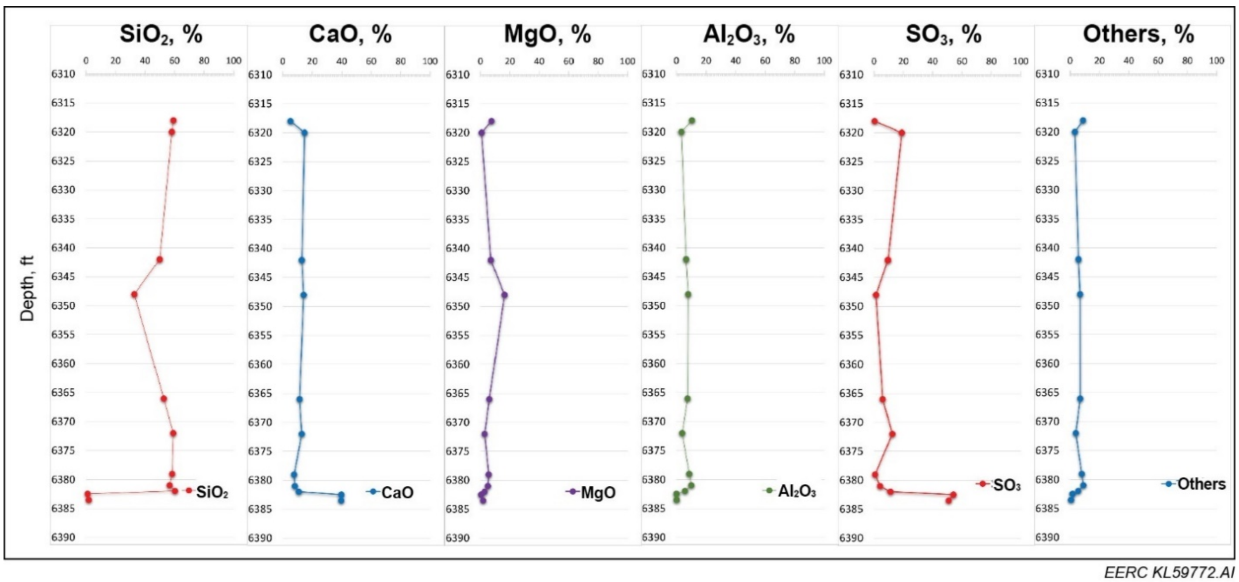


Figure 2-26. XRF data for the Opeche Formation from RTE-10.

2.4.1.2 Geochemical Interaction

Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by diffusion processes. Results were monitored at 1-meter increments above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche determined from XRD analysis was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). This composition was determined from analysis of fluid samples from the RTE-10 well. CO_2 stream composition was as provided by RTE (Table 2-9). Three different CO_2 exposure levels of the CO_2 stream to the cap rock (1.15, 2.3, and 4.5 moles/yr) were used. These values are considerably higher than the actual expected exposure levels. This was done to ensure that the degree and pace of geochemical change would not be underestimated. These three simulations were run for 45 years to represent 20 years of injection plus 25 years postinjection. The simulations were performed at reservoir pressure and temperature conditions.

Table 2-13. XRD Results for RTE-10 Opeche Core Sample from 6,381 feet

Mineral Data	%
Albite	15.8
Anhydrite	3.5
Chlorite	3.2
Dolomite	20.8
Illite	11.8
K-Feldspar	15
Quartz	29.9

Table 2-14. Formation Water Chemistry from Broom Creek Fluid Samples from RTE-10

Parameter	Result, mg/L	Parameter	Result, mg/L
Alkalinity, as Bicarbonate (HCO_3^-)	129	Iron	1.4
Alkalinity, as Carbonate ($CO_3^=$)	0	Potassium	991
Alkalinity, as Hydroxide (OH^-)	0	Lithium	13.3
Boron	21.8	Magnesium	487
Barium	0.405	Sodium	56,900
Bromide	79.4	Lead	0.023
Dissolved Inorganic Carbon (DIC)	25.3	Sulfate	1,990
Dissolved Organic Carbon (DOC)	587	Strontium	131
Calcium	3,490	Zinc	1.07
Chloride	97,300	TDS	164,000

Results showed geochemical processes at work, but even at extreme exposure levels, these processes did not extend more than 3 meters up into the cap rock during the simulation period. Figures 2-27–2-29 show results from the most extreme exposure case. Figure 2-27 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH declines to a level of 4.6 before recovering to a value of 5.25. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH only begins to change after Year 35. Figure 2-28 shows change in mineral dissolution and precipitation in grams. Dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are from Cell C2, 1 to 2 meters into the cap rock. Any effects in Cell C3 are too small to represent at this scale. Figure 2-29 shows change in porosity of the cap rock. Cell 1 experiences a rapid increase in porosity as it is first exposed to CO_2 due to dissolution. The porosity then decreases around Year 9 due to precipitation. As precipitation occurs in Cell 1, reaction products move into Cell 2 where they precipitate, causing decreased porosity. When CO_2 reaches Cell 2 at Year 9, dissolution occurs, increasing the porosity. Note the scale of percent porosity change, ~0.00001%. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results show that exposure to CO_2 will not cause deterioration of the Opeche cap rock.

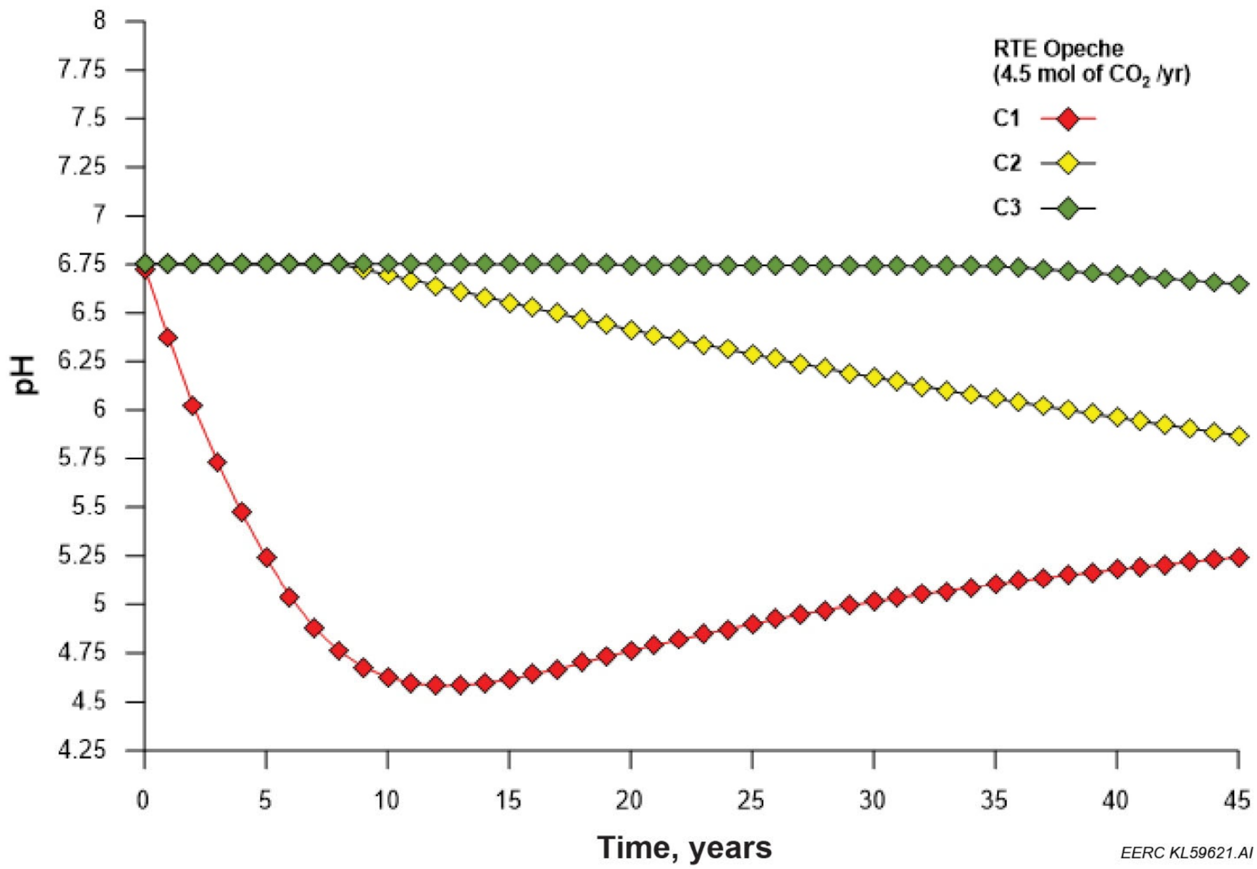


Figure 2-27. Change in fluid pH vs. time. Red line shows pH for Cell C1, 0 to 1 meter above the Opeche cap rock base. Yellow line shows Cell C2, 1 to 2 meters above the cap rock base. Green line shows Cell C3, 2 to 3 meters above the cap rock base. pH for Cell C3 does not begin to change until after 35 years. For cases with lower exposure levels, pH for Cell C3 does not change at all.

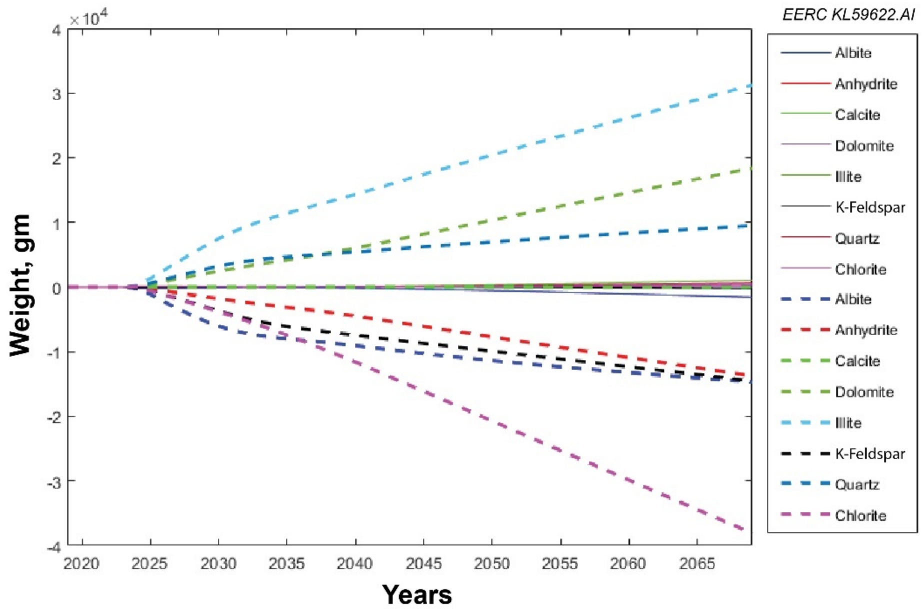


Figure 2-28. Dissolution and precipitation of minerals in the Opeche cap rock. Dashed lines show results for Cell C1, 0 to 1 meter above the cap rock base. Solid lines show results for Cell C2, 1 to 2 meters above the cap rock base; changes are barely visible. Results from Cell C3, 2 to 3 meters above the cap rock base, are not shown as they are too small to be seen.

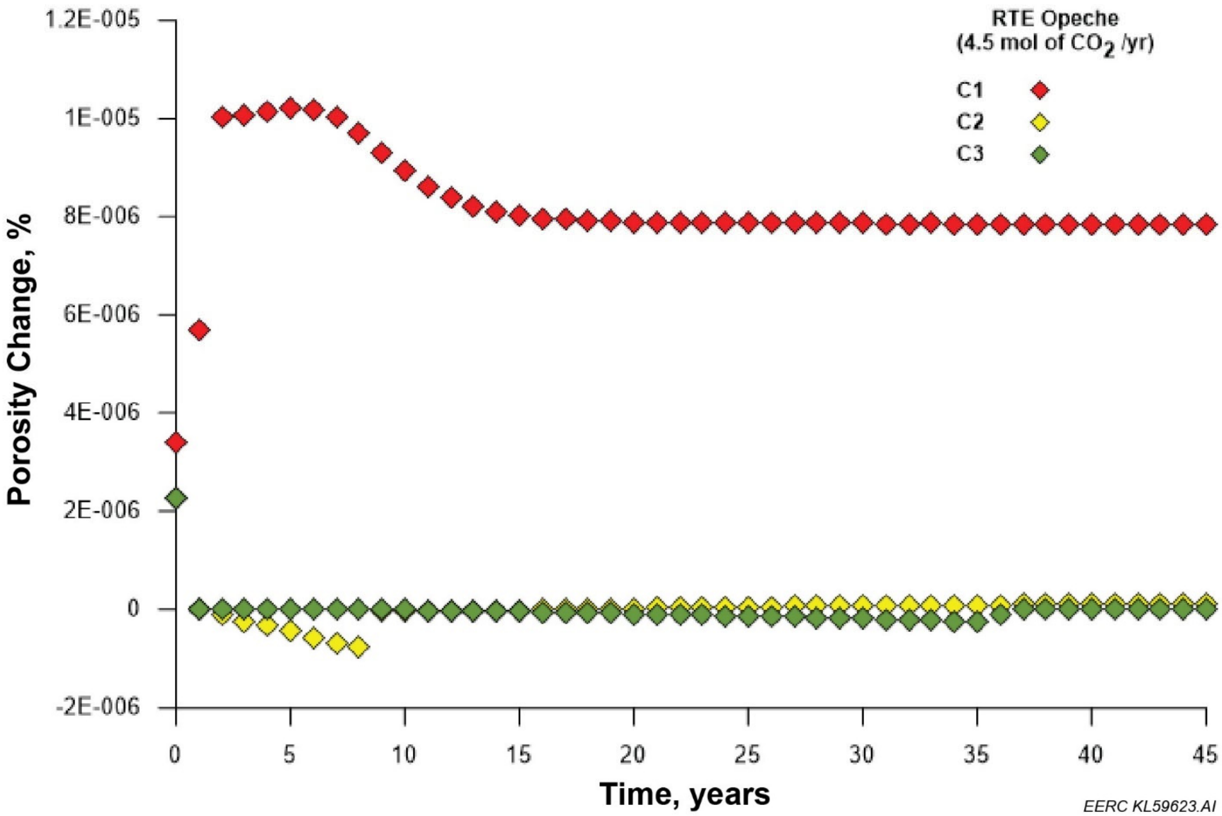


Figure 2-29. Change in percent porosity of the Opeche cap rock. Red line shows porosity change for Cell C1, 0 to 1 meter above the cap rock base. Yellow line shows Cell C2, 1 to 2 meters above the cap rock base. Green line shows Cell C3, 2 to 3 meters above the cap rock base. Long-term change in porosity is miniscule and stabilized.

2.4.2 Additional Overlying Confining Zones

Several additional formations provide additional confinement above the Opeche Formation. Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Opeche, these formations are 1,200 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-30). Above the Inyan Kara Formation, 3,000 ft of impermeable rocks acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-31). Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).

Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the RTE-10 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,969	2,063	0
Greenhorn	Shale	4,032	435	2,063
Mowry	Shale	4,467	314	2,498
Inyan Kara	Sandstone	4,781	345	2,812
Swift	Shale	5,125	494	3,156
Rierdon	Shale	5,619	173	3,650
Piper Kline	Limestone	5,792	139	3,823
Piper Picard	Shale	5,931	68	3,962
Spearfish	Siltstone	5,999	230	4,030
Minnekahta	Limestone	6,229	47	4,260

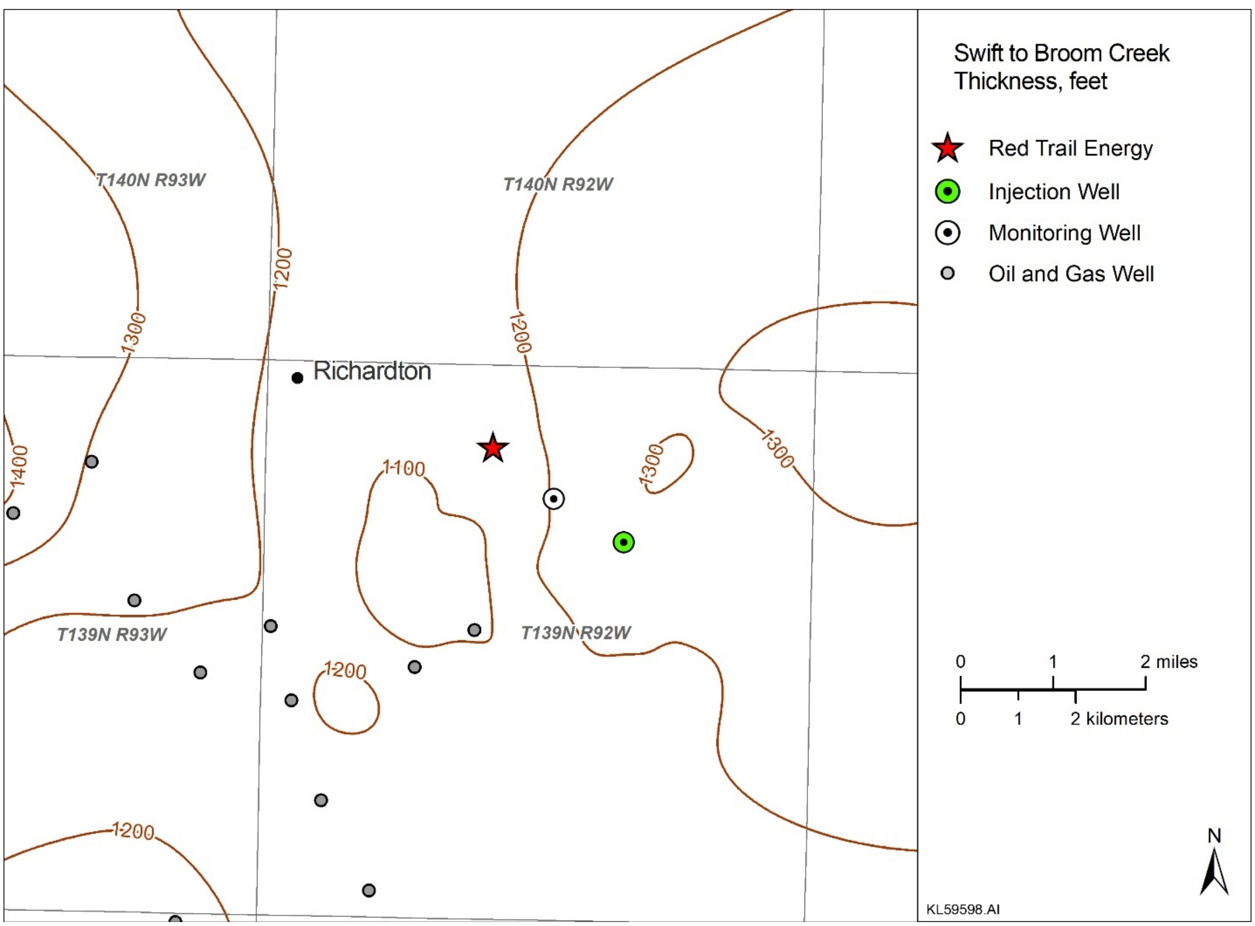


Figure 2-30. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

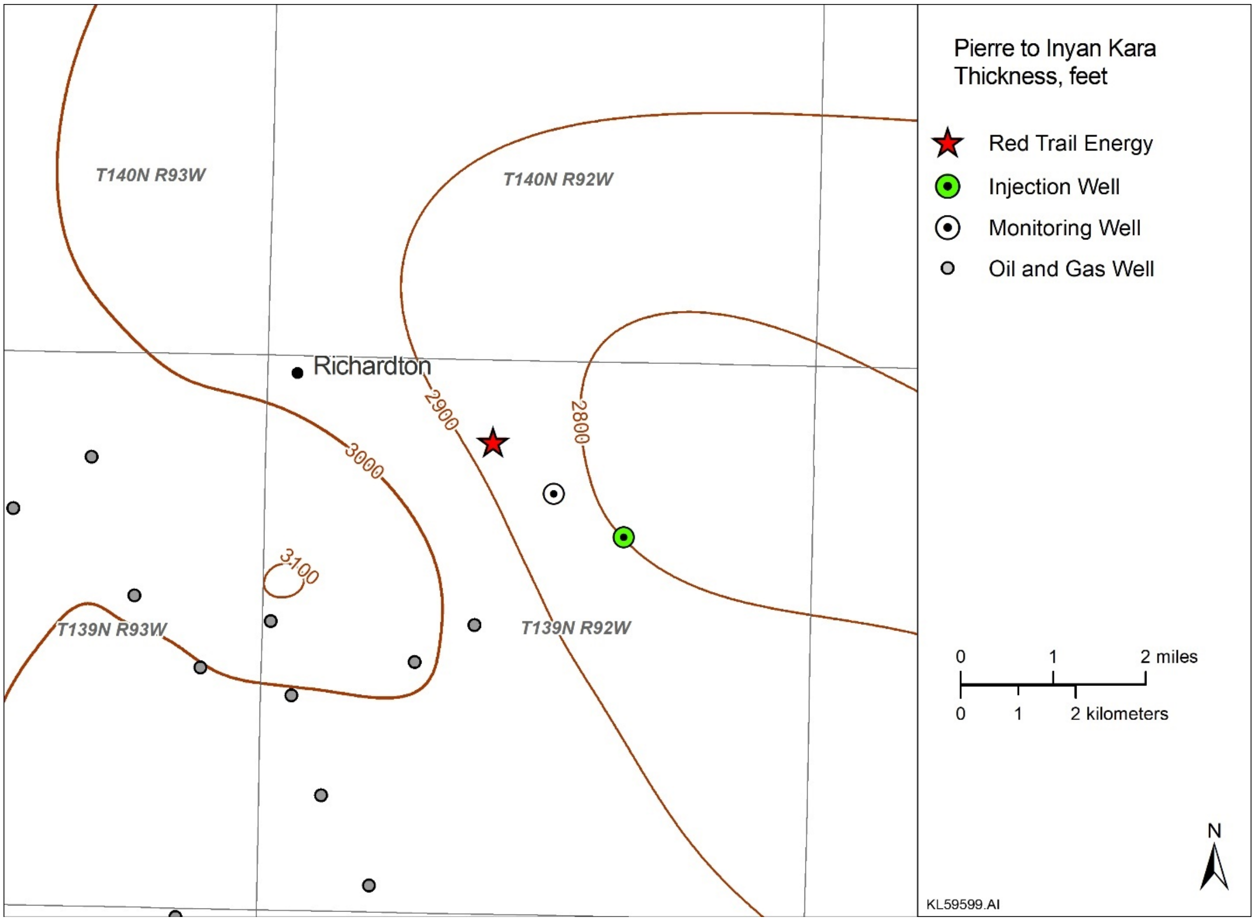


Figure 2-31. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin.

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara. Monitoring the Inyan Kara Formation provides an additional opportunity for monitoring, mitigation, and remediation (Section 4). The depth to the Inyan Kara Formation in the project area is approximately 4,800 ft, and the formation itself is about 350 ft thick.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that could be correlated across the project area (Figures 2-32 and 2-33). The Amsden Formation is 6,677 ft below land surface and 329 ft thick at the RTE site (Table 2-10).

Figure 2-32. Structure map of the Amsden Formation across the greater RTE project area.

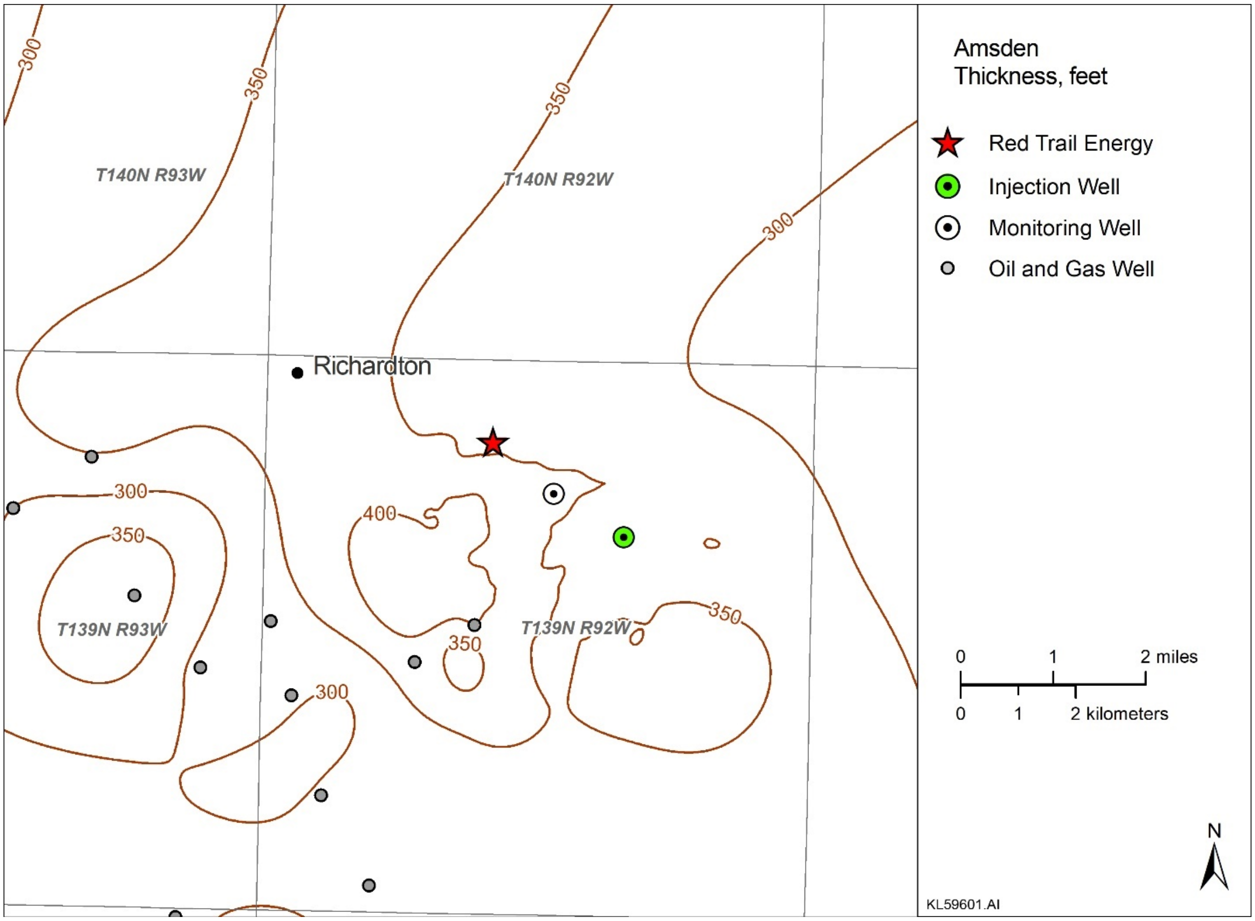


Figure 2-33. Isopach map of the Amsden Formation across the RTE project area.

The contact between the overlying Broom Creek and Amsden is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from RTE-10. The lithology of the cored section of the Amsden from RTE-10 is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Three feet below the contact with the Broom Creek is an 11-ft-thick anhydrite layer. Data acquired from the seven core plug samples taken from the Amsden show porosity values ranging from 2.25% to 9.24% and permeability values from <0.001 to 0.595 mD (Table 2-16).

Table 2-16. Amsden Core Sample Porosity and Permeability from RTE-10

Sample Depth, ft	Porosity %	Permeability, mD
6,684	2.25	<0.001
6,691	8.75	<0.001
6,698	6.85	0.0186
6,706	8.71	0.0595
6,708	9.24	0.0173
6,714	4.26	<0.001
6,721	2.87	<0.001
Range	2.25–9.24	<0.001–0.595

2.4.3.1 Mineralogy

Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. The dolomite is expressed by very fine- to fine-grained dolostone (90%), with the presence of quartz of variable size and shape, feldspar, clay, and iron oxides. The porosity is very low and is mainly due to the dissolution of feldspar and quartz. The porosity averages 5% (Table 2-16).

Anhydrite is present as beds that separate the dolomite intervals. It is composed of needles of anhydrite with minor inclusions of iron oxides. Also, dolomite and quartz are present and found filling rare fractures. The porosity is almost null.

The sandy dolomite is mainly composed of dolomite and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite cement. The porosity is mainly due to the dissolution of feldspar and averages 5%.

Finally, the shaly sandstone comprises quartz, clay, and dolomite. A minor presence of feldspar, anhydrite, and iron oxides exists. The grains of quartz and anhydrite are almost always separated by the dolomite cement and clay minerals. The porosity is very low, averaging 5% and is mainly due to the dissolution of feldspar and quartz.

XRD was performed, and the results confirm the observations made during core analyses and thin-section description.

XRF data show the Amsden Formation has the same major chemical constituents as the Opeche Formation (Figure 2-34). However, the formation at the contact with the Broom Creek is dominated by CaO and SO_3 (major chemical elements of anhydrite). As the formation gets deeper, the chemistry changes to a more carbonate-rich siltstone, as shown by the high percentage of SiO_2, CaO, and MgO.

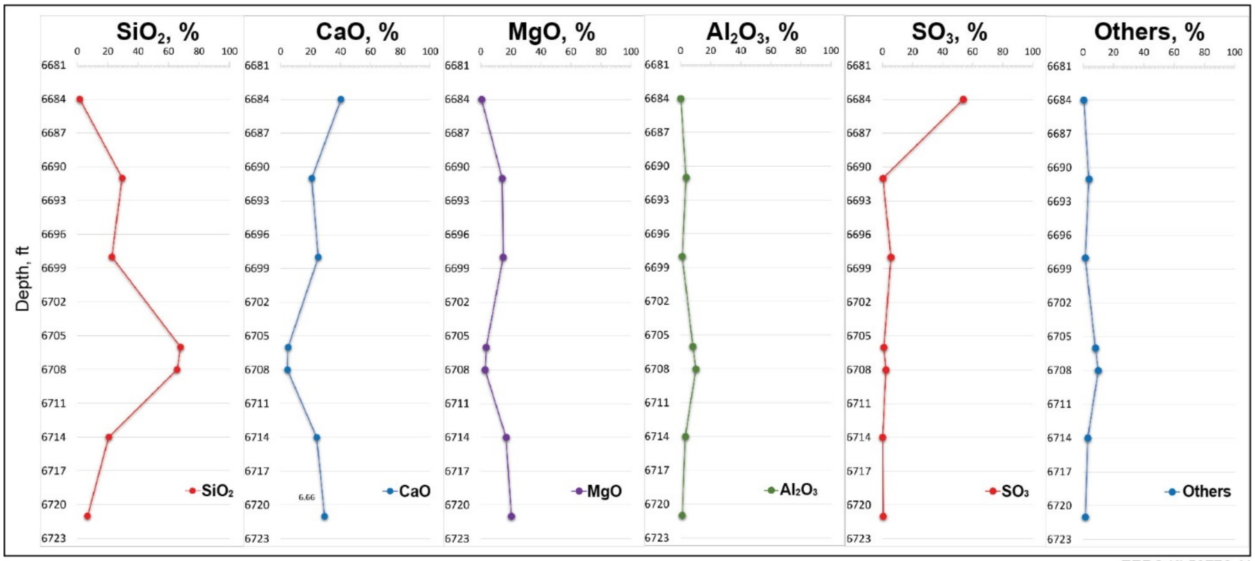


Figure 2-34. XRF data for the Amsden Formation from the RTE-10 well.

2.4.3.2 Geochemical Interaction

Review of simulation results of the Broom Creek Formation suggest that neither free-phase CO_2 saturation nor CO_2 dissolved in formation brine will come in contact with the Amsden Formation. Therefore, no geochemical reaction effects are anticipated in the Amsden.

2.4.4 Geomechanical Information of Confining Zone

2.4.4.1 Fracture Analysis

Fractures within the Opeche Formation, the overlying confining zone, and Amsden Formation, the underlying confining zone, have been assessed during the description of the RTE-10 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural, in situ fractures were assessed through the interpretation of the FMI log acquired during the drilling of the RTE-10 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche Formation are primarily closed and are commonly filled with anhydrite. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter scale.

In the Amsden Formation, closed tension fractures are commonly coincident with the horizontal compaction features (stylolite) observed. Calcite is the dominant mineral found to fill observable fractures. Very few-to-no connected fractures were observed in the Amsden core interval from the RTE well.

2.4.4.3 Borehole Image Fracture Analysis (FMI)

Schlumberger's FMI log was chosen to evaluate the geomechanical condition of the formation in the subsurface. This log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed.

Figures 2-35a and 2-35b show two sections of the interpreted borehole imagery and the primary features observed. The far-right track on Figure 2-35a notes the presence of electrically resistive features. These are interpreted as minor anhydrite-filled fractures. Figure 2-35b demonstrates that the tool provides information on surface boundaries and bedding features. Some isolated fractures are identified in Figure 2-35b and are likely clay-filled because of their electrically conductive signal. Figures 2-36a and 2-36b show two thin-section images and give an indication of different minerals within the reservoir and observed change in the electrical response shown on the FMI log.

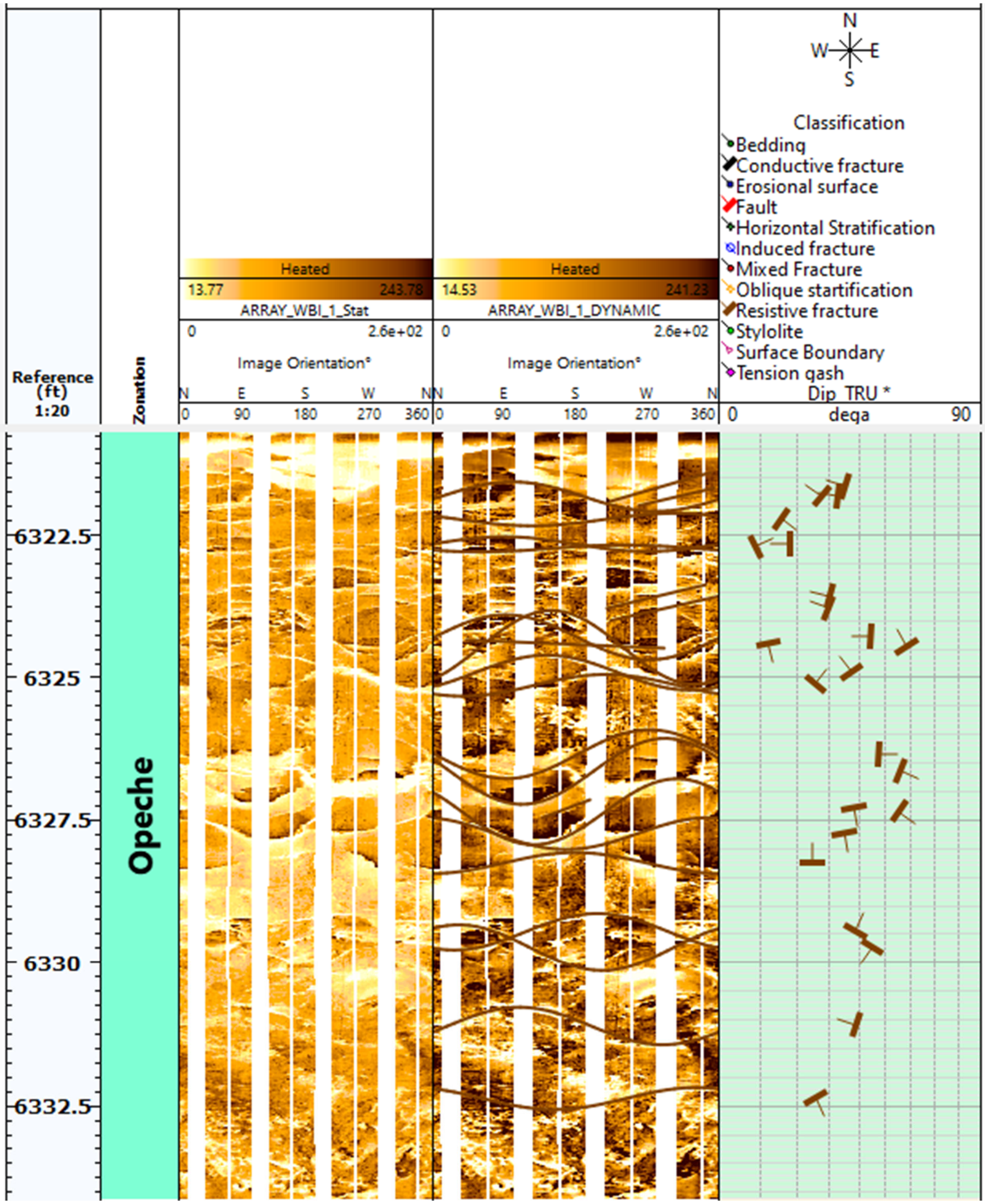


Figure 2-35a. Examples of the interpreted FMI log for the RTE-10 well. Two examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

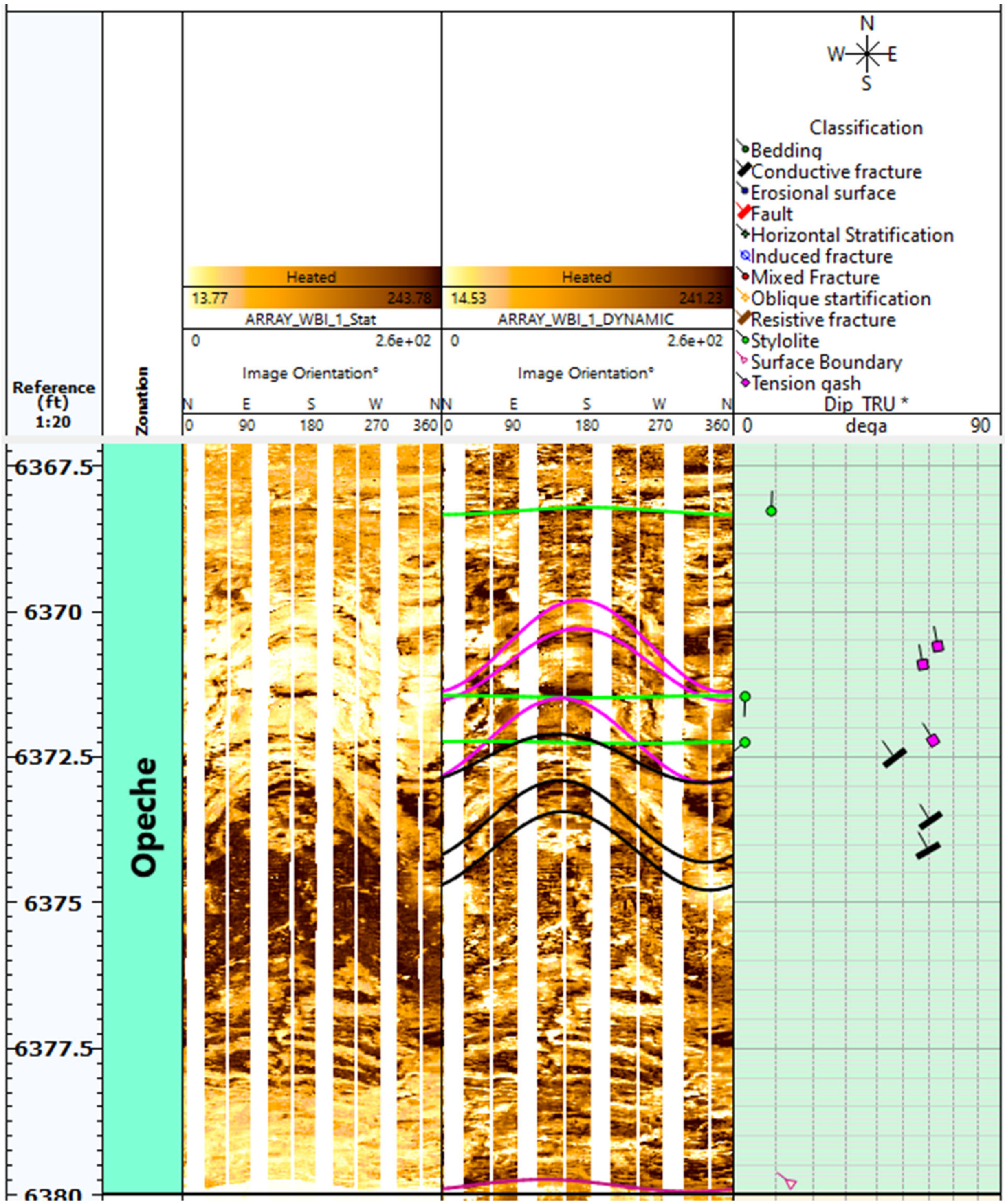


Figure 2-35b. Examples of the interpreted FMI log for the RTE-10 well. Two examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis.

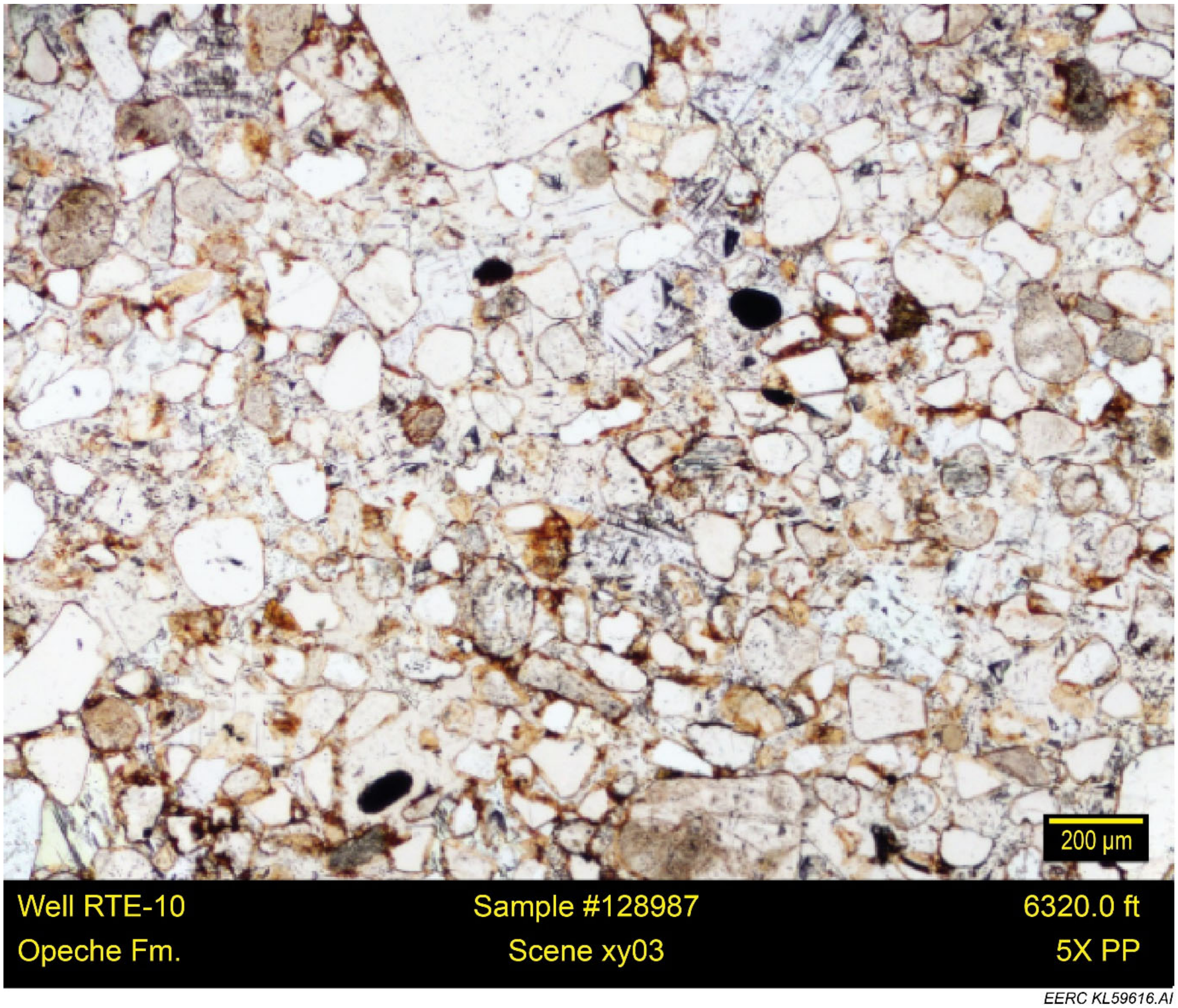


Figure 2-36a. Plane-polarized light thin-section images from the RTE well Opeche Formation. This image shows the silt-rich nature of this interval of the Opeche Formation. On the example shown, the quartz grains (white) are rimmed by iron.

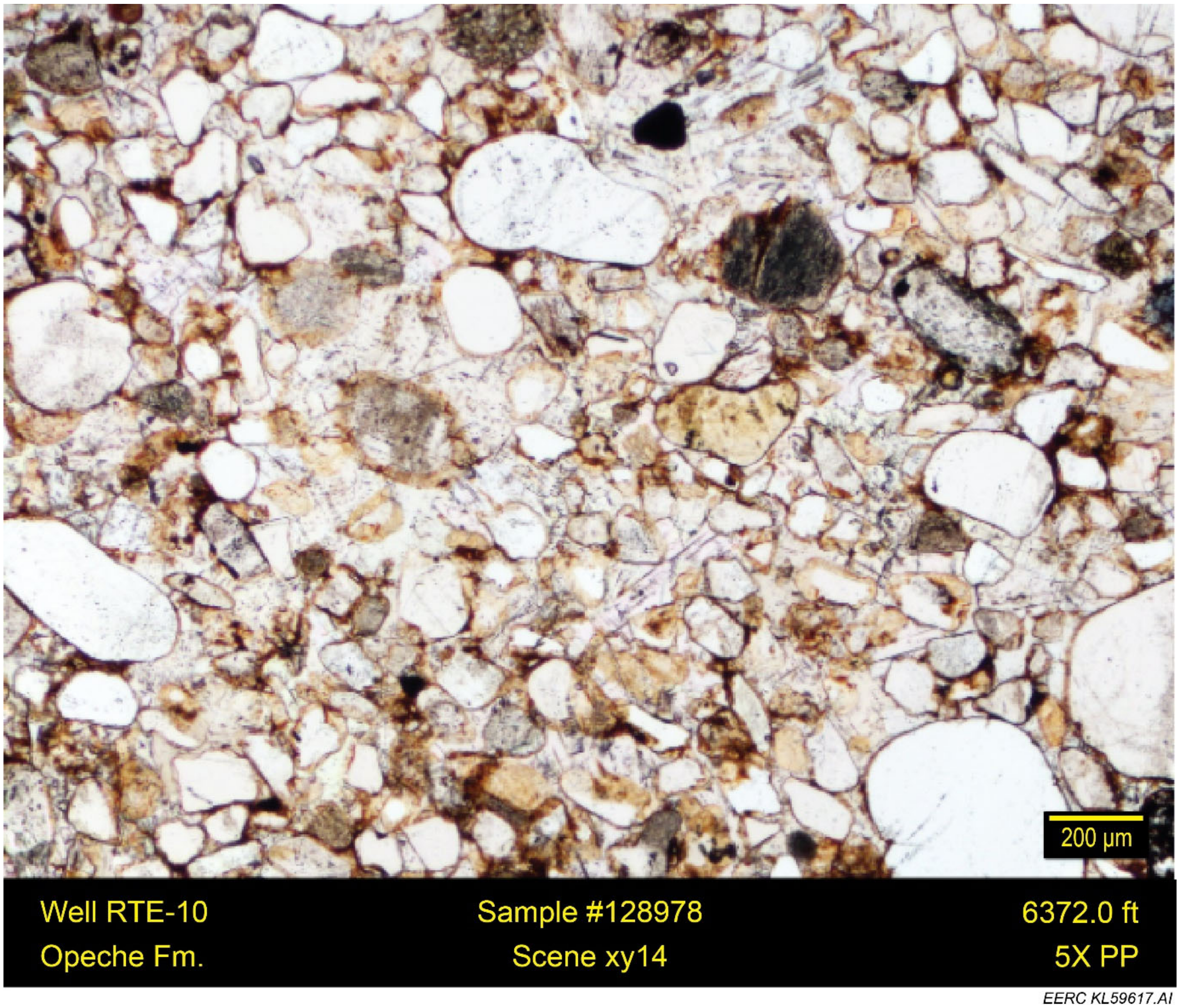


Figure 2-36b. Plane-polarized light thin-section images from the RTE well Opeche Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white quartz grains) is clay and is likely responsible for the electrical conductivity identified on the FMI log.

Finally, Figure 2-37 shows the logged interval for the entire Opeche Formation. As shown, the section closest to the Broom Creek (6377 ft) is dominated by compaction features (stylolites) and has corresponding tensional features, as noted in the core description analysis. The observed stylolites are parallel to bedding and are commonly filled with clay minerals. Effectively, these features reduce the porosity of a formation. The midregion of the formation is dominated by

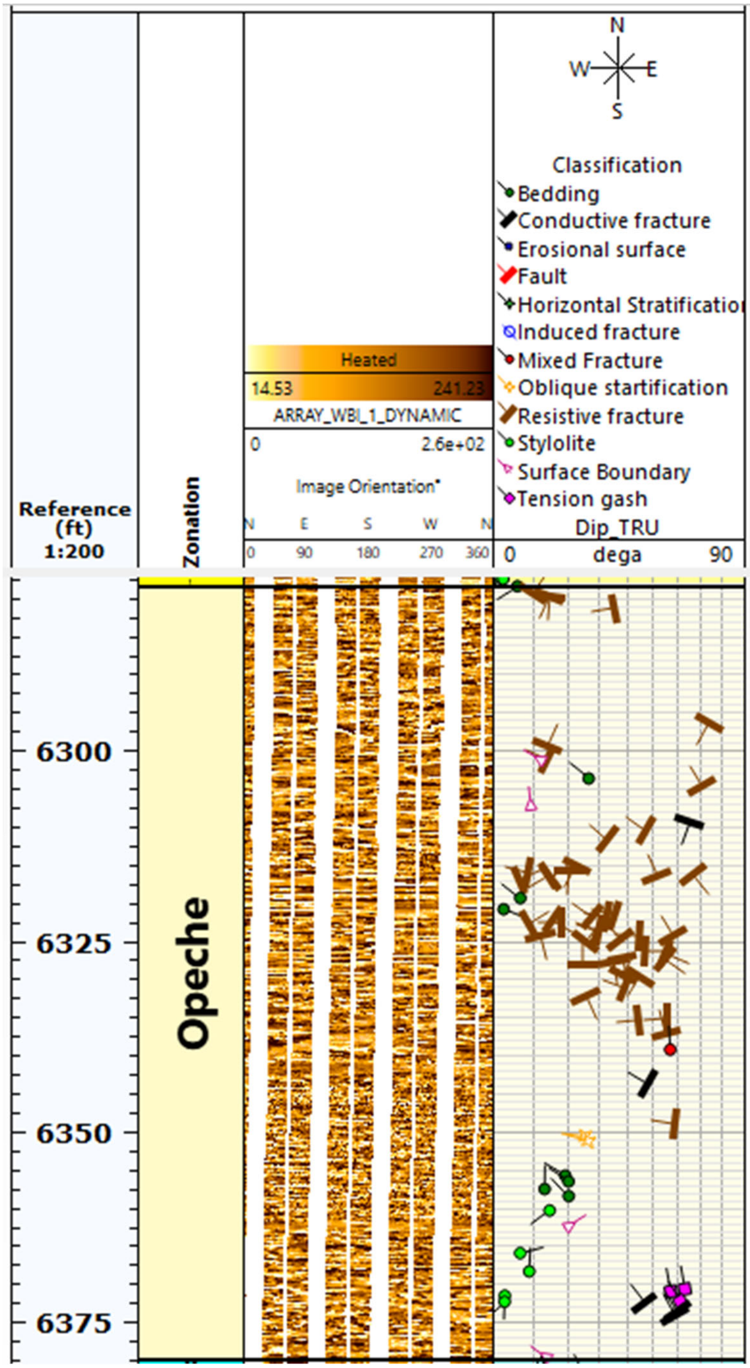


Figure 2-37. Interpreted FMI log through the lower Opeche Formation.

electrically resistive features likely due to the presence of anhydrite-filled fractures. Toward the upper portion of the formation, fractures are fewer in number but are still found to be electrically resistive. The diagrams shown in Figures 2-38 and 2-39 provide the orientation of the electrically conductive and resistive fractures in the Opeche Formation. As shown, the electrically conductive fractures are fewer in number and are mainly oriented NW–SE. On the other hand, the resistive fractures have no preferred orientation.

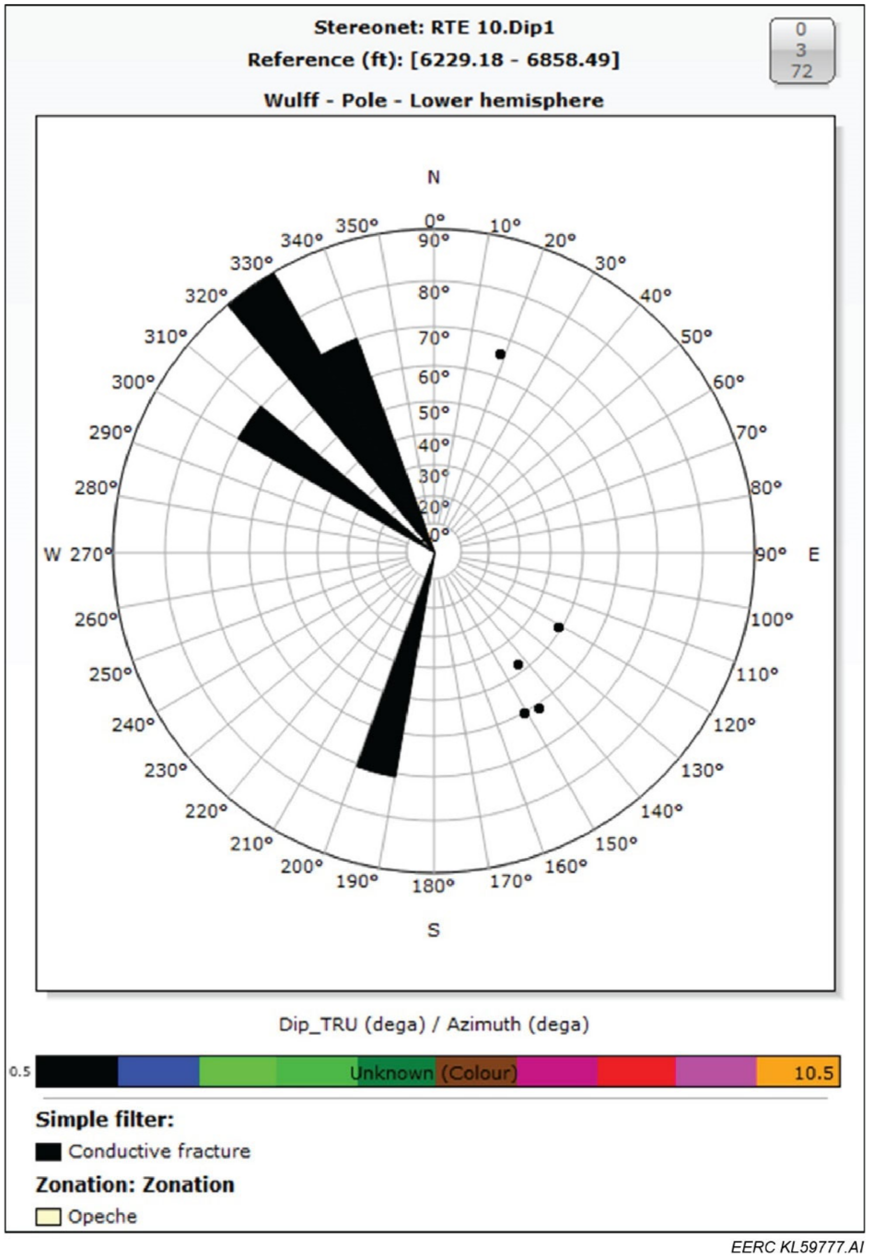


Figure 2-38. Conductive fracture dip orientation in the Opeche Formation.

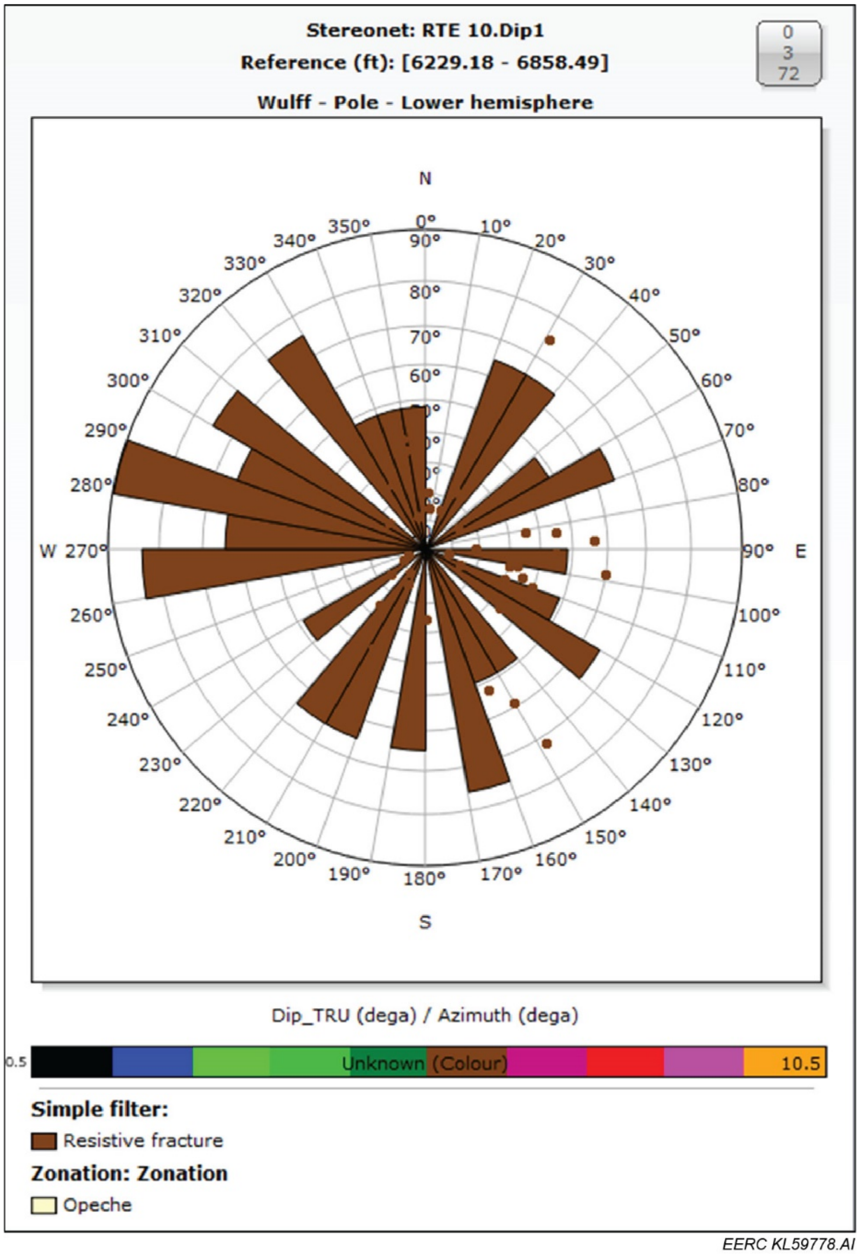


Figure 2-39. Resistive fracture dip orientation in the Opeche Formation.

The logged interval of the Amsden shows that the main features present are stylolite–tension pairs, an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. Two zones at 6,743 and 6,762 ft, respectively, show some evidence of resistive fractures (Figure 2-40). Core was not retrieved from this depth. The interpretation of this logged interval supports the core-based and thin-section descriptions, suggesting these features are anhydrite-filled. The rose diagrams shown in Figures 2-41 and 2-42 provide the orientation of the conductive and resistive features in the Amsden Formation. As shown, only one electrically conductive feature was picked in the Amsden interval and is oriented NE–SW. Some electrically resistive features are present and oriented N–S, NE–SW, and E–W, respectively. Drilling-induced fractures were identified mainly in the Amsden Formation and are oriented NE–SW (Figure 2-43), parallel to the maximum horizontal stress (SH_{max}).

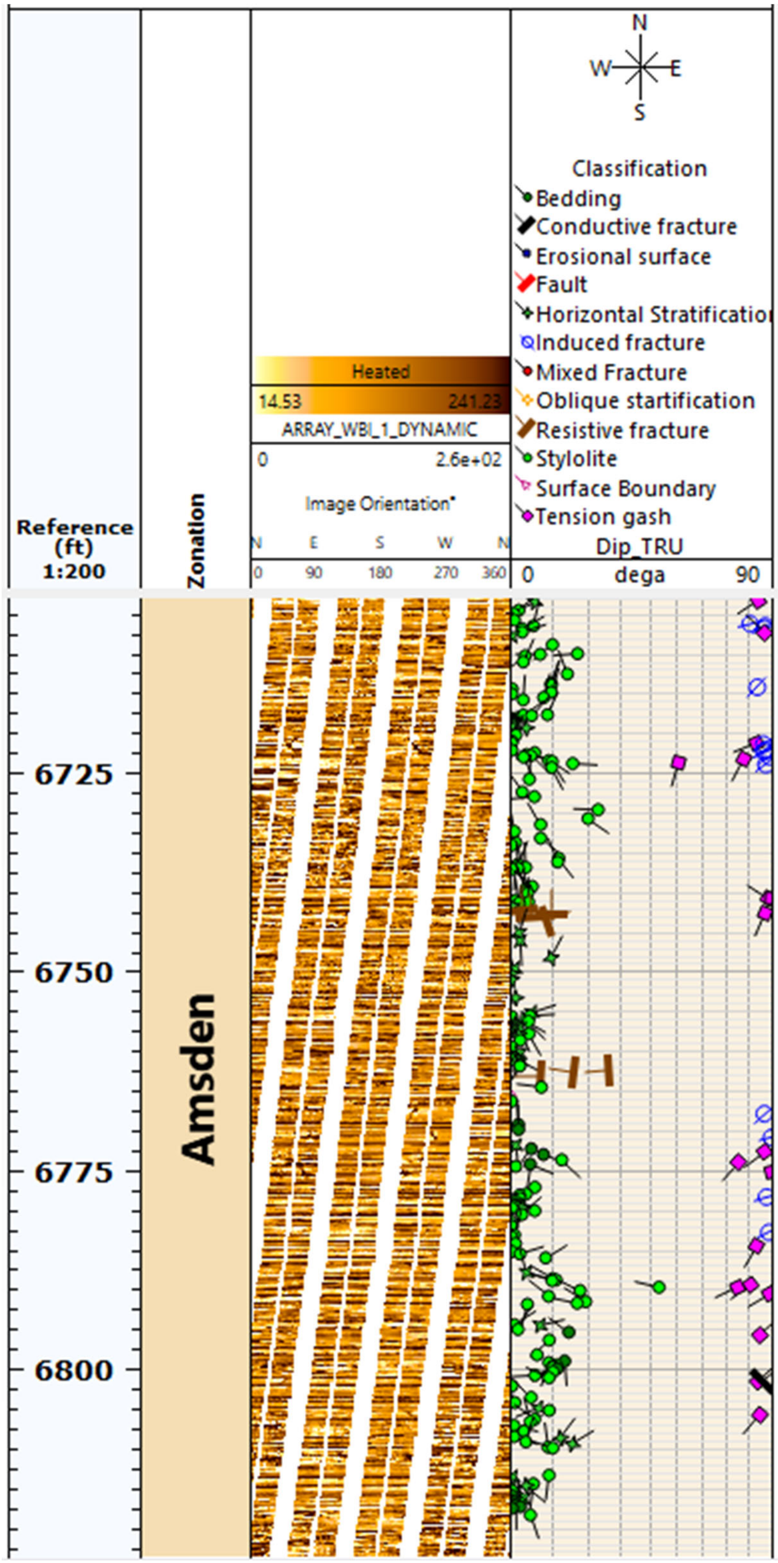


Figure 2-40. Interpreted FMI log through the upper Amsden Formation.

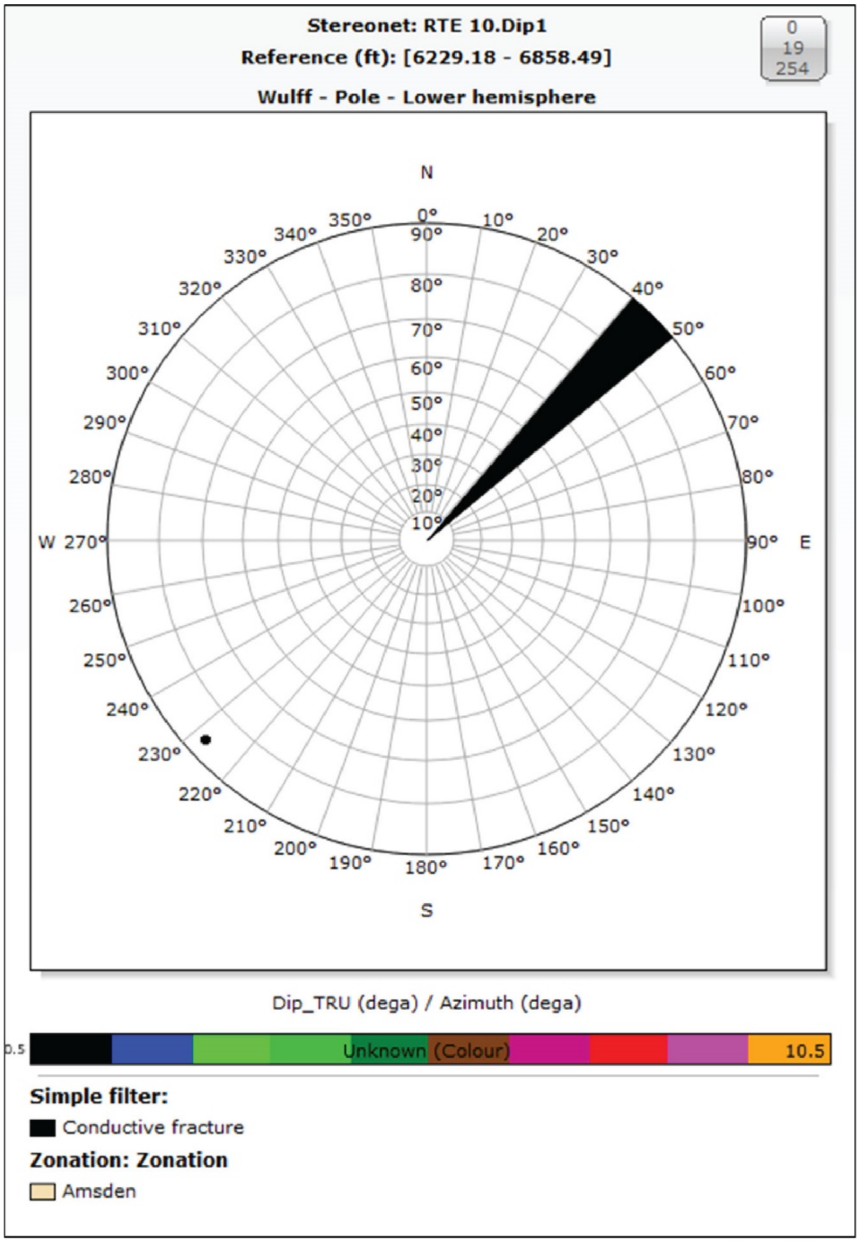


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Figure 2-41. Conductive fracture dip orientation in the Amsden Formation.

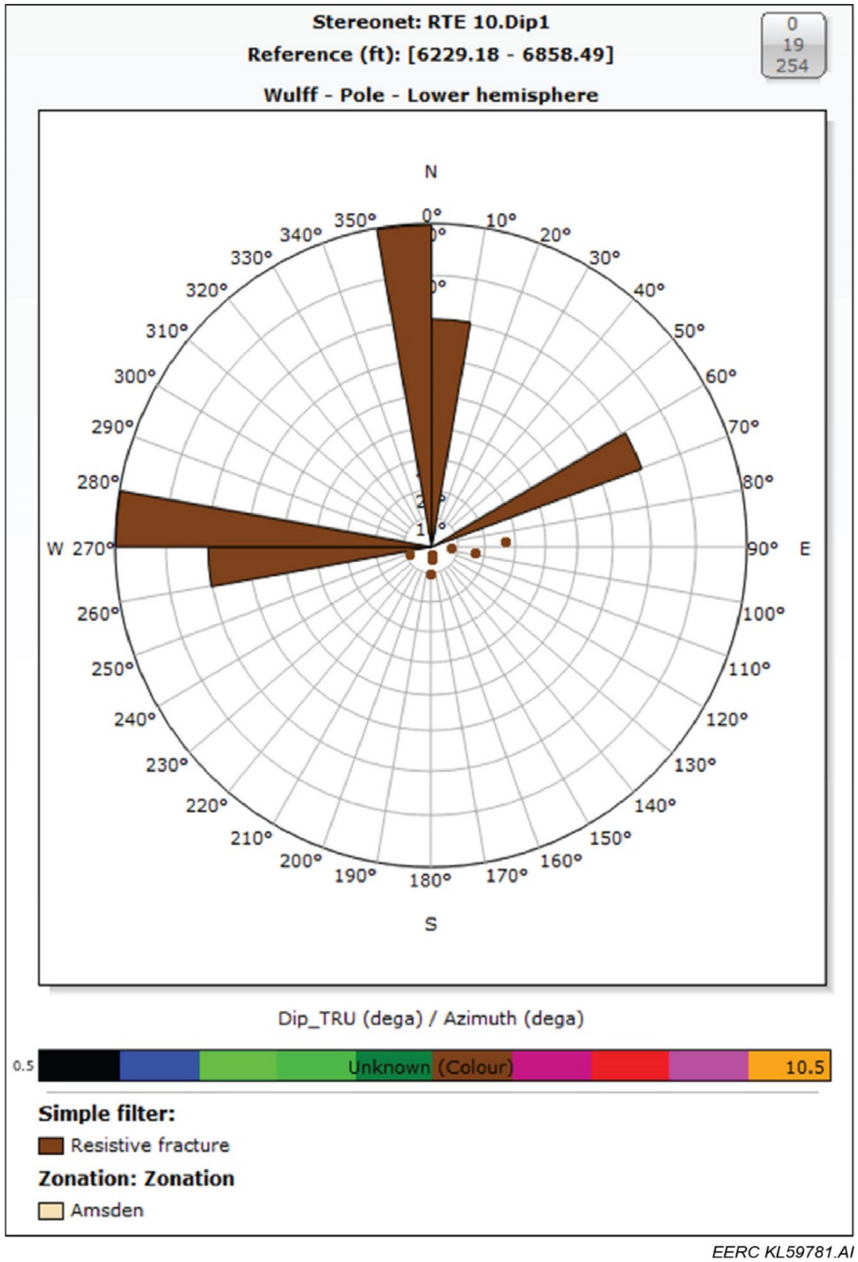

Figure 2-42. Resistive fracture dip orientation in the Amsden Formation.

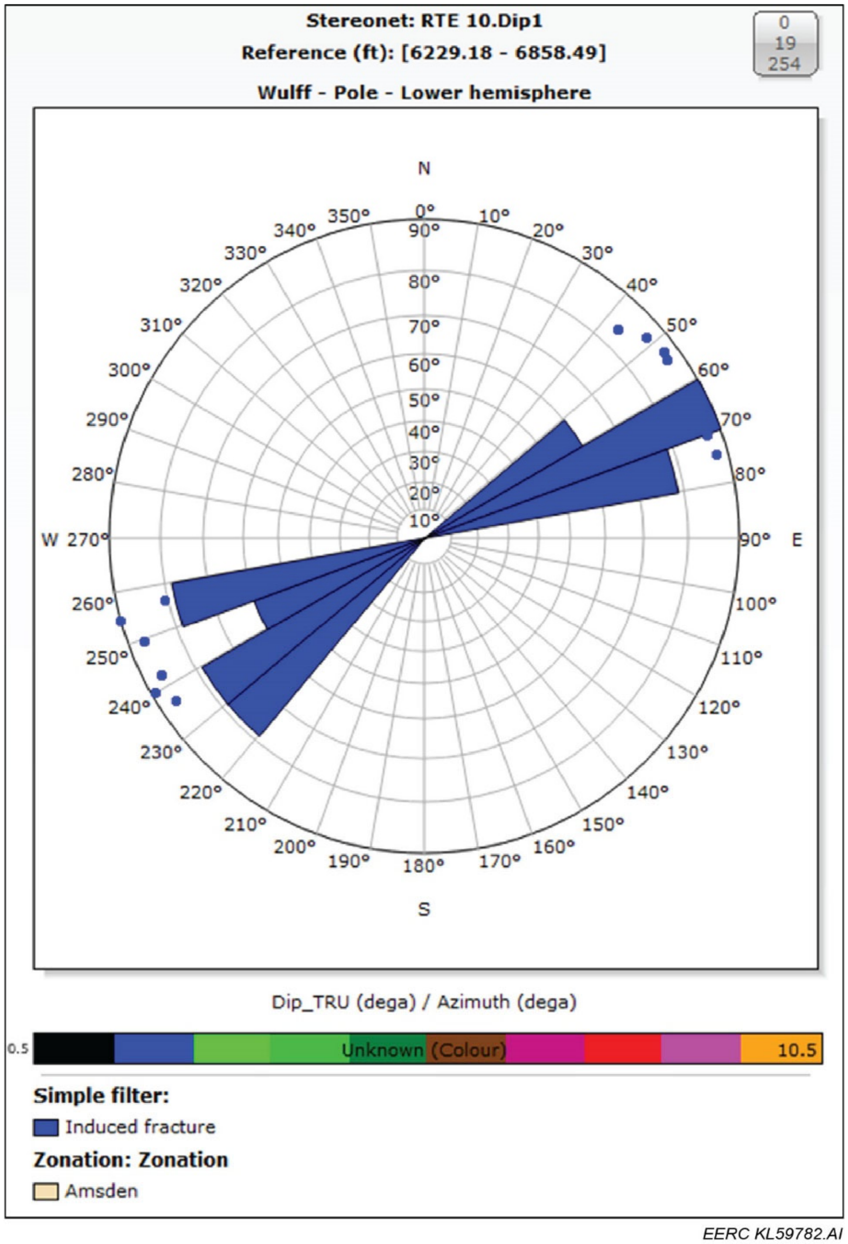

Figure 2-43. Drilling-induced fractures dip orientation in the Amsden Formation.

2.4.4.4 Stress

During drilling of the RTE-10 well, an openhole MDT minifrac was completed to determine the minimum horizontal stress of the formation. The minifrac operation was performed using a dual-packer setup where four minifrac tests were successful among the seven conducted. The induced fractures observed in the Amsden Formation have an orientation NE–SW, parallel to the maximum horizontal stress. Figure 2-44 shows an annotated example of an expected result in the determination of minimum horizontal stress during MDT applications. As shown, the combined insight gained from the propagation pressure, closure pressure, and reopening pressure define the minimum horizontal stress in the subsurface (Figure 2-44).

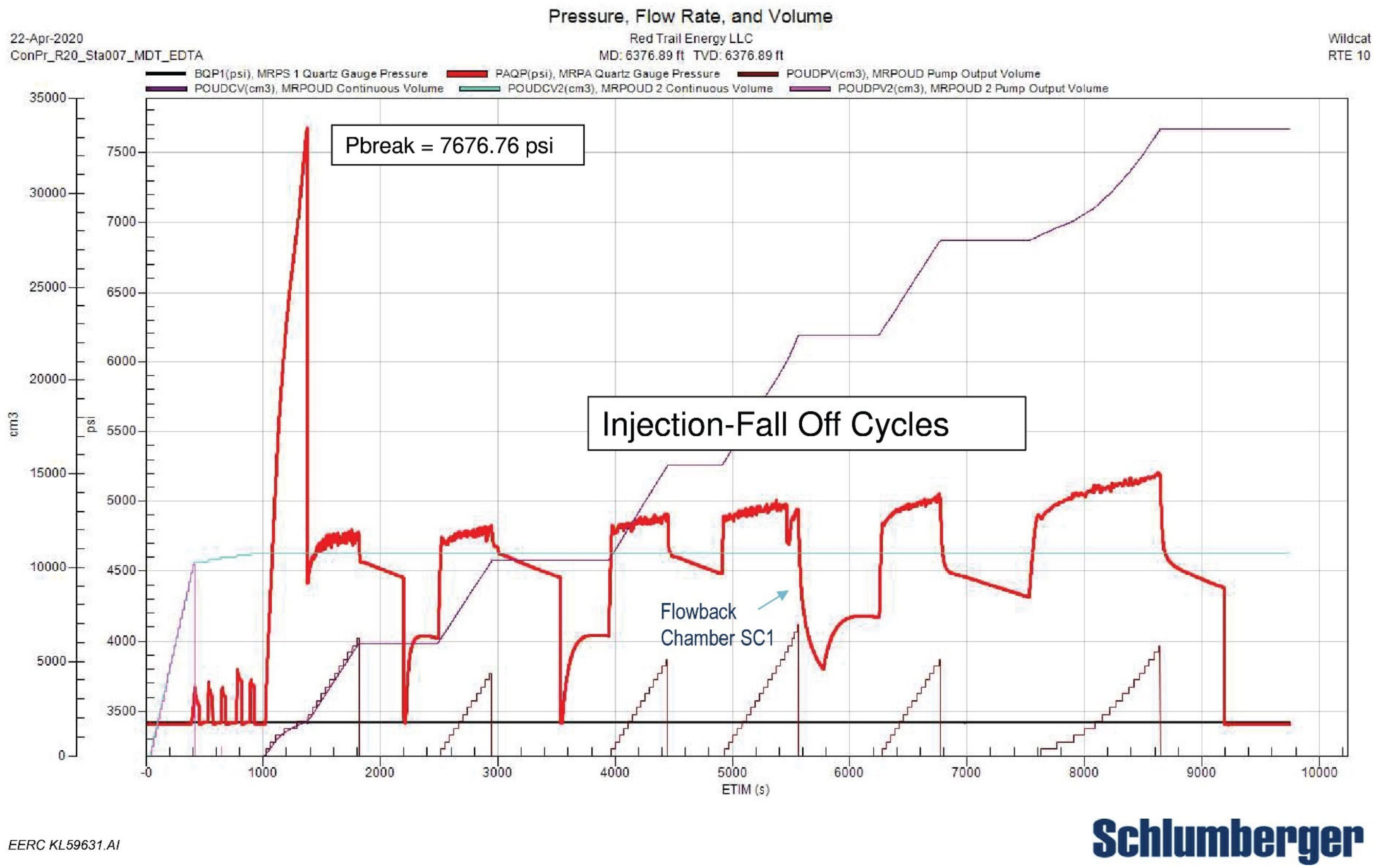

Figure 2-44. Results of MDT testing for a depth interval of 6,377 ft in the Opeche Formation.

Within the Opeche Formation confining zone, several attempts were made to generate the fracture needed to determine a suitable breakdown pressure, which is generally considered a close approximation of minimum horizontal stress of a material. A successful test was performed in the Opeche Formation at a depth of 6,377 ft, 3 vertical feet above the reservoir contact. Figure 2-44 shows the results of testing in the overlying Opeche Formation and presents the multiple cycles performed during the determination of initial breakdown pressure, fracture propagation pressure, and closure pressure. As shown, the breakdown pressure was in excess of 7,500 psi. To determine the potential for reopening and closure pressures, injection was reinitiated and allowed to develop until a stable value was attained. Based on the test, the average minimum stress is shown in Table 2-17.

Table 2-17. Average Minimum Stress of the Opeche Formation as Determined by Horizontal Stress Test

Depth, ft	Average Propagation Pressure, psi	Reopening Pressure, psi	Closure Pressure, psi	Average Minimum Stress, psi
6,377	4,995	4,823	4,680	4,680

2.4.4.5 Ductility and Rock Strength

Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Opeche Formation core in the RTE-10 well. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5,800 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material. Because of the low porosity and anhydrite mineralogy, samples were not saturated for testing. Table 2-18 shows the sample parameters, and Table 2-19 shows the elastic parameters obtained.

Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-45, the sample failed at a maximum stress of 143 MPa (20,740 psi). Based on the plot below, the final stage (Radial Stage 4) of testing, shown in yellow, has significant residual strength postfailure, indicating a high degree of ductility.

Table 2-18. Sample Parameters

Sample and Experiment Information			
Depth:	6,383 ft	Rock Type:	Anhydrite
Formation:	Opeche	Porosity:	1.2%
Dry Bulk Density:	2.970 g/cm^3	Pore Fluids:	None
Diameter:	25.40 mm	Entered Length:	50.80 mm

Table 2-19. Elastic Properties Obtained Through Experimentation: E = Youngs Modulus, n = Poisson's Ratio, K = Bulk Modulus, G = Shear Modulus, P = Uniaxial Strain Modulus

Elastic Properties Measured at Different Confining Pressures							
Event	Conf., MPa	Diff., MPa	E, GPa	n	K, GPa	G, GPa	P, GPa
1	10.0	10.2	72.70	0.237	46.07	29.39	85.25
2	20.1	20.2	70.79	0.270	51.29	27.87	88.46
3	30.2	30.2	73.81	0.271	53.78	29.03	92.49
4	40.2	40.0	77.59	0.270	56.19	30.55	96.92

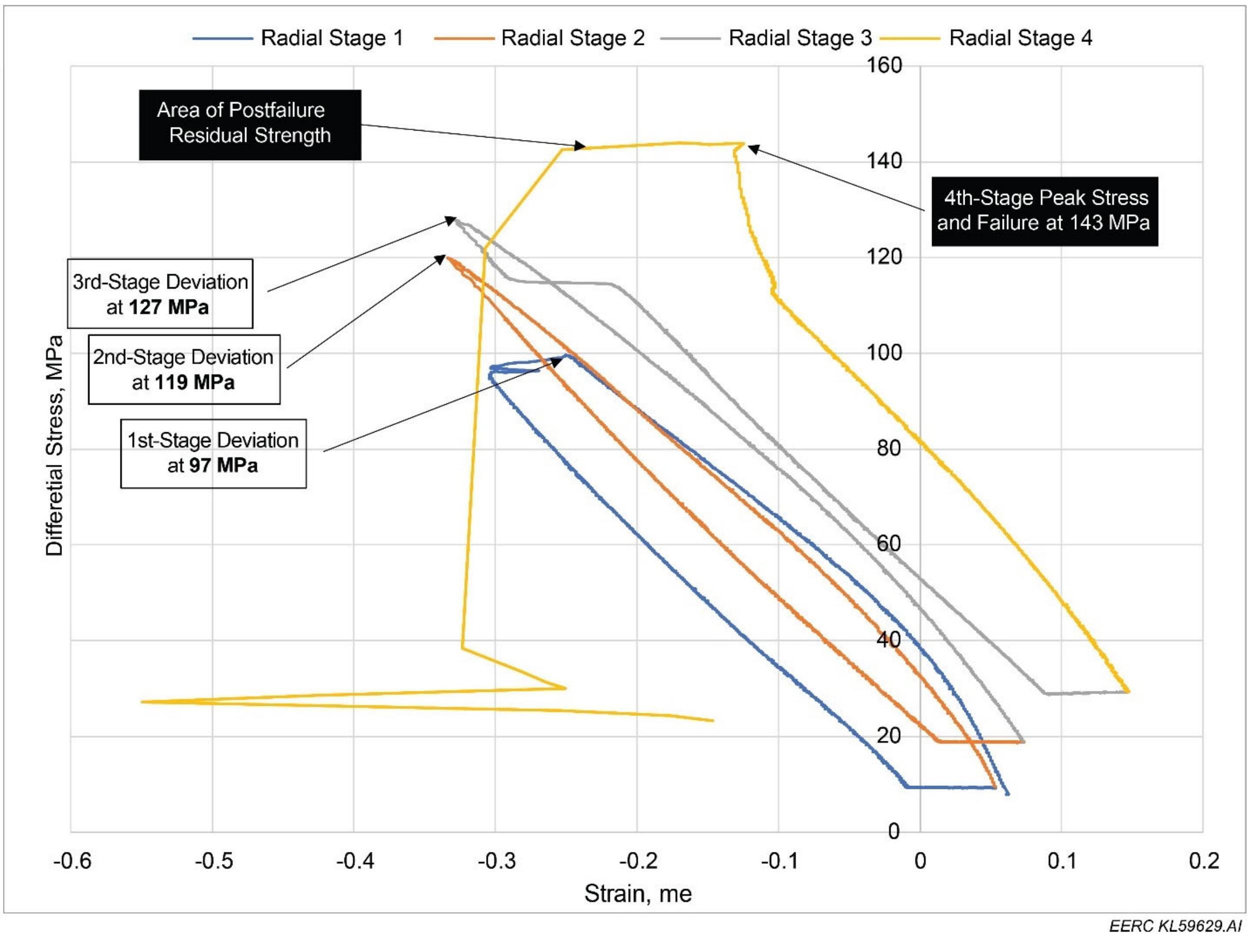

Figure 2-45. Results of multistage triaxial test performed at confining pressures exceeding 40 MPa (5,800 psi), providing information regarding the elastic parameters and peak strength of the rock sample. Failure occurred at the fourth-stage peak stress of 143 MPa.

2.5 Faults, Fractures, and Seismic Activity

In the RTE project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities.

Regional structural features, including the Heart River Fault and collapse features above the Broom Creek Formation, are discussed in this section as well as the data that support the low probability that these features will interfere with containment. This section also discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment.

2.5.1 Heart River Fault

The Heart River Fault is located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the area of review (AoR) for the RTE project (Figure 2-46). This high-angle reverse fault originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 ft in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations (Figure 2-47), well below the Broom Creek Formation (Figure 2-2). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset.

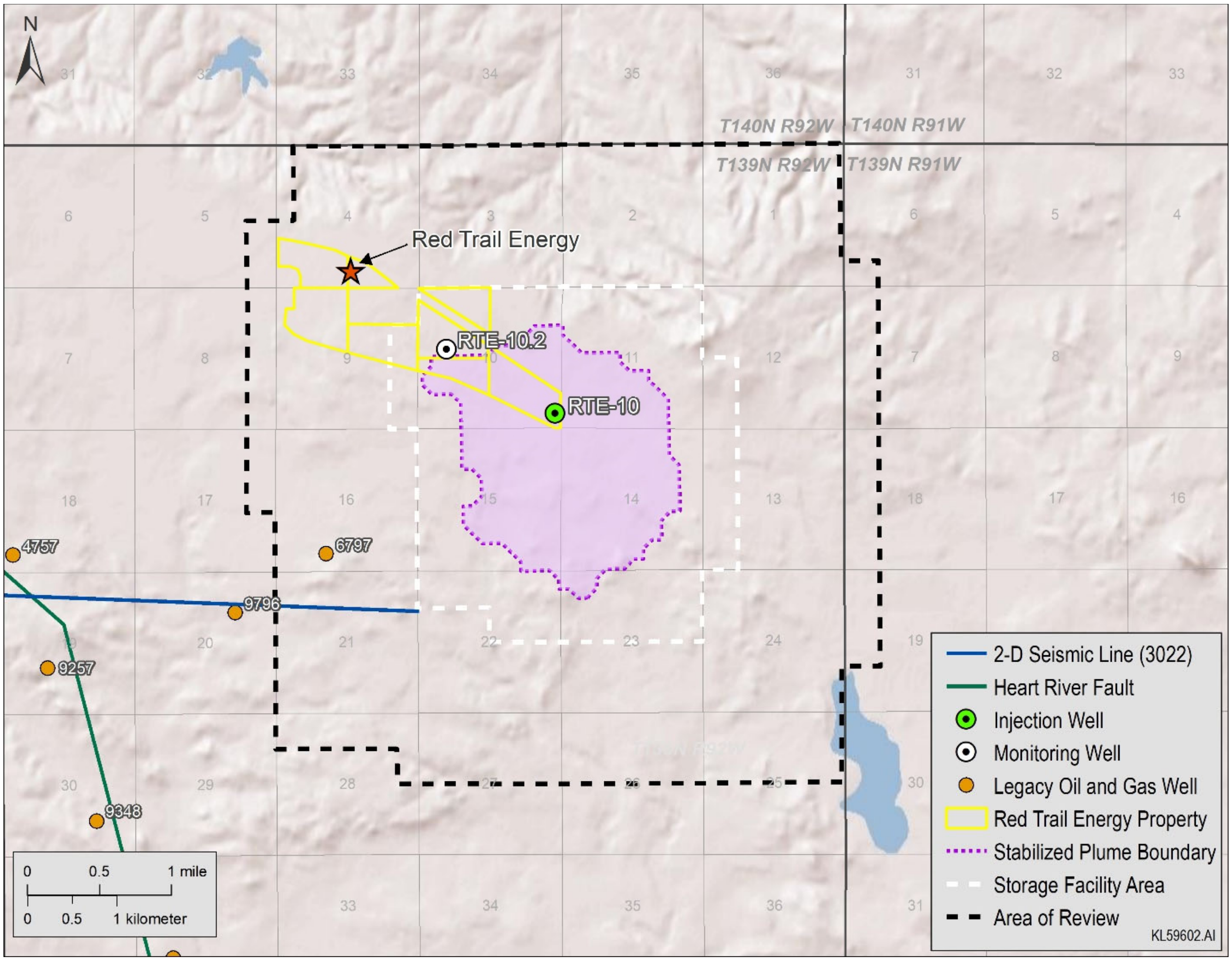

Figure 2-46 Map showing the trend of the Heart River Fault in the RTE project area. The blue line is a 2D seismic line transecting the Heart River Fault. See Figure 2-47 for a geologic interpretation along the seismic line.

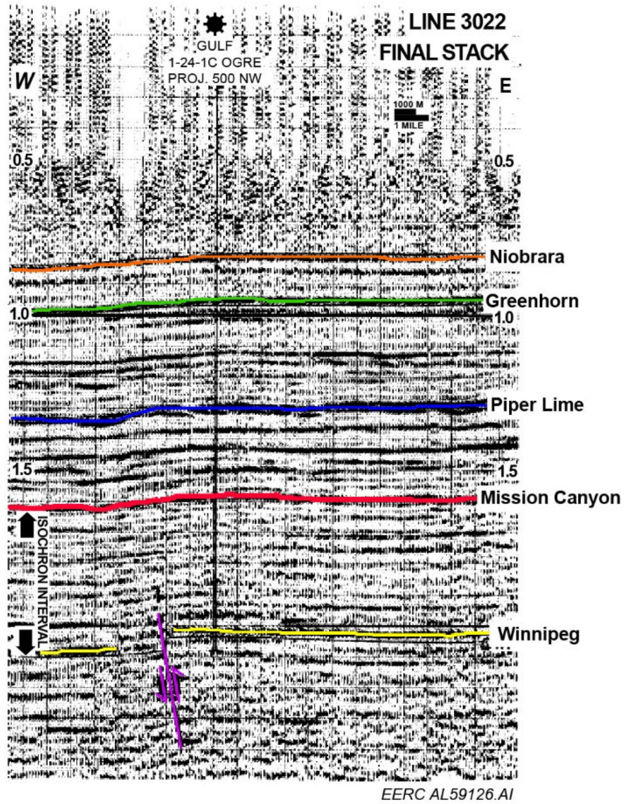

Figure 2-47. Seismic Line 3022 showing the interpreted location of the Heart River Fault in purple (Chimney and others, 1992). Faulting offset is observed in the Winnipeg horizon, but only slight flexure is observed in other overlying interpreted horizons.

2.5.2 Collapse Features above the Broom Creek Formation

The analysis of 3D seismic data acquired specifically for the RTE project in 2019 (Figure 2-6) revealed evidence for suspected collapse features in strata above the Broom Creek Formation. These features appear as depressions in the seismic data and are bounded by dipping or offset reflections (Figures 2-48 and 2-49). These collapse features correlate to 30–50-ft decreases in thickness in known evaporite-bearing formations, the Spearfish and Opeche Formations, suggesting they were caused by dissolution of evaporites and subsequent collapse of overlying sediments (Figure 2-50). The polygonal nature of these features also supports the interpretation of collapse features. The vertical extent of these features and increased thickness in the Inyan Kara Formation suggest collapse of overlying sediment ceased during the deposition of the Inyan Kara and the depressions were filled in with newly deposited sediment (Figures 2-48 and 2-51). The lack of deformation to the reflections in the upper Inyan Kara supports the argument that collapse caused by dissolution stopped during the early Cretaceous.

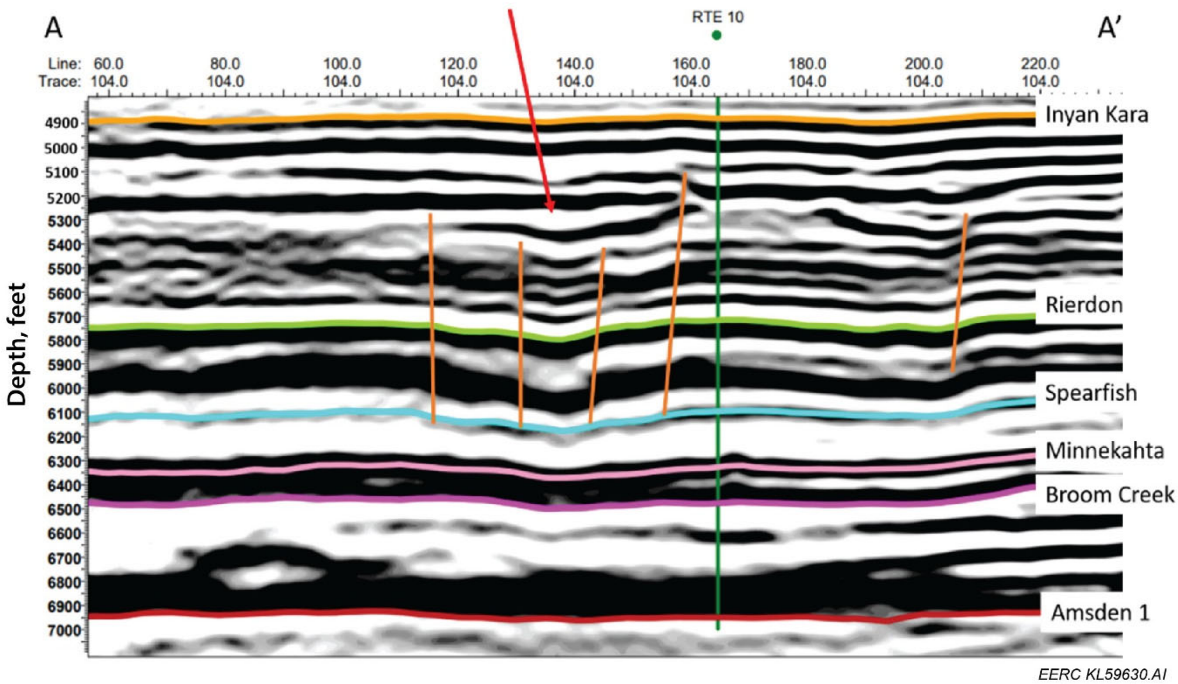

Figure 2-48. Cross-sectional view of the 3D seismic data through the proposed injection well, RTE-10, showing the interpreted boundaries of the collapse features in orange. Identified formations include Inyan Kara (yellow), Rierdon (green), Spearfish (aqua), Minnekahta (pink), Broom Creek (magenta), and Amsden (red). The collapse features near the proposed injection well do not extend below the Spearfish Formation. The red arrow indicates an area of increased thickness in sediment above these features. Figure 2-49 shows the location of this cross section.

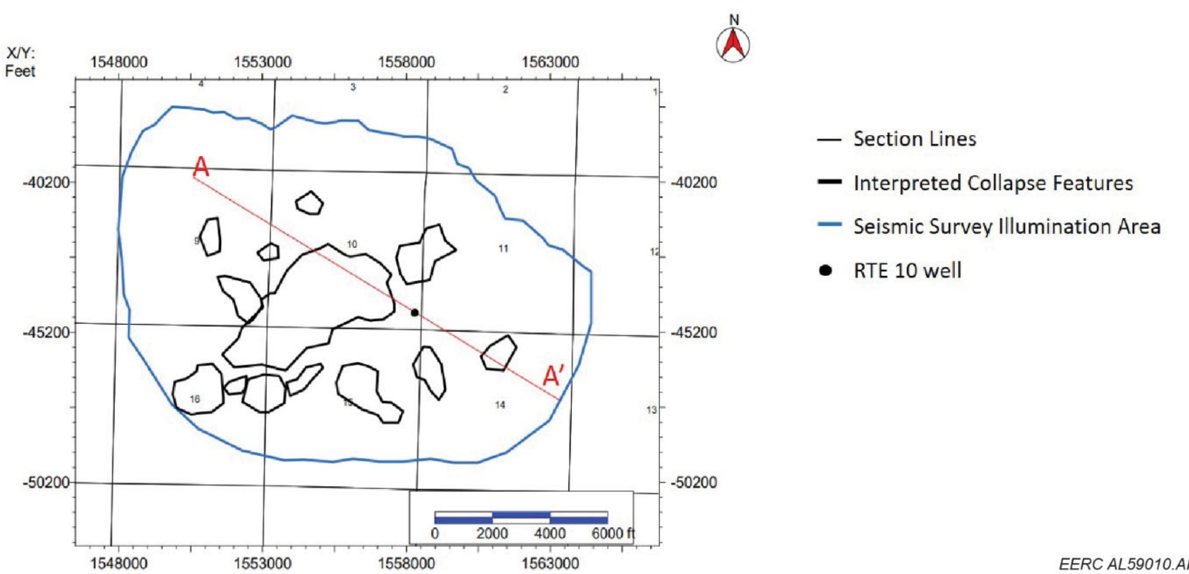

Figure 2-49. The location of the cross section highlighted in Figure 2-48.

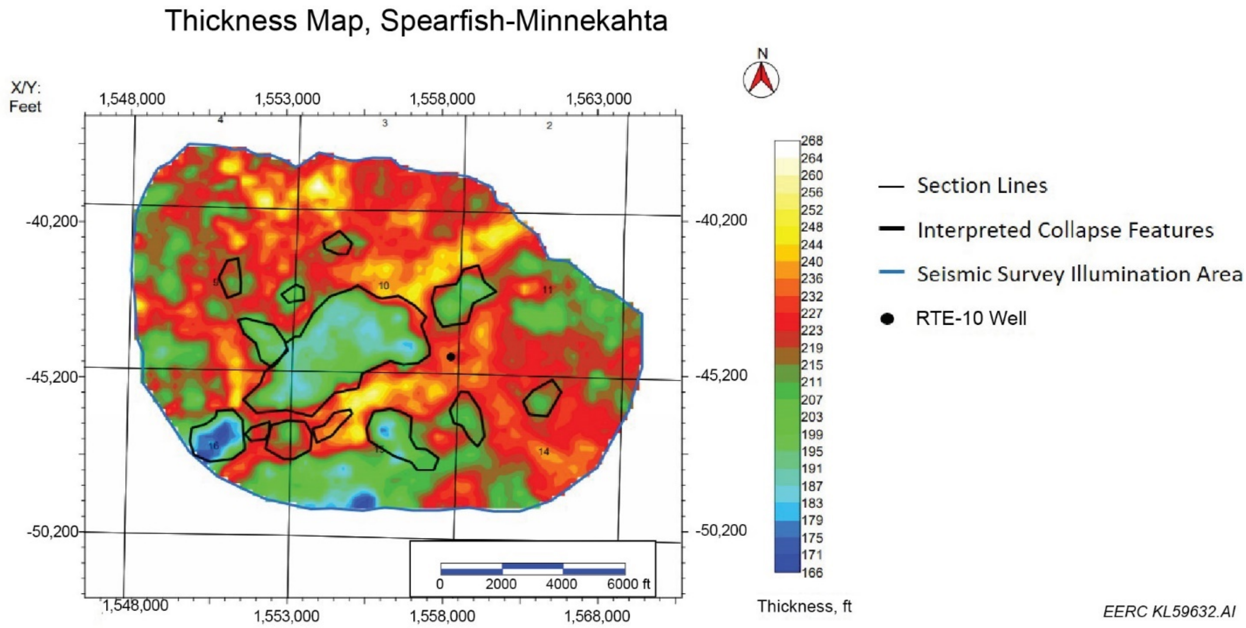

Figure 2-50. Map showing the thickness of the Spearfish–Minnekahta Formations calculated using the seismic data. Several of the interpreted collapse features correspond to areas of decreased thickness.

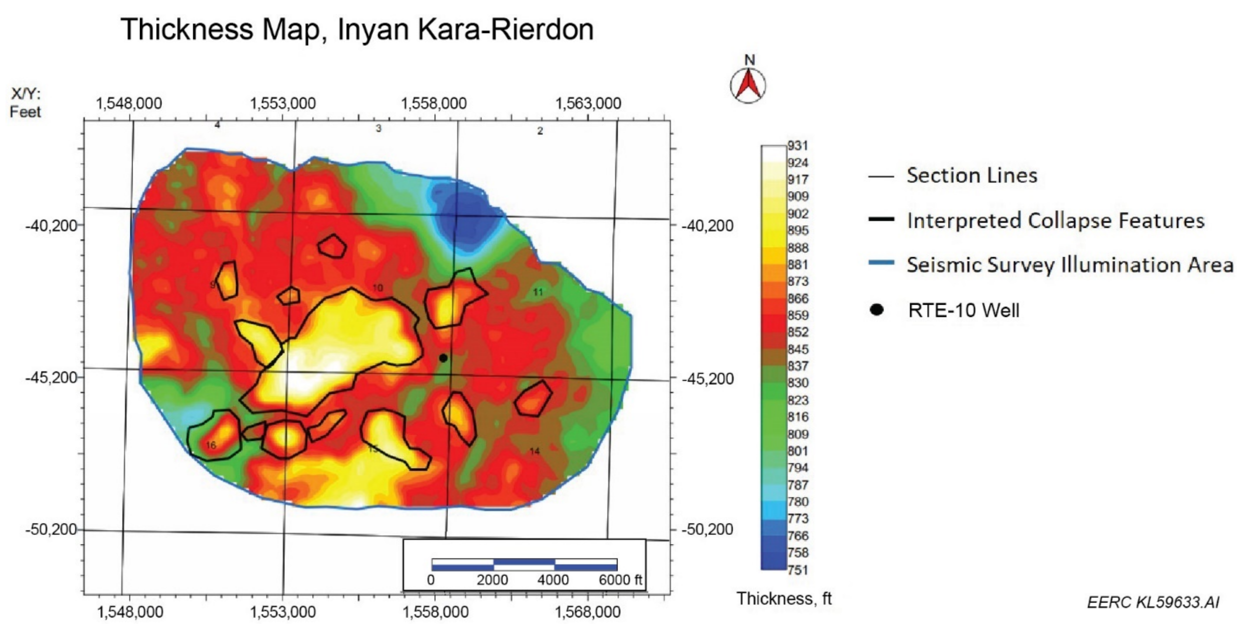

Figure 2-51. Maps showing the thickness of the interval between the top of the Inyan Kara Formation and the top of the Rierdon Formation calculated using the seismic data. The increased thickness supports that the collapse features formed prior to or during the deposition of the Inyan Kara.

Pressure gradients calculated using MDT measurements from RTE-10 and water chemistry from fluid samples collected in RTE-10 for the Broom Creek and Inyan Kara Formations suggest the two formations are hydraulically isolated, indicating the collapse features are not transmissive (Table 2-20). The data suggest that structural elements of the collapse features do not have sufficient permeability and vertical extent to have allowed fluid movement between the Broom Creek and Inyan Kara Formations. The features are interpreted to have a low risk of interfering with containment.

Table 2-20. Pressure Gradients and Water Salinity Measurements from the RTE-10 Well. The differences in pressure gradients and TDS between the Inyan Kara and Broom Creek Formations suggest the two formations are hydraulically isolated, indicating the collapse features are not transmissive.

Formation	Pressure Gradient	TDS
Inyan Kara	0.40 psi/ft	11,100 mg/L
Broom Creek	0.45 psi/ft	159,000 mg/L

2.5.3 Seismic Activity

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).

Between 1870 and 2015, 13 earthquakes have been detected within the North Dakota portion of the Williston Basin (Table 2-21) (Anderson, 2016). Of these 13 earthquakes, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-52). The earthquake recorded closest to the RTE project occurred in 1927 9.4 miles to the east, near Hebron, North Dakota (Table 2-21). The magnitude of this earthquake is estimated to have been 3.2.

Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Map Label	Distance to RTE, miles
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	95.9
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	98.7
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	109.6
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	52.1
Jan 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	128.2
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	113.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	140.9
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	138.7
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	76.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	90.2
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	112.5
April 29, 1927	3.2**	U	−102.10	46.90	Hebron	L	9.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	109.8

* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

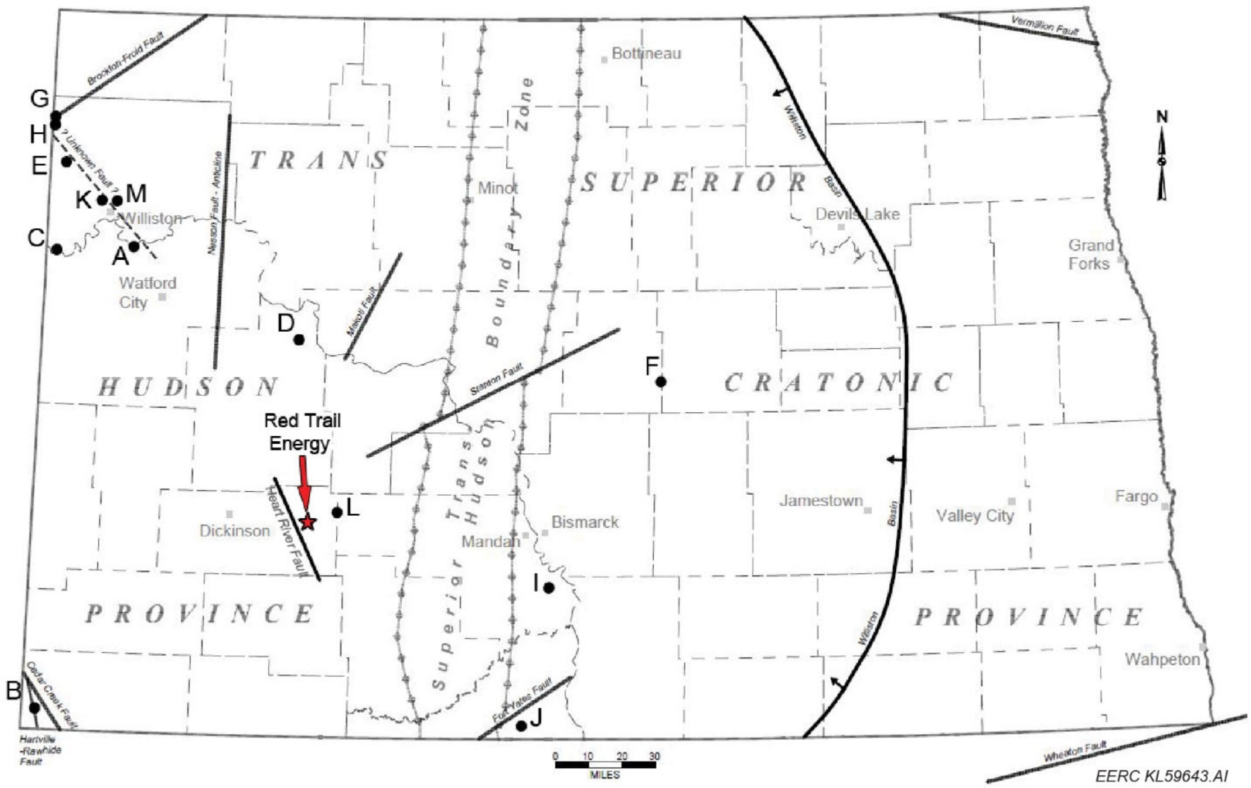

Figure 2-52. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-21.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging earthquake events occurring in North Dakota, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-53) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. Additionally, no earthquakes occurring along the Heart River Fault have been reported. This indicates relatively stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the small volume of CO_2 injected as part of this project suggest the probability that seismicity would interfere with containment is low.

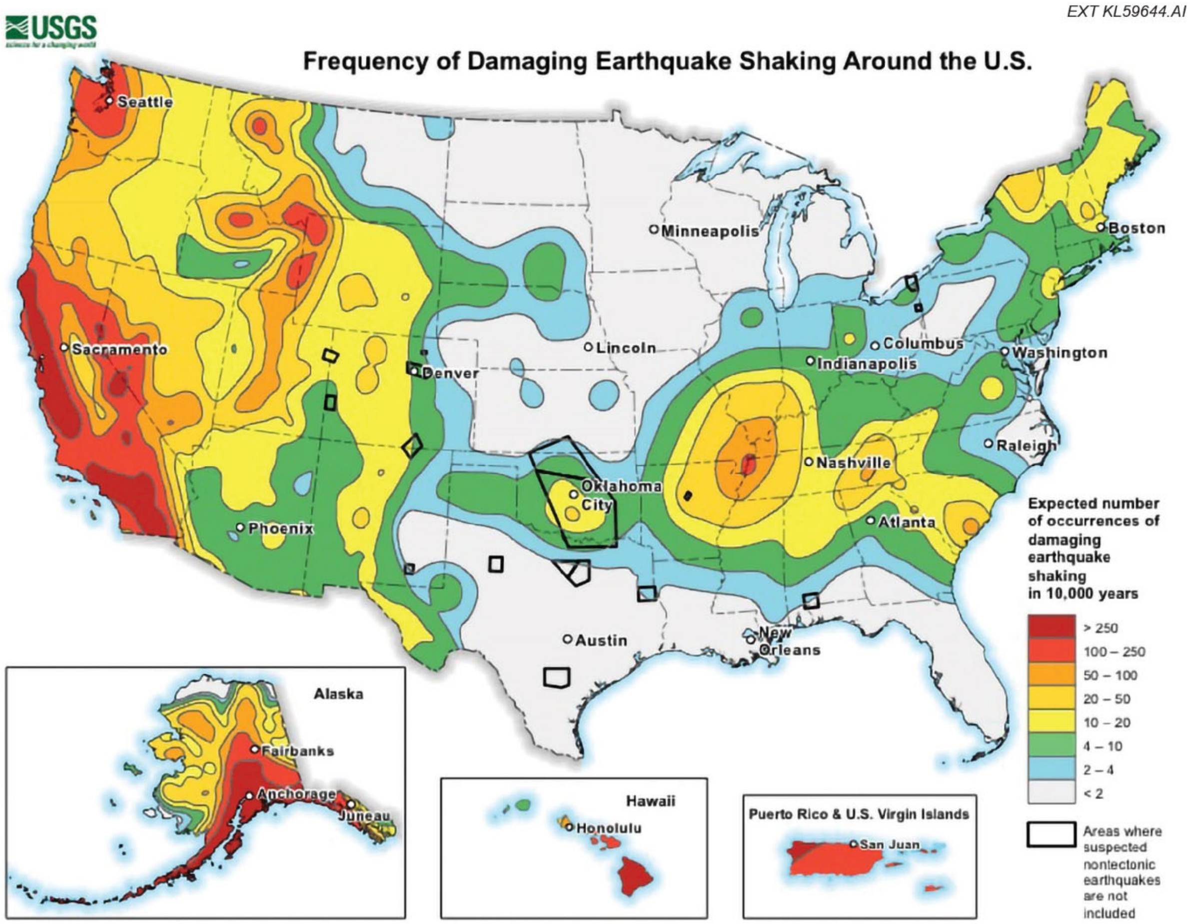

Figure 2-53. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

2.6 Potential Mineral Zones

The North Dakota Geological Survey recognizes the Spearfish as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-54). There has been no exploration for, nor development of, hydrocarbon resource from the Spearfish Formation in the greater RTE project region.

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the storage facility area. Although there was some historical gas production from deeper formations along the nearby Heart River Fault trend, there is no known commercial accumulations of hydrocarbons in the storage facility area.

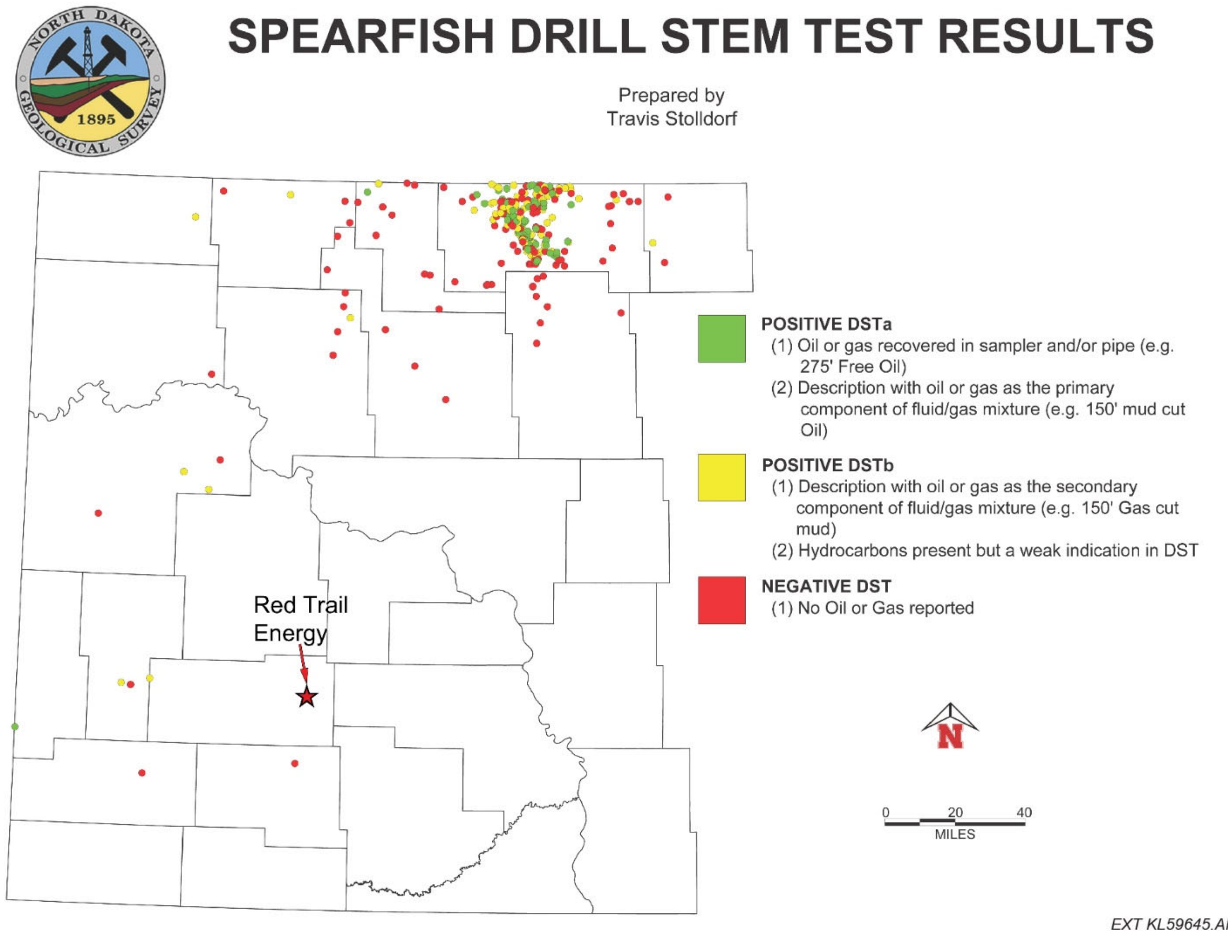

Figure 2-54. Drillstem results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020).

Shallow gas resources can be found in many areas of North Dakota, but there are no known references to shallow gas resources in the greater RTE project area.

2.7 References

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3.0 AREA OF REVIEW

3.0 AREA OF REVIEW

3.1 Area of Review Delineation

3.1.1 Written Description

North Dakota carbon dioxide (CO_2) storage regulations require that each storage facility permit delineate an area of review (AoR), which is defined as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity (North Dakota Administrative Code [NDAC] § 43-05-01-01 subsection 4). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AoR encompasses the region overlying the injected free-phase CO_2 and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or fractures) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and the resultant pressure as the "critical threshold pressure."

The results of computational modeling and simulation of 20 years of CO_2 injection at the Red Trail Energy (RTE) site show that consequent subsurface pressure increases are below the critical threshold pressure necessary to force formation fluids into USDWs (Figure 3-1). Within the bounds of the modeled area and throughout the entire storage facility area, the maximum fluid pressure increase during the final year of injection is estimated to be 52 psi, which occurs near the RTE-10 wellbore. This maximum pressure increase is below the calculated critical threshold pressure increase of 107.3 psi (Appendix A, Table A-2). At the estimated maximum fluid pressure increase (52 psi), a column of formation fluid could be raised to a depth of 4,223 feet (i.e., the Mowry Formation) based on calculations and assuming a vertical migration pathway exists.

NDAC § 43-05-01-05 subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the pressure response of the simulated CO_2 injection, the resulting AoR for the RTE project is delineated as being 1 mile beyond the facility area boundary. This extent ensures compliance with existing state regulations.

Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AoR boundary etc.) and the assumptions and justification used to delineate the AoR.

The two deep wells located in the RTE project AoR that penetrate the storage reservoir were evaluated by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records. The evaluation determined that both wells penetrating the storage reservoir within the AoR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Table 3-2–3-4 and Figures 3-6 and 3-7).

An extensive geologic and hydrogeologic characterization, performed by a team of geologists, has shown no evidence of transmissive faults or fractures in the upper confining zone within the AoR and has shown evidence that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AoR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone to prevent vertical fluid movement and protect USDWs.

This section of the Storage Facility Permit application is accompanied by maps and a cross section (Figures 3-1–3-5) that include information required in accordance with NDAC § 43-05-01-05 subsection 1a and 1b(3) and § 43-05-01-05.1 subsection 2, such as all critical boundaries and the location of any proposed injection wells or monitoring wells, the presence of significant surface structures or land disturbances, and the location of water wells and any other wells within the AoR boundary. Table 3-1 lists all surface and subsurface features that were investigated as part of the AoR evaluation, pursuant to NDAC § 43-05-01-05 subsection 1a and 1b(3) and NDAC § 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AoR boundary are identified in Table 3-1.

3.1.2 Supporting Maps

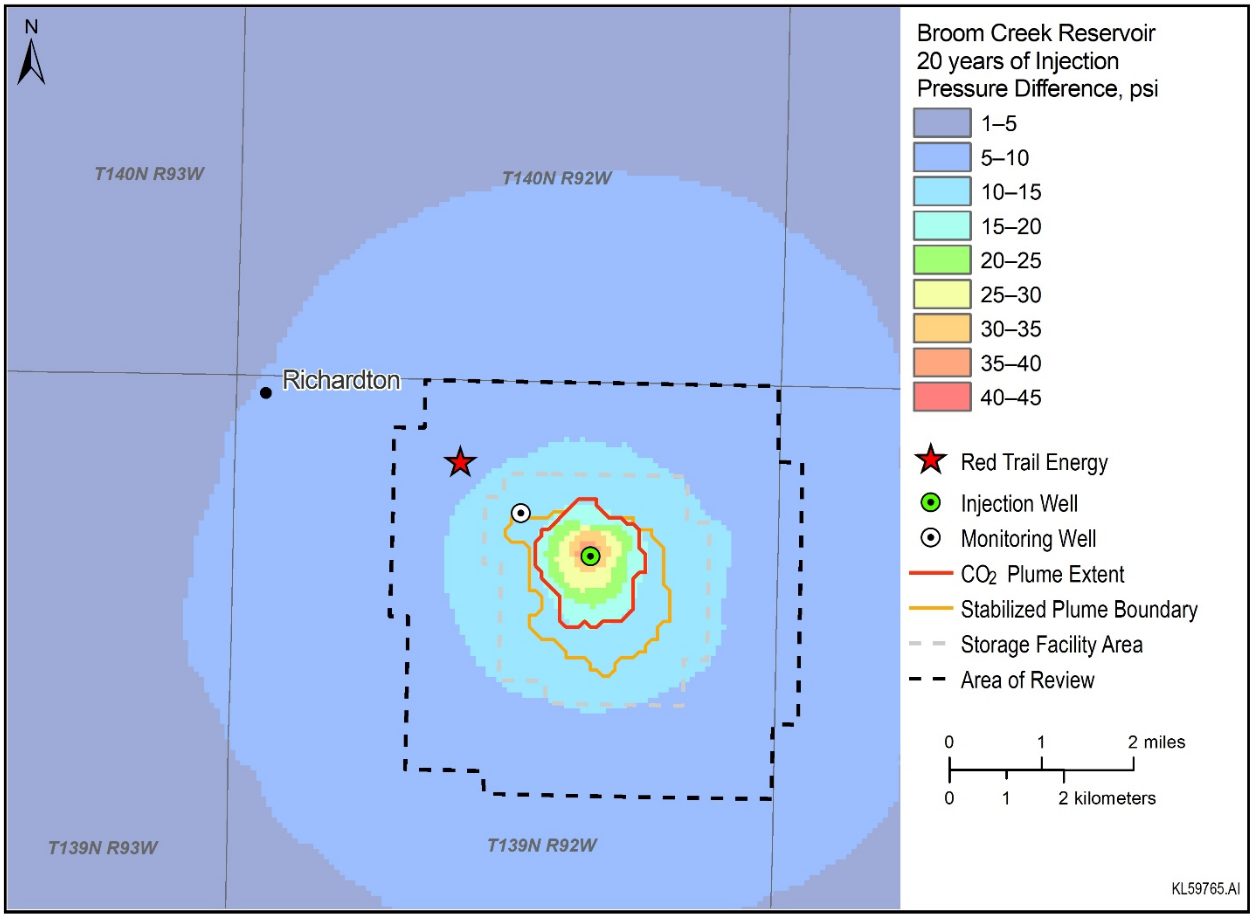


Figure 3-1. Pressure map showing the maximum subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the CO_2 plume extent after 20 years of injection, the stabilized CO_2 plume extent postinjection, the storage facility area, and the 1-mile AoR boundary in relation to the maximum subsurface pressure influence. The maximum pressure increase shown is below the calculated critical threshold pressure increase of 107.3 psi. Subsurface pressure from injection activities immediately begins to subside at cessation of injection.

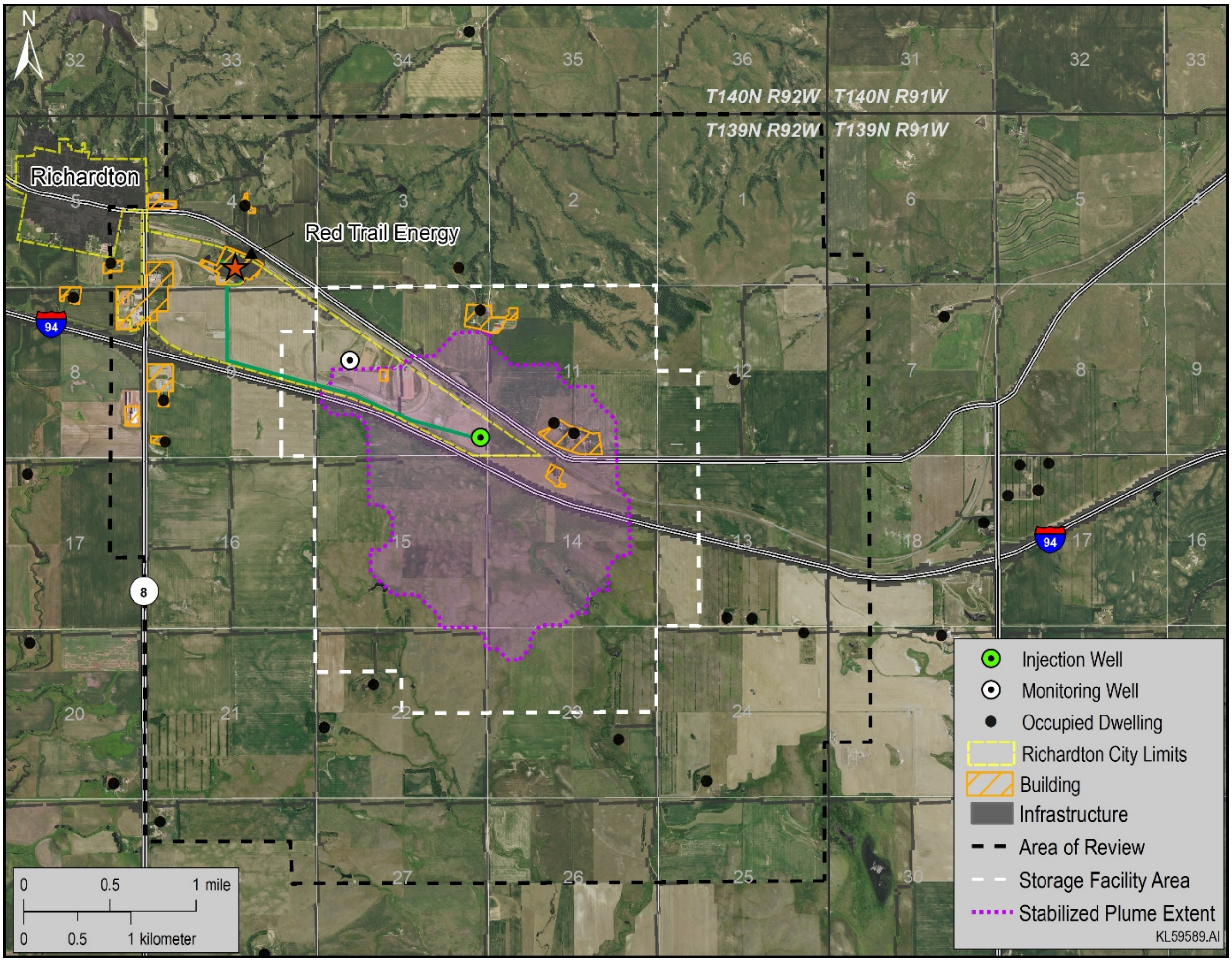


Figure 3-2. Final AoR map showing the RTE storage facility area, including the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and AoR (dotted black boundary). Black circles represent occupied dwellings, and orange boundaries represent buildings.

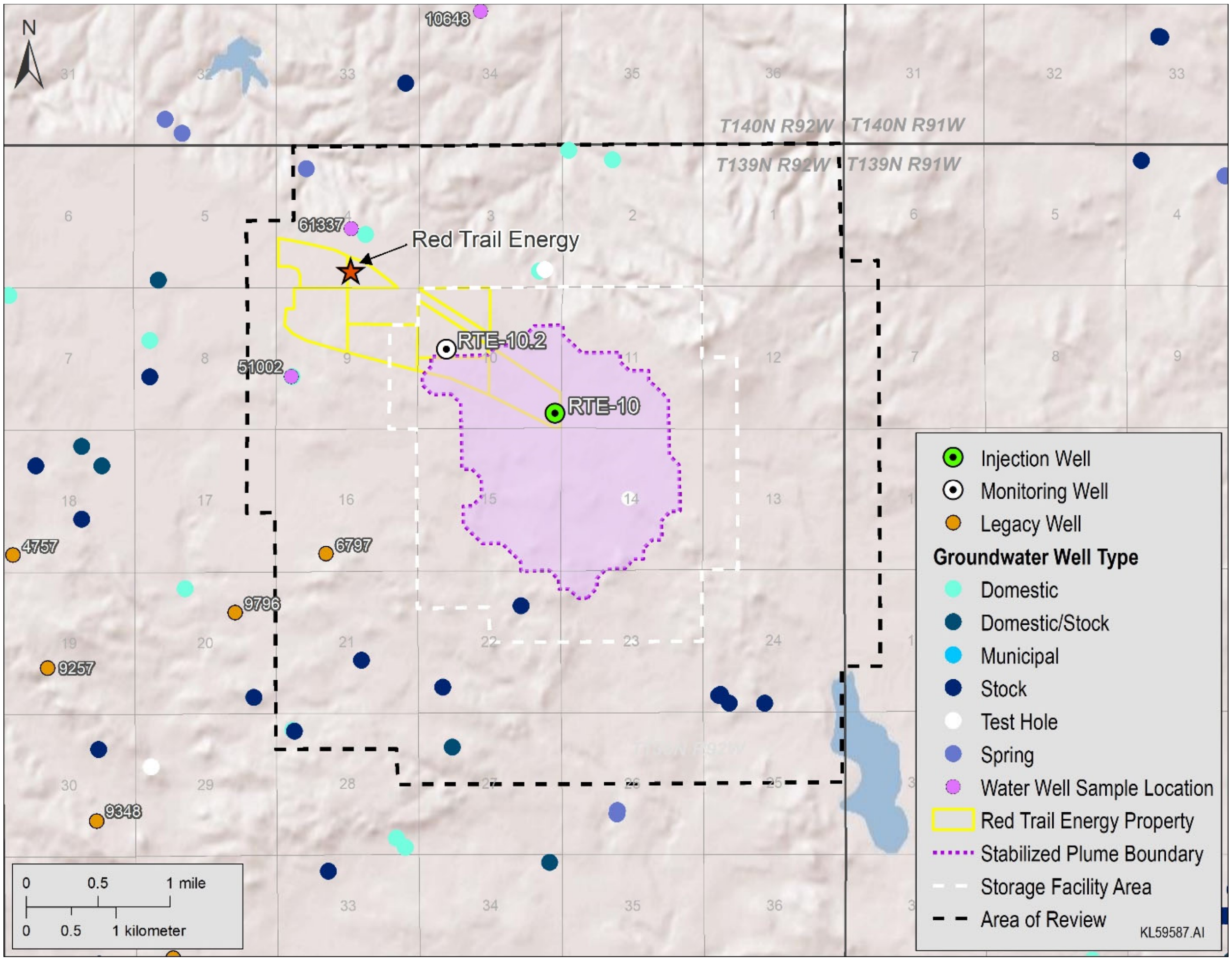


Figure 3-3. AoR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and 1-mile AoR (dotted black boundary). All groundwater wells and springs in the AoR are identified above.

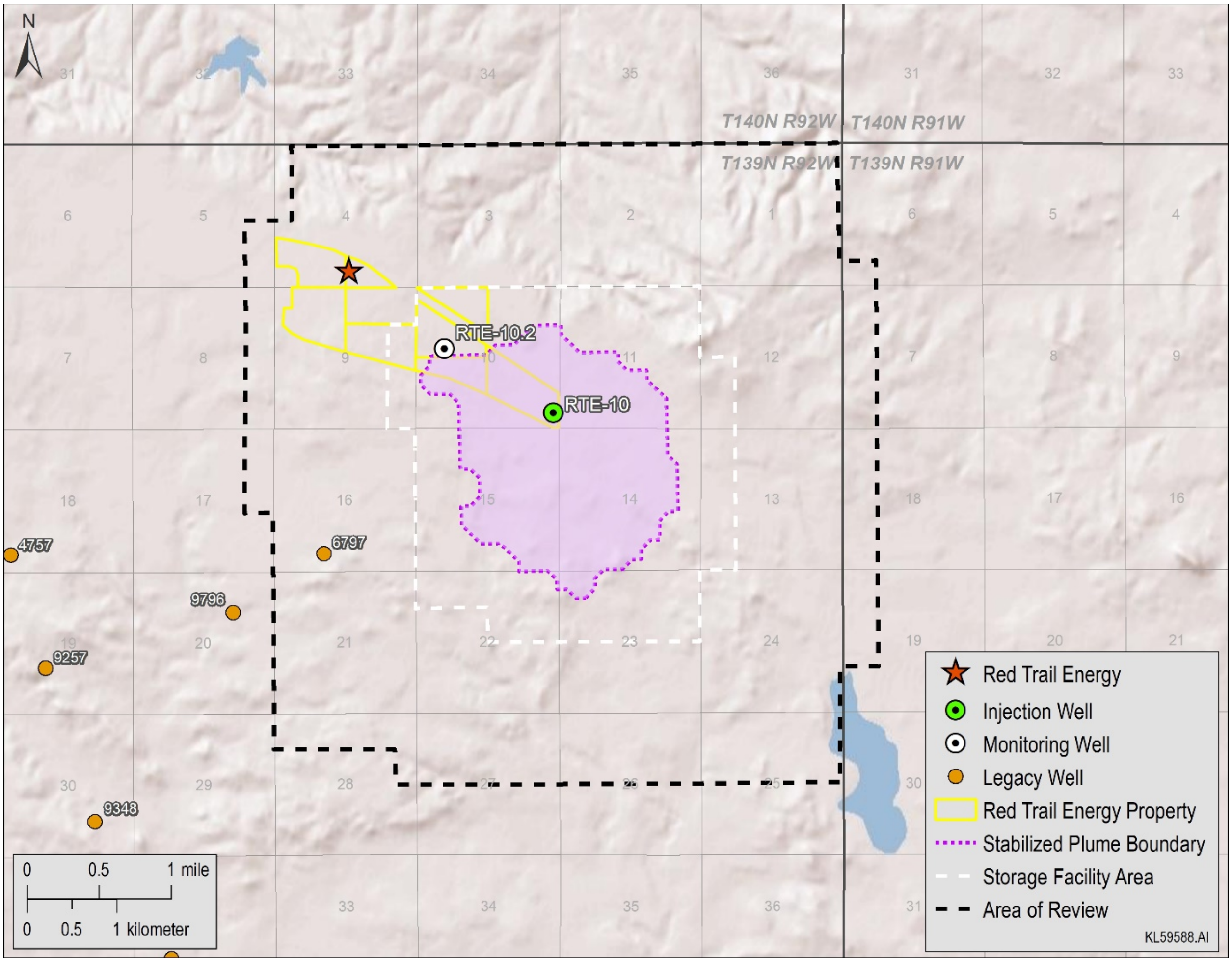


Figure 3-4. AoR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and 1-mile AoR (dotted black boundary). Orange circles represent nearby legacy wells near the project area, including within the 1-mile AoR.

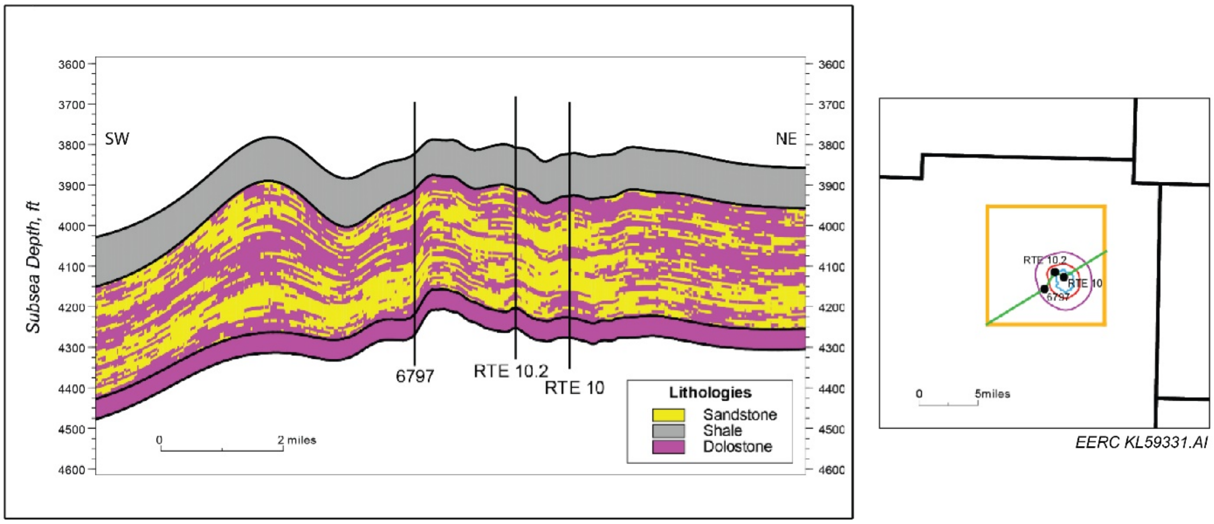


Figure 3-5. Cross section of the AoR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (RTE-10), the proposed monitoring well (RTE-10.2), and the Rummel-State 1 (NDIC File No. 6797) well within the AoR. Depths are referenced to mean sea level.

Table 3-1. Investigated and Identified Surface and Subsurface Features (Figures 3-1 through 3-5)

Surface and Subsurface Features	Investigated and Identified (Figures 3-1–3-5)	Investigated But Not Found in AoR
Producing (active) Wells		x
Abandoned Wells	x	
Plugged Wells or Dry Holes	x	
Deep Stratigraphic Boreholes		x
Subsurface Cleanup Sites		x
Surface Bodies of Water	x	
Springs	x	
Water Wells	x	
Mines (surface and subsurface)		x
Quarries		x
Subsurface Structures (e.g., coal mines)		x
Location of Proposed Wells	x	
*Location of Proposed Cathodic Protection Boreholes	NA	NA
Any Existing Aboveground Facilities	x	
Roads	x	
State Boundary Lines		x
County Boundary Lines	x	
Indian Boundary Lines		x
Other Pertinent Surface Features	x	

*There are no plans for cathodic protection for the RTE injection wells.

3.2 Corrective Action Evaluation

Table 3-2. Wells in AoR Evaluated for Corrective Action

NDIC Well File No.	Operator	Well Name	Spud Date	Surface Casing o.d., inches	Surface Casing Seat, ft	Long-String Casing o.d., inches	Long-String Casing seat, inches	Hole Direction	TD, ft	TVD, ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
6797	W.H. Hunt Trust Estate	Rummel-State 1	12/14/1978	9.625	1,519	Openhole		Vertical	11,270	11,270	P&A	2/4/1979	139 N	92 W	16	SE/SW	Stark	No
37858	Red Trail Energy LLC	RTE-10.2	10/7/2020	9.625	1,952	7	7,024	Vertical	7,025	7,023.74	TAO	N/A	139 N	92 W	10	SW/NW	Stark	No

Table 3-3. Rummel-State 1 (NDIC File No. 6797) Well Evaluation

Well Name: Rummel-State 1 (NDIC File No. 6797)

Cement Plugs				
Number	Interval, ft		Thickness, ft	Volume, sacks
1	11,143	11,043	100	35
2	10,500	10,300	200	35
3	9,500	9,400	100	35
4	7,560	7,460	100	35
5	6,438	6,338	100	35
6	4,900	4,800	100	35
7	3,200	3,100	100	35
8	1,606	1,506	100	35
9	25	0	25	10

*Data and information are provided from well-plugging report found in NDIC database.

Formation		Cement Plug Remarks
Name	Estimated Top, ft	
9⅝" Casing Shoe	1,519	Cement Plug 8 isolates the 9⅝" casing shoe with 87' and 13' cement below and above the casing shoe, respectively.
Pierre	1,850	
Mowry	4,498	Cement Plug 6 isolates the Inyan Kara Formation with 77' within the Inyan Kara and 23' within the Mowry.
Inyan Kara	4,827	
Swift	5,314	
Spearfish	6,182	
Minnekahta	6,273	
Opeche	6,315	Cement Plug 5 isolates the Broom Creek Formation with 30' within the Broom Creek and 70' within the Opeche.
Broom Creek	6,408	
Kibby Lime	7,400	Cement Plug 4 isolates the formations below the Boom Creek Formation.

Spud Date: 12/14/1978
Total Depth: 11,270 (Red River Formation)

Surface Casing: 9⅝" 36# K-55 ST&C casing set at 1,519', cement to surface with 300 sacks Class G cement and 600 sacks Halco lite

Openhole plugging

Corrective Action: No corrective action is necessary. Based on modeling and simulations, the Rummel-State 1 (NDIC File No. 6797) well will not be in contact with the CO_2 plume, and pressure increase in the Broom Creek Formation at this well location is predicted to be approximately 5–10-psi difference. Brine displacement from injection activities below the Broom Creek Formation at this well location is not expected to be an impact beyond what has been occurring since this well was drilled and plugged.

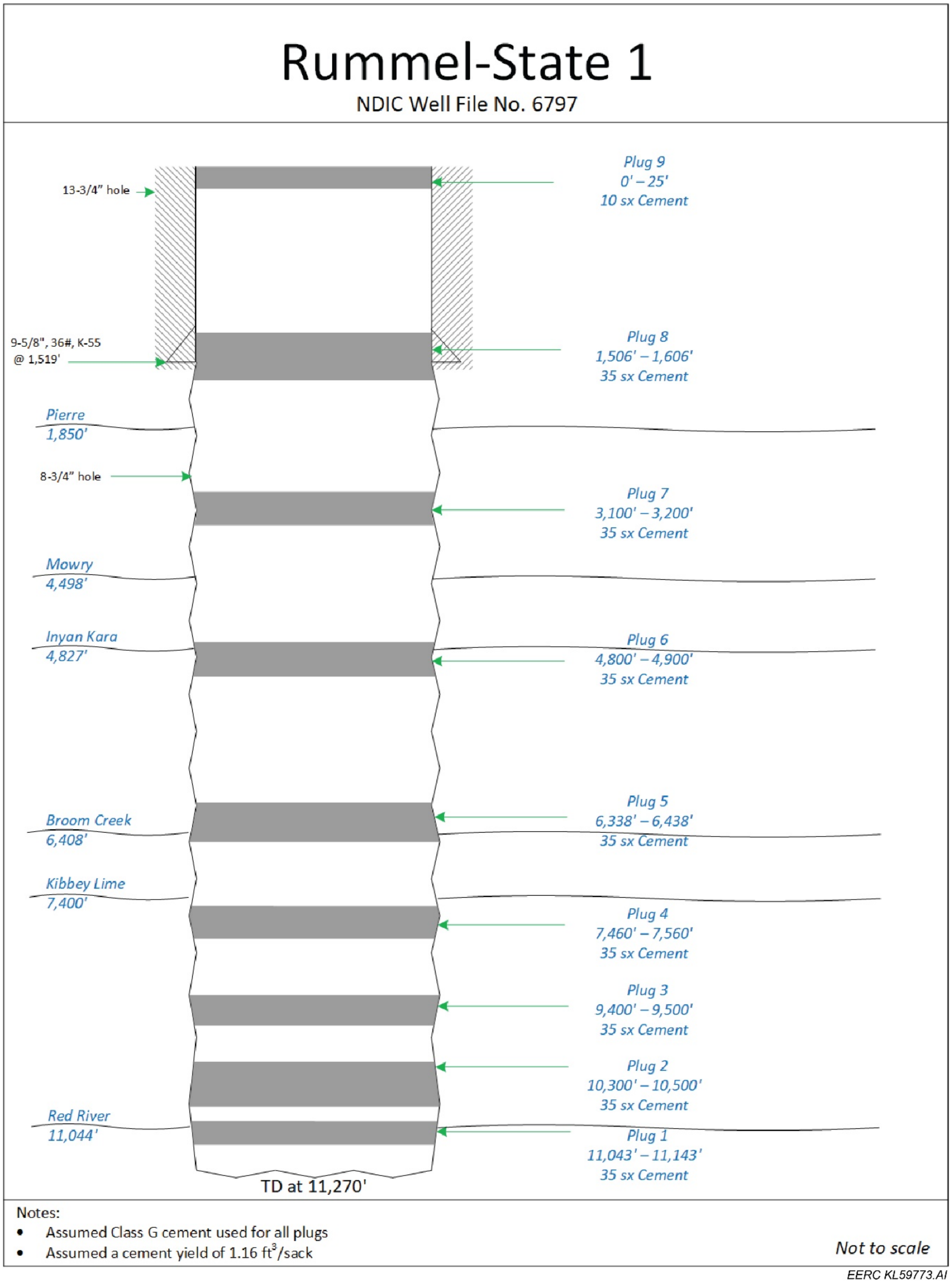


Figure 3-6. Rummel-State 1 (NDIC File No. 6797) well schematic showing the location and thickness of cement plugs.

Table 3-4. RTE 10.2 (NDIC File No. 37858) Well Evaluation

Well Name: RTE 10.2 (NDIC File No. 37858)

Casing Program				
Section	Casing Outside Diameter (o.d.), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	9⅝	36	1,952	J-55
Production	7	29	7,025	L-80
				13Cr-80

Cement Program				
Casing, in.	Cement Type	TOC	Excess, %	Volume, sacks
9⅝	Class G	Surface	100	863
7	Class G	Surface	100	1,378
	CO_2-resistant	4,350		

Formation		Remarks
Name	Estimated Top, ft	
Pierre	1,778	Class G cement isolates the 9⅝" casing shoe.
9⅝" Casing Shoe	1,952	
Mowry	4,516	Production casing and CO_2-resistant cement isolate the Inyan Kara and Mowry Formations.
Inyan Kara	4,853	
Swift	5,205	
Opeche	6,308	Production casing and CO_2-resistant cement isolate the Broom Creek Formation.
Broom Creek	6,431	
Amsden	6,770	

Corrective Action: No corrective action is necessary.

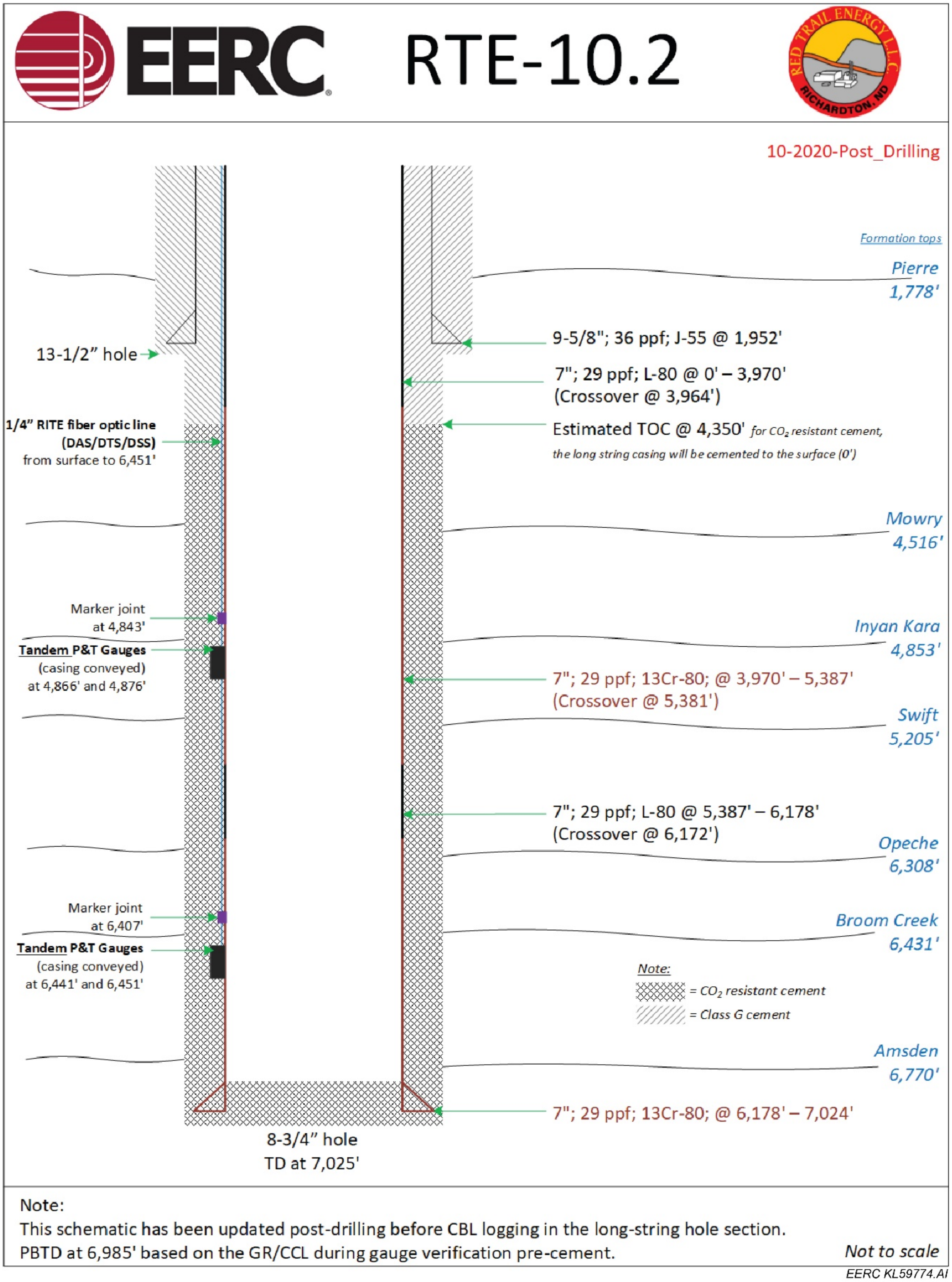


Figure 3-7. RTE 10.2 (NDIC File No. 37858) well schematic showing the current status and wellbore construction.

3.3 Reevaluation of AoR and Corrective Action Plan

RTE will reevaluate the AoR and corrective action plan, with the period between evaluations not to exceed 5 years. AoR reevaluations will address the following:

- Changes to the monitoring and operational data prior to the scheduled 5-year reevaluation date.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the computational simulations to inform a reevaluation of the AoR and corrective action plan, including the computational model that was used to determine the AoR, will be updated, and the operational data to be utilized as the basis for that update will be identified.
- How corrective action, if necessary, will be conducted, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AoR.

3.4 Protection of USDWs

3.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the AoR. The Opeche Formation is the primary confining zone with additional confining layers above, geologically isolating all USDWs from the injection zone (Table 2-14).

3.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 3-8). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley and White River Formations (Figure 3-9). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AoR (Trapp and Croft, 1975).

The lowest USDW in the AoR is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the AoR is approximately 1,000 to 1,600 ft deep and 240–400 ft thick. The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the AoR (Figure 3-10).

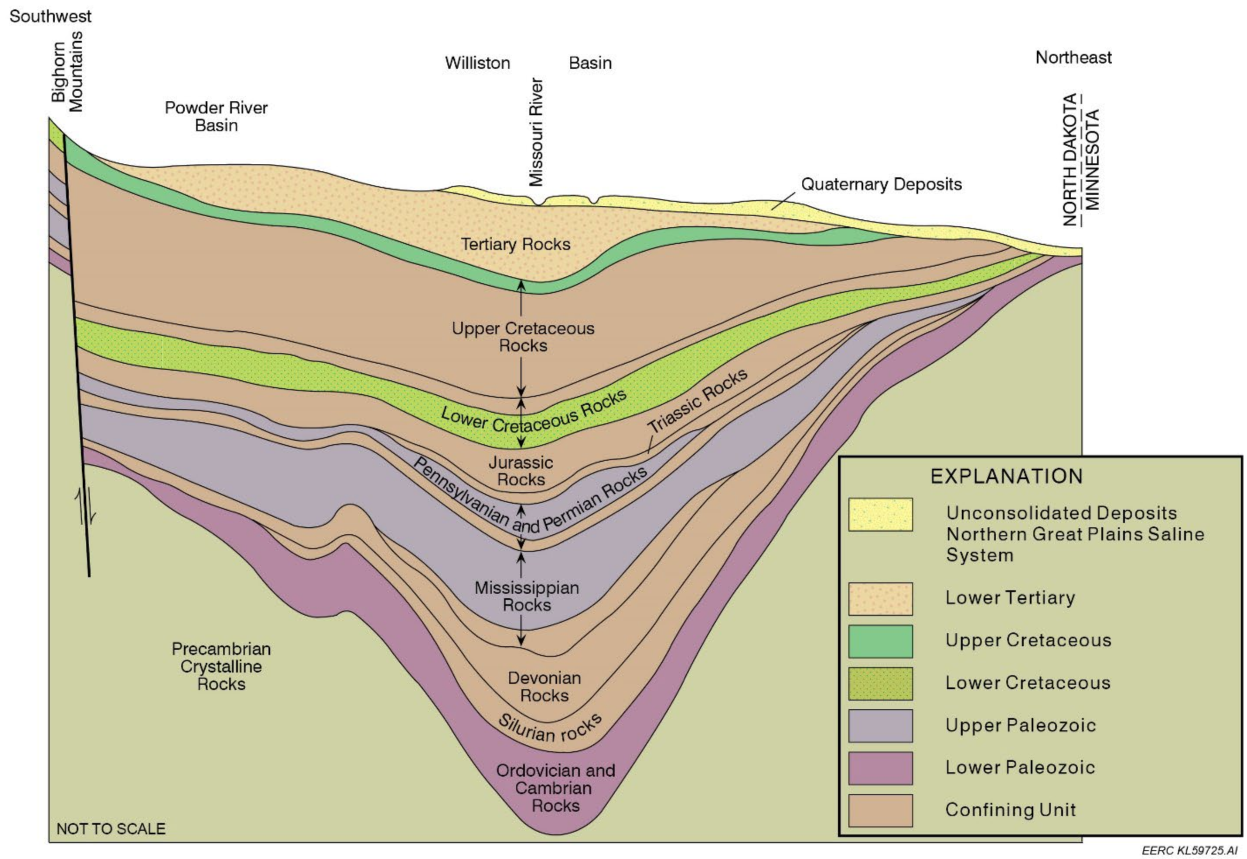


Figure 3-8. Major aquifer systems of the Williston Basin.

The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the AoR (Thamke and others, 2014).

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
	Tertiary		Arikaree	No
			White River	No
			Golden Valley	Yes
		Fort Union	Sentinel Butte	Yes
			Tongue River	Yes
			Cannonball	Yes
Mesozoic	Cretaceous		Hell Creek	Yes
			Fox Hills	Yes
			Pierre	No
		Colorado	Niobrara	No
			Carlile	No
			Greenhorn	No
			Belle Fourche	No

EERC KL59727.AI

Figure 3-9. Upper stratigraphy of Stark County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Trapp and Croft, 1975).

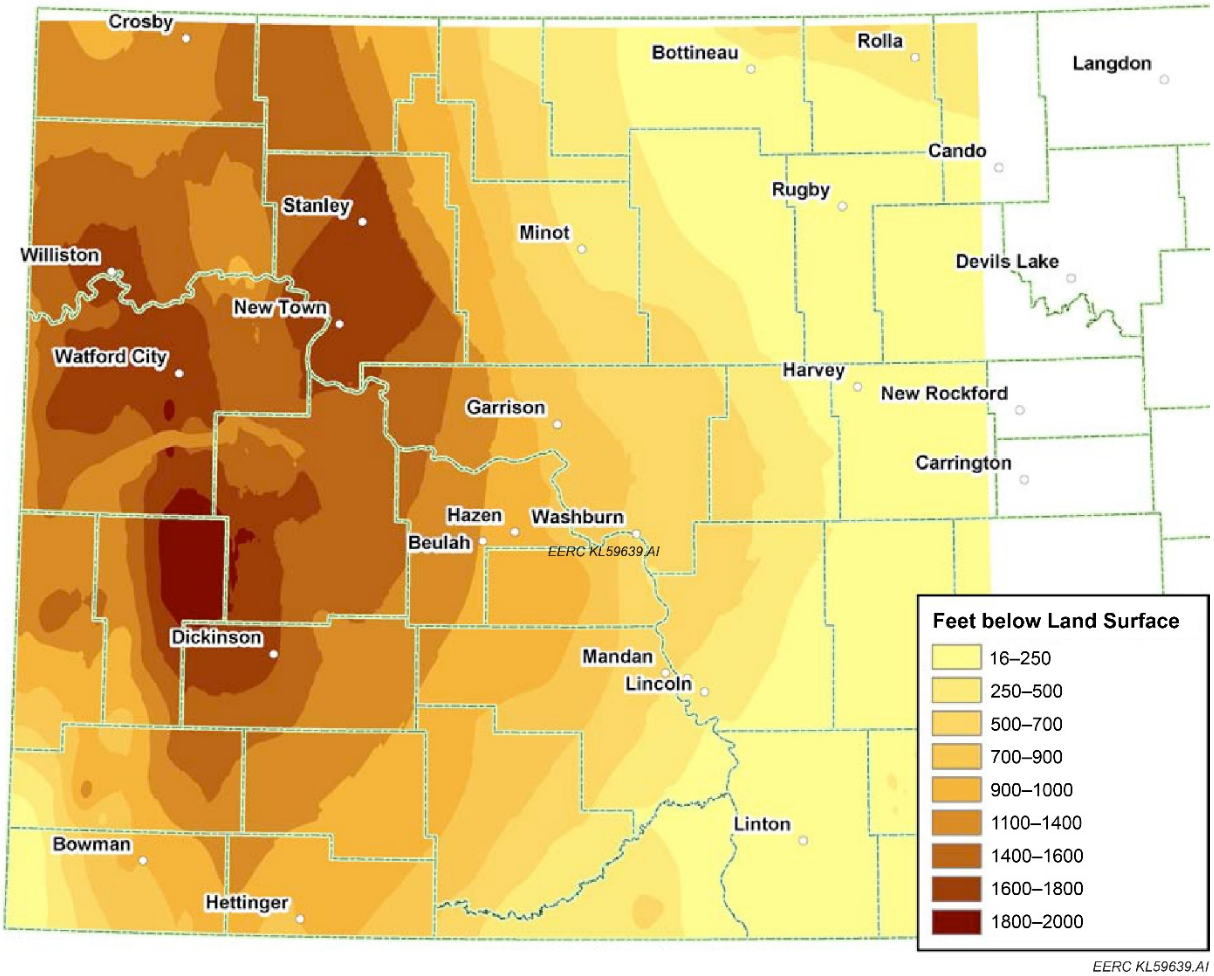


Figure 3-10. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

3.4.3 Hydrology of USDW Formations

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AoR is to the northeast (Figure 3-11). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500–1,600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. One active Fox Hills Formation well in AoR is located immediately south of the RTE site on the south side of Interstate 94 (Figure 3-12). Two other Fox Hills wells previously served the city of Richardton, North Dakota, but were plugged and abandoned in the late 1990s.

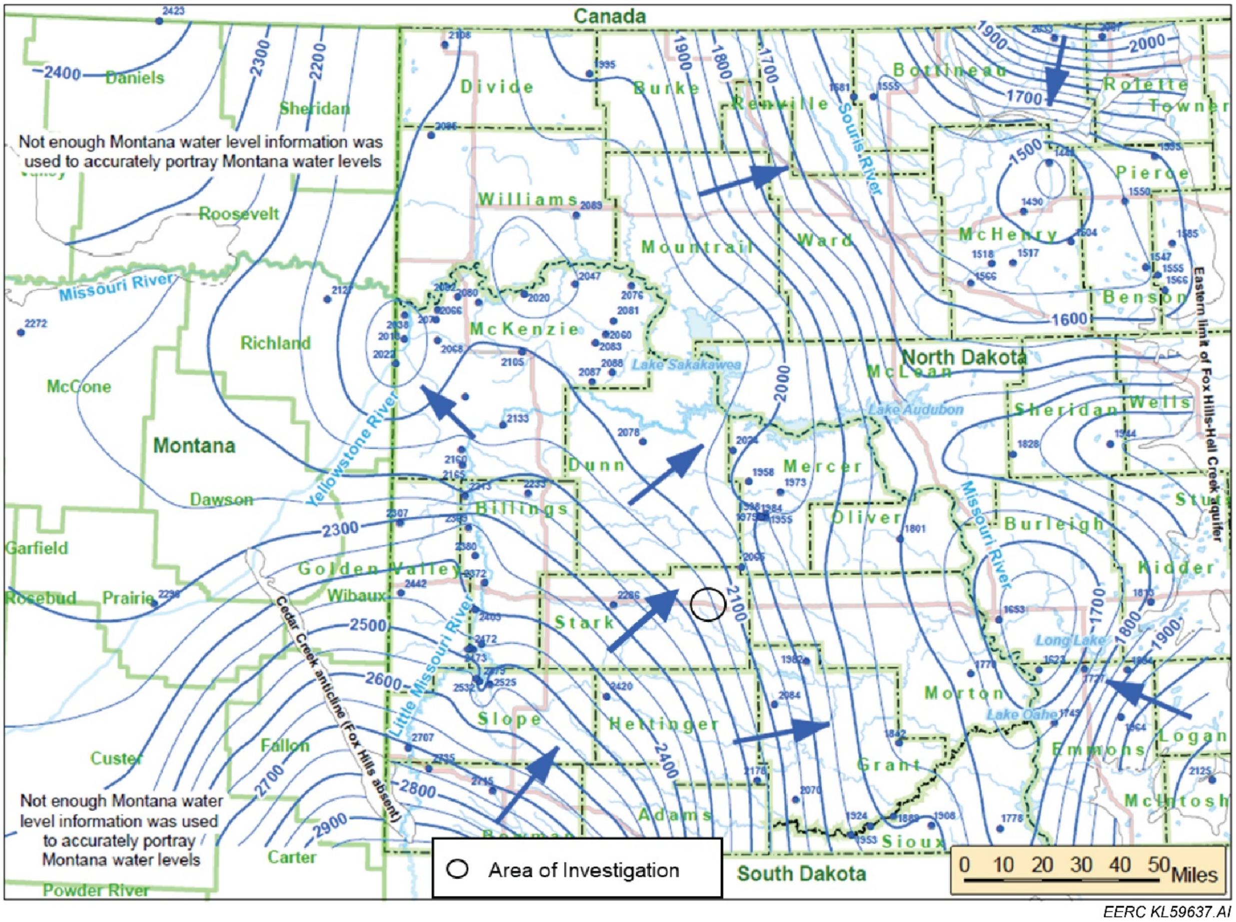


Figure 3-11. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Stark County (modified from Fischer, 2013).

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AoR (Figure 3-13). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. Thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Trapp and Croft, 1975).

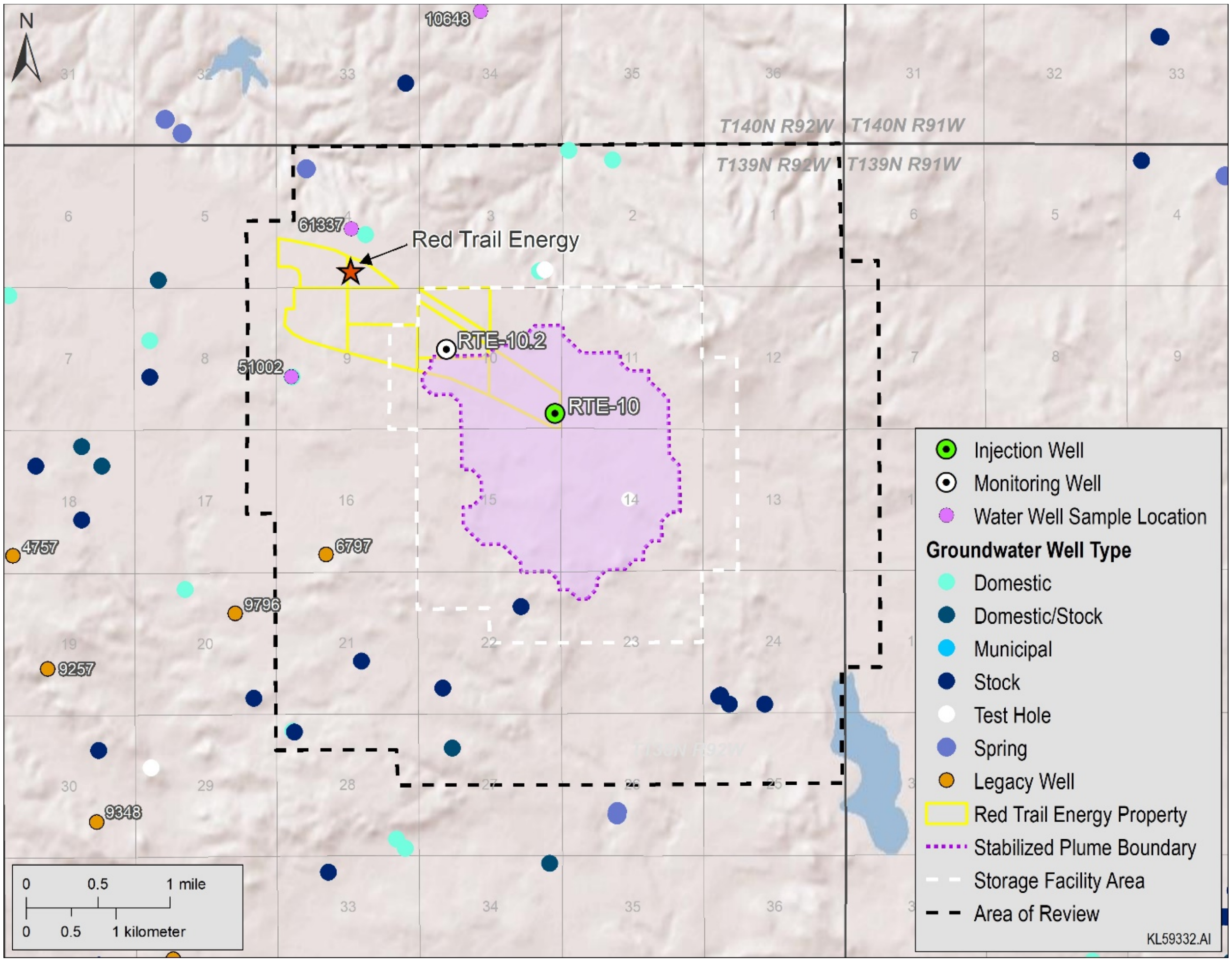


Figure 3-12. Map of water wells in the AoR in relation to the RTE Facility, RTE-10 and RTE-10.2 wells, stabilized CO_2 plume extent, facility area, 1-mile AoR, and legacy oil and gas wells.

The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is 100 to 150 ft thick in the AoR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Trapp and Croft, 1975).

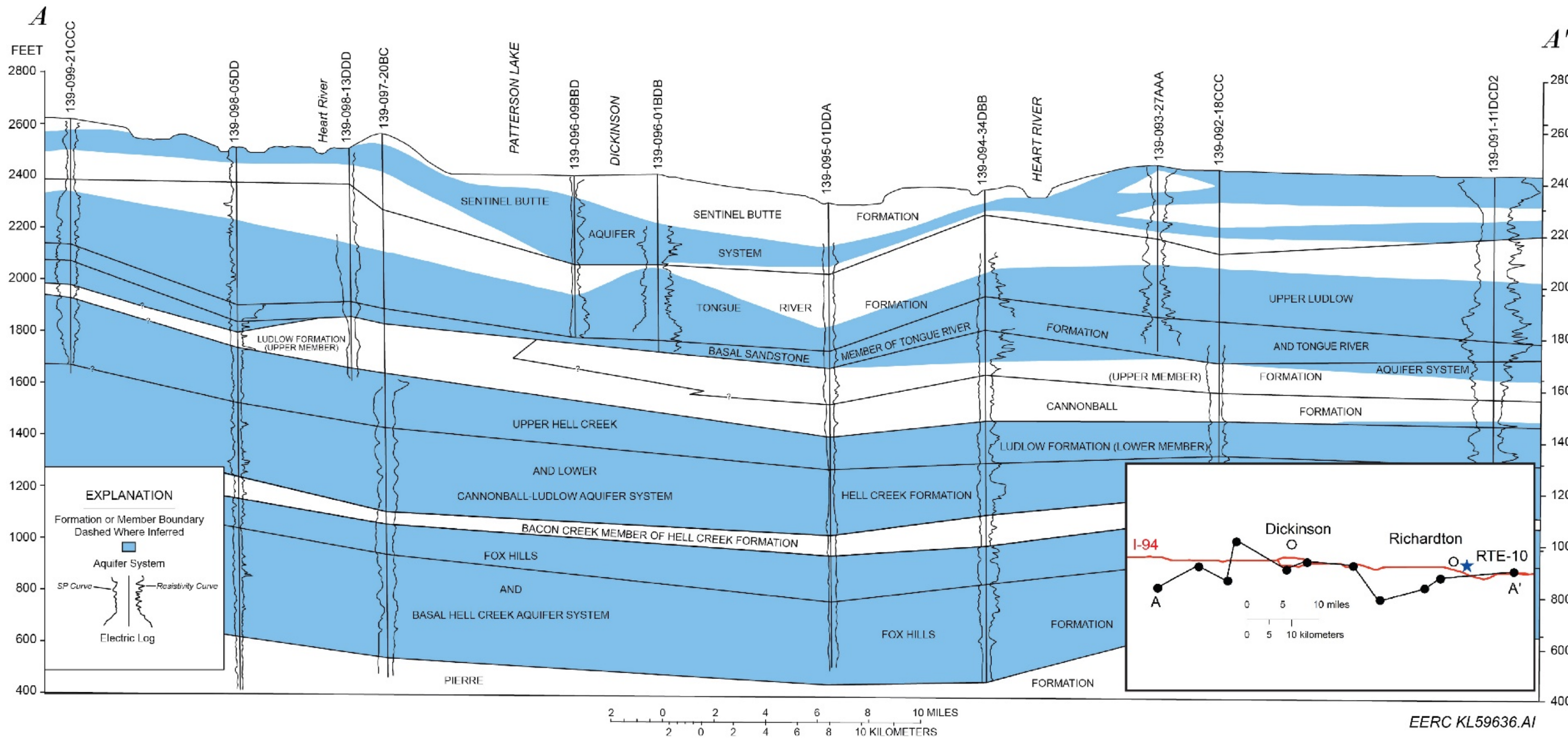


Figure 3-13. West–east cross section of the major aquifer layers in Stark County (modified from Trapp and Kroft, 1975). The black dots on the inset map represent the locations of the eleven water wells used to create the cross section. The water wells are labeled with their designation at the top of the cross section, which correlates to their township range location (e.g., 139-092-18CCC is located in T139N R92W, Section 18).

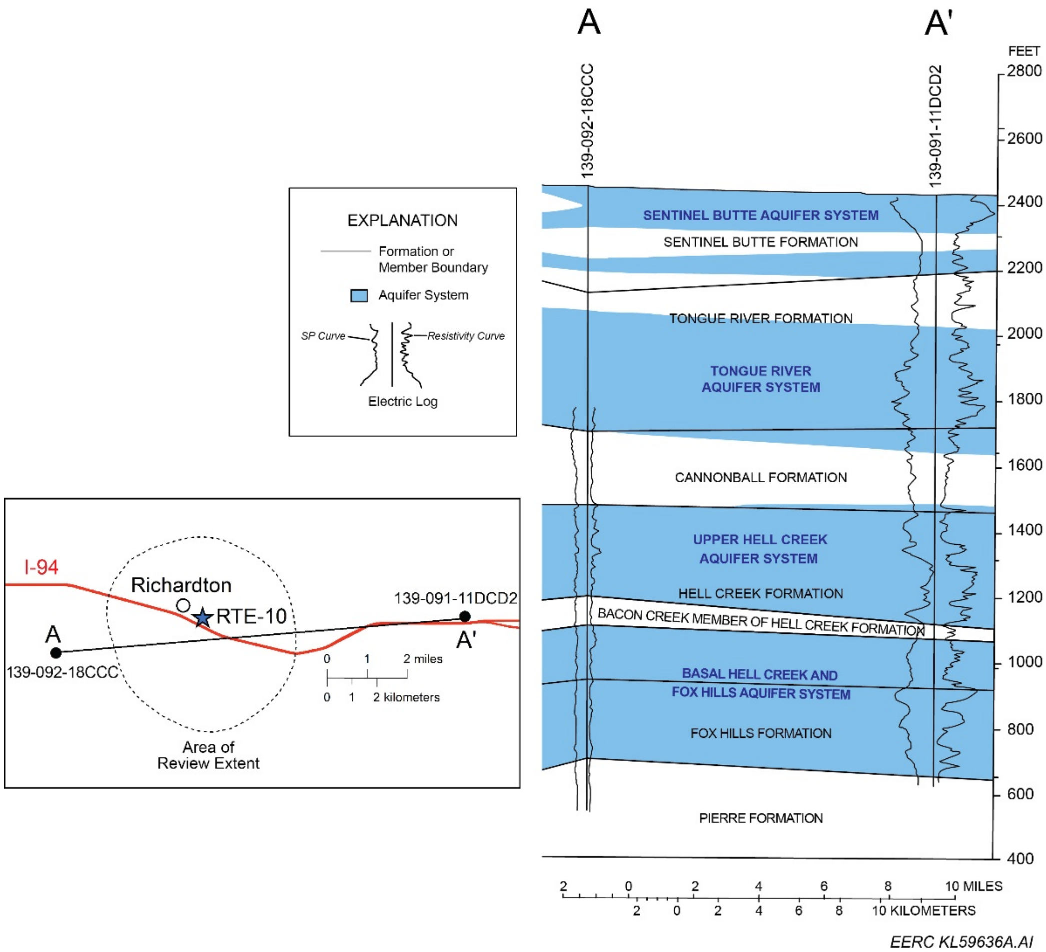


Figure 3-14. Cross section of the major aquifer layers in the RTE storage facility area (modified from Trapp and Kroft, 1975). The location of the water wells used to create the cross section are represented on the inset map. The water wells are labeled with their designation which also correlates to their township range location (e.g., 139-092-18CCC is located in T139N R92W, Section 18).

3.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AoR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous ages (Figure 3-8). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, the Jurassic-aged Piper, Reirdon, and Swift Formations, all of which overly the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature and pressure changes in the injection well (RTE-10) and the monitoring well (RTE-10.2). Results for baseline geochemical data for USDWs in the AoR can be found in Appendix C.

Above the Inyan Kara are the Cretaceous-aged shale formations Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the AoR and the primary geologic barrier between the USDWs and the injection zone. The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the AoR.

3.5 References

Fischer, K., 2013, Groundwater flow model inversion to assess water availability in the Fox Hills–Hell Creek Aquifer: North Dakota State Water Commission Water Resources Investigation No. 54.

Thamke, J. N., LeCain, G.D., Ryter, D.W., Sando, R., and Long, A.J., 2014, Hydrogeologic framework of the uppermost principal aquifer systems in the Williston and Powder River structural basins, United States and Canada: U.S. Geological Survey Groundwater Resources Program Scientific Investigations Report 2014-5047.

Trapp, H., and Croft, M.G., 1975, Geology and ground water resources of Hettinger and Stark Counties North Dakota: U.S. Geological Survey, County Ground Water Studies – 16.

4.0 SUPPORTING PERMIT PLANS

4.0 SUPPORTING PERMIT PLANS

The ten supporting plans of this permit application are listed in Table 4-1 and are provided in this section of the application. To aid in the review of these plans, it should be noted that the four monitoring-related plans (i.e., corrosion monitoring and prevention plan, surface leak detection and monitoring plan, subsurface leak detection and monitoring plan, and testing and monitoring plan) are presented under a single subsection entitled Testing and Monitoring. The other plans are presented as discrete subsections.

Table 4-1. Supporting Plans for Permit Application

Emergency and Remedial Response Plan
Financial Assurance Demonstration Plan
Worker Safety Plan
Testing and Monitoring Plan
Corrosion Monitoring and Prevention Plan*
Surface Leak Detection and Monitoring Plan*
Subsurface Leak Detection and Monitoring Plan*
Well Casing and Cementing Plan
Plugging Plan
Postinjection Site Care and Facility Closure Plan

* These plans are presented under the heading Testing and Monitoring Plan (Section 4.4).

The development of several of the plans identified in Table 4-1 was informed by a screening-level risk assessment (SLRA) of the geologic storage project, which was performed in accordance with the international standard, ISO 31000 (Leroux and others, 2017). The SLRA was conducted through a series of work group sessions involving subject matter experts (SMEs) who were asked to review 26 individual technical project risks and assign them a probability of occurrence and assess their potential impacts on cost, schedule, health and safety, legal/regulatory compliance, permitting compliance, and corporate image/public relations. These technical risks were grouped into the following five risk categories: 1) carbon dioxide (CO_2) supply, injectivity, and storage capacity (seven risks); 2) subsurface containment – lateral migration of CO_2 or formation water brine (three risks); 3) subsurface containment – propagation of subsurface pressure plume (three risks); 4) subsurface containment – vertical migration of CO_2 or formation water brine via injection wells, plugged and abandoned wells, monitoring wells, or faults/fractures (12 risks); and 5) induced seismicity (one risk). The risk assessment results indicated that all of the technical risks were ranked low, i.e., represented low-probability and low- to moderate-impact events. While the results of the SLRA indicated that there are no risks that would preclude the commercial deployment of the project, it did identify a set of operational events with the potential for endangering underground sources of drinking water (USDWs) for future monitoring and provided the basis for the identification and costing of potential emergency response actions during the geologic storage operations.

4.1 Emergency and Remedial Response Plan

This emergency and remedial response plan (ERRP) 1) describes the local resources and infrastructure in proximity to the site; 2) identifies events that have the potential to endanger USDWs during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the SLRA; and 3) describes the response actions that are necessary to manage these risks to USDWs. In addition, the integration of the ERRP with the existing emergency action plan and risk management plan of the Red Trail Energy (RTE) ethanol facility is described, emphasizing the incident action team and command structure of RTE, plant evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project.

4.1.1 Background

CO_2 produced at the ethanol production plant of RTE (U.S. Environmental Protection Agency [EPA] Facility Identifier: 100000197583) will be captured and geologically stored in close proximity to the plant location. The projected composition of the captured gas is greater than 99.9% (by volume) CO_2, with trace quantities (0.1% by volume) of nitrogen and oxygen (Leroux and others, 2018). Figure 4-1 provides the location of the ethanol production plant, which is located in Stark County, North Dakota, and the CO_2 injection well (RTE-10) and monitoring well (RTE-10.2). The well locations, including latitudes and longitudes, are provided below (Table 4-2).

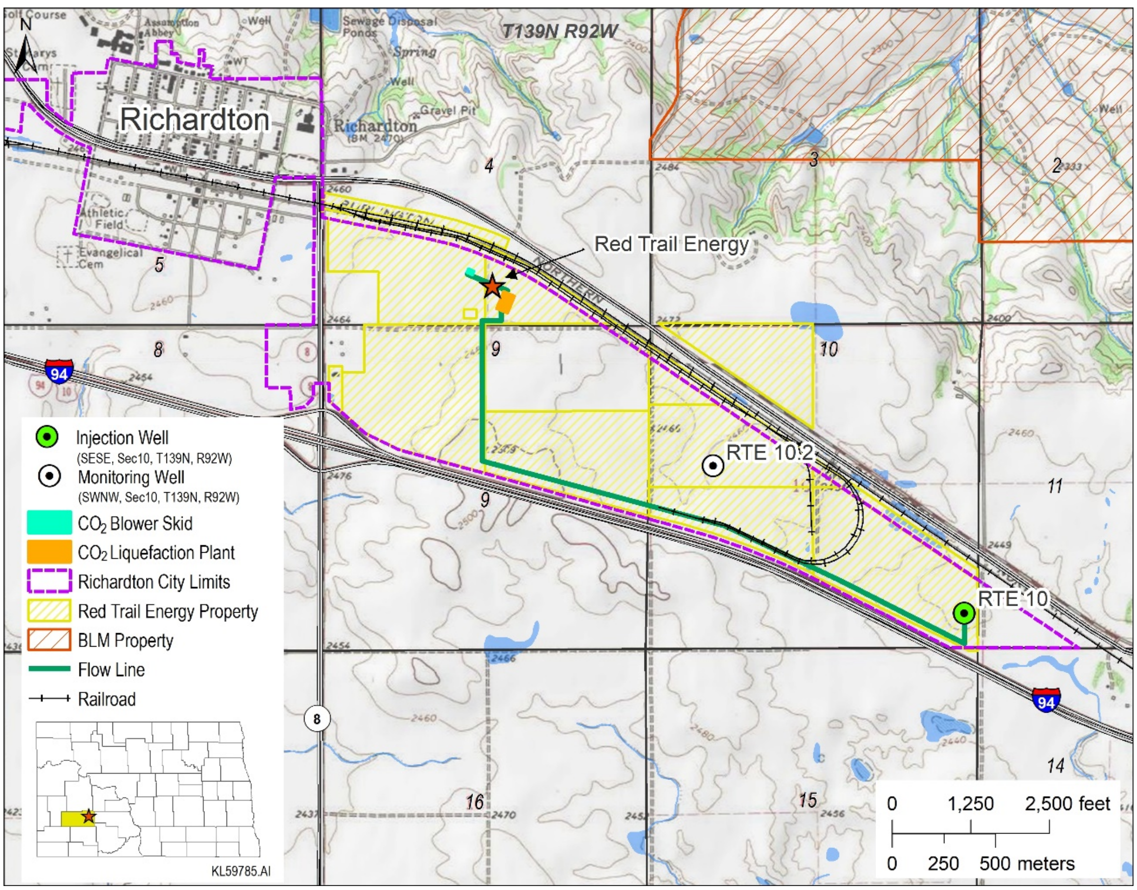


Figure 4-1. Locations of the RTE ethanol plant and CO_2 injection well (RTE-10) and monitoring well (RTE-10.2). Also shown are the city limits of Richardton, North Dakota; the RTE property limits; the Bureau of Land Management (BLM) property limits; the planned CO_2 flow line from the ethanol plant to the CO_2 injection well; and the Burlington Northern Santa Fe (BNSF) railroad.

Table 4-2. Well Name and Location Information for the CO_2 Injection Well and Monitoring Well of the RTE Geologic Storage Operations

Well Name	Purpose	NDIC* File No.	Quarter/Quarter	Section	Township	Range	Latitude	Longitude
RTE -10	CO_2 Injection Well	37229	SE/SE	10	139 North	92 West	46.864092	−102.226022
RTE-10.2	Monitoring Well	37858	SW/NW	10	139 North	92 West	46.870333	−102.282087

* North Dakota Industrial Commission.

The primary RTE contacts for the geologic storage project and their contact information are as follows:

Primary RTE Project Contacts

Individual	Title	Contact Information Office Phone Number
Gerald Bachmeier	Chief Executive Office	701.974.3308
Dustin Willet	Chief Operating Officer	701.974.3308
Tyler Mock	Environmental/Lab Manager – Safety Director	701.974.3308, ext. 1123

Contact names and information for the complete incident action team as well as key local emergency organizations/agencies are provided in a separate section of this ERRP (Section 4.1.6, Emergency Communications Plan).

4.1.2 Local Resources and Infrastructure

Local resources in the vicinity of the project that may be impacted as a result of an emergency event include 1) the holding pond at the plant; 2) one municipal water well located to the northwest within the city limits of Richardton, North Dakota; 3) three potable groundwater wells located to the west and northwest of the project; and 4) Abbey Lake, located north of Richardton.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 4-1 and includes 1) the RTE ethanol plant facilities; 2) the CO_2 injection wellhead (RTE-10) and the monitoring wellhead (RTE-10.2); 3) residential/business structures in Richardton, North Dakota; 4) railroad tracks and other infrastructure of the BNSF; and 5) Highway I-94 and Highway 10. In addition, Figure 4-2 is provided to show land use within 1 mile of the storage facility area boundary as required in North Dakota Administrative Code (NDAC) § 43-05-01-13.

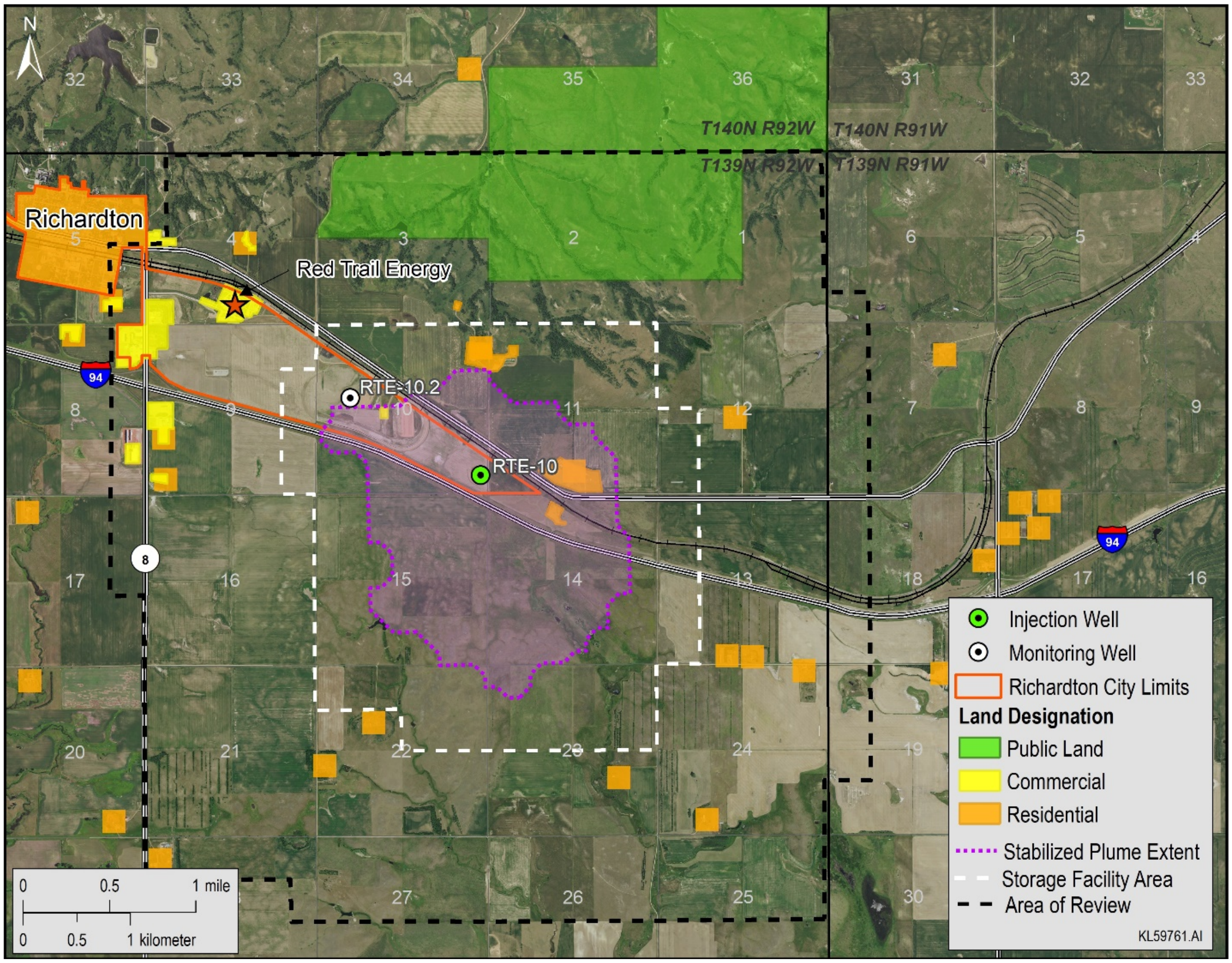


Figure 4-2. Residential, commercial, and public land use within 1 mile of the storage facility area.

4.1.3 *Identification of Potential Emergency Events*

4.1.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move injection fluid or formation fluid in a manner that may endanger a USDW during operation or postinjection site care periods. Another emergency event of interest involves the accidental release of CO_2 to the atmosphere.

Potential Project Emergency Events and Their Detection
The SLRA for the project developed a list of potential technical project risks (i.e., a risk register) which were placed into the following five technical risk categories:

- CO_2 supply, injectivity, and storage capacity
- Containment – lateral migration of CO_2 or formation fluid
- Containment – propagation of subsurface pressure plume
- Containment – vertical migration of CO_2 or formation water brine via injection wells, plugged and abandoned wells, monitoring wells, or faults/fractures
- Induced seismicity

Based on a review of these technical risk categories of the SLRA, a list of geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and require an emergency response was developed for inclusion in this ERRP. These events and means for their detection are provided in Table 4-3.

Table 4-3. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of Underground CO_2 Flow Line from CO_2 Capture System of RTE to CO_2 Injection Wellhead	Distributed temperature sensing (DTS)/distributed acoustic sensing (DAS) fiber optic cable detects a release of CO_2 from the CO_2 flow line. Frozen ground at leak site may be observed. CO_2 monitors located in the enclosed wellhead building detects realase of CO_2 from the flow line connection and/or wellhead.
Integrity Failure of Injection or Monitoring Well	Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit. Annulus pressure indicates a loss of external or internal well containment. Mechanical integrity test results identify a loss of mechanical integrity.
Injection Well-Monitoring Equipment Failure	Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.
Induced Seismic Event	Seismic readings are recorded in excess of predefined limits.

In addition to these technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquakes, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disasters (e.g., tornado or lightning strike) have the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations.

4.1.4 Emergency Response Actions

The response actions that will be taken to address the events listed in Table 4-3, as well as the natural disasters, will follow the same protocol. This protocol consists of the following actions:

- The RTE incident commander (see Section 4.1.6, Emergency Communications Plan) will be notified and, within 24 hours of that notification, make an initial assessment of the severity of the event (i.e., does it represent an emergency event).

- If designated as an emergency event, the RTE incident commander or designee shall notify the NDIC Department of Mineral Resources (DMR) Underground Injection Control (UIC) Program director pursuant to NDAC § 43-05-01-13 and implement the emergency communications plan.

- Following these actions, RTE will:

  1. Initiate a project shutdown plan (RTE may immediately cease CO_2 injection. However, in some circumstances, RTE may, in consultation with the NDIC DMR UIC Program director, determine whether gradual or temporary cessation of injection is more appropriate).

  2. Shut in the CO_2 injection well (close flow valve).

  3. Vent CO_2 from surface facilities.

  4. Limit access to the wellhead to authorized personnel only.

  5. If warranted, initiate the evacuation of the plant in accordance with the RTE action plan and communicate with local emergency authorities (e.g., Stark County) to initiate evacuation plans of nearby residents.

  6. Perform the necessary actions to determine the cause of the event and, in consultation with the NDIC DMR UIC Program director, identify and implement appropriate emergency response actions (see Table 4-4 for details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 4-3).

Table 4-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of Underground CO_2 Flow Line from the CO_2 Capture System of RTE to CO_2 Injection Wellhead	• The CO_2 release and its location will be detected by the DAS/DTS fiber optic cable and/or CO_2 wellhead monitors, which will trigger an alarm and result in the automatic shutdown of the flow line. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the shutdown of the flow line using practices similar to those used to develop the RTE risk management plan. • The pipeline failure will be inspected to determine the root cause of the flow line failure. • Repair/replace the damaged flow line, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection or Monitoring Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC Program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC Program director).
Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC Program director).

Continued . . .

Table 4-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2	• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well, soil gas profile station, and analyze them for indicator parameters (see Testing and Monitoring Plan in Section 4.4 of this document). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC Program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact: a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection following practices similar to those used to develop the RTE risk management plan. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, e.g., biological degradation, active in the environment that can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by RTE and the NDIC DMR UIC Program director) until unacceptable adverse impacts have been fully addressed.

Continued . . .

Table 4-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Induced Seismic Event	• Identify when the event occurred and the epicenter and magnitude of the event. If magnitude is greater than 2.7: 1. Determine whether there is a connection with injection activities. 2. Demonstrate all project wells have maintained mechanical integrity. 3. If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.
Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the RTE emergency action plan (in consultation with the NDIC DMR UIC Program director).

4.1.5 Response Personnel/Equipment and Training

4.1.5.1 Response Personnel and Equipment

All RTE plant and geologic storage project personnel will have undergone hazardous waste operations and emergency response (HAZWOPER) training in accordance with guidelines produced and maintained by the Occupational Safety and Health Administration (OSHA) (OSHA 29 Code of Federal Regulations [CFR] 1910.120). In addition, RTE has arranged to secure assistance from local (Richardton and Dickinson, North Dakota) and county (Stark County) emergency services to implement this ERRP.

Equipment needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a drilling rig or logging equipment or potable water hauling, etc.) is required, the RTE safety director shall be responsible for its procurement (see Section 4.1.6, Emergency Communications).

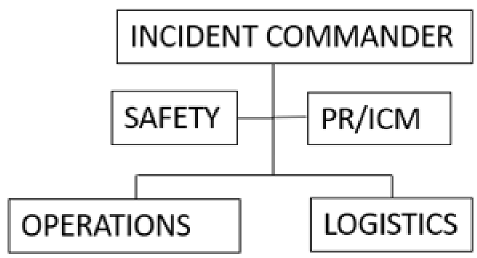
<u>Staff Training and Exercise Procedures</u>

RTE will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and plant operations training programs, which are described in the RTE safety and emergency action plans. Periodic training will be provided, not less than annually, to protect all necessary plant and project personnel. The training efforts will be documented in accordance with the requirements of the RTE plans which, at a minimum, will include a record of the trainee name, date of training, type of training (e.g., initial or refresher), and instructor name. RTE will also work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events such as a significant release of CO_2 to the atmosphere.

4.1.6 Emergency Communications Plan

An incident command system is identified in the RTE emergency action plan that specifies the organization of an incident action team at RTE and team member roles and responsibilities in the event of an emergency. The organizational structure of this system is provided below, along with the identification and contact information of each member of the incident action team.

Organization of Incident Command System



Members and Contact Information of the Incident Action Team		
Position	**RTE Employee**	**Office Phone Number**
Incident Commander (IC)	Kent Glasser	701.974.3308 ext. 1111
Public Relations (PR)/Incident Communications Manager (ICM)	Gerald Bachmeier	701.974.3308 ext. 1110
Alternate PR Manager/ICM	Kent Glasser	701.974.3308 ext. 1114
Alternate IC	Tyler Mock	701.974.3308 ext. 1123
Second Alternate IC	Ray Dobitz	701.974.3308 ext. 1107
Safety Director	Tyler Mock	701.974.3308 ext. 1123
Operations	Ray Dobitz	701.974-.3308 ext. 1107
Logistics	Tyler Mock	701.974.3308 ext. 1123

The ICM is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies, including, but not limited to, the following:

Richardton Police Department	701.974.3700
Richardton Fire Department*	701.974.2436
Richardton Ambulance	701.974.3375
Stark County Emergency Response	701.456.7605
Stark County Sheriff's Office	701.456.7610
Dickinson Police Department*	701.456.7877
North Dakota Highway Patrol	701.328.2447
North Dakota Highway Department	701.328.9921
North Dakota Poison Control	800.222.1222
County (Dickinson) Fire Department*	TBD
Medical Center*	TBD
County (Stark) Resource Management Agency*	TBD
County Fire Department*	TBD
State Emergency Response Commission*	TBD

* Those persons/agencies above marked with an asterisk have received a copy of the RTE emergency action plan.

Lastly, the RTE emergency action plan contact list also includes addresses and contact information for approximately 20 neighboring facilities and residences located within 1 mile of the ethanol plant.

4.1.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an area of review (AoR) reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, the injection rate, etc.
- As required by NDIC DMR.

Should the operational monitoring (see Section 4.4, Testing and Monitoring Plan) of the geologic storage operations identify trends that warrant a modification to the ERRP prior to the scheduled 5-year review, RTE will move forward with revising the plan and submitting a revised ERRP to NDIC DMR within 6 months of that determination.

If the 5-year review indicates that no amendments to the ERRP are necessary, RTE will provide NDIC DMR with the documentation supporting a no-amendment-necessary determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR within 6 months following their identification.

4.2 Financial Assurance Demonstration Plan

This financial assurance demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of CO_2 as prescribed by the state of North Dakota (NDAC

§ 43-05-01-09.1). The facility name, facility contact, and injection well location are provided below:

Facility Name:	RTE Ethanol Facility
Facility Contact:	Dustin Willett
Injection Well Location:	RTE-10 (NDIC File No. 37229) SE/SE of Section 10, T139N, R92W (-102.226022, 46.864092)

RTE is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- RTE has established a surety bond to cover the costs of 1) corrective action in accordance with NDAC § 43-05-01-05.1 and 2) plugging of 4-13injection wells in accordance with NDAC § 43-05-01-11.5).

- A third-party pollution liability insurance policy with an aggregate limit of $20,000,000 to cover the costs of 1) implementing postinjection site care and facility closure activities in accordance with NDAC § 43-05-01-19 and 2) implementing emergency and remedial response actions, if warranted, in accordance with NDAC § 43-05-01-13.

The estimated costs of these activities are presented in Table 4-5.

Table 4-5. Cost Estimates for Activities to Be Covered

Activity	Estimated Total Cost (millions of dollars)
Corrective Action on Wells in the AoR	0
Plugging of Injection and Monitoring Wells	0.25
Postinjection Site Care and Facility Closure	1.73
Emergency and Remedial Response (including endangerment to USDWs)	16.0
Total	17.98

The surety bond, which will identify RTE as the principal on the bond, will be provided by International Fidelity Insurance Company. International Fidelity Insurance Company meets all of the following criteria:

1. The surety company is authorized to transact business in North Dakota.

2. The surety company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the bond rating, when applicable.

3. The surety bond can be maintained until such time that the Commission determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies RTE as the insured party, is provided by the Ascot Specialty Insurance Company. The coverage limits of the policy are summarized below:

- Coverage A – Covered Location Pollution Liability – $20,000,000
- Coverage B – Miscellaneous Pollution Liability – $20,000,000
- Coverage C – Emergency and Crisis Management Costs – $20,000,000
- Coverage D – Business Income and Extra Expense – $1,000,000
- Policy Aggregate – $20,000,000

The Ascot Specialty Insurance Company meets both of the following criteria, as specified in NDAC §43-05-01-09.1(1)(g):

1. The company satisfies financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The company meets a minimum rating ("minimum rating" based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt-equity, assets-liabilities, cash return on liabilities, liquidity, and net profit) and is able to pass bond rating in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa), when applicable.

4.3 Worker Safety Plan

RTE maintains and implements a plantwide safety program that meets all state and federal requirements for worker safety protections, including OSHA and the National Fire Protection Association (NFPA). This program is described in the RTE safety plan, which includes a list of training programs that are currently in place and the frequency with which they will be reviewed and, if necessary, updated.

The CO_2 safety training program of RTE identifies the dangers of CO_2 and requires all employees and visitors to wear the proper PPE (personal protective equipment) and to perform their duties in ways that prevent the discharge of CO_2. Project personnel will participate in annual safety training to include familiarization with operating procedures and equipment configurations that are appropriate to their job assignment as well as emergency response procedures, equipment, and instrumentation. New personnel, if appropriate, will receive similar instruction prior to beginning their work. Lastly, contractors and visitors will undergo an orientation that ensures all persons on-site are trained and aware of the dangers of CO_2. Initial training will be conducted by, or under the supervision of, the safety director or his designated representative, and all trainers will be thoroughly familiar with the project operations plan and ERRP.

Refresher training will be conducted at least annually for all project personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, lessons learned based on actual experience in operating the equipment, and recent storage reservoir-monitoring information.

Only personnel who have been properly trained will participate in the project activities of drilling, construction, operations, and equipment repair. A record including the person's name, date and type of training, and the signatures of the trainee and instructor will be maintained.

4.4 Testing and Monitoring Plan

This testing and monitoring plan for the project includes an analysis of the injected CO_2, periodic testing of the injection well, a corrosion-monitoring plan for the CO_2 injection well components, a leak detection and monitoring plan for surface components of the CO_2 injection system, and a leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir. As such, this plan simultaneously meets the permit requirements for three other required plans: 1) a corrosion-monitoring and prevention plan, 2) a surface leak detection and monitoring plan, and 3) a subsurface leak detection and monitoring plan.

The combination of the above monitoring efforts is used to verify that the geologic storage project is operating as permitted and is protecting USDWs. An overview of these individual monitoring efforts is provided in Table 4-6 along with the structure/project area that is monitored.

A regular assessment and adaptation of the monitoring program (i.e., a minimum of every 5 years) will be conducted to ensure that it remains appropriate for the site and is adequately tracking the injected CO_2, thereby providing an accurate assessment of the performance of the surface/subsurface equipment and subsurface geologic structures in containing the stored CO_2.

If needed, alterations to the monitoring program (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by NDIC. Results of pertinent analyses and data evaluations conducted as part of the monitoring program will be compiled and reported, as required. Another goal of this monitoring program is to establish preinjection baseline data for the storage complex, including baseline data for nearby groundwater wells, the Fox Hills Formation (deepest USDW), and soil gas.

Additional details of the individual efforts of the monitoring program are provided in the remainder of this section.

Table 4-6. Overview of RTE Monitoring Program for the Geologic Storage of CO_2

Monitoring Type	RTE Monitoring Program	Target Structure/Project Area
Analysis of Injected CO_2	Compositional and isotopic analysis of the injected CO_2 stream	Wellhead
CO_2 Flow Line	DTS/DAS and distributed strain sensing (DSS)	Capture facility to the wellsite
Continuous Recording of Injection Pressure, Rate, and Volume	Surface pressure/temperature gauges and a flowmeter installed at the wellhead with shutoff alarms	Surface-to-reservoir (injection well)
Well Annulus Pressure Between Tubing and Casing	Annular pressure gauge for continuous monitoring	Surface-to-reservoir (injection well)
Near-Surface Monitoring	Groundwater wells in the AoR, dedicated Fox Hills monitoring wells, and soil gas sampling and analyses	Near-surface environment, USDWs
Direct Reservoir Monitoring	Wireline logging, external downhole pressure and temperature gauges, and DTS/DAS fiber optic cable	Storage reservoir and primary sealing formation
Indirect Reservoir Monitoring	Time-lapse geophysical surveys, gravity surveys, inSAR and passive seismic measurements.	Entire storage complex
Internal and external mechanical integrity	Tubing-casing annulus pressure testing (internal) DTS/DAS fiber optic cable, ultrasonic imager tool (USIT) (external)	Well infrastructure
Corrosion Monitoring	Flow-through corrosion coupon test system for periodic corrosion monitoring.	Well infrastructure

4.4.1 Analysis of Injected CO_2 and Injection Well Testing

4.4.1.1 CO_2 Analysis

Prior to injection, RTE will determine the chemical and physical characteristics of the CO_2 that has been captured for storage using appropriate analytical methods. An example of the types of chemical composition data that will be generated and compiled is shown in Table 4-7; physical characteristics of interest include density and viscosity.

Table 4-7. Chemical Components Targeted for Characterization in the Injected CO_2

Chemical Components
CO_2
Ethane
Propane
n-Butane
Hydrogen
Nitrogen
Methane
Oxygen
Water, ppm

4.4.1.2 Injection Well Integrity Tests

Until the CO_2 injection well is plugged, RTE will continuously monitor its external mechanical integrity via a DTS/DAS fiber optic cable. A baseline USIT was used to establish the initial baseline external mechanical integrity. A USIT will be ran after the first year of injection and every 5 years thereafter to verify external mechanical integrity of the injection well. Internal mechanical integrity of the injection well will be demonstrated via a tubing-casing annulus pressure test prior to injection, after the first year of injection, and every 5 years thereafter. In addition, a pressure fall-off test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity.

4.4.2 Corrosion Monitoring and Prevention Plan

The purpose of the corrosion monitoring and prevention plan is to monitor the corrosion of injection well components during the operational phase of the project to ensure that the well will meet the minimum standards for material strength and performance.

4.4.2.1 Corrosion Monitoring

Corrosion monitoring will be done using the corrosion coupon method, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. The monitoring will occur quarterly during the first year of injection (i.e., at 3, 6, 9, and 12 months after the initiation of CO_2 injection) and once a year thereafter. Wireline monitoring using USIT will also be considered for assessing the corrosion of the well casing and/or tubing.

<u>Sample Description</u>

Samples of material used in the construction of the injection well that contact CO_2 will be included in the corrosion-monitoring program. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

<u>Sample Exposure</u>

Each sample will be suspended in a flow-through apparatus, which will be located downstream of all process compression/dehydration/pumping equipment (i.e., at the beginning of the flow line to the wellhead). A parallel stream of high-pressure CO_2 will be withdrawn from the flow line, passed through the corrosion-monitoring system, and then routed back into a lower-pressure point upstream in the compression system. This loop will operate any time injection is occurring. The operation of this system will provide exposure of the samples to CO_2 that is representative of the composition, temperature, and pressures that will be present at the wellhead and injection tubing.

Sample Handling and Monitoring

The exposed materials/coupons will be handled and assessed for corrosion in accordance with ASTM International (ASTM) Method G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM International, 2017). The coupons will be photographed, visually inspected for cracking and pitting with a minimum of 10× power, dimensionally measured (to within 0.0001 in.), and weighed (to within 0.0001 g).

4.4.2.2 Corrosion Prevention

Over the lifetime of the project, anticorrosion chemicals will be added to the CO_2 streamline based on the corrosion-monitoring results, and, if warranted, consumable cathodic protection plates will be used to inhibit and/or prevent corrosion on the surface injection system. The corrosion inhibitor, which must be compatible with the CO_2, will be used in the tubing–casing annulus of the injection well prior to initiation of CO_2 injection and continuously throughout the project's lifetime. Periodic fluid sampling will be conducted at critical points in the system to determine the corrosion inhibitor's concentration and confirm that it is present at levels sufficient, but not in excess of what is needed, to prevent corrosion.

4.4.3 Surface Leak Detection and Monitoring Plan

Surface components of the injection system, including the underground CO_2 transport flow line and wellhead, will be monitored using CO_2 leak detection equipment. The flow line from the capture facility to the wellhead will be buried at least 6.5 ft underground and monitored using a DTS/DAS and DSS fiber optic cable with an interrogator system to provide the ability to detect leaks along the flow line. CO_2 detectors will be installed in the injection wellhead building and and key wellsite locations (e.g., flow line riser). Leak detection equipment will be integrated with automated audio and visual warning systems, which will be inspected and tested on a semiannual basis. Any defective equipment will be repaired or replaced within 10 days and retested, if necessary. A record of each inspection result will be kept by the site operator and maintained until project completion and be available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

4.4.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises surface/near-surface- and deep-subsurface-monitoring programs. Surface/near-surface refers to the region from ground surface down to, and including, the deepest USDW as well as surface waters, soil gas (vadose zone), and shallow groundwater (e.g., stock wells, residential drinking water wells, etc.). The deep subsurface zone extends from the base of the deepest USDW to the base of the injection zone of the storage reservoir.

Subsurface leak detection will require multiple approaches to ensure confidence that surface (i.e., ambient and workspace atmospheres and surface waters) and near-surface (i.e., vadose zone, groundwater wells, and the deepest USDWs) environments are protected, and the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for the RTE geologic storage project, near-surface monitoring will include two dedicated Fox Hills Formation monitoring wells to detect if the deepest USDW is being impacted by operations as well as two soil gas profile stations each located at the RTE-10 injection well and RTE-10.2 monitoring well sites. In addition, existing groundwater wells within the AoR have been and will continue to be periodically sampled as outlined in the monitoring program. These monitoring efforts will provide additional lines of evidence to assess whether the surface/near-surface environment is being protected and whether the CO_2 is being safely and permanently stored in the storage reservoir.

To complement near-surface/surface monitoring, additional monitoring of the subsurface will ensure CO_2 is staying in the targeted storage reservoir. Operational monitoring at the injection well (RTE-10) including injection rates, pressures, and temperatures will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection well will also be demonstrated to ensure no leakage pathway exists that may allow vertical movement of the CO_2. Additionally, geophysical (seismic) surveys conducted over regular intervals will monitor subsurface CO_2 plume movement.

More details regarding the surface, near-surface, and deep subsurface-monitoring efforts are provided in the remainder of this section.

4.4.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring

Surface and near-surface environments will be monitored to ensure that an out-of-zone migration has not occurred. This will be accomplished by monitoring the environment within the delineated AoR via groundwater wells (e.g., domestic drinking water wells, stock wells, etc.) and vadose zone soil gas sampling prior to CO_2 injection (preoperational baseline), during active CO_2 injection (operational) and during the postoperational-monitoring time frame.

RTE has completed an initial near-surface baseline sampling program, including seasonal sampling of existing groundwater wells and soil gas (Figure 4-3). This completed sampling program and the results are provided in detail in Section 4.4.6.

Prior to injection, RTE plans to install two dedicated Fox Hills Formation monitoring wells at each well site (RTE-10 injection well and RTE-10.2 monitoring well). The Fox Hills Formation will be sampled, and a state-certified laboratory analysis will be provided to NDIC prior to injection. In addition, two soil gas profile stations will be installed at each well site (RTE-10 injection well and RTE-10.2 monitoring well), and sample analysis will be provided to NDIC prior to CO_2 injection operations (Figure 4-6). The near-surface monitoring plan, including the additional baseline sampling of the Fox Hills Formation and the soil gas profile stations, is provided in Section 4.4.7

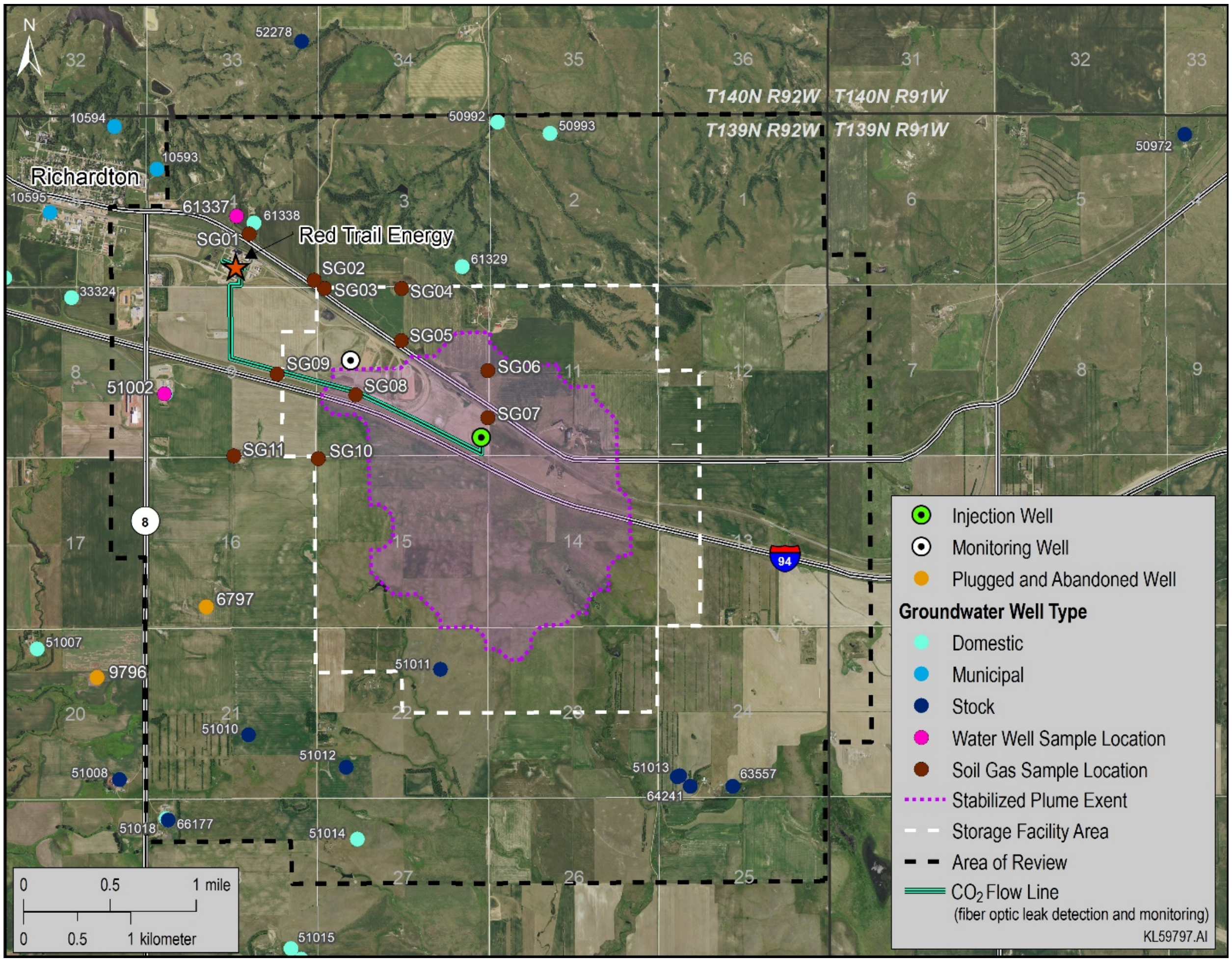


Figure 4-3. RTE completed an initial sampling program for near-surface groundwater wells and vadose zone soil gas. Shown are all sampling locations completed for the establishment of the baseline monitoring program (water well sample locations and soil gas sample locations); the location of all groundwater wells by type, including all plugged and abandoned legacy oil and gas wells; the city of Richardton; the RTE ethanol plant; the CO_2 flow line; and RTE-10 (injection well) and RTE-10.2 (monitoring well) in relation to the extent of the stabilized CO_2 plume, the storage facility area, and the AoR.

4.4.6 Completed Baseline Sampling Program

4.4.6.1 Groundwater Baseline Sampling

An initial baseline of groundwater sampling results has been acquired for the RTE project site by collecting and characterizing groundwater samples taken from Well Nos. 51002, 61337, and 10648 in May, August, and November 2019. The locations of these wells are shown in Figure 4-4, and the results of the baseline measurements for pH, specific conductivity, and alkalinity are provided in Table 4-8, with detailed laboratory analyses for each sampling event provided in Appendix C.

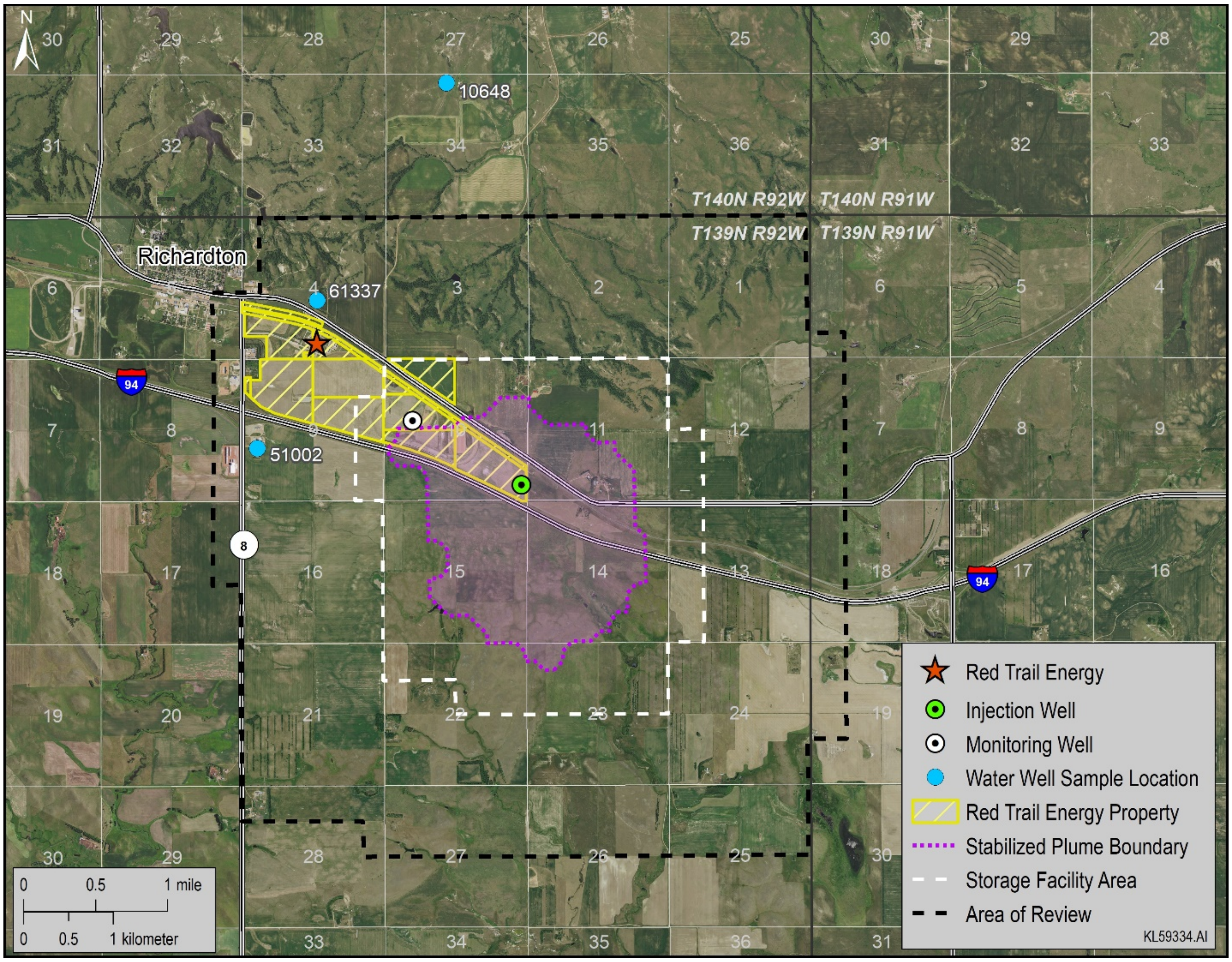


Figure 4-4. RTE completed groundwater well sampling program to establish a groundwater baseline, including seasonal fluctuation. The sample locations were located between the proposed CO_2 injection well and the city of Richardton.

Table 4-8. Baseline Groundwater-Sampling Results – May Through November 2019

Parameter	pH (pH unit)			SpC, µS/cm			Alkalinity as $CaCO_3$, mg/L		
Well No.	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**
51002	8.21	8.42	8.47	2,643	2,740	2,731	1,570	1,540	1,540
61337	8.18	8.46	8.51	1,851	1,886	1,890	1,070	1,060	1,040
10648	*	8.36	8.24	*	1,931	1,928	*	1,010	960

* Well not accessible.

4.4.6.2 Soil Gas Baseline Sampling

Soil gas sampling and analyses have also been performed in order to establish baseline soil-gas concentrations. The sampling and analyses performed to date were generated from 11 soil gas-sampling locations, as shown on Figure 4-5 and identified in Table 4-9 (SG01 through SG11), during the months of May, August, and November 2019. The analyses, which determined the concentration of CO_2, O_2, and N_2, were performed in accordance with ASTM standard procedures (D5314) for soil gas sampling and analysis (ASTM International, 2006). These analytical results were concentrated in the area around and between the injection well (RTE-10) and the monitoring well (RTE-10.2).

The sampling results from these efforts will provide a preoperational baseline of the soil gas chemistry in the vadose zone in and around the CO_2 geologic storage project.

Table 4-9. Soil Gas-Sampling Results from RTE Carbon Capture and Storage (CCS) Study Region by Sampling Date (*italicized values denote likely ambient air reading/contamination*)

Parameter:	CO_2, %			O_2, %			N_2, %		
Sample No.	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**
SG01	0.34	0.34	0.88	20.38	21.08	20.55	78.08	78.62	78.57
SG02	0.21	0.49	0.11	21.03	20.35	21.28	79.11	79.16	78.61
SG03	0.62	1.09	0.72	20.68	20.08	20.54	78.60	78.82	78.74
SG04	0.13	*	*	21.27	*	*	79.21	*	*
SG05	0.25	1.01	*0.05*	21.00	20.19	*21.29*	78.57	78.80	*78.67*
SG06	0.26	0.31	*0.07*	20.44	21.01	*21.20*	78.83	78.68	*78.73*
SG07	*	0.79	0.65	*	20.49	20.74	*	78.72	78.61
SG08	*	*0.04*	0.97	*	*21.30*	16.42	*	*78.66*	82.61
SG09	*	0.38	0.12	*	20.75	20.75	*	78.86	79.13
SG10	*0.08*	0.42	*	*20.84*	20.75	*	*77.71*	78.83	*
SG11	*0.03*	6.86	*	*21.13*	14.68	*	*78.66*	78.46	*

* Sampling location too wet to access/sample.

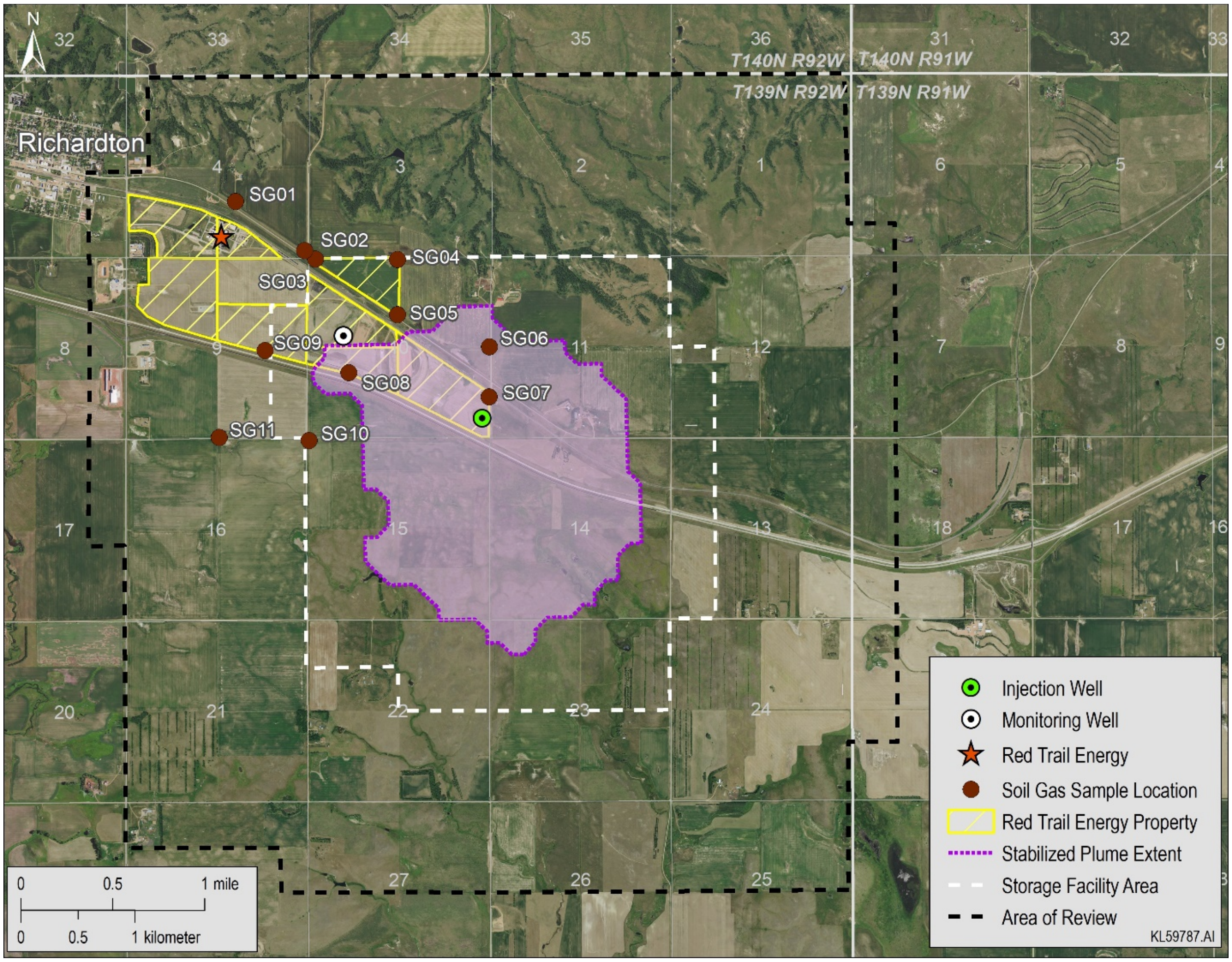


Figure 4-5. RTE completed an initial soil gas-sampling program to establish baseline soil gas concentrations, including seasonal fluctuation. The sample locations were located within and around the CO_2 injection and monitoring wells of the RTE storage site.

4.4.7 Near-Surface (Groundwater- and Soil Gas)-Monitoring Plan

Prior to injection operations, RTE will drill and construct two dedicated groundwater-monitoring wells in the Fox Hills Formation (i.e., deepest USDW) at each well site (RTE-10 CO_2 injection well and RTE-10.2 monitoring well) (Figure 4-6). Baseline Fox Hills Formation[1] water samples will be collected from these two monitoring wells prior to CO_2 injection. RTE plans to monitor the vadose zone by installing two soil gas profile stations, one each at the well sites of the RTE-10 CO_2 injection well (SS01) and RTE-10.2 monitoring well (SS02) (Figure 4-6). RTE is currently investigating Well Nos. 61329 and 51011 to determine accessibility for sampling these existing groundwater wells in the project area, both of which are located within the storage facility area of the RTE geologic CO_2 storage project site (Figure 4-6).

During the first 3 years of CO_2 injection activities, the two Fox Hills Formation monitoring wells, the soil gas profile stations located at each well site (RTE-10 CO_2 injection well and RTE-10.2 monitoring well), and select groundwater wells within the AoR will be sampled on an annual basis, and laboratory results will be filed with NDIC. Starting at Year 5 of injection operations, the Fox Hills Formation monitoring wells and existing groundwater wells will be sampled annually. The sampling of groundwater wells in the AoR will be phased in over time based on monitoring of the CO_2 plume in the injection zone. A detailed near-surface monitoring plan is presented in Table 4-10, including the frequency and duration of the sampling that will be made during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

[1] The Fox Hills aquifer underlying the RTE site and western North Dakota is a confined aquifer system which does not receive measurable flow from overlying aquifers or the underlying Pierre shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the northwest with a rate on the order of single feet per year. Thus groundwater in the Fox Hills aquifer at the RTE site is geochemically stable as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and not known to contain reactive mineralogy. Thus minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

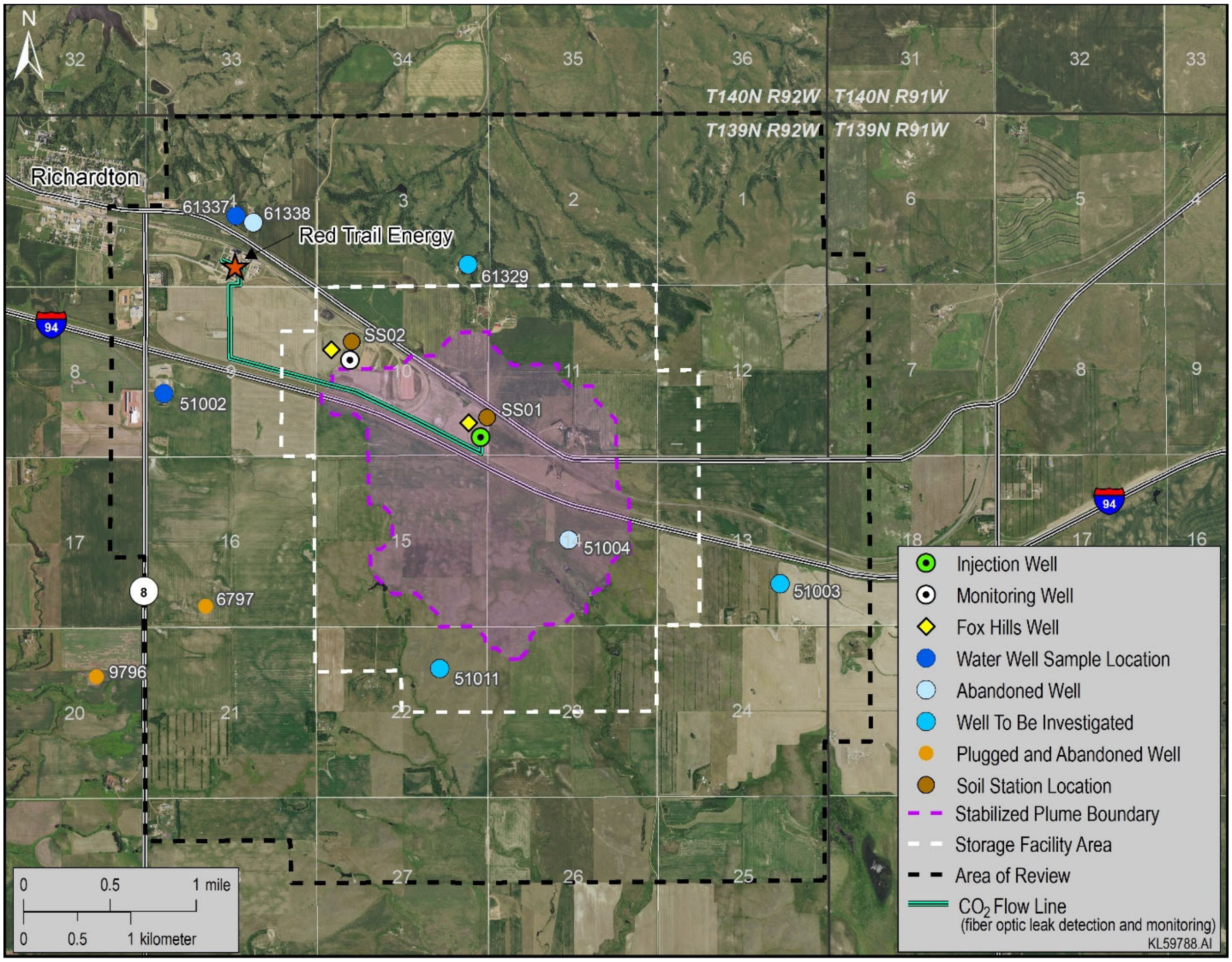


Figure 4-6. RTE near-surface monitoring plan sample locations showing the Fox Hills Formation (deepest USDW) monitoring wells, existing groundwater wells, and the two soil-gas profile stations in and around the RTE geologic CO_2 storage project site. RTE is currently investigating Well Nos. 61329 and 51011 to determine accessibility for potential sampling. Well Nos. 61338 and 51004 are both identified as abandoned in the North Dakota State Water Commission database.

Table 4-10. Baseline (preinjection), Operational, and Postoperational Monitoring Frequency and Duration for Soil Gas, and Groundwater

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Soil Monitoring			
Soil Gas Profile Stations (SS01 and SS02) (Figure 4-6) Soil Gas Probes (SG01 to SG11) (Figures 4-3 and 4-5)	Duration: minimum 1 year Frequency: Sample 3–4 events per well to establish seasonal baseline Soil gas profile stations identified in Figure 4-6 will be sampled prior to initiation of CO_2 injection operations and analyses will be combined with previously completed sampling results from soil gas probe locations SG01 to SG11, identified in Figure 4-5. Two soil-gas profile stations located at the RTE-10 and RTE-10.2 well sites (see Figure 4-6).	Duration: 20 years Frequency: 3–4 sample events per year at soil gas profile stations SS01 and SS02 (Figure 4-6) to account for seasonal fluctuation	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SS01 and SS02 (Figure 4-6) performed every 3 years following cessation of CO_2 injection.
Water Monitoring			
Groundwater (existing freshwater wells)	Duration: minimum 1 year Frequency: completed baseline sampling program (Figure 4-4). RTE is currently investigating Well Nos. 61329 and 51011 to determine accessibility for potential sampling identified in Figure 4-6.	Duration: 20 years Frequency: sampling of select groundwater wells within the AoR will occur at a minimum of once a year during Years 1–3 and during Year 5 of injection operations, then every 5 years thereafter. Wells will be phased in over time based on monitoring of the CO_2 plume in the injection zone.	Duration: 10 years Frequency: 3–4 sample events at cessation of injection and 3–4 sample events as part of the final site closure assessment.

Continued . . .

Table 4-10. Baseline (preinjection), Operational, and Postoperational Monitoring Frequency and Duration for Soil Gas, and Groundwater (continued)

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Water Monitoring			
Fox Hills Formation (deepest USDW)	Duration: minimum of 1 year Frequency: sample 3–4 events per well to establish seasonal baseline. Two Fox Hills Formation monitoring wells located at the RTE-10 and RTE-10.2 well sites (see Figure 4-6).	Duration: 20 years Frequency: sampling of Fox Hills monitoring wells will occur at a minimum of once a year during Years 1–3 and during Year 5 of injection operations, then every 5 years thereafter.	Duration: minimum 10 years Frequency: 3–4 sample events at cessation of injection and 3–4 sample events as part of the final site closure assessment.

* The preinjection baseline monitoring effort is largely complete as of the writing of this permit application. As noted in the text, selected additional samples will be collected between the submission date of this permit application and the start of CO_2 injection.

4.4.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

RTE will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume (plume) and associated pressure (pressure) relative to the permitted storage reservoir. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and postoperational periods. The methods described in Tables 4-11 and 4-12 will be used to characterize the plume and pressure within the AoR. RTE will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan. During each review, monitoring data and operational data will be analyzed, the AoR will be reevaluated, and, if warranted, the testing and monitoring plan will be adjusted accordingly. The testing and monitoring plan will be reviewed in this manner at least once every 5 years. Based on this review, it will either be demonstrated that no amendment to the testing and monitoring program is needed or that modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and that the risk profile of the storage operations is addressed moving forward. This determination will be submitted to the commission for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of CO_2 and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will in turn be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Table 4-11. Description of RTE Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Storage Reservoir Monitoring			
Monitoring During Injection Well Operations: • Flow Rates • Volumes • Surface Injection Pressure • Surface Injectate Temperature • Annulus Pressure, between tubing and long-string	Duration: 1 year Frequency: initial setup The maximum allowable injection pressure and annulus pressure will be derived from preoperational injection tests.	Duration: 20 years Frequency: continuous monitoring	Duration: minimum 10 years postinjection Convert injection well (RTE 10) to postinjection monitoring well for the postinjection monitoring period.
• Packer Fluid (corrosion inhibitor) Volume	Initial volume of packer fluid to fill casing	Record if additional volume to fill annulus. Test corrosion inhibitors effectiveness (as needed during well workovers).	Monitor fluid levels until well is plugged.
Downhole Monitoring (Injection Well RTE-10 and Monitoring Well RTE-10.2)			
• Downhole Pressure Gauge • Downhole Temperature Gauge • Distributed Fiber Optic Temperature (DTS)	Baseline temperature and pressure of the injection zone and pressure dissipation zone above (e.g., Inyan Kara)	Continuous monitoring of the injection zone and pressure dissipation zone above (e.g., Inyan Kara)	Pressure and temperature monitoring until plume stabilization. Monitoring will continue as part of postinjection site care and facility closure plan.
Wireline Logging and Retrievable Monitoring			
• Pulsed-Neutron Log (PNL)	Baseline PNL logging	Annual PNL logging to ensure fluids are contained within storage interval and ground-truth 3D seismic monitors.	At cessation of injection and once every 5 years thereafter until plume stabilization.
• Ultrasonic Imager Tool (USIT) (External Mechanical Integrity)	Baseline USIT prior to injection.	Duration: 20 years Frequency: Perform during well workovers but not more frequently than once every 5 years Will provide corroborating evidence for continuous DAS/DTS fiber optic evaluation of external casing mechanical integrity.	Duration: minimum 10 years postinjection Frequency: perform during well workovers but not more frequently than once every 5 years

Continued . . .

Table 4-11. Description of RTE Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Internal Mechanical Integrity • **Tubing-Casing Annulus Pressure Test**	Tubing-casing annulus mechanical integrity pressure testing.	Perform during well workovers but not more frequently than once every 5 years	Duration: minimum 10 years postinjection Frequency: Perform during well workovers but not more frequently than once every 5 years
External Mechanical Integrity	DTS/DAS baseline temperature and noise through the storage interval to surface.	Continuous through the storage interval to surface.	Continuous until well plugging and site reclamation
Pressure Fall-Off Test (Injection Zone)	Prior to injection	Every 5 years	None
Corrosion Monitoring	Baseline material specifications.	Quarterly sampling for loss of mass, thickness, cracking, pitting, and other signs of corrosion. Corrosion coupons placed in contact with the CO_2 stream.	None
Geophysical Monitoring			
Time-Lapse Seismic	Existing baseline 3D seismic (collected 2019) integrated in reservoir model for site characterization. 3D seismic covers the predicted extent of the CO_2 plume at the end of the operational period.	3D seismic monitor will be collected within first 5 years of injection sufficient to determine distribution of injected free-phase CO_2 plume relative to permitted area.	Time-lapse seismic surveys will continue as part of minimum 10-year post-CO_2 injection operations-monitoring plan and until stability of plume is demonstrated.
DAS/DTS	DAS/DTS fiber will deliver a baseline flow and injection profile (utilizing acoustics and temperature from the fiber optic system).	DAS/DTS fiber will give continuous profile for injected and monitoring intervals and will collect passive seismicity.	
InSAR	Feasibility of surface deformation monitoring with interferometric synthetic aperture radar (InSAR) – baseline data	Continuous monitoring of ground elevation based on relative surface deformation with InSAR	Continuous monitoring of ground elevation based on relative surface deformation with InSAR until storage facility achieves stabilization

Continued . . .

Table 4-11. Description of RTE Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Gravity	Gravity survey will be collected for baseline conditions.	To be determined. Repeat gravity survey (minimum one) collected as part of adaptive plan once adequate mass change is achieved based on reservoir simulation.	To be determined. Repeat gravity survey (minimum one) will be collected in the postoperational period to demonstrate plume stability.
Passive Seismicity	Install seismometer stations for monitoring induced seismicity.	The data collected in the surface geophones will be continuously recorded and analyzed for seismic activity.	

Table 4-12 describes the logging programs for the RTE-10 and RTE-10.2 wellbores. Included in the table is a description of fluid sampling, pressure testing, stress testing, and coring (conventional and sidewall) that will be performed. These wellbore data have been integrated with the baseline 3D seismic survey to provide a detailed reservoir description for the geologic model and to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes based on the current geologic model and simulations are shown in Figures 4-7 and 4-8. These simulated CO_2 plume extents inform the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Table 4-12. Completed Logging Program for RTE-10 and RTE-10.2

Log	Justification	NDAC Section
Ultrasonic, CCL (casing collar locator), VDL (variable-density log), GR (gamma ray), Temperature Log	Identified cement bond quality radially. Detection of cement channels (none observed). Evaluated the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density, porosity, GR, caliper, and spontaneous potential)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.	43-05-01-11.2(1c[1])
Combinable Magnetic Resonance (CMR)	Aided in interpreting reservoir permeability and determined the best location for modular dynamics testing (MDT) fluid sampling depths, packer setting depths, and stress testing depths. CMR and MDT data combined provided enhanced permeability evaluation, fluid identification, and fluid contacts.	43-05-01-11.2(1c[1])
Spectral GR	Identified clays and lithology that could affect injectivity. Also used for core to log depth correlation.	43-05-01-11.2(2)
Dipole Sonic	Identified mechanical properties including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])
Fracture Finder Log	Quantified fractures in the Inyan Kara and Broom Creek Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
MDT Fluid Sampling	Collected fluid sample from the Inyan Kara and Broom Creek for geochemical testing and TDS (total dissolved solids) quantification.	43-05-01-11.2(2)
MDT Formation Pressure Testing	Collected reservoir pressure tests to establish a pressure profile and mobility.	43-05-01-11.2(2)
MDT Stress Testing	Collected breakdown pressure, fracture propagation pressure, fracture closure pressure (minimum in situ stress) to establish injection pressure limits.	43-05-01-11.2(1c[1])

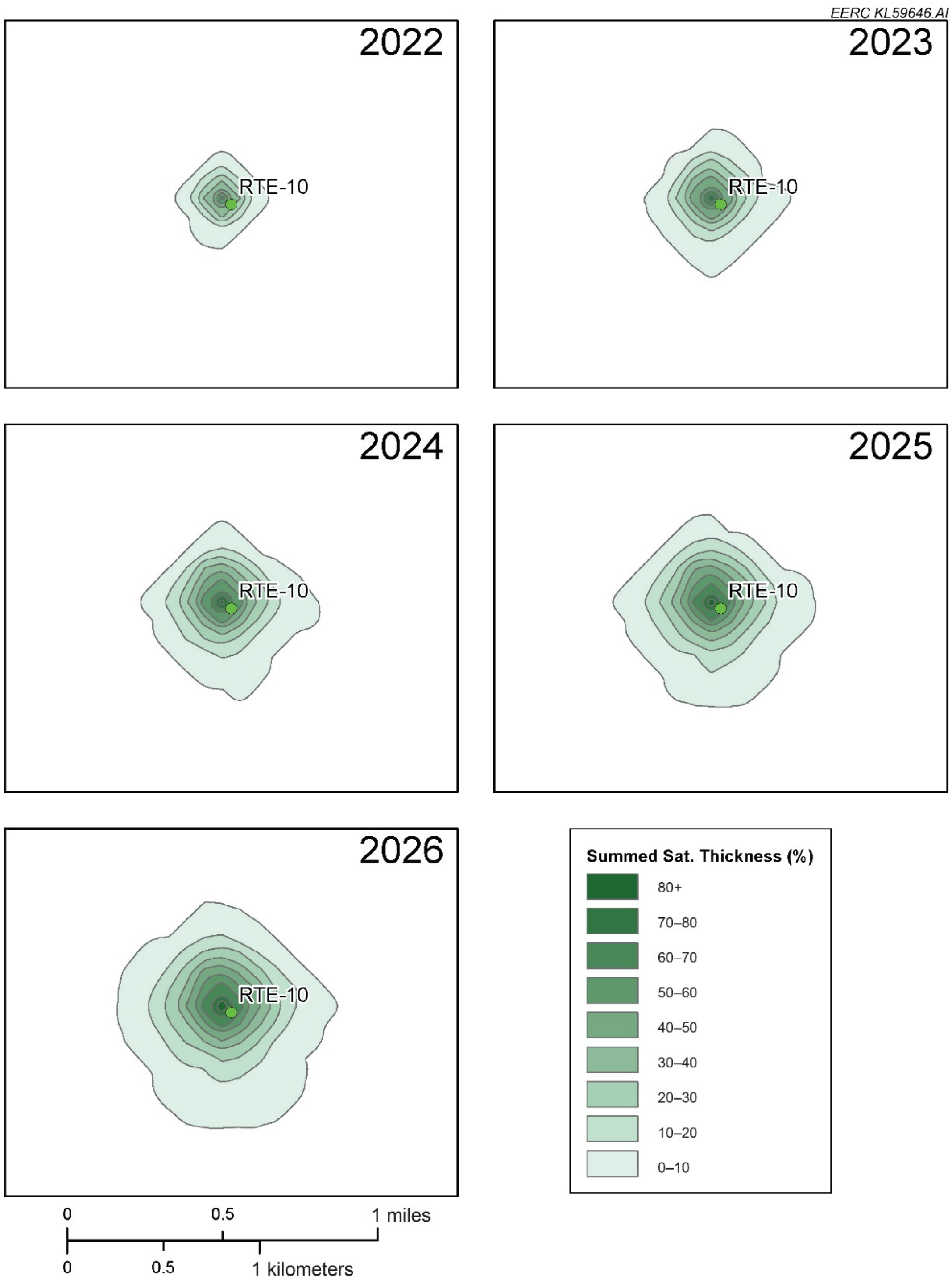


Figure 4-7. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection. The simulated plume extent at 5 years (2026) results in a CO_2 plume with a radius of ~1,500 ft.

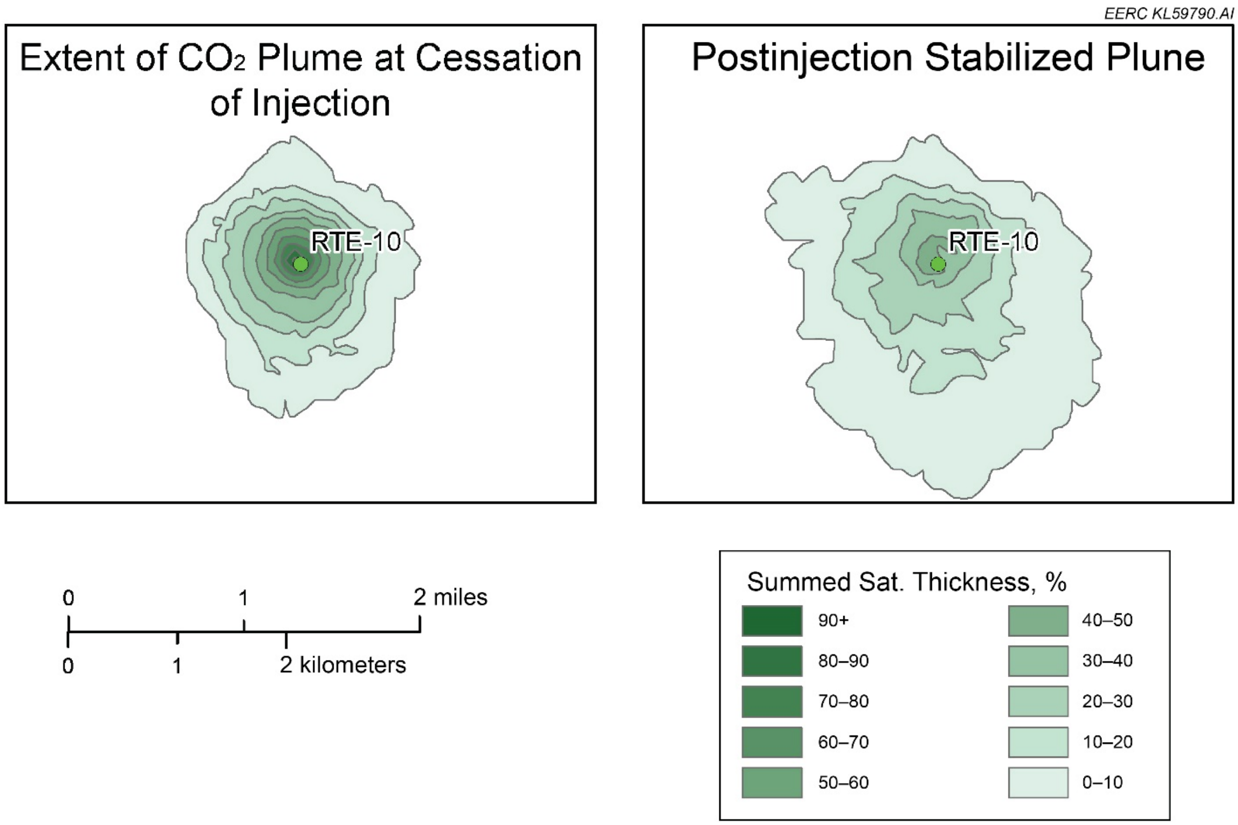


Figure 4-8. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

4.4.8.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, the injection (RTE-10) and monitoring (RTE-10.2) wells are equipped with external temperature (borehole temperature, BHT) and pressure (borehole pressure, BHP) gauges as well as fiber optics (see Figures 4-9 and 4-10). The specifications for these external gauges are provided in Figure 4-11. Continuous reservoir temperature and pressure will be monitored in both the Broom Creek Formation and the overlying Inyan Kara Formation. The pressure and temperature data collected in the overlying Inyan Kara Formation, the nearest overlying, highly permeable interval above the storage reservoir and main sealing formations, will provide confirmation of seal capacity for the Upper Confining Zone (e.g., Opeche) for monitoring the performance of the storage complex. Monitoring of the overlying interval can provide an early warning of out of zone migration of fluids, providing sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

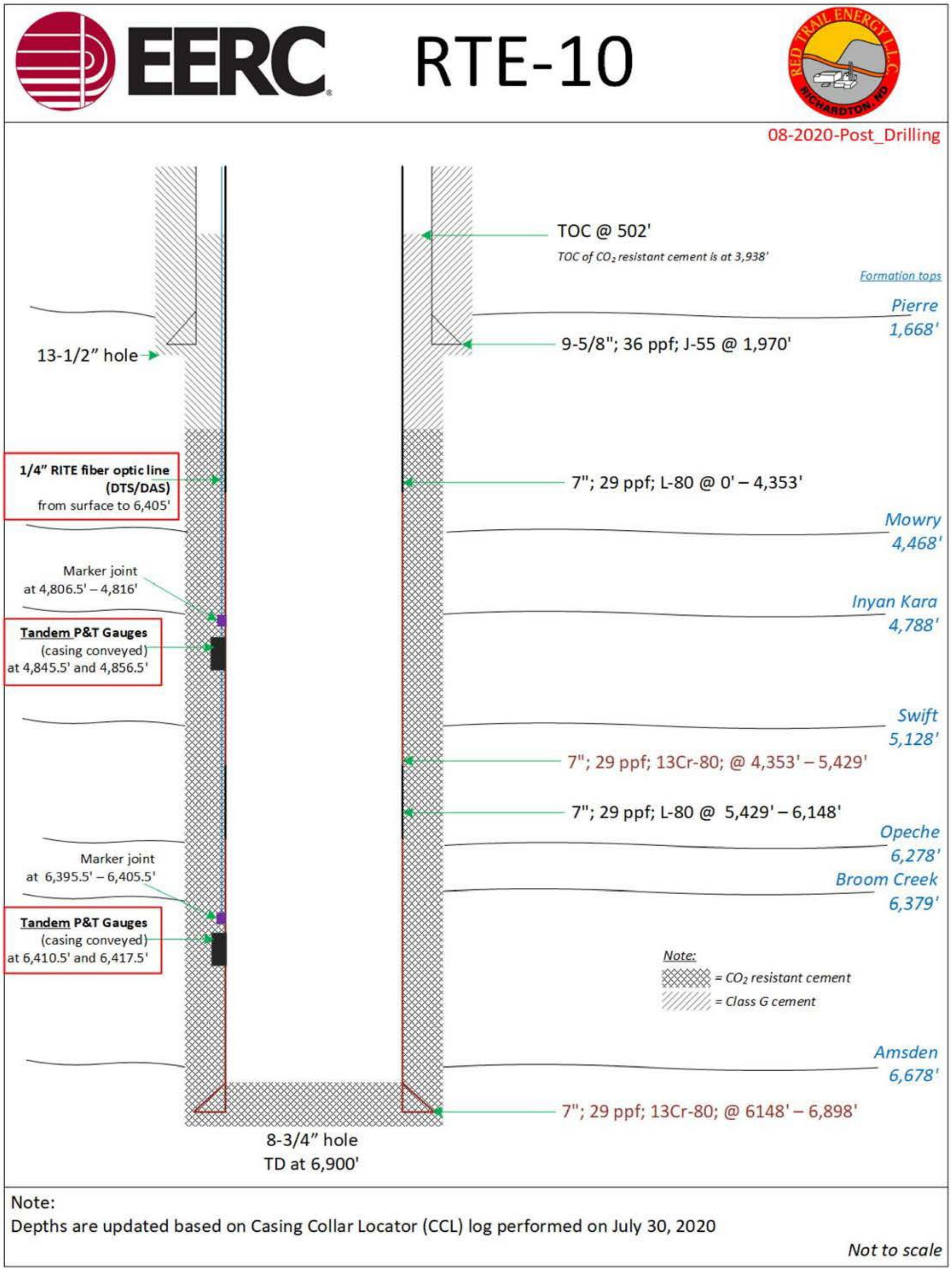


Figure 4-9. RTE-10 wellbore schematic showing placement of external BHT/BHP-monitoring gauges and fiber optic.

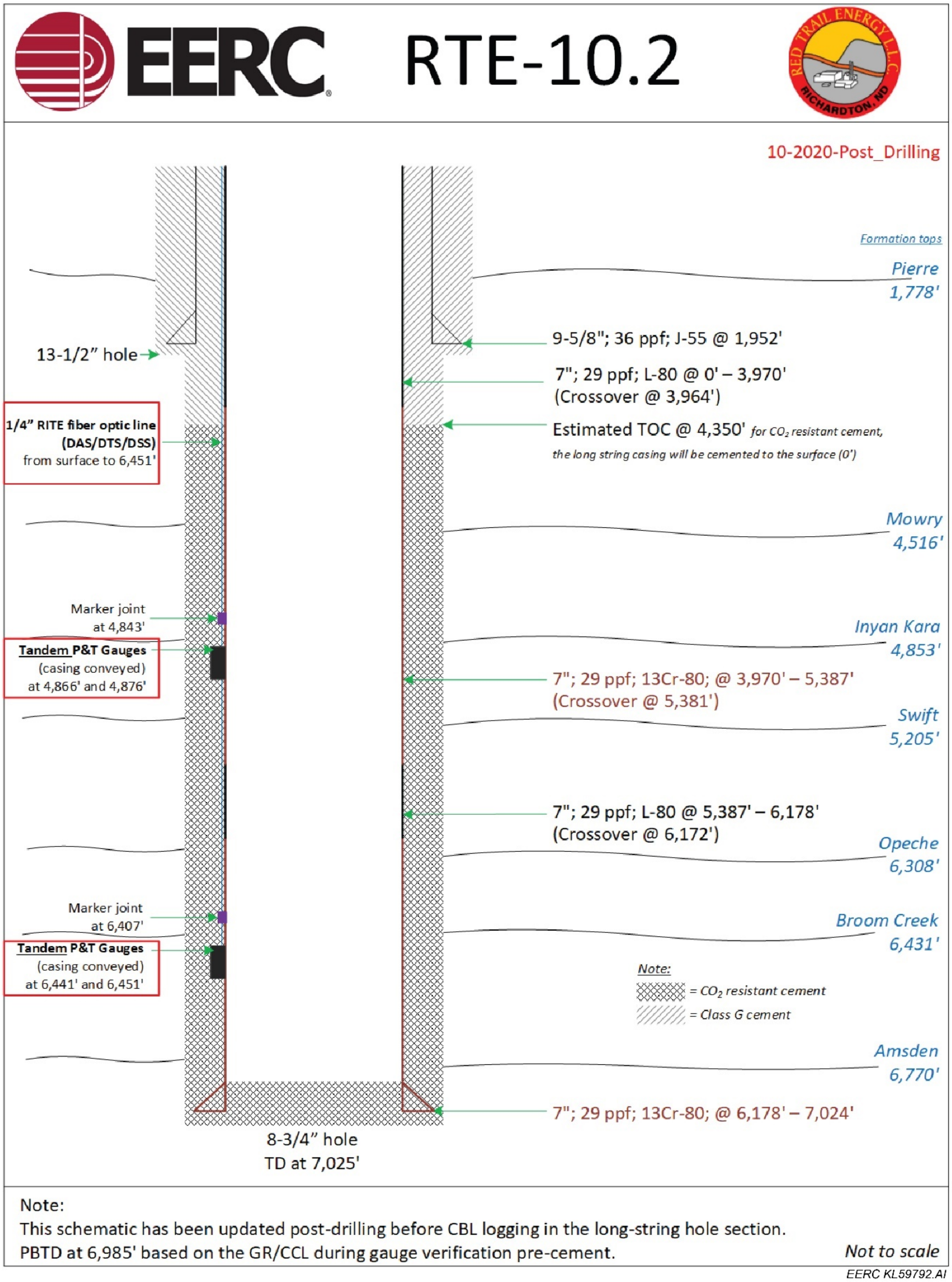


Figure 4-10. RTE-10.2 wellbore schematic showing placement of external BHT/BHP-monitoring gauges and fiber optic.

DataSphere® Array System - Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	< 0.005
Repeatability (°C)	< 0.01
Drift at 177°C (°C/year)	< 0.1

DataSphere® Array System - Temperature Performance

Pressure Range (psi/bar)	0 to 10,000 / 0 to 690
Accuracy (%FS)	0.015
Typical Accuracy (%FS)	0.012
Achievable Resolution (psi/sec)	< 0.006
Repeatability (%FS)	< 0.01
Response Time to FS Step (for 99.5% FS)	< 1 sec
Acceleration Sensitivity (psi/g – any axis)	< 0.02
Drift at 14 psi and 25°C (%FS/year)	Negligible
Drift at Max. Pressure and Temperature (%FS/year)	0.02

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Figure 4-11. Halliburton DataSphere Array System specifications for external BHT/BHP gauges installed in RTE-10 and RTE-10.2.

The distributed strain data, provided by the wellbore annulus distributed fiber optic in situ strain system (DFOSS) installed in RTE-10.2, will be aggregated and interpreted with other pressure data from the monitoring plan and integrated with the reservoir model to map the distribution of pressure associated with the free-phase CO_2 plume relative to the permitted storage facility area. The fiber optic system, installed within both RTE-10 and RTE-10.2, will also be used to acquire distributed temperature data. By interchanging the surface interrogator unit with one capable of DAS, and coupled with active seismic sourcing, vertical seismic profile (VSP) data may also be collected over time as the plan is adapted.

PNLs of the injection and monitoring wells will also be performed on an annual basis to demonstrate that fluids are not moving beyond the sealing formations. Preoperational baseline PNL data have been collected from the RTE-10 and RTE-10.2 wells. These time-lapse saturation data will be used to monitor for CO_2 in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval, or AZMI, as an assurance-monitoring technique.

4.4.8.2 Indirect Monitoring Methods

Indirect monitoring methods will also track the extent of the CO_2 plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AoR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir. Figure 4-12 shows the extent of the injected free-phase CO_2 plume at the end of 20 years of injection relative to the baseline 3D seismic and storage facility area. To demonstrate conformance between the reservoir model simulation and site performance, a repeat 3D seismic survey (4D seismic) will be collected to monitor the extent of the CO_2 plume within the first 5 years of CO_2 injection. These seismic monitoring data will provide confirmation of the simulation predictions and confirm the extents of the CO_2 plume within the AoR. Through the operational phase of the project, the 4D seismic monitoring plan will be adapted based on updated simulations of the predicted extents of the CO_2 plume. At the end of the operational phase, 4D seismic will be utilized during the postinjection period to confirm the stabilization of the plume, as defined in Appendix A. To complement the seismic monitoring surveys and, as improved time-lapse monitoring technologies emerge (e.g., borehole seismic, gravity, electromagnetic [EM], InSAR, passive seismicity), the monitoring plan will be reevaluated at least every 5 years to determine if modifications to the plan would improve the ability to characterize the migrating CO_2 plume. These indirect monitoring methods for characterization of the deep subsurface CO_2 plume are commercially available and are proven time-lapse methods. More details regarding the different indirect monitoring methods that will be employed at the proposed geologic storage site are provided in the remainder of this section.

The time-lapse seismic response (4D seismic) is a measurement of change in fluid compressibility. Since CO_2 is a highly compressible fluid, it can be tracked with conventional seismic methods. Both the surface 3D and borehole seismic (3D VSP) methods are effective for monitoring the distribution of the CO_2 plume. During CO_2 injection operations, the DAS fiber optic system provides a cost-effective and higher-resolution opportunity for monitoring the extents of the CO_2 injection with a 3D VSP. The modeled VSP coverage is illustrated in Figure 4-13. In Figure 4-14, the 3D view shows the illumination area with a radius of approximately 7,000 ft at ~100-fold. This area represents the modeled seismic reflection area based on the configuration of the fiber optic DAS in RTE-10. The simulated CO_2 plume at the end of injection operations and the simulated stabilized CO_2 plume that is reached during the postinjection period are overlain on the VSP illumination plots in Figure 4-14. These simulated plume overlays illustrate that the predicted extents of the CO_2 plume can be imaged with the 3D VSP method throughout CO_2 injection operations and the postinjection period. Figure 4-12 shows the area of VSP and 3D seismic coverage relative to these plume extents and the storage facility area.

Throughout the operational phase of injection operations, continuous monitoring of seismic activity will be performed using surface-installed geophones (sensors) on the project site and DAS fiber optic systems installed on the monitoring and injection well. The wireless sensors and DAS are capable of continuously measuring a wide range of seismicity (micro/macro events). Baseline passive seismic data will be collected both prior to injection as well as throughout the operational phase of the project.

InSAR[2] can detect small-scale surface ground deformation and has been shown to be one such technique for approximately mapping pressure distribution associated with subsurface fluid injection.[3] Geodetic methods, like InSAR, are widely available and allow for multiple nonunique interpretations requiring integration with other monitoring methods (e.g., time lapse seismic). InSAR requires continuous satellite coverage with consistent surface reflectivity.[4] In areas where there is snowfall, agricultural changes, or erosional features, the InSAR results will be uncertain and unreliable for elevation changes. To improve InSAR measurement sensitivity, reflectivity challenges can be mitigated by installing stable reflective monuments.

Gravity is a measure of mass and, when used as a time-lapse method (4D gravity), can provide a measure of mass change related to a difference in density. Monitoring with 4D gravity requires a preoperational baseline survey and monitoring through the operational and postoperational phases to provide a measure of the extents of the CO_2 plume. These data provide a quantitative measure of mass change relative to a change in fluid density over the life of the CO_2 injection. 4D gravity surveys provide a measure of density change associated with the storage interval, complementing the compressibility measurement from seismic. Gravity surveys for monitoring CO_2 densities require high-precision instruments and a significant volume of cumulative CO_2 at appropriate pressure and temperature conditions to achieve a measurable density contrast with the injected fluid.

At the conclusion of the operating phase of the project, the monitoring program will permit an assessment of the long-term containment and stability of the injected CO_2 in the storage complex. This assessment is required to secure a certificate of project completion from NDIC. To this end, monitoring of the storage complex will continue following the cessation of CO_2 injection until it can be established that the injected CO_2 plume is stable.

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[2] Donald, W. et al., 2020, Monitoring the fate of injected CO_2 using geodetic techniques: Vasco, The Leading Edge, v. 39, no. 1, p. 29.
[3] Reed_inSAR_BellCreek.
[4] PSinSAR_May2010.

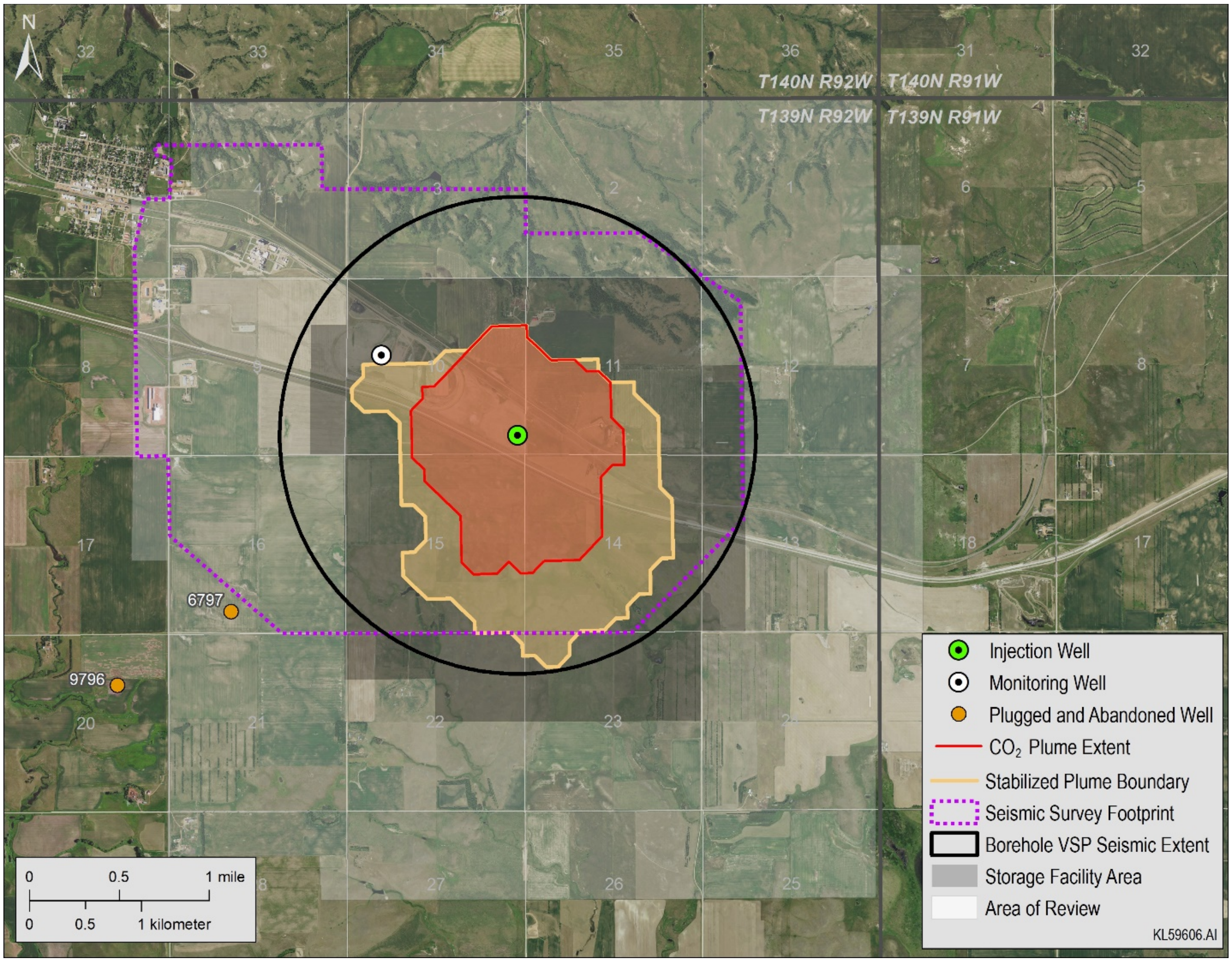

Figure 4-12. Simulated extent of the CO_2 plume at the end of injection operations in red and the stabilized CO_2 plume following the cessation of CO_2 injection in yellow. Surface seismic and borehole VSP seismic data outlines shown on the map will provide coverage for indirectly monitoring the predicted extents of the CO_2 plume over time.

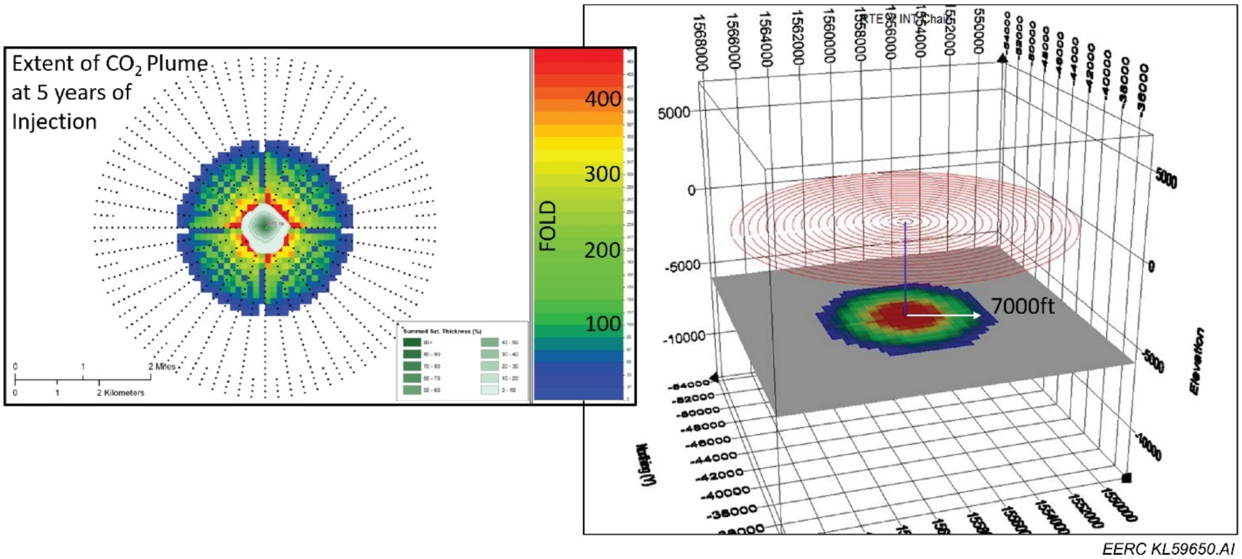

Figure 4-13. The map view (left panel) shows the VSP illumination of surface sourcing (black dots) recorded in the borehole with fiber optic DAS. Also, overlain on the illumination plot (right panel) is the simulated CO_2 plume at 5 years (2026) after the start of CO_2 injection.

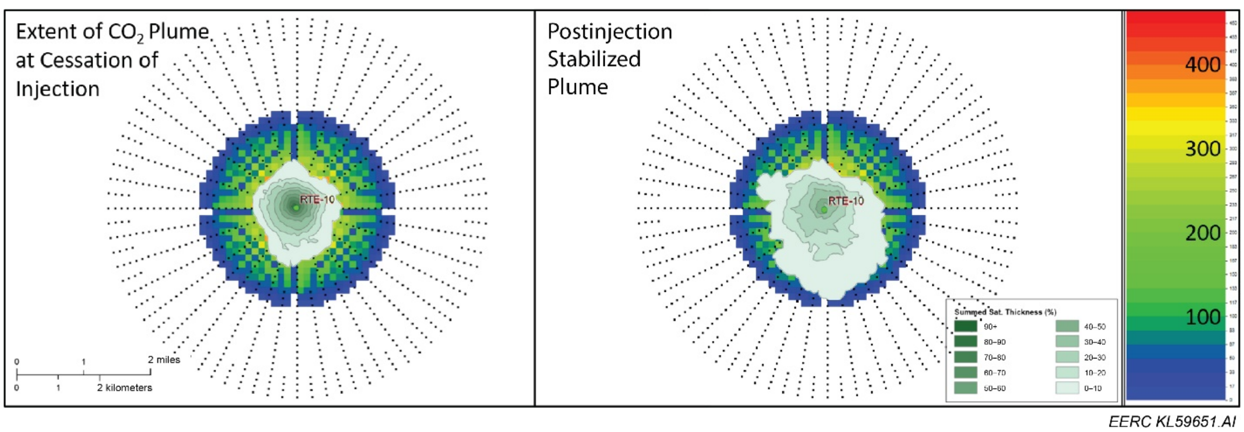

Figure 4-14. The simulated CO_2 maps at the cessation of injection (left panel) and the postinjection stabilized plume (right panel) are overlain on the VSP illumination plots from Figure 4-13. These simulated plume overlays illustrate the plume extents can be imaged with the 3D VSP method throughout CO_2 injection operations. The color bar on the right shows lowfold to highfold illumination of the Broom Creek injection interval depth.

4.4.9 Quality Assurance and Surveillance Plan

RTE has developed a quality assurance and surveillance plan (QASP) as part of the testing and monitoring plan. The QASP is provided in Appendix D of this permit.

4.5 Well Casing and Cementing Program

RTE constructed two wells: RTE-10 and RTE-10.2. Both wells were permitted and drilled as stratigraphic test wells in 2020 and were constructed in compliance with Class VI UIC injection well construction requirements. Application to convert RTE-10 to a CO_2 storage injection well and RTE-10.2 to a monitoring well is being filed in conjunction with this SFP. The following information represents the current, as-constructed state for RTE-10 (illustrated in Figure 4-15 and detailed in Tables 4-13–4-16), a radial evaluation log summary for RTE-10 (Figure 4-16) and the current as-constructed state for RTE-10.2 (illustrated in Figure 4-17 and detailed in Tables 4-17–4-20).

4.5.1 RTE-10 – As-Constructed CO_2 Injection Well Casing and Cementing Programs

The as-constructed state of RTE-10 is provided below in Figure 4-15.

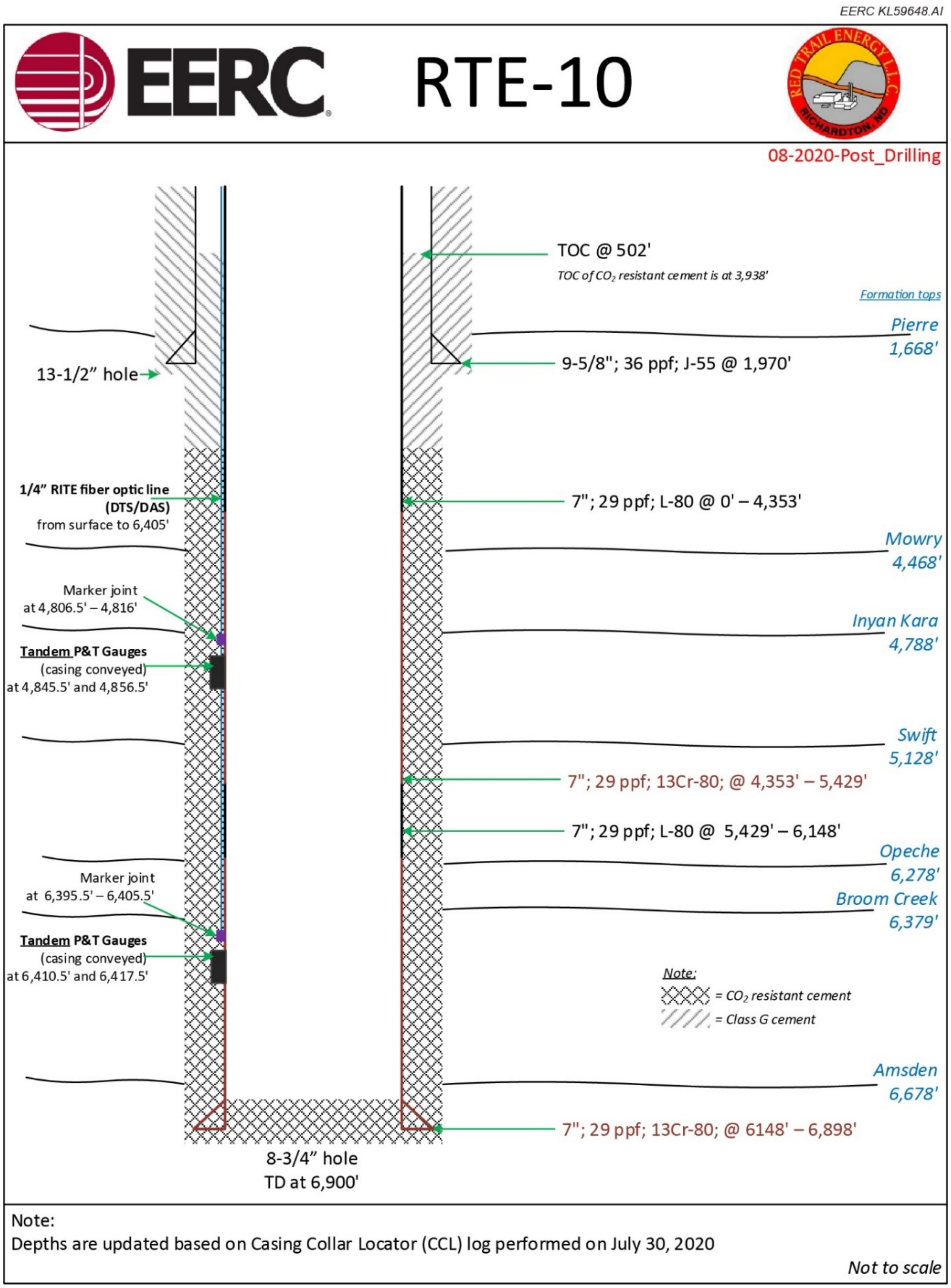

Figure 4-15. RTE-10 as-constructed wellbore schematic.

Tables 4-13–4-16 provide the casing and cement programs for RTE-10 and have been updated according to the drilling performed in April 2020. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for conversion to a CO_2 storage injection well.

Table 4-13. RTE-10 As-Constructed Well Information

Well Name:	**RTE-10**	**NDIC No.:**	**37229**	**API No.:**	**33-089-00904-00-00**
County:	Stark	**State:**	ND	**Operator:**	Red Trail Energy, LLC
Location:	SE/SE Sec. 10 T139N R92W	**Footages*:**	600' FSL 250' FEL*	**Total Depth:**	6,900'

* From the south line, from the east line.

Table 4-14. RTE-10 As-Constructed Casing Program

Section	**Hole Size, in.**	**Casing o.d., in.**	**Weight, lb/ft**	**Grade**	**Connection***	**Top Depth, ft**	**Bottom Depth, ft**	**Objective**
Surface	13½	9⅝	36	J-55	STC	0	1,970	Cover shallow freshwater aquifers
Production	8¾	7	29	L-80	LTC	0	4,353	Production casing
Production	8¾	7	29	13Cr-80	VAM TOP®	4,353	5,429	CO_2-resistant production casing
Production	8¾	7	29	L-80	LTC	5,429	6,148	Production casing
Production	8¾	7	29	13Cr-80	VAM TOP	6,148	6,898	CO_2-resistant production casing

* STC: short-thread and coupled, LTC: long-thread and coupled, VAM TOP: premium thread and coupled.

Table 4-15. RTE-10 As-Constructed Casing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, 1000 lb	
								Body	Connection
9⅝	J-55	36	STC	8.921	8.765	3,520	2,020	564	394
7	L-80	29	LTC	6.184	6.059	8,160	7,030	676	587
7	13Cr-80	29	VAM TOP	6.184	6.059	8,160	7,030	676	676

Table 4-16. RTE-10 As-Constructed Cement Program

Casing, in.	Tail		Lead		Excess, %	Volume, sacks
	Slurry	Interval, ft	Slurry	Interval, ft		
9⅝	14.2 ppg Class G cement	1,450–1,950	11.5 ppg Class G cement	0–1,450	75	726
7	15.8 ppg CO_2-resistant cement	3,938*–6,900	12.2 ppg Class G cement	502*–3,938	75	1,330

* The cement top was obtained from the radial cement evaluation. Figure 4-16 below provides Schlumberger's evaluation of the isolation scanner performed on July 30, 2020. The top of cement is at 502 ft, while the top of CO_2-resistant cement is at 3,938 ft.

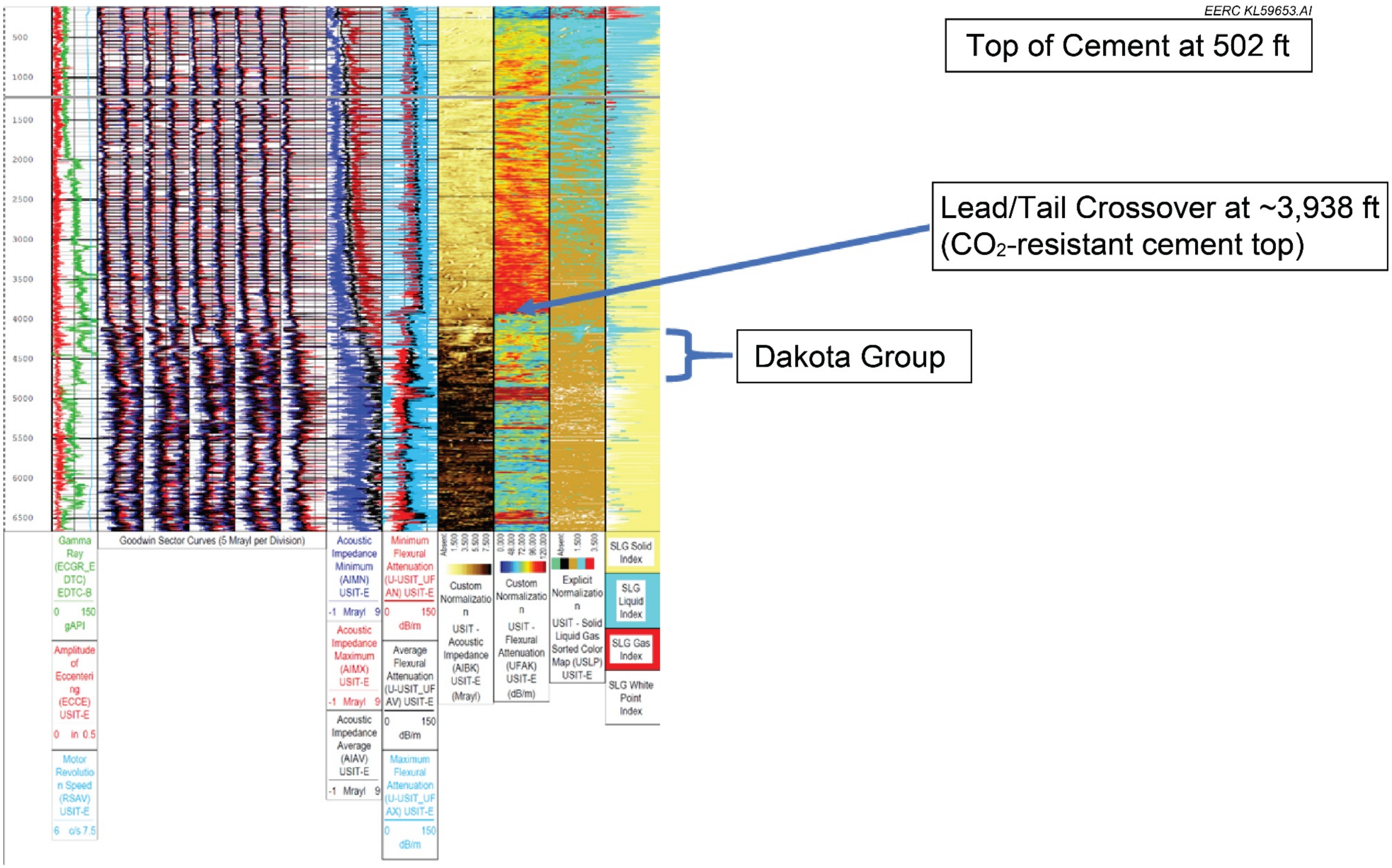

Figure 4-16. RTE-10 isolation scanner results – radial cement evaluation log summary from RTE-10 verifies the material behind the casing and the cement bond index. This enables the analyst to assess isolation in the CO_2 injection zone, confining zones, and USDWs using a high-resolution image.

4.5.2 RTE-10.2 – As-Constructed Monitoring Well Casing and Cementing Programs

The as-constructed state of RTE-10.2 is provided in Figure 4-17.

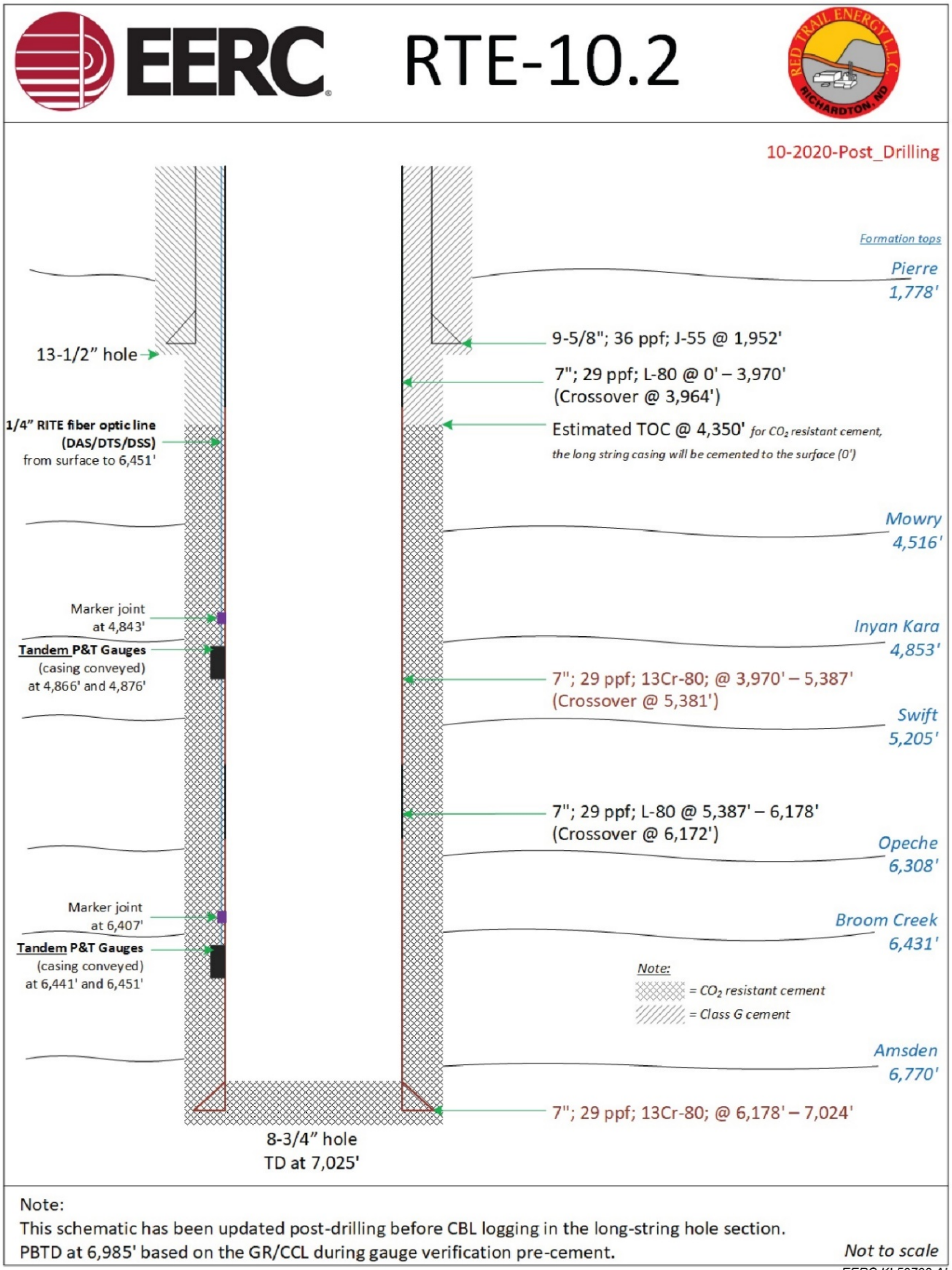

Figure 4-17. RTE-10.2 as-constructed wellbore schematic.

Tables 4-17–4-20 provide the casing and cement programs for RTE-10.2 and have been updated according to the drilling performed in October 2020. The tables demonstrate compliance with NDAC § 43-05-01-09. In addition, the materials used for construction align with NDAC § 43-05-01-09(2) for conversion to a CO_2 storage-monitoring well.

Table 4-17. RTE-10.2 As-Constructed Well Information

Well Name:	**RTE-10.2**	**NDIC No.:**	**37858**	**API No.:**	**33-089-00906-00-00**
County:	Stark	**State:**	ND	**Operator:**	Red Trail Energy, LLC
Location:	SW/NW Sec 10 T139N R92W	**Footages*:**	2,296' FNL 1,043' FWL*	**Total Depth:**	7,025'

* From the north line, from the west line.

Table 4-18. RTE-10.2 As-Constructed Casing Program

Section	Hole Size, in.	Casing o.d., in.	Weight, lb/ft	Grade	Connection*	Top Depth, ft	Bottom Depth, ft	Objective
Surface	13½	9⅝	36	J-55	STC	0	1,952	Cover shallow freshwater aquifers
Production	8¾	7	29	L-80	LTC	0	3,970	Production casing
Production	8¾	7	29	13Cr-80	Tenaris Blue®	3,970	5,387	CO_2-resistant production casing
Production	8¾	7	29	L-80	LTC	5,387	6,178	Production casing
Production	8¾	7	29	13Cr-80	Tenaris Blue	6,178	7,024	CO_2-resistant production casing

* STC: short-thread and coupled, LTC: long-thread and coupled, Tenaris Blue: premium thread and coupled.

Table 4-19. RTE-10.2 As-Constructed Casing Properties

								Yield Strength, 1,000 lb	
o.d., in.	**Grade**	**Weight, lb/ft**	**Connection**	**i.d., in.**	**Drift, in.**	**Burst, psi**	**Collapse, psi**	**Body**	**Connection**
9⅝	J-55	36	STC	8.921	8.765	3,520	2,020	564	394
7	L-80	29	LTC	6.184	6.125*	8,160	7,030	676	587
7	13Cr-80	29	Tenaris Blue	6.184	6.125*	8,160	7,030	676	676

* Special drift of 6.125 in. API (American Petroleum Institute) standard for 7-in. 29# casing is 6.059 in.

Table 4-20. RTE-10.2 As-Constructed Cement Program

	Tail		Lead			
Casing, in.	**Slurry**	**Interval, ft**	**Slurry**	**Interval, ft**	**Excess, %**	**Volume, sacks**
9⅝	14.2 ppg Class G cement	1,400–1,940	11.5 ppg Class G cement	0–1,400	100	735
7	14.5 ppg CO_2-resistant cement	4,350*–7,025	11.5 ppg Class G cement	0*–4,350	100	1,524

* The cement top will be confirmed once the radial cement evaluation log is performed.

4.6 Plugging Plan

The plugging plans for both RTE-10 and RTE-10.2 are intended to be interpreted as proposed conditions and do not reflect the current as-constructed state for both wells. The schematics and procedures in this section are to illustrate what the estimated wellbore conditions will look like before and after the plugging and abandonment (P&A) in each case. Also, the plugging operations are likely to occur at different points in the life cycle for each well. RTE-10 will most likely be plugged and abandoned when CO_2 storage and injection operations cease. RTE-10.2 is likely to be plugged and abandoned after monitoring of the CO_2 plume determines stability within the plume extent.

The CO_2 storage injection well, RTE-10, will satisfy the above requirements at the end of the injection life cycle. The plugging plan will be provided to a representative from NDIC, who will be present during the plugging operations. This will also be documented during workover reports. The plugging record will show that the material used will be compatible with CO_2 and isolate the injection zone.

The CO_2 storage-monitoring well, RTE-10.2, may be plugged at a later time when the CO_2 plume has stabilized postinjection. When it has been verified the plume is in a stable condition, all requirements stated above will be fulfilled during plugging operations. An NDIC representative will be notified of the plugging plan and will also be present and documented by the workover site supervisor. Materials used during the plugging process will be compatible with CO_2 and ensure isolation of the injection zone.

4.6.1 RTE-10: P&A Program

Description of P&A Technique

A proposed CO_2 injection well schematic of RTE-10 is provided in Figure 4-18.

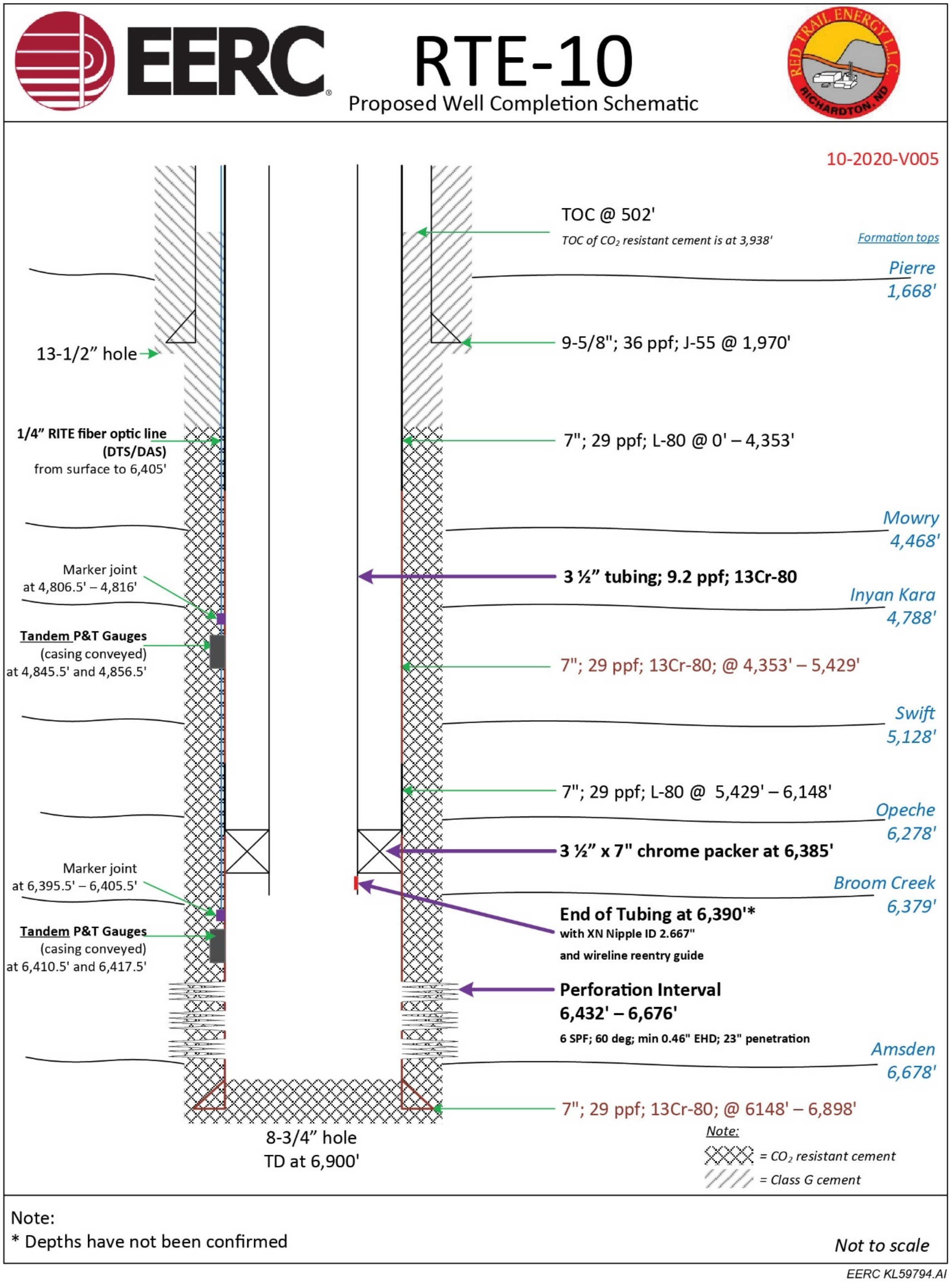

Figure 4-18. Proposed CO_2 injection well schematic for RTE-10.

The NDIC–DMR will be contacted, and an intent to plug and abandon RTE-10 will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on wellbore conditions at that time and NDIC field inspector recommendations. Currently, the proposed procedure for P&A of the well is as follows.

Prepare Well for P&A

The wellbore is to be plugged and abandoned at the end of the injection of CO_2. API standards, NDIC regulations, and best management practices will be employed to control the well at all times. Well work will be performed by experienced crews and contractors and supervised by RTE, with other competent and experienced engineers and NDIC DMR personnel on-site as necessary. Safety and environmental measures will be in place to ensure the well-being of all personnel and subsequent site reclamation.

1. Record bottomhole reservoir pressure for Broom Creek Formation using casing-conveyed gauges – NDAC § 43-05-01-11.5(2a).
   Note: calculate the required corrosion-inhibited kill fluid weight based on bottomhole reservoir pressure plus 200–500 psi for overbalanced pressure. Appropriate storage volume of weighted kill fluid will be stored in portable tanks on location.

2. Move in and rig up (MIRU) workover rig. Move in rental tools, 2⅞-in., 6.4-lb, L-80, external upset end (EUE) work string.

3. Kill well by pumping calculated weight and volume of corrosion-inhibited kill fluid down 3½-in. injection string. Ensure wellhead, tubing, and annular/casing pressures are showing 0 psi and stable.

4. Nipple down (ND) wellhead. Install blowout preventer (BOP), and test low/high 250 psi/ 4,000 psi.

5. While maintaining a hole full of kill fluid, trip out of hole (TOOH) with 3½-in. injection tubing, seal assembly, and locator sub, and lay down 3½-in. tubing with thread protectors. Also, remove injection packer at 6,385 ft.

Proposed Well Completion Tubular Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, klb
7	L-80	29	LTC	6.184	6.059	7,030	8,160	587
7	13Cr-80	29	VAM TOP	6.184	6.059	7,030	8,160	676
3½	13Cr-80	9.2	JFEBEAR™	2.992	2.867	10,540	10,160	207.2

6. MIRU wireline services to perform external mechanical integrity test and set 7-in. cast iron cement retainer (CICR).

7. Install lubricator and pressure-test to 4,000 psi for 10 minutes.

8. Make up and run in hole (RIH) with ultrasonic log–variable-density log (VDL) –casing collar locator (CCL) –temperature–GR log from plug back total depth (PBTD) (anticipated at ~6,853 ft from GR–CCL log run by GoWireline on April 24, 2020, for gauge depth verification) to surface for external mechanical integrity test – NDAC § 43-05-01-11.5(2b). *Note: The proposed logs satisfy requirements for determining external mechanical integrity* – NDAC § 43-05-01-11.2(1d).

9. Make up and RIH with CICR. Set CICR at 6,427 ft, or 5 ft above top perforation.

10. Rig down and move out (RDMO) wireline unit and crew.

Isolate Broom Creek Formation

Perforations will be isolated pursuant to NDAC § 43-05-01-11.5. They will be isolated with a CO_2-resistant cement.

11. RIH with 2⅞-in. L-80 work string and sting-in into the CICR.

12. Rig up (RU) cementing equipment. Mix and pump 134 sacks (sx) of **CO_2-resistant cement** to squeeze from 6,427 to 6,853 ft. Displace with corrosion-inhibited spacer fluid. *Note: Assumptions on the cement properties are 14.2 ppg, 100% excess, and a yield of 1.33 ft^3/sack.*

13. Unsting 2⅞-in. work string from CICR.

14. TOOH and lay down with work string to ± 6,397 ft. Mix and pump a cement plug of 47 sx **CO_2-resistant cement** to plug interval of 6,228–6,427 ft. Displace with corrosion-inhibited spacer fluid. *Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.*

Isolate Dakota Group

The Inyan Kara Formation will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be a CO_2-resistant cement plug placed inside the casing.

15. TOOH and lay down with work string to ±4,838 ft. Mix and pump a balanced plug of 99 sx **CO_2-resistant cement** to plug interval of 4,418–4,838 ft. Displace with corrosion-inhibited spacer fluid. *Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.*

Isolate Surface Casing Shoe

16. TOOH and lay down with work string to ±2,020 ft. Mix and pump a balanced plug of 122 sx Class G cement to plug interval of 1,568–2,020 ft. Displace with corrosion-inhibited spacer fluid.

Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.

Isolate Surface

17. TOOH and lay down with work string to ±115 ft. Mix and pump a balanced plug of 20 sx Class G cement to plug interval of 40–115 ft. Displace with corrosion-inhibited spacer fluid. *Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.*

18. TOOH and lay down remainder of work string.

19. RD cementing equipment.

20. ND BOP and RDMO workover rig.

21. Dig out wellhead and cut off casing 5 ft below ground level (GL). Weld 1/2-in. steel cap on casing with well name, date inscribed (confined space entry), and information that it was used for CO_2 injection. Dig out deadman if applicable – NDAC § 43-05-01-19(6). *Note: Cut off the cables (casing-conveyed gauges and fiber optic).*

22. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

23. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for RTE-10 is provided in Figure 4-19 and summarized in Table 4-21.

Table 4-21. Summary of P&A Plan for RTE-10

Cement Plug Number	Interval Range, ft		Thickness, ft	Volume, sacks	Note
1	6,427	6,853	426	134	CO_2-resistant cement plug from CICR to PBTD. Squeezed cement will isolate perforations in the Broom Creek.
2	6,228	6,427	199	47	CO_2-resistant cement plug isolates the Broom Creek Formation and 50 ft above the top of the Opeche Formation.
3	4,418	4,838	420	99	CO_2-resistant balanced cement plug 50 ft above the top of the Mowry Formation and 50 ft below the top of the Inyan Kara Formation.
4	1,568	2,020	452	122	Class G balanced cement plug to isolate the 9⅝-in. casing shoe.
5	40	115	75	20	Class G balanced surface cement plug.

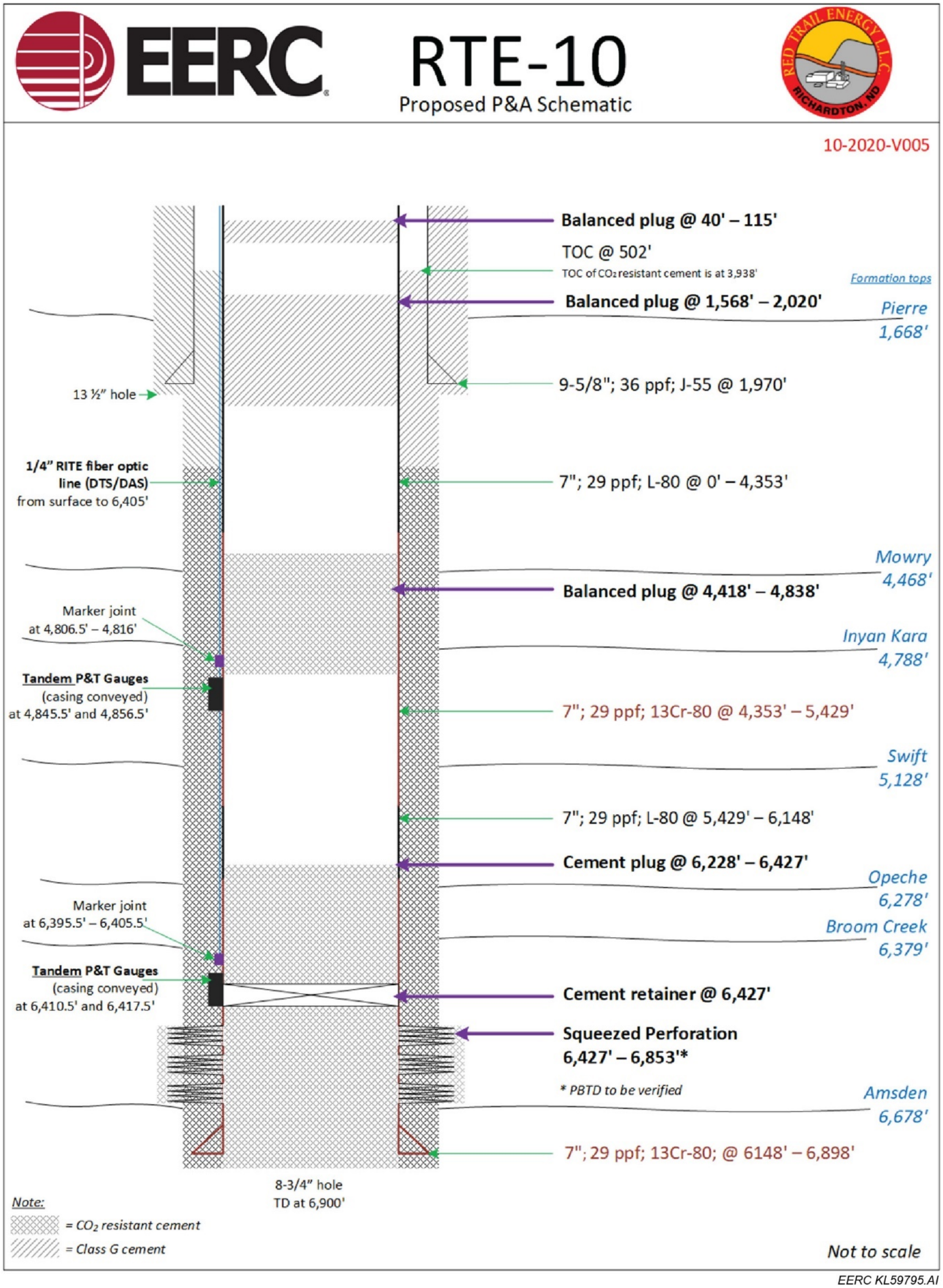

Figure 4-19. Schematic of proposed abandonment plan for RTE-10.

4.6.2 RTE-10.2: P&A Program

Description of P&A Technique

A proposed CO_2-monitoring well schematic of RTE-10.2 is provided in Figure 4-20.

The procedure for P&A of the well will be performed as follows.

Prepare Well for P&A

The wellbore is to be plugged and abandoned when the CO_2 plume has stabilized and monitoring of the plume extent is no longer necessary. API standards, NDIC regulations, and best management practices will be employed to control the well at all times. Well work will be performed by experienced crews and contractors and supervised by RTE, with other competent and experienced engineers and NDIC DMR personnel on-site as necessary. Safety and environmental measures will be in place to ensure the well-being of all personnel and subsequent site reclamation.

1. Record bottomhole reservoir pressure for Broom Creek Formation using the casing-conveyed gauges – NDAC § 43-05-01-11.5(2a).

2. MIRU workover rig. Move in rental tools, 2⅞-in., 6.4-lb, L-80, EUE work string.

3. ND wellhead. Install BOP, and test low/high 250 psi/4,000 psi at 6,426 ft.

Proposed Well Completion Tubular Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, klb
7	L-80	29	LTC	6.184	6.059	7,030	8,160	587
7	13Cr-80	29	Tenaris Blue	6.184	6.125	7,030	8,160	587
3 ½	13Cr-80	9.2	JFEBEAR	2.992	2.867	10,540	10,160	207.2
2 ⅞	L-80	6.4	EUE	2.441	2.347	11,170	10,570	105.6

4. MIRU wireline services to perform external mechanical integrity test.

   Make up and RIH with ultrasonic log-VDL–CCL–temperature–GR log from PBTD (anticipated at ~6,985 ft from GR–CCL log run by GoWireline on October 19, 2020, for gauge depth verification) to surface for external mechanical integrity test – NDAC § 43-05-01-11.5(2b).

   Note: The proposed logs satisfy requirements for determining external mechanical integrity – NDAC § 43-05-01-11.2(1d).

5. RDMO wireline unit and crew.

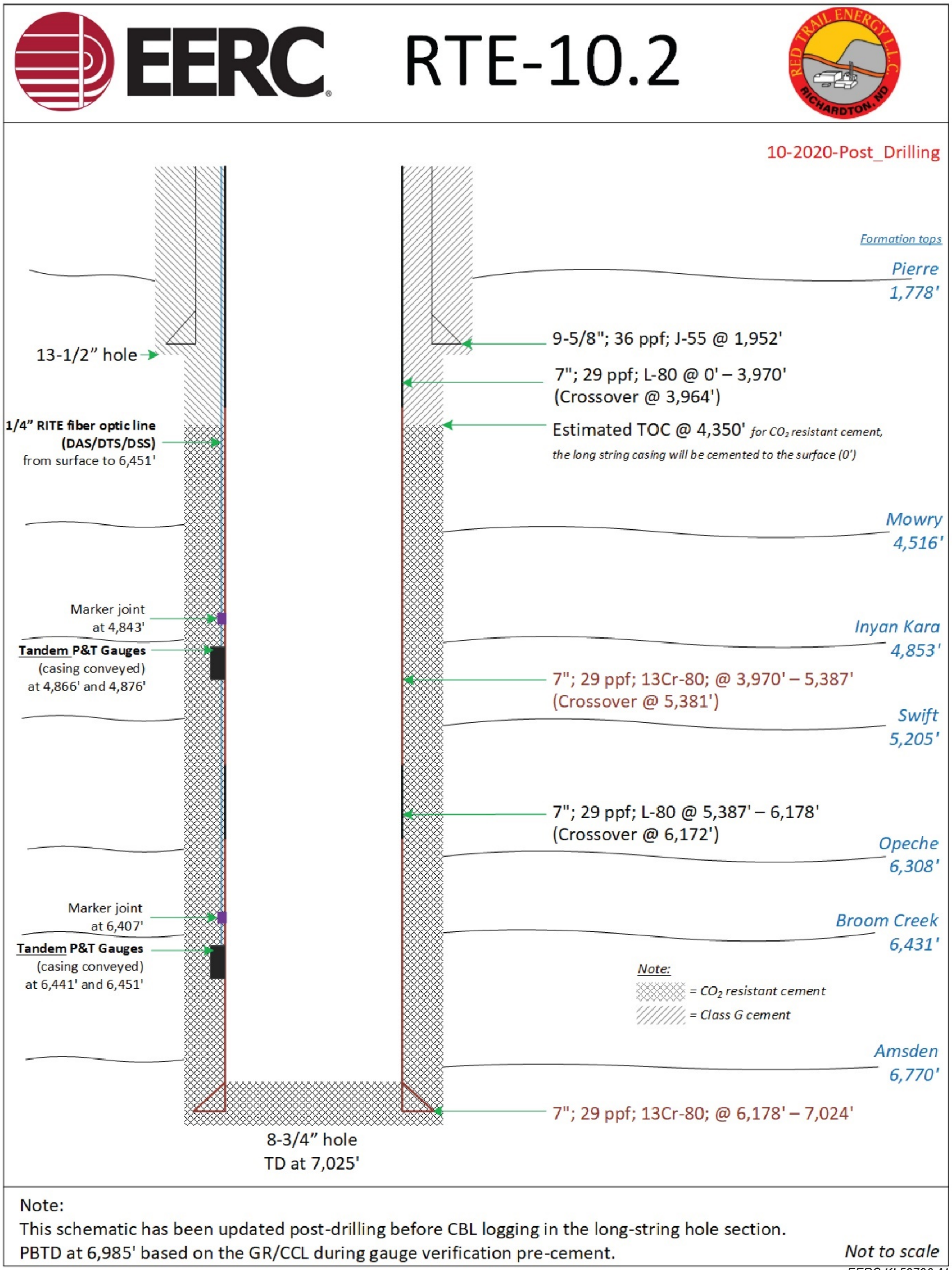

Figure 4-20. Proposed CO_2-monitoring well schematic for RTE-10.2.

Isolate Broom Creek Formation

This interval will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be a CO_2-resistant cement plug placed inside the casing.

6. RIH with 2⅞-in. L-80 work string to ±6,258 ft.

7. RU cementing equipment. Mix and pump a cement plug of 171 sx **CO_2-resistant cement** to plug interval of 6,258–6,985 ft. Displace with corrosion-inhibited spacer fluid.
   Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.

Isolate Dakota Group

This interval will be isolated pursuant to NDAC § 43-05-01-11.5. The method of isolation will be cement plugs placed inside the casing.

8. TOOH and lay down with work string to ±4,903 ft. Mix and pump a balanced plug of 103 sx **CO_2-resistant cement** to plug interval of 4,466–4,903 ft. Displace with corrosion-inhibited spacer fluid.
   Note: Assumptions on the cement properties are 14.2 ppg, 50% excess, and a yield of 1.33 ft^3/sack.

Isolate Surface Casing Shoe

9. TOOH and lay down with work string to ±2,002 ft. Mix and pump a balanced plug of 87 sx Class G cement to plug interval of 1,678–2,002 ft. Displace with corrosion-inhibited spacer fluid.
   Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.

Isolate Surface

10. TOOH and lay down with work string to ±115 ft. Mix and pump a balanced plug of 20 sx Class G cement to plug interval of 40–115 ft. Displace with corrosion-inhibited spacer fluid.
    Note: Assumptions on the cement properties are 15.8 ppg, 50% excess, and a yield of 1.16 ft^3/sack.

11. TOOH and lay down remainder of work string.

12. RD cement equipment.

13. ND BOP and RDMO workover rig.

14. Dig out wellhead and cut off casing 5 ft below GL. Weld ½-in. steel cap on casing with well name, date inscribed (confined space entry), and information that it was used for CO_2 injection. Dig out deadman if applicable – NDAC § 43-05-01-19(6).
    Note: Cut off the cables (casing-conveyed gauges and fiber optic).

15. Within 60 days, submit Form 7 plugging report after plugging operations are complete – NDAC § 43-05-01-11.5(4).

16. Submit notice of intent to reclaim to NDIC 30 days in advance prior to reclamation – NDAC § 43-05-01-18(10d).

The proposed P&A plan for RTE-10.2 is in Figure 4-21 and summarized in Table 4-22.

Table 4-22. Summary of P&A Plan for RTE-10.2

Cement Plugs Number	Interval Range, ft		Thickness, ft	Volume, sacks	Note
1	6,258	6,985	727	171	CO_2-resistant cement plug 50 ft above the top of the Opeche Formation to PBTD.
2	4,466	4,903	437	103	CO_2-resistant balanced cement plug 50 ft above the top of the Mowry Formation and 50 ft below the top of the Inyan Kara Formation.
3	1,678	2,002	324	87	Class G balanced cement plug to isolate the 9⅝-in. casing shoe.
4	40	115	75	20	Class G balanced surface cement plug.

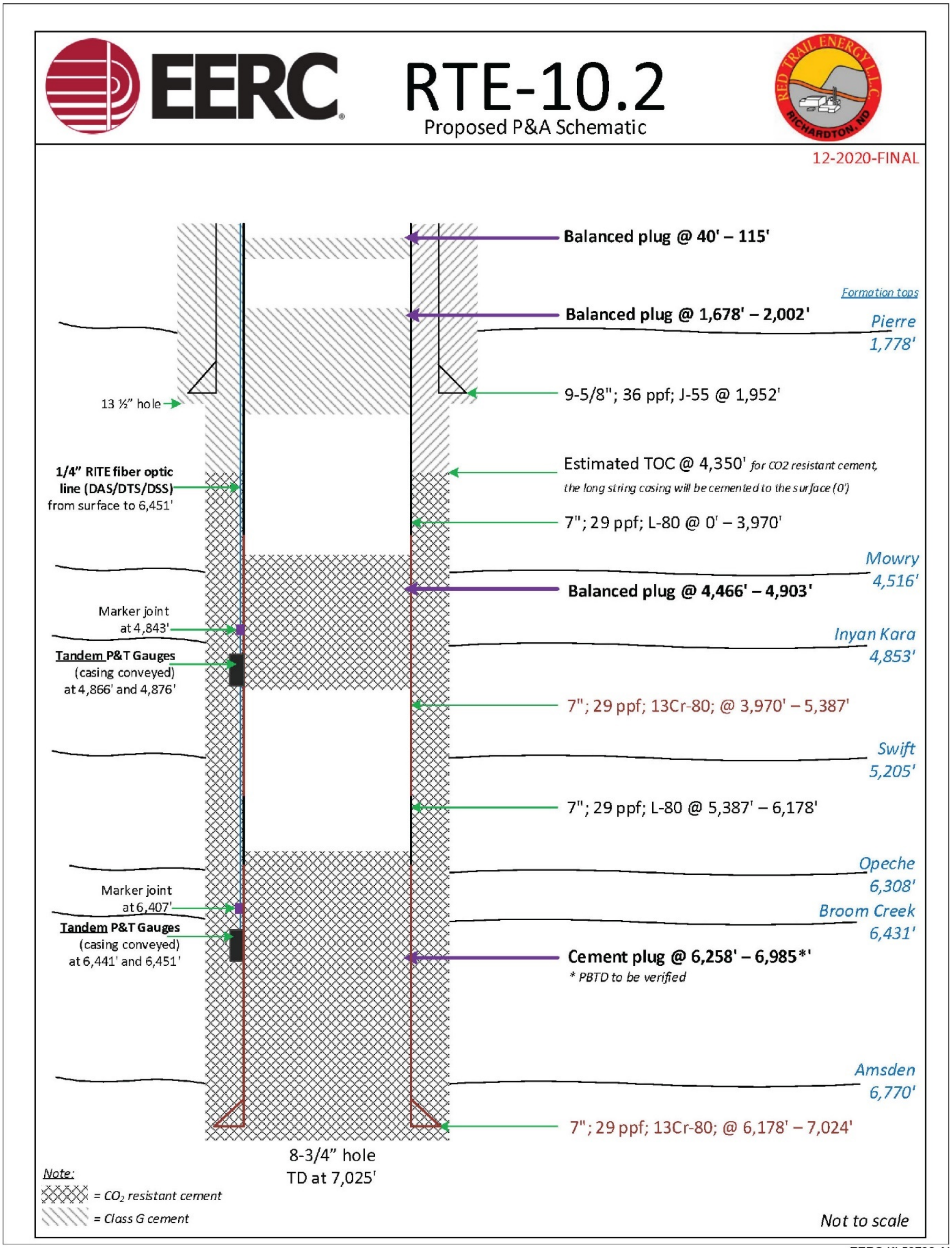

Figure 4-21. Schematic of proposed abandonment plan for monitoring well RTE-10.2.

4.7 Postinjection Site and Facility Closure Plan

This postinjection site care (PISC) and facility closure plan describes the activities that RTE will perform following the cessation of CO_2 injection to achieve final closure of the site. A primary component of this plan is a postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable, i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area. Based on current simulations of the CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (see Appendix A). Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current predictions of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume. The nature and duration of that extension will be determined based on an update of this plan and NDIC approval.

In addition to executing the postinjection monitoring program, the Class VI injection and monitoring wells will be plugged as described in the plugging plan of this permit application (Section 4.6), all surface equipment not associated with long-term monitoring will be removed, and the surface land of the site will be reclaimed to as close as is practical to its original condition. Lastly, following the plume stability demonstration, a final assessment will be prepared to document the status of the site and submitted as part of a site closure report.

4.7.1 Predicted Postinjection Subsurface Conditions

4.7.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection at a rate of 180,000 tonnes per year, followed by a postinjection period of 10 years. Figure 4-22 shows the predicted pressure differential at the conclusion of 20 years of CO_2 injection. As shown, at the time that CO_2 injection operations have stopped, the model predicts an increase in the pressure of the reservoir, with a maximum pressure differential of 35 to 40 psi at the location of the injection well. It is important to note that this maximum pressure increase is not sufficient to move formation fluids from the storage reservoir to the deepest USDW. The details of this pressure evaluation are provided as part of the AoR delineation of this permit application (see Appendix A). A description of the predicted decrease in this pressure profile over the 10-year postinjection period is provided in Figure 4-23. As expected, the pressure in the reservoir gradually decreases over time following the cessation of CO_2 injection, with the pressure at the injection well after 10 years of postinjection predicted to decrease 25 to 30 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoir is anticipated to continue over time until the pressure of the storage reservoir approaches the original storage reservoir pressure conditions prior to any CO_2 injection activities.

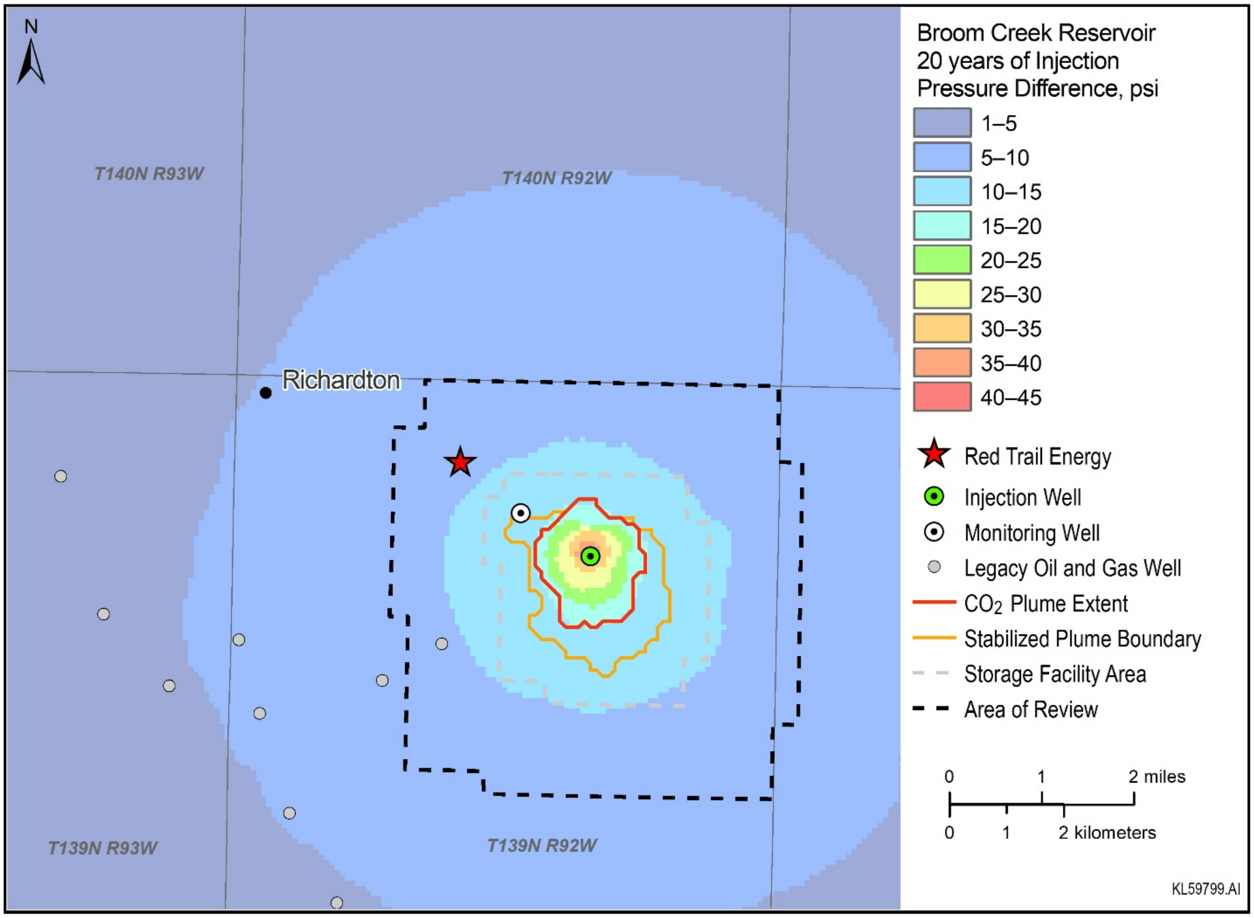

Figure 4-22. Predicted pressure increase in storage reservoir following 20 years of injection of 180,000 tonnes per year of CO_2.

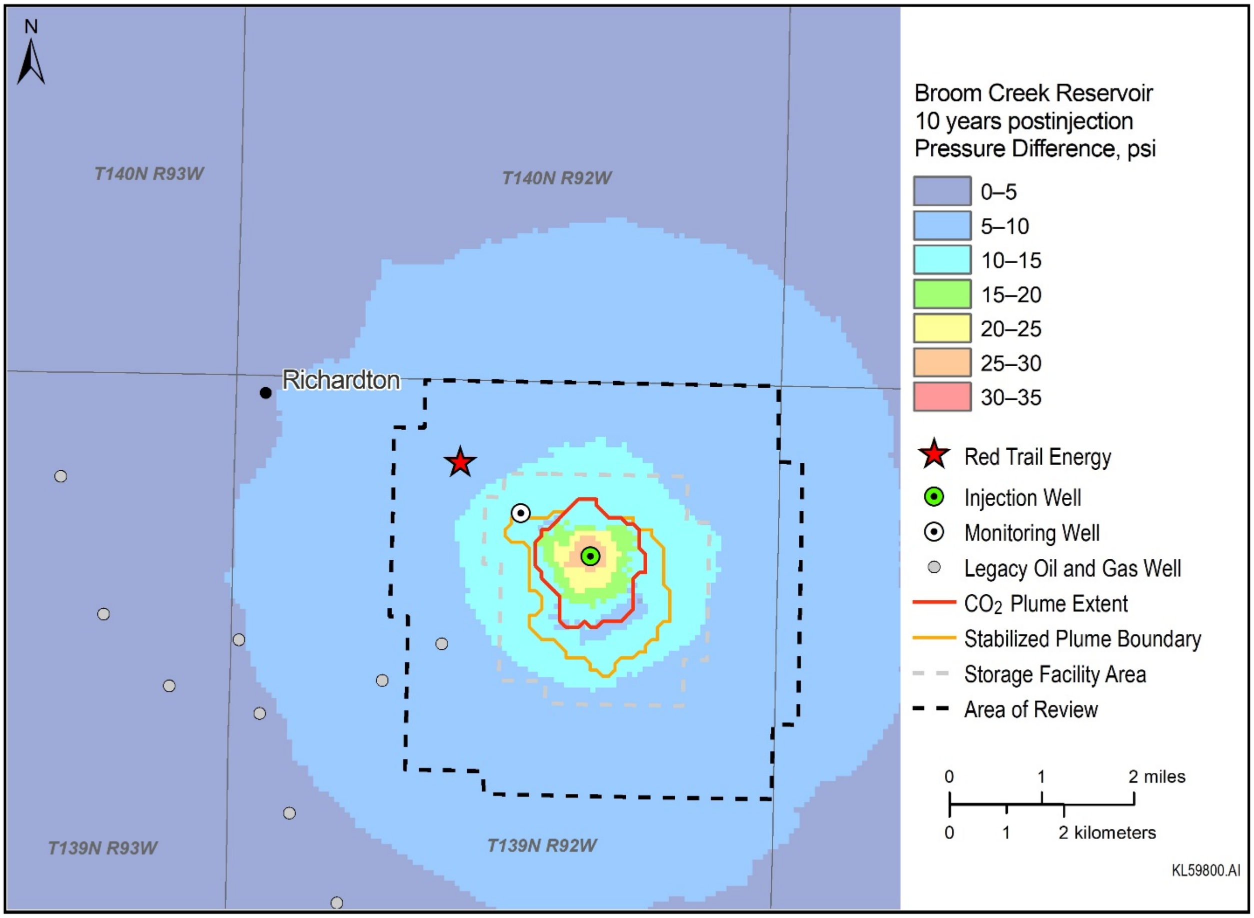

Figure 4-23. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

4.7.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 4-22 and 4-23 are numerical simulation predictions of the extent of the CO_2 plume at the time CO_2 injection was terminated (i.e., after 20 years of injection) and following the planned 10-year PISC period, respectively. The results of these simulations predict that 99.0% of the separate-phase CO_2 mass would be contained within an area of 1.15 mi^2 at the end of CO_2 injection (see Figure 4-22). As shown in Figure 4-23, the areal extent of the CO_2 plume is not predicted to change substantially over the planned 10-year PISC period.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site, which is shown on both Figures 4-22 and 4-23, extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year postinjection period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5d) and qualify the geologic storage site for receipt of a certificate of project completion.

4.7.1.3 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 4-23. The plan includes a combination of soil gas and groundwater/USDW monitoring, storage reservoir pressure/temperature and CO_2 saturation monitoring, well integrity testing, and geophysical monitoring of the CO_2 plume in the storage reservoir. Each of these monitoring efforts is described in more detail in Table 4-23.

Table 4-23. Summary of 10-year Postinjection Site Care-Monitoring Program

Type of Monitoring	Frequency	Comments
Near-Surface Monitoring		
Soil Gas Profile Stations (soil gas sampling locations SS01 and SS02 – Figure 4-24)	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas stations SS01 and SS02 performed every 3 years following cessation of CO_2 injection.	Located at the wellsite of the RTE-10 (CO_2 injection well) and the RTE-10.2 (monitoring well) (Figure 4-24).
Groundwater Wells	Duration: 10 years Frequency: 3–4 sample events at cessation of injection and 3–4 sample events as part of the final site closure assessment.	Sampling will be performed on all active freshwater groundwater wells within the AoR, as shown in Figure 4-24.
Fox Hills Formation	Duration: minimum 10 years Frequency: 3–4 sample events at cessation of injection and 3–4 sample events as part of the final site closure assessment.	Deepest USDW

Continued . . .

Table 4-23. Summary of 10-year Postinjection Site Care Monitoring Program (continued)

Type of Monitoring	Frequency	Comments
Storage Reservoir Monitoring		
Injection Well	Duration: minimum 10 years postinjection	Convert injection well (RTE 10) to postinjection monitoring well for the postinjection monitoring period.
Downhole Monitoring (Injection Well RTE-10 and Monitoring Well RTE-10.2)		
Downhole Pressure and Temperature Gauges Distributed Fiber Optic (DTS)	Continuous monitoring of the injection zone and pressure dissipation zone above (e.g., Inyan Kara).	Pressure and temperature monitoring until plume stabilization is demonstrated.
Pulsed-Neutron Log (PNL)	At cessation of injection and once every 5 years thereafter until plume stabilization is demonstrated.	
Ultrasonic Imager Tool (USIT) (External Mechanical Integrity)	Duration: minimum 10 years postinjection Frequency: Perform during well workovers but not more frequently than once every 5 years.	Will provide corroborating evidence for continuous DTS fiber optic evaluation of external casing mechanical integrity.
Internal Mechanical Integrity • Tubing-Casing Annulus Pressure Test	Duration: minimum 10 years postinjection Frequency: Perform during well workovers but not more frequently than once every 5 years.	
External Mechanical Integrity (DTS)	Continuous until well plugging and site reclamation.	

Continued . . .

Table 4-23. Summary of 10-year Postinjection Site Care Monitoring Program (continued)

Type of Monitoring	Frequency	Comments
Geophysical Monitoring		
Time-Lapse Seismic	Duration: minimum 10-year post-CO_2 injection operations-monitoring plan and until stability of plume is demonstrated. Frequency: Perform 3D seismic surveys at the cessation of CO_2 injection and every 5 years during the postinjection period.	Time-lapse seismic surveys will continue as part of the 10-year postinjection period to support a stabilization assessment of the CO_2 plume.
InSAR	Continuous	InSAR will give continuous monitoring of ground elevation based on relative surface deformation with InSAR until storage facility achieves stabilization.
Gravity	To be determined	To be determined – repeat gravity survey (minimum of one) to support the demonstration of CO_2 plume stabilization.
Passive Seismicity	Continuous.	Data collected at seismometer stations will be continuously recorded and analyzed to identify seismic events and, if warranted, investigate causation of the seismic event.

4.7.2 Groundwater and Soil Gas Monitoring

Two soil gas profile stations, two Fox Hills Formation (i.e., deepest USDW) monitoring wells, and the groundwater wells that were identified and sampled during the operations phase of the project will be sampled during the proposed 10-year PISC period. Figure 4-24 identifies the location of the soil gas profile stations, the Fox Hills Formation monitoring wells, and groundwater monitoring wells that will be included in this monitoring effort. It is proposed that these samples will be analyzed for the same list of parameters as described in the testing and monitoring plan (Section 4.4 of this permit application); however, it is anticipated that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations.

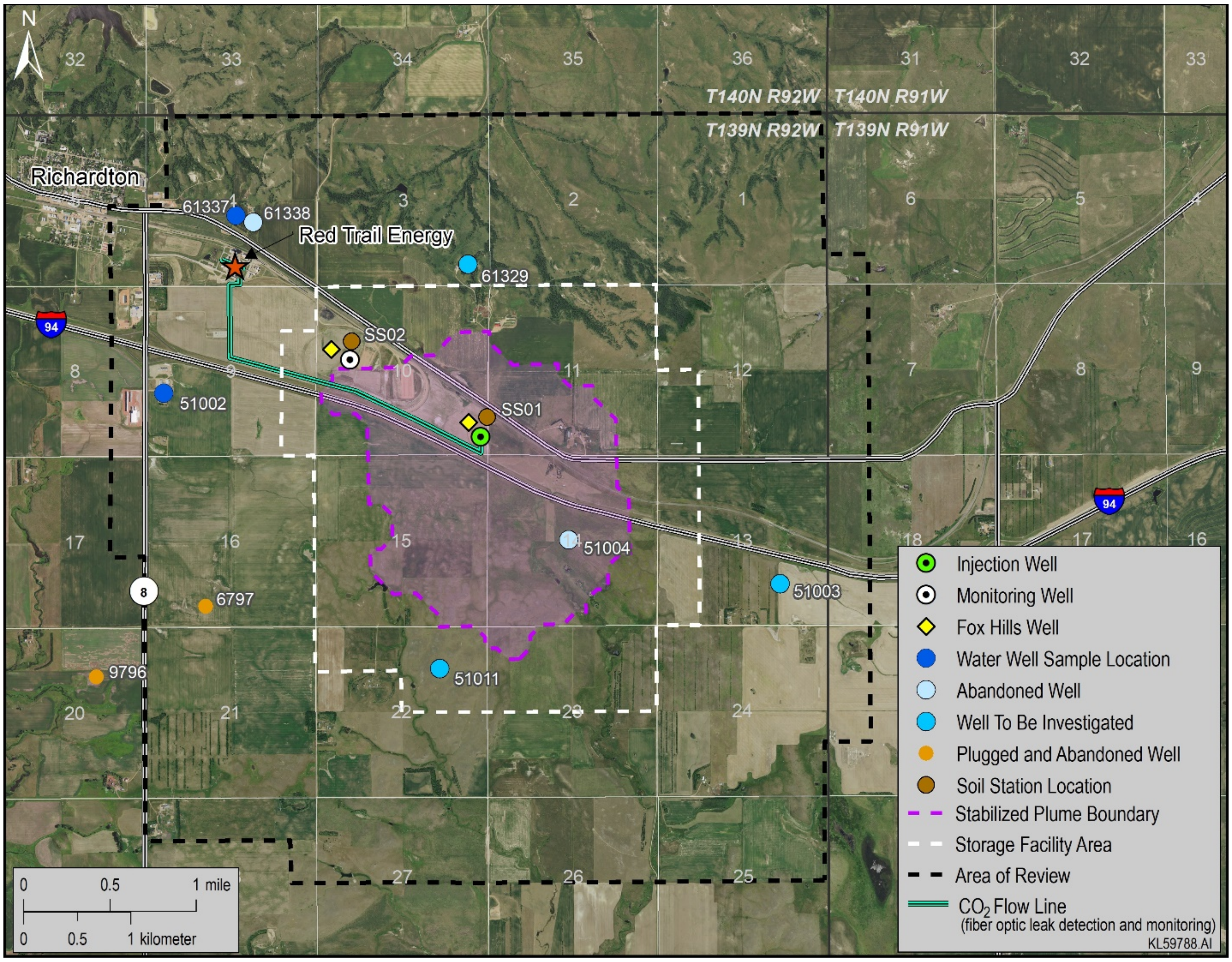

Figure 4-24. Location of soil gas and groundwater well sampling locations included in the PISC monitoring program.

4.7.3 Monitoring of CO_2 Plume and Pressure Front

Monitoring of the CO_2 plume location and the storage reservoir pressure will be conducted during the PISC period using the methods summarized in Table 4-23, which are also discussed in more detail in the testing and monitoring plan of this permit application (Section 4.4). Monitoring methods include a combination of formation-monitoring methods (e.g., downhole pressure, temperature, mechanical integrity tests; PNLs, and capture/reservoir saturation tool logs); and geophysical monitoring techniques (i.e., surface and borehole seismic and gravity) that monitor CO_2 saturation. Figure 4-25 provides an areal view of the extents of both the 3D seismic surveys and the borehole seismic (or VSP) surveys as compared to the predicted areal extents of the CO_2 plume at cessation of injection and the stabilized plume.

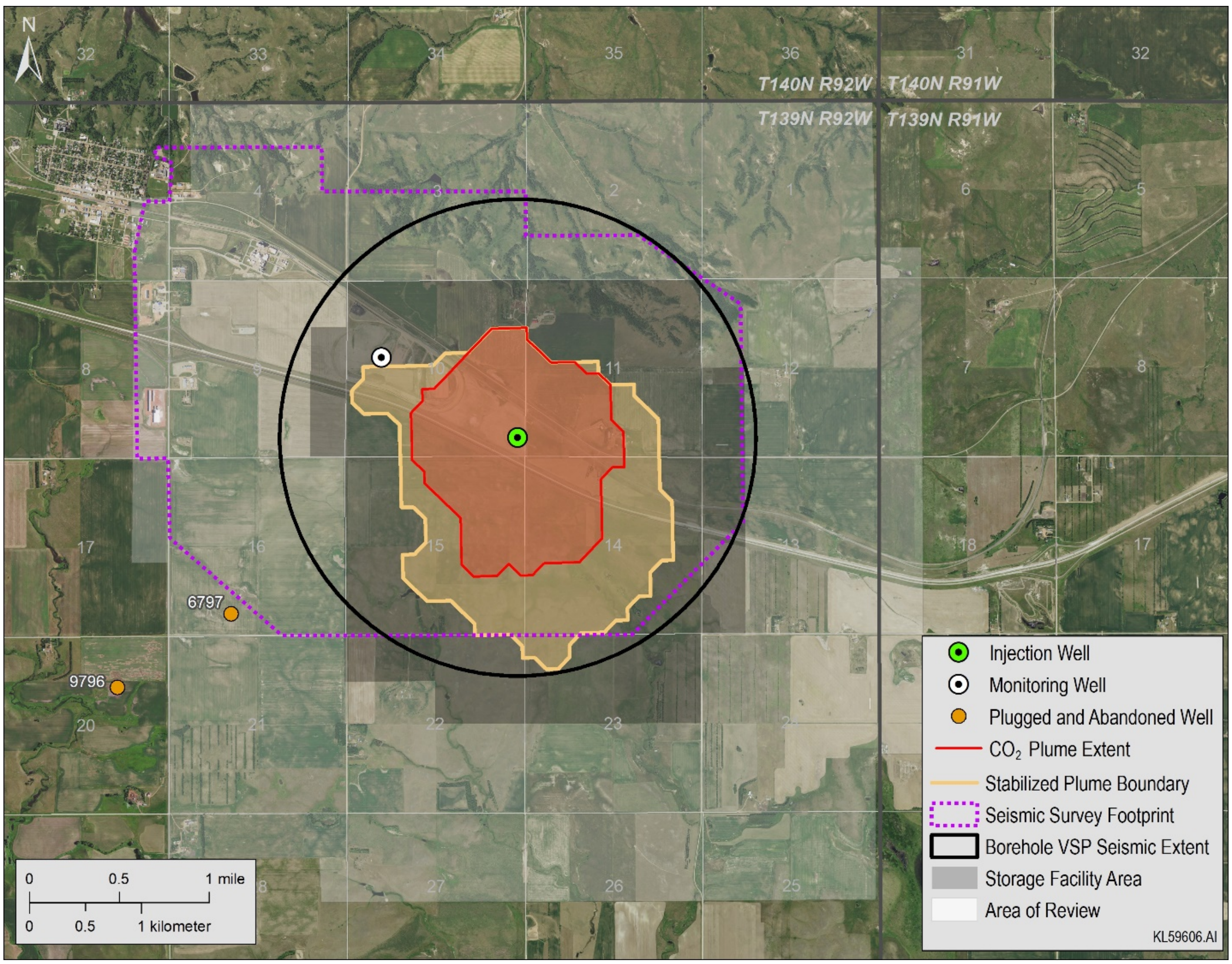

Figure 4-25. Areal extents of the 3D and borehole seismic surveys proposed during the PISC period in comparison to the areal extents of the CO_2 plume at cessation of injection and the stabilized plume.

4.7.3.1 Schedule for Submitting Postinjection Monitoring Results

All postinjection site care-monitoring data and monitoring results will be submitted to NDIC in annual reports. These reports will be submitted each year, within 60 days following the anniversary date on which the CO_2 injection ceased.

The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation-monitoring data, soil gas and groundwater sample analytical results, and simulation results from updated site models and numerical simulations.

4.7.3.2 Site Closure Plan

RTE will submit a final site closure plan and notify NDIC at least 90 days prior of its intent to close the site. The site closure plan will describe a set of closure activities that will be performed, following approval by NDIC, at the end of the postinjection site care period. Site closure activities will include the plugging of all wells that are not targeted for use as future subsurface observation wells; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., structures/buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practical to its original condition.

4.7.3.3 Submission of Site Closure Report, Survey, and Deed

A site closure report will be prepared and submitted to NDIC within 90 days following the execution of the postinjection site care and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The site closure report will also document the following:

- Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged).
- Location of sealed injection well on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, RTE will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection well relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, RTE will record a notation on the deed (or any other title search document) to the property on which the injection well was located pursuant to NDAC § 43-05-01-19.

4.8 References

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5.0 INJECTION WELL AND STORAGE OPERATIONS

5.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the Storage Facility Permit (SFP) application presents the engineering criteria for completing and operating the injection well in a manner that protects underground sources of drinking water (USDWs). The information that is presented meets the permit requirements for injection well and storage operations as presented in North Dakota Administrative Code (NDAC) § 43-05-01-05 (SFP, Table 5-1) and NDAC § 43-05-01-11.3

Table 5-1. RTE-10 Proposed Injection Well Operating Parameters

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume	3.7 million tonnes (71 Bscf)	Based 180,000 tonnes/year (3.5 Bscf/year) for 20 years at an average daily injection rate of 500 tonnes/day (using 360 operating days per year).
Injection Rates		
Proposed Average Injection Rate	500 tonnes/day (9.6 MMscf/day)	Based 180,000 tonnes/year for 20 years (using 360 operating days per year).
Calculated Maximum Daily Injection Rate	4,100 tonnes/day (120 MMscf/day)	Based on surface maximum injection pressure (2,250 psi).
Pressures		
Formation Fracture Pressure at Top Perforation	4,466 psi	Modular dynamics testing (MDT) results fracture propagation formation fracture gradient of 0.7 psi/ft.
Average Operating Surface Injection Pressure	1,300 psi	Proposed injection well operating surface injection pressure.
Surface Maximum Injection Pressure	2,250 psi	Based on maximum pressure rating of the flow line.
Average Operating Bottomhole Pressure (BHP)	3,000 psi	An average BHP of 3,000 psi based on average daily injection rate of 500 tonnes/day.
Maximum BHP	4,019 psi	Calculated maximum BHP 4,019 psi based 90% of the formation fracture pressure 4,466 psi
Tubing-Casing Annular Pressure	100 psi	Variance requested (see Section 5.3) from NDAC § 43-05-01-11.3 Subsection 3 requiring the storage operator to maintain on the annulus a pressure that exceeds the operating injection pressure.

5.1 RTE-10 Well – Proposed Completion Procedure to Conduct Injection Operations

Red Trail Energy (RTE) constructed the RTE-10 well (Figure 5-1 and Table 5-2) with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the RTE-10 well for injection purposes.

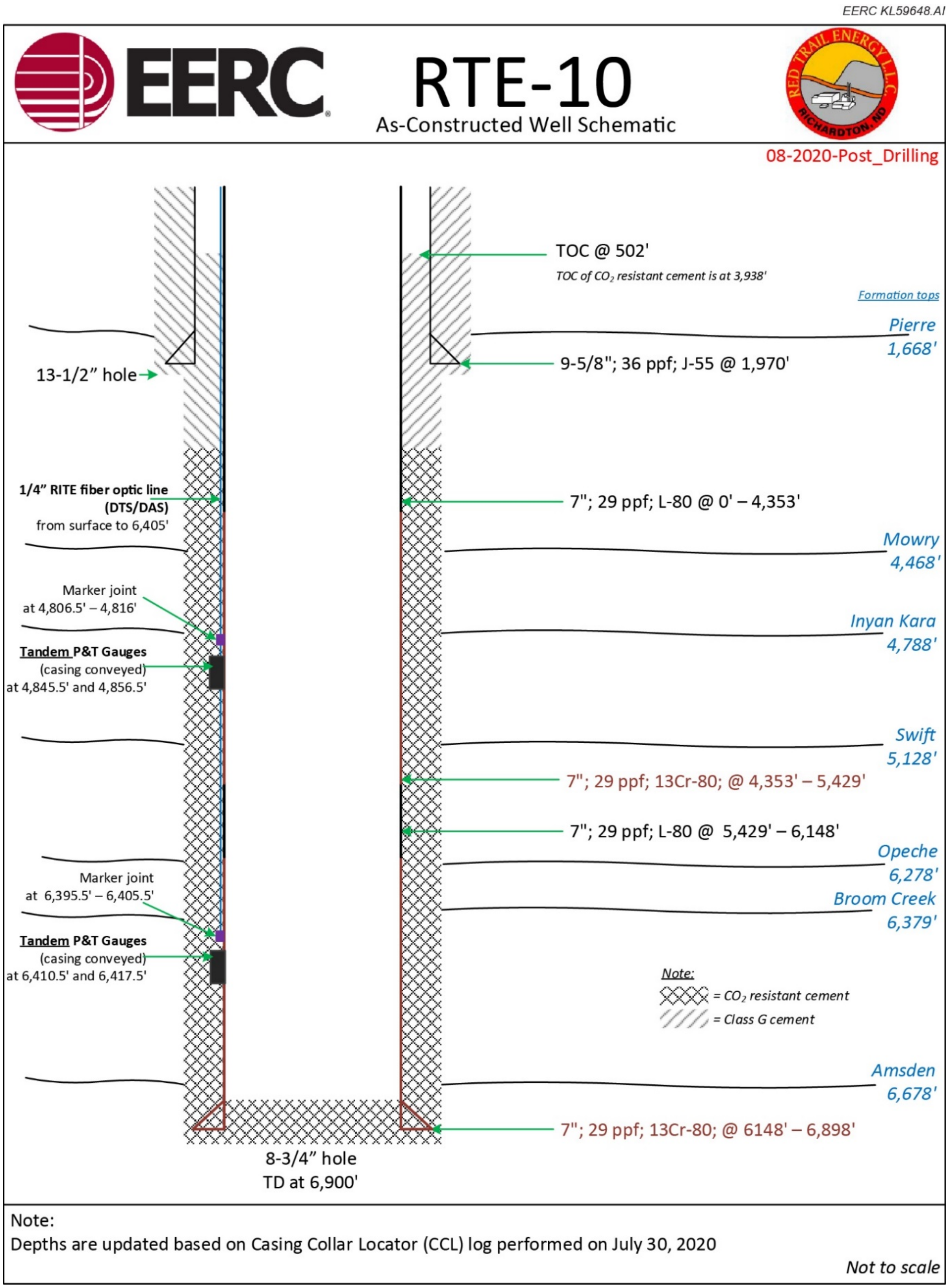


Figure 5-1. RTE-10 as-constructed wellbore schematic.

Table 5-2. RTE-10 Wellbore Casing and Proposed Injection Tubing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, klb
7	L-80	29	LTC	6.184	6.059	7,030	8,160	587
7	13Cr-80	29	VAM TOP	6.184	6.059	7,030	8,160	587
3½	13Cr-80	9.2	JFEBEAR	2.992	2.867	10,540	10,160	207.2

RTE-10 Proposed Completion Procedure for CO_2 Injectate Well

Site and Well Work Preparation

- Contact the North Dakota Industrial Commission (NDIC) and provide schedule to perform NDIC-approved well work.
- Work road and location as needed for safe operations.
- Install rig anchors and test to 20,000 lbf (or as required). If installed, confirm recent anchor test date and that tension has been performed according to company policy.
- Confirm actual casing depths and casing-conveyed gauges with the company representative and designated field engineer.
- Conduct safety meetings prior to shifts and treatments.
- Move in rental equipment:
  1. ~7,000 ft of 2⅞-in. L-80 workover (WO) string – inspect and drift tubing prior to use.
  2. Four 400-barrel (bbl) tanks filled with produced saltwater.
- Move in ~6,400 ft of 3½-in. 13Cr-80 injection tubing plus pup joints, inspect and drift tubing prior to running downhole.

Clean Wellbore and Test Production Casing

1. Move in and rig up (MIRU) workover rig.

2. Check wellhead pressure gauge for pressure prior to removing wellhead. If under pressure, bleed pressure off slowly to a tank if possible.

3. Nipple down (ND) wellhead (7¹⁄₁₆-in. valve and night cap).

4. Nipple up (NU) blowout preventer (BOP), record BOP test with a low/high pressure of 250 psi/4,000 psi.

5. Pick up (PU) 2⅞-in. L-80 WO string.

6. Round-trip (RT) 6-in. bit on 2⅞-in. L-80 WO string and tag plug back total depth (PBTD).

7. Fill 2⅞-in. WO string with 40 bbl of produced saltwater and circulate hole with bottoms up, a minimum of 201 bbl of produced saltwater.
   Record volume required to fill/catch pressure if fluid level is not at surface.

8. Lay down (LD) 6-in. bit and stand back 2⅞-in. L-80 WO string.

9. Pressure-test production casing to 1,000 psi.
   a. Top off production casing with produced saltwater.
   b. Pressure casing to 1,000 psi and shut-in valves, record pressure for a minimum of 30 min.
   c. If casing pressure drops more than 10% variance (NDAC § 43-02-03-21), contact designated field engineer and RTE representative for further instructions.

<u>Run Cased-Hole Logs</u>

10. MIRU wireline service company.

11. Rig up (RU) wireline lubricator and pressure-test to 4,000 psi.

12. Run in hole (RIH) with ultrasonic–variable density log (VDL) –casing collar locator (CCL) –temperature–gamma ray (GR) log from plug back total depth (PBTD) to surface.

13. Review cement evaluation log with designated field engineer and wireline company domain. If poor cement shows, repeat test with 1,000 psi applied pressure on production casing. Correlate the cement log depths with the triple combo openhole log March 2020 and with the isolation scanner log July 2020.

<u>Perforate Broom Creek Formation</u>

14. RU perforating guns to perforate the Broom Creek Formation to encompass depths from 6,432 to 6,676 ft measured depth (MD), Figure 5-2, with proposed intervals denoted by the green-shaded sections utilizing the RTE-10_triple combo openhole log March 2020.
   a. Halliburton recommends a minimum of 10 ft from the casing-conveyed bottomhole temperature and pressure (BHT/P) gauges, at 6,410.5 and 6,417.5 ft to minimize impact.
   b. Actual perforation depths will be determined by designated geologist and engineers and based on the log analysis review.
   c. Perforation parameters recommended for ~0.46-in. holes with ±28 in. penetration and 6 spf 60° phasing.

15. Rig down (RD) wireline service company.

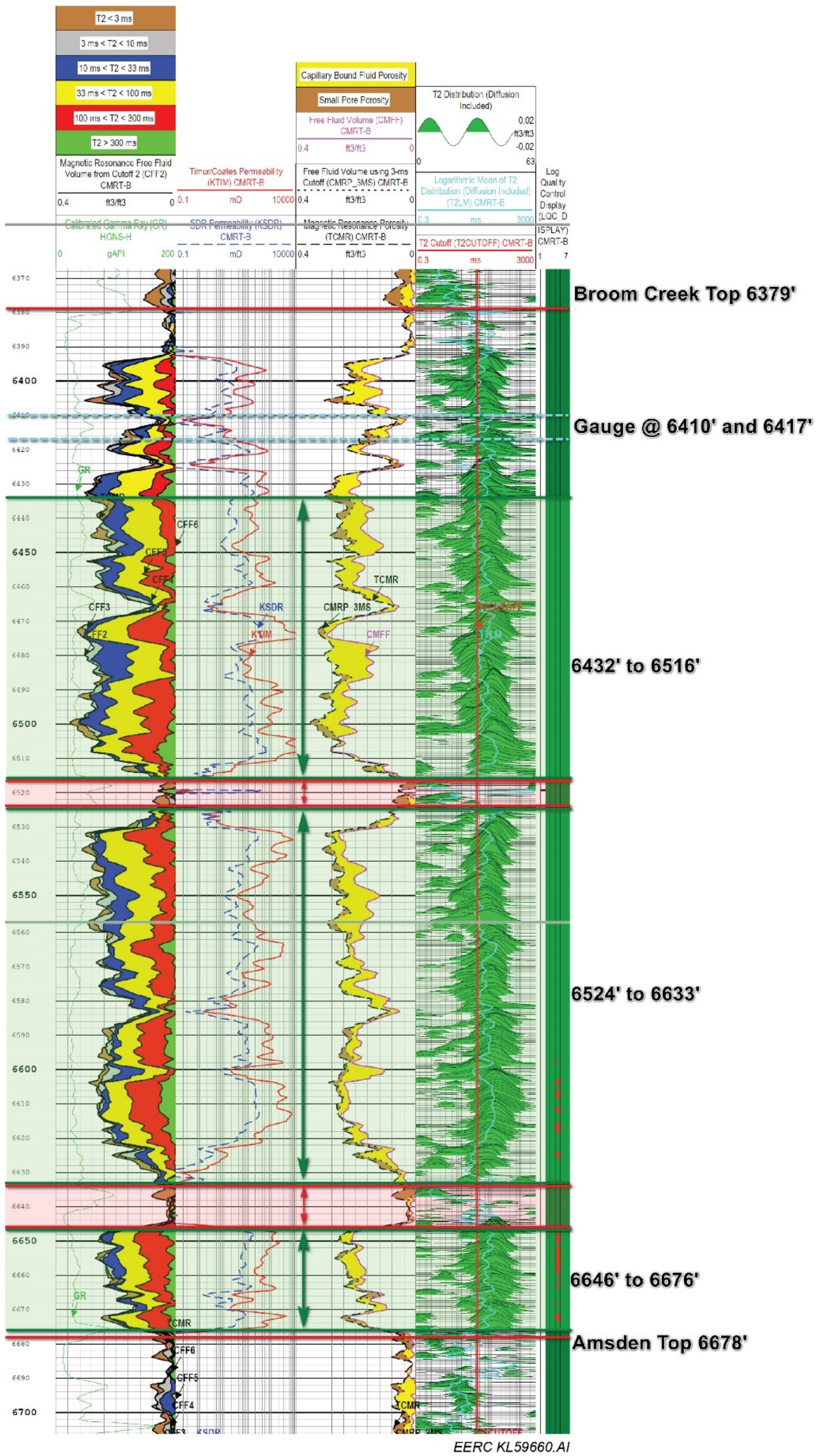


Figure 5-2. RTE-10 proposed perforation intervals of the Broom Creek Formation (green-shaded sections based on the RTE-10_triple combo openhole log March 2020).

Perform Injection Test and Stimulate Broom Creek Formation

16. PU 7-in. retrievable packer on 2⅞-in. L-80 WO string and set at ±6,390 ft.
    Avoid setting packer within 10 ft of casing-conveyed BHT/P gauges installed at 6,410.5 and 6,417.5 ft.

17. Fill 2⅞-in. WO string with 37 bbl and top off annulus with produced saltwater.

18. Pressure-test packer via annulus to 1,000 psi for 15 min. If greater than 10% variance, discuss with RTE and designated field representative, as packer will need to be reset.

19. RU pump service company
    a. Hold prejob safety meeting and fill out job safety analysis (JSA).
    b. Pressure-test surface lines to 5,000 psi.
    c. Set pressure relief valve (PRV) at 4,000 psi or the maximum surface treating pressure.
    d. Monitor annulus with annular pressure gauge for communication.
    e. Ensure treating fluid has temporary clay stabilizer added. Actual injection fluid is to be determined (TBD) by selected vendor.
    f. Open master valve and perform proposed step rate injection test (SRT), detailed in Table 5-3.
        a. Inject at step rates of 1 barrel per minute (bpm).
        b. Inject at constant rate for 15-min increments.
    g. After indication of formation breakdown (change in pressure slope):
        a. Continue to inject at breakdown rate for an additional 15 min.
        b. Increase rate by ±1 bpm (as pump truck capable) for an additional 15 min.
        c. Continuously record rate vs. pressure data throughout the entire test.
    h. Shut down and record instant shut-in pressure (ISIP), 5-, 10-, and 15-min pressure readings.
    i. Shut-in well via master valve and bleed pressure off the surface lines back to the pump truck.
    j. Monitor and record all pressures for initial reservoir radial flow and continue to monitor for stable radial flow as required (NDAC § 43-05-01-11.2), for pressure falloff testing.
    k. RD service company pumping equipment.

Table 5-3. RTE-10 Proposed Step Rate Injection Test of Broom Creek Formation

Step	Rate, bpm	Time, min	Volume, bbl	Cumulative Volume, bbl	Max. Tubing Pressure, psi	Casing Pressure, psi	Comments
0	0	0	0	0		500	Pressure test
1	0.75	15	11.25	11.25			Minimum in lockup
2	1	15	15	26.25			
3	2	15	30	56.25			
4	3	15	45	101.25			
5	4	15	60	161.25			
6	5	15	75	236.25			
7	6	15	90	326.25			
8	7	15	105	431.25			
9	8	15	120	551.25			
10	8.5	15	127.5	678.75			
ISIP							Record ISIP
5 min							Record 5-min SIP
10 min							Record 10-min SIP
15 min							Record 15-min SIP
Total		150		678.75			

20. If operations are not continuous after SRT above, RU pump service company for stimulation.
    a. Hold prejob safety meeting and fill out JSA.
    b. Pressure-test surface lines to 5,000 psi.
    c. Set PRV at 4,000 psi, or maximum surface treating pressure, not to exceed determined fracture pressure.
    d. Monitor annulus for communication.

21. Perform a matrix acid, hydrochloric or hydrofluoric, treatment based on recommendation of chosen vendor based on formation solubility test.

22. **Maximum pressure not to exceed formation fracture pressure determined in SRT**.

23. Remain shut-in and monitor as recommended.

24. RD service pump company.

25. Trip out of hole (TOOH) and LD 7-in. retrievable packer and 2⅞-in. WO string.

26. Change out the pipe ram from 2⅞ to 3½ in. and pressure-test accordingly (test low/high 250 psi/4,000 psi).

27. MIRU wireline service company.

28. Install and pressure-test lubricator to 4,000 psi.

29. Make up 3½-in. chrome wireline reentry guide, XN and 7-in. × 3½-in. packer assembly (wireline-set packer) with pump-out plug or ceramic burst disc.

30. Set 7-in. chrome packer at ±6,385 ft.
    a. Note: If packer is set greater than 50 ft from top perforation, NDIC variance is required (NDAC § 43-05-01-11).
    b. Avoid setting packer within 10 ft of casing-conveyed BHT/P gauges installed at 6,410.5 and 6,417.5 ft.
    c. Avoid setting packer in casing collars at 6,364.4 and 6,405.6 ft, based upon casing tally.
    d. Ensure the end of tubing has the ability to land a plug and prong or alternative plug while maintaining the largest inner diameter possible (alternative plug types available).

31. Pressure-test packer to 1,000 psi, pending maximum injection pressure, with rig pump. Ensure that pressure does not exceed tubing pump-out plug rating (~2,100 psi).

32. Rig down move out (RDMO) wireline service company.

33. Make up seal assembly, locator subs, and necessary connections. RIH with 3½-in. chrome tubing (13Cr -80, 9.2#, JFEBEAR).

34. Pump 161.5 bbl corrosion-inhibited packer fluid down 3½-in. tubing and displace with 56 bbl clean saltwater to displace packer fluid into the annulus.

35. Sting the seal–bore assembly into the packer bore, space out and stack ±30,000 lb compression on packer. Pre-pressure-test annulus, packer, and seal bore to 1,000 psi for 30 min with rig pump. Record pressure readings every 5 min.

36. Contact NDIC to witness mechanical integrity test (MIT) 24-hr prior to official testing.
    a. Pressure well to 1,000 psi, or as directed by NDIC while charting entire pressure test.
    b. NDIC must witness MIT in accordance with state regulations.

37. Land tubing with tubing head, lock down, and secure.

38. ND BOP and NU proposed CO_2-resistant wellhead, Figure 5-3.

39. Pressure up tubing to ±2,100 psi to pump out the plug using the rig pump.

40. RDMO workover rig, continuing to be careful of wellhead equipment. Load out surplus equipment. Clear and clean location.

41. Well is to begin injection operations after NDIC approval, including approved MIT.

42. Well is ready for installation of surface equipment for injection operations, Figure 5-4, proposed completed wellbore.

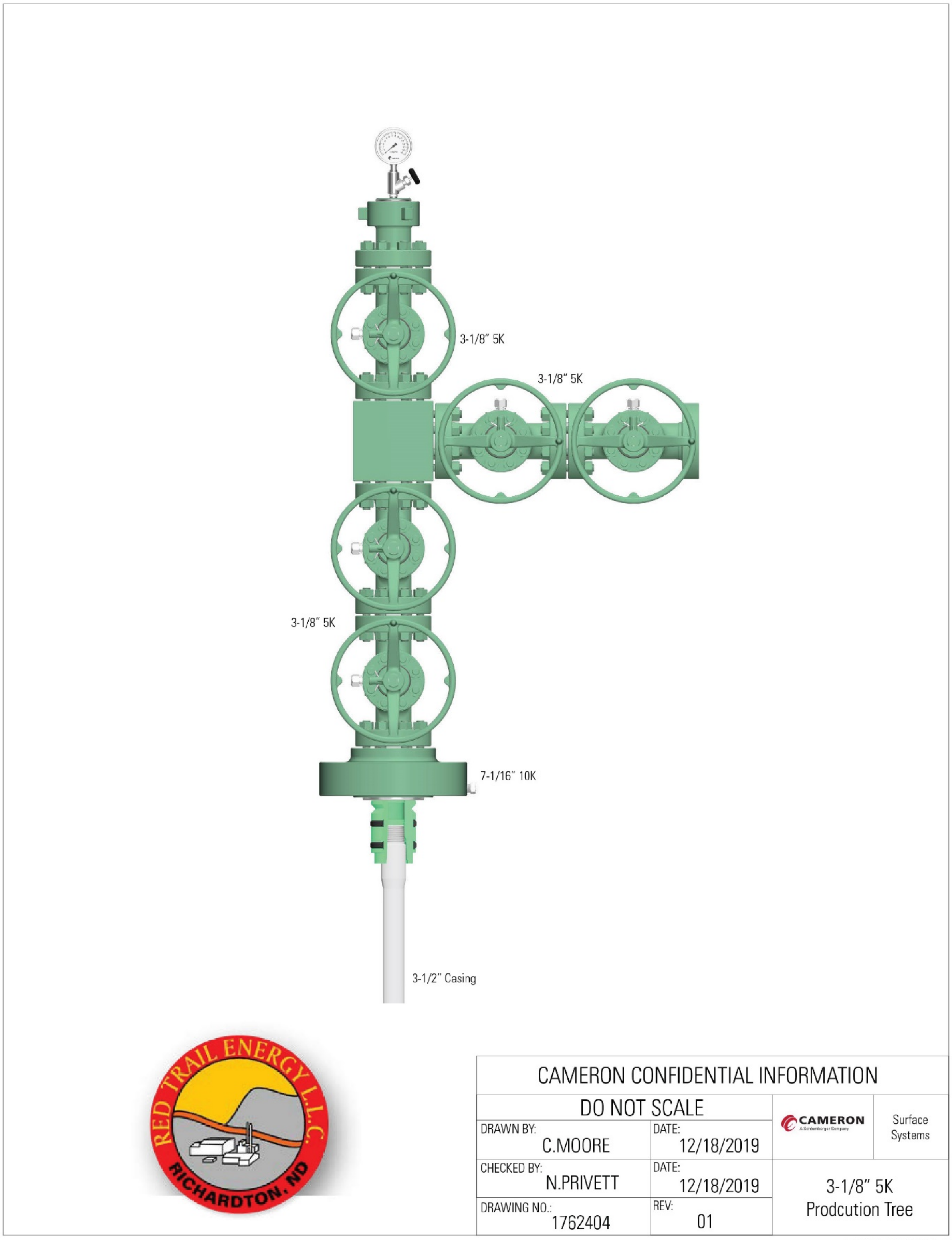


Figure 5-3. RTE-10 well – proposed CO_2-resistant wellhead schematic – Cameron Supplier.

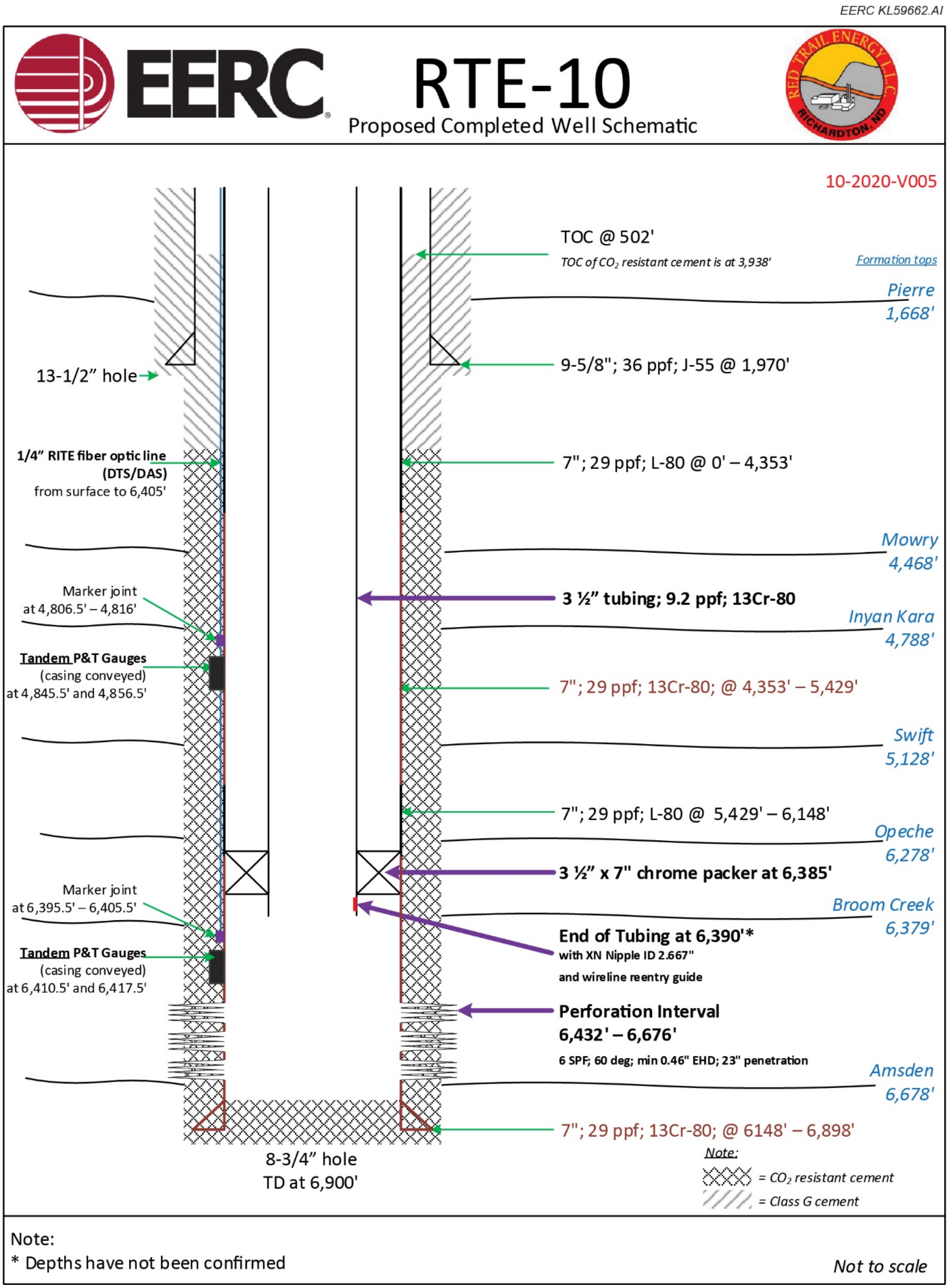


Figure 5-4. RTE-10 well – proposed completed wellbore schematic.

5.2 RTE-10.2 Well – Proposed Procedure for Monitoring Well Operations

RTE constructed a second well, the RTE-10.2, Figure 5-5, for direct reservoir-monitoring purposes, as referenced in Section 4, to support deep subsurface monitoring of the RTE-10 CO_2 stream injection well. Monitoring of the CO_2 plume location and the storage reservoir pressure will be conducted continuously through use of the casing-conveyed temperature and pressure gauges installed on the outside of the long-string production casing. Monitoring will be conducted during injection operations, Table 4-6, as well as during the PISC period using the methods summarized in Table 4-23, which are also discussed in more detail in the Testing and Monitoring section of this permit application. Monitoring methods include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, MITs; pulsed-neutron capture/reservoir saturation tool logs) that support CO_2 plume stabilization assessments.

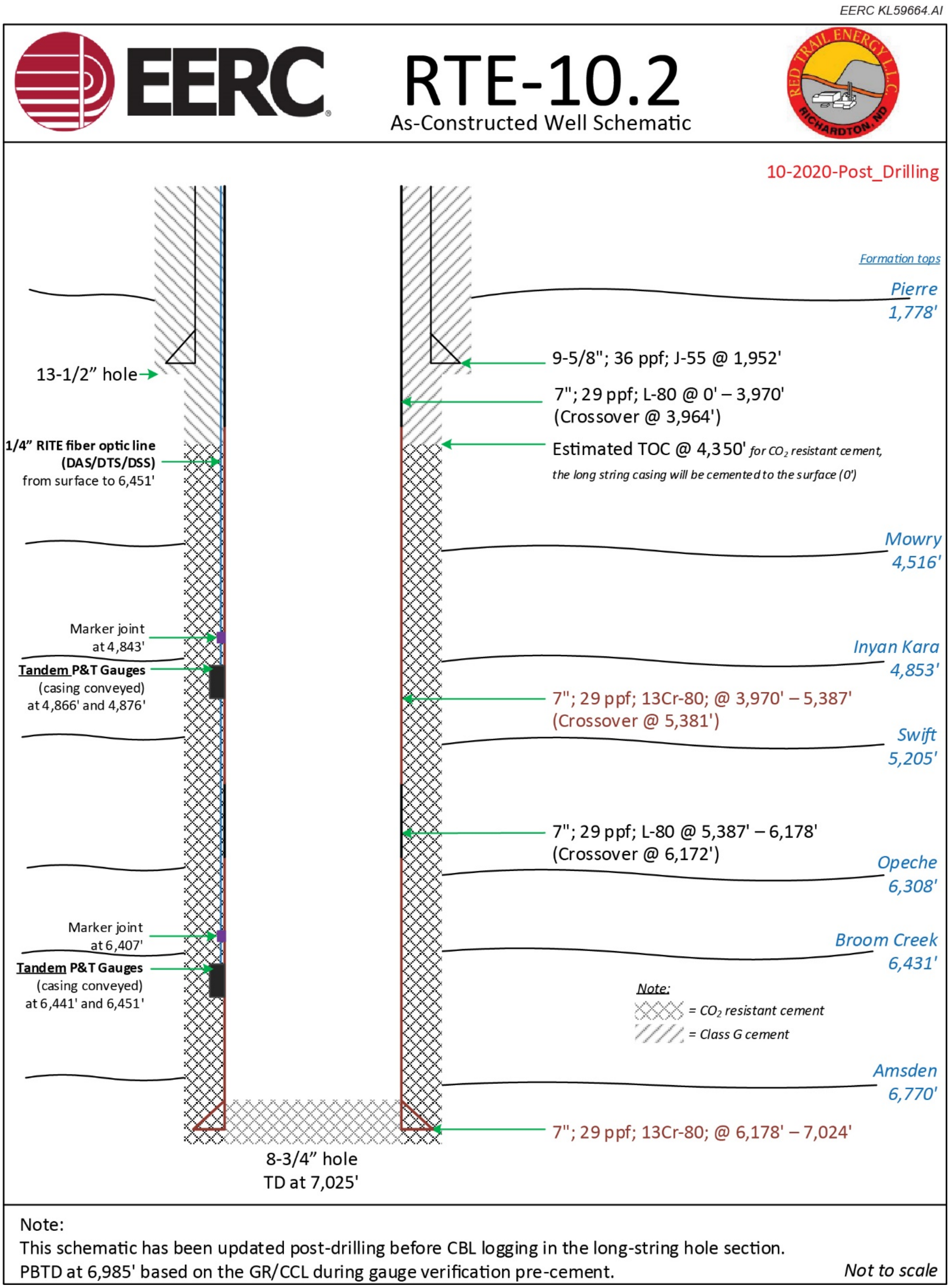


Figure 5-5. RTE-10.2 as-constructed well schematic.

Table 5-4. RTE-10.2 As-Constructed Wellbore Casing Properties

o.d., in.	Grade	Weight, lb/ft	Connection	i.d., in.	Drift i.d., in.	Collapse, psi	Burst, psi	Tension, klb
7	L-80	29	LTC	6.184	6.059	7,030	8,160	587
7	13Cr-80	29	Tenaris Blue®	6.184	6.125	7,030	8,160	587

RTE-10.2 – Proposed Procedure for Monitoring Well for CO_2 Plume

Site and Well Work Preparation

- Contact NDIC and provide schedule to perform NDIC-approved well work.
- Work road and location as needed for safe operations.
- Conduct safety meetings prior to shifts and treatments.

Install Wellhead

1. Check wellhead pressure gauge for wellbore pressure prior to removing wellhead. If under pressure, bleed pressure off slowly to a tank if possible.

2. ND current wellhead assembly (7¹⁄₁₆-in. valve and night cap).

3. NU CO_2-resistant wellhead, Figure 5-6, Cameron Supplier.

4. Pressure-test production casing to 1,000 psi.
   a. Top off/fill casing with produced saltwater – *Record volume required to fill if fluid level is not at surface.*
   b. PU casing to 1,000 psi. Shut-in valves, record pressure for a minimum of 30 min.
   c. If casing pressure drops more than 10% variance (NDAC § 43-02-03-21) contact designated field engineer and RTE representative for further instructions.

Run Cased-Hole Logs

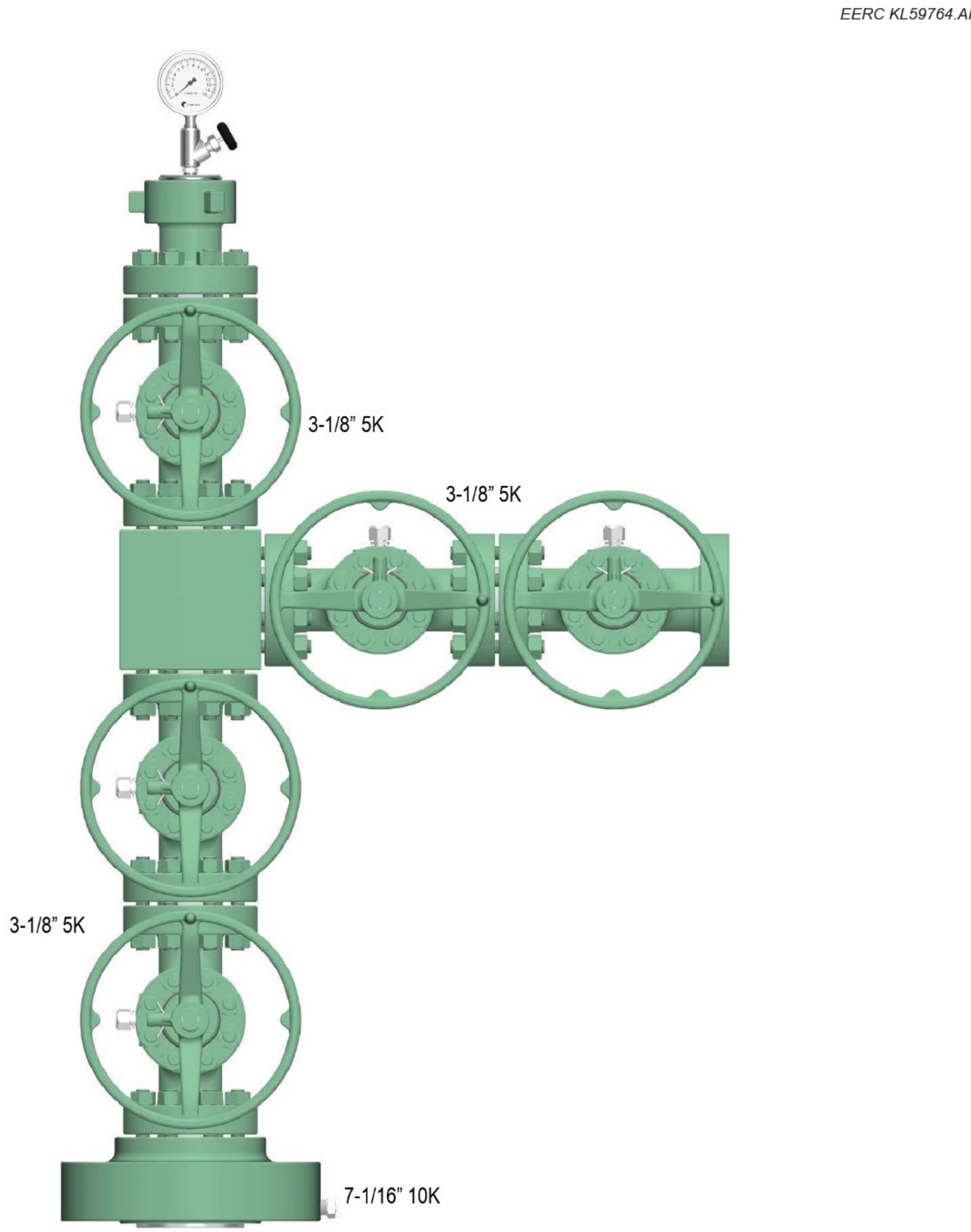
5. MIRU wireline service company.

6. RIH with ultrasonic–VDL–CCL–temperature–GR log from PBTD to surface. If TOC is not at surface, discuss with RTE company representative.

7. Review cement evaluation log with field engineer and wireline company domain. If poor cement shows, repeat with 1,000 psi pressure on production casing. Correlate the log depths with RTE-10.2_triple combo openhole log October 2020 and compare with the RTE-10.2_isolation scanner log October 2020.

8. RD wireline service company.

9. Install surface equipment installation for continual monitoring operations with proposed completed wellbore, Figure 5-7.



RED TRAIL ENERGY L.L.C.
RICHARDTON, ND

CAMERON CONFIDENTIAL INFORMATION			
DO NOT SCALE		CAMERON A Schlumberger Company	Surface Systems
DRAWN BY: C.MOORE	DATE: 12/18/2019		
CHECKED BY: N.PRIVETT	DATE: 12/18/2019	3-1/8" 5K Production Tree	
DRAWING NO.: 1762404	REV: 01		

Figure 5-6. RTE-10.2 well – proposed CO_2-resistant wellhead schematic – Cameron Supplier.

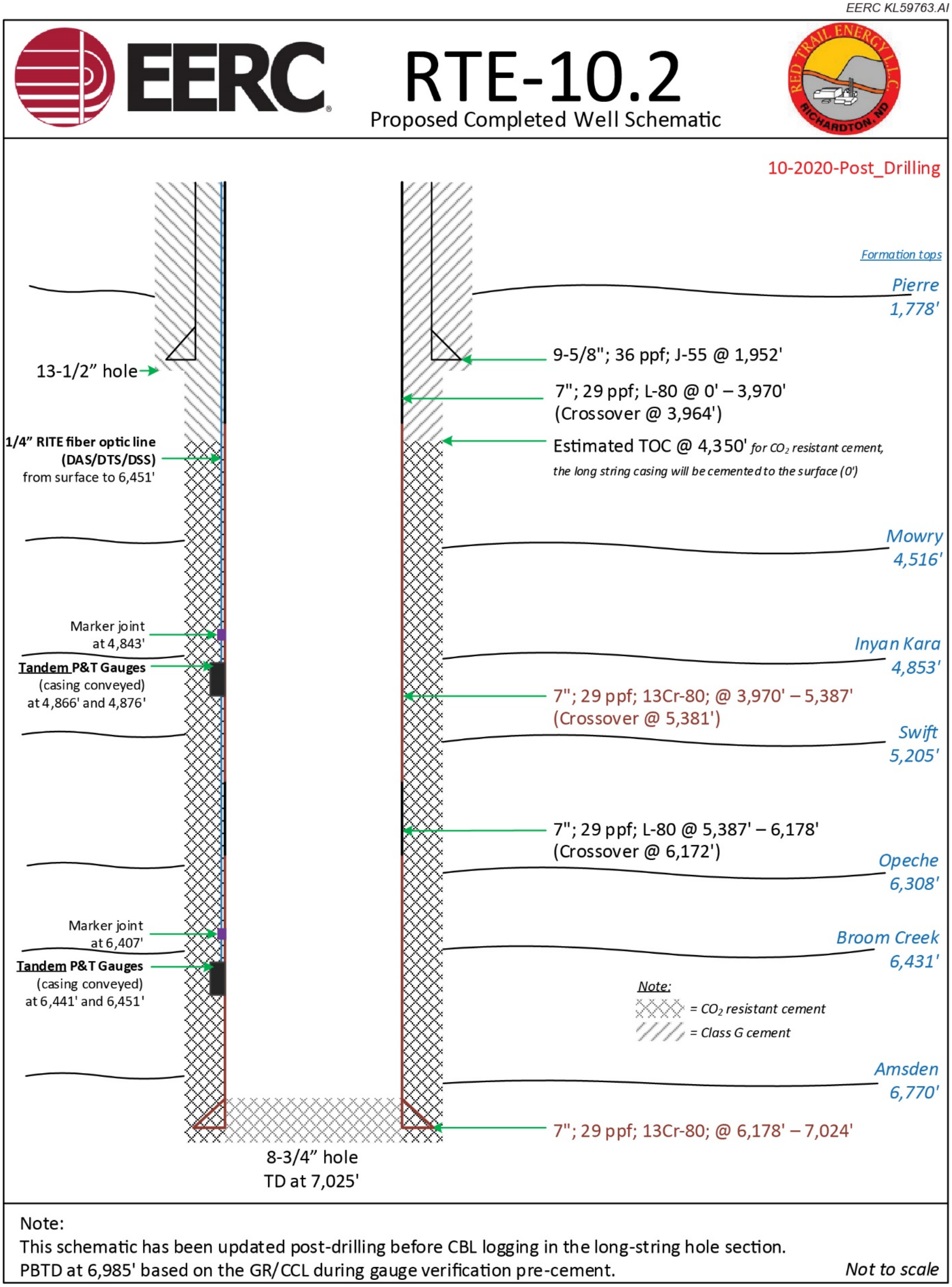


Figure 5-7. RTE-10.2 well – proposed completed wellbore schematic.

5.3 Variance Request for Operating Annular Pressure

RTE requests a variance from NDAC §43-05-01-11.3 Subsection 3 requiring the storage operator to maintain pressure on the tubing-casing annulus that exceeds the operating injection pressure. The basis for this request is to minimize the risk of well integrity degradation.

NDAC § 43-05-01-11.3 Subsection 3 states in part, “The storage operator shall maintain on the annulus a pressure that exceeds the operating injection pressure, unless the commission determines that such requirement might harm the integrity of the well or endanger underground sources of drinking water.”

The RTE-10 proposed CO_2 injection well is designed to operate at 1,300 psi surface injection pressure, with a maximum surface injection pressure at 2,250 psi. Operating the annulus pressure above these injection pressures could result in the debonding of the well cement interfaces with the long-string casing being exposed to varying pressures throughout the wellbore. Micro annuli are the most common failures caused by the tensile forces exceeding the cement bonding strength (ARMA 18-1298, Numerical investigations of cement interface debonding for assessing well integrity risks).

RTE is proposing to operate the RTE-10 annular pressure at 100 psi (Table 5-1).

RED TRAIL ENERGY, LLC

APPENDIX A

DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

INTRODUCTION

A detailed geologic model of the Red Trail Energy (RTE) site was built to simulate carbon dioxide (CO_2) injection for 20 years and assess the site's fitness for permanent geologic CO_2 storage. The RTE site is located near Richardton, North Dakota, in the south-central portion of North Dakota's Williston Basin. RTE will be injecting 180,000 tonnes of CO_2 into the sandstone of the underlying Broom Creek Formation. During the creation of the geologic model, data from RTE-10.2 were not yet ready for integration. Well logs from RTE-10.2 were later used to verify and correlate data from RTE-10. A 3D seismic survey was collected over the RTE site, and a stratigraphic test well was drilled on location to augment data available from the few offset wells in the study area. Data collected from these sources were incorporated into a geologic model of the Broom Creek Formation and the overlying and underlying sealing formations. Simulated CO_2 injection studies were conducted to determine the wellhead and downhole pressure resulting from injection and how the injected CO_2 would distribute in the Broom Creek. Reservoir conditions observed from the stratigraphic test well were used to establish the initial conditions. Results of the injection studies were then used to determine the project's area of review (AoR) pursuant to North Dakota's geologic CO_2 storage regulations.

A geologic model was constructed using Schlumberger's Petrel software suite. Petrel is a software platform that allows for the development of geologic models using well and seismic data in combination with geostatistics. The geologic model represents the subsurface geology of the proposed CO_2 storage reservoir and its upper and lower confining zones, which are made up of the Opeche and Broom Creek Formations and the upper interval (i.e., 50 ft) of the Amsden Formation (Figure A-1). Geologic properties were distributed within the 3D volume of the reservoir as inputs for numerical simulations of CO_2 injection to predict the migration of CO_2 and pressure effects throughout the storage reservoir. These geologic properties included 1) lithofacies/lithology (bodies of rock with similar geologic characteristics), which were used to assign relative permeability data; 2) porosity; 3) matrix permeability; 4) temperature; and 5) pressure.

Multiple sets of data were used to construct the geologic model. Publicly available data, which included well logs and formation top depths, were acquired from the online database of the North Dakota Industrial Commission (NDIC). Site-specific data, which were collected as part of storage reservoir characterization efforts and included geophysical well logs, petrophysical analyses, formation fluid analyses, and a surface seismic survey, were also used in the model construction.

The well logs acquired in the RTE-10 well were used to pick formation top depths, interpret lithology, estimate petrophysical properties, and determine a time–depth shift for seismic data. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. Regional formation top depths from wellbores within a 25-mile radius of the study area were added to these existing site-specific data to understand the geologic extent, depth, and thickness of subsurface geologic strata. Lateral structure trends from the acquired seismic data were used to reinforce interpolation of the formation tops to create structural surfaces which served as inputs for geologic model construction.

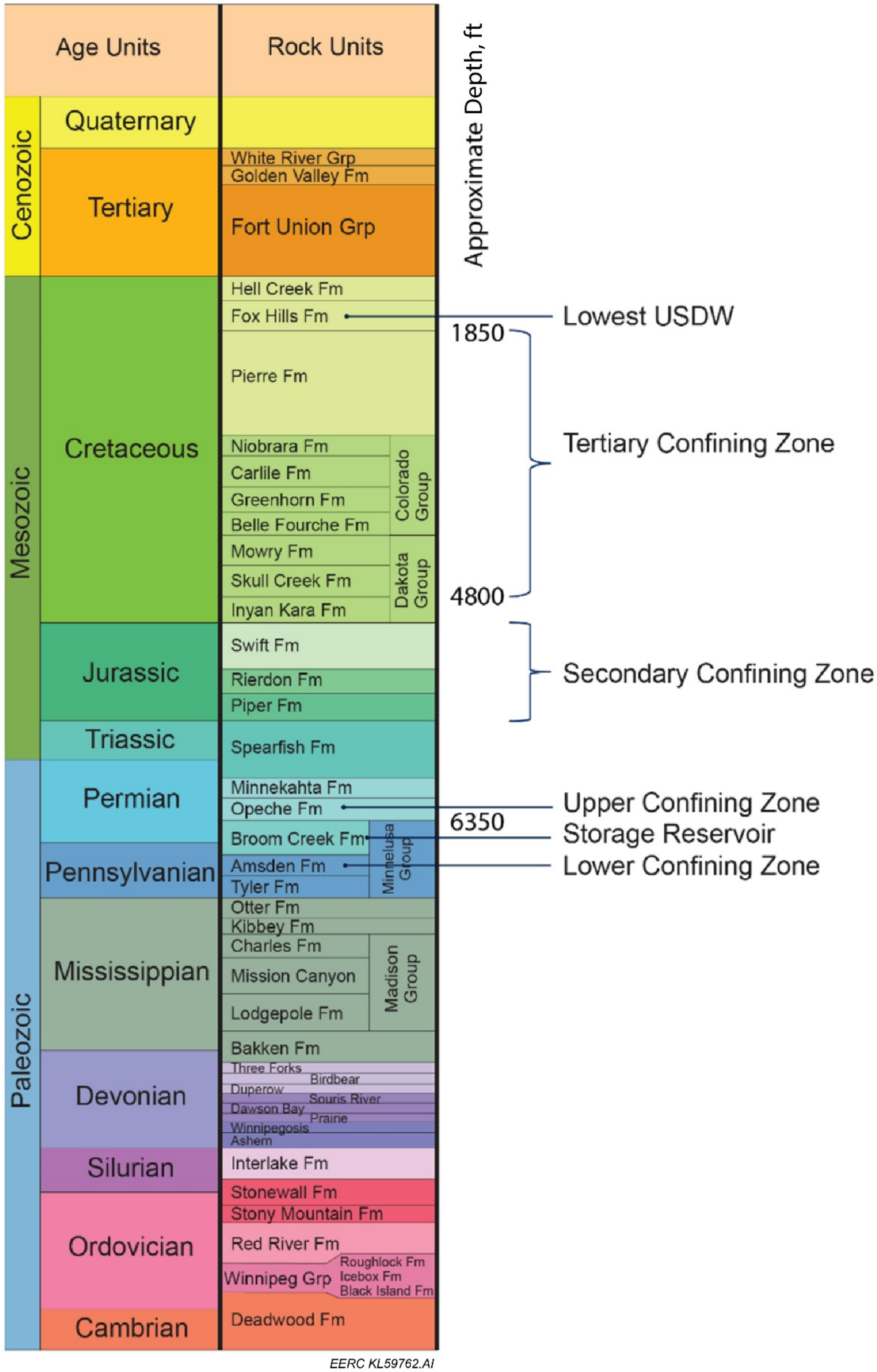


Figure A-1. Stratigraphic column identifying the storage reservoir and confining zones for the geology overlying the storage facility area.

Core samples obtained from the RTE-10 wellbore were analyzed and added to existing Opeche, Broom Creek, and Amsden data sets that were obtained from the NDIC database. These analyses included x-ray fluorescence (XRF), x-ray diffraction (XRD), thin sections, porosity, and flow measurements. Learnings from these site-specific core data analyses and well logs collected from the RTE-10 wellbore were used to determine Broom Creek Formation lithologies in legacy wellbores throughout the area for which no core data were collected. Lithologies assigned to each wellbore were then used to generate the facies properties of the Broom Creek Formation. Eleven offset wells with porosity logs were used to inform petrophysical property distributions in addition to the core data from RTE-10. The various data sets derived from RTE-10 showed good agreement with the limited offset well data available near the RTE-10 site.

OVERVIEW OF SIMULATION ACTIVITIES

Modeling of the Injection Zone and Overlying and Underlying Seals

The geologic modeling activities performed to characterize the injection zone and overlying and underlying sealing formations included data aggregation, structural modeling, data analysis, property distribution (including, lithofacies and petrophysical properties), and uncertainty analysis. Major inputs for the geologic model, which acted as control points during distribution of the geologic properties throughout the modeled area, included seismic survey data, nearby well logs, and core sample measurements.

Structural Framework

Structural modeling of the Opeche, Broom Creek, and Amsden Formation surfaces was accomplished using interpolation methods with Petrel software. Input data included formation top depths, from the online NDIC database and data collected from the RTE-10 well and a 3D seismic survey conducted at the site. The interpolated data were used to constrain the model extent in 3D space.

Data Analysis and Property Distribution

Confining Zones (Opeche and Amsden Formations)

The Opeche and Amsden Formations were assigned a single lithology, based on their primary lithology determined by well log analysis to be shale and dolostone, respectively. Porosity and permeability logs, after comparison with core data sets, were upscaled from a well log scale to the scale of the geologic model grid to serve as control points for property distributions in combination with circular 5000-ft-diameter variogram structures in the lateral direction and a 10-ft vertical variogram length.

Injection Zone (Broom Creek Formation)

Seismic data were resampled to match the resolution of the geologic model grid and used to determine lateral heterogeneity within the geologic model via a variogram assessment. On a general level, variograms are geostatistical structures used to model semivariance and express the rate of change of a regionalized variable along a specific orientation (Davis, 2002). Variogram mapping investigations, which entailed experimenting with the size and shape of variograms in several azimuthal directions, indicated that geobody structures with the following dimensions are present in the Broom Creek Formation: major axis range of 4,000 ft, minor axis range of 3,100 ft, and an azimuth of 75°. Well logs recorded from the RTE-10 wellbore served as the basis for deriving a vertical variogram length of 15 ft.

To aid in discovering trends between well log data and primary wave velocity (Vp) seismic data, available sonic well logs (ΔT) in the area were transformed to Vp logs (1,000,000/ΔT). The Vp logs were smoothed to resolve vertical resolution differences between the two data sets. For each point in the derived Vp log, a smoothing algorithm calculated an arithmetic average from the point itself and the seven samples above and below. With this smoothing method, a correlation coefficient of 0.922 was observed between the Vp logs and Vp seismic (Figure A-2). This correlation allows for a higher level of control when using seismic results to apply trends during property distributions.

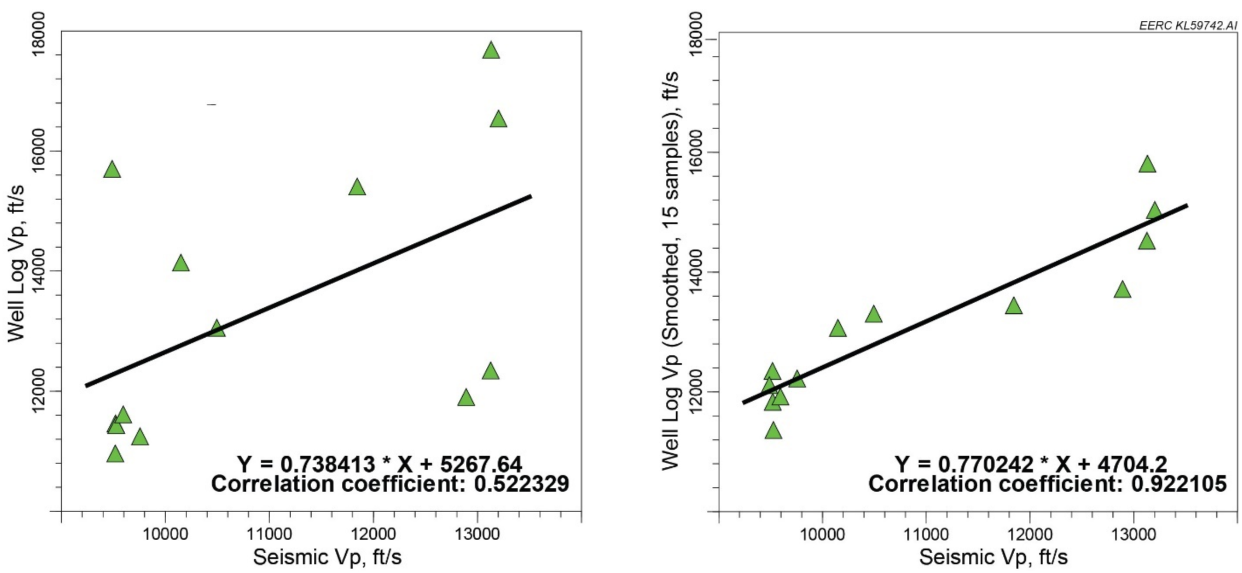


Figure A-2. Correlation coefficient between well log-derived Vp and seismic Vp data: 1) correlation coefficient of 0.522 was determined based on the initial data (left panel) and 2) correlation coefficient of 0.922 was determined after performing smoothing every 15 samples to resolve vertical resolution differences (right panel).

Because of a low count of well logs containing DT logs near the RTE-10 wellsite, two pseudologs were added to the geologic model, one at the north (Pseudo_North) and one at the south (Pseudo_South) edges (Figure A-3). Only sonic data from wells from outside the bounds of the model were projected onto the pseudowells, which were used to help control Vp distribution outside of the seismic boundary. Sonic data from well 9074 was projected on to Pseudo_North and sonic data from well 8169 was projected on to Pseudo_South.

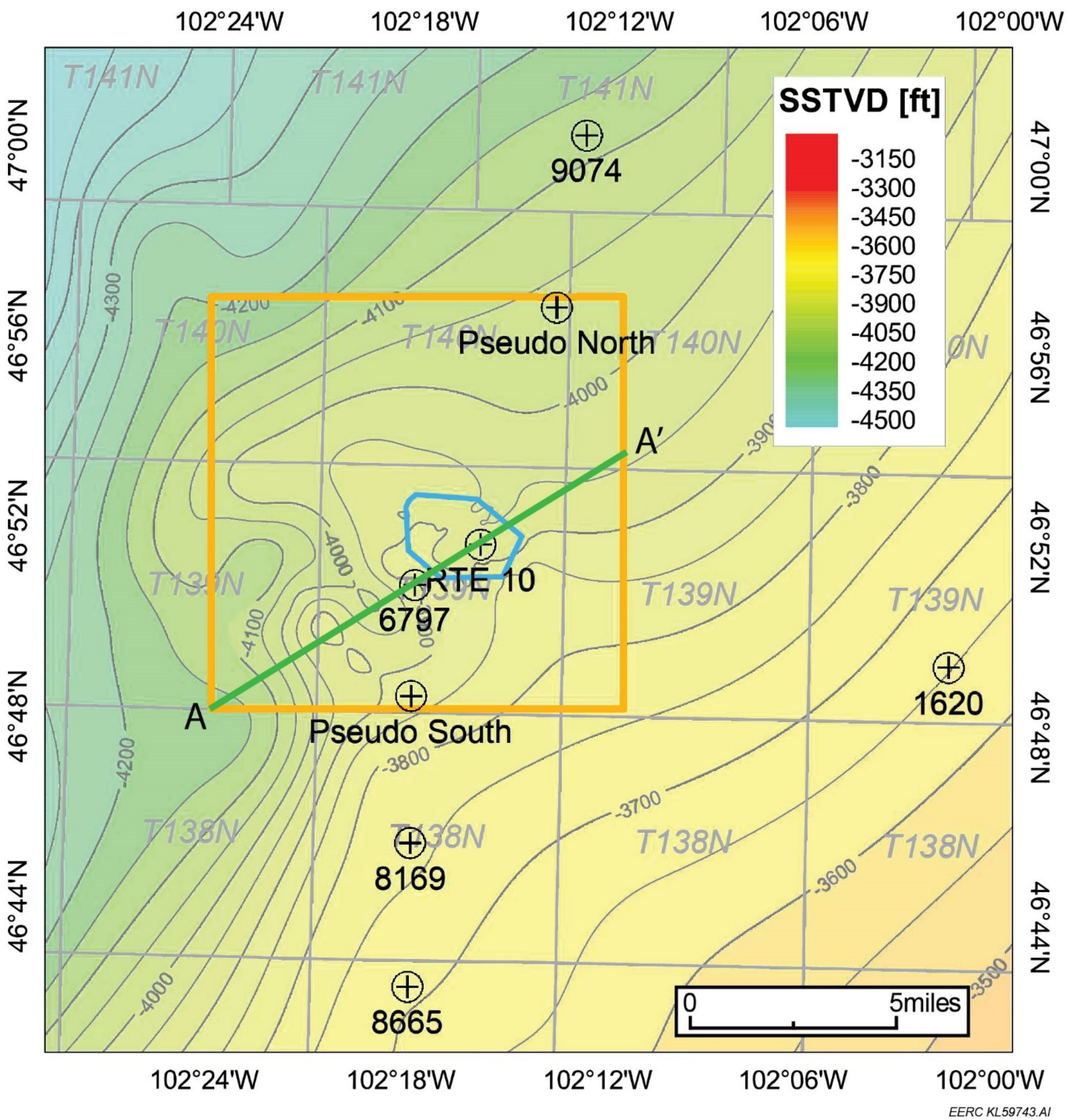


Figure A-3. Map of the geologic model boundary (orange polygon), seismic survey (blue polygon), SW–NE cross section (A = A' in green), pseudo-DT logs (Pseudo North and Pseudo South) and nearby wells with available DT logs overlain on a structural surface of the Broom Creek Formation. Sonic data from Well 9074 was projected on to Pseudo North, and sonic data from Well 8169 was projected onto Pseudo South.

Facies distributions were performed by applying a value cutoff to the distributed Vp property. A cutoff of 12,500 ft/s was selected after comparing porosity and gamma ray logs to derived Vp well logs (Figure A-4). All cells with Vp values >12,500 ft/s were designated as dolostone, while cells with VP values <12,500 ft/s were classified as sandstone (Figure A-5 and A-6). Figure A-7 reflects the sandstone and dolostone heterogeneity and the correlation of the Vp property based upon seismic data.

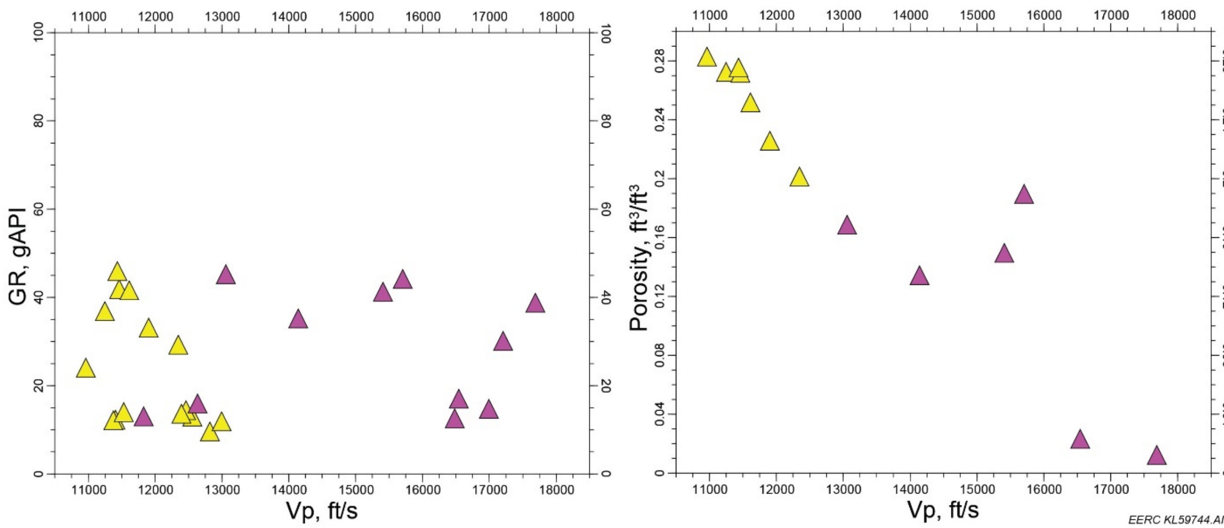


Figure A-4. Upscaled gamma ray logs vs. upscaled Vp logs (left panel) and upscaled porosity logs vs. upscaled Vp logs (right panel). Upscaled cells colored by interpreted lithology: yellow represents sandstone and purple represents dolostone. A cutoff of 12,500 ft/s captures the primary interpreted lithologies within the injection zone.

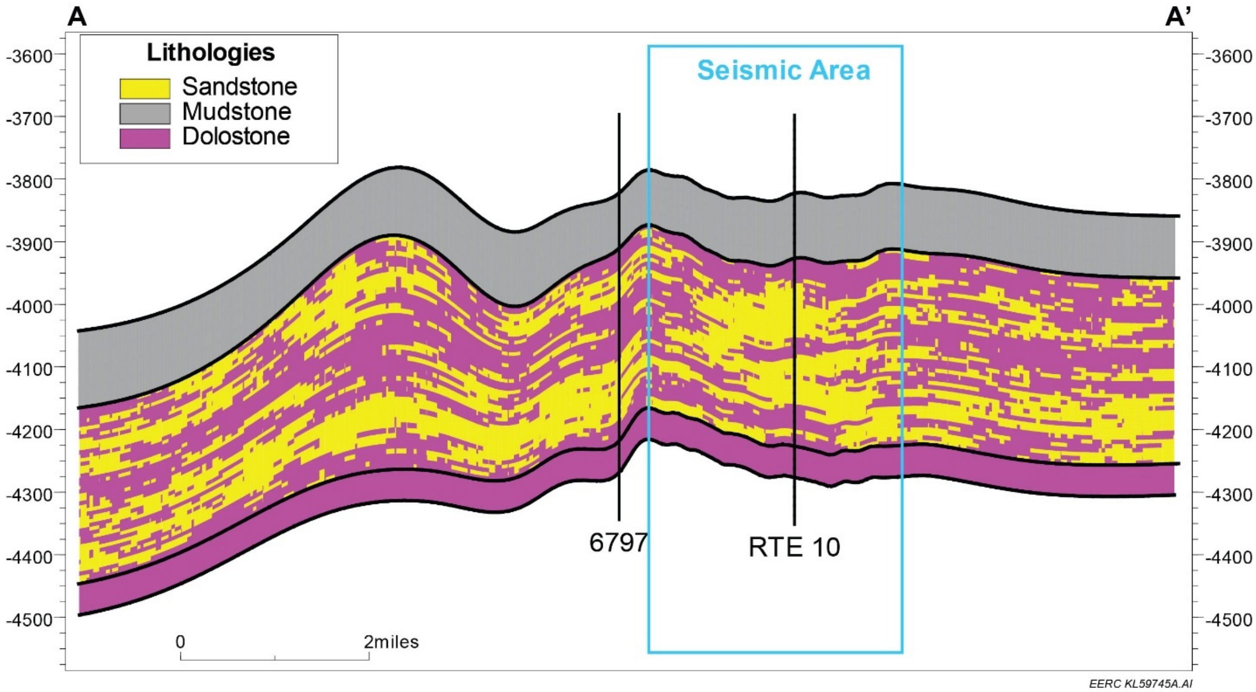


Figure A-5. Lithofacies classification based on a Vp cutoff value of 12,500 ft/s. Sandstone and dolostone heterogeneity is reflected and correlates well with the Vp property based on seismic data (Figure A-7). Vertical units on the Y-axis are displayed as feet below sea level (30× vertical exaggeration shown).

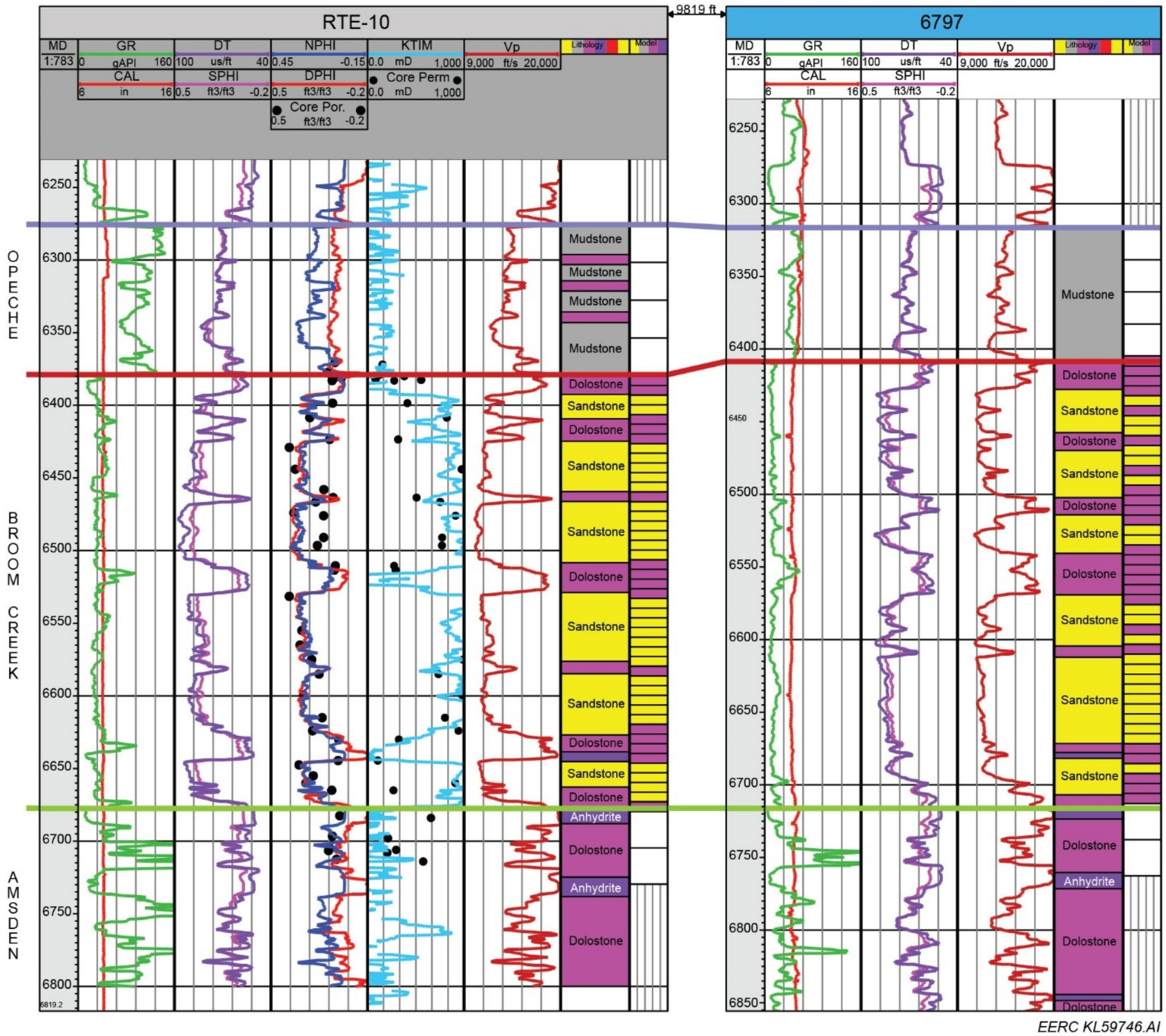


Figure A-6. Lithofacies classification in wells RTE-10 and 6797. Logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red); 2) delta time (dark purple) and sonic porosity (light purple); 3) neutron porosity (dark blue), density porosity (red), and core porosity (black dots); 4) permeability (light blue) and core permeability (black dots); 5) derived primary velocity (dark red; 6) interpreted lithology log; and 7) calculated lithology based upon primary velocity cutoff.

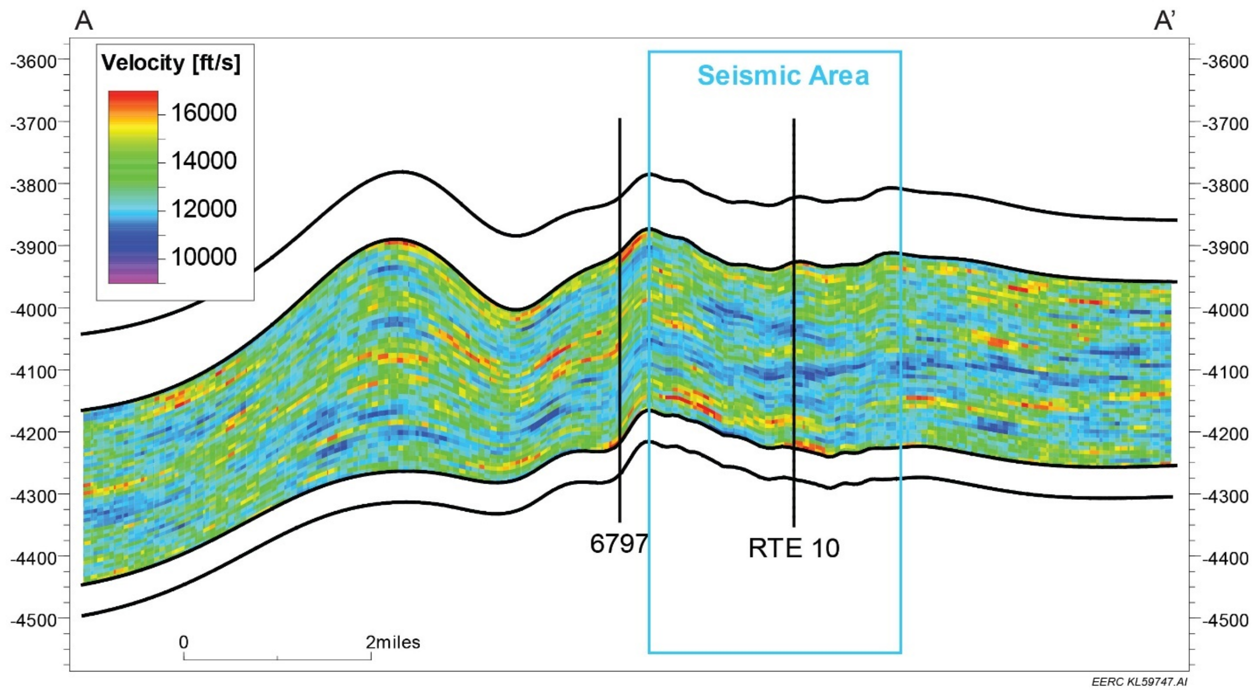


Figure A-7. Distributed Vp property along the SW–NE cross section, as illustrated in Figure A-3. The distributed Vp property was used to distribute lithofacies and petrophysical properties to seismic data. Vertical units on the Y-axis are displayed as feet below mean sea level (30× vertical exaggeration shown).

Prior to distributing the porosity property, core data from the RTE-10 well were compared with well logs to ensure good agreement between the two data sets. A porosity property was distributed using porosity well logs, upscaled to the resolution of the 3D model (approximately 7.0 ft on average) as control points; variogram structures described previously; and the distributed Vp property as a secondary cokriging variable.

After porosity was distributed, a sandstone connected volume property of the sandstone was estimated. The connected volume property estimates the total gridded volume of sandstone cells which are next to one another, effectively creating a single connected sandstone. This property, used in combination with the distributed porosity property, yielded an estimate of the pore volume of the sandstone throughout the model.

Uncertainty Analysis and Case Selection

An uncertainty analysis was performed on several properties, (i.e., Vp, lithofacies, porosity, and connected volume) to account for the uncertainty inherently associated with any geologic modeling activity and the stochastic nature of the property distributions.. This was achieved by generating hundreds of realizations of each property, which would be analyzed and reduced to representative cases. Realizations were generated by randomly altering the parameters of the Vp and porosity distributions and then regenerating the associated connected volume. Specifically, the Vp cutoff was randomly altered by up to ±150 ft/ms for lithofacies classification and the porosity range was randomly altered by ±1 porosity unit (pu). A total of 826 realizations were generated.

The method from Belobraydic and Kaufman (2014) was used to select a number of cases from the 826 realizations, based on the ratio of the total pore volume to the connected sand pore volume. One hundred cases were chosen by using linear regression of the midpoints of these ratios from P10, P25, P33, P50, P67, P75, and P90 rankings (Figure A-8). The first 100 points closest to the regression line were chosen and ranked by connected sand pore volume. The median case from each ranking set was then chosen as the basis for the remainder of the modeling activities.

For each median case selected from the uncertainty analysis and ranking, permeability was distributed in a similar manner to the porosity property. Permeability logs, once upscaled from well log resolution to the resolution of the 3D grid, had the expected logarithmic relationship with upscaled porosity logs (Figure A-9). After distribution methods were tested, it was found the correlation trend matched upscale data more consistently after a base-10 logarithm was applied to upscaled permeability values prior to distribution. This allowed the permeability values to be distributed along a better fit to the porosity trend as scalar values. Permeability was distributed using 1) upscaled values as control points converted to scalar values by applying the logarithmic, 2) previously described variogram ranges, and 3) the distributed porosity volume as an ordinarily kriged trend. The ordinary kriging algorithm recalculated a mean for each location based upon the porosity-permeability trend. In effect, the resulting property better fit the trend of the observed porosity-permeability trend. Finally, a power function was used to return the distributed permeability values back to the original logarithmic scale.

A small artifact in the porosity and permeability relationship is visible (Figure A-9) in a small percentage of sandstone cells (0.14% of model pore volume) reaching a permeability "floor" of 20 mD. The artifact is attributed to the lithofacies classification and the minimum range of permeability within the classified sand lithofacies. Upscaled permeability values demonstrate a minimum permeability of 20 mD for cells classified as sand lithofacies. Therefore, a minimum permeability value for the entire model was assigned to 20 mD for sandstone classified cells, resulting in a modeling artifact for porosity vs. permeability crossplots.

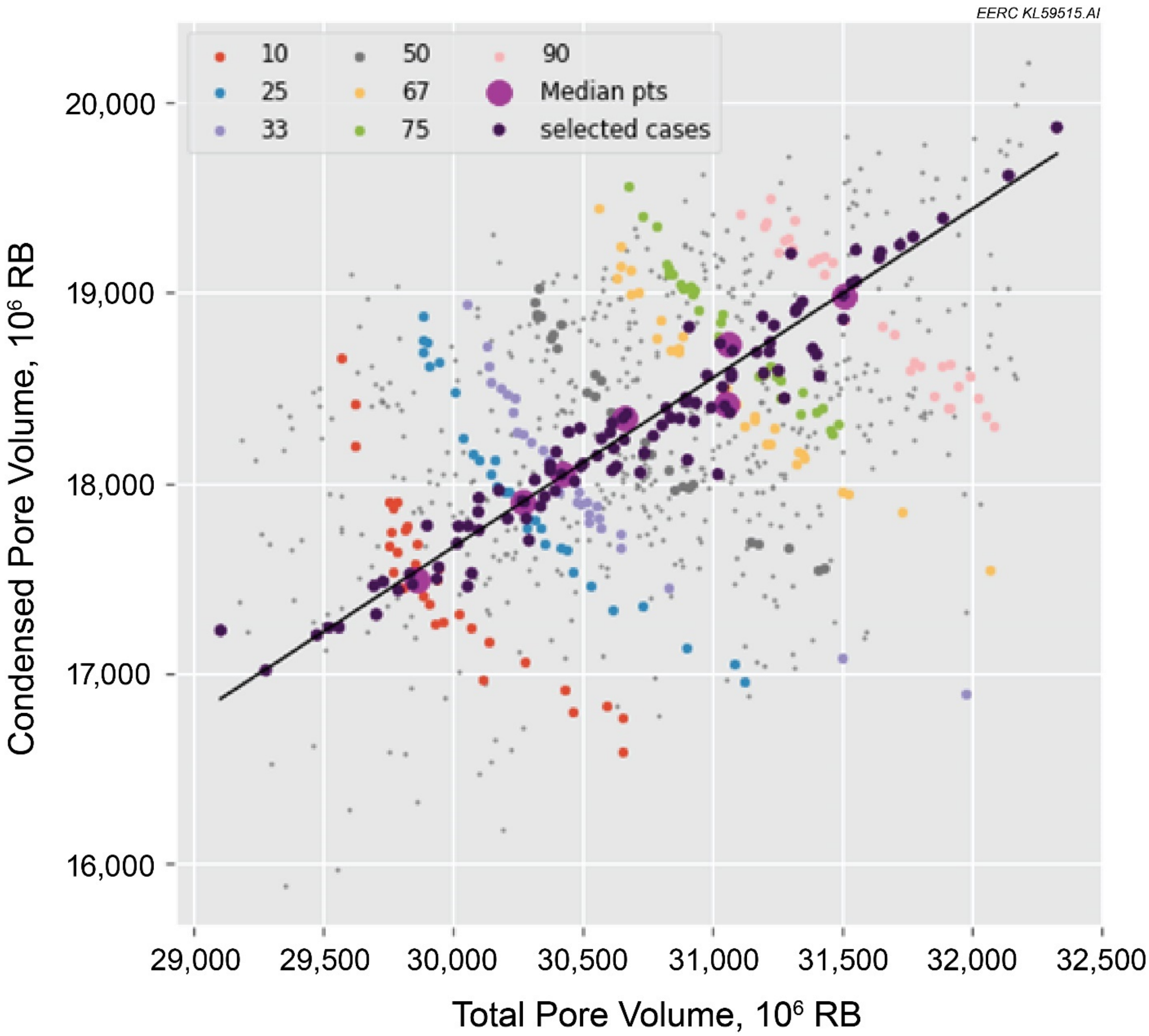


Figure A-8. Illustration of the selection process from an ensemble of 826 property realizations (Belobraydic and Kaufman, 2014). Total modeled pore volume is displayed along the X-axis. Pore volume of the classified sand lithofacies is displayed along the Y-axis; both axes use millions of barrels as units. Each realization is displayed as a point on the graph. Colored points represent probability groups, P10 (red), P25 (blue), P33 (light purple), P50 (large gray points), P67 (orange), P75 (green), and P90 (pink). Large magenta points represent median cases of each probability group. Selected cases are represented by bold black dots and are chosen according to distance from the linear regression of the median cases.

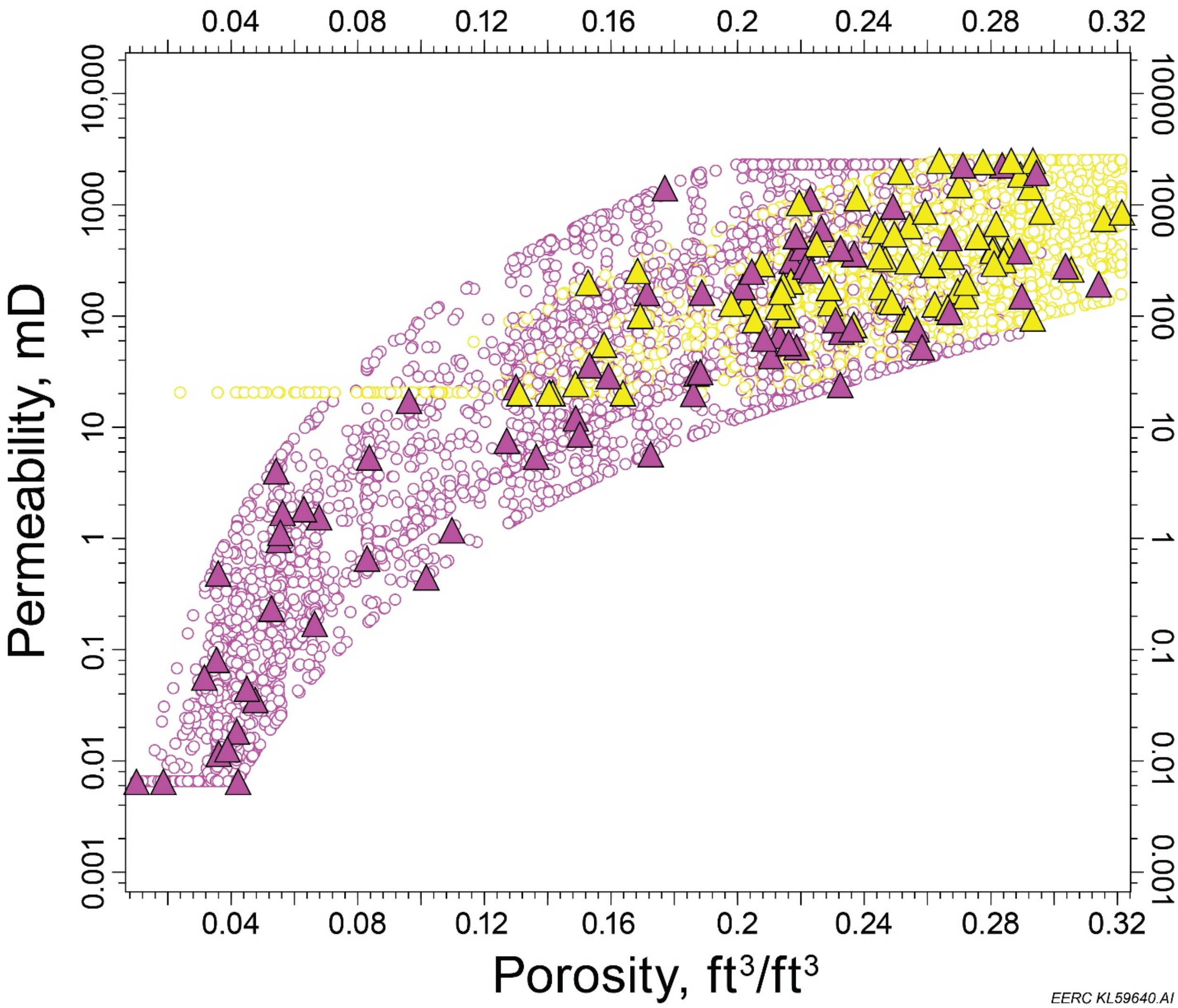


Figure A-9. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies distribution, as seen in Figure A-5 (yellow = sandstone; purple = dolostone). The logarithmic relationship between upscaled values is illustrated.

Temperature data recorded from logging the RTE-10 wellbore were used to derive a temperature gradient of 0.016°F/ft for the proposed injection site. In combination with depth, this temperature gradient was used to calculate subsurface temperatures throughout the geologic model of the study area. Pressure testing within the RTE-10 well was performed with a modular formation dynamics tester (MDT) logging tool. Multiple pressure readings recorded from the Broom Creek Formation were used to derive a pore pressure gradient of 0.45 psi/ft (Table A-1). Combined with depth, this gradient was used to distribute pressure throughout the geologic model.

Table A-1. MDT Pressure Measurements Recorded from the RTE-10 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
6,438	2,932.88	0.45
6,441	2,932.21	0.45
6,511	2,963.00	0.45
6,539	2,976.54	0.45
6,540	2,975.64	0.45

* Measured depth.

Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium condition for performing numerical simulations using Computer Modelling Group's (CMG's) GEM, a fully compositional equation-of-state (EOS) reservoir simulator. A compositional simulator is the one of the most mechanistically accurate methods to solve compositional multiphase fluid flow processes. It utilizes cubic equations of state, such as Peng–Robinson's EOS, which calculates thermal dynamic properties of fluids within the reservoir, including the resulting mixture of fluids when CO_2 is injected into the saline formation. During the simulation process for this study, the compositional EOS simulator accounts for and estimates CO_2 solubility, residual gas trapping, and flow dynamics through a duration of time.

Numerical Simulation

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model of the Opeche, Broom Creek, and Amsden Formations described above. Simulations were carried out using CMG's GEM, a compositional reservoir simulation module (Figure A-10). The simulation model boundaries were assigned infinite-acting conditions to allow lateral water flux and pressure dispersion through the simulated-boundary aquifer. The reservoir was assumed to be 100% brine saturated with an initial formation salinity of 164,000 ppm total dissolved solids (TDS). The fluid model used Henry's solubility model, which allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for Broom Creek were analyzed and generated through the laboratory evaluation at the EERC (Figure A-11). Relative permeability curves were not upscaled or smoothed to avoid significantly altering the data and correlations determined from the laboratory evaluation. Table A-2 shows the general properties used for numerical simulation analysis in this study. The injection well, RTE-10, is simulated as perforated across the Broom Creek Formation interval. The RTE-10 well constraints and wellbore model inputs for the simulation model are shown in Table A-3.

Sensitivity Analysis

Because the availability of data for this study included well logs, core data, and rock-fluid properties (such as relative permeability), the need to investigate influential parameters in typical sensitivity studies has been reduced. Wellhead temperature, tubing roughness, permeability/porosity reduction, and formation compressibility were the parameters that remained to be analyzed for larger influences on simulation results. A preliminary sensitivity analysis suggested that, at the given injection volume, wellhead temperature played the most prominent role in determining wellhead pressure response. Thus a higher wellhead temperature value was chosen for the well constraint during the simulation study.

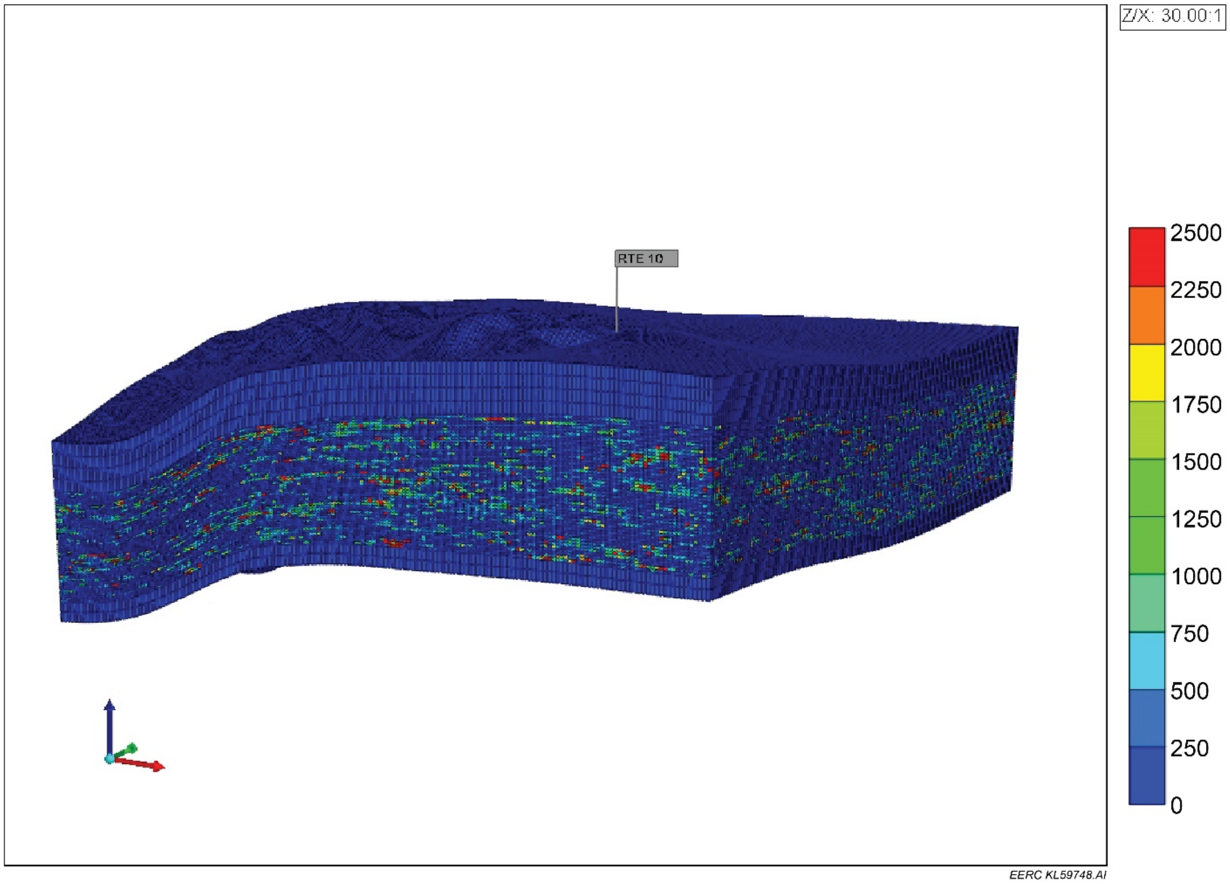
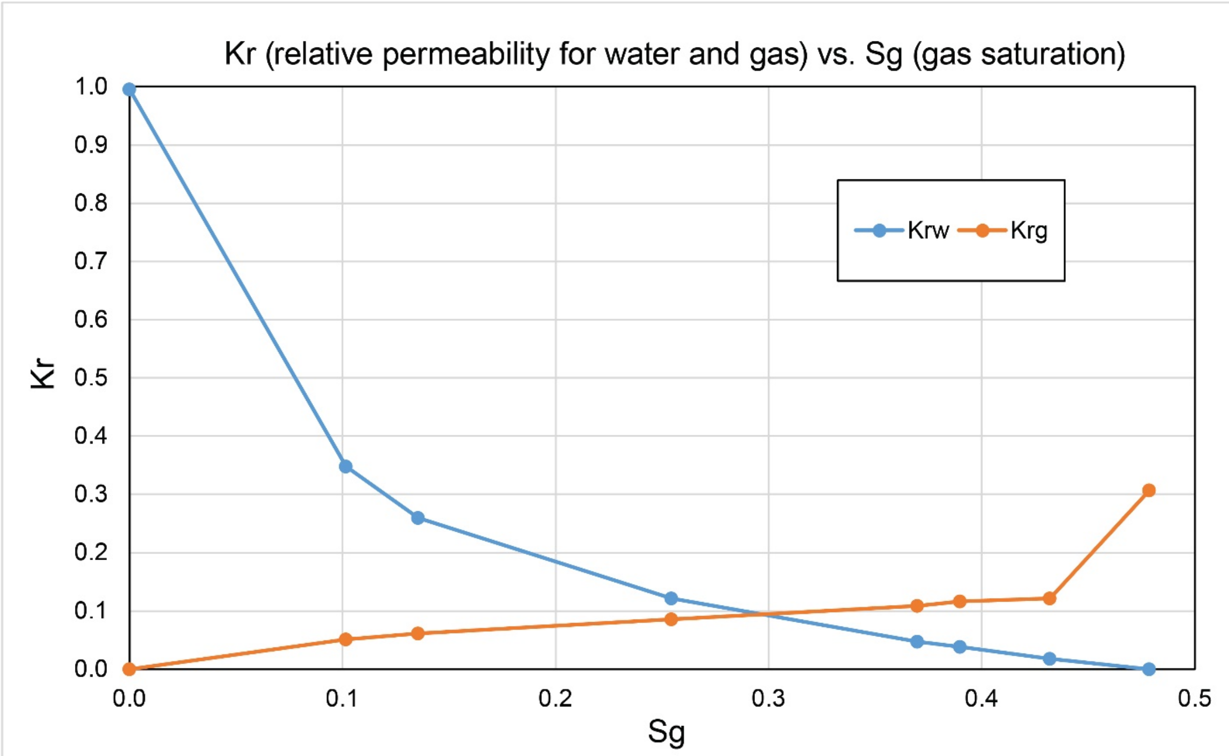
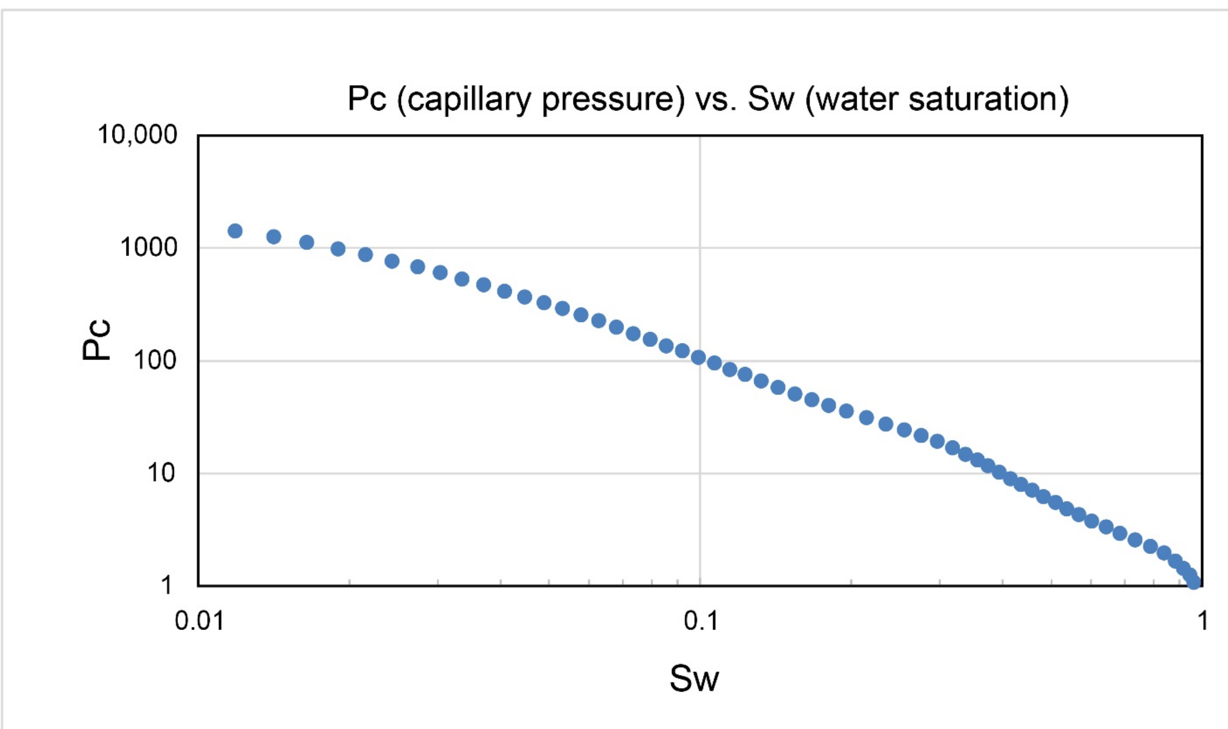


Figure A-10. The 3D view of the simulation model with the permeability property displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Opeche Formation (upper) and the Amsden Formation (lower). The varied permeability of the Broom Creek is observed in between these layers.





EERC KL59753.AI

Figure A-11. Relative permeability (top) and capillary pressure curves (bottom) for the Broom Creek Formation.

Table A-2. Summary of Reservoir Properties in the Simulation Model

Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche: 0.03 Broom Creek: ~471 Amsden: ~0.54	Opeche: ~14 Broom Creek: ~23 Amsden: ~4	~2,900	164,000	Open (infinite-acting)

Table A-3. Well Constraints and Wellbore Model in the Simulation Model

Primary Constraint, injection rate	Secondary Constraint, wellhead pressure	Tubing Size	Wellhead Temperature	Downhole Temperature
500 tonnes/day	1,500 psi	3.5 in.	90°F	148°F

Simulation Results

The model incorporated the latest geologic data acquired from well logs, core, and the rock-fluid property (relative permeability). Therefore, most of the influential parameters which typically need to be investigated in a sensitivity study have been reduced to wellhead temperature, tubing roughness, permeability/porosity reduction, and formation compressibility. A preliminary sensitivity analysis suggested, with the given injection volume, the wellhead temperature played the most important role in determining the wellhead pressure response. Thus a higher wellhead temperature value was chosen for the well constraint during the simulation study.

Simulation with the given well constraints predicted that wellhead injection pressure (WHP) will not exceed 1,300 psi during injection operations, and the bottomhole pressure (BHP) is expected to rise to just above 3,000 psi (Figure A-12). The injection rate was held constant over the 20 years of injection. At the end of 20 years of simulated injection, a total of 3.7 million tonnes of CO_2 was injected into the Broom Creek Formation (Figure A-13).

During and after injection, free-phase (supercritical) CO_2 accounts for the majority of CO_2 observed in the model's pore space, but the mass of free-phase CO_2 declines during the postinjection period. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the formation's pores through a process known as residual trapping. In residual trapping, a portion of the CO_2 that enters a pore clings to the pore wall and is unable to exit the pore. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterwards), although the rate of dissolution slows over time. The relative portions of free-phase, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure A-14).

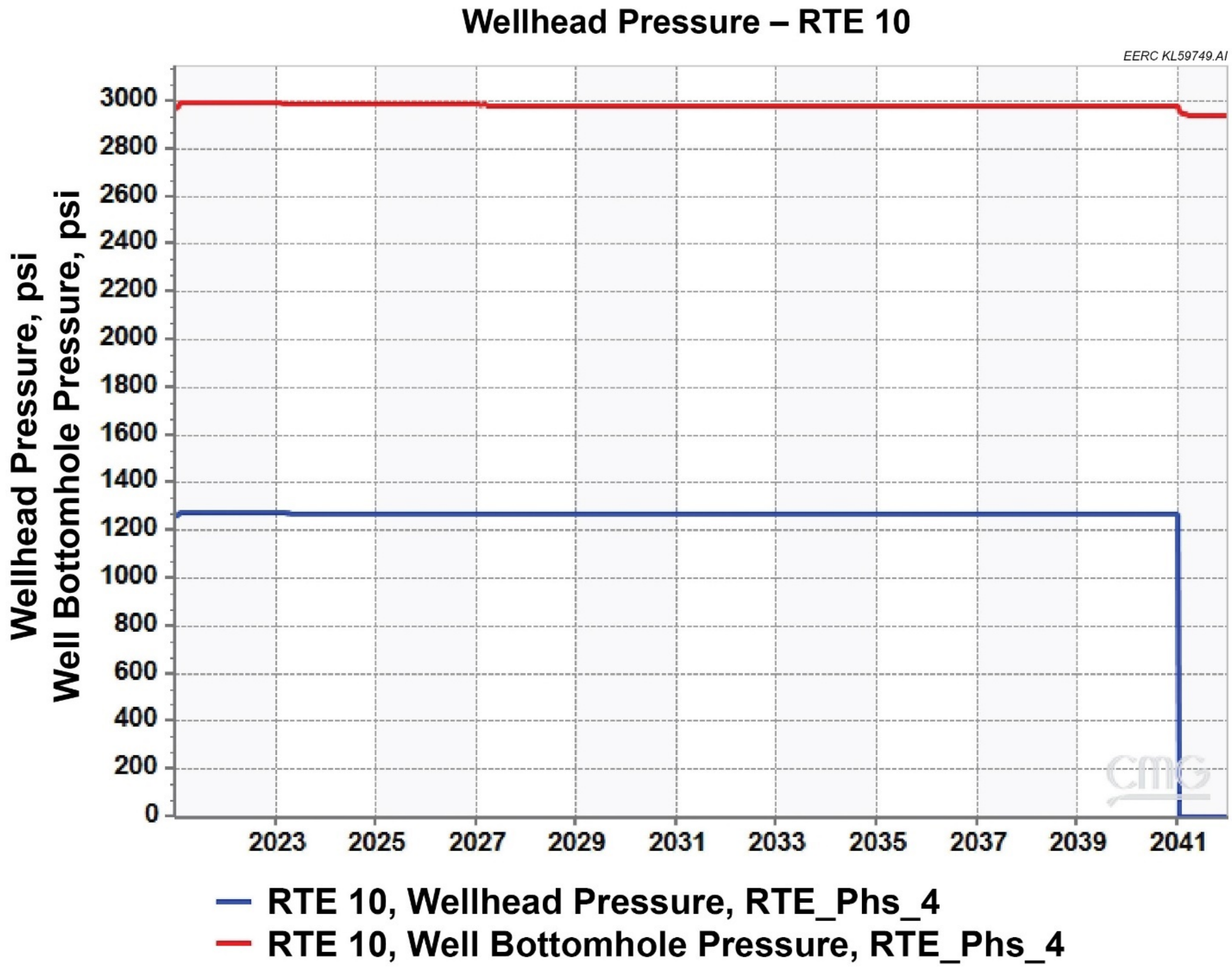


Figure A-12. WHP and BHP response with the expected injection rate.

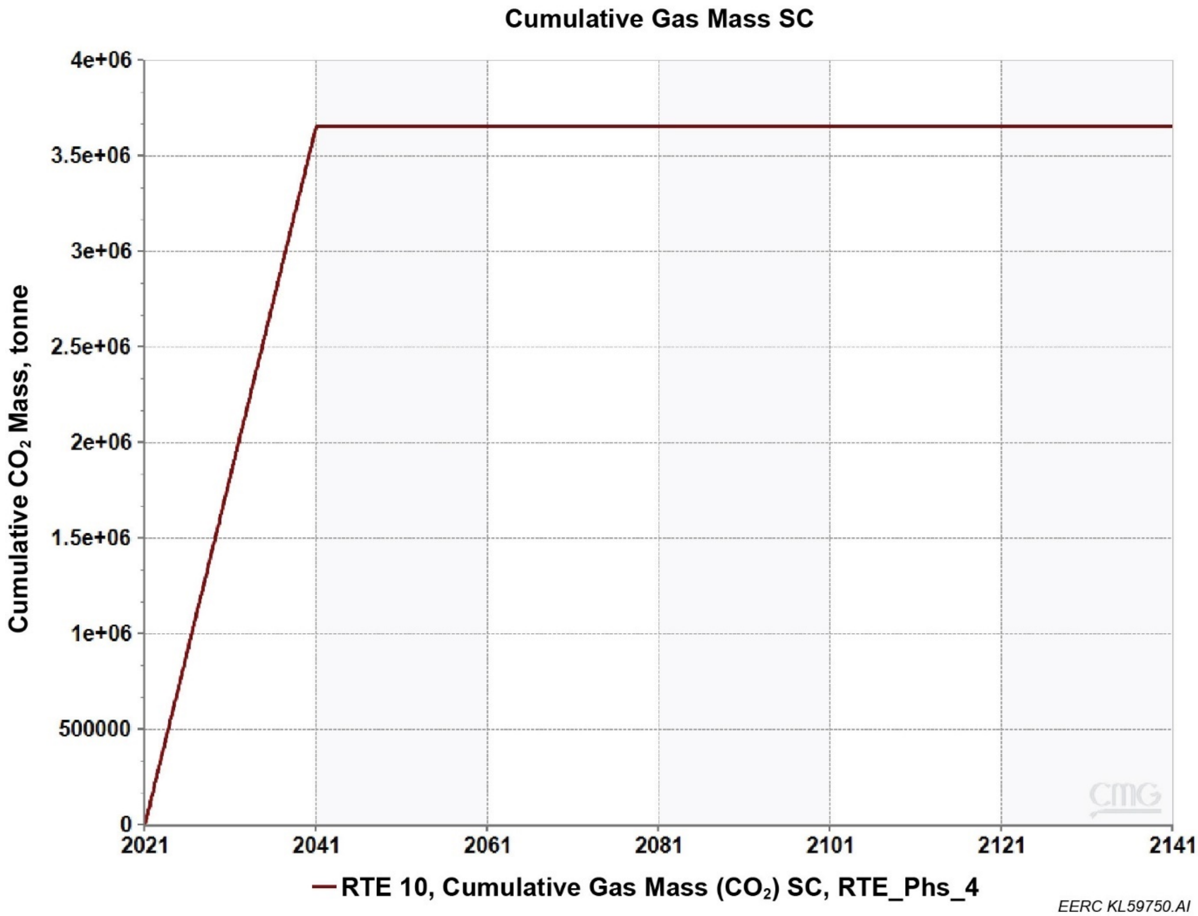


Figure A-13. Cumulative injected gas mass over 20 years of injection.

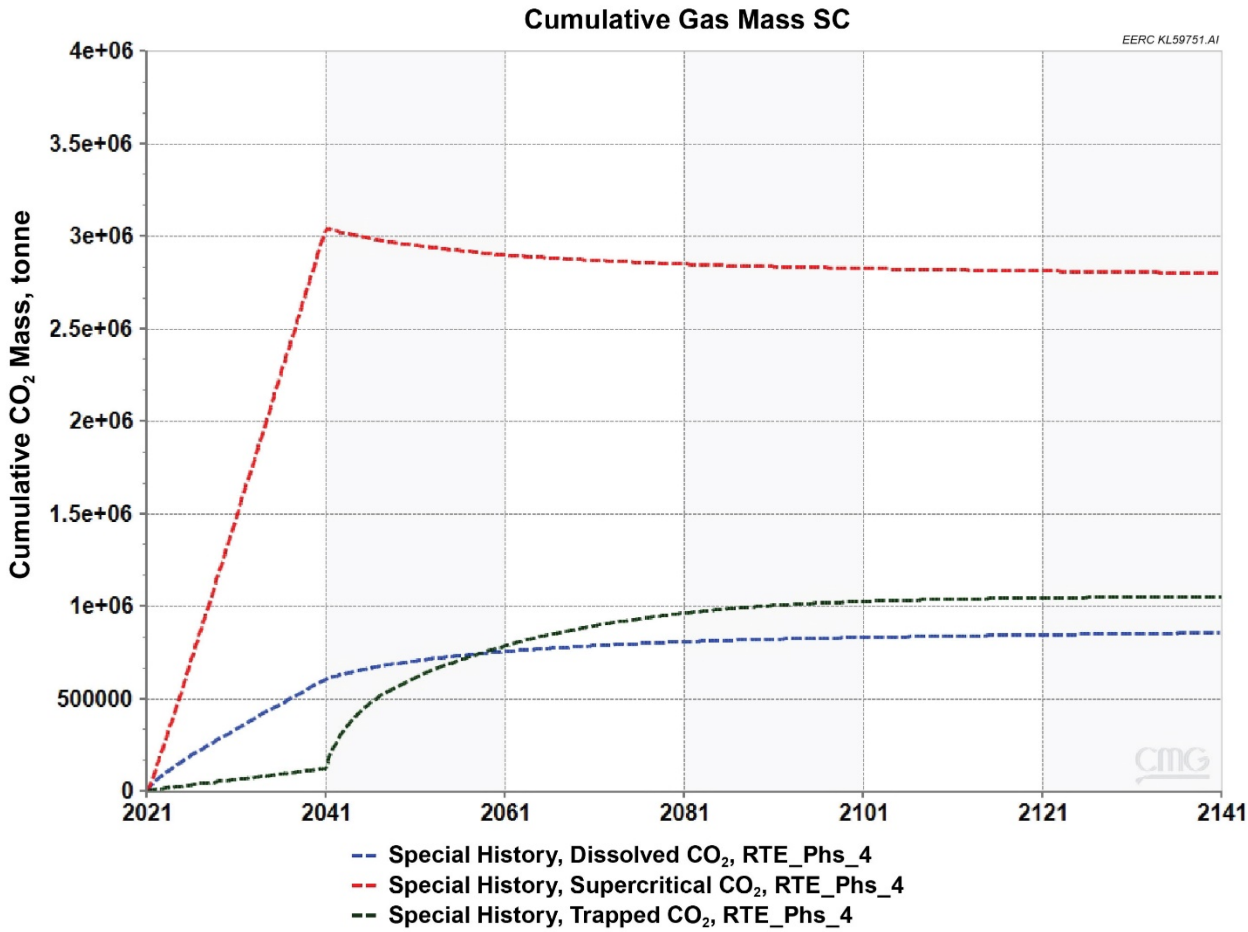


Figure A-14. Simulated total dissolved CO_2 in brine, supercritical-phase CO_2, and trapped CO_2.

The pressure plume shows the distribution of pressure increase in the Broom Creek Formation during the 20-year injection period. Figure A-15 shows where the pressure increase is greater than 10 psi. The largest increase will appear in the near-wellbore area, where a maximum increase of 52 psi is observed.

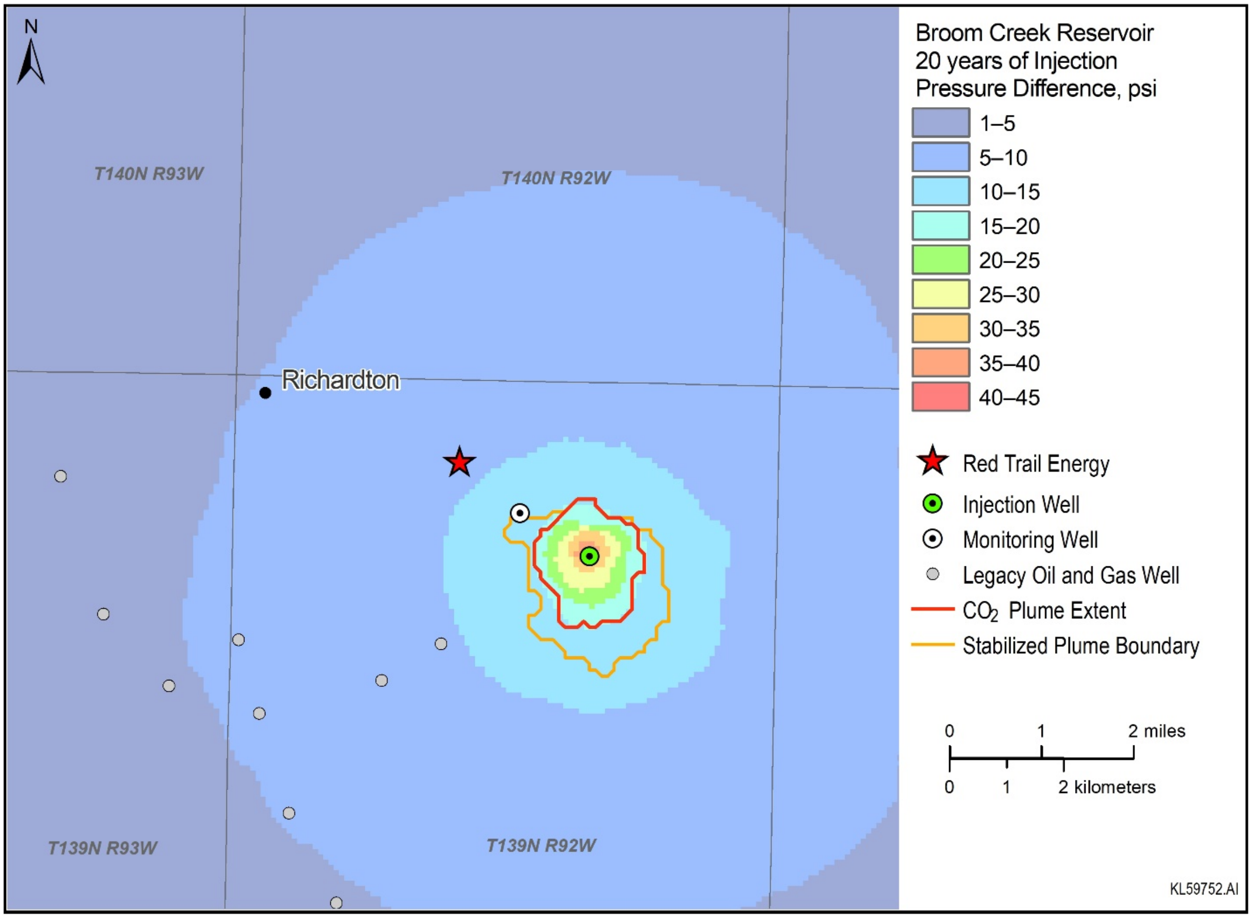
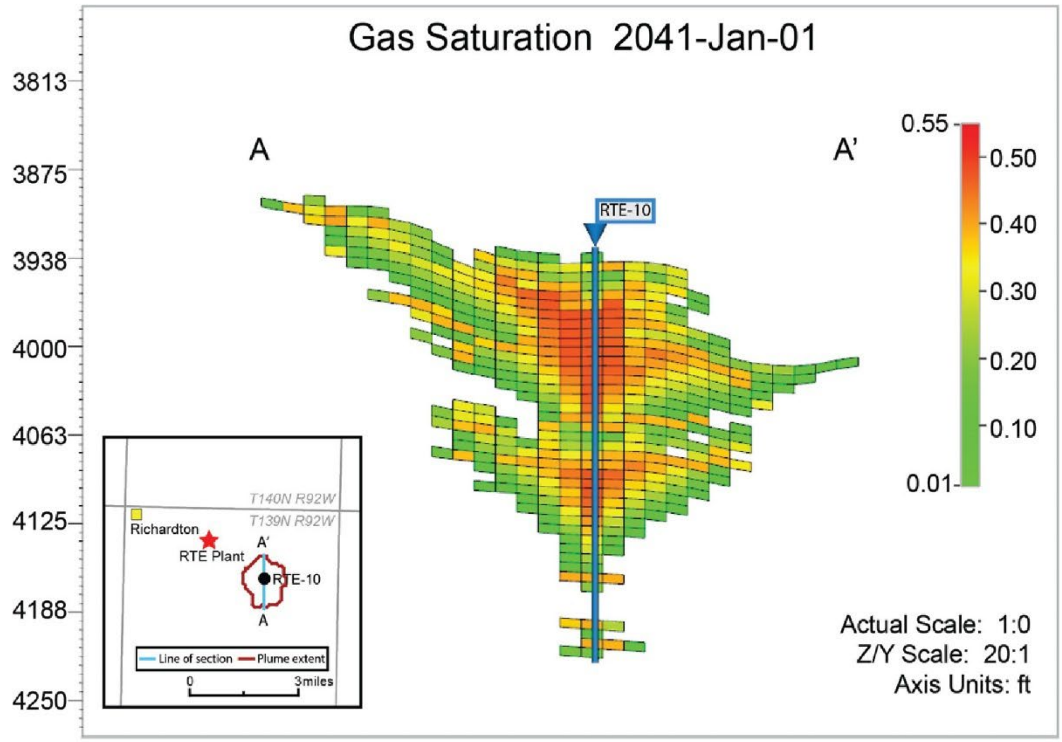


Figure A-15. Pressure response at the top of the Broom Creek Formation at the end of a simulated 20-year CO_2 injection operation. The area adjacent to the injection wellbore is expected to experience a pressure increase of 52 psi.

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the cap rock or lower-permeability layers present in the Broom Creek and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Figures A-16 and A-17 show the gas saturation changes between the end of injection (year 2041) and 100 years postinjection (year 2141) in the cross-sectional view. The RTE-10 wellbore displayed is perforated below well gauge depths.



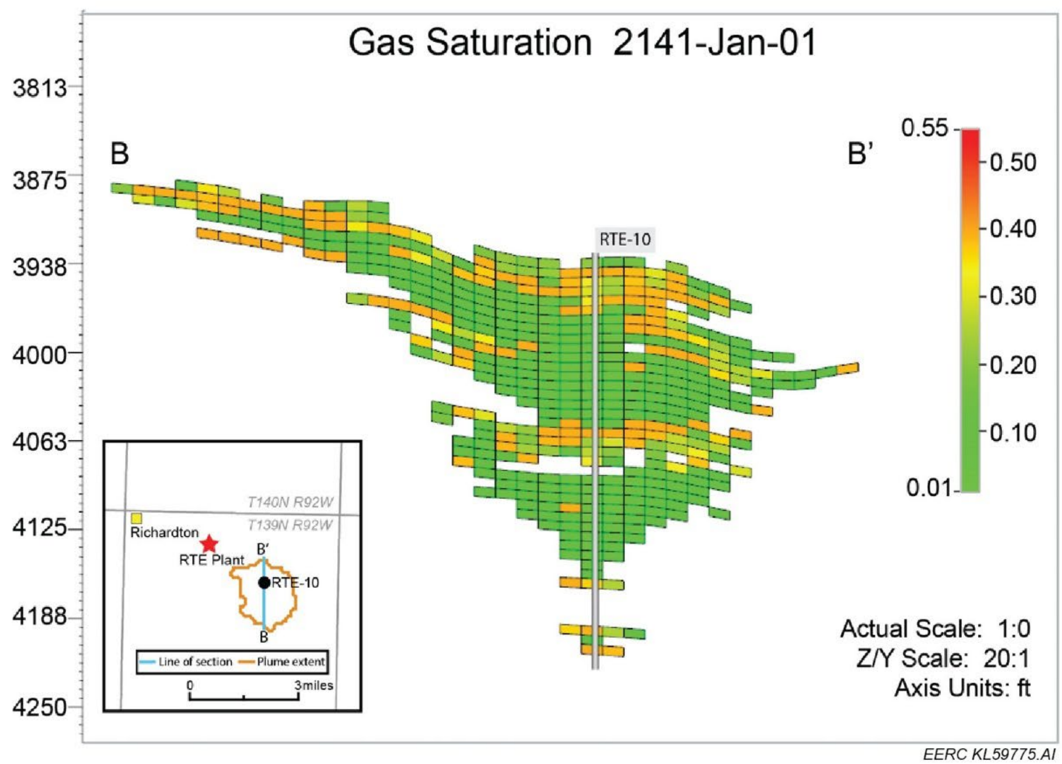
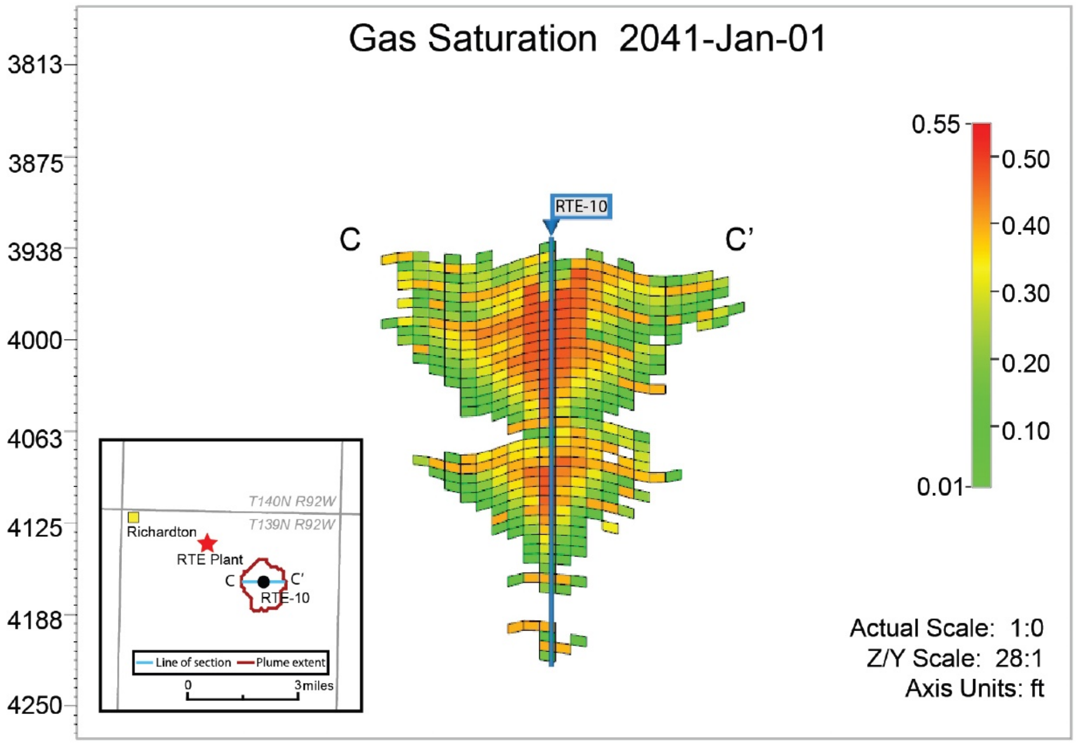


Figure A-16. CO_2 plume cross section at the end of injection (top) and as a stabilized plume (bottom), displayed south to north through the RTE-10 well.



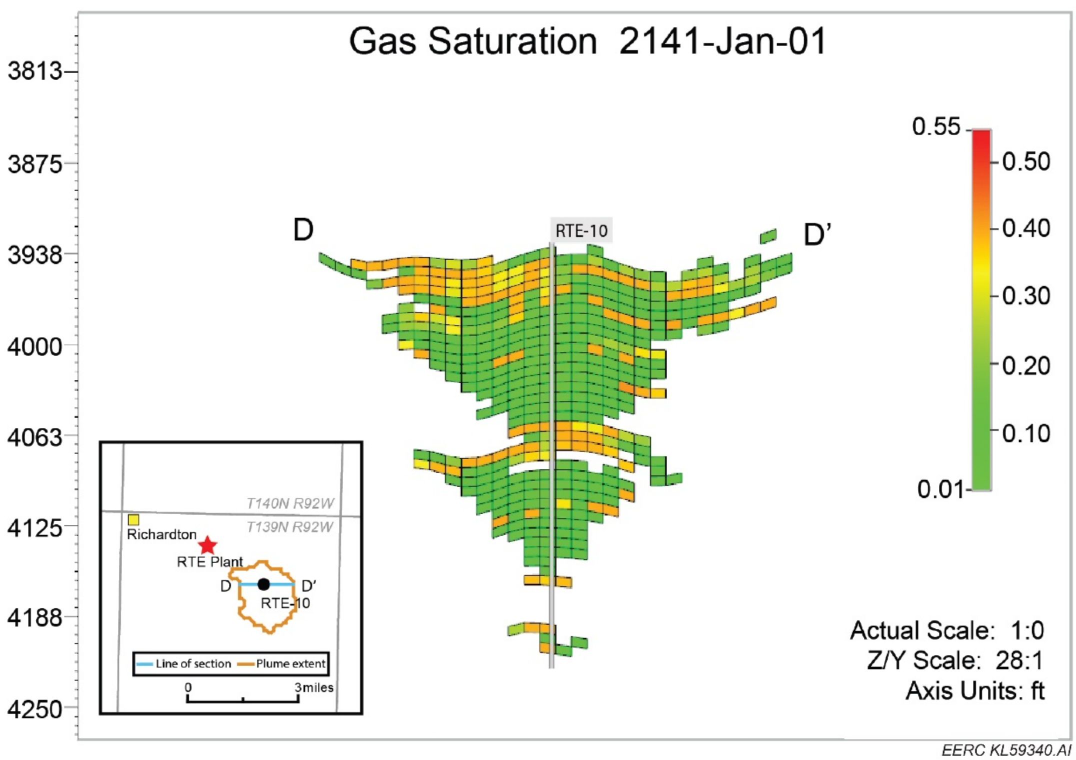


Figure A-17. CO_2 plume cross section at the end of injection (top) and as a stabilized plume (bottom), displayed east to west through the RTE-10 well.

Maximum Surface Injection Pressure
Additional cases were run to determine if the well would ultimately be limited by the maximum calculated surface injection pressure of 2,250 psi (based on flow line rating) or by the maximum calculated downhole pressure of 4,019 psi (90% of the formation fracture pressure). Other parameters were kept the same for the additional tests.

The maximum surface pressure was reached in the simulations before the maximum BHP was encountered. At the maximum surface pressure of 2,250 psi, the predicted BHP response was observed with a peak of less than 3,200 psi and an average pressure of less than 3,100 psi. At this pressure, the well is able to injection 2,140 tonnes/day of CO_2 with 3.5-in.-diameter tubing. Simulations with 4.5-in.-diameter tubing showed that the well can achieve a higher injection rate of 4,150 tonnes/day of CO_2, but the BHP does not exceed 3,360 psi, with an average BHP of 3,240 psi. These values are all below the maximum calculated BHP of 4,019 psi.

Stabilized Plume
Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome capillary entry pressure of the surround reservoir rock. At this point. the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's AoR and the corresponding scale and scope of the project's monitoring and safety plans.

Plume stabilization can be visualized at the micro scale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macro scale these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent. For the RTE project, stabilization was defined as the time when CO_2 no longer migrates to adjacent cells within the simulation model. CO_2 may still experience gradual redistribution within the plume, but the geographic extents of the plume remain unchanged.

The CO_2 plume was simulated in 1-year time steps until the extent ceased to change in order to define the plume extent boundary and the associated buffers and boundaries (Figures A-16 and A-17). This estimate is anticipated to be regularly updated during the CO_2 storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO_2.

Delineation of AoR
The AoR is defined as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by CO_2 injection activity (North Dakota Administrative Code [NDAC] § 43-05-01-05). The primary endangerment risk is due to the potential for vertical migration of CO_2 and/or formation fluids to a USDW from the storage reservoir. Therefore, the AoR encompasses the region overlying the extent of reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., abandoned wells or fractures) are present. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking

water aquifer is referred to as the “critical threshold pressure increase” and the resultant pressure as the “critical threshold pressure.” The U.S. Environmental Protection Agency (EPA) guidance for AoR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and the resulting critical threshold pressure.

The method presented by Nicot and others (2008) and Bandilla and others (2012) was used to calculate the critical threshold pressure increase (ΔPc), which is the fluid pressure increase sufficient to drive formation fluids into the closest USDW, the Fox Hills Formation. This ΔPc is determined using Equation 2, assuming 1) hydrostatic conditions, 2) initially linearly varying densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_c = \frac{1}{2}\, g\, \xi\, (z_u - z_i)^2$$

[Eq. 2]

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i}$$

[Eq. 3]

Where:

ΔP_c is the change in pressure from baseline (hydrostatic) conditions (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m).
z_i is the elevation of the top of the injections zone (m).
p_i is the fluid density in the injection zone (kg/m^3).
p_u is the fluid density in the USDW (kg/m^3).

Critical Threshold Pressure Increase Estimation at RTE-10

For the purposes of delineating the ΔPc for the RTE study area, constant fluid densities for the lowermost USDW (the Fox Hills Formation) and the injection zone (the Broom Creek Formation) were used. A density of 1001 kg/m^3 was used to represent the USDW fluids, and a density of 1106 kg/m^3, which is estimated based on the in situ brine salinity, temperature, and pressure, was used to represent injection zone fluids.

Critical pressure threshold increases were calculated for the proposed storage reservoir at a range of depths across the reservoir using Equations 2 and 3, depth from the bottom of the USDW, injection zone depth, and fluid density values from the RTE-10 well (Table A-4). Using this method, the threshold pressure increase at the top of the Broom Creek Formation at the RTE-10 well was determined to be 107.3 psi.

Table A-4. Critical Threshold Pressure Increase Calculated at the RTE-10 Wellbore Location. Chosen depths represent the top, middle, and base of the Broom Creek Formation.

Depth, ft MD	Depth Descriptor	Elevation, m AMSL*	pi, kg/m^3	pu, kg/m^3	zu, m	zi, m	ξ, coefficient	ΔPc, psi
1668	Fox Hills Base	785	–	–	–	–	–	–
6379	Broom Creek Top	−1,197	1,106	1,001	239	−1,197	0.0731	107.3
6529	Broom Creek Middle	−1,242	1,106	1,001	239	−1,242	0.0709	110.7
6678	Broom Creek Base	−1,288	1,110	1,001	239	−1,288	0.0688	114.1

* Above mean sea level.

These estimates of critical threshold pressure increase were compared to potential pressure increases within the storage facility area that would result from CO_2 injection and the potential lateral extent of the injection fluid as determined by predictive simulations. Table A-2 provides estimates of ΔP_c for various depths within the Broom Creek Formation, which were then compared against the difference in pressure predicted for each cell in the simulation model at the end of injection, where the greatest increase in pressure was observed. Within the bounds of the modeled area and throughout the entire storage facility area, the maximum pressure difference during the final year of injection is estimated to reach approximately 52 psi, which occurs in near proximity to the injection well. This pressure is below the calculated critical threshold pressure increase of 107.3 psi. Therefore, the critical pressure is not exceeded at the RTE injection site anywhere within or around the injected CO_2 plume and critical pressure is not a deciding factor in determining the AoR extent.

At RTE, the maximum extent of injected CO_2 plus one-half mile is the storage facility area, as the critical pressure is not exceeded by injection of CO_2 in the "storage reservoir." The AoR is then 1 mile beyond the storage facility area (Figure A-18). As shown, the AoR is depicted by the black dotted line, which includes the simulated CO_2 extent (purple boundary and shaded area), storage facility area (dotted white boundary), and AoR (dotted black boundary). Figure A-19 illustrates the land use within the AoR.

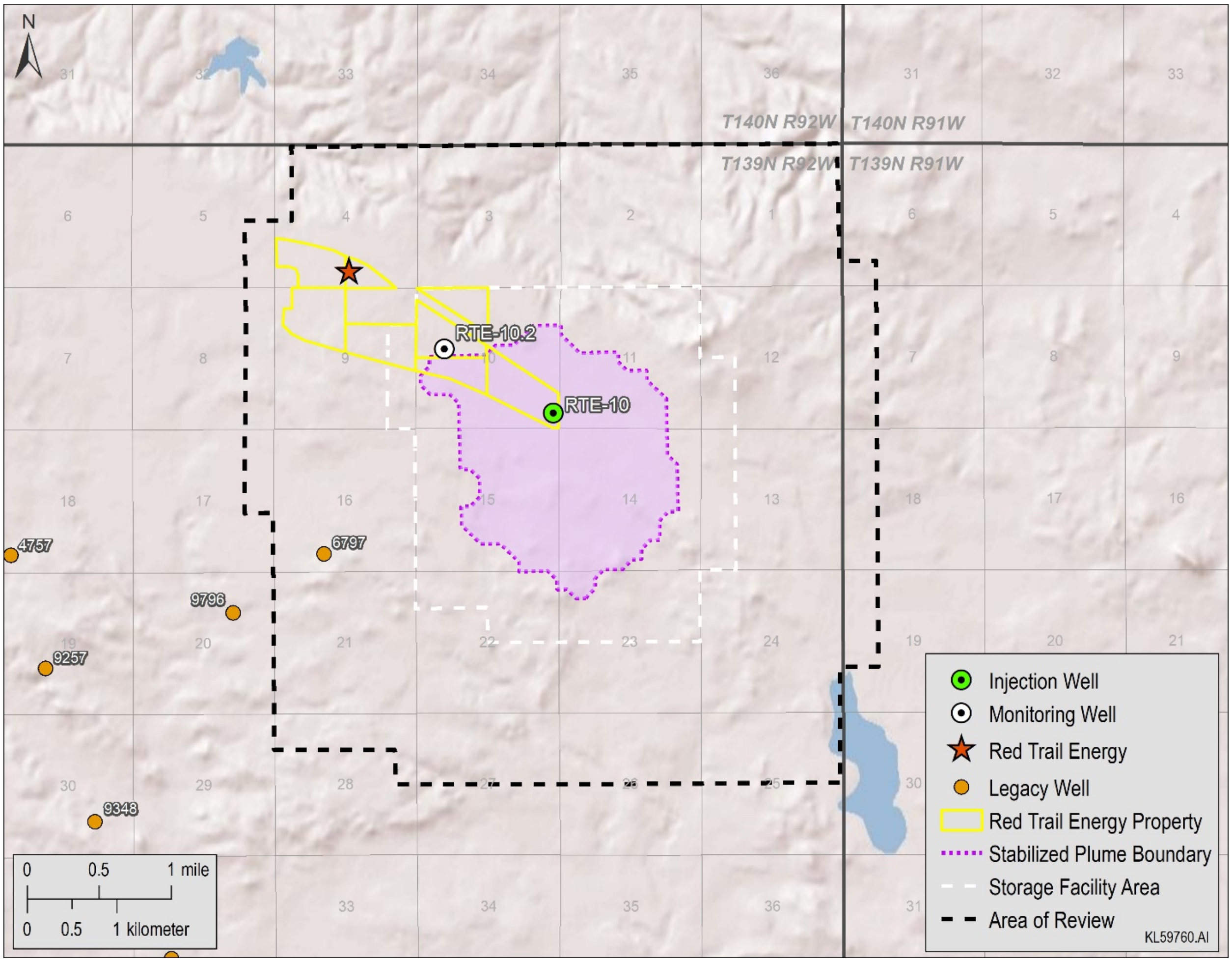


Figure A-18. Final AoR estimations of the RTE-10 storage facility area in relation to nearby legacy wells. Shown are the simulated CO_2 extent (purple boundary and shaded area), storage facility area (dotted white boundary), and AoR (dotted black boundary). Orange circles represent nearby legacy wells near the storage facility area.

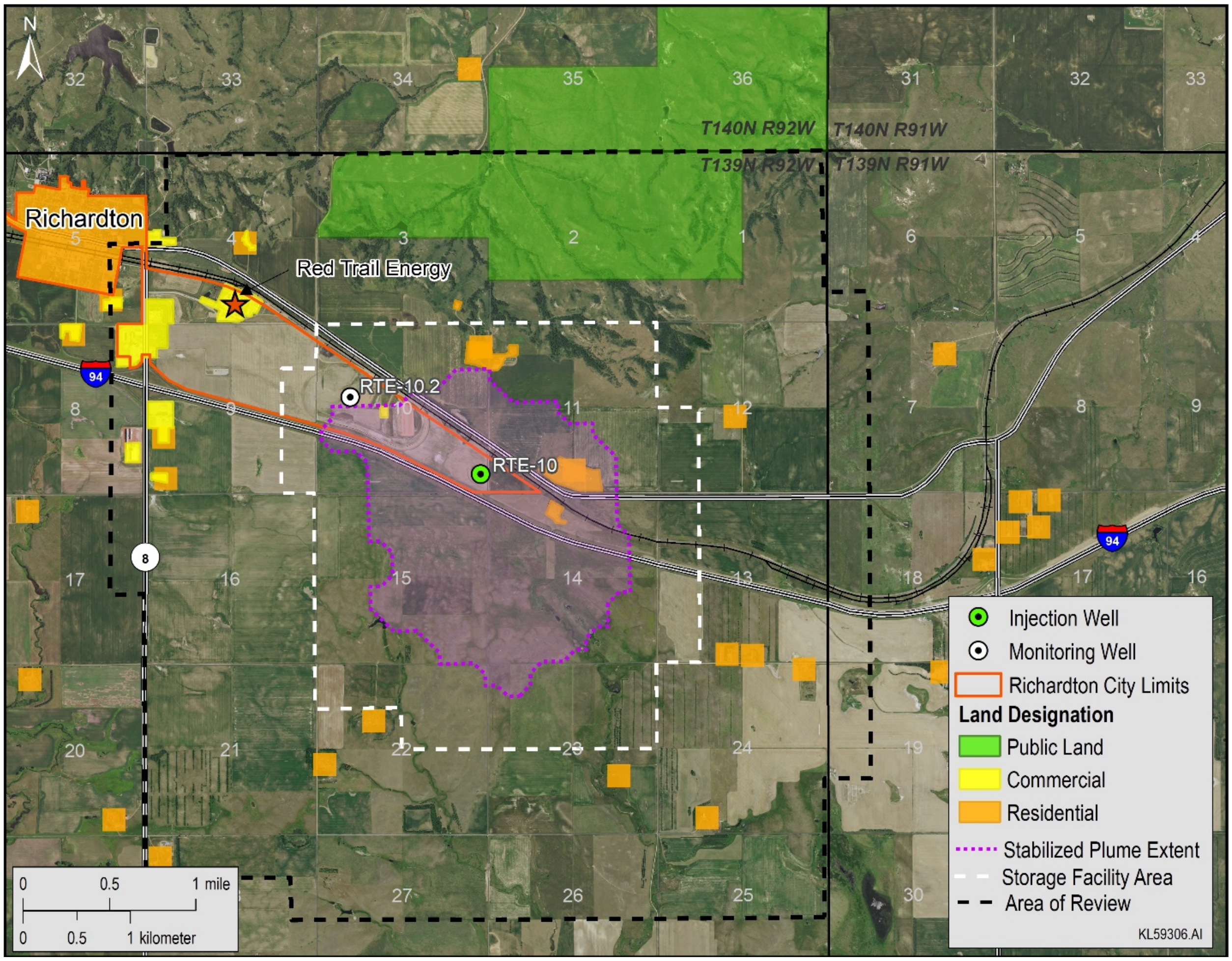


Figure A-19. Land use in and around the AoR of the RTE-10 storage facility.

References

Bandilla, K.W., Kraemer, S.R., and Birkholzer, J.T., 2012, Using semi-analytical solutions to approximate the area of potential impact for carbon dioxide injection: International Journal of Greenhouse Gas Control, v. 8, p. 196–204.

Belobraydic, M., and Kaufman, P., 2014, Geomodeling unconventional plays—improved selection of uncertainty cases: Unconventional Resources Technology Conference. doi:10.15530/URTEC-2014-1922075.

Davis, J., 1986, Statistics and data analysis in geology: New York, John Wiley & Sons.

Nicot, J.P., Oldenburg, C.M., Bryant, S.L., and Hovorka, S.D., 2008, Pressure perturbations from geologic carbon sequestration—area-of-review boundaries and borehole leakage driving forces: Proceedings of the 9th International Conference of Greenhouse Gas Control Technologies, Washington, USA, November 2008.

APPENDIX B

RTE-10 AND RTE-10.2 FORMATION FLUID-SAMPLING LABORATORY ANALYSIS

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Janet Crossland
UND - EERC
15 N 23rd St, Stop 9018
Grand Forks ND 58202-9018

Report Date: 5 May 20
Lab Number: 20-W741
Work Order #: 82-0924
Account #: 007033
Date Sampled: 21 Apr 20 7:31
Date Received: 22 Apr 20 8:00
Sampled By: MVTL Field Services
PO #: J. Crossland

Project Name: RTE 10
Sample Description: Inyan Kara

Temp at Receipt: 5.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Apr 20	SD
pH	* 7.5	units	N/A	SM4500 H+ B	22 Apr 20 17:00	SD
Conductivity (EC)	17772	umhos/cm	N/A	SM2510-B	22 Apr 20 17:00	SD
pH - Field	7.38	units	NA	SM 4500 H+ B	21 Apr 20 7:31	JSM
Temperature - Field	20.1	Degrees C	NA	SM 2550B	21 Apr 20 7:31	JSM
Total Alkalinity	243	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Bicarbonate	243	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Conductivity - Field	18624	umhos/cm	1	EPA 120.1	21 Apr 20 7:31	JSM
Total Organic Carbon	708	mg/l	0.5	SM5310-C	24 Apr 20 13:05	NAS
Sulfate	261	mg/l	5.00	ASTM D516-11	22 Apr 20 9:51	EMS
Chloride	7570	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:19	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Apr 20 15:14	EV
Ammonia-Nitrogen as N	17.1	mg/l	0.20	EPA 350.1	28 Apr 20 12:22	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Total Dissolved Solids	11100	mg/l	10	I1750-85	22 Apr 20 15:39	HT
Calcium - Total	346	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Magnesium - Total	15.8	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Sodium - Total	3840	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Potassium - Total	96.0	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Iron - Total	1.98	mg/l	0.10	6010D	23 Apr 20 14:55	SZ
Manganese - Total	0.40	mg/l	0.05	6010D	23 Apr 20 14:55	SZ
Copper - Dissolved	< 0.25 @	mg/l	0.05	6010D	23 Apr 20 15:55	SZ
Molybdenum - Dissolved	< 0.5 @	mg/l	0.10	6010D	23 Apr 20 15:55	SZ
Strontium - Dissolved	16.3	mg/l	0.10	6010D	23 Apr 20 15:55	SZ
Arsenic - Dissolved	0.0036	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Barium - Dissolved	0.3737	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Cadmium - Dissolved	< 0.001 +	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Lead - Dissolved	< 0.001 +	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 10:20	CC
Silver - Dissolved	< 0.001 +	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 6 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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2616 East Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 5 May 20
Lab Number: 20-W742
Work Order #: 82-0924
Account #: 007033
Date Sampled: 21 Apr 20 16:07
Date Received: 22 Apr 20 8:00
Sampled By: MVTL Field Services
PO #: J. Crossland

Janet Crossland
UND - EERC
15 N 23rd St, Stop 9018
Grand Forks ND 58202-9018

Project Name: RTE 10
Sample Description: Broom Creek

Temp at Receipt: 5.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Apr 20	SD
pH	* 6.7	units	N/A	SM4500 H+ B	22 Apr 20 17:00	SD
Conductivity (EC)	154610	umhos/cm	N/A	SM2510-B	22 Apr 20 17:00	SD
pH - Field	6.41	units	NA	SM 4500 H+ B	21 Apr 20 16:07	JSM
Temperature - Field	25.2	Degrees C	NA	SM 2550B	21 Apr 20 16:07	JSM
Total Alkalinity	100	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Bicarbonate	100	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Apr 20 17:00	SD
Conductivity - Field	156450	umhos/cm	1	EPA 120.1	21 Apr 20 16:07	JSM
Total Organic Carbon	155	mg/l	0.5	SM5310-C	24 Apr 20 13:05	NAS
Sulfate	774	mg/l	5.00	ASTM D516-11	22 Apr 20 9:51	EMS
Chloride	98100	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:19	EV
Nitrate-Nitrite as N	274	mg/l	0.10	EPA 353.2	23 Apr 20 15:14	EV
Ammonia-Nitrogen as N	28.6	mg/l	0.20	EPA 350.1	28 Apr 20 14:01	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Total Dissolved Solids	159000	mg/l	10	I1750-85	22 Apr 20 15:39	HT
Calcium - Total	3740	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Magnesium - Total	473	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Sodium - Total	46300	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Potassium - Total	1010	mg/l	1.0	6010D	24 Apr 20 13:37	MDE
Iron - Total	< 5 @	mg/l	0.10	6010D	23 Apr 20 13:55	SZ
Manganese - Total	< 2.5 @	mg/l	0.05	6010D	23 Apr 20 13:55	SZ
Copper - Dissolved	< 2.5 @	mg/l	0.05	6010D	23 Apr 20 15:55	SZ
Molybdenum - Dissolved	< 5 @	mg/l	0.10	6010D	23 Apr 20 15:55	SZ
Strontium - Dissolved	133	mg/l	0.10	6010D	23 Apr 20 15:55	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Barium - Dissolved	0.0951	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Cadmium - Dissolved	0.0105	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Lead - Dissolved	0.0045	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Selenium - Dissolved	0.0341	mg/l	0.0050	6020B	27 Apr 20 10:20	CC
Silver - Dissolved	< 0.01 @	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 6 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Chain of Custody Record

Project Name: EERC	Event:	Work Order Number: 82-0924
Report To: EERC Attn: Janet Crossland Address: 15 North 23rd St, Stop 9018 Grand Forks, ND 58202-9018 Phone: 701-777-5000 Email: jcrossland@undeerc.org	CC:	Collected By: Jeremy Meyer

Lab Number	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL Nitric	500 mL Nitric (filtered)	250 mL Sulfuric	3 VOC	3 TOC	1 Liter Amber	1 Liter Amber HCL	Temp (°C)	Spec. Cond.	pH	Analysis Required
W741	Inyan Kara	20 Apr 2020	0731	GW	X	X	X	X		X			20.06	18624	7.38	See quote PG-54-20 R-8Apr20
W742	Broom Creek	21 Apr 2020	1607	GW	X	X	X	X		X			25.21	156448	6.41	

Comments:

Relinquished By: Name	Date/Time	Sample Condition: Location	Temp (°C)
1 Jeremy Meyer	21 Apr 20 1840	Log In / Walk In #2	R01 5.4 TM562 / TM805
2			

Received By: Name	Date/Time
Emily Sclaum	22 Apr 2020 0800

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 6 Nov 20
Lab Number: 20-W4082
Work Order #: 82-2903
Account #: 007033
Date Sampled: 16 Oct 20 1:15
Date Received: 16 Oct 20 8:00
Sampled By: MVTL Field Services

Lonny Jacobson
UND EERC/SBG Energy
3682 ND8
Richardton ND 58652

Project Name: RTE 10.2
Sample Description: Broom Creek

Temp at Receipt: 6.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	16 Oct 20	HT
pH	* 7.0	units	N/A	SM4500-H+-B-11	19 Oct 20 17:05	HT
Conductivity (EC)	145600	umhos/cm	N/A	SM2510B-11	16 Oct 20 19:00	HT
pH - Field	6.68	units	NA	SM 4500 H+ B	16 Oct 20 1:15	JSM
Temperature - Field	18.8	Degrees C	NA	SM 2550B	16 Oct 20 1:15	JSM
Total Alkalinity	104	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Bicarbonate	104	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Conductivity - Field	169910	umhos/cm	1	EPA 120.1	16 Oct 20 1:15	JSM
Cation Summation	2720	meq/L	NA	SM1030-F	20 Oct 20 13:45	Calculated
Anion Summation	3030	meq/L	NA	SM1030-F	21 Oct 20 13:51	Calculated
Percent Error	-5.36	%	NA	SM1030-F	21 Oct 20 13:51	Calculated
Total Organic Carbon	112	mg/l	0.5	SM5310C-11	28 Oct 20 23:56	NAS
Sulfate	1880	mg/l	5.00	ASTM D516-11	21 Oct 20 10:33	SD
Chloride	105000	mg/l	2.0	SM4500-Cl-E-11	19 Oct 20 10:14	SD
Nitrate-Nitrite as N	307	mg/l	0.20	EPA 353.2	21 Oct 20 13:51	SD
Ammonia-Nitrogen as N	< 0.2	mg/l	0.20	EPA 350.1	20 Oct 20 11:29	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	21 Oct 20 13:46	MDE
Total Dissolved Solids	161000	mg/l	10	USGS I1750-85	20 Oct 20 14:30	HT
Calcium - Total	3080	mg/l	1.0	6010D	20 Oct 20 11:38	MDE
Magnesium - Total	437	mg/l	1.0	6010D	20 Oct 20 11:38	MDE
Sodium - Total	57500	mg/l	1.0	6010D	20 Oct 20 11:38	MDE
Potassium - Total	1040	mg/l	1.0	6010D	20 Oct 20 11:38	MDE

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The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

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2616 E. Broadway Ave. ~ Bismarck, ND 58501 ~ 800-279-6885 ~ Fax 701-258-9724
51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 6 Nov 20
Lab Number: 20-W4082
Work Order #: 82-2903
Account #: 007033
Date Sampled: 16 Oct 20 1:15
Date Received: 16 Oct 20 8:00
Sampled By: MVTL Field Services

Lonny Jacobson
UND EERC/SBG Energy
3682 ND8
Richardton ND 58652

Project Name: RTE 10.2
Sample Description: Broom Creek

Temp at Receipt: 6.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Iron - Total	< 5 @	mg/l	0.10	6010D	20 Oct 20 13:45	SZ
Manganese - Total	< 2.5 @	mg/l	0.05	6010D	20 Oct 20 13:45	SZ
Strontium - Dissolved	106	mg/l	0.10	6010D	20 Oct 20 10:45	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	21 Oct 20 11:32	CC
Barium - Dissolved	0.9254	mg/l	0.0020	6020B	21 Oct 20 11:32	CC
Cadmium - Dissolved	0.0604	mg/l	0.0005	6020B	21 Oct 20 11:32	CC
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	21 Oct 20 11:32	CC
Copper - Dissolved	0.1193	mg/l	0.0020	6020B	21 Oct 20 11:32	CC
Lead - Dissolved	0.0126	mg/l	0.0005	6020B	21 Oct 20 11:32	CC
Molybdenum - Dissolved	0.4949	mg/l	0.0020	6020B	21 Oct 20 11:32	CC
Selenium - Dissolved	0.1164	mg/l	0.0050	6020B	21 Oct 20 11:32	CC
Silver - Dissolved	< 0.01 @	mg/l	0.0005	6020B	21 Oct 20 11:32	CC

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MVTL

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MEMBER
ACIL

Report Date: 6 Nov 20
Lab Number: 20-W4083
Work Order #: 82-2903
Account #: 007033
Date Sampled: 16 Oct 20 1:25
Date Received: 16 Oct 20 8:00
Sampled By: MVTL Field Services

Lonny Jacobson
UND EERC/SBG Energy
3682 ND8
Richardton ND 58652

Project Name: RTE 10.2
Sample Description: Inyan Kara

Temp at Receipt: 6.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	20 Oct 20	SD
pH	* 7.8	units	N/A	SM4500-H+-B-11	19 Oct 20 17:05	HT
Conductivity (EC)	9573	umhos/cm	N/A	SM2510B-11	16 Oct 20 19:00	HT
pH - Field	7.62	units	NA	SM 4500 H+ B	16 Oct 20 1:25	JSM
Temperature - Field	17.6	Degrees C	NA	SM 2550B	16 Oct 20 1:25	JSM
Total Alkalinity	269	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Bicarbonate	269	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	16 Oct 20 19:00	HT
Conductivity - Field	10457	umhos/cm	1	EPA 120.1	16 Oct 20 1:25	JSM
Cation Summation	98.0	meq/L	NA	SM1030-F	5 Nov 20 10:27	Calculated
Anion Summation	109	meq/L	NA	SM1030-F	21 Oct 20 14:10	Calculated
Percent Error	-5.36	%	NA	SM1030-F	5 Nov 20 10:27	Calculated
Total Organic Carbon	1320	mg/l	0.5	SM5310C-11	28 Oct 20 23:56	NAS
Sulfate	418	mg/l	5.00	ASTM D516-11	21 Oct 20 10:33	SD
Chloride	3370	mg/l	2.0	SM4500-Cl-E-11	19 Oct 20 10:14	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	21 Oct 20 14:10	SD
Ammonia-Nitrogen as N	2.10	mg/l	0.20	EPA 350.1	20 Oct 20 11:29	SD
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	21 Oct 20 13:46	MDE
Total Dissolved Solids	5850	mg/l	10	USGS I1750-85	20 Oct 20 14:30	HT
Calcium - Total	47.7	mg/l	1.0	6010D	5 Nov 20 10:27	MDE
Magnesium - Total	< 5 @	mg/l	1.0	6010D	5 Nov 20 10:27	MDE
Sodium - Total	2190	mg/l	1.0	6010D	5 Nov 20 10:27	MDE
Potassium - Total	11.0	mg/l	1.0	6010D	5 Nov 20 10:27	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix — # = Due to concentration of other analytes
! = Due to sample quantity — + = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.

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MEMBER
ACIL

Report Date: 6 Nov 20
Lab Number: 20-W4083
Work Order #: 82-2903
Account #: 007033
Date Sampled: 16 Oct 20 1:25
Date Received: 16 Oct 20 8:00
Sampled By: MVTL Field Services

Lonny Jacobson
UND EERC/SBG Energy
3682 ND8
Richardton ND 58652

Project Name: RTE 10.2
Sample Description: Inyan Kara

Temp at Receipt: 6.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Iron - Total	< 0.5 @	mg/l	0.10	6010D	27 Oct 20 11:37	MDE
Manganese - Total	< 0.25 @	mg/l	0.05	6010D	27 Oct 20 11:37	MDE
Strontium - Dissolved	0.54	mg/l	0.10	6010D	20 Oct 20 10:45	SZ
Arsenic - Dissolved	0.0085	mg/l	0.0020	6020B	20 Oct 20 14:56	CC
Barium - Dissolved	0.3166	mg/l	0.0020	6020B	20 Oct 20 14:56	CC
Cadmium - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	20 Oct 20 14:56	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Oct 20 14:56	CC
Copper - Dissolved	0.0029	mg/l	0.0020	6020B	20 Oct 20 14:56	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Oct 20 14:56	CC
Molybdenum - Dissolved	0.0101	mg/l	0.0020	6020B	20 Oct 20 14:56	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Oct 20 14:56	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Oct 20 14:56	CC

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

RED TRAIL ENERGY, LLC

APPENDIX C

FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS

FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS

The preinjection baseline of groundwater-monitoring results acquired for the RTE project site were collected and characterized groundwater samples taken from Well Nos. 51002, 61337, and 10648 in May, August, and November 2019. The locations of these wells are shown in the repeat figure and table below, with detailed laboratory analyses for each sampling event following.

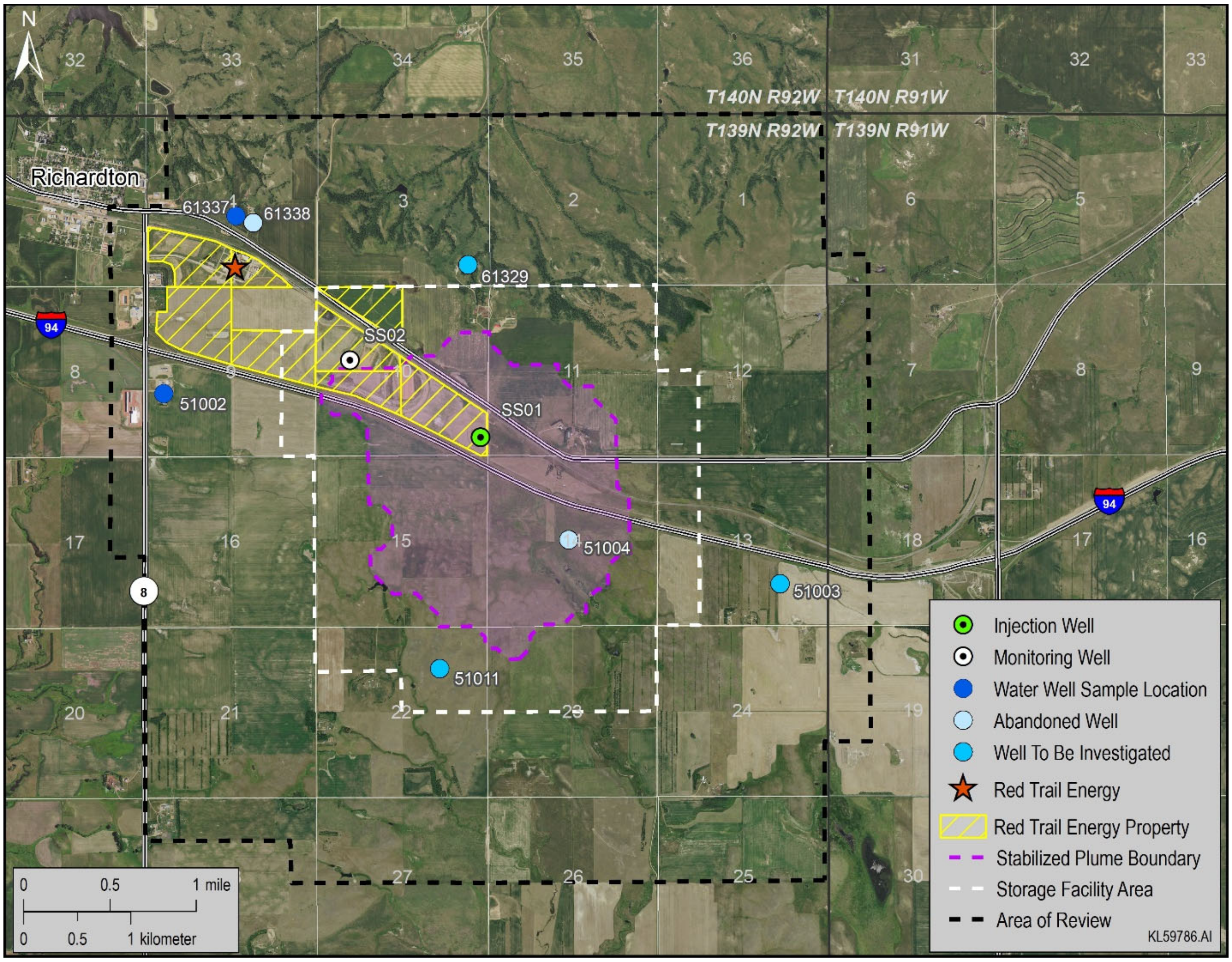

Figure C-1. Location of baseline groundwater wells (currently sampled and planned for sampling prior to injection) and abandoned wells within a 1.5-mile buffer around the CO_2 injection well.

Table C-1. Baseline Groundwater-Sampling Results – May Through November 2019
Note: Highlighted well colors coordinate with the following analysis results reports.

Parameter	pH (pH unit)			SpC, µS/cm			Alkalinity as $CaCO_3$, mg/L		
Well No.	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**	**May-19**	**Aug-19**	**Nov-19**
51002	8.21	8.42	8.47	2,643	2,740	2,731	1,570	1,540	1,540
61337	8.18	8.46	8.51	1,851	1,886	1,890	1,070	1,060	1,040
10648	*	*8.36*	*8.24*	*	*1,931*	*1,928*	*	*1,010*	*960*

* Well not accessible.

Numerous assessments have shown several key indicators linked to chemical and biological processes that provide a strong chemical response during exposure laboratory tests to low CO_2 concentrations (Leroux and others, 2018; Gal and others, 2013). Groundwater indicators specifically included a sudden significant drop of pH coupled with a doubling of alkalinity and an increase in specific conductance (Leroux and others, 2018). Other potential indicators include significant increases in total dissolved solids and total inorganic carbon. These same key indicators are to be expected at the RTE CCS site; thus the previous assessments provided a guide to site selection, sampling protocols (described in Appendix D), and selection of baseline parameters to be monitored (Leroux and others, 2020).

References

Gal, F., Proust, E., Humez, P., Braibant, G., Brach, M., Koch, F., Widory, D., and Girard, J., 2013, Inducing a CO_2 leak into a shallow aquifer (CO_2FieldLab EUROGIA+ project) —monitoring the CO_2 plume in groundwaters: International Journal of Greenhouse Gas Control Technologies, v. 37, p. 3583–3593.

Leroux, K.M., Azzolina, N.A., Glazewski, K.A., Kalenze, N.S., Botnen, B.W., Kovacevich, J.T., Abongwa, P.T., Thompson, J.S., Zacher, E.J., Hamling, J.A., and Gorecki, C.D., 2018, Lessons learned and best practices derived from environmental monitoring at a large-scale CO_2 injection project: International Journal of Greenhouse Gas Control, v. 78, p. 254–270.

Leroux, K.M., Klapperich, R.J., Ayash, S.C., Kalenze, N.S., Jensen, M.D., Jacobson, L.L., Crocker, C.R., Doll, T.E., Livers-Douglas, A.J., Azzolina, N.A., Crossland, J.L., Connors, K.C., Nakles, D.V., Hamling, J.A., Peck, W.D., Bosshart, N.W., Daly, D.J., Wilson IV, W.I., Gorecki, C.D., Brad D. Piggott Austyn E. Vance Piggott, B., and Vance, A.E., 2020, Subtask 1.3 –Integrated carbon capture and storage for North Dakota ethanol production: Final report (November 1, 2016 – May 31, 2020) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0024233, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

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ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland
Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result	
54442-01	**51002 5/17/19 10:00**		
	Alkalinity, as Bicarbonate (HCO3-)	1920	mg/L
	Alkalinity, as Carbonate (CO3=)	0	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	1570	mg/L
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	104	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	1.75	mg/L
	Bromide	< 1	mg/L
	Cadmium	< 2	µg/L
	Calcium	2.91	mg/L
	Chloride	18.8	mg/L
	Chromium	< 5	µg/L
	Cobalt	< 5	µg/L
	Copper	< 5	µg/L
	Dissolved Inorganic Carbon	369	mg/L
	Dissolved Organic Carbon	3.7	mg/L
	Fluoride	< 1	mg/L
	Iron	0.38	mg/L
	Lead	< 5	µg/L
	Lithium	0.096	mg/L
	Magnesium	1.38	mg/L
	Manganese	< 5	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	13.3	µg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result	
54442-01	**51002 5/17/19 10:00**		
	Nickel	< 5	µg/L
	Phosphorus	0.146	mg/L
	Potassium	2.5	mg/L
	Selenium	< 1	µg/L
	Silicon	5.03	mg/L
	Silver	< 5	µg/L
	Sodium	763	mg/L
	Strontium	0.177	mg/L
	Sulfate	27.5	mg/L
	Sulfide	< 0.05	mg/L
	Thallium	< 0.5	µg/L
	Thorium	< 0.5	µg/L
	Total Dissolved Solids	1720	mg/L
	Total Inorganic Carbon	370	mg/L
	Total Organic Carbon	3.4	mg/L
	Uranium	< 1	µg/L
	Vanadium	< 5	µg/L
	Zinc	< 0.005	mg/L
54442-02	**61337 5/17/19 11:00**		
	Alkalinity, as Bicarbonate (HCO3-)	1250	mg/L
	Alkalinity, as Carbonate (CO3=)	27.1	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	1070	mg/L
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	83.0	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	0.937	mg/L
	Bromide	< 1	mg/L
	Cadmium	< 2	µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result	
54442-02	**61337 5/17/19 11:00**		
	Calcium	1.94	mg/L
	Chloride	8.5	mg/L
	Chromium	< 5	µg/L
	Cobalt	< 5	µg/L
	Copper	< 5	µg/L
	Dissolved Inorganic Carbon	246	mg/L
	Dissolved Organic Carbon	6.1	mg/L
	Fluoride	5.6	mg/L
	Iron	0.020	mg/L
	Lead	< 5	µg/L
	Lithium	0.053	mg/L
	Magnesium	1.00	mg/L
	Manganese	< 5	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	8.67	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.362	mg/L
	Potassium	2.3	mg/L
	Selenium	< 1	µg/L
	Silicon	3.42	mg/L
	Silver	< 5	µg/L
	Sodium	521	mg/L
	Strontium	0.092	mg/L
	Sulfate	7.6	mg/L
	Sulfide	< 0.05	mg/L
	Thallium	< 0.5	µg/L
	Thorium	< 0.5	µg/L
	Total Dissolved Solids	1160	mg/L
	Total Inorganic Carbon	246	mg/L
	Total Organic Carbon	6.3	mg/L
	Uranium	< 1	µg/L
	Vanadium	< 5	µg/L
	Zinc	0.104	mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result
54442-02	**61337 5/17/19 11:00**	
54442-03	**Field Blank 5/17/19**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chloride	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Fluoride	< 1 mg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Sulfate	< 1 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result
54442-03	**Field Blank 5/17/19**	
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54442-04	**Trip Blank**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chloride	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Fluoride	< 1 mg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result
54442-04	**Trip Blank**	
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Sulfate	< 1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54442-05	**Equipment Blank**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chloride	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Fluoride	< 1 mg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54442
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019

Sample	Parameter	Result	
54442-05	**Equipment Blank**		
	Molybdenum	< 5	µg/L
	Nickel	< 5	µg/L
	Phosphorus	< 0.1	mg/L
	Potassium	< 1	mg/L
	Selenium	< 1	µg/L
	Silicon	< 1	mg/L
	Silver	< 5	µg/L
	Sodium	< 1	mg/L
	Strontium	< 0.1	mg/L
	Sulfate	< 1	mg/L
	Thallium	< 0.5	µg/L
	Thorium	< 0.5	µg/L
	Uranium	< 1	µg/L
	Vanadium	< 5	µg/L
	Zinc	< 0.005	mg/L

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ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54443
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019 (Total Metals)

Sample	Parameter	Result	
54443-01	**51002 5/17/19 (Total Metals)**		
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	110	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	1.79	mg/L
	Cadmium	< 2	µg/L
	Calcium	3.32	mg/L
	Chromium	5.1	µg/L
	Cobalt	< 5	µg/L
	Copper	7.5	µg/L
	Iron	0.512	mg/L
	Lead	< 5	µg/L
	Lithium	0.098	mg/L
	Magnesium	1.36	mg/L
	Manganese	< 5	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	15.0	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.150	mg/L
	Potassium	2.5	mg/L
	Selenium	< 1	µg/L
	Silicon	5.20	mg/L
	Silver	< 5	µg/L
	Sodium	821	mg/L
	Strontium	0.179	mg/L
	Thallium	< 0.5	µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54443

Fund#: 23717

PI: Nick Kalenze

Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019

Due Date: Monday, June 3, 2019

Set Description: Red Trail Energy Water Samples May 2019 (Total Metals)

Sample	Parameter	Result	
54443-01	**51002 5/17/19 (Total Metals)**		
	Thorium	< 0.5	µg/L
	Uranium	< 1	µg/L
	Vanadium	< 5	µg/L
	Zinc	0.020	mg/L
54443-02	**61337 5/17/19 (Total Metals)**		
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	83.3	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	0.946	mg/L
	Cadmium	< 2	µg/L
	Calcium	2.05	mg/L
	Chromium	5.8	µg/L
	Cobalt	< 5	µg/L
	Copper	< 5	µg/L
	Iron	0.152	mg/L
	Lead	< 5	µg/L
	Lithium	0.054	mg/L
	Magnesium	1.01	mg/L
	Manganese	< 5	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	9.36	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.373	mg/L
	Potassium	2.3	mg/L
	Selenium	< 1	µg/L
	Silicon	3.57	mg/L
	Silver	< 5	µg/L
	Sodium	580	mg/L
	Strontium	0.093	mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

June 14, 2019

Set Number: 54443
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, May 20, 2019
Due Date: Monday, June 3, 2019
Set Description: Red Trail Energy Water Samples May 2019 (Total Metals)

Sample	Parameter	Result
54443-02	**61337 5/17/19 (Total Metals)**	
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.051 mg/L

Distribution ____________________ Date __________

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Web Site: www.undeerc.org

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-01	**51002 8/14/19 0930**	
	Alkalinity, as Bicarbonate (HCO3-)	1820 mg/L
	Alkalinity, as Carbonate (CO3=)	26.8 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1530 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	168 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.30 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	3.10 mg/L
	Chloride	20.9 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	7.0 µg/L
	Dissolved Inorganic Carbon	366 mg/L
	Dissolved Organic Carbon	3.7 mg/L
	Fluoride	< 1 mg/L
	Iron	0.426 mg/L
	Lead	< 5 µg/L
	Lithium	0.068 mg/L
	Magnesium	1.52 mg/L
	Manganese	5.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	20.0 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-01	**51002 8/14/19 0930**	
	Nickel	< 5 µg/L
	Phosphorus	0.155 mg/L
	Potassium	2.50 mg/L
	Selenium	< 1 µg/L
	Silicon	5.03 mg/L
	Silver	< 5 µg/L
	Sodium	718 mg/L
	Strontium	0.213 mg/L
	Sulfate	28.0 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1700 mg/L
	Total Inorganic Carbon	366 mg/L
	Total Organic Carbon	3.6 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.012 mg/L
54508-02	**51002 8/14/19 0930 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1860 mg/L
	Alkalinity, as Carbonate (CO3=)	12.2 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1550 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.0 µg/L
	Barium	167 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.31 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-02	**51002 8/14/19 0930 dup**	
	Calcium	3.10 mg/L
	Chloride	21.9 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	16.0 µg/L
	Dissolved Inorganic Carbon	366 mg/L
	Dissolved Organic Carbon	3.8 mg/L
	Fluoride	< 1 mg/L
	Iron	0.399 mg/L
	Lead	< 5 µg/L
	Lithium	0.068 mg/L
	Magnesium	1.52 mg/L
	Manganese	5.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	20.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.146 mg/L
	Potassium	2.50 mg/L
	Selenium	< 1 µg/L
	Silicon	5.06 mg/L
	Silver	< 5 µg/L
	Sodium	722 mg/L
	Strontium	0.217 mg/L
	Sulfate	29.8 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1700 mg/L
	Total Inorganic Carbon	367 mg/L
	Total Organic Carbon	3.6 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.017 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result	
54508-02	**51002 8/14/19 0930 dup**		
54508-03	**61337 8/14/19 0930**		
	Alkalinity, as Bicarbonate (HCO3-)	1240	mg/L
	Alkalinity, as Carbonate (CO3=)	23.2	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	1050	mg/L
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	139	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	0.679	mg/L
	Bromide	< 1	mg/L
	Cadmium	< 2	µg/L
	Calcium	2.12	mg/L
	Chloride	10.1	mg/L
	Chromium	< 5	µg/L
	Cobalt	< 5	µg/L
	Copper	8.0	µg/L
	Dissolved Inorganic Carbon	242	mg/L
	Dissolved Organic Carbon	6.2	mg/L
	Fluoride	4.7	mg/L
	Iron	0.015	mg/L
	Lead	< 5	µg/L
	Lithium	0.040	mg/L
	Magnesium	1.17	mg/L
	Manganese	< 5	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	12.0	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.411	mg/L
	Potassium	2.17	mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-03	**61337 8/14/19 0930**	
	Selenium	< 1 µg/L
	Silicon	3.65 mg/L
	Silver	< 5 µg/L
	Sodium	500 mg/L
	Strontium	0.115 mg/L
	Sulfate	9.2 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1150 mg/L
	Total Inorganic Carbon	248 mg/L
	Total Organic Carbon	6.2 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.065 mg/L
54508-04	**61337 8/14/19 0930 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1250 mg/L
	Alkalinity, as Carbonate (CO3=)	19.3 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1060 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	139 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.685 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.10 mg/L
	Chloride	9.6 mg/L
	Chromium	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-04	**61337 8/14/19 0930 dup**	
	Cobalt	< 5 µg/L
	Copper	8.0 µg/L
	Dissolved Inorganic Carbon	246 mg/L
	Dissolved Organic Carbon	6.4 mg/L
	Fluoride	4.9 mg/L
	Iron	0.015 mg/L
	Lead	< 5 µg/L
	Lithium	0.040 mg/L
	Magnesium	1.16 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	12.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.433 mg/L
	Potassium	2.18 mg/L
	Selenium	< 1 µg/L
	Silicon	3.63 mg/L
	Silver	< 5 µg/L
	Sodium	491 mg/L
	Strontium	0.115 mg/L
	Sulfate	8.4 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1140 mg/L
	Total Inorganic Carbon	242 mg/L
	Total Organic Carbon	6.0 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.063 mg/L
54508-05	**10648 8/14/19 0930**	
	Alkalinity, as Bicarbonate (HCO3-)	1210 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result	
54508-05	**10648 8/14/19 0930**		
	Alkalinity, as Carbonate (CO3=)	7.9	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	1000	mg/L
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	2.0	µg/L
	Barium	197	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	0.629	mg/L
	Bromide	< 1	mg/L
	Cadmium	< 2	µg/L
	Calcium	22.4	mg/L
	Chloride	21.6	mg/L
	Chromium	< 5	µg/L
	Cobalt	< 5	µg/L
	Copper	6.0	µg/L
	Dissolved Inorganic Carbon	229	mg/L
	Dissolved Organic Carbon	9.0	mg/L
	Fluoride	4.3	mg/L
	Iron	0.035	mg/L
	Lead	< 5	µg/L
	Lithium	0.043	mg/L
	Magnesium	14.3	mg/L
	Manganese	21.0	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	9.0	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.332	mg/L
	Potassium	11.6	mg/L
	Selenium	< 1	µg/L
	Silicon	3.66	mg/L
	Silver	< 5	µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-05	**10648 8/14/19 0930**	
	Sodium	460 mg/L
	Strontium	0.274 mg/L
	Sulfate	27.0 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1180 mg/L
	Total Inorganic Carbon	232 mg/L
	Total Organic Carbon	8.3 mg/L
	Uranium	3.0 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.033 mg/L
54508-06	**10648 8/14/19 0930 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1200 mg/L
	Alkalinity, as Carbonate (CO3=)	19.3 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1020 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	2.0 µg/L
	Barium	147 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.635 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	22.4 mg/L
	Chloride	18.5 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	7.0 µg/L
	Dissolved Inorganic Carbon	230 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-06	**10648 8/14/19 0930 dup**	
	Dissolved Organic Carbon	8.6 mg/L
	Fluoride	4.4 mg/L
	Iron	0.037 mg/L
	Lead	< 5 µg/L
	Lithium	0.045 mg/L
	Magnesium	14.3 mg/L
	Manganese	22.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.334 mg/L
	Potassium	11.5 mg/L
	Selenium	< 1 µg/L
	Silicon	3.66 mg/L
	Silver	< 5 µg/L
	Sodium	454 mg/L
	Strontium	0.278 mg/L
	Sulfate	21.2 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1170 mg/L
	Total Inorganic Carbon	232 mg/L
	Total Organic Carbon	7.9 mg/L
	Uranium	3.0 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.034 mg/L
54508-07	**Field Blank 8/14/19 0930**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-07	**Field Blank 8/14/19 0930**	
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 5 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54508-08	**Trip Blank 8/14/19 0930**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-08	**Trip Blank 8/14/19 0930**	
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	11.0 µg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 5 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.018 mg/L
54508-09	**Equipment Blank 8/14/19 0930**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54508
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019

Sample	Parameter	Result
54508-09	**Equipment Blank 8/14/19 0930**	
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 5 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L

Distribution ______________________ Date __________

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Web Site: www.undeerc.org

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509

Fund#: 23717

PI: Nick Kalenze

Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019

Due Date: Thursday, September 5, 2019

Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-01	**51002 8/14/19 0930 (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.0 µg/L
	Barium	169 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.36 mg/L
	Cadmium	< 2 µg/L
	Calcium	3.22 mg/L
	Chromium	5.0 µg/L
	Cobalt	< 5 µg/L
	Copper	26.0 µg/L
	Iron	0.416 mg/L
	Lead	< 5 µg/L
	Lithium	0.072 mg/L
	Magnesium	1.55 mg/L
	Manganese	5.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	20.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.130 mg/L
	Potassium	2.6 mg/L
	Selenium	< 1 µg/L
	Silicon	5.00 mg/L
	Silver	< 5 µg/L
	Sodium	732 mg/L
	Strontium	0.218 mg/L
	Thallium	< 0.5 µg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-01	**51002 8/14/19 0930 (Total Metals)**	
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.022 mg/L
54509-02	**51002 8/14/19 0930 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.0 µg/L
	Barium	162 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.55 mg/L
	Cadmium	< 2 µg/L
	Calcium	3.14 mg/L
	Chromium	6.0 µg/L
	Cobalt	< 5 µg/L
	Copper	20.0 µg/L
	Iron	0.448 mg/L
	Lead	< 5 µg/L
	Lithium	0.084 mg/L
	Magnesium	1.53 mg/L
	Manganese	5.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	20.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.149 mg/L
	Potassium	2.5 mg/L
	Selenium	< 1 µg/L
	Silicon	5.04 mg/L
	Silver	< 5 µg/L
	Sodium	720 mg/L
	Strontium	0.213 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-02	**51002 8/14/19 0930 dup (Total Metals)**	
	Thallium	< 0.5 μg/L
	Thorium	< 0.5 μg/L
	Uranium	< 1 μg/L
	Vanadium	< 5 μg/L
	Zinc	0.017 mg/L
54509-03	**61337 8/14/19 0930 (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 μg/L
	Arsenic	< 1 μg/L
	Barium	136 μg/L
	Beryllium	< 4 μg/L
	Bismuth	< 0.5 μg/L
	Boron	0.784 mg/L
	Cadmium	< 2 μg/L
	Calcium	2.24 mg/L
	Chromium	6.0 μg/L
	Cobalt	< 5 μg/L
	Copper	15.0 μg/L
	Iron	0.030 mg/L
	Lead	5.0 μg/L
	Lithium	0.047 mg/L
	Magnesium	1.20 mg/L
	Manganese	< 5 μg/L
	Mercury	< 0.1 μg/L
	Molybdenum	12.0 μg/L
	Nickel	< 5 μg/L
	Phosphorus	0.393 mg/L
	Potassium	2.2 mg/L
	Selenium	< 1 μg/L
	Silicon	3.70 mg/L
	Silver	< 5 μg/L
	Sodium	494 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-03	**61337 8/14/19 0930 (Total Metals)**	
	Strontium	0.115 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.036 mg/L
54509-04	**61337 8/14/19 0930 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.0 µg/L
	Barium	133 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.780 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.16 mg/L
	Chromium	7.0 µg/L
	Cobalt	< 5 µg/L
	Copper	8.0 µg/L
	Iron	0.015 mg/L
	Lead	< 5 µg/L
	Lithium	0.048 mg/L
	Magnesium	1.16 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	12.0 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.397 mg/L
	Potassium	2.2 mg/L
	Selenium	< 1 µg/L
	Silicon	3.67 mg/L
	Silver	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

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Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-04	**61337 8/14/19 0930 dup (Total Metals)**	
	Sodium	495 mg/L
	Strontium	0.113 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.049 mg/L
54509-05	**10648 8/14/19 0930 (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	2.0 µg/L
	Barium	117 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.719 mg/L
	Cadmium	< 2 µg/L
	Calcium	16.4 mg/L
	Chromium	6.0 µg/L
	Cobalt	< 5 µg/L
	Copper	7.0 µg/L
	Iron	0.129 mg/L
	Lead	< 5 µg/L
	Lithium	0.051 mg/L
	Magnesium	10.5 mg/L
	Manganese	19.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.0 µg/L
	Nickel	5.0 µg/L
	Phosphorus	0.325 mg/L
	Potassium	8.9 mg/L
	Selenium	< 1 µg/L
	Silicon	3.45 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-05	**10648 8/14/19 0930 (Total Metals)**	
	Silver	< 5 µg/L
	Sodium	469 mg/L
	Strontium	0.213 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	3.0 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.035 mg/L
54509-06	**10648 8/14/19 0930 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	2.0 µg/L
	Barium	116 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.723 mg/L
	Cadmium	< 2 µg/L
	Calcium	16.2 mg/L
	Chromium	5.0 µg/L
	Cobalt	< 5 µg/L
	Copper	7.0 µg/L
	Iron	0.126 mg/L
	Lead	< 5 µg/L
	Lithium	0.051 mg/L
	Magnesium	10.2 mg/L
	Manganese	19.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.0 µg/L
	Nickel	5.0 µg/L
	Phosphorus	0.342 mg/L
	Potassium	8.8 mg/L
	Selenium	< 1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

October 10, 2019

Set Number: 54509
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Thursday, August 22, 2019
Due Date: Thursday, September 5, 2019
Set Description: Red Trail Energy - Richardton Water Samples August 2019 (Total Metals)

Sample	Parameter	Result
54509-06	**10648 8/14/19 0930 dup (Total Metals)**	
	Silicon	3.45 mg/L
	Silver	< 5 µg/L
	Sodium	468 mg/L
	Strontium	0.211 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	3.0 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.034 mg/L

Distribution ______________________ Date __________

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ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-01	**51002 11/19/19 0900**	
	Alkalinity, as Bicarbonate (HCO3-)	1780 mg/L
	Alkalinity, as Carbonate (CO3=)	47.2 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1540 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	147 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.46 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.98 mg/L
	Chloride	16.0 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	379 mg/L
	Dissolved Organic Carbon	3.7 mg/L
	Fluoride	1.1 mg/L
	Iron	0.672 mg/L
	Lead	< 5 µg/L
	Lithium	0.137 mg/L
	Magnesium	1.4 mg/L
	Manganese	5.5 µg/L
	Mercury	1.11 µg/L
	Molybdenum	16.4 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-01	**51002 11/19/19 0900**	
	Nickel	< 5 µg/L
	Phosphorus	0.16 mg/L
	Potassium	2.5 mg/L
	Selenium	< 1 µg/L
	Silicon	4.95 mg/L
	Silver	< 5 µg/L
	Sodium	748 mg/L
	Strontium	0.182 mg/L
	Sulfate	27.7 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1710 mg/L
	Total Inorganic Carbon	386 mg/L
	Total Organic Carbon	3.5 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54560-02	**51002 11/19/19 0900 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1780 mg/L
	Alkalinity, as Carbonate (CO3=)	43.3 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1540 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	147 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.50 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L

Distribution ______________________ Date ________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-02	**51002 11/19/19 0900 dup**	
	Calcium	3.00 mg/L
	Chloride	16.2 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	388 mg/L
	Dissolved Organic Carbon	3.8 mg/L
	Fluoride	1.1 mg/L
	Iron	0.661 mg/L
	Lead	< 5 µg/L
	Lithium	0.139 mg/L
	Magnesium	1.4 mg/L
	Manganese	5.5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	16.5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.16 mg/L
	Potassium	2.5 mg/L
	Selenium	< 1 µg/L
	Silicon	4.91 mg/L
	Silver	< 5 µg/L
	Sodium	742 mg/L
	Strontium	0.186 mg/L
	Sulfate	27.8 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1680 mg/L
	Total Inorganic Carbon	388 mg/L
	Total Organic Carbon	4.1 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-02	**51002 11/19/19 0900 dup**	
54560-03	**61337 11/19/19 1000**	
	Alkalinity, as Bicarbonate (HCO3-)	1220 mg/L
	Alkalinity, as Carbonate (CO3=)	19.4 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1030 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	112 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.78 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.05 mg/L
	Chloride	7.5 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	253 mg/L
	Dissolved Organic Carbon	6.4 mg/L
	Fluoride	5.5 mg/L
	Iron	0.040 mg/L
	Lead	< 5 µg/L
	Lithium	0.075 mg/L
	Magnesium	1.0 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	10.3 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.40 mg/L
	Potassium	2.3 mg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-03	**61337 11/19/19 1000**	
	Selenium	< 1 µg/L
	Silicon	3.49 mg/L
	Silver	< 5 µg/L
	Sodium	521 mg/L
	Strontium	< 0.1 mg/L
	Sulfate	8.2 mg/L
	Sulfide	0.22 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1110 mg/L
	Total Inorganic Carbon	253 mg/L
	Total Organic Carbon	6.1 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.038 mg/L
54560-04	**61337 11/19/19 1000 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1230 mg/L
	Alkalinity, as Carbonate (CO3=)	21.6 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	1050 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	113 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.78 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.05 mg/L
	Chloride	7.5 mg/L
	Chromium	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
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Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-04	**61337 11/19/19 1000 dup**	
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	254 mg/L
	Dissolved Organic Carbon	6.3 mg/L
	Fluoride	5.5 mg/L
	Iron	0.036 mg/L
	Lead	< 5 µg/L
	Lithium	0.075 mg/L
	Magnesium	1.1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.7 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.40 mg/L
	Potassium	2.4 mg/L
	Selenium	< 1 µg/L
	Silicon	3.49 mg/L
	Silver	< 5 µg/L
	Sodium	509 mg/L
	Strontium	< 0.1 mg/L
	Sulfate	8.1 mg/L
	Sulfide	0.20 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1120 mg/L
	Total Inorganic Carbon	256 mg/L
	Total Organic Carbon	6.2 mg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.035 mg/L
54560-05	**10648 11/19/19 1100**	
	Alkalinity, as Bicarbonate (HCO_3^-)	1170 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
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Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-05	**10648 11/19/19 1100**	
	Alkalinity, as Carbonate (CO3=)	0 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	957 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.6 µg/L
	Barium	83.4 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.68 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	25.2 mg/L
	Chloride	25.4 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	233 mg/L
	Dissolved Organic Carbon	9.0 mg/L
	Fluoride	4.2 mg/L
	Iron	0.066 mg/L
	Lead	< 5 µg/L
	Lithium	0.079 mg/L
	Magnesium	17.9 mg/L
	Manganese	13.2 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	7.8 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.37 mg/L
	Potassium	12.1 mg/L
	Selenium	< 1 µg/L
	Silicon	3.77 mg/L
	Silver	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
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Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-05	**10648 11/19/19 1100**	
	Sodium	452 mg/L
	Strontium	0.252 mg/L
	Sulfate	43.9 mg/L
	Sulfide	< 0.05 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1110 mg/L
	Total Inorganic Carbon	237 mg/L
	Total Organic Carbon	9.2 mg/L
	Uranium	3.3 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.044 mg/L
54560-06	**10648 11/19/19 1100 dup**	
	Alkalinity, as Bicarbonate (HCO3-)	1170 mg/L
	Alkalinity, as Carbonate (CO3=)	2.8 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	963 mg/L
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.6 µg/L
	Barium	84.2 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.68 mg/L
	Bromide	< 1 mg/L
	Cadmium	< 2 µg/L
	Calcium	25.3 mg/L
	Chloride	23.0 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Dissolved Inorganic Carbon	239 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
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Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-06	**10648 11/19/19 1100 dup**	
	Dissolved Organic Carbon	9.0 mg/L
	Fluoride	4.3 mg/L
	Iron	0.065 mg/L
	Lead	< 5 µg/L
	Lithium	0.081 mg/L
	Magnesium	17.8 mg/L
	Manganese	13.2 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	7.9 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.37 mg/L
	Potassium	12.1 mg/L
	Selenium	< 1 µg/L
	Silicon	3.73 mg/L
	Silver	< 5 µg/L
	Sodium	447 mg/L
	Strontium	0.252 mg/L
	Sulfate	39.0 mg/L
	Sulfide	0.10 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Total Dissolved Solids	1090 mg/L
	Total Inorganic Carbon	235 mg/L
	Total Organic Carbon	9.2 mg/L
	Uranium	3.3 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.043 mg/L
54560-07	**Field Blank 11/19/19 0900**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-07	**Field Blank 11/19/19 0900**	
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54560-08	**Trip Blank 11/19/19 0900**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
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PI: Nick Kalenze
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Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-08	**Trip Blank 11/19/19 0900**	
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	< 0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	< 1 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	< 0.005 mg/L
54560-09	**Equipment Blank 11/19/19 0900**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54560
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Monday, November 25, 2019
Due Date: Monday, December 9, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019

Sample	Parameter	Result
54560-09	**Equipment Blank 11/19/19 0900**	
	Arsenic	< 1 µg/L
	Barium	< 5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	< 0.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	< 1 mg/L
	Chromium	< 5 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	0.005 mg/L
	Lead	< 5 µg/L
	Lithium	< 0.005 mg/L
	Magnesium	< 1 mg/L
	Manganese	< 5 µg/L
	Mercury	0.11 µg/L
	Molybdenum	< 5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	< 0.1 mg/L
	Potassium	2.4 mg/L
	Selenium	< 1 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	< 1 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.011 mg/L

Distribution ______________________ Date __________

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ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result	
54561-01	**51002 11/19/19 0900 (Total Metals)**		
	Aluminum	< 0.05	mg/L
	Antimony	< 5	µg/L
	Arsenic	< 1	µg/L
	Barium	148	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 0.5	µg/L
	Boron	1.67	mg/L
	Cadmium	< 2	µg/L
	Calcium	3.09	mg/L
	Chromium	6.0	µg/L
	Cobalt	< 5	µg/L
	Copper	26.7	µg/L
	Iron	0.744	mg/L
	Lead	< 5	µg/L
	Lithium	0.137	mg/L
	Magnesium	1.4	mg/L
	Manganese	6.3	µg/L
	Mercury	0.12	µg/L
	Molybdenum	15.2	µg/L
	Nickel	< 5	µg/L
	Phosphorus	0.15	mg/L
	Potassium	2.5	mg/L
	Selenium	< 1	µg/L
	Silicon	5.04	mg/L
	Silver	< 5	µg/L
	Sodium	729	mg/L
	Strontium	0.184	mg/L
	Thallium	< 0.5	µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result
54561-01	**51002 11/19/19 0900 (Total Metals)**	
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.016 mg/L
54561-02	**51002 11/19/19 0900 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	146 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	1.65 mg/L
	Cadmium	< 2 µg/L
	Calcium	3.06 mg/L
	Chromium	6.5 µg/L
	Cobalt	< 5 µg/L
	Copper	5.5 µg/L
	Iron	0.740 mg/L
	Lead	< 5 µg/L
	Lithium	0.139 mg/L
	Magnesium	1.4 mg/L
	Manganese	6.2 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	15.4 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.16 mg/L
	Potassium	2.5 mg/L
	Selenium	< 1 µg/L
	Silicon	5.06 mg/L
	Silver	< 5 µg/L
	Sodium	735 mg/L
	Strontium	0.182 mg/L

Distribution ______________________ Date __________

Sample	Parameter	Result
54561-02	**51002 11/19/19 0900 dup (Total Metals)**	
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.007 mg/L
54561-03	**61337 11/19/19 1000 (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	114 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.88 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.12 mg/L
	Chromium	6.1 µg/L
	Cobalt	< 5 µg/L
	Copper	8.3 µg/L
	Iron	0.056 mg/L
	Lead	< 5 µg/L
	Lithium	0.076 mg/L
	Magnesium	1.1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.5 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.38 mg/L
	Potassium	2.3 mg/L
	Selenium	< 1 µg/L
	Silicon	3.63 mg/L
	Silver	< 5 µg/L
	Sodium	503 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result
54561-03	**61337 11/19/19 1000 (Total Metals)**	
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.028 mg/L
54561-04	**61337 11/19/19 1000 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	< 1 µg/L
	Barium	113 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.85 mg/L
	Cadmium	< 2 µg/L
	Calcium	2.13 mg/L
	Chromium	6.5 µg/L
	Cobalt	< 5 µg/L
	Copper	6.6 µg/L
	Iron	0.046 mg/L
	Lead	< 5 µg/L
	Lithium	0.075 mg/L
	Magnesium	1.1 mg/L
	Manganese	< 5 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	9.4 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.39 mg/L
	Potassium	2.3 mg/L
	Selenium	< 1 µg/L
	Silicon	3.62 mg/L
	Silver	< 5 µg/L

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result
54561-04	**61337 11/19/19 1000 dup (Total Metals)**	
	Sodium	501 mg/L
	Strontium	< 0.1 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	< 1 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.027 mg/L
54561-05	**10648 11/19/19 1100 (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.6 µg/L
	Barium	89.5 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.72 mg/L
	Cadmium	< 2 µg/L
	Calcium	30.6 mg/L
	Chromium	7.0 µg/L
	Cobalt	< 5 µg/L
	Copper	< 5 µg/L
	Iron	0.119 mg/L
	Lead	< 5 µg/L
	Lithium	0.079 mg/L
	Magnesium	21.5 mg/L
	Manganese	14.8 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	7.2 µg/L
	Nickel	5.1 µg/L
	Phosphorus	0.36 mg/L
	Potassium	14.1 mg/L
	Selenium	< 1 µg/L
	Silicon	3.77 mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result
54561-05	**10648 11/19/19 1100 (Total Metals)**	
	Silver	< 5 µg/L
	Sodium	439 mg/L
	Strontium	0.291 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	3.7 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.055 mg/L
54561-06	**10648 11/19/19 1100 dup (Total Metals)**	
	Aluminum	< 0.05 mg/L
	Antimony	< 5 µg/L
	Arsenic	1.7 µg/L
	Barium	75.3 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 0.5 µg/L
	Boron	0.75 mg/L
	Cadmium	< 2 µg/L
	Calcium	20.2 mg/L
	Chromium	8.1 µg/L
	Cobalt	< 5 µg/L
	Copper	11.5 µg/L
	Iron	0.170 mg/L
	Lead	< 5 µg/L
	Lithium	0.078 mg/L
	Magnesium	14.0 mg/L
	Manganese	13.0 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	7.7 µg/L
	Nickel	< 5 µg/L
	Phosphorus	0.38 mg/L
	Potassium	9.9 mg/L
	Selenium	< 1 µg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

January 23, 2020

Set Number: 54561
Fund#: 23717
PI: Nick Kalenze
Contact Person: Janet Crossland

Request Date: Tuesday, November 26, 2019
Due Date: Tuesday, December 10, 2019
Set Description: Red Trail Energy - Richardton Water Samples November 2019 (Total Metals)

Sample	Parameter	Result
54561-06	**10648 11/19/19 1100 dup (Total Metals)**	
	Silicon	3.54 mg/L
	Silver	< 5 µg/L
	Sodium	459 mg/L
	Strontium	0.209 mg/L
	Thallium	< 0.5 µg/L
	Thorium	< 0.5 µg/L
	Uranium	2.5 µg/L
	Vanadium	< 5 µg/L
	Zinc	0.077 mg/L

Distribution ____________________ Date __________

APPENDIX D

QUALITY ASSURANCE AND SURVEILLANCE PLAN

QUALITY ASSURANCE AND SURVEILLANCE PLAN

The primary goal of the testing and monitoring plan of this storage facility permit application is to ensure that the geologic sequestration project is operating as permitted and is not endangering underground sources of drinking water (USDW). In compliance with NDAC Section 43-05-01-11.4 (Testing and Monitoring Requirements), this Quality Assurance and Surveillance Plan (QASP) was developed and is being provided as part of the testing and monitoring program.

D.1 Overview

The testing and monitoring program for the project includes the analysis of the injected CO_2, periodic testing of the injection well (i.e., testing of external and internal mechanical integrity), a corrosion-monitoring plan for the CO_2 injection well components, a leak detection and monitoring plan for surface components of the CO_2 injection system (e.g., CO_2 flow line and wellhead), and a near-surface/deep-subsurface leak detection plan to monitor any movement of the CO_2 outside of the storage reservoir (see Table 4-6). The latter consists of a combination of soil gas and groundwater monitoring, storage reservoir monitoring, downhole monitoring, and geophysical monitoring. The quality assurance and surveillance procedures for this testing and monitoring plan are provided in the remainder of this QASP.

D.2 Monitoring and Analysis of Injected CO_2

NDAC § 43-05-01-11.4 subsection 1a requires analysis of the carbon dioxide stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics.

Samples of the injected CO_2 stream will be characterized to determine the concentrations of CO_2, nitrogen, oxygen, hydrogen, water, and a suite of hydrocarbons (i.e., ethane, propane, n-butane, and methane) as well as selected isotopes (i.e., isotopes of carbon dioxide [^{13}C and ^{14}C], methane [^{14}C], and deuterium [^{2}H]). These analyses will be outsourced to commercial laboratories, with the isotopic analyses performed by Isotech Laboratories, Inc., and all other analyses performed by Minnesota Valley Testing Laboratories, Inc. (MVTL). These laboratories utilize analytical methods and standards that are generally accepted by industry and will employ their standard analytical QA/QC (quality assurance/quality control) protocols (www.iostechlabs.com and www.mvtl.com/QualityAssurance).

D.3 Injection Well Testing

The external mechanical integrity of the CO_2 injection well (RTE-10) will be continuously monitored using a DAS (distributed acoustic sensing)/DTS (distributed temperature sensing) fiber optic cable that is externally installed on the long string casing (Figure 4-9). The technical specifications for the DAS/DTS fiber optic cable are provided in Attachment A-1 of this appendix. An ultrasonic log will be run after the first year of injection and once every 5 years thereafter to provide corroborating evidence of the external mechanical integrity of the wellbore. The technical specifications for the ultrasonic imager tool are provided in Attachment A-2.

The internal mechanical integrity of the injection well will be tested at a minimum of once every 5 years by performing tubing/casing annular pressure tests. A detailed description of this test is provided in Attachment A-3.

The pressure test provides an assessment of the internal mechanical integrity of the wellbore between the tubing-casing annulus. The pressure test procedure will be generated following the NDIC Injection Well Construction and Completion Standards (NDAC § 43-05-01-11) that the pressure must be applied for a period of 30 minutes and must have no decrease in pressure greater than 10% of the required minimum test pressure.

D.4 Corrosion Monitoring and Prevention

D.4.1 Corrosion Monitoring

Corrosion coupons that are representative of the construction materials of the flow line and injection well will be tested quarterly during the first year of injection, and once per year thereafter, to aid in ensuring the mechanical integrity of the injection well equipment. These coupons will be prepared, installed, and analyzed in accordance with NACE Standard RP0775 (Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations) and/or ASTM Method G1-03 (Standard Practice of Preparing, Cleaning, and Evaluating Corrosion Test Specimens) to determine and document corrosion loss rates based on mass loss. The testing will be performed on the captured CO_2 gas stream at the beginning of the flow line to the injection wellhead. The quality assurance and quality control procedures specified in the NACE and ASTM methods will be followed.

D.4.2 Corrosion Prevention

The primary actions taken to prevent corrosion include 1) maintaining a low moisture content in the injected CO_2 and 2) using CO_2-resisitant materials of construction in both the flow line and injection well. To that end, the target moisture level of the injected CO_2 is estimated to be 0.1% (by volume). The injection well tubulars will use materials manufactured to API 5CT (Casing and Tubing Specification) and ISO 11960 (Petroleum and Natural Gas Industries – Steel Pipes for Use as Casing or Tubing for Wells) (e.g., Grade 13Cr-80 martensitic stainless steel with gastight premium seal connection such as VAM TOP or JFE BEAR). The cement and additives will comply with API 10A (Specification for Cements and Materials for Well Cementing). However, if warranted, based on the results of the corrosion monitoring, removal of corrosive constituents from the CO_2 stream may be necessary using a variety of methods: 1) dehydration of the gas when water is present (e.g., water separator, coalescers, filters, glycol, or dry desiccant) and 2) corrosion inhibitor packages (anodic, cathodic, or both) (e.g., solvents, surfactants, phosphate esters, phosphonates, amine-containing compounds, or imidazolines). Should this be necessary, deployment methods will be chosen by the appropriate vendor that has designed a catered approach to removing corrosive components from the CO_2 stream. Over time, the effectiveness of the catered design will be evaluated based on the corrosion monitoring results, and corrosion removal methods will be adjusted accordingly.

D.5 Monitoring of Surface Equipment Leaks

DAS/DTS fiber optic cables located along the CO_2 flow line to the wellhead and CO_2 detectors located on the wellhead and key wellsite locations (e.g., flow line riser), which will be integrated into an automatic alarm system, will be used to monitor for any leaks of CO_2 from the flow line and/or surface equipment of the storage facility. The technical specifications for the DAS/DTS fiber optic cable are provided in Attachment A-1 of this QASP.

D.6 Near-Surface Monitoring: Soil Gas and Groundwater

Near-surface sampling discussed herein comprises 1) sampling of shallow groundwater aquifers (USDWs) and 2) sampling of soil gas in the shallow vadose zone. Sampling and chemical analysis of these zones provide concentrations of chemical constituents, including carbon dioxide (CO_2), which are focused on detecting movement of the CO_2 out of the reservoir. Ultimately, these monitoring efforts will provide data to confirm that near-surface environments are not adversely impacted by CO_2 injection and storage operations.

D.6.1 Soil Gas

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of 13 soil gas-sampling sites were identified in the area around and between the injection well (RTE-10) and the monitoring well (RTE-10.2) (SG01 through SG11 and SS01 and SS02 as shown in Figures 4-5 and 4-6, respectively). Five of these locations (SG01, SG02, SG06, SG10, and SG11) are on private land; the remainder are on RTE property.

D.6.1.1 Soil Gas-Sampling and Analysis Protocol

Soil Gas Locations: SG01 to SG11

Hand-driven probes were used to collect the soil gas samples at locations SG01 through SG11. All of these soil gas-sampling locations were identified and marked using GPS. At each location, a stainless steel rod with a retractable tip was driven into the ground (either with a slide hammer or electric rotary hammer) to a depth of approximately 3.5 feet. The rod was then retracted to expose an integrated mesh screen through which soil gas samples were obtained.

Prior to the collection of each sample, a minimum of three probe casing volumes were removed, and the representativeness of the gas flow was determined by analyzing the soil gas over time for CO_2, total VOCs, hydrogen sulfide (H_2S), and O_2 using a RAE System PGM-54 handheld multigas meter, which was calibrated daily based on manufacturer instructions. After these measurements of the soil gas composition stabilized, two soil gas samples were collected for characterization at each location using a Tedlar® bag, which was labeled with the appropriate sample number and site information and transported to the Energy & Environmental Research Center (EERC) laboratory for analysis. The composition of one sample was determined at the EERC using an Agilent 7890A refinery gas analyzer (RGA) gas chromatograph (GC). The second sample was transferred to an IsoBag® for isotope analyses by mass spectrometer at Isotech Laboratories, Inc. (Champaign, Illinois). The target analytes for these analyses are shown below in Table D-1 and Table D-2, respectively.

Table D-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

RAE Handheld Meter	Agilent Technologies RGA-GC 7890A
CO_2	CO_2
O_2	O_2
H_2S	N_2
Total VOCs*	He
	H_2
	CH_4
	CO
	C_2H_6
	C_2H_4
	C_3H_8
	C_2H_8
	$(CH_3)_2CH\text{-}CH_3C_4H_{10}$
	$HC{\equiv}CH$
	$H_2C{=}CH\text{-}C_2H_5$
	$H_3C\text{-}CH{=}CH\text{-}CH_3$
	$(CH_3)_2C{=}CH_2$
	$H_3C\text{-}CH{=}CH\text{-}CH_3$
	$(CH_3)_2CH\text{-}CH_2\text{-}CH_3$
	C_5H_{12}
	$H_2C{=}CH\text{-}CH{=}CH_2$

* Volatile organic compounds.

Table D-2. Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2	‰
δD	‰
^{14}C in CO_2	pMC
^{14}C in CH_4	pMC

Soil Gas Locations: SS01 and SS02

Fixed soil gas profile stations will be installed for the sampling of soil gas at locations SS01 and SS02 prior to the initiation of CO_2 injection. A schematic of these soil gas profile stations is shown below in Figure D-1. As shown, each soil profile station contains three isolated gas sampling probes from which individual soil gas samples will be obtained.

The procedures for the acquisition of the soil gas samples from the soil gas profile stations will follow the same procedures as described above for the hand-driven probes; i.e., sampling will not proceed until the probes have been purged and the composition of the soil gas has been determined to be stable. Following industry standards for landfill gas analysis, MVTL, Inc., will perform an on-site analysis of the soil gas for the parameters identified in Table D-1 using a high accuracy handheld meter, i.e., Landtec GEMTM 5000 portable gas analyzer. In addition, a sample will be collected and sent to Isotech Laboratories, Inc. (Champaign, Illinois) for isotopic analyses (see Table D-2).

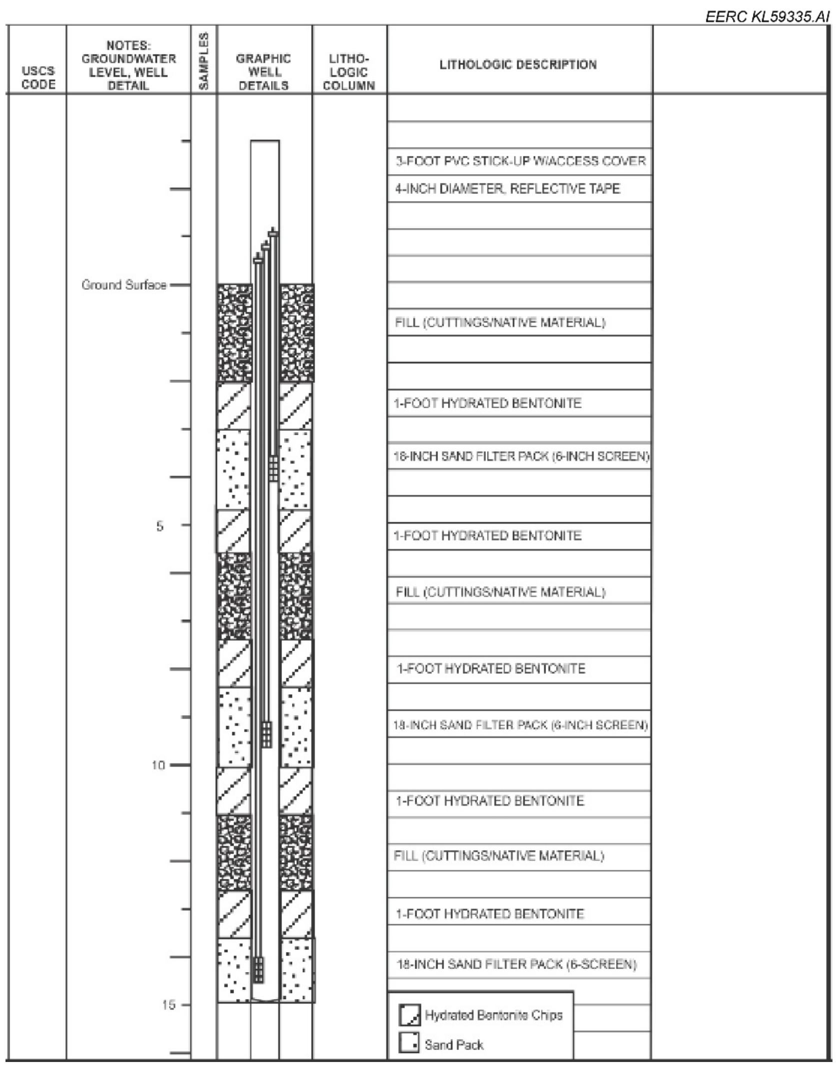

Figure D-1. Schematic of Soil Gas Profile Stations SS01 and SS02.

D.6.1.2 Quality Assurance/Quality Control Procedures

Soil Gas Locations: SG01 to SG11.
A field blank (ambient air) was collected three times daily (morning, midday, day's end) through the sample probe prior to the insertion of the probe into the ground. If an anomaly was detected with the RAE handheld meter, decontamination procedures were deployed, and a blank was collected again. If collection of anomalous results continued, the calibration of the meter was examined and, if necessary, adjusted. This process was repeated until a satisfactory blank was collected from the probe. Additionally, results from the handheld meter and the EERC laboratory GC were compared for all sampling events as a QA/QC measure to the generation of a valid data set.

Duplicate gas samples were collected at a rate of one for each ten samples taken to assess the comparative accuracy of the field sampling and laboratory analyses. Sample collection procedures followed guidance outlined in ASTM International D-5314 (2006).

Soil Gas Locations SS01 and SS02
The standard sampling and analytical QA/QC protocols which will be applied by MVTL, Inc., and Isotech Laboratories at these sample locations were provided earlier in this QASP (see www.iostechlabs.com and www.mvtl.com/QualityAssurance).

D.6.2 Groundwater-Sampling and Analysis Protocol

Baseline Groundwater Wells (Well Nos. 51002, 61337, and 10648)
Groundwater field samples were collected from these wells using the well's submersible pump. Individual wells were purged a minimum of three casing volumes (typically 20 to 30 minutes of pumping) prior to sampling. Physical parameters were measured using the flow-through cell of the YSI Professional Plus handheld multiparameter meter. The YSI handheld multiparameter meter was then turned on to monitor dissolved oxygen (DO) until the measurements had stabilized (i.e., remained within ±10%). Following DO stabilization, readings were recorded for the rest of the field parameters (pH, temperature, and specific conductance [SpC]). A groundwater sample was then collected in a clean container for the analysis of alkalinity as $CaCO_3$, dissolved CO_2, and chloride using the Hanna test kit.

The YSI handheld multiparameter meter was calibrated daily prior to sampling in accordance with the manufacturer-specified procedures. The YSI probe was placed in contact with the water sample to obtain a field reading. TDS measurements were calculated automatically by the YSI meter, multiplying the SpC measurements by a factor of 0.65.

For laboratory analyses, sample bottles were filled directly from the designated groundwater well by personnel wearing disposable gloves to avoid potential contamination of the sample. Each sample container was labeled with a sample identification number, date, and time of sample collection. Filtration and preservation requirements for the specific laboratory analytical methods and procedures were implemented. Sample bottles were placed in a cooler with ice along with a completed chain-of-custody form and submitted to the appropriate laboratory for analysis.

Two laboratories were used to analyze the water samples: 1) the EERC laboratory analyzed samples for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables D-3 and D-4) and 2) Isotech Laboratories, Inc., analyzed the samples for isotopic signatures (Table D-5).

Table D-3. Measurements of General Parameters for Groundwater Samples

Parameter	Method
Alkalinity	SM[1] 2320B
Bromide	EPA[2] 300.0
Chloride	EPA 300.0
Dissolved Inorganic Carbon (DIC)	EPA 9060
Dissolved Mercury	EPA 245.2
Dissolved Metals[3] (31 metals)	EPA 200.7/200.8
Dissolved Organic Carbon (DOC)	SM 5310B
Fluoride	EPA 300.0
Sulfate	EPA 300.0
Sulfide	SM 4500-S^{2-} F
TDS	SM 2540C
Total Inorganic Carbon (TIC)	EPA 9060
Total Mercury	EPA 7470A
Total Metals[2] (31 metals)	EPA 6010B/6020
Total Organic Carbon (TOC)	SM 5310B

[1] Standard method; American Public Health Association (2017).
[2] U.S. Environmental Protection Agency.
[3] See Table B-2 for entire sampling list of total and dissolved metals.

Table D-4. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Metals	Major Cations	Trace Metals
Antimony	Barium	Aluminum
Arsenic	Boron	Bismuth
Beryllium	Calcium	Cobalt
Cadmium	Iron	Lithium
Chromium	Magnesium	Molybdenum
Copper	Manganese	Thorium
Lead	Phosphorus	Uranium
Mercury	Potassium	Vanadium
Nickel	Silicon	
Selenium	Sodium	
Silver	Strontium	
Thallium		
Zinc		

Table D-5. Isotope Measurements for Groundwater Samples

Isotope	Units
δ^2H H_2O	‰[1]
$\delta^{18}O$ H_2O	‰
Tritium	TU[2]
$\delta^{13}C$ DIC	‰
^{14}C DIC	pMC[3]

[1] One tenth of a percent (0.1%).
[2] Tritium unit.
[3] Percent modern carbon.

Operational and PISC Groundwater Wells

The operational and PISC groundwater wells that will be monitored include sampling of the baseline groundwater wells that are operational and accessible within the AoR (area of review) and the two dedicated groundwater Fox Hills Formation monitoring wells installed at RTE-10 and RTE-10.2. MVTL, Inc., will perform the sampling of the wells to provide two samples for analysis from each well. One sample will be analyzed by MVTL, Inc., for the general parameters, anions, cations, metals (dissolved and total), and nonmetals listed in Tables D-3 and D-4; the other sample will be sent to Isotech, Inc., for the determination of the isotopic signatures (see Table D-5). These sampling and analysis efforts will be performed MVTL, Inc., in conjunction with Isotech Laboratories, Inc., with the specific sampling and analysis SOPs (standard operating procedures).

D.6.3 Quality Assurance/Quality Control

Baseline Groundwater Wells (51002, 61337, and 10648)

A field QA/QC program including control samples was employed to evaluate the accuracy of the groundwater sampling effort (field sampling and laboratory analysis). Field blanks, trip and equipment blanks, duplicate samples, and field control samples were used as part of the comprehensive QA/QC program to ensure accuracy of the monitoring results. In addition, all field and laboratory analytical instruments were calibrated on a routine basis to ensure that they were operating within manufacturer specifications. More details regarding these efforts are provided in the remainder of this section.

Field blanks were utilized to identify sample contamination caused by exposure to ambient air during the sampling process. Field blanks were prepared by filling sample containers with deionized water during each sampling event. A sampling frequency of one field blank a day was employed throughout the baseline sampling program.

Trip blanks were employed to help identify whether sample contamination specific to the presence of VOCs was present. The trip blank containers were filled in the laboratory with purified water, transported, handled like a sample during field activities, and then returned to the laboratory for analysis. Containers testing positive for VOCs suggested contamination of the sample during its handling from the field to the laboratory. One trip blank accompanied every cooler containing VOC samples.

Equipment blanks were used to verify sources of contaminants that may be present on the sampling equipment. Equipment blanks were collected by pouring deionized water over and/or through any of the sampling devices. One equipment blank was collected from each applicable piece of equipment (flow-through cell, etc.) during each sampling event. To avoid cross-contamination, all field sampling equipment was decontaminated prior to use and between samples. Decontamination procedures included washing and rinsing sample probes and field multiparameter meters using Alconox® and deionized water.

All of the laboratory analyses conducted by the EERC and Isotech Laboratories, Inc., were performed in accordance with their internal QA/QC procedures (Table D-3 and www.iostechlabs.com). In addition, duplicate samples were taken to assess the combined accuracy of the field sampling and laboratory analysis methods. These duplicate samples were collected at the same time and location for each of the groundwater wells.

Operational and PISC Groundwater Wells

The standard sampling and analytical QA/QC protocols that will be applied by MVTL, Inc., and Isotech Laboratories, Inc., as part of the monitoring efforts at these sample locations were provided earlier in this QASP (www.iostechlabs.com and www.mvtl.com/QualityAssurance).

D.7 Storage Reservoir Monitoring

Monitoring of the storage reservoir during injection well operations includes monitoring of the injection flow rates and volumes, wellhead injection temperature and pressure (WHT/P), bottomhole injection pressure, and the tubing-casing annulus pressure or casing pressure. In addition, the volume of the corrosion inhibited packer fluid in the casing will be monitored and recorded throughout the project.

The storage monitoring will be accomplished using flowmeters, surface digital pressure and temperature gauges, and bottomhole pressure/temperature (BHP/BHT) gauges. The specifications for these bottomhole pressure/temperature gauges are provided in Attachment A-5. The surface injection temperature along with the flowline, wellhead, and bottomhole will be continuously monitored and recorded in real time. These pressure/temperature data will be either periodically downloaded (i.e., monthly basis or bimonthly basis) or continuously recorded as part of the supervisory control and data acquisition or SCADA (see Attachment A-4) system that is employed on-site.

D.8 Downhole Monitoring

The downhole monitoring of the injection (RTE-10) and monitoring (RTE-10.2) wells will focus on the downhole pressure and temperature. This monitoring will be achieved on both wells using external borehole temperature (BHT) and pressure (BHP) gauges along with a fiber optic DTS system to provide continuous data recorded in real time. The specifications for the DTS and the BHT/BHP gauges are provided in Attachments A-1 and A-5, respectively. These pressure and temperature data will be either periodically downloaded (i.e., monthly basis or bimonthly basis) or continuously recorded as part of the SCADA system that is employed on-site.

D.9 Wireline Logging and Retrievable Monitoring

The wireline logging and retrievable monitoring that will be performed comprise pulse neutron logs (PNLs) and ultrasonic logs, injection zone pressure falloff tests, DAS/DTS fiber optic, and corrosion monitoring. The information provided by these monitoring efforts is as follows:

- PNL: provides information regarding gas saturation in the formations, which can be used to determine if the injected CO_2 is contained within the storage formation as well as ground-truth information provided by 3D seismic surveys.

- Ultrasonic log (ultrasonic imager tool) and casing pressure test: provides an assessment of the external and internal mechanical integrity, respectively, of the wellbore.

- DAS/DTS: provides a continuous assessment of the external mechanical integrity of the wellbore.

- Corrosion monitoring: provides a measure of the loss of mass of the wellbore materials over time due to interaction of the wellbore with the injected CO_2 and formation fluids.

- Pressure fall-off test: provides an assessment of the storage reservoir injectivity.

All wireline logging events will follow API (American Petroleum Institute) guidelines along with the SOPs of a third-party wireline operator. More details regarding each of these monitoring techniques is provided below.

D.9.1 Pulse Neutron Logs

PNL provides formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays (Rose and others, 2015). High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements (Schlumberger, 2019).

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) tool is a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The PNX tool can provide a direct volumetric measurement of gas-filled porosity and differentiate between gas-filled porosity, liquid-filled, and tight zones (Schlumberger, 2019). Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity as shown in Table D-6 below. Detailed measurement and mechanical specifications for the PNX tool are provided in Attachment A-6. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Table D-6. Gas Saturation Detection Limits for PNL – PNX Tool

Porosity Value, %	Gas Saturation Detection Limit, % Minimum at Logging Speed of 1000 ft/hour	Gas Saturation Detection Limit, % Minimum at Logging Speed of 200 ft/hour
10	~39	~18
15	~22	~10
20	~18	~8

D.9.2 Ultrasonic Logs

The UltraSonic Imager tool (USIT) indicates the quality of the cement bond at the cement/casing interface and provides casing inspection (corrosion detection, monitoring, and casing thickness analysis). The tool is deployed on wireline with a transmitter emitting ultrasonic pulses and measuring the reflected ultrasonic waveforms received from the internal and external casing interfaces. The entire circumference of the casing is scanned, enabling the evaluation of the radial cement bond and the detection of internal and external casing damage or deformation. The high angular and vertical tool resolutions can detect cement channels as narrow as 1.2 in. (Schlumberger, 2004). Detailed measurement and mechanical specifications for the USIT tool are provided in Attachment A-2. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

D.9.3 Injection Zone Pressure Fall-Off Test

The injection zone pressure fall-off test will be performed in the injection well prior to initiation of CO_2 injection activities and at least once every 5 years thereafter to demonstrate storage reservoir injectivity. Pressure data will be recorded during the pressure fall-off test at the bottomhole and at the wellhead using the tandem BHP gauges and wellhead pressure gauge, respectively. The BHP gauge specification is provided in Attachment A-5.

D.10 Geophysical Monitoring Methods

The geophysical monitoring that is planned for the project includes time lapse seismic surveys, gravity surveys, interferometric synthetic aperture radar (InSAR) and passive seismic recording. These indirect monitoring methods will characterize attributes associated with the injected CO_2, including the plume extents, mass changes, pressure changes, and potential seismicity. The proven monitoring methods that will be implemented as part of this testing and monitoring plan are the state of the art in their application. These methods can be applied as both standalone and time lapse measurements. Details regarding the application and quality of these methods are provided in the remainder of this section:

- Time lapse seismic surveys: provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

- Gravity surveys: provide a measurement of the mass of injected CO_2 that has accumulated in the storage formation.

- InSAR: provides frequent measurements of satellite-based surface deformation over the entire AoR.

- Passive seismic recording: provides continuous collection of seismicity measurements over the AoR.

D.10.1 Time Lapse Seismic Surveys

Application of time-lapse seismic surveys (4D seismic) for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of 4D seismic quality (Lumley, D. et al., 4D seismic risk analysis spreadsheet, SEG abstract, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced 4D seismic interpreter.

D.10.2 Gravity Surveys

Gravity is a measure of mass and, when used as a time-lapse method (4D gravity), can provide a measure of mass change related to a difference in density. The changes in gravity related to CO_2 density diminish with depth requiring a large volume of mass change for the measurement. This measurement requires high-precision instruments with microgal precision. Ideally, a field-worthy instrument (i.e., MicroG Lacoste A10 and/or CG5) can achieve this level of precision. Monitoring with 4D gravity requires a baseline survey with high resolution location and elevation (Hare et al., 2008, Society of Exploration Geophysicists. *Geophysics*, v. 73, no. 6, p. WA173–WA180, http://zonge.com/4d-microgravity-method-for-waterflood-surveillance-part-iv-modeling-and-interpretation-of-early-epoch-4d-gravity-surveys-at-prudhoe-bay-alaska/ (accessed 2020).

D.10.3 InSAR

InSAR[1] can detect small-scale surface ground deformation and has been shown to be one such technique for approximately mapping pressure distribution associated with subsurface fluid injection.[2] Geodetic methods, like InSAR, are widely available and allow for multiple nonunique interpretations requiring integration with other monitoring methods (e.g., time lapse seismic). InSAR requires continuous satellite coverage with consistent surface reflectivity.[3] In areas where there is snowfall, agricultural changes, or erosional features, the InSAR results will be uncertain and unreliable for elevation changes. To improve inSAR measurement sensitivity, reflectivity challenges can be mitigated by installing stable reflective monuments.

D.10.4 Passive Seismic Recording

Continuous monitoring of seismic activity will include five surface-installed seismometer stations near the project site and DAS fiber optic systems installed on the injection well RTE-10 and the monitoring well RTE-10.2. The seismic monitoring stations and DAS are capable of autonomously and continuously measuring a wide range of seismicity (micro/macro events). Baseline passive seismic data will be collected both prior to injection as well as throughout the operational phase of the project to understand the level of preoperational seismicity.

[1] Donald, W. et al., 2020, Monitoring the fate of injected CO_2 using geodetic techniques: Vasco, The Leading Edge, v. 39, no. 1, p. 29.
[2] Reed_inSAR_BellCreek.
[3] PSinSAR_May2010.

D.11 Completed Well Logging – RTE 10 and RTE 10.2

Several continuous measurements of the storage formation properties were made in Injection Well RTE-10 and Monitoring Well RTE-10.2 using wireline logging techniques. These logs, which are identified along with the justification for their use in Table 4-12, are listed below:

- Ultrasonic log
- Casing collar locator (CCL) log
- Variable density log (VDL)
- Gamma ray log
- Triple combo logs (i.e., resistivity, density, porosity, caliper, and spontaneous potential)
- Combinable magnetic resonance (CMR) log
- Spectral gamma ray log
- Dipole sonic log
- Fracture finder log

D.12 Modular Formation Dynamics Tester (MDT) Tool

The Schlumberger MDT* modular formation dynamics tester tool, a wireline formation testing tool, was used to collect real-time formation fluid samples, pressure measurements, and test formation stress of the injection zone and the upper confining zone.

Formation Fluid Sample

The wireline-conveyed MDT tool assembly incorporated a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection.

Fluid samples from the Broom Creek and Inyan Kara Formations were collected from the RTE-10 wellbore via MDT tool (Table 2-5), using the Schlumberger Saturn 3D radial probe. Schlumberger Saturn 3D radial probe specifications are found at https://www.slb.com/-/media/files/fe/product-sheet/saturn-ps.ashx.

In situ fluid pressure testing was performed in the upper confining zone, the Opeche Formation, with the MDT tool. This test utilized the tools large-diameter probe to test both mobility and reservoir pressure.

Microfracture Testing

Microfracture testing was also performed using the MDT tool. In situ reservoir stress testing measurements provided real-time formation temperatures, formation, fracture breakdown, fracture propagation, and closure pressures.

Microfracture tests were performed in the Mowry, Inyan Kara, Opeche, and Broom Creek Formations (Table 2-4). The use of the dual-packer module on the MDT tool assembly to isolate the designated intervals tested a 1.5-foot section of the zone of interest. This small representative sample should be taken into consideration in the analysis of the pressures.

Schlumberger MDT tool Specifications are at https://www.slb.com/-/media/files/fe/brochure/mdt-br.ashx.

ATTACHMENTS: SPECIFICATIONS FOR SPECIALIZED MONITORING TOOLS

A-1. Distributed Acoustic Sensing/Distributed Temperature Sensing Fiber Optics

Items	Description
Contractor	Research Institute of Innovative Technology for the Earth (RITE), Japan
Service	Distributed temperature sensing (DTS) and Distributed acoustic sensing (DAS)
Line OD, in.	1/4
Line Length, ft	Up to 7,000 (2,100 m)
Temperature Rating, °F	Up to 302 (150°C)
Pressure Rating	–
Spooling Unit	56" × 32" × 32" spool
Clamp	Run in tandem with BHT/P gauges

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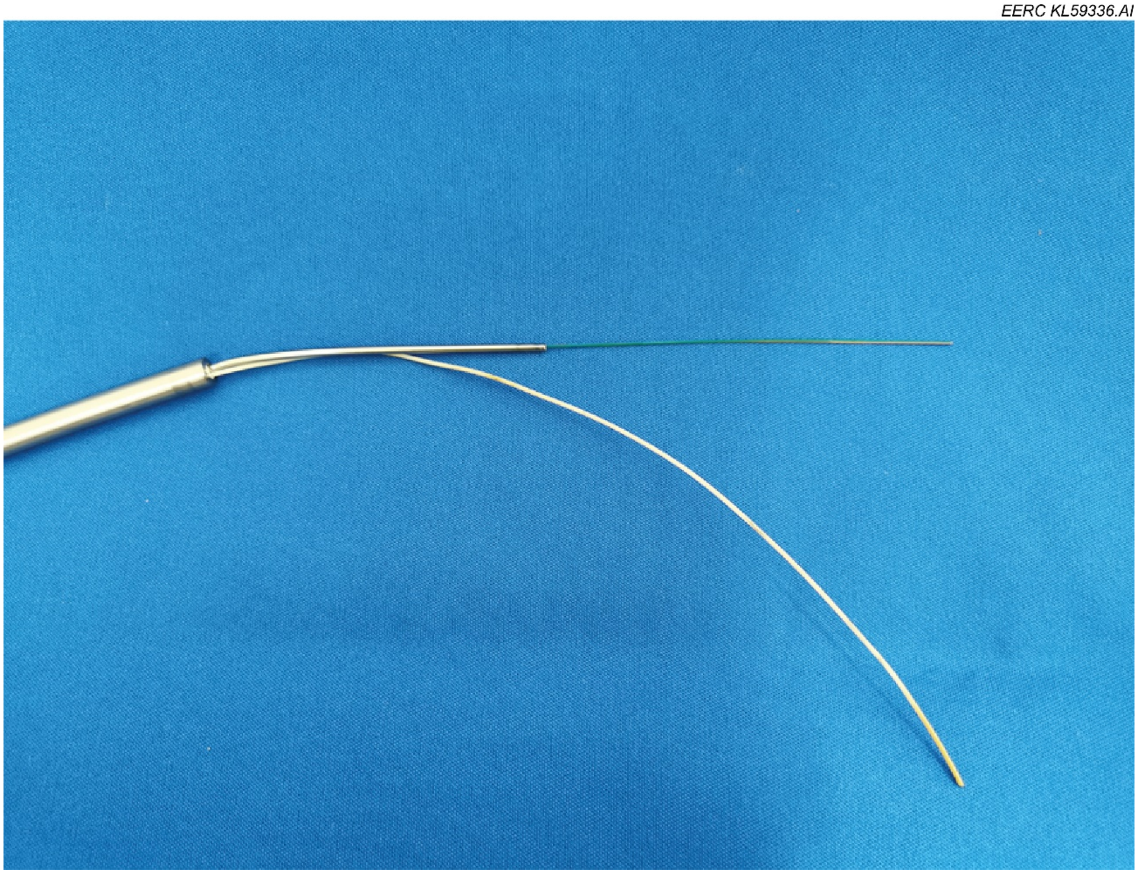
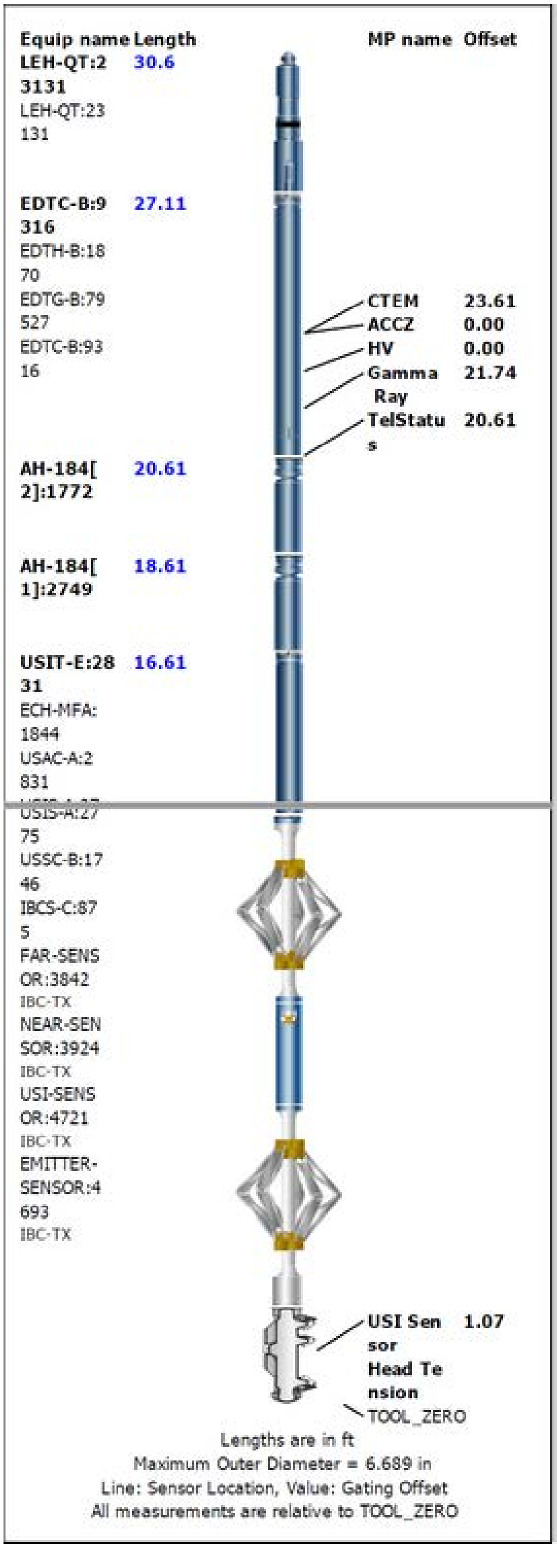


Specifications for DAS/DTS fiber optics from RITE currently installed in RTE-10.

A-2. Ultrasonic Logging Tool (Mechanical Integrity Test)



Measurement Specifications

	Isolation Scanner Tool
Output[†]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Max. logging speed	Standard resolution (6 in, 10° sampling): 823 m/h [2,700 ft/h] High resolution (0.6 in, 5° sampling): 172 m/h [563 ft/h]
Range of measurement	Min. casing thickness: 0.38 cm [0.15 in] Max. casing thickness: 2.01 cm [0.79 in]
Vertical resolution	High resolution: 1.52 cm [0.6 in] High speed: 15.24 cm [6 in]
Acoustic impedance[‡]	Range: 0 to 10 Mrayl Resolution: 0.2 Mrayl Accuracy: 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15%
Flexural attenuation	Range: 0 to 2 dB/cm[§] Resolution: 0.05 dB/cm[§] Accuracy: 0.01 dB/cm[§]
Min. quantifiable channel width	30 mm [1.2 in]
Depth of investigation[†]	Casing and annulus up to 7.62 cm [3 in]
Mud type or weight limitation[††]	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H_2S service

[†] Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log (VDL) of the annulus waveform and polar movies in AVI format.

[‡] Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 MRayl between the fluid behind the casing and a solid.

[§] For 8-mm [0.3-in] casing thickness.

[††] Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging.

Mechanical Specifications

	Isolation Scanner Tool
Max. temperature	177 degC [350 degF]
Pressure range	1 to 138 MPa [145 to 20,000 psi]
Casing size—min.[†]	4½ in (min. pass-through restriction: 4 in)
Casing size—max.[†]	9⅝ in
Outside diameter	IBCS-A: 8.57 cm [3.375 in] IBCS-B: 11.36 cm [4.472 in] IBCS-C: 16.91 cm [6.657 in]
Length without sub	6.01 m [19.73 ft]
Weight without sub	151 kg [333 lbm]
Sub length, weight	IBCS-A: 61.22 cm [24.10 in], 7.59 kg [16.75 lbm] IBCS-B: 60.32 cm [23.75 in], 9.36 kg [20.64 lbm] IBCS-C: 60.32 cm [23.75 in], 10.73 kg [23.66 lbm]
Sub max. tension	10,000 N [2,250 lbf]
Sub max. compression	50,000 N [12,250 lbf]

[†] Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9⅝ in with low-attenuation mud (e.g., water, brine).

Schlumberger's isolation scanner ultrasonic imager tool used to provide evidence of external mechanical integrity in RTE-10 and RTE-10.2

A-3. Mechanical Integrity Test Procedure

Standard Annulus Pressure Test – Internal MIT – pursuant to Section 43-05-01-11.1

1. Contact NDIC (North Dakota Industrial Commission) to witness MIT procedure a minimum of 24 hours prior to test.

2. Completely fill the tubing/casing annulus with corrosion-inhibited packer fluid.
   Temperature stabilization of the well and annulus fluid is necessary; therefore, injection shall either be ceased, or a stabilized injection rate and temperature will be maintained.

3. After stabilization, the annulus will be pressurized to the maximum allowable injection pressure or an alternate pressure approved by NDIC.
   A positive pressure differential between the annulus and the injection string shall be maintained throughout the entire annulus.

4. Following pressurization, the annulus will be isolated from the source of pressure by a closed valve.

5. The annulus will remain isolated for a period no less than 30 minutes or as otherwise approved by NDIC. Pressure measurements will be recorded every 5 minutes, as well as continuously charted.

6. If the pressure deviates more than 10% of the required minimum test pressure, check for seal leaks, otherwise repeat steps. If failure occurs, well will be shut in, report of the failure will be sent to NDIC, and isolation and repair of the leak will commence within 90 days, unless otherwise approved by NDIC.

A-4. Supervisory Control and Data Acquisition (SCADA) System

The supervisory control and data acquisition (SCADA) system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the Red Trail Energy (RTE) CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the server. With specified process algorithms, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valve/s, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert on-site or off-site operators of near or excessive violations of set parameters within the system.

A-5 External Borehole Temperature/Pressure Gauges

DataSphere® Array System - Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	< 0.005
Repeatability (°C)	< 0.01
Drift at 177°C (°C/year)	< 0.1

DataSphere® Array System - Temperature Performance

Pressure Range (psi/bar)	0 to 10,000 / 0 to 690
Accuracy (%FS)	0.015
Typical Accuracy (%FS)	0.012
Achievable Resolution (psi/sec)	< 0.006
Repeatability (%FS)	< 0.01
Response Time to FS Step (for 99.5% FS)	< 1 sec
Acceleration Sensitivity (psi/g – any axis)	< 0.02
Drift at 14 psi and 25°C (%FS/year)	Negligible
Drift at Max. Pressure and Temperature (%FS/year)	0.02

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DATASPHERE ARRAY SYSTEM DESIGNS

- Quartz transducer and hybrid technology
- ASIC technology
- Maximum 175°C operating temperature
- Multi-drop capability to 30,000 ft max depth
- Can be used in conjunction with existing gauges
- Improved shock and vibration performance
- 0.625-in. OD ultra slim design
- Less than 7-in. length per sensor
- Does not need a gauge mandrel to be deployed
- Short-circuit protection per sensor, prevents line takedowns

Temperature and Pressure Sensor > The DataSphere® Array system is comprised of multiple ultra slim, highly accurate quartz-based temperature and pressure sensors.

Halliburton DataSphere array system specifications for external BHT/BHP gauges installed in RTE-10 and RTE-10.2.

A-6 Wireline Logging

Pulsar

Multifunction spectroscopy service

Measurement Specifications	
Acquisition	Real time with surface readout
Output	
Time domain	Sigma (SIGM), porosity (TPHI), fast-neutron cross section (FNXS)
Energy domain	Inelastic and capture yields of various elements, carbon/oxygen ratio, total organic carbon
Logging speed†	
Inelastic capture mode	200 ft/h [61 m/h]
Inelastic gas, sigma, and hydrogen index (GSH) mode	3,600 ft/h [1,097 m/h]
Sigma lithology mode	1,000 ft/h [305 m/h]
Range of measurement	Porosity: 0 to 60 pu
Mud type or weight limitations	None
Combinability	Combinable with tools that use the PS Platform production services platform's telemetry system and ThruBit through-the-bit logging services
Special application	Qualified per the requirements of NACE MR0175 H_2S and CO_2 resistance

† Logging speed determined using the tool planner

Mechanical Specifications	
Temperature rating	350 degF [175 degC]
Pressure rating	15,000 psi [103.4 MPa]
Casing size—min.	2⅜ in [6.03 cm]
Casing size—max.	9⅝ in [24.45 cm]
Outside diameter	1.72 in [4.37 cm]
Length	18.3 ft [5.58 m]
Weight	88 lbm [40 kg]
Tension	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N]

Measurement and mechanical specifications for Schlumberger's pulsar multifunction spectroscopy service or PNX tool.

SPE 127233

Advances in Wireline Conveyed In-situ Reservoir Stress Testing Measurements: Case Studies from the Sultanate of Oman

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This paper was prepared for presentation at the 2009 Kuwait International Petroleum Conference and Exhibition held in Kuwait City, Kuwait, 14–16 December 2009.

Abstract

In-situ reservoir stress measurements are essential input to a wide variety of the production and injection applications of reservoirs. Most of the reservoirs in this article require water injection to maximize recovery without breaking the matrices unintentionally. In some cases, it is also important to create a controlled fracture growth in a formation unit without breaking bordering barriers or zones. The main purpose of the in-situ reservoir stress testing of the case studies in this article is to calculate the minimum stress to improve the reservoir management plans for well placement, production, injection and fracturing processes.

One approach of measuring stresses in many zones is to use the wireline conveyed stress testing tools. The wireline conveyed in-situ reservoir stress testing measurements are frequently performed in the Sultanate of Oman for a wide range of operational and geomechanics applications such as but not limited to:

- Hydraulic fracturing
- Fracture growth/containment issues
- Polymer injection
- Borehole stability
- Sand production prediction
- Stress evolution with depletion, hot and cold injection

The stress testing zones vary from tight to high permeable zones as well as shale zones. The complexity and wide variety of the stress testing applications inevitably led modifications and improvements on the wireline conveyed stress testing tools. These improvements mainly are various types of pumps, higher performance dual packers and mandrels, innovative stress testing methods. The latest improvements and methods in stress testing help addressing the broader range of formations (deep and shallow, tight and permeable) in an extensive type of wells from vertical or deviated to horizontal.

In this article, the examples of several unique stress testing applications are presented. Shale stress testing with a viscous fluid, horizontal well stress testing, tight and very high permeability formation stress testing, sleeve fracturing stress testing methods are discussed in details.

Introduction

In-situ stress magnitude and direction measurements in vertical and lateral directions are required in a reservoir for several reasons. These are for hydraulic fracture design, fracture type identification, water and gas injection management, fault activity, wellbore stability, sand production, rock mechanical properties, casing strings design, cap and base rock integrity, subsidence, and gas storage design.

In-situ reservoir stress testing (ST) measurements provide formation breakdown, propagation and closure pressures. The pressure data is further interpreted for tensile strength and minimum stress determination. The minimum stress is one of the most requested answers of stress testing measurements. The fracturing pressure has a strong relationship with the minimum stress. Knowing the fracturing pressure, for example, will help maximize the matrix sweep efficiency in a water flooding application without creating an unintended fracture (Roegiers *et al.*, 2000). The fracturing pressure is generally set to the fracture closure pressure in which a rock has fissures and natural fractures. The bordering cap and base rock minimum stress values are other important parameters to create directionally controlled fracture growth in a formation. Auxiliary measurements such as sonic and formation imager tools compliment the stress magnitude values obtained from ST measurements.

Stress Testing Tool String and Methodology

The operation requires mud injection to break the rock initially and to re-open /close the rock subsequently with the repeated injection cycles (Desroches, Kurkjian, 1998). ST is conducted with a wireline formation tester which has a dual packer module and a single probe for pressure measurements, pumps, a flow control module for low permeability zones and sample chambers for high permeability zones (Fig.1). The wireline formation tester can have many objectives in the same descent such as pressure measurements, downhole fluid identifications, sampling, and vertical interference tests with real-time measurements (Khalil *et al.* 2008). The dual packer interval seals across the 1-m. length of the wellbore. This small interval lowers the wellbore storage effects and focuses on zonal applications. It has an accurate depth control measures allowing the tests conducted at the desired depth intervals. The wireline conveyed in-situ reservoir stress testing can be extended to carbonate and sandstone formations, shales, tight zones, high permeability and/or fractured intervals. The operation can be conducted with a wireline or drill-pipe-conveyed method. Several tests can be performed during the same trip in vertical, deviated or horizontal wells. ST can also be performed in a cased hole if required.

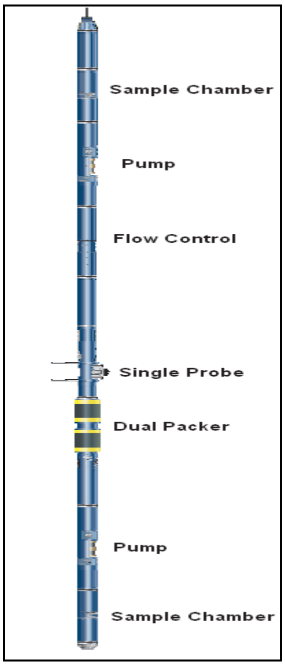

Figure 1- Wireline formation tester designed for an in-situ reservoir stress testing measurement.

The ST objective is to create a controlled fracture in a desired zone and to measure the related pressure response. The created fracture plane is perpendicular to the direction of the minimum in-situ stress (Fig.2). The fracture then is re-opened and closed for the measurement repeatability with several constant rate injection cycles. The repeated cycles also assist fracture to grow 2-well-diameter away beyond hoop stresses to sense far field stresses accurately.

Stress testing operation is performed as following:

(1) Inflate the dual packers by pumping mud into them from the wellbore or from sample chambers filled with water when a high solid content exists in the mud system.
(2) Perform several cycles of small volume mud injections into the formation, which will lead pressure increase stepwise. This looks like very short period of pressure increasing and decreasing cycles. These are called filtration cycles which help choosing the suitable pump speed to initiate the fracture and confirm the dual packer seal.
(3) Inject the mud into formation through the interval of the dual packers. The pressure will sharply increase and will suddenly drop. This is an indication of fracture initiation. Breakdown pressure is the highest pressure at which the fracture is initiated. When the sudden drop in pressure is observed, the mud injection is continued for a short period. Then the pumping is stopped and stabilization is monitored. As the pumping stops, the fracture starts closing back with the reducing pressure. This is called fall-off or bleed-off.

(4) Repeat the cycles with the same injection rate. Fracture re-opens and reaches a rather constant pressure. This is called propagation pressure. The pump is later stopped for a subsequent fall-off. The cycles can be repeated three to five times as needed.
(5) Deflate and move to the next ST depth station if required (Fig. 3).

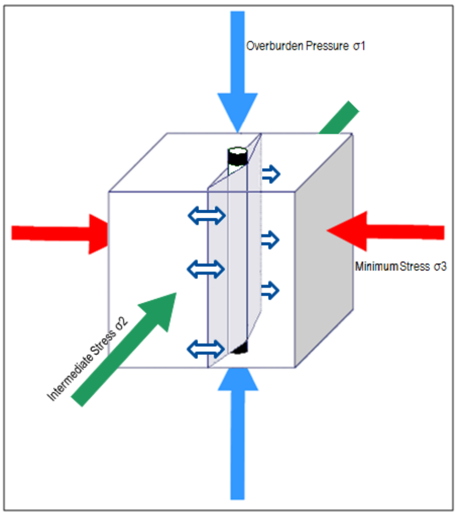

Figure 2- shows the principal stresses acting on the reservoir. The created fracture plane is perpendicular to the direction of the minimum stress.

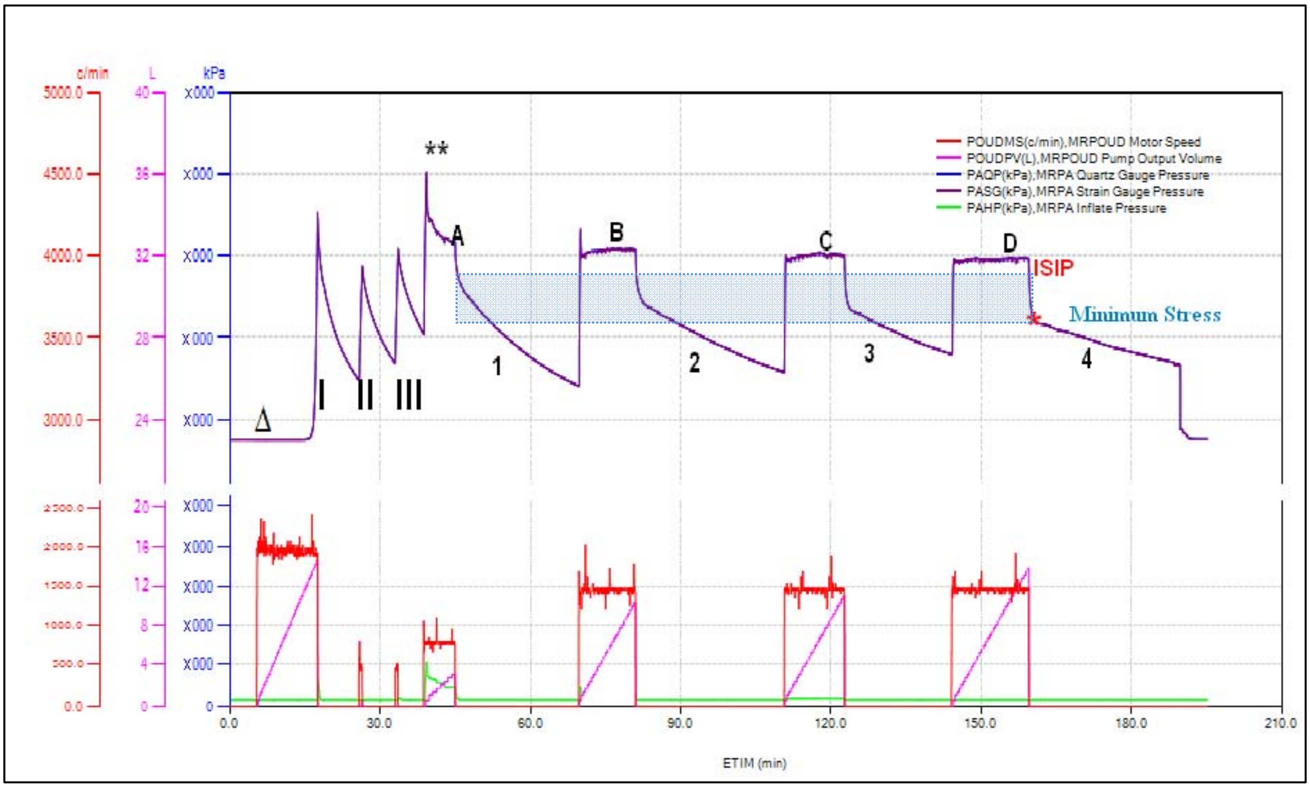

Figure 3- Stress testing measurement. Δ represents packer inflation. I, II, III are filtration cycles. ** is Fracture initiation pressure. A, B, C, D are propagation pressures. 1, 2, 3, 4 are fall-off pressures. * is closure pressure. ISIP is instantaneous shut-in pressure. Minimum stress is located between ISIP and closure pressure.

The station may take 1-4 hrs depending on the rock type, depth and injection fluid type. The test time is mostly consumed by the fall-off duration of the cycles. ST measurements are non damaging fracturing operations. Fractures are closed most of the cases after completing the tests.

There is a difference between the Extended Leak-Off Test (ELOT) and the wireline conveyed in-situ reservoir stress testing. ELOT rates and pressures are measured at the surface. Fluid compressibility and wellbore storage will play a big part in stress measurements in ELOT operations. Injected fluid will enter and fracture the weakest formation measuring the stress of highest permeability rock since generally large openhole intervals are exposed.

Stress Testing Interpretation

Stress is a tensor. For reservoir geomechanics, we are interested in the so-called principal stresses. These are three and often referred to as great principal stress (σ_1), intermediate principal stress (σ_2), and least principal stress (σ_3). In 95% of the crust, one of the principal stresses is vertical (σ_v) and the other two are horizontal (σ_H , σ_h).

- In normal fault environment, $\sigma_1 = \sigma_v$ and $\sigma_3 = \sigma_h$.
- In strike slip environment, $\sigma_1 = \sigma_H$.
- In reverse fault environment, $\sigma_1 = \sigma_H$ *and* $\sigma_3 = \sigma_v$.

ST provides a number of measurements namely formation breakdown pressure, fracture propagation and closure pressures. The following section describes briefly the theory of fracturing and ST data analysis:

ST creates a fracture plane perpendicular to the direction of the minimum horizontal stress (Fig. 2). In other words, the fracture initiated by ST will propagate (away from the borehole) parallel to the maximum horizontal stress direction and opens against the minimum horizontal stress.

The rock breakdown pressure (P_b) is dependent on stress distribution and anisotropy. Lower breakdown pressure is measured in higher stress anisotropy formations. Rock breakdown pressure estimation is very important for the success of the operation (Carnegie *et al.*, 2000). This is related to pump and dual packer selection of the wireline tester equipment. Rocks with a larger tensile strength are fractured with higher rated wireline tester modules. Tensile strength can be obtained with a laboratory analysis or estimated during ST from the difference between propagation and breakdown pressures. There are also developed relationships between unconfined compressive strength (UCS) to tensile strength (Desroches and Thiercelin, 1994).

Considering a normal fault environment, the breakdown pressure (P_b) for a vertical wellbore can be estimated as:

$$P_b = 3\sigma_h - \sigma_H - P + T$$

Where:

P = Formation pressure
T = Rock tensile strength
σ_h = Minimum stress (σ_3)
σ_H = Maximum horizontal stress (σ_2)

The re-opening pressure (P_r) for a vertical well can be predicted from:

$$P_r = 3\sigma_h - \sigma_H + P_f$$

Where:

P_f= Fluid pressure in the fracture. P_f is considered equal to formation pressure in a relatively permeable formation. P_f is taken as equal to hydrostatic mud pressure in a very low permeability formation.
σ_h = Minimum stress (σ_3)
σ_H = Intermediate stress (σ_2)

The measured pressure data is stacked together for injection (propagation) and shut-in (fall-off) cycles. The cycles then are interpreted separately:

Propagation cycles are plotted as pressure vs. volume (or time if rates are constant). The plot provides a range of propagation pressures and fracture re-opening pressures. The re-opening pressures are obtained in the early time from the deviation of the straight line of the pressure measurements (Fig. 4). Re-opening pressure represents the opening of the fracture initiated in the first cycle. Propagation pressure is verified with the relatively constant pressures after re-opening of the fracture is achieved.

Fall-off pressures can be analyzed with pressure derivative analyses (Bourdet *et al.*, 1989) (Fig. 6) or they can be plotted with a square root of shut-in time (Fig. 5). The plot yields straight lines with different slopes. The fracture closure is estimated from the intersection of the straight lines.

Reconciliation plot is later prepared with the interpreted re-opening, propagation, instantaneous shut-in (ISIP) and closure pressures (Fig.7). ISIP is the pressure at the shut-in (when injection is stopped); the pressure quickly stabilizes to a value. ISIP represents a pressure value at which the fracture is open and stops growing (Desroches and Woods, 1998). ISIP does not have frictional pressure effects as opposed to propagation pressure. Reconciliation plot shows the trend of each cycle. If the interpreted pressures in cycles have nearly same values, this is an indication of the measurement in the far field region. Minimum stress can safely be reported between the stacked closure pressures.

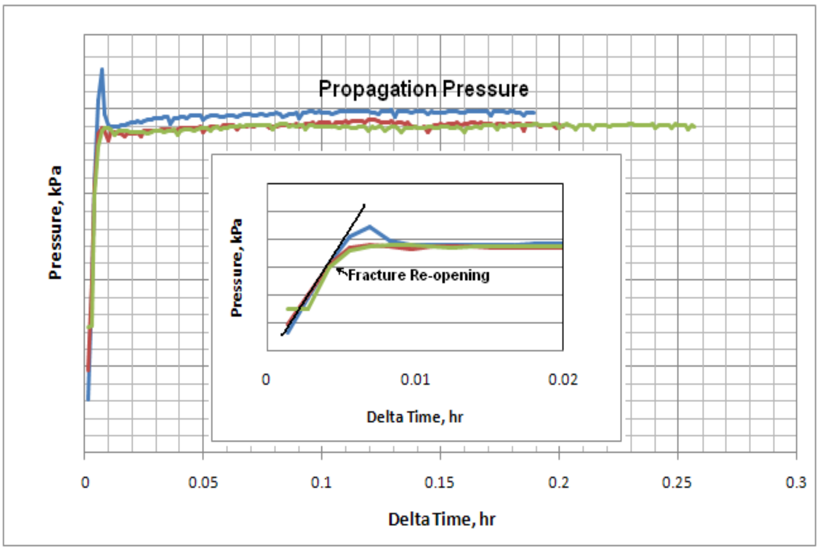

Figure 4- The stacked plot shows pressure vs. volume (delta time if rate is constant). The deviation from a linear line in early time represents the fracture re-opening.

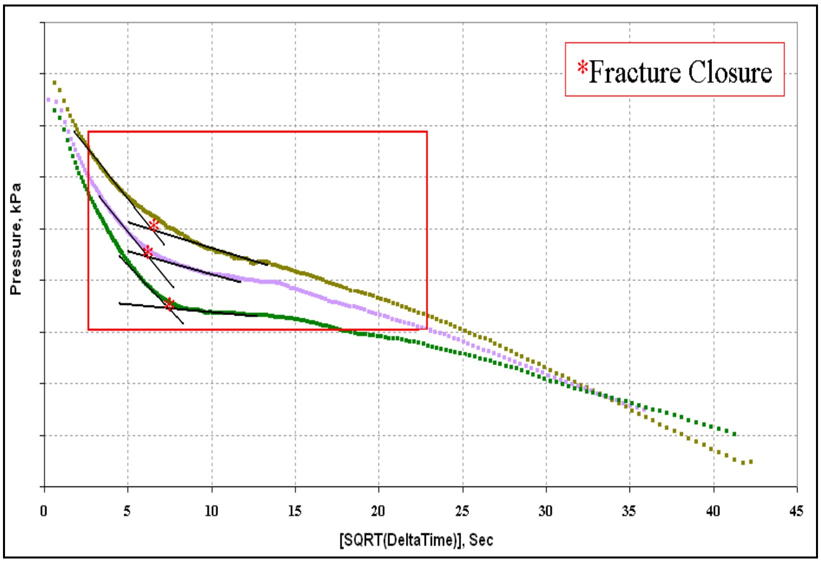

Figure 5- The stacked plot represents pressure vs. square root of delta time. Two distinct straight lines in the same cycle identify the fracture closure pressure.

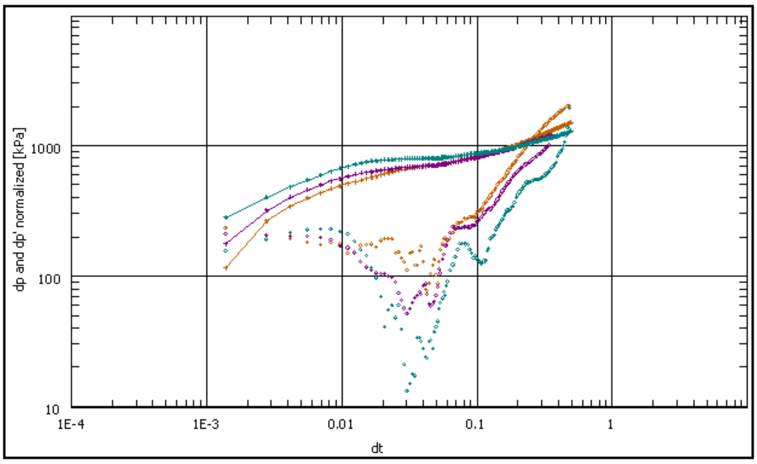

Figure 6- Fall-off pressure derivative analysis which shows the closure of the fracture in each cycle.

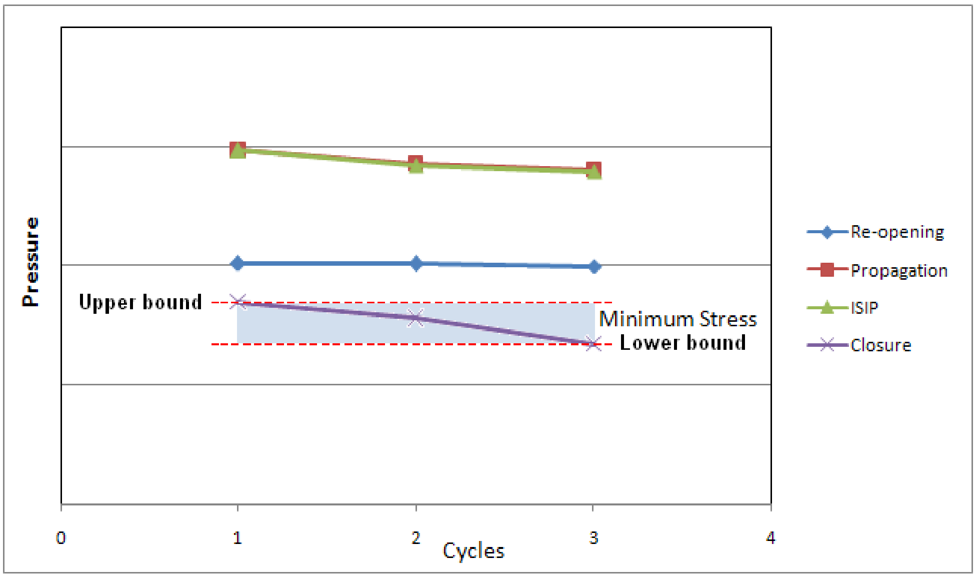

Figure 7- Reconciliation plot shows the trend of each cycle. If the interpreted pressures in cycles have nearly same values, this is an indication of the measurement in the far field region. Minimum stress resides in between the stacked closure pressures.

Auxiliary measurements will assist to complete the estimation of stresses in the far field region. Formation imager tools can provide the azimuthal direction for the fracture created. Sonic Logs with a geomechanical interpretation derive continues curves of stresses throughout the far field region. ST further calibrates the stress curves estimated in the geomechanical interpretation.

New Technologies

Modular Formation Dynamics Tester (MDT) has been utilized for stress testing more than 15 years (Thiercelin *et al.*, 1994, 1996). Prior to recent technological improvements, MDT ST applications were suitable for a limited permeability range. ST limits occurred in two ways: (1) Tight formations (<1 md) experience higher breakdown pressures. These cases require larger pressure rating pumps, higher differential pressure limits for dual packers and mandrels. (2) High permeability formations (>50 md) require larger wellbore fluid injection rates to initiate the fracture.

Increasing demands in mature and exploratory fields for extensive applications, new modules and methods are developed to improve MDT ST capabilities. The recent improvements paved a way for expanding the permeability envelope around 0.1 - 1000 md. Introducing higher rating MDT dual packer mandrel allows up to 6000 psia differential pressure (maximum pump provided pressure – mud pressure). Recently introduced High Performance (HP) dual packers can withstand differential pressures as high as 6000 psia. This means if breakdown pressure is within the range of mud pressure plus 6000 psia, the fracture is created and ST is completed as planned. These high pressures are required when formations are extremely tight. HP dual packers can be used for more than 10 different settings. The dual packers can be set in the wellbores from 6 in. to 14 in.

Previous generation packers have a maximum differential limit of 4000 psia with 3-5 settings. A variety of pumps for their volumes and pressures can be also selected at the present. The utilization of dual pumps is another possibility for increasing a pump capacity.

When formations have relatively high permeabilities (>50 md), the injected mud viscosity is not enough to achieve the fracture. The injected fluid dissipates into a formation before creating enough stress to achieve a fracture. This drawback can be solved in two ways: Either the volume injected should be raised or the viscosity of the injected fluid should be increased. Both methods are introduced. Increasing volume requires two pumps injecting fluid simultaneously. Another method is to carry a viscous fluid downhole with chambers in the tool string and inject it in the high permeability zones. The injected viscous fluid can be easily chosen from heavy oil of a producing well. Let us assume that maximum mobility that fracture can be initiated with the wellbore fluid (mud) is very moderately around $(k/\mu) = 10$ md/cp. If mud filtrate viscosity is taken around as 1 cp, the maximum permeable zone to fracture is around 10 md. If we choose to change an injection fluid viscosity to 100 cp in downhole conditions, then maximum permeability range can go up to 1000 md (1 Darcy).

Case Studies

The wireline conveyed stress testing measurements are frequently performed in the Sultanate of Oman. The stress testing zones vary from tight to higher permeable zones as well as shale zones. Geomechanical computations and predictions are important part of the decision making in reservoir management processes such as drilling performance, reservoir depletion mechanism, and water/gas/steam injection management in the Sultanate of Oman. The chosen examples below are some of the many wireline conveyed stress testing cases:

1. Stress Testing in a High Permeability Sandstone Formation with Viscous Fluid

The objective of the stress testing was to understand the minimum stress in a heavy oil formation for water flooding. Several overlaying formations were tested for the cap rock integrity since a layered reservoir system exists with different producing zones. One of the tests was performed successfully in a sandstone formation where the formation mobility was measured as 549 md/cp. A viscous fluid of 100 cp at 30 Deg.C was carried downhole and injected into the formation. The viscous fluid was the produced and treated oil from the same field. The downhole condition of the viscous fluid was estimated around 65 cp at 54 Deg.C. HP dual packers were utilized in an 8.5-in. vertical well drilled with water based mud. Figure 8 depicts the formation pressures with openhole logs. Figure 9 shows the high mobility stress testing station. The test time was 3.3 hrs. The compressibility of the viscous fluid is higher than that of water based mud. This is very pronounced with the changing slope just before initiating the fracture. The previous stress testing experience in the same field showed that injecting mud alone into this high mobility formation will not result in successful fracture initiation. The stress testing with the mobility of 549 md/cp is a world record to date with a wireline formation tester. Total of 5 successful tests were conducted in carbonate, sandstone, shale and shally sandstone layers in the same run. 2 out 5 tests were with the viscous fluid injection method. The important factor in this stress testing operation was to know the formation pressures and mobilities to selectively choose the fluid types for each zone to achieve the fractures, consequently minimum stress values.

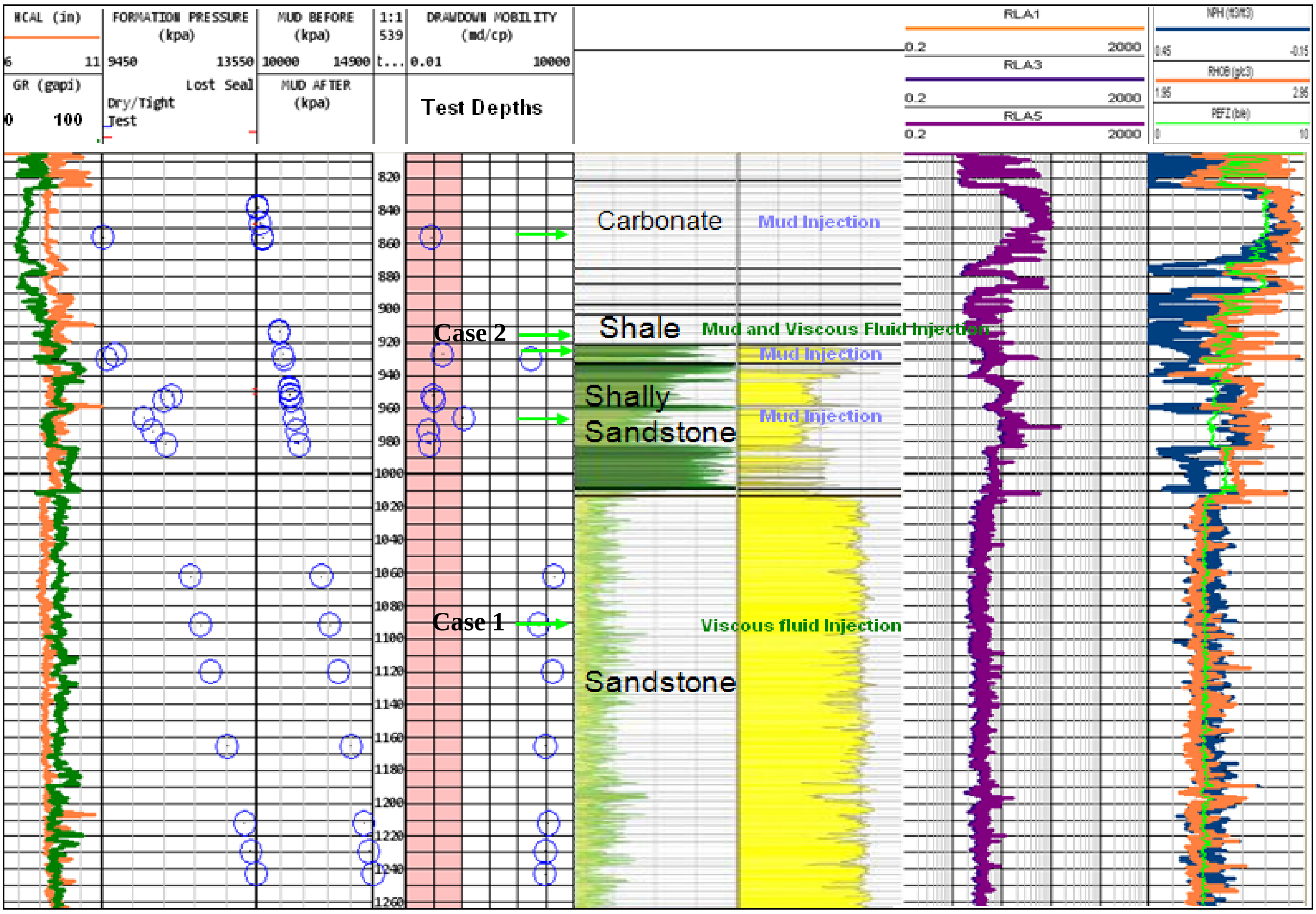

Figure 8- shows the openhole logs and measured pressures and mobilities. Total of 5 stress tests were conducted successfully in sandstone, carbonate, shale and shally sandstone layers. The fluid types varied from wellbore fluid to viscous fluid (heavy oil) which is carried downhole with the wireline formation tester tool. Case 1 example is located in the Sandstone layer and Case 2 example is located in the Shale layer.

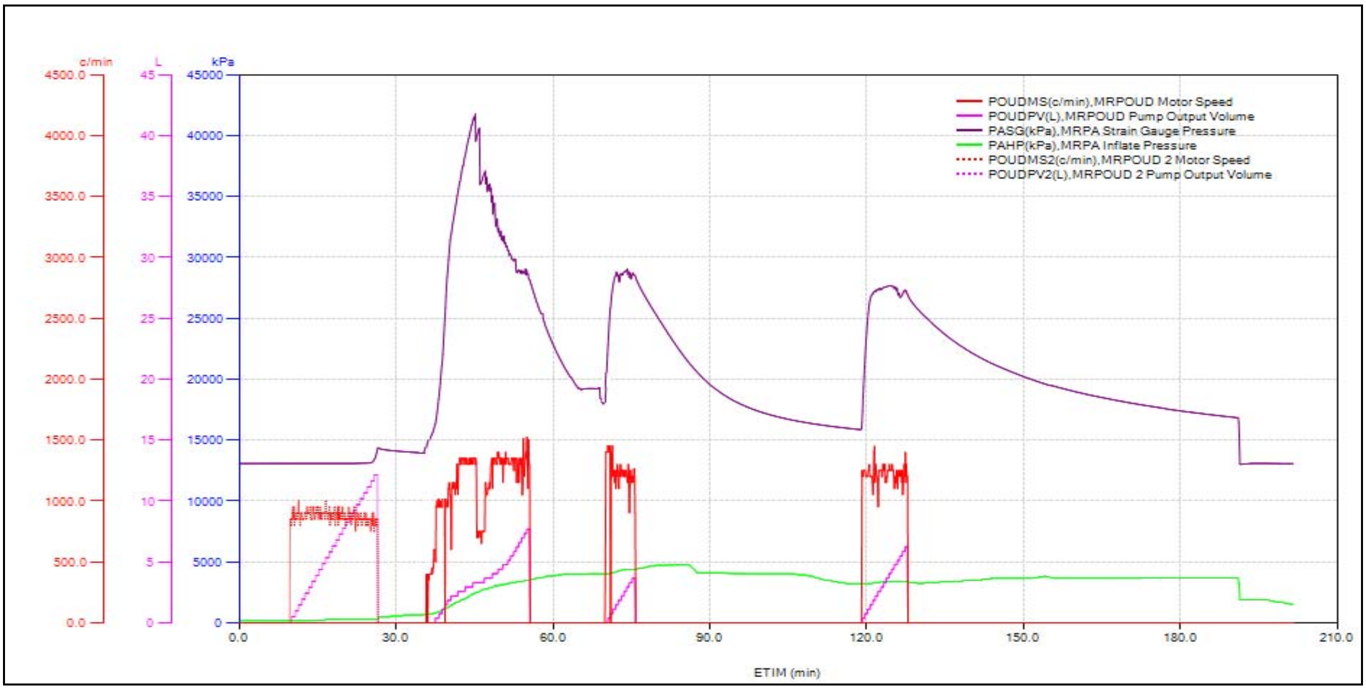

Figure 9- shows the stress testing in high mobility sandstone formation in the Case 1. Figure 8 depicts the location of the test. The viscous fluid of 100 cp was carried downhole and injected into formation.

2. Stress Testing in a Shale Layer with Viscous Fluid

This example station is taken from the same well as in the Case 1. A shallower shale layer as in the figure 8 was tested for the cap rock integrity. Mud was injected in the first attempt but it was not possible to break the shale due its plastic behavior. The viscous fluid was injected to initiate the fracture and later stage mud and viscous fluid were used together. Figure 10 shows the stress testing station. The test time was 3.2 hrs. The changing slope just before initiating the fracture is also seen in this shale zone. This may be due to the plastic behavior of the shale layer.

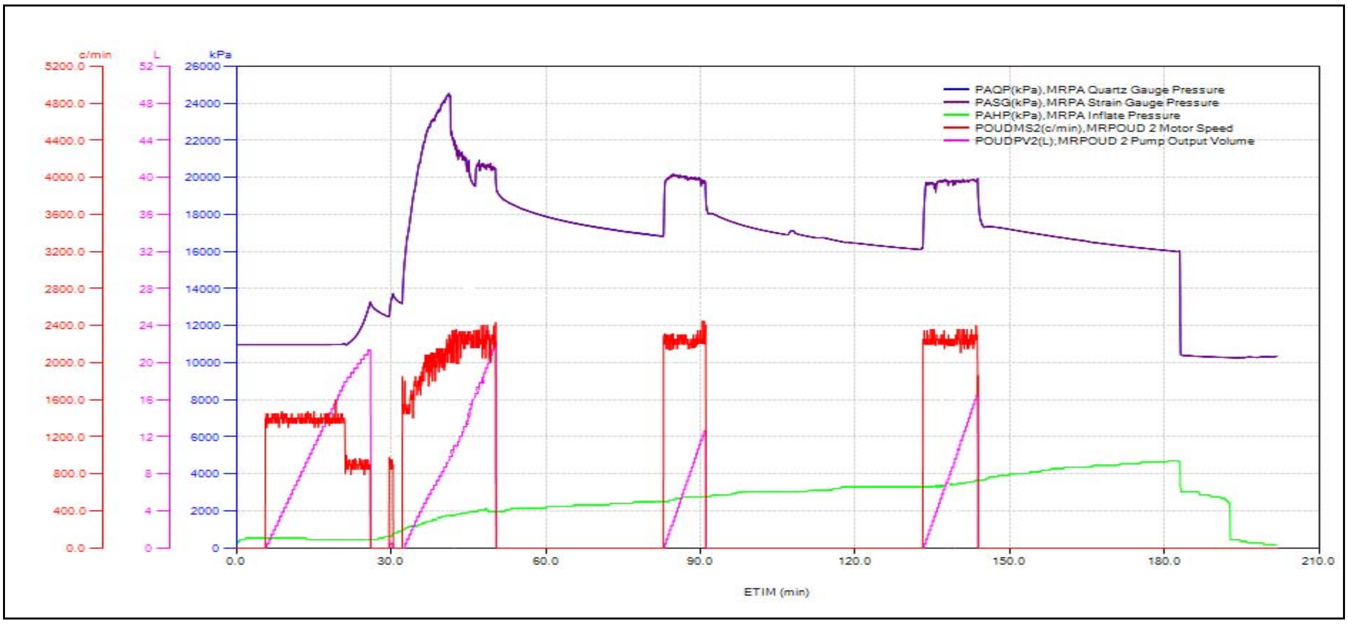

Figure 10- Stress testing in the shale layer in the Case 2. Figure 8 depicts the location of the test. The viscous fluid initiated the fracture in this station. The changing slope just before initiating the fracture is also seen in the shale zone. This may be due to viscous fluid compressibility and plastic behavior of the shale layer.

3. Stress Testing in a Shale Layer with Two Pumps

The objective of the test was to obtain stress magnitude in an exploration well. The vertical well was drilled with water based mud in 8.5 in. hole. First time in the Sultanate of Oman, two pumps were used simultaneously to achieve a stress testing. 20 liters of fluid was pumped with two pumps in 10 mins in each cycle, which is quite large amount of fluid in a short period of time for a wireline formation tester. The volume was required to overcome the plastic behavior of the shale (Fig. 11). The test time was 2.5 hrs. The pressure increase during the fracture initiation was very steep with a same slope due to the wellbore fluid injection.

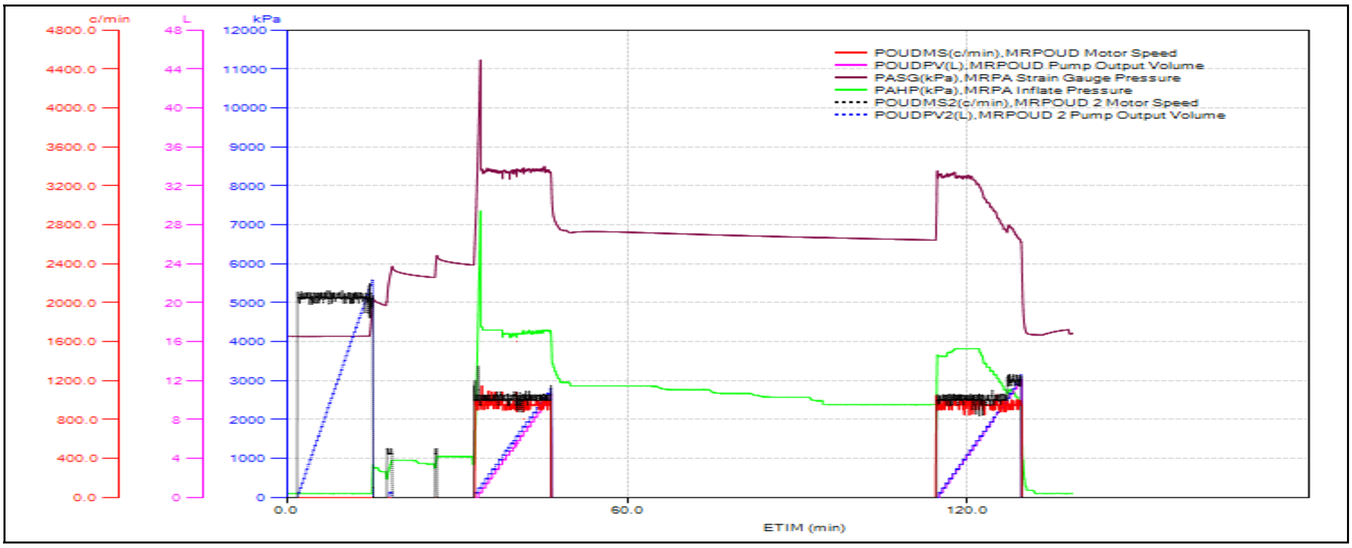

Figure 11- Stress testing was achieved with the usage of two synchronized pumps (Case 3). The pressure increase during the fracture initiation was very steep with a same slope due to wellbore fluid injection.

4. Stress Testing in a Tight Carbonate Formation with Sleeve Fracturing

The stress testing was conducted to understand the magnitude of the minimum stress and to improve the drilling practices in this part of the field. Breakouts are commonly observed in the wellbores in this field. This particular well having a maximum deviation of 15 Deg. was drilled in 6 in. hole with water based mud. The target formation was a tight carbonate gas reservoir. HP dual packers were utilized and the maximum temperature observed was 125 Deg.C. The mobility of the formation was 1.4 md/cp. The test was attempted at 3373.7 m. without a success. However, an excessive dual packer pressure was applied to the formation during the test. Therefore, there was a possibility of achieving a sleeve fracture.

Sleeve Fracturing occurs during the standard stress testing procedure, which initiates the fracture under one of the dual packer elements if the formation is nearly impermeable. This can also be achieved by pumping the fluid at a constant rate into one of the packer elements up to the maximum allowable inflatable pressure. The packer element itself initiates the fracture rather than the packer interval. In fact in this test station, the standard stress test failed prematurely. The packer then was deflated and the tool was positioned so that the dual packer interval was at the level of an expected fracture. Therefore the tool was moved to 3372.6 m. and the stress testing procedure was repeated with a success. Figure 12 shows the sleeve fracturing application. The plot on the right at 3372.6 m. shows no fracture initiation but a successful re-opening and closure cycles because the fracture was initiated by sleeve fracturing with the previous attempt.

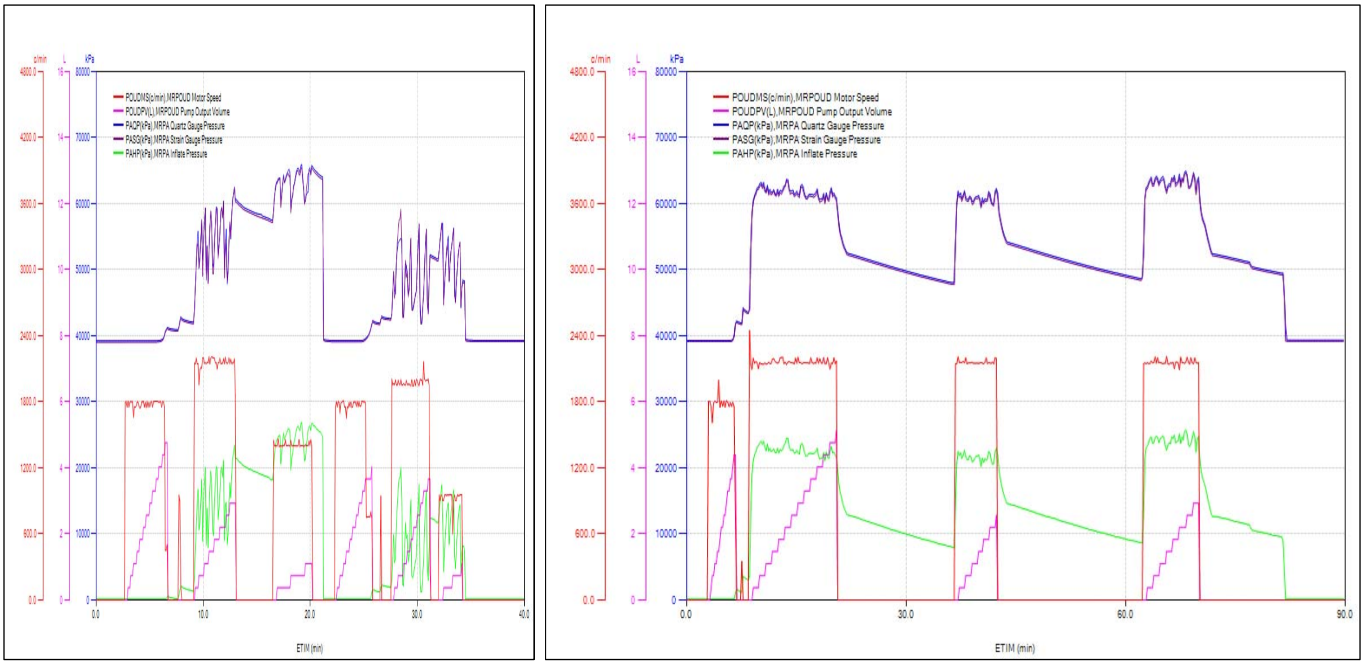

Figure 12- The plot on the left shows the failed stress testing attempt at 3373.7 m. However, the upper packer element achieved the sleeve fracturing as explained in the Case 4. The plot on the right shows the successful stress testing after the dual packer interval is positioned 1.1 m. higher at 3372.6 m. It does not show breakdown pressure since the fracture was initiated by sleeve fracturing previously.

5. Stress Testing with Rebound (Flowback) Pressure Technique in a Shale Formation

The stress testing objective is similar to Case 4 since the well in this example was drilled in the same field. The wellbore size is 6 in. with a maximum deviation of 45 Deg. The target formation is a tight carbonate gas reservoir. HP dual packers were utilized in this well. The maximum temperature observed was 127 Deg.C. The stress testing was conducted at 3125.5 m in a shale zone. The shale acts as a cap rock for the deeper, gas producing carbonate zones. Shale is practically impermeability at this depth. Fracture was initiated at 5870 psia above the hydrostatic pressure (Fig. 13). Breakdown pressure was 75150 kPa (10900 Psia). Hydrostatic pressure was 36540 kPa (5030 Psia). After the fracture initiation to re-confirm the fracture, the dual packer interval pressure was bled to hydrostatic pressure. Then the injection cycle was repeated. The injection cycle pressure did not increase higher than the propagation pressure. It showed a pressure reading similar to the propagation pressure in the fracture initiation cycle. This method confirmed the existence of the fracture by re-opening it. The repeated injection cycle needed a fall-off period to obtain the closure pressure. After nearly four hours of fall-off period, it had been clear that the pressure would not be reduced to the hydrostatic pressure for a classical interpretation. It was decided to use re-bound pressure technique. It required withdrawing the injected fluid very slowly from the open fracture with a flow control module. The flow control module, having a volume of 1 lt., can flow the fluid with very small rates and assist closing the fracture. This method provided the rebound pressure.

Rebound Pressure: When injection is stopped, the fluid can be withdrawn from the fracture to close it in the vicinity of the wellbore only. The rest of the fracture is still pressurized above the closure pressure and it is open. The fluid in the fracture flows back to the wellbore, resulting in a pressure to rebound. If a rebound pressure level is higher than the mud pressure, it is an indicator that a hydraulic fracture has certainly been created and it can help providing an estimation of minimum stress.

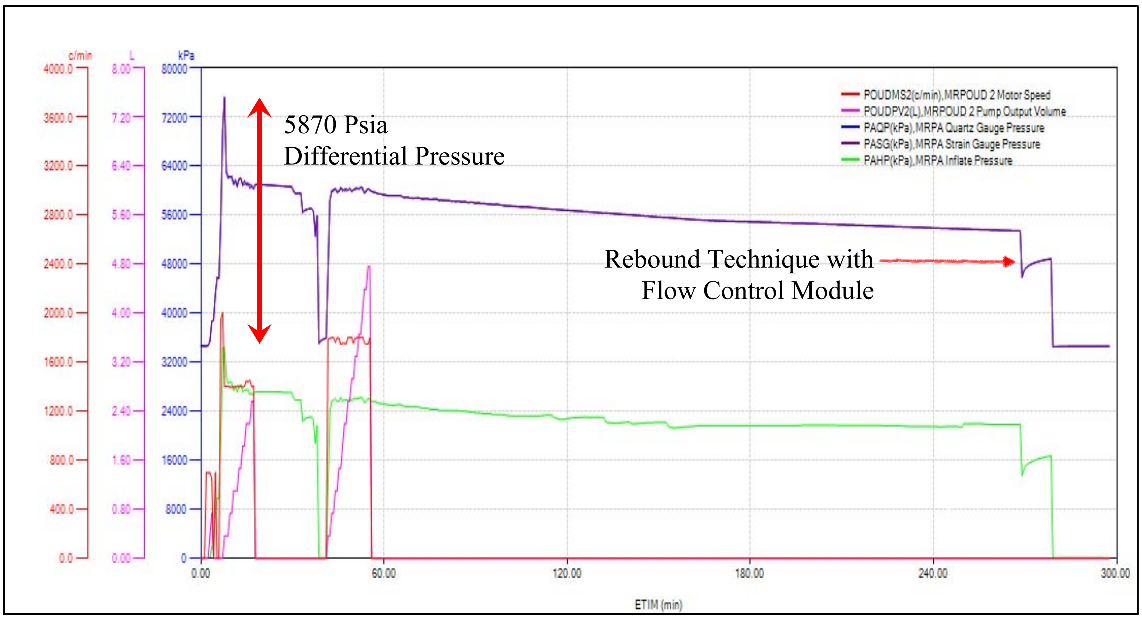

Figure 13- The stress testing in a shale formation in the Case 5. The rebound technique was used for the closure pressure estimation.

6. Stress Testing in a Horizontal Well

The objective of the stress testing application in this horizontal well was to obtain the minimum stress for a water injection design under matrix and controlled fracture conditions. The 6.125-in. horizontal well was drilled with water based mud in a carbonate formation. The geology of the reservoir shows a stratigraphic trap in a carbonate formation sealed by a shale layer above and by argillaceous limestone facies laterally. The horizontal wells in this field were drilled with Logging While Drilling (LWD) to target the carbonate structures in several branches. Some of the horizontal branches will be later converted into water injectors. The wireline tester tool is designed for pressures, sampling, interference testing and stress testing in the same drill-pipe-conveyed run. Figure 14 depicts the horizontal well stress testing in a carbonate formation. This particular station was completed in 2 hrs.

The principle stresses may not be parallel or orthogonal to the borehole axis in a horizontal well. The stress will be dependent on all three far field stress components. Moreover, the angle between minimum stress and the horizontal wellbore is subjected to the changing wellbore trajectory. When a fracture is created, it will open against the local minimum stress. The hydraulic fracture will not display itself as a planar feature and will typically be created with an angle to the borehole axis.

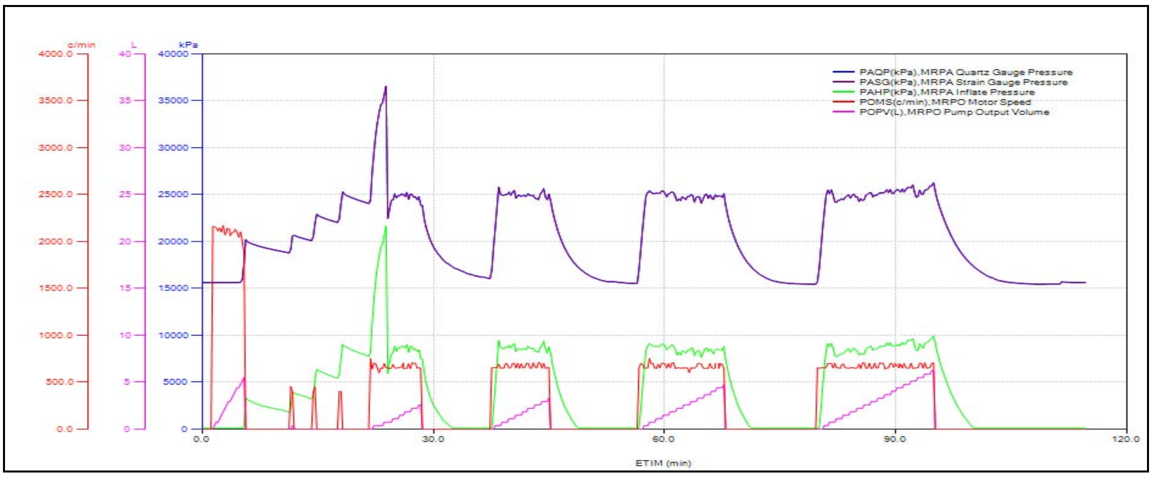

Figure 14- The horizontal well stress testing in the Case 6. The test was design to improve water flooding process in the field.

7. Stress Testing Calibration with Sonic Logs

The objective of the stress testing in this well was to optimize the water flooding operations in the depleted carbonate reservoir. The wellbore was drilled in 6.125 in. hole with water based mud. The maximum wellbore deviation was 11 Deg. The open hole and sonic logs were acquired prior to the stress testing. Figure 15 shows one of the stress tests conducted in the carbonate formation. Sonic measurements provide compressional, fast shear, slow shear, and stoneley wave slownesses in the formation. The geomechanical interpretation of the sonic logs in this particular well supplied continues curves of far field stress measurements. Figure 16 shows the results of the wireline formation tester pressures and stress tests and the geomechanical interpretation.

The Sonic log interpretation results can also assist choosing the stress test stations. Stresses are calculated with the open hole logs such as density, porosity and Gamma-Ray and saturation curves and sonic logs such as compressional and shear wave slownesses. Young's Modulus, Poisson's Ratio, Shear Modulus, Bulk Modulus are calculated from the mechanical earth model. Then UCS, minimum and maximum stresses are further calculated from the formulas. The magnitude difference should be noted between the stress tests and the uncalibrated stress curves in Figure 16. The stress testing results will assist re-calibrating the stress curves with parameter changes in the geomechanical interpretation (Plumb *et al.* 2000, Russell *et al.* 2006).

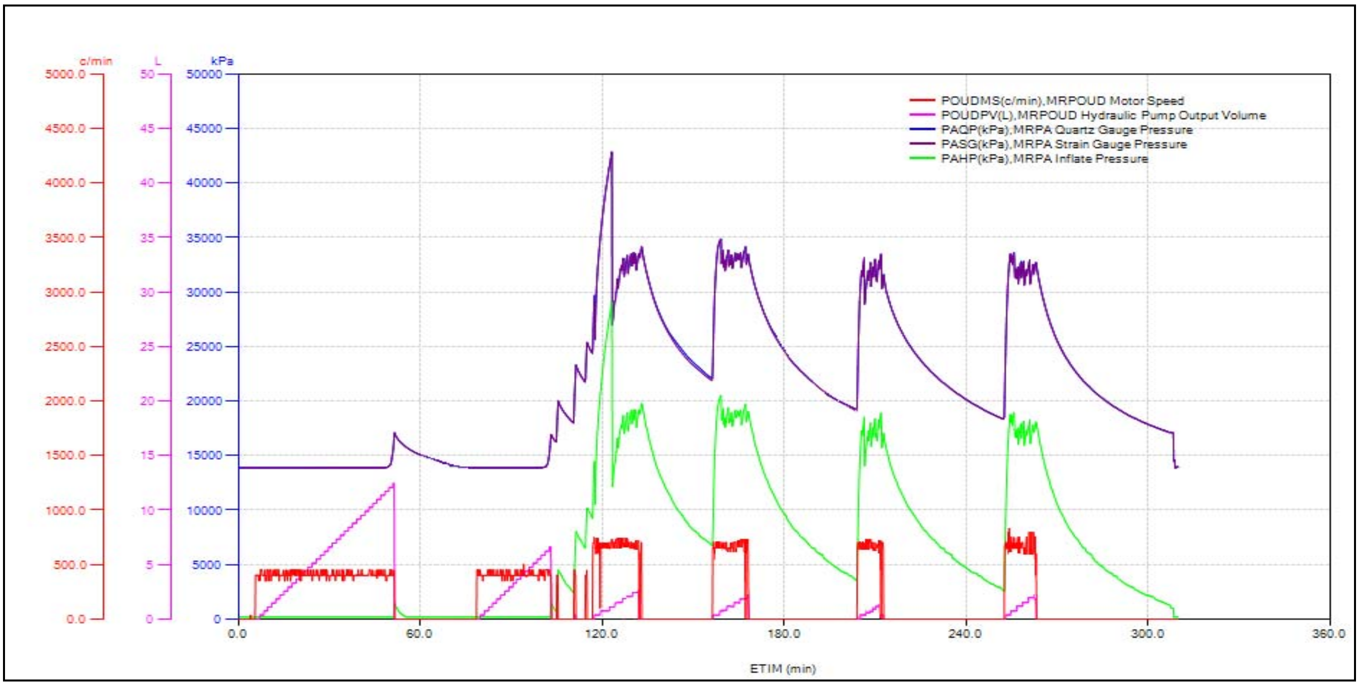

Figure 15- shows one of the stress testing stations in a carbonate formation in the Case 7. Stress testing interpretations were conducted for individual stations. This test was one of the stress tests used for calibrating sonic log interpretation results.

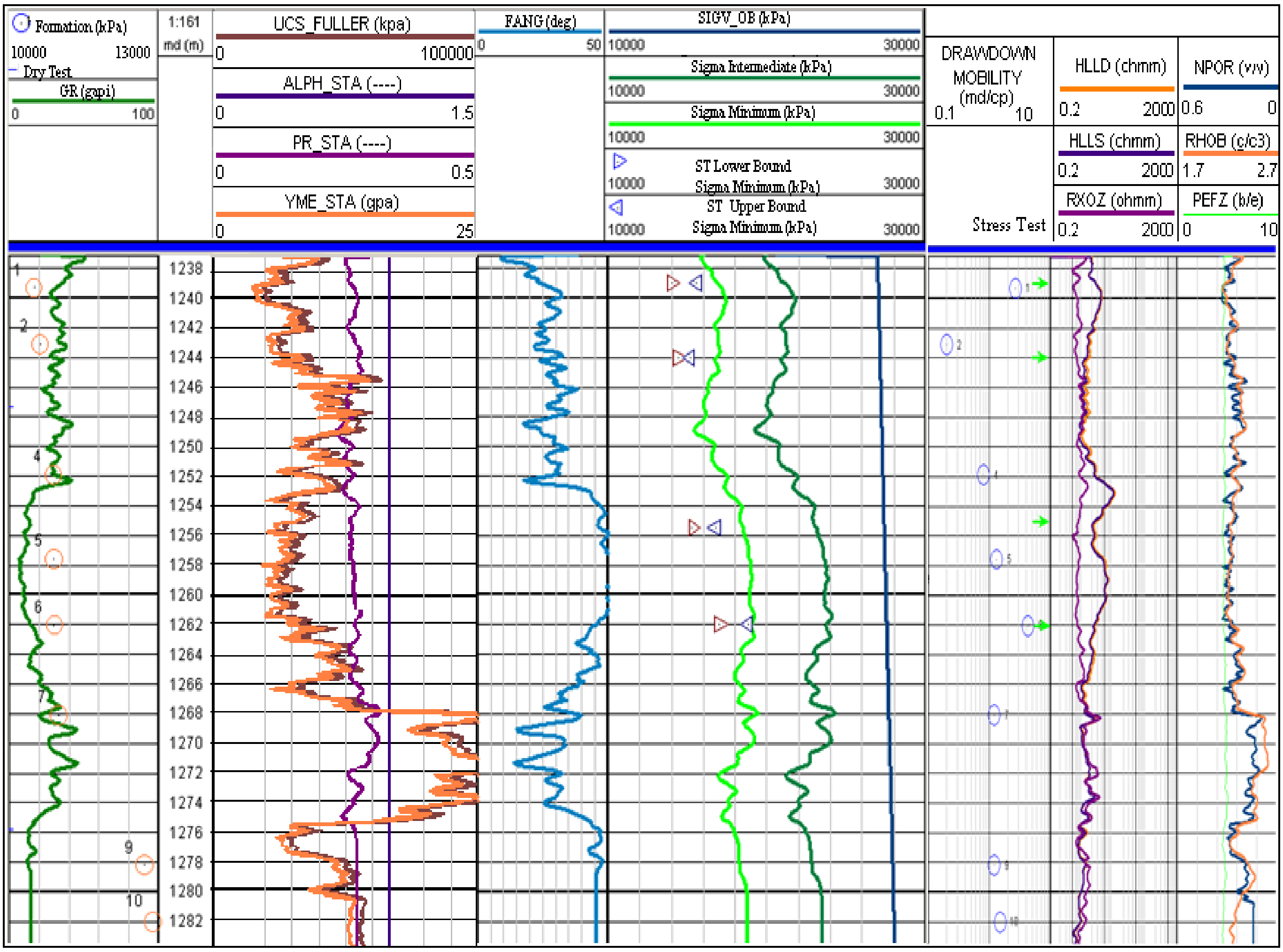

Figure 16- shows stress testing results with the uncalibrated geomechanical interpretation in the Case 7. The sonic log interpretation requires a calibration with stress test results to obtain accurate curves of stress values. In the above figure, GR is Gamma Ray, Formation is Formation Pressure, UCS_FULLER is unconfined compressive strength, ALP_STA is 1 as a constant, PR_STA is Poisson's Ratio Static, YME_STA is Young's Modulus Static, FANG is Fraction Angle, SIGV_OB is Sigma Vertical (Overburden Pressure), HLLD, HLLS are Laterolog Deep and Shallow Resistivities respectively, RXOZ is Invaded Zone Resistivity, NPHI is Formation Porosity, RHOB is Formation Density, PEFZ is Formation Photoelectric Factor.

Conclusions

The wireline conveyed in-situ reservoir stress testing measurements are frequently performed in the Sultanate of Oman to meet an extensive range of business requirements in a wide variety of sedimentary formations. The success rate has increased from 30% (when we started providing this service) to 60% today. The major factors for this increasing success rate are:

1. The continuous efforts in understanding where the tool limitations reside and react to them by generating solutions to overcome these limitations
2. Overall good communication between the service provider and the study and asset teams in order to have clarity of the test objectives on case by case basis. This includes a pre-job planning to decide on the measurement depths (based on all available other data), the pressures and rates.
3. The real-time decision making of a witnessing technologist
4. Valuable feedback session to assess the success or not of the test

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Saturn

Fluid flow and pressure measurement where not previously possible

Applications
- Formation fluid sampling
- Downhole fluid analysis (DFA)
- Formation pressure measurement
- Fluid-gradient determination
- Far-field permeability measurement and anisotropy determination
- Well testing design optimization

Benefits
- Fluid sampling and DFA for
  - Low-permeability formations
  - Heavy oil
  - Fluids with a bubble- or dewpoint near reservoir pressure
  - Unconsolidated formations
  - Rugose boreholes
- Low-permeability formation pressure testing
- Interval pressure transient testing (IPTT) with reduced storage for fast flow-regime identification

Features

- Combinable with all MDT* modular formation dynamics tester modules
- High-temperature rated to 350 degF
- 8,000-psi differential pressure rating between flowline and hydrostatic pressure
- Low storage effect
- No sump, eliminating fluids mixing with stationary mud
- Four field-replaceable, elliptical suction probes
- 79.44-in^2 total surface flow area
- Individual probe filters to prevent flowline plugging
- Self-sealing drain assembly for excellent seal maintenance during sampling in any quality of borehole

The keys to fluid acquisition and pressure pretests

A revolution in sampling and pressure-testing technology

The self-sealing Saturn* 3D radial probe enables true 3D circumferential flow in the formation around the borehole, significantly reducing the time needed to obtain representative formation fluids and extend fluid sampling and downhole fluid analysis (DFA) to what were previously challenging environments:

- low-permeability formations
- heavy oil
- near-critical fluids
- unconsolidated formations
- rugose boreholes.

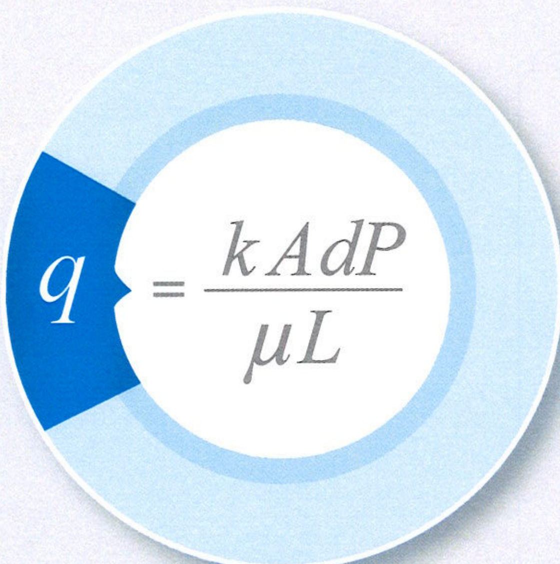
The low storage volume of the Saturn design not only facilitates fluid sampling and DFA but also the efficient performance of complete pressure surveys in extremely low-permeability formations.

Surface area open to flow and pressure drawdown

Successful wireline fluid sampling and DFA begin with accessing a representative sample of the virgin reservoir fluid, ideally in a minimum amount of time. Formation pressure testing similarly requires fluid withdrawal.

The fluid extraction is typically conducted with a probe module that includes a packer, telescoping backup pistons, and a flowline.

The pistons extend the probe and packer assembly against the borehole wall to provide a sealed fluid path from the reservoir to the flowline. The governing principle behind flowing any fluid from a reservoir for formation testing is Darcy's law, in which flow (q) is a function of permeability (k), drawdown pressure (dp), surface area open to flow (A), fluid viscosity (μ), and the length (L) over which the drawdown is applied.

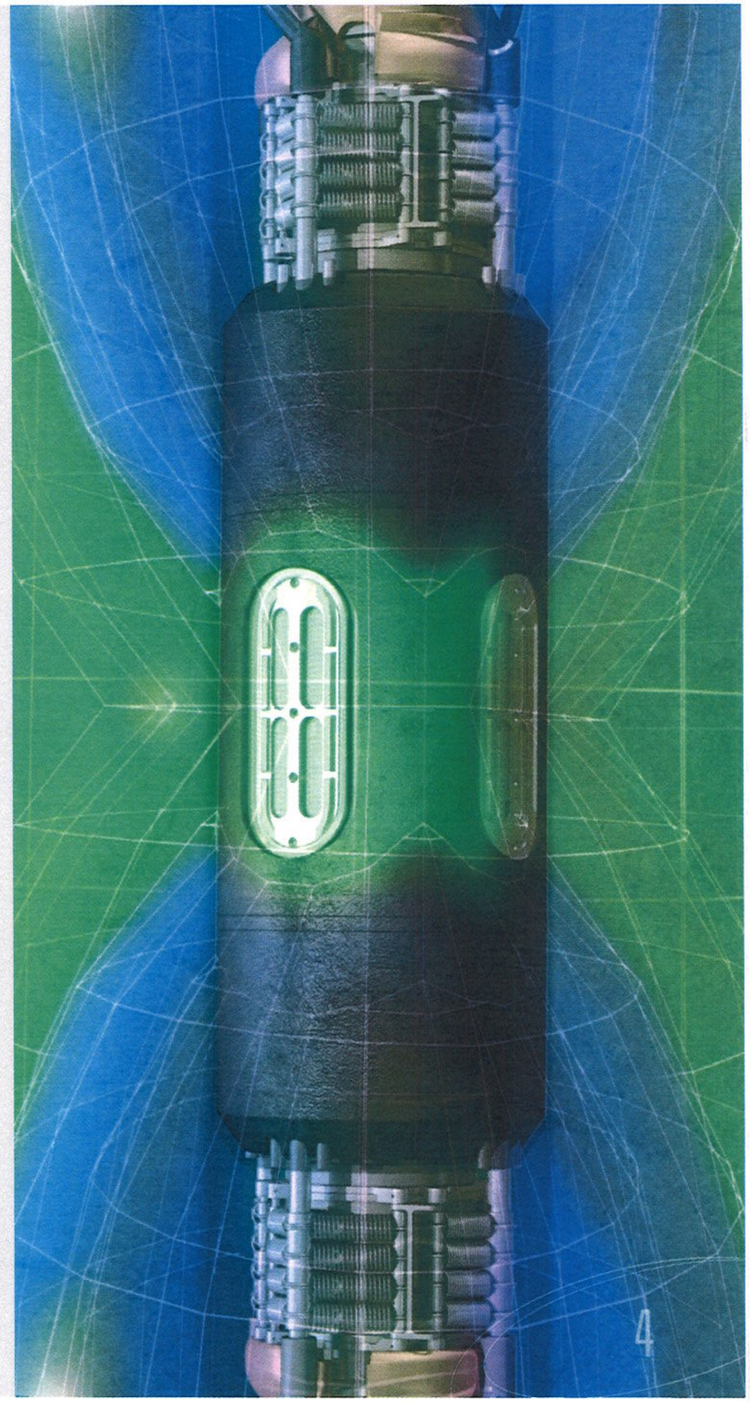


Flow from the formation to a conventional formation tester is narrowed to the intake of the single probe, not from the entire circumference of the borehole wall.

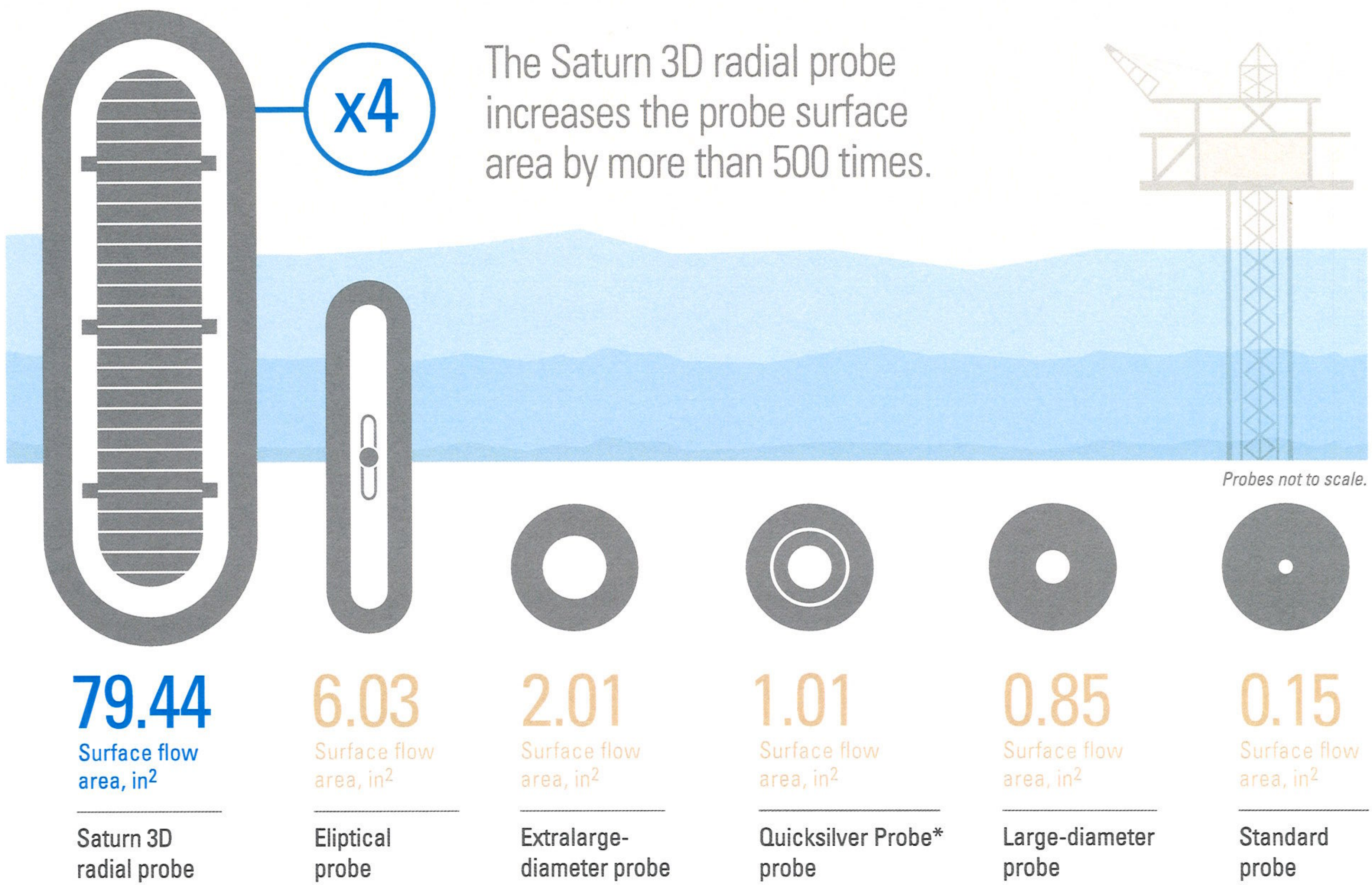
Different probe surface flow areas and the maximum pressure drawdowns that the formation tester can manage are used depending on the formation permeability and fluid viscosity. Typically, the larger the surface area and the higher the maximum drawdown pressure, the higher the flow rate of fluid from the formation that can be achieved for a formation testing operation.

Over the years, Schlumberger innovation has increased the maximum allowable differential pressure from 4,596 psi with the standard pumpout displacement unit to 11,760 psi with the high-pressure displacement unit. Concurrently, the available surface area of the probes has increased by nearly 40 times, from the standard probe's 0.15 in^2 to the 6.03-in^2 elliptical probe. This technical progression enables successfully performing formation testing in a wider range of environments. However, as operators attempt to tap into hydrocarbons previously thought to be unproducible—low-permeability or unconsolidated reservoirs, high-viscosity formation fluids—or where reduced drawdown is necessary to test reservoirs in which the saturation pressure of the fluid is close to the reservoir pressure, formation testing is technologically challenged.

The **Saturn 3D radial probe** meets these challenges with a radical redesign of the fluid-extraction module to deploy multiple self-sealing probes around the borehole. With a total surface flow area of 79.44 in^2, Saturn technology expands the operating envelope of formation testing for both fluid flow and reservoir environments.



The self-sealing drain assembly incorporating the four Saturn probes circumferentially extracts fluid from the formation instead localizing flow at a single probe.



x4
The Saturn 3D radial probe increases the probe surface area by more than 500 times.
Probes not to scale.
79.44
Surface flow area, in²
Saturn 3D radial probe
6.03
Surface flow area, in²
Eliptical probe
2.01
Surface flow area, in²
Extralarge-diameter probe
1.01
Surface flow area, in²
Quicksilver Probe* probe
0.85
Surface flow area, in²
Large-diameter probe
0.15
Surface flow area, in²
Standard probe

Flow certainty for understanding your heavy oil and low-permeability reservoir

The 79.44 in^2 of surface flow area of the Saturn 3D radial probe makes it easy to extract heavy oils for conducting DFA, sampling, and pressure testing. Having brought uncontaminated oil with a relative density as low as 7.5 API to the surface, the Saturn probe significantly expands the operating envelope of sampling and determining mobility for viscous fluids.

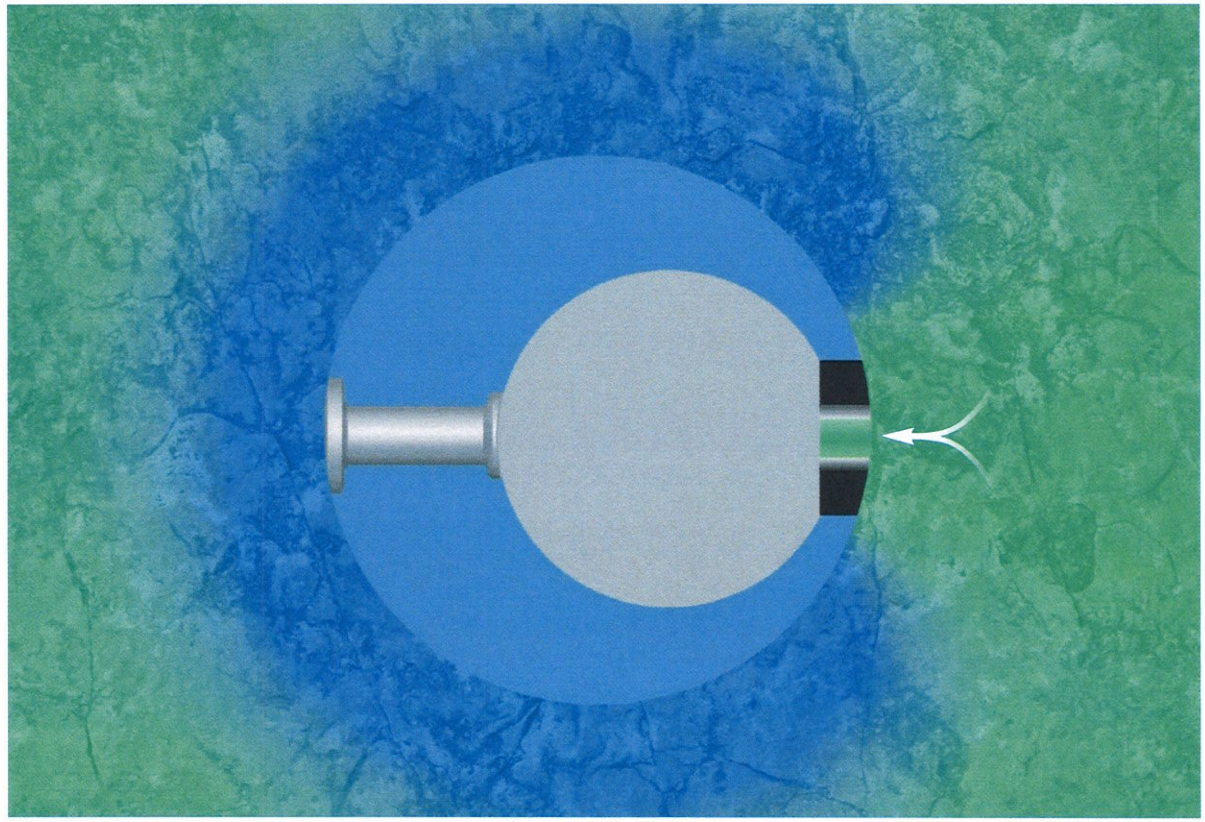
Reliably out of the hole, every time

Sixty-four individual heavy-duty springs mounted around the edges of the Saturn assembly and two large-diameter heavy-duty springs around the mandrel ensure reliable, consistent retraction of the elliptical suction probes after every station. The large cumulative closing force of the mechanical spring system keeps operational risk to a bare minimum.

The mechanical retract mechanism of the Saturn 3D radial probe employs heavy-duty springs to secure the probes when not deployed.

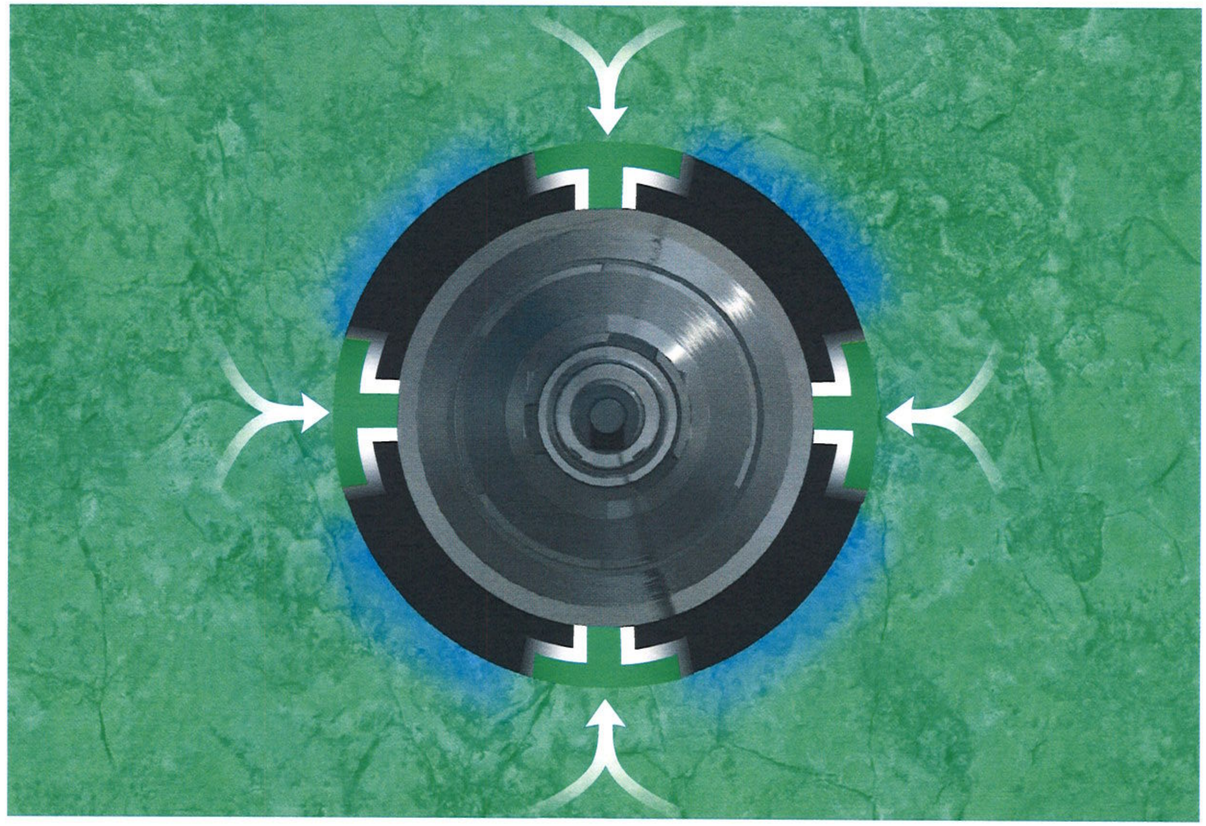
Flow fluid in three dimensions

The Saturn 3D radial probe comprises four elliptical-shaped suction probes, distributed at 90° intervals around the circumference of the tool. This placement pulls fluid circumferentially from around the borehole, instead of the conventional probe arrangement of one port as the sole fluid access point. Each of the four Saturn probes has a surface flow area of 19.86 in^2, which is more than 2 times larger than the surface area of the largest conventional probe. Together, the four Saturn probes total 79.44 in^2 of surface flow area, an increase of more than 500 times over the area of the standard conventional probe.



Flow from the formation to a conventional formation tester is narrowed to the intake of the single probe, not from the entire circumference of the borehole wall.

Circumferential flow around the wellbore has significant benefits for both sampling cleanup and interval pressure transient testing (IPTT). The Saturn 3D radial probe quickly removes the filtrate from the entire circumference of the wellbore to draw in uncontaminated formation fluid. In addition, the significantly larger flow area of the 3D radial probe can induce and sustain flow in low-mobility formations, formations in which the matrix is uncemented, and the viscous fluid content of heavy oil reservoirs.



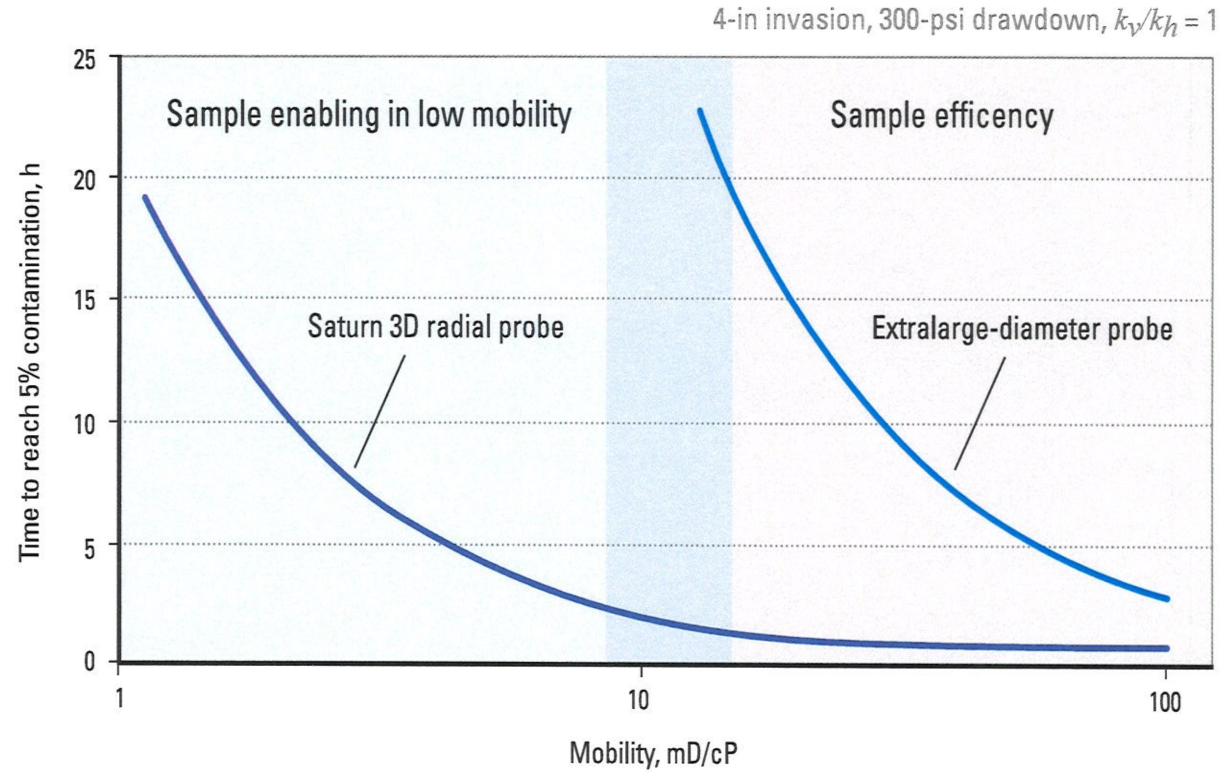
The four Saturn probes efficiently establish circumferential flow from the formation to quickly remove filtrate-contaminated fluid and flow uncontaminated, representative fluid for DFA, sampling, and pressure measurements.

Sealing with confidence

Unlike the packer incorporated in a conventional probe assembly or operations using a dual straddle packer in the testing string, the Saturn probes self-seal with suction to the borehole wall to receive direct flow from the formation with faster cleanup.

Direct rig-time savings in low-permeability formations

As the permeability of a formation decreases, the performance improvement of the Saturn 3D radial probe over conventional probes widens significantly. As shown in comparison with the extralarge-diameter probe for achieving 5% contamination, the Saturn 3D radial probe improves sampling efficiency beginning at formation mobilities of 500 mD/cP, with the performance gap greatly expanding as the mobility decreases. Once mobility approaches 10 mD/cP, the extralarge-diameter probe cannot move the formation fluid, whereas the Saturn 3D radial probe is an enabling technology.



Modeled cleanup times for the Saturn 3D radial probe and a conventional extralarge-diameter probe show the increase in sampling efficiency possible. The Saturn 3D radial probe is an enabling technology for sampling at mobilities less than 10 mD/cP, at which the conventional probe cannot perform.

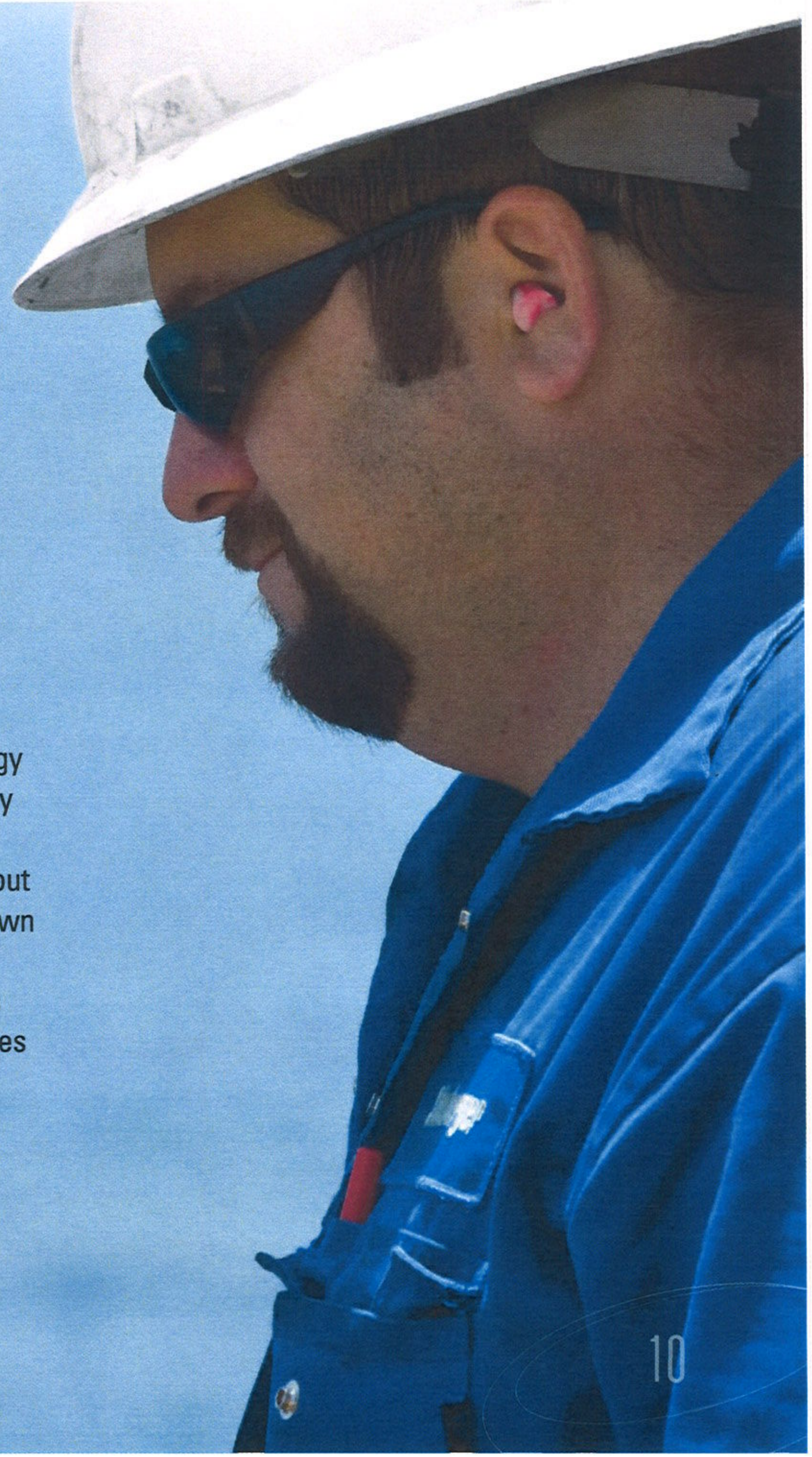
Complete pressure surveys in low-mobility formations

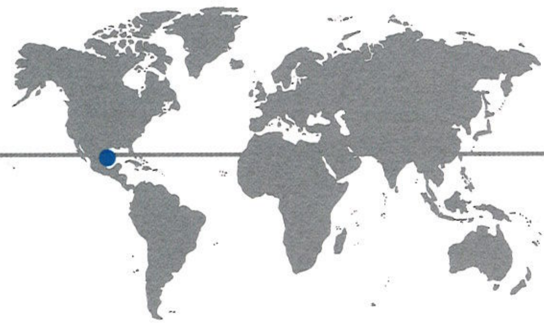
The technology that makes the Saturn 3D radial probe excel at fluid extraction also delivers a step change in formation pressure testing. Conventional formation tester probes with the largest surface flow area currently available are limited to pressure testing formations with mobilities no lower than about 1 mD/cP. Pretesting-only service is the current benchmark for excellent performance in low-permeability formations, but the mobility limit for pressure tests is about 0.1 mD/cP.

The Saturn 3D radial probe, with 79.44 in^2 of surface flow area, can perform pressure tests at mobilities as low as 0.01 mD/cP. In addition to its unprecedented pressure-testing capability in very tight formations, the Saturn 3D radial probe has proved far less susceptible to supercharging. Conducted with the MDT Pumpout Module, Saturn pressure tests produce significantly more fluid than during a conventional probe test.

Circumferential support for unconsolidated formations

The circumferential self-sealing technology of the Saturn 3D radial probe mechanically supports the borehole with the compliant rubber seal of its drain assembly throughout the sampling operation. Pressure drawdown is localized to the four elliptical suction probes, which minimizes the matrix stress while flowing fluid. If any matrix disengages while flowing fluid, the Saturn 3D radial probe is equipped with sandface filtering mechanisms on each of the probes to prevent plugging of the system.





Saturn probe retrieves uncontaminated 7.5-API oil from friable sandstone

Accurate fluid description and determination of pressure differentials were needed to guide well placement and completion in an onshore Mexico field to avoid the development of preferential flow along higher-mobility intervals. However, the combination of a poorly consolidated formation, with unconfined compressive strength (UCS) values ranging from 100 to 800 psi, and high-viscosity fluid content meant that the pressure differential generated by conventional formation testing inevitably caused collapse of the wellbore wall and failure of the seal or sanding out of the tool.

The operator had to resort to temporarily perforating, completing, and flowing each sand separately to collect samples in coiled tubing–deployed bottles on a DST string. The complicated logistics and high costs of this approach were not sustainable.

Unlike single-probe conventional formation testers, the Saturn 3D radial probe is ideal for flowing fluid in these challenging conditions of an unconsolidated reservoir with low mobility. The four self-sealing elliptical probes, with the industry's largest surface flow area of more than 79 in^2, quickly establish and maintain flow from the entire circumference of the wellbore instead of funneling fluid from the reservoir to a single access point. The result is quicker cleanup and the efficient performance of pressure measurements.

In unconsolidated formations, the compliant rubber surface of the Saturn drain assembly mechanically supports the borehole throughout the sampling operation. Pressure drawdown is localized to the four elliptical probes, which minimizes matrix stress while fluid is flowing.

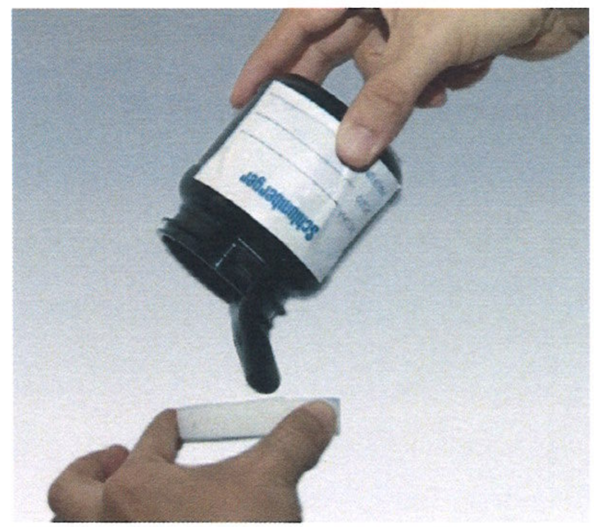
Each self-sealing Saturn probe incorporates a filter to capture any dislodged matrix and prevent plugging.

If sand grains were drawn in with the flowing fluid, the Saturn drain assembly incorporates individual probe filters to prevent flowline plugging.

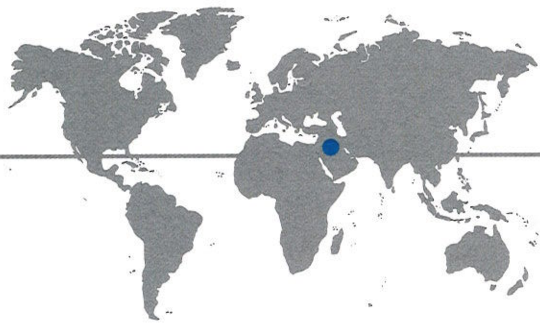
The Saturn 3D radial probe was deployed in the field to test and sample at multiple stations in several wells, which have up to 12% ovalization. Whereas conventional probes commonly experienced lost seals in the rugose holes, the Saturn self-sealing probes maintained seal integrity to support the borehole in the unconsolidated sandstone reservoirs. There was no evidence of sand grains reaching the pumps.

Full pressure surveys were conducted in both water- and oil-base mud environments with only minor storage effects observed in the pressure responses. The pressure surveys in combination with the mobilities determined from every pretest are being used to design completions that will evenly distribute injected steam among designated intervals and avoid channeling.

Fluid sampling successfully captured an uncontaminated sample of 7.5-API oil; subsequent laboratory analysis reported a viscosity of approximately 1,030 cP at downhole conditions. Being able to use the Saturn 3D radial probe to collect what were previously unobtainable high-quality samples and pressure data is providing a wealth of information for the operator.



The Saturn 3D radial probe collected an uncontaminated sample of 7.5-API oil from an unconsolidated sandstone reservoir without sanding or seal failure.



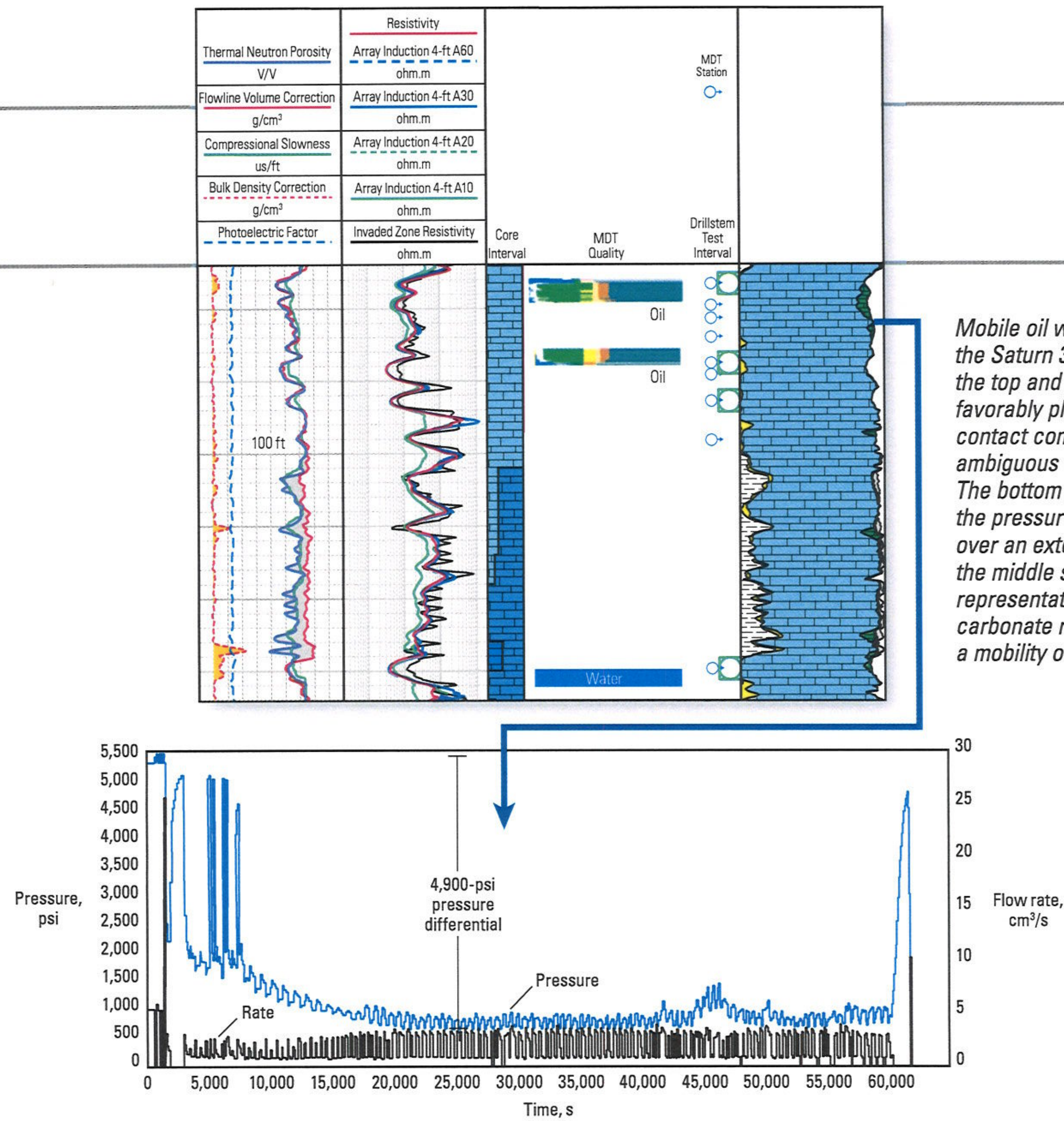
Saturn probe delineates low-mobility oil zone in carbonate reservoir

The extent of the oil zone in a tight carbonate reservoir in a Middle East field was not clear. Openhole logs strongly indicated that the top of the formation was oil bearing and the bottom was water-wet, but the fluid contents of the middle zone were ambiguous. The middle zone had a lower resistivity response that was similar to that in the underlying water zone. The location of the oil/water contact could not be determined from the logs alone, and conventional formation tester probes would not be able to acquire fluid samples from the tight formation.

By establishing true 3D circumferential flow around the borehole in the low-permeability formation, the Saturn 3D radial probe successfully collected samples from the top, middle, and bottom of the carbonate reservoir.

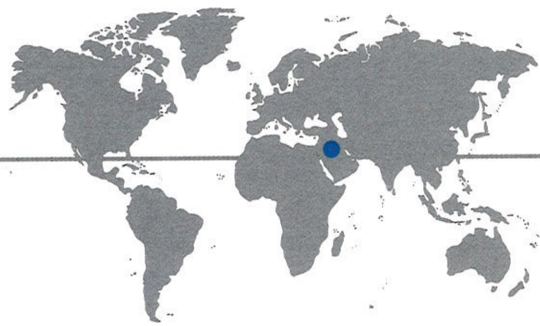
Extensive pumpout by the Saturn probe confirmed light oil in the top zone through DFA. A radial flow regime was established with an estimated horizontal permeability of approximately 1 mD. The station in the bottom zone yielded water and had a similar permeability.

DFA then identified mobile light oil in the middle of the reservoir, and the operator was able to determine the thickness of the oil zone with confidence. Pumpout for the middle station was achieved with a 4,900-psi pressure differential for 15 h, resulting in a mobility determination of 0.04 mD/cP.



Mobile oil was acquired by the Saturn 3D radial probe at the top and middle stations to favorably place the oil/water contact compared with the ambiguous low-resistivity logs. The bottom pressure plot shows the pressure differential applied over an extensive pumpout at the middle station to retrieve representative oil from the carbonate reservoir, with a mobility of 0.04 mD/cP.

Case Study

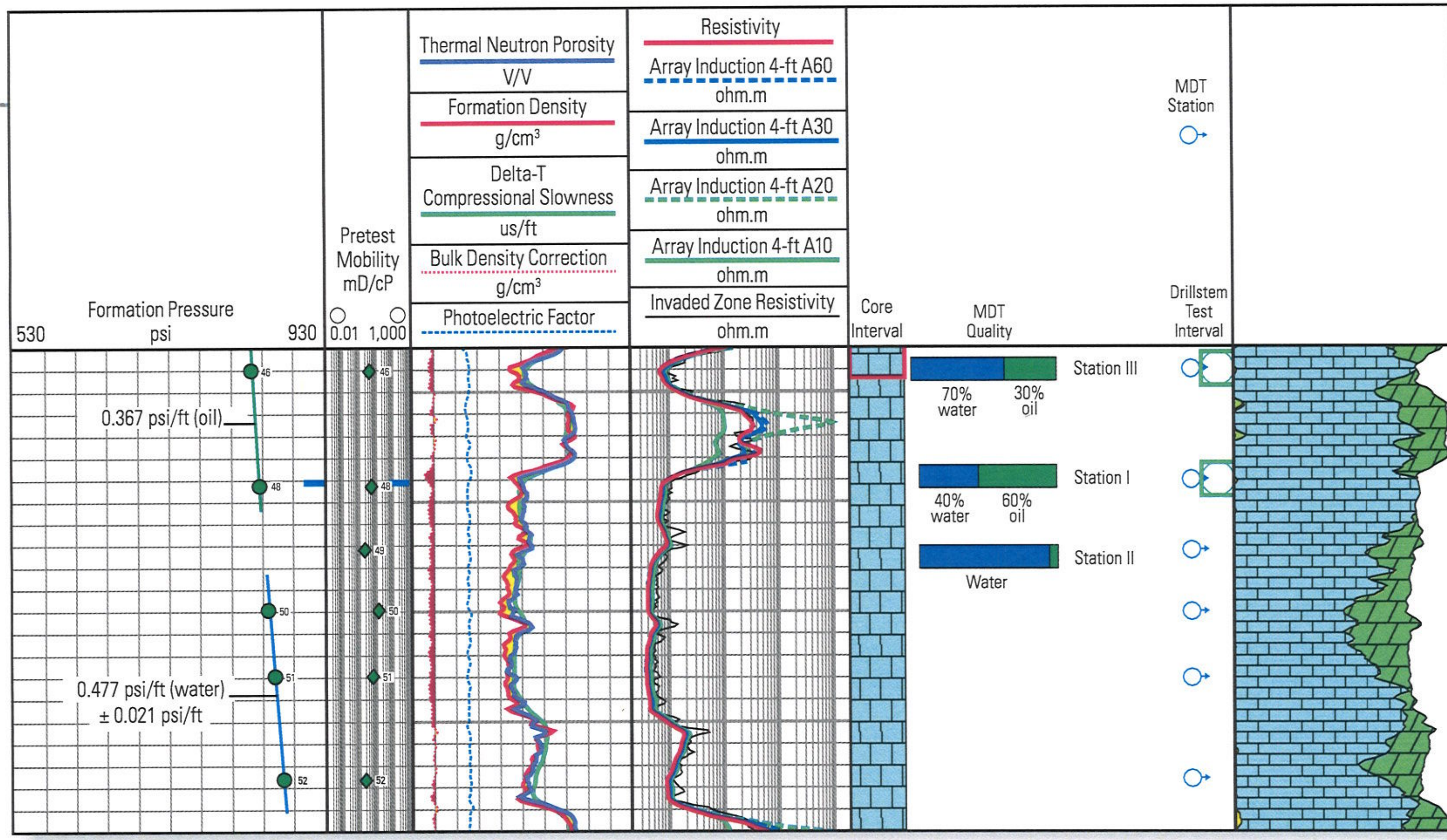


650% faster flow rate efficiently acquires fluids from dolomite

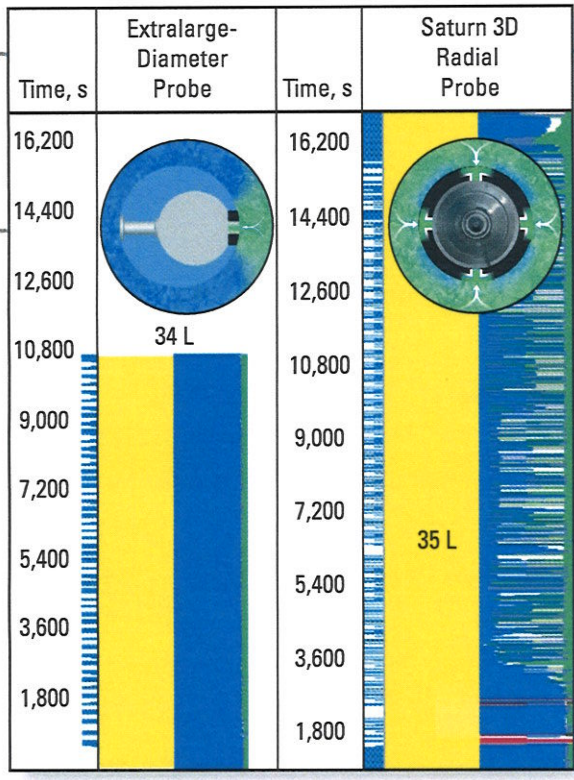
The openhole logs from a dolomitic limestone interval drilled with saline water-base mud in the Middle East did not indicate the presence of hydrocarbon, but the analysis was ambiguous because some zones had resistivity values as low as 0.7 ohm.m. The operator wanted to conduct DFA and collect samples to resolve the identity of the reservoir fluids, but the time allowed at each sampling station was limited to 4 h in consideration of mud losses during the job.

Schlumberger deployed an advanced wireline formation tester toolstring that included both the Saturn 3D radial probe and an extralarge-diameter conventional probe to acquire fluid at multiple stations in a single trip.

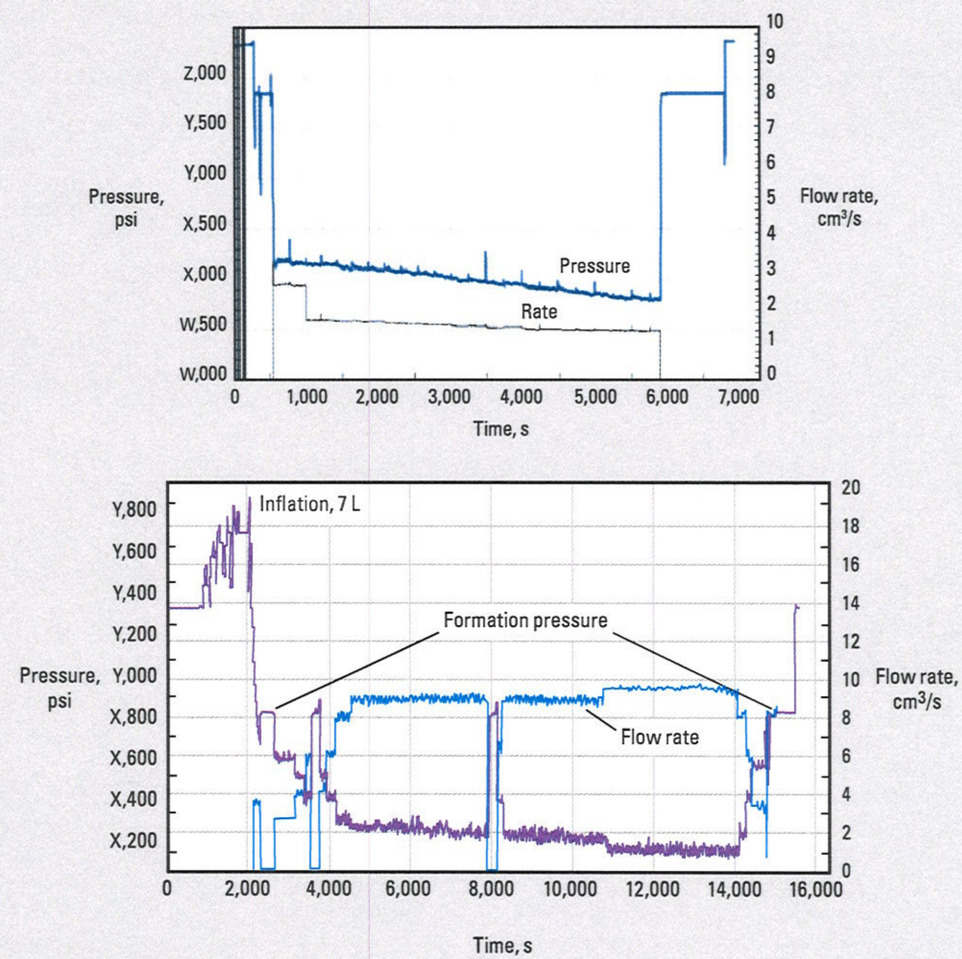
After DFA at Station I clearly identified 60%–70% oil, Station II was selected for determining the lowest mobile oil. The initial sampling attempt with the extralarge-diameter probe experienced a significant pressure drop, with 2,000-psi drawdown and a low flow rate of 5.2 L/h. The resulting pretest mobility was 1.5 mD/cP. After 1.5 h of pumping out, flow was switched to the Saturn 3D radial probe, and the rate increased 650% with only 680-psi drawdown. The performance of the Saturn 3D radial probe for the ratio of rate to pressure drop was a 19-times improvement over that of the extralarge-diameter probe for the 1.5-mD/cP mobility. Flowline resistivity stabilization was achieved with water identification at Station II within the 4-h limit for the well, and the water collected in the sample bottle confirmed the DFA results.



The extralarge-diameter probe was able to collect reservoir fluid at Station I, but after 1.5 h of pumping out at Station II, flow was switched to the Saturn 3D radial probe, which increased the flow rate by 650%.



No oil was observed by the optical analyzers for the 34 L of fluid extracted at Station II by the extralarge-diameter probe (left) at a large drawdown and low rate. Once flow was switched to the Saturn 3D radial probe (right), cleanup was achieved at a rate that was about 3.5 times faster. The insets show how the fluid flow in the reservoir is to a single point for the conventional probe but circumferentially for the four self-sealing Saturn probes.



Comparison of pressure and rate of the extralarge-diameter probe (left) and Saturn 3D radial probe (right) at Station II shows that the Saturn probe increased the flow rate 650% with only 680-psi drawdown, which is one-third of the conventional single probe's drawdown. The resulting ratio of rate to pressure drop delivered an improvement of 19 times over the single probe's performance.

Specifications	
	Saturn 3D Radial Probe
Measurement	
Output	Ultralow-contamination formation fluids, formation pressure, fluid mobility
Logging speed	Stationary
Mud type or weight limitations	None
Combinability	Fully integrates with MDT modular formation dynamics tester system and InSitu Family* sensors
Special applications	Low-permeability formations, heavy oil, near-critical fluids, unconsolidated formations, and rugose boreholes
Mechanical	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	7.875 in [20.00 cm]
Borehole size—max.	9.5 in [24.13 cm]
Max. hole ovality	20%
Outside diameter	Tool body: 4.75 in [12.06 cm] Drain assembly: 7 in [17.78 cm]
Length	5.7 ft [1.74 m] With Modular Reservoir Sonde and Electronics (MRSE): 12.4 ft [3.78 m]
Weight (in air)	385 lbm [175 kg] With MRSE: 585 lbm [265 kg]

Saturn

www.slb.com/saturn

Schlumberger

APPENDIX E

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Permit Item	NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit (section; see main body for reference cited)	Figure/Table Number and Description
Pore Space Amalgamation	NDCC 38-22-06 §3 & 4 NDAC 43-05-01-08 §1 & 2	**NDCC 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary. b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary. c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary. d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary. e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary.	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project.	Red Trail Energy (RTE) has identified the owners (surface and mineral); in addition, no mineral lessees or operators of mineral extraction activities are within the facility area or within one-half mile of its outside boundary. RTE will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to the North Dakota Industrial Commission (NDIC) to certify that these notifications were made.	
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project.	**1.0 PORE SPACE ACCESS** North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate, i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31-Subsurface Pore Space Policy). Prior to issuance of the Storage Facility Permit (SFP), the storage operator is mandated by North Dakota statute for geologic storage of carbon dioxide (CO_2) to obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir. The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are or will be equitably compensated. North Dakota law grants NDIC the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application (NDCC § 38-22-06(3) and -06(4) and North Dakota Administrative Code [NDAC] § 43-05-01-08(1) and -08(2)). In connection herewith, Red Trail Energy (RTE) submits the form of storage agreement attached hereto as Attachment 1, which, upon final approval by NDIC, shall govern certain rights and obligations of the storage operator and the persons owning pore space within the amalgamated storage reservoir. RTE has identified the owners (surface and mineral); in addition, no mineral lessees or operators of mineral extraction activities are within the facility area or within one-half mile of its outside boundary. RTE will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO_2 storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made. The identification of the owners, lessees, and operators that require notification was based on the following, recognizing that all surface owners also own the underlying pore space per North Dakota law, which vests the title to pore space in all strata underlying the surface of lands to the owner of the overlying surface estate (NDCC Chapter 47-31): • A map showing the extent of the pore space that will be occupied by CO_2 over the life of the project, including the storage reservoir boundary and 0.5 miles (0.8 kilometers) outside of the storage reservoir boundary with a description of pore space ownership, surface owner, and pore space lessees of record (Figure 1-1 and Figure 1-2). • A table identifying all pore space (surface) owners, each owner's mailing address, and a legal description of pore space landownership (Table 1-1). • A table identifying each owner of record of minerals and each mineral lessee of record (Table 1-2). Note: All surface owners and pore space owners and lessees are the same owner of record, and there are no operators of mineral extraction activities within the storage facility area.	Figure 1-1. Storage facility area map showing pore space ownership. Figure 1-2. Landowners hearing notification area.
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership.		Figure 1-1. Storage facility area map showing pore space ownership. Figure 1-2. Landowners hearing notification area.
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities.		Table 1-2 showing mineral ownership and lessees
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record.		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record.		Figure 1-1. Storage Facility area map showing pore space ownership. Figure 1-2. Landowners hearing notification area.
			g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification

<table>
<tr>
<td></td>
<td></td>
<td>f. Any other persons as required by the commission.

2. The notice given by the applicant must contain:

a. A legal description of the land within the facility area.

b. The date, time, and place that the commission will hold a hearing on the permit application.

c. A statement that a copy of the permit application and draft permit may be obtained from the commission.</td>
<td></td>
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<tr>
<td rowspan="2">Geologic Exhibits</td>
<td>NDAC 43-05-01-05 §1b(1) and §1b(2)(k)</td>
<td>NDAC 43-05-01-05 §1b(1) and §1b(2)(k)
(1) The name, description, and average depth of the storage reservoirs.
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;</td>
<td>a. Geologic description of the storage reservoir:
Name
Lithology
Average depth
Average thickness</td>
<td>2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2).

At RTE-10, the Broom Creek Formation is made up of 201 ft of sandstone and 97 ft of dolostone and is located at a depth of 6,379 ft. Across the project area, the Broom Creek Formation varies in thickness from 210 to 406 ft (Figure 2-9), with an average thickness of 313 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the project area ranges from 48 to 324 ft, with an average of 192 ft.

For additional information, go to Section 2.3 of the RTE SFP.

Table 2-1. Formations Comprising the RTE CO_2 Storage Complex
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Average Thickness at RTE Site, ft</th><th>Average Depth at RTE Site, SSTVD ft</th><th>Lithology</th></tr>
<tr><td rowspan="3">Storage Complex</td><td>Opeche</td><td>Upper confining zone</td><td>103</td><td>3,871</td><td>Mudstone/siltstone</td></tr>
<tr><td>Broom Creek</td><td>Storage reservoir (i.e., injection zone)</td><td>313</td><td>3,974</td><td>Sandstone, dolomite</td></tr>
<tr><td>Amsden</td><td>Lower confining zone</td><td>329</td><td>4,285</td><td>Dolomite/shaly sand</td></tr>
</table></td>
<td>Table 2-1. Formations Comprising the RTE CO_2 Storage Complex</td>
</tr>
<tr>
<td>NDAC 43-05-01-05 §1b(2)(k)</td>
<td>NDAC 43-05-01-05 §1b(2)(k)
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions.</td>
<td>b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure</td>
<td>Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the RTE-10 Well
<table>
<tr><th colspan="2">Injection Zone Properties</th></tr>
<tr><th>Property</th><th>Description</th></tr>
<tr><td>Formation Name</td><td>Broom Creek</td></tr>
<tr><td>Lithology</td><td>Sandstone, dolomite</td></tr>
<tr><td>Formation Top Depth, ft</td><td>6,379</td></tr>
</table></td>
<td>Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the RTE-10 Well

Figure 2-8. Areal extent of the Broom Creek Formation in North Dakota

Figure 2-9. Isopach map of the Broom Creek Formation in the RTE project area.</td>
</tr>
</table>

			Facies changes	Thickness, ft: 298 (sandstone 201; dolomite 97) Capillary Entry Pressure (GW), psi: 1.1	Figure 2-10. Well log display of the interpreted lithologies of the lower Opeche, Broom Creek, and upper Amsden Formation in RTE-10. Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red); 2) delta time (purple) and 3) interpreted lithology log. Figure 2-11b. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (purple). Figure 2-12. Structure map of the Broom Creek Formation across the greater RTE project area. Figure 2-13. Cross section of the RTE CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced to mean sea level. Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the RTE CO_2 storage complex. Figure 2.15 Laboratory-derived mineralogical characteristics of the Broom Creek Formation. Figure 2-16. XRF data from the Broom Creek from RTE-10. Figure 2-17. Upper graph shows cumulative injection vs. time. The two cases overlay each other. Lower graph shows wellhead injection pressure for the two cases. There is no observable change in injection performance. Figure 2-18a. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality. Figure 2-18b. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine. The extent of the pH-affected area is slightly larger (~300 feet) than the extent of the CO_2 accumulation.

Thickness, ft	298 (sandstone 201; dolomite 97)		
Capillary Entry Pressure (GW), psi	1.1		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Broom Creek (sandstone)	Porosity, %	21.68 (12.18–33.65)*	25.26 (1.01 – 32.14)*
	Permeability, mD	419.1 (25.35–5,120)**	277.45 (20.20 – 2,483.64)**
Broom Creek (dolomite)	Porosity, %	6 (2.91–8.54)*	15.24 (1.01 – 32.14)*
	Permeability, mD	0.08 (0.004–1.12)**	8.65 (0.01–2,261.53)**

2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2).

At RTE-10, the Broom Creek Formation is made up of 201 ft of sandstone and 97 ft of dolostone and is located at a depth of 6379 ft. Across the project area, the Broom Creek Formation varies in thickness from 210 to 406 ft (Figure 2-9), with an average thickness of 313 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the project area ranges from 48 to 324 ft, with an average of 192 ft.

For additional information, go to Section 2.3 of the RTE SFP.

2.3.1 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation is dominated by fine- to medium-grained sandstone with lesser amounts of carbonates and anhydrites. Forty-three depth intervals representing nearly 300 ft of the Broom Creek Formation were sampled for thin-section creation, x-ray diffraction (XRD) mineralogical determination, and x-ray fluorescence (XRF) bulk chemical analysis. For the assessment below, thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals show that quartz (80%) is the dominant mineral. Throughout these intervals are minor occurrence of feldspar (3%), dolomite (5%), and anhydrite as cement (10%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The contact between grains is long (straight) to tangential. The porosity ranges between 20% to 25%.

Two distinct carbonate intervals are notable. First is the presence of a very fine- to fine-grained dolostone (80%), with quartz of variable size and shape (5%) and iron oxides (10%) present. The porosity is intercrystalline and not well-developed, averaging 5%. Diagenesis is expressed by dolomitization of the original calcite grains. Fossils are not present in this interval. In the second occurrence of carbonate, the texture becomes coarse and more fossil-rich, comprising fine-grained dolomite (35%), dolomitized fossils (25%), quartz (15%), and silicified fossils (25%). Diagenesis is expressed by the dissolution of dolomite, resulting in shelter and vuggy porosity. The presence of quartz crystallized inside fossils shows

				several episodes of crystallization partially obstructing the vuggy porosity. The porosity averages 20%. The anhydrite intervals are expressed as thin beds that separate different sand bodies and as cement. The porosity is almost null. XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, feldspar, dolomite, anhydrite, clay, and iron oxides (Figure 2-15). XRF data are shown in Figure 2-16 for the Broom Creek Formation. As shown, the majority of the sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (70%–90%), CaO (5%–10%), and MgO (5%–10%). The high percentage of CaO and SO_3 at 6,640 ft indicates a presence of a thin layer of anhydrite. The formation shows very little clay, with a range of 0.0.5% to 3% being the highest detected. To locate permit text, go to Section 2.3.1 of the RTE SFP. ***2.3.2 Mechanism of Geologic Confinement*** For the RTE project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams. ***2.3.3 Geochemical Information of Injection Zone*** Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone. The effects have been found to be minimal and not threatening to the geologic integrity of the storage system. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO_2 injection. The project's base case simulation (base case) was rerun with the geochemical analysis option included (geochemistry case), and results from the two cases were compared. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause observable change to storage reservoir performance or to mechanical integrity of the storage formation. The geochemistry case was constructed using the base case simulation inputs and assumptions as well as honoring the average mineralogical composition of the Broom Creek rock materials (80% of bulk reservoir volume) and the average formation brine composition (20% of bulk reservoir volume). XRD data from the RTE 10 core samples were used to inform the mineralogical composition of the Broom Creek used in the geochemical modeling (Table 2-8). CO_2 injection stream composition remained the same as the base case, as described by RTE (Table 2-9). The geochemistry case was run for the 20-year injection period followed by 25 years of postinjection shutdown and monitoring. **Table 2-8. XRD Results for RTE-10 Broom Creek Core Samples** <table><tr><td colspan="2">Depth 6,599.5 ft</td><td colspan="2">Depth 6,667 ft</td></tr><tr><td>**Mineral Data**</td><td>**%**</td><td>**Mineral Data**</td><td>**%**</td></tr><tr><td>Kaolinite</td><td>2</td><td>Illite/muscovite</td><td>3.9</td></tr><tr><td>Illite/Muscovite</td><td>5.3</td><td>Chlorite</td><td>1.1</td></tr></table>	Figure 2-19. Dissolution and precipitation quantities of reservoir minerals due to CO_2 injection. Figure 2-20a. Molar distribution of key dissolved and precipitated minerals at the end of the injection period. Dissolution of halite is shown by the dark blue color. Compare to the molar CO_2 distribution in the left side of Figure 2-18a. Some reprecipitation of halite is indicated in lower and peripheral areas of the reservoir, as shown by areas of green and yellow color. Figure 2-20b. Molar distribution of key dissolved and precipitated minerals at the end of the injection period. Illite precipitation is indicated throughout the affected area of the reservoir. Figure 2-21. Change in porosity due to geochemical dissolution after the 20-year injection period (compare to the molar CO_2 distribution in the left side of Figure 2-18). Table 2-8. XRD Results for RTE-10 Broom Creek Core Samples

K-Feldspar	3	K-feldspar	12.3
Quartz	58.2	Quartz	53.2
Rutile	0.8	Calcite	0.8
Aphthitalite	1.1	Dolomite	1.3
Halite	0.9	Anhydrite	27.4
Anhydrite	28.7		

For additional information, go to Section 2.3.3 of the RTE SFP.

c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
- Depth
- Areal extent
- Thickness
- Mineralogy
- Porosity
- Permeability
- Capillary pressure
- Facies changes

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Opeche Formation and underlying Amsden Formation (Figure 2-2, Table 2-10). Both the Amsden and the Opeche Formations consist of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Lithology	Mudstone/siltstone	Dolomite/shaly sand
Formation Top Depth, ft	6,276	6,677
Thickness, ft	103	329
Porosity, % (core data)	4.01 (1.36–9.89)*	6.13 (2.25–9.24)*
Permeability, mD (core data)	0.0046 (0.0029–0.0056)**	0.0267 (0.017–0.059)**
Capillary Entry Pressure (GW), psi	27.1	23.8
Depth below Lowest Identified USDW, ft	4307	4708

* Porosity values are reported as the arithmetic mean followed by the range of values in parenthesis.
** Permeability values are reported as the geometric mean followed by the range of values in parenthesis.

2.4.1 Upper Confining Zone

In the RTE project area, the Opeche Formation consists of silty mudstone with interbedded fine sandstone and anhydrite. The Opeche is laterally extensive across the project area (Figures 2-22 and 2-23) and is 6,276 ft below the land surface and 103 ft thick at the RTE site (Table 2-10 and Figure 22-24). The contact between the underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-25).

For additional information, go to section 2.4.1 of the RTE SFP.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche Formation comprises alternating intervals of silty mudstone, argillaceous siltstone, mudstone, and anhydrite. In all, 11 thin sections were created covering greater than 60 ft of the Opeche. The mineral components present are clay, quartz, anhydrite, feldspar, dolomite, and iron oxides. The grains are almost always surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. The porosity ranges between 1% and 3%.

Table 2-10. Properties of Upper and Lower Confining Zones

Figure 2-22. Areal extent of the Opeche Formation in western North Dakota. Extent is derived from Carlson (1993).

Figure 2-23. Structure map of the Opeche Formation across the greater RTE project area.

Figure 2-24. Isopach map of the Opeche Formation in the RTE project area.

Figure 2-25. Well log display of the Opeche Formation at the RTE-10 well.

Figure 2-26. XRF data for the Opeche Formation from RTE-10.

Figure 2-27. Change in fluid pH vs. time. Red line shows pH for Cell C1, 0 to 1 meter above the Opeche cap rock base. Yellow line shows Cell C2, 1 to 2 meters above the cap rock base. Green line shows Cell C3, 2 to 3 meters above the cap rock base. pH for Cell C3 does not begin to change until after 35 years. For cases with lower exposure levels, pH for Cell C3 does not change at all.

Figure 2-28. Dissolution and precipitation of minerals in the Opeche cap rock. Dashed lines show results for Cell C1, 0 to 1 meter above the cap rock base. Solid lines show results for Cell C2, 1 to 2 meters above the cap rock base; changes are barely visible. Results from Cell C3, 2 to 3 meters above the cap rock base, are not shown as they are too small to be seen.

Figure 2-29. Change in percent porosity of the Opeche cap rock. Red line shows porosity change for Cell C1, 0 to 1 meter above the cap rock base. Yellow line shows Cell C2, 1 to 2 meters above the cap rock base. Green line

				XRD data from 11 samples from the RTE-10 core supported facies interpretations from core descriptions and thin-section analysis. The Opeche Formation mainly comprises clay, quartz, dolomite, and anhydrite. XRF analysis of the Opeche Formation shown in Figure 2-26 identifies the major chemical constituents to be dominated by SiO_2 (30%–60%), Al_2O_3 (3%–10%), CaO (5%–40%), and MgO (1%–16%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by XRD (Figure 2-26). Two samples toward the base of the Opeche show high percentages of CaO and SO_3 attributed to an interval of anhydrite separating the two formations. This correlates with XRD, core description, and thin-section analysis. For additional information, go to Section 2.4.1.1 of the RTE SFP. *2.4.1.2 Geochemical Interaction* Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 on the Opeche Formation, the primary confining zone. A vertically oriented 1D simulation was created where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by diffusion processes. Results were monitored at 1-meter increments above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche determined from XRD analysis was honored (Table 2-13). Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone below (Table 2-14). This composition was determined from analysis of fluid samples from the RTE-10 well. CO_2 stream composition was as provided by RTE (Table 2-9). Three different CO_2 exposure levels of the CO_2 stream to the cap rock (1.15, 2.3, and 4.5 moles/yr) were used. These values are considerably higher than the actual expected exposure levels. This was done to ensure that the degree and pace of geochemical change would not be underestimated. These three simulations were run for 45 years to represent 20 years of injection plus 25 years postinjection. The simulations were performed at reservoir pressure and temperature conditions. Results showed geochemical processes at work, but even at extreme exposure levels, these processes did not extend more than 3 meters up into the cap rock during the simulation period. Figures 2-27–2-29 show results from the most extreme exposure case. Figure 2-27 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH declines to a level of 4.6 before recovering to a value of 5.25. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH only begins to change after Year 35. Figure 2-28 shows change in mineral dissolution and precipitation in grams. Dashed lines are for Cell C1; solid lines that are only faintly seen in the figure are from Cell C2, 1 to 2 meters into the cap rock. Any effects in Cell C3 are too small to represent at this scale. Figure 2-29 shows change in porosity of the cap rock. Cell 1 experiences a rapid increase in porosity as it is first exposed to CO_2 due to dissolution. The porosity then decreases around Year 9 due to precipitation. As precipitation occurs in Cell 1, reaction products move into Cell 2 where they precipitate, causing decreased porosity. When CO_2 reaches Cell 2 at Year 9, dissolution occurs, increasing the porosity. Note the scale of percent porosity change, ~0.00001%. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results show that exposure to CO_2 will not cause deterioration of the Opeche cap rock. For additional information, go to Section 2.4.1.2 of the RTE SFP. ***2.4.2 Additional Overlying Confining Zones*** Several additional formations provide additional confinement above the Opeche Formation. Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Opeche, these formations are 1,200 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-30). Above the Inyan Kara Formation, 3,000 ft of impermeable rocks acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-31). Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15). These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin.	shows Cell C3, 2 to 3 meters above the cap rock base. Long-term change in porosity is miniscule and stabilized. Figure 2-30. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. Figure 2-31. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. Figure 2-32. Structure map of the Amsden Formation across the greater RTE project area. Figure 2-33. Isopach map of the Amsden Formation across the RTE project area. Figure 2-34. XRF data for the Amsden Formation from the RTE-10 well. Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the RTE-10 well)

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara. Monitoring the Inyan Kara Formation provides an additional opportunity for monitoring, mitigation, and remediation (Section 4). The depth to the Inyan Kara Formation in the project area is approximately 4,800 ft, and the formation itself is about 350 ft thick.

For additional information, go to section 2.4.2 of the RTE SFP.

Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the RTE-10 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,969	2,063	0
Greenhorn	Shale	4,032	435	2,063
Mowry	Shale	4,467	314	2,498
Inyan Kara	Sandstone	4,781	345	2,812
Swift	Shale	5,125	494	3,156
Rierdon	Shale	5,619	173	3,650
Piper Kline	Limestone	5,792	139	3,823
Piper Picard	Shale	5,931	68	3,962
Spearfish	Siltstone	5,999	230	4,030
Minnekahta	Limestone	6,229	47	4,260

2.4.3 Lower Confining Zones

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that could be correlated across the project area (Figures 2-32 and 2-33). The Amsden Formation is 6,677 ft below land surface and 329 ft thick at the RTE site (Table 2-10).

The contact between the overlying Broom Creek and Amsden is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from RTE-10. The lithology of the cored section of the Amsden from RTE-10 is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Three feet below the contact with the Broom Creek is an 11-ft-thick anhydrite layer. Data acquired from the seven core plug samples taken from the Amsden show porosity values ranging from 2.25% to 9.24% and permeability values from <0.001 to 0.595 mD (Table 2-16).

For additional information, go to Section 2.4.3 of the RTE SFP.

				2.4.3.1 Mineralogy Thin-section analysis shows that the Amsden Formation comprises dolomite, anhydrite, sandy dolomite, and shaly sand. The dolomite is expressed by very fine- to fine-grained dolostone (90%), with the presence of quartz of variable size and shape, feldspar, clay, and iron oxides. The porosity is very low and is mainly due to the dissolution of feldspar and quartz. The porosity averages 5% (Table 2-16). Anhydrite is present as beds that separate the dolomite intervals. It is composed of needles of anhydrite with minor inclusions of iron oxides. Also, dolomite and quartz are present and found filling rare fractures. The porosity is almost null. The sandy dolomite is mainly composed of dolomite and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite cement. The porosity is mainly due to the dissolution of feldspar and averages 5%. Finally, the shaly sandstone comprises quartz, clay, and dolomite. A minor presence of feldspar, anhydrite, and iron oxides exists. The grains of quartz and anhydrite are almost always separated by the dolomite cement and clay minerals. The porosity is very low, averaging 5% and is mainly due to the dissolution of feldspar and quartz. XRD was performed, and the results confirm the observations made during core analyses and thin-section description. XRF data show the Amsden Formation has the same major chemical constituents as the Opeche Formation (Figure 2-34). However, the formation at the contact with the Broom Creek is dominated by CaO and SO_3 (major chemical elements of anhydrite). As the formation gets deeper, the chemistry changes to a more carbonate-rich siltstone, as shown by the high percentage of SiO_2, CaO, and MgO. <u>To locate permit text, go to Section 2.4.3.1 of the RTE SFP.</u> *2.4.3.2 Geochemical Interaction* Review of simulation results of the Broom Creek Formation suggest that neither free-phase CO_2 saturation nor CO_2 dissolved in formation brine will come in contact with the Amsden Formation. Therefore, no geochemical reaction effects are anticipated in the Amsden.	
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional	d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including: Rock properties Regional pressure gradients Adsorption processes	***2.3.2 Mechanism of Geologic Confinement*** For the RTE project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	Figure 2-6. Map showing the extent of the 7.8-square-mile 3D seismic survey in the RTE project area. Figure 2-7. Cross section of the inverted compressional wave velocity volume that transects the RTE-10 well. The compressional wave velocities from the RTE-10 sonic log are shown on the inset panel. Figure 2-8. Areal extent of the Broom Creek Formation in North Dakota.

		pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within 1 mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	NDAC 43-05-01-05 §1b(2)(g)	**NDAC 43-05-01-05 §1b(2)(g)** (g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir.	e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including: Structural spill points Stratigraphic discontinuities	***2.3.2 Mechanism of Geologic Confinement*** For the RTE project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine). After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. Adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams. *2.2.2.6 Seismic Survey* A 7.8-square-mile 3D seismic survey was acquired in early 2019 (Figure 2-6). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The seismic data were used for assessment of geologic structure, interpretation of interwell heterogeneity, and to inform well placement. Additionally, data products generated from the interpretation of the 3D seismic data were used as inputs into the geologic model. The 3D seismic data and RTE-10 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from the RTE-10 sonic log. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. These surfaces captured detailed information about the structure and varying thickness of the formations between wells. Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points in the RTE project area. No structural features, faults, or discontinuities that would cause a concern about seal integrity were observed in the seismic data. Section 2.5.2 describes interpretation of the seismic data in more detail. The 3D seismic data were also used to gain a better understanding of interwell heterogeneity across the study area for petrophysical property distributions. The 3D seismic data suggest the interbedded dolomite and anhydrite intervals within the Broom Creek Formation seen in RTE-10 are laterally discontinuous in the RTE project area; however, the data do not suggest that these lower-permeability intervals compartmentalize the storage reservoir in the RTE project area. A compressional wave (P-wave) velocity volume was created using the 3D seismic data and RTE-10 sonic and density log data (Figure 2-7). The velocity volume was used to classify sandstone and dolostone lithofacies of the Broom Creek Formation and distribute lithofacies through the geologic model as well as inform petrophysical property distribution in the geologic model.	Figure 2-6. Map showing the extent of the 7.8-square-mile 3D seismic survey in the RTE project area. Figure 2-7. Cross section of the inverted compressional wave velocity volume that transects the RTE-10 well. The compressional wave velocities from the RTE-10 sonic log are shown on the inset panel. Figure 2-8. Areal extent of the Broom Creek Formation in North Dakota. Figure 2-17. Upper graph shows cumulative injection vs. time. The two cases overlay each other. Lower graph shows wellhead injection pressure for the two cases. There is no observable change in injection performance. Figure 2-18a. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality. Figure 2-18b. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine. The extent of the pH-affected area is slightly larger (~300 feet) than the extent of the CO_2 accumulation. Figure 2-19. Dissolution and precipitation quantities of reservoir minerals due to CO_2 injection. Figure 2-20. Molar distribution of key dissolved and precipitated minerals at the end of the injection period. Left: halite showing dissolution in the areas of dark blue color.

					Compare to the molar CO_2 distribution in the left side of Figure 2-18. Some reprecipitation of halite is indicated in lower and peripheral areas of the reservoir, as shown by areas of green and yellow color. Right: illite precipitation is indicated throughout the affected area of the reservoir. Figure 2-21. Change in porosity due to geochemical dissolution after the 20-year injection period (compare to the molar CO_2 distribution in the left side of Figure 2-18).
	NDAC 43-05-01-05 §1b(2)c	**NDAC 43-05-01-05 §1b(2)c** (c) Any regional or local faulting;	f. Any regional or local faulting;	**2.5 Faults, Fractures, and Seismic Activity** In the RTE project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. Regional structural features, including the Heart River Fault and collapse features above the Broom Creek Formation, are discussed in this section as well as the data that support the low probability that these features will interfere with containment. This section also discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment. ***2.5.1 Heart River Fault*** The Heart River Fault is located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AoR for the RTE project (Figure 2-46). This high-angle reverse fault originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 ft in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations (Figure 2-47), well below the Broom Creek Formation (Figure 2-2). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset.	Figure 2-46. Map showing the trend of the Heart River Fault in the RTE project area. The blue line is a 2D seismic line transecting the Heart River Fault. See Figure 2-47 for a geologic interpretation along the seismic line. Figure 2-47. Seismic Line 3022 showing the interpreted location of the Heart River Fault shown in purple (Chimney and others, 1992). Faulting offset is observed in the Winnipeg horizon, but only slight flexure is observed in other overlying interpreted horizons.
	NDAC 43-05-01-05 §1b(2)(j)	**NDAC 43-05-01-05 §1b(2)(j)** (j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment.	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation Determination of the probability that they would interfere with containment	***2.5.1 Heart River Fault*** The Heart River Fault is located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AoR for the RTE project (Figure 2-46). This high-angle reverse fault originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 ft in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations (Figure 2-47), well below the Broom Creek Formation (Figure 2-2). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset.	Figure 2-46. Map showing the trend of the Heart River Fault in the RTE project area. The blue line is a 2D seismic line transecting the Heart River Fault. See Figure 2-47 for a geologic interpretation along the seismic line. Figure 2-47. Seismic Line 3022 showing the interpreted location of the Heart River Fault shown in purple (Chimney and others, 1992). Faulting offset is observed in the Winnipeg horizon, but only slight flexure is observed in other overlying interpreted horizons.
	NDAC 43-05-01-05 §1b(2) ¶ & §1b(2)(m)	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources. Determination of the probability that seismicity would interfere with containment.	**2.5 Faults, Fractures, and Seismic Activity** In the RTE project area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. Regional structural features, including the Heart River Fault and collapse features above the Broom Creek Formation, are discussed in this section as well as the data that support the low probability that these features will interfere with	Table 2-21. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016) Figure 2-46. Map showing the trend of the Heart River Fault in the RTE project area. The blue line is a 2D seismic line transecting the Heart River Fault. See Figure 2-47 for a geologic interpretation along the seismic line.

		for monitoring. The data and assessments of any regional or local fault regional structural or confinement, including that confinement to prevent storage reservoir. The existing or potential any underground sources of mile [1.61 kilometers] of its exhibits and plan view **NDAC 43-05-01-05 §1b(2)(m)** seismic history, including the that the seismicity would not		containment. This section also discusses the seismic history of North Dakota and low probability that seismic activity will The Heart River Fault is located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AoR for the Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent ***2.5.2 Collapse Features above the Broom Creek Formation*** The analysis of 3D seismic data acquired specifically for the RTE project in 2019 (Figure 2-6) revealed evidence for suspected collapse features in strata above the Broom Creek Formation. These features appear as depressions in the seismic data and are bounded by dipping or offset reflections (Figure 2-48 and 2-49). These collapse features correlate to 30–50-ft decreases in thickness in known evaporite-bearing formations, the Spearfish and Opeche Formations, suggesting they were caused by dissolution of evaporites and subsequent collapse of overlying sediments (Figure 2-50). The polygonal nature of these features also supports the interpretation of collapse features. The vertical extent of these features and increased thickness in the Inyan Kara Formation suggest collapse of overlying sediment ceased during the deposition of the Inyan Kara and the depressions were filled in with newly deposited sediment (Figures 2-48 and 2-51). The lack of closest to the RTE project occurred in 1927 9.4 miles to the east, near Hebron, North Dakota (Table 2-21). The magnitude	Figure 2-47. Seismic Line 3022 showing the interpreted location of the Heart River Fault shown in purple (Chimney and others, 1992). Faulting offset is observed in the Winnipeg horizon, but only slight flexure is observed in other overlying interpreted Figure 2-48. Cross-sectional view of the 3D seismic data through the proposed injection well, RTE-10, showing the interpreted boundaries of the collapse features in orange. Identified formations include Inyan Kara (yellow), Rierdon (green), Spearfish (aqua), Minnekahta (pink), Broom Creek (magenta), and Amsden (red). The collapse features near the proposed injection well do not extend below the Spearfish Formation. The red arrow sediment above these features. Figure 2-49 Figure 2-49. The location of the cross section highlighted in Figure 2-48. Figure 2-50. Map showing the thickness of the Spearfish–Minnekahta Formations calculated using the seismic data. Several of the interpreted collapse features correspond to Figure 2-51. Maps showing the thickness of the interval between the top of the Inyan Kara Formation and the top of the Rierdon Formation calculated using the seismic data. The increased thickness supports that the collapse features formed prior to or during the deposition of the Inyan Kara. Figure 2-52. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-20. Figure 2-53. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps	**2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek	Figure 2-8. Areal extent of the Broom Creek Formation in North Dakota.

NDAC 43-05-01-05 §1b(2)(n)

information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within 1 mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:

NDAC 43-05-01-05 §1b(2)(n)
(n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area.

Topographic maps
Cross sections

Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2).

For additional information, go to Section 2.3 of the RTE SFP.

Table 2-1. Formations Comprising the RTE CO_2 Storage Complex

	Formation	Purpose	Average Thickness at RTE Site, ft	Average Depth at RTE Site, SSTVD, ft	Lithology
Storage Complex	Opeche	Upper confining zone	103	3,871	Mudstone/siltstone
	Broom Creek	Storage reservoir (i.e., injection zone)	313	3,974	Sandstone, dolomite
	Amsden	Lower confining zone	329	4,285	Dolomite/shaly sand

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the RTE-10 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolomite
Formation Top Depth, ft	6,379
Thickness, ft	298 (sandstone 201; dolomite 97)
Capillary Entry Pressure (GW), psi	1.1

Geologic Properties

Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Broom Creek (sandstone)	Porosity, %	21.68 (12.18–33.65)*	25.26 (1.01 – 32.14)*
	Permeability, mD	419.1 (25.35–5,120)**	277.45 (20.20 – 2,483.64)**
Broom Creek (dolomite)	Porosity, %	6 (2.91–8.54)*	15.24 (1.01 – 32.14)*
	Permeability, mD	0.08 (0.004–1.12)**	8.65 (0.01–2,261.53)**

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Opeche Formation and underlying Amsden Formation. Both the Amsden and the Opeche Formations consist of impermeable rock layers.

Figure 2-9. Isopach map of the Broom Creek Formation in the RTE project area.

Figure 2-10. Well log display of the interpreted lithologies of the lower Opeche, Broom Creek, and upper Amsden Formation in RTE-10.

Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (purple), and 3) interpreted lithology log.

Figure 2-11b. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (purple).

Figure 2-12. Structure map of the Broom Creek Formation across the greater RTE project area.

Figure 2-13. Cross section of the RTE CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced to mean sea level.

Figure 2-22. Areal extent of the Opeche Formation in western North Dakota. Extent is derived from Carlson (1993).

Figure 2-23. Structure map of the Opeche Formation across the greater RTE project area.

Figure 2-24. Isopach map of the Opeche Formation in the RTE project area.

Figure 2-25. Well log display of the Opeche Formation at the RTE-10 well.

Figure 2-30. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

Figure 2-31. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

Table 2-9. Properties of Upper and Lower Confining Zones

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche	Amsden
Lithology	Mudstone/siltstone	Dolomite/shaly sand
Formation Top Depth, ft	6,276	6,677
Thickness, ft	103	159
Porosity, % (core data)	4.01 (1.36–9.89)*	6.13 (2.25–9.24) *
Permeability, mD (core data)	0.0046 (0.0029–0.0056)**	0.0267 (0.017–0.059)**
Capillary Entry Pressure (GW), psi	27.1	23.8
Depth Below Lowest Identified USDW, ft	4,307	4,708

2.4.1 Upper Confining Zone

In the RTE project area, the Opeche Formation consists of silty mudstone with interbedded fine sandstone and anhydrite. The Opeche is laterally extensive across the project area and is 6,276 ft below the land surface and 103 ft thick at the RTE site. The contact between the underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact.

For additional information, go to Section 2.4.1 of the RTE SFP.

2.4.2 Additional Overlying Confining Zones

Several additional formations provide additional confinement above the Opeche Formation. Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1200 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 3,000 ft of impermeable rocks acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations.

For additional information, go to Section 2.4.2 of the RTE SFP.

Table 2-14. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the RTE-10 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth Below Lowest Identified USDW, ft
Pierre	Shale	1,969	2,063	0
Greenhorn	Shale	4,032	435	2,063
Mowry	Shale	4,467	314	2,498
Inyan Kara	Sandstone	4,781	345	2,812
Swift	Shale	5,125	494	3,156
Rierdon	Shale	5,619	173	3,650
Piper Kline	Limestone	5,792	139	3,823
Piper Picard	Shale	5,931	68	3,962
Spearfish	Siltstone	5,999	230	4,030
Minnekahta	Limestone	6,229	47	4,260

2.4.3 Lower Confining Zones

Figure 2-32. Structure map of the Amsden Formation across the greater RTE project area.

Figure 2-33. Isopach map of the Amsden Formation across the RTE project area.

Figure 3-8. Major aquifer systems of the Williston Basin.

Figure 3-9. Upper stratigraphy of Stark County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Trapp and Croft, 1975).

Figure 3-10. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

Figure 3-11. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Stark County (modified from Fischer, 2013).

Figure 3-12. Map of water wells in the AoR in relation to the RTE Facility, RTE-10 and RTE-10.2 wells, stabilized CO_2 plume extent, facility area, 1-mile AoR, and legacy oil and gas wells.

Figure 3-13. West–east cross section of the major aquifer layers in Stark County (modified from Trapp and Kroft, 1975). The black dots on the inset map represent the locations of the wells illustrated on the cross section.

Figure 3-14. Cross section of the major aquifer layers in the RTE storage facility area (modified from Trapp and Kroft, 1975). The location of the water wells used to create the cross section are represented on the inset map. The water wells are labeled with their designation which also correlates to their township range location (e.g., 139-092-18CCC is located in T139N R92W, Section 18).

				The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that could be correlated across the project area. The Amsden Formation is 6,677 ft below land surface and 329 ft thick at the RTE site. <u>For additional information, go to Section 2.4.3 of the RTE SFP.</u> **3.4 Protection of USDWs** ***3.4.1 Introduction of USDW Protection*** The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest underground source of drinking water (USDW) in the AoR. The Opeche Formation is the primary confining zone with additional confining layers above, geologically isolating all USDWs from the injection zone (Table 2-14). ***3.4.2 Geology of USDW Formations*** The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 3-8). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014). The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley and White River Formations (Figure 3-9). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AoR (Trapp and Croft, 1975). The lowest USDW in the AoR is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the AoR is approximately 1,000 to 1,600 ft deep and 240–400 ft thick. The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the AoR (Figure 3-10). The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically over 1,000 ft thick in the AoR (Thamke and others, 2014). <u>For additional information, go to section 3.4.2 of the RTE SFP.</u> ***3.4.3 Hydrology of USDW Formations*** The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AoR is to the northeast (Figure 3-11). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1,500–1,600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. One active Fox Hills Formation well in AoR is located immediately south of the RTE site on the south side of Interstate 94 (Figure 3-12). Two other Fox Hills wells previously served the city of Richardton, North Dakota, but were plugged and abandoned in the late 1990s.	

				Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AoR (Figure 3-13). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. Thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Trapp and Croft, 1975). The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is 100 to 150 ft thick in the AoR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Trapp and Croft, 1975). For additional information, go to Section 3.4.3 of the RTE SFP. ***3.4.4 Protection of USDWs*** The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AoR. The injection zone (Broom Creek Formation) and the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous ages (Figure 3-8). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, the Jurassic-aged Piper, Reirdon, and Swift Formations, all of which overly the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. The Inyan Kara will be monitored for temperature and pressure changes in the injection well (RTE-10) and the monitoring well (RTE-10.2). Results for baseline geochemical data for USDWs in the AoR can be found in Appendix C. Above the Inyan Kara are the Cretaceous-aged shale formations Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the AoR and the primary geologic barrier between the USDWs and the injection zone. The geologic strata overlying the injection zone consists of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the AoR. For additional information, go to Section 3.4.4 of the RTE SFP.	
	NDAC 43-05-01-05 §1b(2)(d)	**NDAC 43-05-01-05 §1b(2)(d)** (d) An isopach map of the storage reservoirs.	j. An isopach map of the storage reservoir(s);	**Figure 2-9** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2). For additional information, go to Section 2.3 of the RTE SFP.	Figure 2-9. Isopach map of the Broom Creek Formation in the RTE project area.
	NDAC 43-05-01-05 §1b(2)(e)	**NDAC 43-05-01-05 §1b(2)(e)** (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir.	k. An isopach map of the primary containment barrier for the storage reservoir.	**Figure 2-24 and Figure 2-33** **2.4 Confining Zones**	Figure 2-24. Isopach map of the Opeche Formation in the RTE project area. Figure 2-33. Isopach map of the Amsden Formation across the RTE project area.

				The confining zones for the Broom Creek Formation are the overlying Opeche Formation and underlying Amsden Formation (Figure 2-2, Table 2-10). Both the Amsden and the Opeche Formations consist of impermeable rock layers. ***2.4.1 Upper Confining Zone*** In the RTE project area, the Opeche Formation consists of silty mudstone with interbedded fine sandstone and anhydrite. The Opeche is laterally extensive across the project area (Figures 2-22 and 2-23) and is 6,276 ft below the land surface and 103 ft thick at the RTE site (Table 2-10 and Figure 22-24). The contact between the underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-25). <u>For additional information, go to Section 2.4.1 of the RTE SFP.</u> *2.4.3 Lower Confining Zones* The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that could be correlated across the project area (Figures 2-32 and 2-33). The Amsden Formation is 6,677 ft below land surface and 329 ft thick at the RTE site (Table 2-10). <u>For additional information, go to Section 2.4.3 of the RTE SFP.</u>	
			l. An isopach map of the secondary containment barrier for the storage reservoir.	**Figure 2-30 and Figure 2-31** ***2.4.2 Additional Overlying Confining Zones*** Several additional formations provide additional confinement above the Opeche Formation. Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Opeche, these formations are 1,200 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-30). Above the Inyan Kara Formation, 3,000 ft of impermeable rocks acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-31). Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15). <u>For additional information, go to Section 2.4.2 of the RTE SFP.</u>	Figure 2-30. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. Figure 2-31. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.
	NDAC 43-05-01-05 §1b(2)(f)	**NDAC 43-05-01-05 §1b(2)(f)** (f) A structure map of the top and base of the storage reservoirs.	m. A structure map of the top of the storage formation.	**Figure 2-12 and Figure 2-23** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2). <u>For additional information, go to Section 2.3 of the RTE SFP.</u> ***2.4.1 Upper Confining Zone*** In the RTE project area, the Opeche Formation consists of silty mudstone with interbedded fine sandstone and anhydrite. The Opeche is laterally extensive across the project area (Figures 2-22 and 2-23) and is 6276 ft below the land surface and 103 ft thick at the RTE site (Table 2-10 and Figure 22-24). The contact between the underlying Broom Creek sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-25).	Figure 2-12. Structure map of the Broom Creek Formation across the greater RTE project area. Figure 2-23. Structure map of the Opeche Formation across the greater RTE project area.

				For additional information, go to Section 2.4.1 of the RTE SFP.	
			n. A structure map of the base of the storage formation.	**Figure 2-12 and Figure 2-32** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2). For additional information, go to Section 2.3 of the RTE SFP. *2.4.3 Lower Confining Zones* The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, mudstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that could be correlated across the project area (Figures 2-32 and 2-33). The Amsden Formation is 6677 ft below land surface and 329 ft thick at the RTE site (Table 2-10). For additional information, go to Section 2.4.3 of the RTE SFP.	Figure 2-12. Structure map of the Broom Creek Formation across the greater RTE project area. Figure 2-32. Structure map of the Amsden Formation across the greater RTE project area.
	NDAC 43-05-01-05 §1b(2)(i)	**NDAC 43-05-01-05 §1b(2)(i)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir.	o. Structural cross sections that describe the geologic conditions at the storage reservoir.	**Figures 2-11a and 2-11b; and 2-13** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2). At RTE-10, the Broom Creek Formation is made up of 201 ft of sandstone and 97 ft of dolostone and is located at a depth of 6,379 ft. Across the project area, the Broom Creek Formation varies in thickness from 210 to 406 ft (Figure 2-9), with an average thickness of 313 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the project area ranges from 48 to 324 ft, with an average of 192 ft. The top of the Broom Creek Formation was picked across the project area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek (Figure 2-10). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that could be correlated across the project area. Seismic data collected as part of site characterization efforts (Figure 2-6) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near RTE-10 (Figures 2-11a and 2-11b). The 3D seismic data suggest the interbedded dolomite and anhydrite intervals in the RTE-10 well are laterally discontinuous and do not compartmentalize the storage reservoir in the RTE project area. A structure map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figures 2-12 and 2-13). For additional information, go to Section 2.3 of the RTE SFP.	Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red); 2) delta time (purple) and 3) interpreted lithology log. Figure 2-11b. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (purple). Figure 2-13. Cross section of the RTE CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced to
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir.	**Figures 2-11a and 2-11b; and 2-13** **2.3 Storage Reservoir (Injection Zone)**	Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche and Broom Creek Formations flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red);

				Regionally, the Broom Creek is laterally extensive (Figure 2-8) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone and siltstones of the Opeche Formation (Figure 2-2). At RTE-10, the Broom Creek Formation is made up of 201 ft of sandstone and 97 ft of dolostone and is located at a depth of 6,379 ft. Across the project area, the Broom Creek Formation varies in thickness from 210 to 406 ft (Figure 2-9), with an average thickness of 313 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the project area ranges from 48 to 324 ft, with an average of 192 ft. The top of the Broom Creek Formation was picked across the project area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek (Figure 2-10). The top of the Amsden Formation was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that could be correlated across the project area. Seismic data collected as part of site characterization efforts (Figure 2-6) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and analyses indicate that there should be few-to-no major reservoir stratigraphic discontinuities near RTE-10 (Figures 2-11a and 2-11b). The 3D seismic data suggest the interbedded dolomite and anhydrite intervals in the RTE-10 well are laterally discontinuous and do not compartmentalize the storage reservoir in the RTE project area. A structure map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figures 2-12 and 2-13). For additional information, go to Section 2.3 of the RTE SFP.	2) delta time (purple) and 3) interpreted lithology log. Figure 2-11b. Regional well log cross sections showing the structure of the Opeche, Broom Creek, and Amsden Formations. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (purple). Figure 2-13. Cross section of the RTE CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Depths are referenced to mean sea level.
	NDAC 43-05-01-05 §1b(2)(h)	**NDAC 43-05-01-05 §1b(2)(h)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any.	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any.	**3.1 Area of Review Delineation** ***3.1.1 Written Description*** North Dakota CO_2 storage regulations require that each storage facility permit delineate an AoR, which is defined as the region surrounding the geologic storage project where USDWs may be endangered by the injection activity (NDAC § 43-05-01-01 Subsection 4). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AoR encompasses the region overlying the injected free-phase CO_2 and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or fractures) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and the resultant pressure as the "critical threshold pressure." The results of computational modeling and simulation of 20 years of CO_2 injection at the RTE site show that consequent subsurface pressure increases are below the critical threshold pressure necessary to force formation fluids into USDWs (Figure 3-1). Within the bounds of the modeled area and throughout the entire storage facility area, the maximum fluid pressure increase during the final year of injection is estimated to be 52 psi, which occurs near the RTE-10 wellbore. This maximum pressure increase is below the calculated critical threshold pressure increase of 107.3 psi (Appendix A, Table A-2). NDAC § 43-05-01-05 Subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within 1 mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the pressure response of the simulated CO_2 injection, the resulting AoR for the RTE project is delineated as being 1 mile beyond the facility area boundary. This extent ensures compliance with existing state regulations. Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AoR boundary etc.) and the assumptions and justification used to delineate the AoR.	Figure 3-8. Major aquifer systems of the Williston Basin. Figure 3-9. Upper stratigraphy of Stark County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Trapp and Croft, 1975). Figure 3-10. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). Figure 3-11. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Stark County (modified from Fischer, 2013). Figure 3-12. Map of water wells in the AoR in relation to the RTE Facility, RTE-10 and RTE-10.2 wells, stabilized CO_2 plume extent, facility area, 1-mile AoR, and legacy oil and gas wells. Figure 3-13. West–east cross section of the major aquifer layers in Stark County (modified from Trapp and Kroft, 1975). The black dots on the inset map represent the locations of the wells illustrated on the cross section.

The two deep wells located in the RTE project AoR that penetrate the storage reservoir were evaluated by a professional engineer pursuant to NDAC § 43-05-01-05 Subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records. The evaluation determined that both wells penetrating the storage reservoir within the AoR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Table 3-2–3-4 and Figures 3-6 and 3-7).

An extensive geologic and hydrogeologic characterization, performed by a team of geologists, has shown no evidence of transmissive faults or fractures in the upper confining zone within the AoR and has shown evidence that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AoR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone to prevent vertical fluid movement and protect USDWs.

Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

Delineation of AoR

The AoR is defined as the region surrounding the geologic storage project where USDWs may be endangered by CO_2 injection activity (NDAC § 43-05-01-05). The primary endangerment risk is due to the potential for vertical migration of CO_2 and/or formation fluids to a USDW from the storage reservoir. Therefore, the AoR encompasses the region overlying the extent of reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., abandoned wells or fractures) are present. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and the resultant pressure as the "critical threshold pressure." The U.S. Environmental Protection Agency (EPA) guidance for AoR delineation under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical threshold pressure increase and the resulting critical threshold pressure.

The method presented by Nicot and others (2008) and Bandilla and others (2012) was used to calculate the critical threshold pressure increase (ΔPc), which is the fluid pressure increase sufficient to drive formation fluids into the closest USDW, the Fox Hills Formation. This ΔPc is determined using Equation 2, assuming 1) hydrostatic conditions, 2) initially linearly varying densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_c = \frac{1}{2}\, g\, \xi\, (z_u - z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq. 3]}$$

Where:

- ΔPc is the change in pressure from baseline (hydrostatic) conditions (Pa).
- g is the acceleration of gravity (m/s^2).
- zu is the elevation of the base of the lowermost USDW (m).
- zi is the elevation of the top of the injections zone (m).
- pi is the fluid density in the injection zone (kg/m^3).
- pu is the fluid density in the USDW (kg/m^3).

Critical Threshold Pressure Increase Estimation at RTE-10

For the purposes of delineating the ΔPc for the RTE study area, constant fluid densities for the lowermost USDW (the Fox Hills Formation) and the injection zone (the Broom Creek Formation) were used. A density of 1,001 kg/m^3 was used to

Figure 3-14. Cross section of the major aquifer layers in the RTE storage facility area (modified from Trapp and Kroft, 1975). The location of the water wells used to create the cross section are represented on the inset map. The water wells are labeled with their designation which also correlates to their township range location (e.g., 139-092-18CCC is located in T139N R92W, Section 18).

				represent the USDW fluids, and a density of 1,106 kg/m^3, which is estimated based on the in situ brine salinity, temperature, and pressure, was used to represent injection zone fluids. Critical pressure threshold increases were calculated for the proposed storage reservoir at a range of depths across the reservoir using Equations 2 and 3, depth from the bottom of the USDW, injection zone depth, and fluid density values from the RTE-10 well (Table A-4). Using this method, the threshold pressure increase at the top of the Broom Creek Formation at the RTE-10 well was determined to be 107.3 psi. These estimates of critical threshold pressure increase were compared to potential pressure increases within the storage facility area that would result from CO_2 injection and the potential lateral extent of the injection fluid as determined by predictive simulations. Table A-2 provides estimates of ΔPc for various depths within the Broom Creek Formation, which were then compared against the difference in pressure predicted for each cell in the simulation model at the end of injection, where the greatest increase in pressure was observed. Within the bounds of the modeled area and throughout the entire storage facility area, the maximum pressure difference during the final year of injection is estimated to reach approximately 52 psi, which occurs in near proximity to the injection well. This pressure is below the calculated critical threshold pressure increase of 107.3 psi. Therefore, the critical pressure is not exceeded at the RTE injection site anywhere within or around the injected CO_2 plume and critical pressure is not a deciding factor in determining the AoR extent.	
	NDAC 43-05-01-05 §1b(2)(l)	**NDAC 43-05-01-05 §1b(2)(l)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream.	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	***2.4.4 Geomechanical Information of Confining Zone*** *2.4.4.1 Fracture Analysis* Fractures within the Opeche Formation, the overlying confining zone, and Amsden Formation, the underlying confining zone, have been assessed during the description of the RTE-10 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural, in situ fractures were assessed through the interpretation of the FMI log acquired during the drilling of the RTE-10 well. *2.4.4.2 Fracture Analysis Core Description* Fractures within the Opeche Formation are primarily closed and are commonly filled with anhydrite. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter scale. were observed in the Amsden core interval from the RTE well. direction of features observed. Figures 2-35a and 2-35b show two sections of the interpreted borehole imagery and the primary features observed. The far-right track on Figure 2-35a notes the presence of electrically resistive features. These are interpreted as minor anhydrite-filled fractures. Figure 2-35b demonstrates that the tool provides information on surface boundaries and bedding features. Some isolated fractures are identified in Figure 2-35b and are likely clay-filled because of their electrically conductive signal. Figures 2-36a and 2-36b show two thin-section images and give an indication of different minerals within the reservoir and observed change in the electrical response shown on the FMI log. Finally, Figure 2-37 shows the logged interval for the entire Opeche Formation. As shown, the section closest to the Broom Creek (6,377 ft) is dominated by compaction features (stylolites) and has corresponding tensional features, as noted in the core description analysis. The observed stylolites are parallel to bedding and are commonly filled with clay minerals. Effectively, these features reduce the porosity of a formation. The midregion of the formation is dominated by electrically resistive features likely due to the presence of anhydrite-filled fractures. Toward the upper portion of the formation, fractures are fewer in number but are still found to be electrically resistive. The diagrams shown in Figures 2-38 and 2-39	the traces of features observed and their the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche FMI borehole image analysis. Figure 2-36a. Plane-polarized light thin-section images from the RTE well Opeche Formation. This image shows the silt-rich nature of this interval of the Opeche Formation. On the example shown, the quartz grains (white) are rimmed by iron. Figure 2-36b. Plane-polarized light thin-section images from the RTE well Opeche Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white quartz grains) is clay and is likely responsible for the electrical conductivity identified on the FMI log. Figure 2-37. Interpreted FMI log through the lower Opeche Formation. Figure 2-38. Conductive fracture dip orientation in the Opeche Formation. Figure 2-39. Resistive fracture dip orientation in the Opeche Formation.

				provide the orientation of the electrically conductive and resistive fractures in the Opeche Formation. As shown, the electrically conductive fractures are fewer in number and are mainly oriented NW–SE. On the other hand, the resistive fractures have no preferred orientation. The logged interval of the Amsden shows that the main features present are stylolite–tension pairs, an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. Two zones at 6,743 and 6,762 ft, respectively, show some evidence of resistive fractures (Figure 2-40). Core was not retrieved from this depth. The interpretation of this logged interval supports the core-based and thin-section descriptions, suggesting these features are anhydrite-filled. The rose diagrams shown in Figures 2-41 and 2-42 provide the orientation of the conductive and resistive features in the Amsden Formation. As shown, only one electrically conductive feature was picked in the Amsden interval and is oriented NE–SW. Some electrically resistive features are present and oriented N–S, NE–SW, and E–W, respectively. Drilling-induced fractures were identified mainly in the Amsden Formation and are oriented NE–SW (Figure 2-43), parallel to the maximum horizontal stress (SH_{max}). For additional information, go to Section 2.4.4.3 of the RTE SFP. *2.4.4.4 Stress* During drilling of the RTE-10 well, an openhole MDT minifrac was completed to determine the minimum horizontal stress of the formation. The minifrac operation was performed using a dual-packer setup where four minifrac tests were successful among the seven conducted. The induced fractures observed in the Amsden Formation have an orientation NE–SW, parallel to the maximum horizontal stress. Figure 2-44 shows an annotated example of an expected result in the determination of minimum horizontal stress during MDT applications. As shown, the combined insight gained from the propagation pressure, closure pressure, and reopening pressure define the minimum horizontal stress in the subsurface (Figure 2-44). Within the Opeche Formation confining zone, several attempts were made to generate the fracture needed to determine a suitable breakdown pressure, which is generally considered a close approximation of minimum horizontal stress of a material. A successful test was performed in the Opeche Formation at a depth of 6,377 ft, 3 vertical feet above the reservoir contact. Figure 2-44 shows the results of testing in the overlying Opeche Formation and presents the multiple cycles performed during the determination of initial breakdown pressure, fracture propagation pressure, and closure pressure. As shown, the breakdown pressure was in excess of 7,500 psi. To determine the potential for reopening and closure pressures, injection was reinitiated and allowed to develop until a stable value was attained. Based on the test, the average minimum stress is shown in Table 2-17. **Table 2-17. Average Minimum Stress of the Opeche Formation as Determined by Horizontal Stress Test** Depth, ft: 6,377; Average Propagation Pressure, psi: 4,995; Reopening Pressure, psi: 4,823; Closure Pressure, psi: 4,680; Average Minimum Stress, psi: 4,680 For additional information, go to Section 2.4.4.4 of the RTE SFP. *2.4.4.5 Ductility and Rock Strength* Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Opeche Formation core in the RTE-10 well. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5,800 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material. Because of the low porosity and anhydrite mineralogy, samples were not saturated for testing. Table 2-18 shows the sample parameters, and Table 2-19 shows the elastic parameters obtained. Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-45, the sample failed at a maximum stress of 143 MPa (20,740 psi). Based on the plot below, the final stage (Radial Stage 4) of testing, shown in yellow, has significant residual strength postfailure, indicating a high degree of ductility.	Figure 2-40. Interpreted FMI log through the upper Amsden Formation. Figure 2-41. Conductive fracture dip orientation in the Amsden Formation. Figure 2-42. Resistive fracture dip orientation in the Amsden Formation. Figure 2-43. Drilling-induced fractures dip orientation in the Amsden Formation. Figure 2-44. Results of MDT testing for a depth interval of 6,377 ft in the Opeche Formation. Figure 2-45. Results of multistage triaxial test performed at confining pressures exceeding 40 MPa (5800 psi), providing information regarding the elastic parameters and peak strength of the rock sample. Failure occurred at the fourth-stage peak stress of 143 MPa.

Table 2-17. Average Minimum Stress of the Opeche Formation as Determined by Horizontal Stress Test

Depth, ft	Average Propagation Pressure, psi	Reopening Pressure, psi	Closure Pressure, psi	Average Minimum Stress, psi
6,377	4,995	4,823	4,680	4,680

				For additional information, go to Section 2.4.4.5 of the RTE SFP.	

Table 2-3. Description of RTE-10 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Inyan Kara	4,849.66	1,947.97
Inyan Kara	4,869.73	1,956.62
Inyan Kara	4,910.08	1,974.03
Mean Inyan Kara Pressure	1,959.51	
Inyan Kara Formation Pressure Gradient, psi/ft	0.40	
Broom Creek	6,432.17	2,935.16
Broom Creek	6,458.91	2,947.73
Broom Creek	6,565.09	2,997.91
Mean Broom Creek Pressure	2,960.14	
Broom Creek Pressure Gradient, psi/ft	0.45	

Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

Table A-1. MDT Pressure Measurements Recorded from the RTE-10 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
6,438	2,932.88	0.45
6,441	2,932.21	0.45
6,511	2,963.00	0.45
6,539	2,976.54	0.45
6,540	2,975.64	0.45

* Measured depth.

Table A-2. Summary of Reservoir Properties in the Simulation Model

Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche: 0.03 Broom Creek: ~471 Amsden: ~0.54	Opeche: ~14 Broom Creek: ~23 Amsden: ~4	~2,900	164,000	Open (Infinite-Acting)

	NDAC 43-05-01-05 §1b(2)(o)	**NDAC 43-05-01-05 §1b(2)(o)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones*** Several additional formations provide additional confinement above the Opeche Formation. Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-15). Together with the Opeche, these formations are 1,200 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-30). Above the Inyan Kara Formation, 3,000 ft of impermeable rocks acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-31). Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-15).	Figure 2-30. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. Figure 2-31. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

				These formations between the Broom Creek and Inyan Kara and between the Inyan Kara and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin. Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Inyan Kara. Monitoring the Inyan Kara Formation provides an additional opportunity for monitoring, mitigation, and remediation (Section 4). The depth to the Inyan Kara Formation in the project area is approximately 4,800 ft, and the formation itself is about 350 ft thick. For additional information, go to Section 2.4.2 of the RTE SFP. **Table 2-15. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the RTE-10 well)** Name of Formation / Lithology / Formation Top Depth, ft / Thickness, ft / Depth Below Lowest Identified USDW, ft Pierre / Shale / 1,969 / 2,063 / 0 Greenhorn / Shale / 4,032 / 435 / 2,063 Mowry / Shale / 4,467 / 314 / 2,498 Inyan Kara / Sandstone / 4,781 / 345 / 2,812 Swift / Shale / 5,125 / 494 / 3,156 Rierdon / Shale / 5,619 / 173 / 3,650 Piper Kline / Limestone / 5,792 / 139 / 3,823 Piper Picard / Shale / 5,931 / 68 / 3,962 Spearfish / Siltstone / 5,999 / 230 / 4,030 Minnekahta / Limestone / 6,229 / 47 / 4,260	
Area of Review Delineation	NDAC 43-05-01-05 §1j & §1b(3)	**NDAC 43-05-01-05 §1j** j. An area of review and corrective action plan that meets the requirements pursuant to Section 43-05-01-05.1. **NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within 1 mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and 1 mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:	**3.0 AREA OF REVIEW** **3.1 AOR Delineation** ***3.1.1 Written Description*** North Dakota CO_2 storage regulations require that each storage facility permit delineate an AoR, which is defined as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity (North Dakota Administrative Code [NDAC] § 43-05-01-01 Subsection 4). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AoR encompasses the region overlying the injected free-phase CO_2 and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or fractures) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and the resultant pressure as the "critical threshold pressure." The results of computational modeling and simulation of 20 years of CO_2 injection at the RTE site show that consequent subsurface pressure increases are below the critical threshold pressure necessary to force formation fluids into USDWs (Figure 3-1). Within the bounds of the modeled area and throughout the entire storage facility area, the maximum fluid pressure increase during the final year of injection is estimated to be 52 psi, which occurs near the RTE-10 wellbore. This maximum pressure increase is below the calculated critical threshold pressure increase of 107.3 psi (Appendix A, Table A-2). At the estimated maximum fluid pressure increase (52 psi), a column of formation fluid could be raised to a depth of 4,223 feet (i.e., the Mowry Formation) based on calculations and assuming a vertical migration pathway exists. NDAC § 43-05-01-05 Subsection 1b(3) requires, "A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within 1 mile [1.61 kilometers], or any other distance as deemed	

				necessary by the commission, of the facility area boundary." Based on the pressure response of the simulated CO_2 injection, the resulting AoR for the RTE project is delineated as being 1 mile beyond the facility area boundary. This extent ensures compliance with existing state regulations. Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AoR boundary etc.) and the assumptions and justification used to delineate the AoR. The two deep wells located in the RTE project AoR that penetrate the storage reservoir were evaluated by a professional engineer pursuant to NDAC § 43-05-01-05 Subsection 1b(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records. The evaluation determined that both wells penetrating the storage reservoir within the AoR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Table 3-2–3-4 and Figures 3-6 and 3-7). An extensive geologic and hydrogeologic characterization, performed by a team of geologists, has shown no evidence of transmissive faults or fractures in the upper confining zone within the AoR and has shown evidence that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AoR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone to prevent vertical fluid movement and protect USDWs. This section of the storage facility permit application is accompanied by maps and a cross section (Figures 3-1–3-5) that include information required in accordance with NDAC § 43-05-01-05 Subsection 1a and 1b(3) and § 43-05-01-05.1 Subsection 2, such as all critical boundaries and the location of any proposed injection wells or monitoring wells, the presence of significant surface structures or land disturbances, and the location of water wells and any other wells within the AoR boundary. Table 3-1 lists all surface and subsurface features that were investigated as part of the AoR evaluation, pursuant to NDAC § 43-05-01-05 Subsection 1a and 1b(3) and NDAC § 43-05-01-05.1 Subsection 2. Surface features that were investigated but not found within the AoR boundary are identified in Table 3-1. **See Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS.**	
	NDAC 43-05-01-05 §1b(3) & §1a	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within 1 mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC 43-05-01-05 §1a** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area.	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir. ii. Location of all proposed wells. iii. Location of proposed cathodic protection boreholes. iv. Any existing or proposed above ground facilities.	**3.1.2 Supporting Maps**	Figure 3-2. Final AoR map showing the RTE storage facility area, including the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and AoR (dotted black boundary). Black circles represent occupied dwellings, and orange boundaries represent buildings. Table 3-1. Investigated and Identified Surface and Subsurface Features (Figures 3-1 through 3-5)
	NDAC 43-05-01-05 §1b(2)(a)	**NDAC 43-05-01-05 §1b(2)(a)** (a) All wells, including water, oil, and natural gas exploration and development wells, and	b. A map showing the following within the storage reservoir area and within 1 mile outside of its boundary:	**3.1.2 Supporting Maps**	Figure 3-2. Final AoR map showing the RTE storage facility area, including the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area

		other man-made subsurface structures and activities, including coal mines, within the facility area and within 1 mile [1.61 kilometers] of its outside boundary.	i. All wells, including water, oil, and natural gas exploration and development wells. ii. All other man-made subsurface structures and activities, including coal mines.		(dotted white boundary), and AoR (dotted black boundary). Black circles represent occupied dwellings, and orange boundaries represent buildings. Figure 3-3. AoR map in relation to nearby legacy wells and groundwater wells. Shown are the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and 1-mile AoR (dotted black boundary). All groundwater wells and springs in the AoR are identified above. Figure 3-4. AoR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and 1-mile AoR (dotted black boundary). Orange circles represent nearby legacy wells near the project area, including within the 1-mile AoR. Figure 3-5. Cross section of the AoR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (RTE-10), the proposed monitoring well (RTE-10.2), and the Rummel-State 1 (NDIC File No. 6797) well within the AoR. Depths are referenced to mean sea level.
	NDAC 43-05-01-05 §1c NDAC 43-05-01-05.1 §1a	**NDAC 43-05-01-05 §1c** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational. **NDAC 43-05-01-05.1 §1a** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based.	c. A description of the method used for delineating the area of review, including: i. The computational model to be used. ii. The assumptions that will be made. iii. The site characterization data on which the model will be based.	**Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS**	
	NDAC 43-05-01-05.1 §1b(1-4)	**NDAC 43-05-01-05.1 §1b(1-4)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review.	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review. (2) Any monitoring and operational conditions that would warrant a	**3.3 Reevaluation of AOR and Corrective Action Plan** It is required that the storage operator routinely reevaluate the AOR and corrective action plan, with the period between evaluations not to exceed 5 years. As part of the SFP, the application describes the following: • Any monitoring and operational conditions that would warrant a reevaluation of the AOR prior to the scheduled 5-year reevaluation date.	

		(2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation. (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	reevaluation of the area of review prior to the next scheduled reevaluation date. (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation. (4) How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection. b. How corrective action will be adjusted if there are changes in the area of review.	• How monitoring and operational data (e.g., injection rate and pressure) will be used to inform a reevaluation of the AOR and corrective action plan, including how the computational model that was used to determine the AOR will be updated and what operational data will be used as the basis for that update. • How corrective action, if necessary, will be conducted, including 1) what corrective action will be performed prior to, or following, injection and 2) how corrective action will be adjusted if there are changes in the AOR.	
	NDAC 43-05-01-05 §1b(2)(b)	**NDAC 43-05-01-05 §1b(2)(b)** (b) All man-made surface structures that are intended for temporary or permanent human occupancy within the facility area and within 1 mile [1.61 kilometers] of its outside boundary.	e. A map showing the areal extent of all man-made surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within 1 mile outside of its boundary.	**3.1.2 Supporting Maps**	Figure 3-2. Final AoR map showing the RTE storage facility area, including the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and AoR (dotted black boundary). Black circles represent occupied dwellings, and orange boundaries represent buildings.
	NDAC 43-05-01-05 §1b(2) ¶	**NDAC 43-05-01-05 §1b(2)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within 1 mile outside of its boundary.	**2.6 Potential Mineral Zones** The North Dakota Geological Survey recognizes the Spearfish as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-54). There has been no exploration for, nor development of, hydrocarbon resource from the Spearfish Formation in the greater RTE project region. There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the storage facility area. Although there was some historical gas production from deeper formations along the nearby Heart River Fault trend, there is no known commercial accumulations of hydrocarbons in the storage facility area. Shallow gas resources can be found in many areas of North Dakota, but there are no known references to shallow gas resources in the greater RTE project area.	Figure 2-54. Drillstem results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020).

		features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within 1 mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	NDAC 43-05-01-05 §1b(3) NDAC 43-05-01-05.1 §2b	**NDAC 43-05-01-05 §1b(3)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within 1 mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC 43-05-01-05.1 §2b** b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone.	g. A map identifying all wells within the AoR, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	**3.1.2 Supporting Maps**	Figure 3-4. AoR map in relation to nearby legacy wells. Shown are the stabilized CO_2 plume extent postinjection (purple boundary and shaded area), storage facility area (dotted white boundary), and 1-mile AoR (dotted black boundary). Orange circles represent nearby legacy wells near the project area, including within the 1-mile AoR.

<table>
<tr>
<td></td>
<td></td>
<td>Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>NDAC 43-05-01-05 §1b(3)(a)

NDAC 43-05-01-05 §1b(3)(b)

NDAC 43-05-01-05 §1b(3)(c)

NDAC 43-05-01-05 §1b(3)(d)

NDAC 43-05-01-05 §1b(3)(e)</td>
<td>NDAC 43-05-01-05 §1b(3)(a)
(a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir.

NDAC 43-05-01-05 §1b(3)(b)
(b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion.

NDAC 43-05-01-05 §1b(3)(c)
(c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within the area of review; their positions relative to the injection zone; and the direction of water movement, where known.

NDAC 43-05-01-05 §1b(3)(d)
(d)Maps and cross sections of the area of review.

NDAC 43-05-01-05 §1b(3)(e)
(e) A map of the area of review showing the number or name and location of all injection</td>
<td>h. A review of these wells must include the following:

(1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation.

(2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation.

(3) A description of each well:
a. Type
b. Construction
c. Date drilled
d. Location
e. Depth
f. Record of plugging
g. Record of completion

(4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following:
a. Their positions relative to the injection zone
b. The direction of water movement, where known
c. General vertical and lateral limits
d. Water wells
e. Springs

(5) Map and cross sections of the area of review.

(6) A map of the area of review showing the following:</td>
<td>3.2 Corrective Action Evaluation

Table 3-2. Wells in AoR Evaluated for Corrective Action

Table 3-3. Rummel-State 1 (NDIC File No. 6797) Well Evaluation

Table 3-4. RTE 10.2 (NDIC File No. 37858) Well Evaluation

Table 3-1. Investigated and Identified Surface and Subsurface Features (Figures 3-1 through 3-5)
<table>
<tr><th>Surface and Subsurface Features</th><th>Investigated and Identified (Figures 3 1–3-5)</th><th>Investigated But Not Found in AoR</th></tr>
<tr><td>Producing (active) Wells</td><td></td><td>x</td></tr>
<tr><td>Abandoned Wells</td><td>x</td><td></td></tr>
<tr><td>Plugged Wells or Dry Holes</td><td>x</td><td></td></tr>
<tr><td>Deep Stratigraphic Boreholes</td><td></td><td>x</td></tr>
<tr><td>Subsurface Cleanup Sites</td><td></td><td>x</td></tr>
<tr><td>Surface Bodies of Water</td><td>x</td><td></td></tr>
<tr><td>Springs</td><td>x</td><td></td></tr>
<tr><td>Water Wells</td><td>x</td><td></td></tr>
<tr><td>Mines (surface and subsurface)</td><td></td><td>x</td></tr>
<tr><td>Quarries</td><td></td><td>x</td></tr>
<tr><td>Subsurface Structures (e.g., coal mines)</td><td></td><td>x</td></tr>
<tr><td>Location of Proposed Wells</td><td>x</td><td></td></tr>
<tr><td>*Location of Proposed Cathodic Protection Boreholes</td><td>NA</td><td>NA</td></tr>
<tr><td>Any Existing Aboveground Facilities</td><td>x</td><td></td></tr>
<tr><td>Roads</td><td>x</td><td></td></tr>
<tr><td>State Boundary Lines</td><td></td><td>x</td></tr>
<tr><td>County Boundary Lines</td><td>x</td><td></td></tr>
<tr><td>Indian Boundary Lines</td><td></td><td>x</td></tr>
<tr><td>Other Pertinent Surface Features</td><td>x</td><td></td></tr>
</table>
*There are no plans for cathodic protection for the RTE injection wells</td>
<td>Figure 3-5. Cross section of the AoR from the geologic model showing lithofacies distribution in the Broom Creek Formation, the proposed injection well (RTE-10), the proposed monitoring well (RTE-10.2), and the Rummel-State 1 (NDIC File No. 6797) well within the AoR. Depths are referenced to mean sea level.

Figure 3-6. Rummel-State 1 (NDIC File No. 6797) well schematic showing the location and thickness of cement plugs.

Figure 3-7. RTE 10.2 (NDIC File No. 37858) well schematic showing the current status and wellbore construction.</td>
</tr>
</table>

		wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads.	a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads		
	NDAC 43-05-01-05 §1b(3)(b)(f)	**NDAC-43-05-01-05 §1b(3)(b)(f)** (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines.	(7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		
	NDAC 43-05-01-05 §1b(3)(g)	**NDAC 43-05-01-05 §1b(3)(g)** (g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	**Appendix C – FRESHWATER WELL FLUID-SAMPLING LABORATORY ANALYSIS** **3.4 Protection of USDWs** ***3.4.1 Introduction of USDW Protection*** The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the AoR. The Opeche Formation is the primary confining zone with additional confining layers above, geologically isolating all USDWs from the injection zone (Table 2-14).	Figure 3-8. Major aquifer systems of the Williston Basin. Figure 3-9. Upper stratigraphy of Stark County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Trapp and Croft, 1975).

				3.4.2 Geology of USDW Formations The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 3-8). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1,000 and 1,500 ft thick (Thamke and others, 2014). The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and the Tertiary Golden Valley and White River Formations (Figure 3-9). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not The lowest USDW in the AoR is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a ft thick. The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently The Pierre Shale is a thick, regionally extensive shale unit which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox (Figure 3-11). Water sampled from the Fox Hills Formation is sodium bicarbonate type with a total dissolved solids (TDS) fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a 12). Two other Fox Hills wells previously served the city of Richardton, North Dakota, but were plugged and abandoned in Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AoR (Figure 3-13). These formations are often used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. Thickness of this basal sand ranges from approximately 50 to 200 ft and can be found at a depth of approximately 550 ft. Tongue River groundwaters are generally sodium bicarbonate with a TDS of approximately 1,000 ppm (Trapp and Croft, 1975). The Sentinel Butte Formation, a silty fine- to medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The upper Sentinel Butte Formation is predominantly sandstone with lignite interbeds, forming another important source of groundwater in the region. Generally, the upper Sentinel Butte is 100 to 150 ft thick in the AoR. TDS in the Sentinel Butte Formation range from approximately 400–1000 ppm (Trapp and Croft, 1975).	Figure 3-10. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). Figure 3-11. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Stark County (modified from Fischer, 2013). Figure 3-12. Map of water wells in the AoR in relation to the RTE Facility, RTE-10 and RTE-10.2 wells, stabilized CO_2 plume extent, facility area, 1-mile AoR, and legacy oil and gas wells. Figure 3-13. West–east cross section of the major aquifer layers in Stark County (modified from Trapp and Kroft, 1975). The black dots on the inset map represent the locations of the Figure 3-14. Cross section of the major aquifer layers in the RTE storage facility area (modified from Trapp and Kroft, 1975). The cross section are represented on the inset map. designation which also correlates to their township range location (e.g., 139-092-18CCC is located in T139N R92W, Section 18).
Required Plans	NDAC 43-05-01-05 §1k	**NDAC 43-05-01-05 §1k** k. The storage operator shall comply with the financial responsibility requirements	a. Financial Assurance Demonstration	**4.2 Financial Assurance Demonstration Plan** **Table 4-5. Cost Estimates for Activities to Be Covered**	

		pursuant to Section 43-05-01-9.1.			

Activity	Estimated Total Cost (millions of dollars)
Corrective Action on Wells in the AoR	0
Plugging of Injection and Monitoring Wells*	0.25
Postinjection Site Care and Facility Closure	1.73
Emergency and Remedial Response (including endangerment to USDWs)	16.0
Total	17.98

	NDAC 43-05-01-05 §1d	**NDAC 43-05-01-05 §1d** d. An emergency and remedial response plan pursuant to Section 43-05-01-13.	b. An emergency and remedial response plan.	**4.1 Emergency and Remedial Response Plan** ***4.1.1 Background*** ***4.1.2 Local Resources and Infrastructure*** ***4.1.3 Identification of Potential Emergency Events*** *4.1.3.1 Definition of an Emergency Event* ***4.1.4 Emergency Response Actions*** ***4.1.5 Response Personnel/Equipment and Training*** 4.1.5.1 Response Personnel and Equipment ***4.1.6 Emergency Communications Plan*** ***4.1.7 ERRP Reviews and Updates***	Figure 4-1. Locations of the RTE ethanol plant and CO_2 injection well (RTE-10) and monitoring well (RTE-10.2). Also shown are the city limits of Richardton, North Dakota; the RTE property limits; the Bureau of Land Management (BLM) property limits; the planned CO_2 flow line from the ethanol plant to the CO_2 injection well; and the Burlington Northern Santa Fe (BNSF) railroad. Figure 4-2. Residential, commercial, and public land use within 1 mile of the storage facility area.
	NDAC 43-05-01-05 §1e	**NDAC 43-05-01-05 §1e** e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to Section 43-05-01-13.	c. A detailed worker safety plan that addresses the following: i. Carbon dioxide safety training ii. Safe working procedures at the storage facility	***4.3 Worker Safety Plan (NDAC 43-05-01-05 §1e; NDAC 43-05-01-13)***	
	NDAC 43-05-01-05 §1f	**NDAC 43-05-01-05 §1f** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to Section 43-05-01-15.	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	***4.4.2 Corrosion Monitoring and Prevention Plan*** *4.4.2.1 Corrosion Monitoring* *4.4.2.2 Corrosion Prevention*	
	NDAC 43-05-01-05 §1g	**NDAC 43-05-01-05 §1g** g. A leak detection and monitoring plan for all wells and surface facilities pursuant to Section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere.; (2) Identify potential degradation of ground water resources with particular emphasis on underground	e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to North Dakota Administrative Code (NDAC) Section 43-05-01-14.	***4.4.3 Surface Leak Detection and Monitoring Plan***	Figure 4-4. RTE completed groundwater well sampling program to establish a groundwater baseline, including seasonal fluctuation. The sample locations were located between the proposed CO_2 injection well and the city of Richardton. Figure 4-5. RTE completed an initial soil gas-sampling program to establish baseline soil gas concentrations, including seasonal fluctuation. The sample locations were located within and around the CO_2 injection and monitoring wells of the RTE storage site.

		sources of drinking water. (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.			Figure 4-6. RTE near-surface monitoring plan sample locations showing the Fox Hills Formation (deepest USDW) monitoring wells, existing groundwater wells, and the two soil-gas profile stations in and around the RTE geologic CO_2 storage project site. RTE is currently investigating Well Nos. 61329 and 51011 to determine accessibility for potential sampling. Well Nos. 61338 and 51004 are both identified as abandoned in the North Dakota State Water Commission database.
	NDAC 43-05-01-05 §1h	**NDAC 43-05-01-05 §1h** h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within 1 mile [1.61 kilometers] of the facility area's outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere. (2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water. (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within 1 mile of the facility area's outside boundary.	***4.4.4 Subsurface Leak Detection and Monitoring Program*** ***4.4.5 Near Surface Groundwater and Soil Gas Sampling Monitoring*** ***4.4.6 Completed Baseline Sampling Program*** *4.4.6.1 Groundwater Baseline Sampling* *4.4.6.2 Soil Gas Baseline Sampling*	
	NDAC 43-05-01-05 §1l	**NDAC 43-05-01-05 §1l** l. A testing and monitoring plan pursuant to Section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4.	**4.4 Testing and Monitoring Plan** ***4.4.1 Analysis of Injected Co2 and Injection Well Testing*** *4.4.1.1 CO2 Analysis* *4.4.1.2 Injection Well Integrity Tests* ***4.4.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring*** ***4.4.6 Completed Baseline Sampling Program*** ***4.4.7 Near-Surface (Groundwater – and Soil Gas) Monitoring Plan*** ***4.4.8 Deep Subsurface Monitoring of Free-Phase CO2 Plume and Pressure Front***	Table 4-6. Overview of RTE Monitoring Program for the Geologic Storage of CO_2 Table 4-7. Chemical Components Targeted for Characterization in the Injected CO_2 Table 4-10. Baseline (preinjection), Operational, and Postoperational Monitoring Frequency and Duration for Soil Gas, Groundwater, and Surface Air Table 4-11. Description of RTE Monitoring Program

				4.4.8.1 Direct Monitoring Methods *4.4.8.2 Indirect Monitoring Methods* 4.4.9 Quality Assurance Surveillance Plan; See Appendix D	Figure 4-3. RTE completed an initial sampling program for near-surface groundwater wells and vadose zone soil gas. Shown are all sampling locations completed for the establishment of the baseline monitoring program (water well sample locations and soil gas sample locations); the location of all groundwater wells by type, including all plugged and abandoned legacy oil and gas wells; the city of Richardton; the RTE ethanol plant; the CO_2 flow line; and RTE-10 (injection well) and RTE-10.2 (monitoring well) in relation to the extent of the stabilized CO_2 plume, the storage facility area, and the AoR. Figure 4-7. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection. The simulated plume extent at 5 years (2026) results in a CO_2 plume with a radius of ~1,500 ft. Figure 4-8. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume. Figure 4-9. RTE-10 wellbore schematic showing placement of external BHT/BHP-monitoring gauges and fiber optic. Figure 4-10. RTE-10.2 wellbore schematic showing placement of external BHT/BHP-monitoring gauges and fiber optic. Figure 4-11. Halliburton DataSphere Array System specifications for external BHT/BHP gauges installed in RTE-10 and RTE-10.2. Figure 4-12. Simulated extent of the CO_2 plume at the end of injection operations in red and the stabilized CO_2 plume following the cessation of CO_2 injection in yellow. Surface seismic and borehole VSP seismic data outlines shown on the map will provide coverage for indirectly monitoring the predicted extents of the CO_2 plume over time. Figure 4-13. The map view (left panel) shows the VSP illumination of surface sourcing (black dots) recorded in the borehole with fiber optic DAS. Also, overlain on the illumination plot (right panel) is the simulated CO_2 plume at 5 years (2026) after the start of CO_2 injection. Figure 4-14. The simulated CO_2 maps at the cessation of injection (left panel) and the postinjection stabilized plume (right panel) are

					overlain on the VSP illumination plots from Figure 4-13. These simulated plume overlays illustrate the plume extents can be imaged with the 3D VSP method throughout CO_2 injection operations. The color bar on the right shows lowfold to highfold illumination of the Broom Creek injection interval depth.
	NDAC 43-05-01-05 §1i	**NDAC 43-05-01-05 §1i** i. The proposed well casing and cementing program detailing compliance with Section 43-05-01-09.	h. The proposed well casing and cementing program.	**4.5 Well Casing and Cementing Program** ***4.5.1 RTE-10 – As-Constructed CO_2 Injection Well Casing and Cementing Programs*** ***4.5.2 RTE-10.2 – As-Constructed Monitoring Well Casing and Cementing Programs***	Figure 4-15. RTE-10 as-constructed wellbore schematic. Figure 4-16. RTE-10 isolation scanner results – radial cement evaluation log summary from RTE-10 verifies the material behind the casing and the cement bond index. This enables the analyst to assess isolation in the CO_2 injection zone, confining zones, and USDWs using a high-resolution image. Figure 4-17. RTE-10.2 as-constructed wellbore schematic
	NDAC 43-05-01-05 §1m	**NDAC 43-05-01-05 §1m** m. A plugging plan that meets requirements pursuant to Section 43-05-01-11.5.	i. A plugging plan.	**4.6 Plugging Plan** 4.6.1 RTE-10: P&A Program ***4.6.2 RTE-10: P&A Program***	Figure 4-18. Proposed CO_2 injection well schematic for RTE-10. Figure 4-19. Schematic of proposed abandonment plan for RTE-10. Figure 4-20. Proposed CO_2-monitoring well schematic for RTE-10.2. Figure 4-21. Schematic of proposed abandonment plan for monitoring well RTE-10.2.
	NDAC 43-05-01-05 §1n	**NDAC 43-05-01-05 §1n** n. A postinjection site care and facility closure plan pursuant to Section 43-05-01-19.	j. A post-injection site care and facility closure plan.	**4.7 Postinjection Site and Facility Closure Plan** ***4.7.1 Predicted Postinjection Subsurface Condition*** *4.7.1.1 Pre- and Postinjection Pressure Differential* *4.7.1.2 Predicted Extent of CO_2 Plume* *4.7.1.3 Postinjection Monitoring Plan* ***4.7.2 Groundwater and Soil Gas Monitoring*** ***4.7.3 Monitoring of CO_2 Plume and Pressure Front*** *4.7.3.1 Schedule for Submitting Postinjection Monitoring Results* *4.7.3.2 Site Closure Plan* *4.7.3.3 Submission of Site Closure Report, Survey, and Deed*	Figure 4-22. Predicted pressure increase in storage reservoir following 20 years of injection of 180,000 tonnes per year of CO_2. Figure 4-23. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection. Figure 4-24. Location of soil gas and groundwater well sampling locations included in the PISC monitoring program. Figure 4-25. Areal extents of the 3D and borehole seismic surveys proposed during the PISC period in comparison to the areal extents of the CO_2 plume at cessation of injection and the stabilized plume.

Storage Facility Operations

NDAC 43-05-01-05 §1b(4)

NDAC 43-05-01-05 §1b(4)
(4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission.

The following items are required as part of the storage facility permit application:

a. The proposed average and maximum daily injection rates.

b. The proposed average and maximum daily injection volume.

c. The proposed total anticipated volume of the carbon dioxide to be stored.

NDAC 43-05-01-05 §1b(5)

NDAC 43-05-01-05 §1b(5)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

d. The proposed average and maximum bottom hole injection pressure to be utilized.

e. The proposed average and maximum surface injection pressures to be utilized.

5.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the SFP application presents the engineering criteria for completing and operating the injection well in a manner that protects USDWs. The information that is presented meets the permit requirements for injection well and storage operations as presented in NDAC § 43-05-01-05 (SFP, Table 5-1) and NDAC § 43-05-01-11.3

For additional information, go to Section 5.0 of the RTE SFP.

Table 5-1. RTE-10 Proposed Injection Well Operating Parameters

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume	3.7 million tonnes (71 Bscf)	Based 180,000 tonnes/year (3.5 Bscf/year) for 20 years at an average daily injection rate of 500 tonnes/day (using 360 operating days per year).
Injection Rates		
Proposed Average Injection Rate	500 tonnes/day (9.6 MMscf/day)	Based 180,000 tonnes/year for 20 years (using 360 operating days per year).
Calculated Maximum Daily Injection Rate	4,100 tonnes/day (120 MMscf/day)	Based on surface maximum injection pressure (2,250 psi).
Pressures		
Formation Fracture Pressure at Top Perforation	4,466 psi	Modular dynamics testing (MDT) results fracture propagation formation fracture gradient of 0.7 psi/ft.
Average Operating Surface Injection Pressure	1,300 psi	Proposed injection well operating surface injection pressure.
Surface Maximum Injection Pressure	2,250 psi	Based on maximum pressure rating of the flow line.
Average Operating Bottomhole Pressure (BHP)	3,000 psi	An average BHP of 3,000 psi based on average daily injection rate of 500 tonnes/day.
Maximum BHP	4,019 psi	Calculated maximum BHP 4,019 psi based 90% of the formation fracture pressure 4,466 psi
Tubing-Casing Annular Pressure	100 psi	Variance requested (see Section 5.3) from NDAC § 43-05-01-11.3 Subsection 3 requiring the storage operator to maintain on the annulus a pressure that exceeds the operating injection pressure.

NDAC 43-05-01-05 §1b(6)

NDAC 43-05-01-05 §1b(6)
(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to Section 43-05-01-11.2.

f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone.

g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone.

Table 4-12. Completed Logging Program for RTE-10 and RTE-10.2

Log	Justification	NDAC Section
Ultrasonic, CCL (casing collar locator), VDL (variable-density log), GR (gamma ray), Temperature Log	Identified cement bond quality radially. Detection of cement channels (none observed). Evaluated the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density, porosity, GR, caliper, and spontaneous potential)	Quantified variability in reservoir properties such as resistivity and lithology. Identified the wellbore volume to calculate the required cement volume. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.	43-05-01-11.2(1c[1])

Combinable Magnetic Resonance (CMR)	Aided in interpreting reservoir permeability and determined the best location for modular dynamics testing (MDT) fluid sampling depths, packer setting depths, and stress testing depths. CMR and MDT data combined provided enhanced permeability evaluation, fluid identification, and fluid contacts.	43-05-01-11.2(1c[1])
Spectral GR	Identified clays and lithology that could affect injectivity. Also used for core to log depth correlation.	43-05-01-11.2(2)
Dipole Sonic	Identified mechanical properties including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])
Fracture Finder Log	Quantified fractures in the Inyan Kara and Broom Creek Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
MDT Fluid Sampling	Collected fluid sample from the Inyan Kara and Broom Creek for geochemical testing and TDS (total dissolved solids) quantification.	43-05-01-11.2(2)
MDT Formation Pressure Testing	Collected reservoir pressure tests to establish a pressure profile and mobility.	43-05-01-11.2(2)
MDT Stress Testing	Collected breakdown pressure, fracture propagation pressure, fracture closure pressure (minimum in situ stress) to establish injection pressure limits.	43-05-01-11.2(1c[1])

Appendix B – RTE-10 AND RTE-10.2 FORMATION FLUID SAMPLING LABORATORY ANALYSIS

	NDAC 43-05-01-05 §1b(7)	**NDAC 43-05-01-05 §1b(7)** (7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment.	h. The proposed stimulation program: 1. A description of the stimulation fluids to be used. 2. A determination of the probability that stimulation will interfere with containment.	**5.1 RTE-10 Well – Proposed Completion Procedure to Conduct Injection Operations** Perform Injection Test and Stimulate Broom Creek Formation		

	NDAC 43-05-01-05 §1b(8)	**NDAC 43-05-01-05 §1b(8)** (8) The proposed procedure to outline steps necessary to conduct injection operations.	i. Steps to begin injection operations	**5.1 RTE-10 Well – Proposed Completion Procedure to Conduct Injection Operations** RTE constructed the RTE-10 well (Figure 5-1 and Table 5-2) with intentions to conduct CO_2 stream injection operations, as referenced in previous sections. The following proposed completion procedure outlines the steps necessary to complete the RTE-10 well for injection purposes. For additional information, go to Section 5.1 of the RTE SFP. **5.2 RTE-10.2 Well – Proposed Procedure for Monitoring Well Operations** RTE constructed a second well, the RTE-10.2, Figure 5-5, for direct reservoir-monitoring purposes, as referenced in Section 4, to support deep subsurface monitoring of the RTE-10 CO_2 stream injection well. Monitoring of the CO_2 plume location and the storage reservoir pressure will be conducted continuously through use of the casing-conveyed temperature and pressure gauges installed on the outside of the long-string production casing. Monitoring will be conducted during injection operations, Table 4-6, as well as during the PISC period using the methods summarized in Table 4-23, which are also discussed in more detail in the Testing and Monitoring section of this permit application. Monitoring methods include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, MITs; pulsed-neutron capture/reservoir saturation tool logs) that support CO_2 plume stabilization assessments. For more additional information, go to Section 5.2 of the RTE SFP.	Figure 5-1. RTE-10 as-constructed wellbore schematic. Figure 5-2. RTE-10 proposed perforation intervals of the Broom Creek Formation (green-shaded sections based on the RTE-10_triple combo openhole log March 2020). Figure 5-3. RTE-10 well – proposed CO_2 resistant wellhead schematic – Cameron Supplier. Figure 5-4. RTE-10 well – proposed completed wellbore schematic. Figure 5-5. RTE-10.2 as-constructed well schematic. Figure 5-6. RTE-10.2 well – proposed CO_2-resistant wellhead schematic – Cameron Supplier. Figure 5-7. RTE-10.2 well – proposed completed wellbore schematic.

APPENDIX F

POST-HEARING SUPPLEMENTAL FILING – FINANCIAL RESPONSIBILTY DEMONSTRATION PLAN

SUPPORTING INFORMATION – FINANCIAL RESPONSIBILITY DEMONSTRATION PLAN

1.0 INTRODUCTION

Pursuant to the North Dakota Administrative Code (NDAC) Section 43-05-01-09.1, the storage facility permit application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with the following actions:

- Pursuant to NDAC Section 43-05-01-05.1, corrective action on all active and abandoned wells, which are within the area of review (AOR) and penetrate the confining zone, that have the potential to endanger underground sources of drinking water through the subsurface movement of the injected carbon dioxide or other fluids.

- Pursuant to NDAC Section 43-05-01-11.5, plugging of injection wells.

- Pursuant to NDAC Section 43-05-01-19, implementation of postinjection site care (PISC) and facility closure activities, which includes the 10-year PISC monitoring program.

- Pursuant to NDAC Section 43-05-01-13, implementation of emergency and remedial response actions.

This supporting information for the Financial Responsibility Demonstration Plan provides the details for the cost estimates for each of the above actions based on the information that is provided in the storage facility permit application.

2.0 FINANCIAL RESPONSIBILITY COST ESTIMATES

2.1 Corrective Action

Approach: 1) delineate AOR, 2) identify and evaluate active and abandoned legacy wells within AOR, and 3) remediate legacy wells identified as potential leakage pathways from $300K to $500K per well. No corrective action necessary at time of permitting.

2.2 Plugging of Injection Wells

Approach: assume plugging of one Class VI injection well and one Class VI-compliant monitoring well from $35K to $60K per well, with an expected value of $50K. Wellsite reclamation costs estimate at $75K, with a total well plugging and site reclamation cost of $125K.

2.3 Implementation of Postinjection Site Care (PISC) and Facility Closure Activities

The estimated costs of $1.73 million for implementing PICS as described in the postinjection site care and facility closure plan is provided in Table 2-1 which includes the following: a) near-surface monitoring (e.g., soil gas, shallow groundwater, and Fox Hills Formation Aquifer); b) formation monitoring (e.g., injection well annulus pressure, packer fluid levels, downhole pressure and temperature profiles, pulse neutron logs, ultrasonic logs, and mechanical integrity well tests); and c) coordinated repeat 3D seismic, 3D borehole seismic (vertical seismic), and gravity tests and 2) estimate cost of site closure activities, which has been estimated at $100K based on the integrated environmental control.

Table 2-1. Cost Estimates for Ten-Year PISC Monitoring Efforts

Near-Surface Monitoring	Notes/Comments	Total Estimated Cost
• Soil Gas Sampling and Analysis	24 samples [2 soil gas stations sampled 4 times per year for 3 years] at $6300 per sample	$151,200
• Groundwater Sampling and Analysis • Fox Hills Aquifer Sampling and Analysis	56 samples [7 wells sampled 4 times per year for 2 years] at $4400 per sample	$246,400
Downhole Monitoring		
• PNL Logs	3 logs and $20,000 per log	$60,000
• USIT Tests	3 tests @ $5,000 per test	$15,000
• Mechanical Integrity Tests	2 tests @ $10,000 per test	$20,000
Geophysical Monitoring		
• DAS/DTS equipment and maintenance		$110,000
• 3-D seismic data acquisition	Perform 3 3-D seismic surveys	$890,000
• 3-D seismic data processing		$60,000
• Gravity test data acquisition and processing	Perform minimum of 2 tests	$60,000
Planning, Coordination, Data Interpretation, and Reporting		$116,000
Total		$1,728,600

2.4 Implementation of Emergency and Remedial Response Actions

2.4.1 Emergency Response Actions

A review of the technical risk categories for the Red Trail Energy (RTE) storage project identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger an underground source of drinking water (USDW) and require an emergency response. These events are as follows:

- Integrity failure of injection and/or monitoring well
- Injection well monitoring equipment failure
- Storage reservoir is unable to contain the formation fluid or stored CO_2
- An induced seismic event

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the Emergency and Remedial Response Plan. These response actions are summarized in Table 2-2.

Table 2-2. Response Actions for Potential Emergency Events

Emergency Event	Response Action
Integrity Failure of Injection or Monitoring Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Stop CO_2 injection/vent CO_2 from surface facilities. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the North Dakota Industrial Commission (NDIC) Department of Mineral Resources (DMR) underground injection control (UIC) program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Injection Well-Monitoring Equipment Failure	• Monitor well pressure, temperature, and annulus pressure (manually if necessary) to determine the cause and extent of failure. • Stop CO_2 injection/vent CO_2 from surface facilities. • Identify and, if necessary, implement appropriate remedial actions to repair/replace well monitoring equipment (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 2-2. Response Actions for Potential Emergency Events (continued)

Emergency Event	**Response Action**
The Storage Reservoir Is Unable to Contain the Formation Fluid or Stored CO_2	• Collect confirmation sample(s) of groundwater, soil gas, ambient air, and/or surface water, and analyze them for indicator parameters (see Testing and Monitoring Plan of the supporting plans of the storage facility permit application). • If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to: 1. Install additional monitoring points near the impacted area to delineate the extent of impact. a. If a USDW is impacted above drinking water standards, arrange for an alternative potable water supply for all users of that USDW. b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air monitoring program at the plant boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection, following practices similar to those described in the RTE Risk Management Plan for analyzing the potential impacts of other chemical releases from the RTE plant. c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are being exceeded. 2. Proceed with efforts, if necessary, to 1) remediate USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to air-strip CO_2 from the impacted water (or implement other active remediation processes) and reinject treated water into the subsurface, 2) monitor CO_2 concentrations in the workspace and ambient air to document

Continued . . .

Table 2-2. Response Actions for Potential Emergency Events (continued)	
Emergency Event	**Response Action**
The Storage Reservoir Is Unable to Contain the Formation Fluid or Stored CO_2 (continued)	reduction of CO_2 concentrations to background levels over time; and 3) monitor the reduction of impacts to surface waters to background levels as a result of natural attenuation processes or implement active/passive remediation of surface waters to achieve acceptable background levels of impacts. • Continue all remediation and monitoring at an appropriate frequency (as determined by RTE and the NDIC DMR UIC program director) until the unacceptable, adverse impacts have been fully addressed.
Induced Seismic Event	• Identify where (i.e., the epicenter) and when the event occurred. • Determine whether there is a connection with injection activities. • Determine mechanical integrity of all project wells and formation seals. • If warranted, stop CO_2 injection/vent CO_2 from surface facilities, and implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify status of wells and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment of USDWs are detected, identify and implement appropriate response actions in accordance with the RTE Emergency Action Plan (in consultation with the NDIC DMR UIC program director).

2.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing these emergency response actions in Table 2-2 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Without this knowledge, it is not possible to design appropriate remedial measures. Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or analogies with other pollutants, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geological storage unit (Manceau and others, 2014).

2.4.2.1 Identification of Remediation Technologies

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 2-3. The impacted media in Table 2-3 include groundwater/USDWs, unsaturated zone soil, surface water, indoor environments, and atmosphere;

Table 2-3. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Unsaturated Zone	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active venting systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Environment	Sealing of leak points
	Depressurization
	Ventilation adjustment

the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, there is no widely accepted methodology for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

2.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at the CO_2 geologic storage site of RTE, cost estimates developed by Bielicki and others (2014) were used to derive a cost range for the project related to the undesired migration of CO_2 from a geologic storage unit. Extrapolating these literature costs, which were based on a case study site in the Michigan Sedimentary Basin, to the RTE project only provides an order-of-magnitude estimate of the potential costs due to the significant site-specific differences in the storage projects; however, the range of costs estimated in this manner are believed to be conservatively high in nature, making them more than sufficient for informing the value of the financial instrument that must be secured for the project, as described in the Financial Responsibility Demonstration Plan.

<u>Case Study Description</u>

Bielicki and others (2014) examined the costs associated with remediating undesired migration of CO_2 from a geologic storage unit as part of a case study of an extreme leakage situation. The case study involved the continuous annual injection of 9.5 Mt (9,500,000 metric tons) of CO_2 into the Mt. Simon sandstone of the Michigan Sedimentary Basin over a period of 30 years. It assumed every well in the basin was a potential leakage pathway and that no action was taken to mitigate any of these leakage pathways. In addition, eight UIC Class I injection wells, which were located within approximately 1 mile of the CO_2 injection well, were also identified as leakage pathways. Four hundred probabilistic simulations of the CO_2 injection were performed and produced estimates of the area of the CO_2 plume as well as leakage rates of CO_2 from the storage reservoir to four aquifers as well as to the surface.

<u>Cost Estimates</u>

Story lines were developed for the site based on 1) risk assessments for the geologic storage of CO_2; 2) consequences of leakage; 3) lay and expert opinion of leakage risk; 4) modeling of CO_2 injection and leakage for the case study; and 5) input from local experts, oil and gas engineers, academics, attorneys, and other environmental professionals familiar with the Michigan Sedimentary Basin. Cost estimates for managing leakage events were then generated for first-of-a-kind (FOAK) and nth-of-a-kind (NOAK) projects based on a low-cost and high-cost story line. These cost estimates provided a breakdown of the costs into the following categories:

- Find and fix a leak
- Environmental remediation
- Injection interruption
- Technical remedies for damages
- Legal costs
- Business disruption to others, e.g., natural gas storage

- Labor burden to others

Of interest for the financial responsibility demonstration plan is the environmental remediation cost estimate, which was provided for a leak scenario where there was interference with groundwater as well as a scenario where there was groundwater interference combined with CO_2 migration to the surface.

Environmental Remediation – Low-Cost and High-Cost Story Line

The low-cost and high-cost story lines for the two components of environmental remediation, groundwater interference and migration to the surface are summarized in Table 2-4. As shown in Table 2-4, the low-cost story lines are characterized by independent leak scenarios that either result in interference with groundwater or CO_2 migration to the surface. On the other hand, the high-cost story lines are interrelated, where it is assumed that the high-cost story line for CO_2 migration to the surface is conditional upon the existence of the high-cost story line for groundwater interference.

Estimated Environmental Remediation Costs – FOAK and NOAK Projects

Based on the above story lines, the estimated environmental remediation costs for the high-cost story lines are basically the same for both FOAK and NOAK projects:

- High-cost story line – Groundwater interference, alone: ~ $13M
- High-cost story line – Groundwater interference with CO_2 migration to the surface: $15M to $16M

2.4.2.3 Input for the Financial Responsibility Demonstration Plan

The estimated costs for the environmental remediation of the high-cost story line for the case study, $15M to $16M, likely represents a conservatively high estimate of similar costs for the RTE CO_2 geologic storage project. This statement is based primarily on the fact that the quantity of CO_2 injection of the case study (9,500,000 metric tons of CO_2 per year) is significantly larger than the planned injection quantity of the RTE CO_2 geologic storage project (180,000 metric tons of CO_2 per year). Furthermore, the case study site had 450,000 active and abandoned wells, 400,000 of which penetrate the shallow subsurface to provide for drinking water, irrigation, and industrial uses. In contrast, there is one abandoned well (no corrective action necessary), one proposed CO_2 injection well, and one CO_2 storage monitoring well located in the area of the RTE CO_2 geologic storage project. As such, the extreme leakage scenario of the case study represents a more extensive leakage scenario that could exist at the RTE site. Accordingly, even though the same remedial technologies and strategies may be used at both sites to address CO_2 migration, it is assumed that the cost estimates provided for the case study represent a conservatively high, maximum cost, for the RTE project. It is on this basis that the value of $16M has been used as one of the cost inputs into the determination of the financial instrument that will be put in place for the RTE CO_2 geologic storage project.

Table 2-4. Low-Cost and High-Cost Story Line for Environmental Remediation

Low-Cost Story Line	
Groundwater Interference	• A small amount of CO_2 migrates into a deep formation that has a total dissolved solids concentration of ~9000 ppm. By definition, this unit is a USDW, but the state has abundant water resources, and there are no foreseeable uses for water from this unit. • Regulators require that two monitoring wells be drilled into the affected USDW and three monitoring wells be drilled into the lower most potable aquifer (total dissolved solids concentration of <1000 ppm) to verify the extent of the impacts of the leak. No legal action is taken. • Injection is halted from the time that the leak is discovered until monitoring confirms that containment is effective (9 months). • The UIC regulator determines that no additional remedial actions are necessary.
CO_2 Migration to the Surface	• A leaking well provides a pathway whereby CO_2 discharges directly to the atmosphere. • Neither CO_2 nor brine leaks into the subsurface formation outside the injection formation in significant quantities. • The CO_2 injection is halted for 5 days, and the leaking well is promptly plugged.
High-Cost Story Line	
Groundwater Interference	• A community water system reports elevated arsenic. Monitoring suggests that the native arsenic in the formation may have been mobilized by pH changes in the aquifer caused by CO_2 impacts to the aquifer. • A new water supply well is installed to serve the community, and the former water supply wells are plugged and capped. • Potable water is provided to the affected households during the 6 months required to drill the new water supply wells. • Groundwater regulators take legal action on the geologic storage operator to force remediation of the affected USDW using pump and treat technology. • UIC regulators require remedial action to remove, through a CO_2 extraction well, an accumulation of CO_2 that has the potential to affect the drinking water. • CO_2 injection is halted for 1 year during these remediation activities.
CO_2 Migration to the Surface	• The high-cost story line for groundwater is required. • A hyperspectral survey completed during the diagnostic monitoring program identifies surface leakage in a sparsely populated area. • Elevated CO_2 concentrations are detected by a soil-gas survey and by indoor air quality sampling in basements of several residences. • Affected residents are housed in a local hotel for several nights while venting systems are installed in their basements. • A soil venting system is installed at the site. • CO_2 injection is halted for a year during these remediation activities.

To provide additional perspective for this \$16M cost estimate for environmental remediation, two other cost estimates for the remediation of potential environmental impacts associated with the geologic storage of CO_2 were found in the literature. These costs ranged from \$9M to \$34M. The source of the lower limit (\$9M) was a 2012 study ("Valuation of Potential Risks Arising from a Model, Commercial Scale CCS Project Site, prepared for CCS Valuation Project Sponsor Group by Industrial Economics, Inc., June 2012") which estimated the damages, i.e., dollars necessary to remediate or compensate for harm, should a release occur at a commercial storage site (i.e., FutureGen 1.0 located in Jewett, TX) that planned to inject 1,000,000 metric tons of CO_2 per year. This study estimated the "most likely (50th percentile)" total damages to be approximately \$8.7M and the "upper end (95th and 99th percentiles)" of the total damages to be approximately \$20.1M and \$26.2M, respectively (all estimates in 2020 dollars).

The upper limit of the range (\$34M) came from a Class VI, Underground Injection Control Permit, which was issued to Archer Daniels Midland (ADM) by EPA (Underground Injection Control Permit – Class VI; Permit Number: IL-115-6A-0001). As part of the Financial Responsibility Demonstration Plan of the ADM permit, a cost estimate of \$33.8M was provided for the cost element, Emergency and Remedial Response, which is slightly higher than the 99th percentile cost estimate of \$26.2M for the FutureGen 1.0 site. The planned injection rate for the ADM geologic storage project was ~1,200,000 metric tons per year.[1]

REFERENCES

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., Wilson, E.J., 2013, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO_2 from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., Bolthrunis, S., 2012, Valuation of potential risks arising from a model, commercial-scale CCS project site: Prepared for CCS Valuation Sponsor Group, June 1, 2012.

U.S. Environmental Protection Agency. Underground injection control permit—Class VI wells used for geologic sequestration of CO_2: https://www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2.

[1] Note that both of these examples are injecting CO_2 at a rate that is approximately 5 to 7 times the planned injection at the RTE geologic CO_2 storage facility, which suggests that these cost estimates are likely greater than the costs that will be required for the RTE project.

APPENDIX G

POST-HEARING SUPPLEMENTAL FILING – CERTIFICATION OF LIABILITY INSURANCE

CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY): 10/07/2021

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

PRODUCER Willis Towers Watson Midwest, Inc. c/o 26 Century Blvd P.O. Box 305191 Nashville, TN 372305191 USA	**CONTACT NAME:** Willis Towers Watson Certificate Center **PHONE (A/C, No, Ext):** 1-877-945-7378 **FAX (A/C, No):** 1-888-467-2378 **E-MAIL ADDRESS:** certificates@willis.com
INSURED Red Trail Energy, LLC 3682 Hwy 8 South PO Box 11 Richardton, ND 58652	

INSURER(S) AFFORDING COVERAGE	NAIC #
INSURER A : Ascot Specialty Insurance Company	45055
INSURER B :	
INSURER C :	
INSURER D :	
INSURER E :	
INSURER F :	

COVERAGES **CERTIFICATE NUMBER:** W22432947 **REVISION NUMBER:**

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

INSR LTR	TYPE OF INSURANCE	ADDL INSD	SUBR WVD	POLICY NUMBER	POLICY EFF (MM/DD/YYYY)	POLICY EXP (MM/DD/YYYY)	LIMITS	
	COMMERCIAL GENERAL LIABILITY CLAIMS-MADE / OCCUR GEN'L AGGREGATE LIMIT APPLIES PER: POLICY / PRO-JECT / LOC OTHER:						EACH OCCURRENCE	$
							DAMAGE TO RENTED PREMISES (Ea occurrence)	$
							MED EXP (Any one person)	$
							PERSONAL & ADV INJURY	$
							GENERAL AGGREGATE	$
							PRODUCTS - COMP/OP AGG	$
								$
	AUTOMOBILE LIABILITY ANY AUTO OWNED AUTOS ONLY / SCHEDULED AUTOS HIRED AUTOS ONLY / NON-OWNED AUTOS ONLY						COMBINED SINGLE LIMIT (Ea accident)	$
							BODILY INJURY (Per person)	$
							BODILY INJURY (Per accident)	$
							PROPERTY DAMAGE (Per accident)	$
								$
	UMBRELLA LIAB / OCCUR EXCESS LIAB / CLAIMS-MADE DED / RETENTION $						EACH OCCURRENCE	$
							AGGREGATE	$
								$
	WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y / N ANYPROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? (Mandatory in NH) If yes, describe under DESCRIPTION OF OPERATIONS below	N / A					PER STATUTE / OTH-ER	
							E.L. EACH ACCIDENT	$
							E.L. DISEASE - EA EMPLOYEE	$
							E.L. DISEASE - POLICY LIMIT	$
A	Pollution Liability			ENPR2110000335-01	02/01/2021	02/01/2024	SEE BELOW	0.00

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)

SEE ATTACHED

CERTIFICATE HOLDER	CANCELLATION
State of North Dakota 600 E Boulevard Ave Bismarck, ND 58501	**SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.** **AUTHORIZED REPRESENTATIVE**

SR ID: 21682581 BATCH: 2262990

AGENCY CUSTOMER ID:

LOC #:

ADDITIONAL REMARKS SCHEDULE

AGENCY Willis Towers Watson Midwest, Inc.		NAMED INSURED Red Trail Energy, LLC 3682 Hwy 8 South PO Box 11 Richardton, ND 58652
POLICY NUMBER See Page 1		
CARRIER See Page 1	NAIC CODE See Page 1	EFFECTIVE DATE: See Page 1

ADDITIONAL REMARKS

THIS ADDITIONAL REMARKS FORM IS A SCHEDULE TO ACORD FORM,

FORM NUMBER: 25 FORM TITLE: Certificate of Liability Insurance

Coverage A - Covered Location Pollution Liability Limit: $20,000,000
Coverage B - Miscellaneous Pollution Liability Limit: $20,000,000
Coverage C - Emergency and Crisis Management Costs Limit: $20,000,000
Coverage D - Business Income and Extra Expense Limit: $1,000,000
Policy Aggregate Limit: $20,000,000

SR ID: 21682581 BATCH: 2262990 CERT: W22432947

A (Excellent)

A.M. Best has assigned Ascot Bermuda a Financial Strength Rating of A (Excellent) and a Long-Term Credit Rating of 'A' with a Financial Size Category of Class XIV ($1.5 Billion to $2 Billion). The outlook of these Credit Ratings is positive.

S&P has assigned Ascot Group Limited a long term issuer credit rating of 'BBB'. The outlook for this rating is stable.

Ascot Specialty Insurance Company

AMB #: 011545 **NAIC #: 45055** **FEIN #: 050420799**

Administrative Office
55 West 46th Street
New York, New York 10036
United States

Web: www.ascotgroup.com
Phone: 646-356-8101
View Additional Address Information

AM Best Rating Unit: AMB #: 046638 - Ascot Group Limited

Assigned to insurance companies that have, in our opinion, an excellent ability to meet their ongoing insurance obligations.

AM BEST A Excellent

View additional news, reports and products for this company.

Based on AM Best's analysis, 054092 - Canada Pension Plan Investment Board is the **AMB Ultimate Parent** and identifies the topmost entity of the corporate structure. View a list of operating insurance entities in this structure.

Best's Credit Ratings

Financial Strength View Definition

Rating (Rating Category):	A (Excellent)
Affiliation Code:	g (Group)
Outlook (or Implication):	Stable
Action:	Affirmed
Effective Date:	September 17, 2021
Initial Rating Date:	December 20, 2018

Long-Term Issuer Credit View Definition

Rating (Rating Category): a+ (Excellent)
Outlook (or Implication): Stable
Action: Upgraded
Effective Date: September 17, 2021
Initial Rating Date: December 20, 2018

Financial Size Category View Definition

Financial Size Category: XIV ($1.5 Billion to $2 Billion)

u Denotes Under Review Best's Rating

Best's Credit Rating Analyst

Rating Office: A.M. Best Rating Services, Inc.
Financial Analyst: Billiah Moturi
Director: Jennifer Marshall, CPCU, ARM
Note: *See the Disclosure information Form or Press Release below for the office and analyst at the time of the rating event.*

Note: Credit Ratings on this company are European Union Endorsed

Disclosure Information

Disclosure Information Form
View AM Best's Rating Disclosure Form

Press Release
AM Best Upgrades Issuer Credit Ratings of Ascot Group Limited's Operating Subsidiaries
September 17, 2021

View AM Best's Rating Review Form

Rating History

AM Best has provided ratings & analysis on this company since 2018.

Financial Strength Rating

Effective Date	Rating
9/17/2021	A
9/4/2020	A
8/29/2019	A
12/20/2018	A

Long-Term Issuer Credit Rating

Effective Date	Rating
9/17/2021	a+
9/4/2020	a
8/29/2019	a
12/20/2018	a

Best's Credit & Financial Reports

Best's Credit Report - financial data included in Best's Credit Report reflects the data used in determining the current credit rating(s) for AM Best Rating Unit: AMB #: 046638 - Ascot Group Limited.

Best's Credit Report - Archive - reports which were released prior to the current Best's Credit Report.

Best's Financial Report - financial data included in Best's Financial Report reflects the most current data available to AM Best, including updated financial exhibits and additional company information, and is available to subscribers of Best's Insurance Reports.

View additional news, reports and products for this company.

Press Releases

Date	Title
Sep 17, 2021	AM Best Upgrades Issuer Credit Ratings of Ascot Group Limited's Operating Subsidiaries
Dec 15, 2020	AM Best Assigns Issue Credit Rating to Ascot Group Limited's Senior Unsecured Notes
Sep 04, 2020	AM Best Revises Issuer Credit Rating Outlooks to Positive and Affirms Ratings of Ascot Group Limited's Operating Subsidiaries
Aug 29, 2019	AM Best Affirms Credit Ratings of Ascot Group Limited's Operating Subsidiaries
Dec 20, 2018	AM Best Assigns Credit Ratings to Ascot Insurance Company and Ascot Specialty Insurance Company

European Union Disclosures
A.M. Best (EU) Rating Services B.V. (AMB-EU), a subsidiary of A.M. Best Rating Services, Inc., is an External Credit Assessment Institution (ECAI) in the EU. Therefore, credit ratings issued and endorsed by AMB-EU may be used for regulatory purposes in the EU as per Directive 2013/36/EU.

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Australian Disclosures

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APPENDIX H

POST-HEARING SUPPLEMENTAL FILING –GEOLOGIC STORAGE AGREEMENT: SUMMARY OF SURFACE OWNERS WHO HAVE RATIFIED

Red Trail Energy LLC

Case No. 28848

Application of Red Trail Energy, LLC requesting consideration for the geologic storage of carbon dioxide from the Red Trail Energy, LLC ethanol facility located in Sections 9, 10, 11, 12, 13, 14, 15, 22 and 23, Township 139 North, Range 92 West, Stark County, North Dakota pursuant to North Dakota Administrative Code Section 43-05-01. View the draft storage facility permit, fact sheet, and storage facility permit application at www.dmr.nd.gov/oilgas/. Red Trail intends to capture carbon dioxide from their ethanol plant and sequester it in the Broom Creek Formation. The Commission will accept and consider written comments on the merits of the application and draft permit if received no later than 5:00 pm CDT August 11, 2021. Submit written comments to the Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov. Further draft permit information may be obtained from Steve Fried, and further hearing information may be obtained from Bethany Kadrmas, both at the North Dakota Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512, 701-328-8020. Red Trail Energy, LLC, PO Box 11, Richardton, ND 58652.

August 12, 2021

TABLE OF CONTENTS

GEOLOGIC STORAGE AGREEMENT
BROOM CREEK FORMATION
STARK COUNTY, NORTH DAKOTA

THIS AGREEMENT ("Agreement") is entered into as of the 1st day of August, 2021, by the parties who have executed a pore space lease, signed the original of this instrument, a counterpart thereof, ratification and joinder by order of the Commission or other instrument agreeing to become a Party hereto.

WITNESSETH:

WHEREAS, it is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's ethanol industry, to the economic benefit of North Dakota and its citizens;

WHEREAS, to further geologic storage of carbon dioxide, a potentially valuable commodity, may allow for its ready availability if needed for commercial, industrial, or other uses, including enhanced recovery of oil, gas, and other minerals; and

WHEREAS, for geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners, which may require procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources.

NOW, THEREFORE, in consideration of the premise and of the mutual agreements herein contained, it is agreed as follows:

ARTICLE 1
DEFINITIONS

As used in this Agreement:

1.1 **Carbon Dioxide** means carbon dioxide in gaseous, liquid, or supercritical fluid state together with incidental associated substances derived from the source materials, capture process and any substances added or used to enable or improve the injection process.

1.2 **Commission** means the North Dakota Industrial Commission.

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 3480.00 acres, more or less.

1.5 **Party** is any individual, corporation, limited liability company, partnership, association, receiver, trustee, curator, executor, administrator, guardian, tutor, fiduciary, or other representative of any kind, any department, agency, or instrumentality of the state, or any governmental subdivision thereof, or any other entity capable of holding an interest in the Storage Reservoir.

1.6 **Pore Space** means a cavity or void, whether natural or artificially created, in any subsurface stratum.

1.7 **Pore Space Interest** is a right to or interest in the Pore Space in any Tract within the boundaries of the Facility Area.

1.8 **Pore Space Owner** is a Party hereto who owns Pore Space Interest.

1.9 **Storage Equipment** is any personal property, lease and well equipment, plants and other facilities and equipment for use in Storage Operations.

1.10 **Storage Expense** is all costs, expense or indebtedness incurred by the Storage Operator pursuant to this Agreement for or on account of Storage Operations.

1.11 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the Broom Creek Formation and geologically confined by the Opeche Formation (upper confining zone) and the Amsden Formation (lower confining zone), identified by the gamma ray and resistivity logs run in the Runnel-State 1 well (File No. 6797), located in the SE/4 SW/4 of Section 16, Township 139 North, Range 92 West, Stark County, North Dakota, which encompasses the stratigraphic interval from a depth of 6315 feet to a depth of 7060 feet as measured from the Kelly Bushing elevation of 2494 feet, within the limits of the Facility Area.

1.12 **Storage Facility** is the unitized or amalgamated Storage Reservoir created pursuant to an order of the Commission.

1.13 **Storage Facility Participation** is the percentage shown on Exhibit "C" for allocating payments for use of the Pore Space under each Tract identified in Exhibit "B".

1.14 **Storage Operations** are all operations conducted by the Storage Operator pursuant to this Agreement or otherwise authorized by any lease covering any Pore Space Interest.

1.15 **Storage Operator** is the person or entity named in Section 4.1 of this Agreement.

1.16 **Storage Rights** are the rights to explore, develop, and operate lands within the Facility Area for the storage of Storage Substances.

1.17 **Storage Substances** are Carbon Dioxide and incidental associated substances and fluids.

1.18 **Tract** is the land described as such and given a Tract number in Exhibit "B."

ARTICLE 2
EXHIBITS

2.1 **Exhibits.** The following exhibits, which are attached hereto, are incorporated herein by reference:

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Storage Facility area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Storage Facility area;

2.1.3 Exhibit "C" is a schedule that shows the Storage Facility Participation of each Tract; and

2.1.4 Exhibit "D" is the Form of Surface Use and Pore Space Lease.

2.2 **Reference to Exhibits.** When reference is made to an exhibit, it is to the exhibit as originally attached or, if revised, to the last revision.

2.3 **Exhibits Considered Correct.** Exhibits "A," "B," "C" and "D" shall be considered to be correct until revised as herein provided.

2.4 **Correcting Errors.** The shapes and descriptions of the respective Tracts have been established by using the best information available. If it subsequently appears that any Tract, mechanical miscalculation or clerical error has been made, Storage Operator, with the approval of Pore Space Owners whose interest is affected, shall correct the mistake by revising the exhibits to conform to the facts. The revision shall not include any re-evaluation of engineering or geological interpretations used in determining Storage Facility Participation. Each such revision of an exhibit made prior to thirty (30) days after the Effective Date shall be effective as of the Effective Date. Each such revision thereafter made shall be effective at 7:00 a.m. on the first day of the calendar month next following the filing for record of the revised exhibit or on such other date as may be determined by Storage Operator and set forth in the revised exhibit.

2.5 **Filing Revised Exhibits.** If an exhibit is revised, Storage Operator shall execute an appropriate instrument with the revised exhibit attached and file the same for record in the county or counties in which this Agreement or memorandum of the same is recorded and shall also file the amended changes with the Commission.

ARTICLE 3
CREATION AND EFFECT OF STORAGE FACILITY

3.1 **Unleased Pore Space Interests.** Any Pore Space Owner in the Storage Facility who owns a Pore Space Interest in the Storage Reservoir that is not leased for the purposes of this Agreement and during the term hereof, shall be treated as if it were subject to the Form of Surface Use and Pore Space Lease attached hereto as Exhibit "D".

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Form of Surface Use and Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

3.4 **Continuation of Leases and Term Interests.** Injection in to any part of the Storage Reservoir, or other Storage Operations, shall be considered as injection in to or upon each Tract within said Storage Reservoir, and such injection or operations shall continue in effect as to each lease as to all lands and formations covered thereby just as if such operations were conducted on and as if a well were injecting in each Tract within said Storage Reservoir.

3.5 **Titles Unaffected by Storage.** Nothing herein shall be construed to result in the transfer of title of the Pore Space Interest of any Party hereto to any other Party or to Storage Operator.

3.6 **Injection Rights.** Storage Operator is hereby granted the right to inject into the Storage Reservoir any Storage Substances in whatever amounts Storage Operator may deem expedient for Storage Operations, together with the right to drill, use, and maintain injection wells in the Facility Area, and to use for injection purposes.

3.7 **Transfer of Storage Substances from Storage Facility.** Storage Operator may transfer from the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, to any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The transfer of such Storage Substances out of the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.8 **Receipt of Storage Substances.** Storage Operator may accept and receive into the Storage Facility any Storage Substances, in whatever amounts Storage Operator may deem expedient for Storage Operations, being stored in any other reservoir, subsurface stratum or formation permitted by the Commission for the storage of carbon dioxide under Chapter 38-22 of the North Dakota Century Code. The receipt of such Storage Substances into the Storage Facility shall be disregarded for the purposes of calculating the royalty under any lease covering a Pore Space Interest (including Exhibit "D") and shall not affect the allocation of Storage Substances injected into the Storage Facility through the surface of the Facility Area in accordance with Article 6 of this Agreement.

3.9 **Cooperative Agreements.** Storage Operator may enter into cooperative agreements with respect to lands adjacent to the Facility Area for the purpose of coordinating Storage Operations. Such cooperative agreements may include, but shall not be limited to, agreements regarding the transfer and receipt of Storage Substances pursuant to Sections 3.7 and 3.8 of this Agreement.

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

ARTICLE 4
STORAGE OPERATIONS

4.1 **Storage Operator.** Red Trail Energy, LLC is hereby designated as the initial Storage Operator. Storage Operator shall have the exclusive right to conduct Storage Operations, which shall conform to the provisions of this Agreement and any lease covering a Pore Space Interest. If there is any conflict between such agreements, this Agreement shall govern.

4.2 **Successor Operators**. The initial Storage Operator and any subsequent operator may, at any time, transfer operatorship of the Storage Facility with and upon the approval of the Commission.

4.3 **Method of Operation.** Storage Operator shall engage in Storage Operations with diligence and in accordance with good engineering and injection practices.

4.4 **Change of Method of Operation.** Nothing herein shall prevent Storage Operator from discontinuing or changing in whole or in part any method of operation which, in its opinion, is no longer in accord with good engineering or injection practices. Other methods of operation may be conducted or changes may be made by Storage Operator from time to time if determined by it to be feasible, necessary or desirable to increase the injection or storage of Storage Substances.

ARTICLE 5
TRACT PARTICIPATIONS

5.1 **Tract Participations.** The Storage Facility Participation of each Tract is shown in Exhibit "C." The Storage Facility Participation of each Tract shall be based 100% upon the ratio of surface acres in each Tract to the total surface acres for all Tracts within the Facility Area.

5.2 **Relative Storage Facility Participations.** If the Facility Area is enlarged or reduced, the revised Storage Facility Participation of the Tracts remaining in the Facility Area and which were within the Facility Area prior to the enlargement or reduction shall remain in the same ratio to one another.

ARTICLE 6
ALLOCATION OF STORAGE SUBSTANCES

6.1 **Allocation of Tracts.** All Storage Substances injected shall be allocated to the several Tracts in accordance with the respective Storage Facility Participation effective during the period that the Storage Substances are injected. The amount of Storage Substances allocated to each tract, regardless of whether the amount is more or less than the actual injection of Storage Substances from the well or wells, if any, on such Tract, shall be deemed for all purposes to have been injected into such Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.1.

6.2 **Distribution within Tracts.** The Storage Substances injected and allocated to each Tract shall be distributed among, or accounted for to, the Pore Space Owners who own a Pore Space Interest in such Tract in accordance with the Pore Space Owners' Storage Facility Participation effective during the period that the Storage Substances were injected. If any Pore Space Interest in a Tract hereafter becomes divided and owned in severalty as to different parts of the Tract, the owners of the divided interests, in the absence of an agreement providing for a different division, shall be compensated for the storage of the Storage Substances in proportion to the surface acreage of their respective parts of the Tract. Storage Substances transferred or received pursuant to Sections 3.7 and 3.8 of this Agreement shall be disregarded for the purposes of this Section 6.2.

ARTICLE 7
TITLES

7.1 **Warranty and Indemnity.** Each Pore Space Owner who, by acceptance of revenue for the injection of Storage Substances into the Storage Reservoir, shall be deemed to have warranted title to its Pore Space Interest, and, upon receipt of the proceeds thereof to the credit of such interest, shall indemnify and hold harmless the Storage Operator and other Parties from any loss due to failure, in whole or in part, of its title to any such interest.

7.2 **Injection When Title Is in Dispute.** If the title or right of any Pore Space Owner claiming the right to receive all or any portion of the proceeds for the storage of any Storage Substances allocated to a Tract is in dispute, Storage Operator shall require that the Pore Space

Owner to whom the proceeds thereof are paid furnish security for the proper accounting thereof to the rightful Pore Space Owner if the title or right of such Pore Space Owner fails in whole or in part.

7.3 **Payments of Taxes to Protect Title.** The owner of surface rights to lands within the Facility Area is responsible for the payment of any *ad valorem* taxes on all such rights, interests or property, unless such owner and the Storage Operator otherwise agree. If any *ad valorem* taxes are not paid by or for such owner when due, Storage Operator may at any time prior to tax sale or expiration of period of redemption after tax sale, pay the tax, redeem such rights, interests or property, and discharge the tax lien. Storage Operator shall, if possible, withhold from any proceeds derived from the storage of Storage Substances otherwise due any Pore Space Owner who is a delinquent taxpayer an amount sufficient to defray the costs of such payment or redemption, such withholding to be credited to the Storage Operator. Such withholding shall be without prejudice to any other remedy available to Storage Operator.

7.4 **Pore Space Interest Titles.** If title to a Pore Space Interest fails, but the tract to which it relates is not removed from the Facility Area, the Party whose title failed shall not be entitled to share under this Agreement with respect to that interest.

ARTICLE 8
EASEMENTS OR USE OF SURFACE

8.1 **Grant of Easement.** Storage Operator shall have the right to use as much of the surface of the land within the Facility Area as may be reasonably necessary for Storage Operations and the injection of Storage Substances.

8.2 **Use of Water.** Storage Operator shall have and is hereby granted free use of water from the Facility Area for Storage Operations, except water from any well, lake, pond or irrigation ditch of a Pore Space Owner; notwithstanding the foregoing, Storage Operator may access any well, lake, or pond as provided in Exhibit "D".

8.3 **Surface Damages.** Storage Owner shall pay surface owners for damage to growing crops, timber, fences, improvements and structures located on the Facility Area that result from Storage Operations.

8.4 **Surface and Sub-Surface Operating Rights.** Except to the extent modified in this Agreement, Storage Operator shall have the same rights to use the surface and sub-surface and use of water and any other rights granted to Storage Operator in any lease covering Pore Space Interests. Except to the extent expanded by this Agreement or the extent that such rights are common to the effected leases, the rights granted by a lease may be exercised only on the land covered by that lease. Storage Operator will to the extent possible minimize surface impacts.

ARTICLE 9
ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing

Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

9.2 **Determination of Tract Participation.** Storage Operator, subject to Section 5.2, shall determine the Storage Facility Participation of each Tract within the Storage Facility as enlarged, and shall revise Exhibits "A", "B" and "C" accordingly and in accordance with the rules, regulations and orders of the Commission.

9.3 **Effective Date.** The effective date of any enlargement of the Storage Facility shall be effective as determined by the Commission.

ARTICLE 10
TRANSFER OF TITLE PARTITION

10.1 **Transfer of Title.** Any conveyance of all or part of any interest owned by any Party hereto with respect to any Tract shall be made expressly subject to this Agreement. No change of title shall be binding upon Storage Operator, or any Party hereto other than the Party so transferring, until 7:00 a.m. on the first day of the calendar month following thirty (30) days from the date of receipt by Storage Operator of a photocopy, or a certified copy, of the recorded or filed instrument evidencing such a change in ownership.

10.2 **Waiver of Rights to Partition.** Each Party hereto agrees that, during the existence of this Agreement, it will not resort to any action to partition any Tract or parcel within the Facility Area or the facilities used in the development or operation thereof, and to that extent waives the benefits or laws authorizing such partition.

ARTICLE 11
RELATIONSHIP OF PARTIES

11.1 **No Partnership.** The duties, obligations and liabilities arising hereunder shall be several and not joint or collective. This Agreement is not intended to create, and shall not be construed to create, an association or trust, or to impose a partnership duty, obligation or liability with regard to any one or more of the Parties hereto. Each Party hereto shall be individually responsible for its own obligations as herein provided.

11.2 **No Joint Marketing.** This Agreement is not intended to provide, and shall not be construed to provide, directly or indirectly, for any joint marketing of Storage Substances.

11.3 **Pore Space Owners Free of Costs.** This Agreement is not intended to impose, and shall not be construed to impose, upon any Pore Space Owner any obligation to pay any Storage Expense unless such Pore Space Owner is otherwise so obligated.

11.4 **Information to Pore Space Owners.** Each Pore Space Owner shall be entitled to all information in possession of Storage Operator to which such Pore Space Owner is entitled by an existing lease or a lease imposed by this Agreement.

ARTICLE 12
LAWS AND REGULATIONS

12.1 **Laws and Regulations.** This Agreement shall be subject to all applicable federal, state and municipal laws, rules, regulations and orders.

ARTICLE 13
FORCE MAJEURE

13.1 **Force Majeure.** All obligations imposed by this Agreement on each Party, except for the payment of money, shall be suspended while compliance is prevented, in whole or in part, by a labor dispute, fire, war, civil disturbance, or act of God; by federal, state or municipal laws; by any rule, regulation or order of a governmental agency; by inability to secure materials; or by any other cause or causes, whether similar or dissimilar, beyond reasonable control of the Party. No Party shall be required against his will to adjust or settle any labor dispute. Neither this Agreement nor any lease or other instrument subject hereto shall be terminated by reason of suspension of Storage Operations due to any one or more of the causes set forth in this Article.

ARTICLE 14
EFFECTIVE DATE

14.1 **Effective Date.** This Agreement shall become effective as determined by the Commission.

14.2 **Ipso Facto Termination.** If the requirements of Section 14.1 are not accomplished on or before December 31, 2021 this Agreement shall *ipso facto* terminate on that date (hereinafter called "termination date") and thereafter be of no further effect, unless prior thereto Pore Space Owners owning a combined Storage Facility Participation of at least thirty percent (30%) of the Facility Area have become Parties to this Agreement and have decided to extend the termination date for a period not to exceed six (6) months. If the termination date is so extended and the requirements of Section 14.1 are not accomplished on or before the extended termination date this Agreement shall *ipso facto* terminate on the extended termination date and thereafter be of no further effect.

14.3 **Certificate of Effectiveness.** Storage Operator shall file for record in the county or counties in which the land affected is located a certificate stating the Effective Date of this Agreement.

ARTICLE 15
TERM

15.1 **Term.** Unless sooner terminated in the manner hereinafter provided or by order of the Commission, this Agreement shall remain in full force and effect until the Commission has issued a certificate of project completion with respect to the Storage Facility in accordance with Section 38-22-17 of the North Dakota Century Code.

15.2 **Termination by Storage Operator.** This Agreement may be terminated at any time by the Storage Operator.

15.3 **Effect of Termination.** Upon termination of this Agreement all Storage Operations shall cease. Each lease and other agreement covering Pore Space within the Facility Area shall remain in force for ninety (90) days after the date on which this Agreement terminates, and for such further period as is provided by Exhibit "D" or other agreement.

15.4 **Salvaging Equipment Upon Termination.** If not otherwise granted by Exhibit "D" or other instruments affecting each Tract, Pore Space Owners hereby grant Storage Operator a period of six (6) months after the date of termination of this Agreement within which to salvage and remove Storage Equipment.

15.5 **Certificate of Termination.** Upon termination of this Agreement, Storage Operator shall file for record in the county or counties in which the land affected is located a certificate that this Agreement has terminated, stating its termination date.

ARTICLE 16
APPROVAL

16.1 **Original, Counterpart or Other Instrument.** A Pore Space Owner may approve this Agreement by entering into a pore space lease with Storage Operator signing the original of this instrument, a counterpart thereof, ratification or joinder or other instrument approving this instrument hereto. The signing of any such instrument shall have the same effect as if all Parties had signed the same instrument.

16.2 **Joinder in Dual Capacity.** Execution as herein provided by any Party as either a Pore Space Owner or the Storage Operator shall commit all interests owned or controlled by such Party and any additional interest thereafter acquired in the Facility Area.

16.3 **Approval by the North Dakota Industrial Commission.**
Notwithstanding anything in this Article to the contrary, all Tracts within the Facility Area shall be deemed to be qualified for participation if this Agreement is duly approved by order of the Commission.

ARTICLE 17
GENERAL

17.1 **Amendments Affecting Pore Space Owners.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **Construction.** This agreement shall be construed according to the laws of the State of North Dakota.

ARTICLE 18
SUCCESSORS AND ASSIGNS

18.1 **Successors and Assigns.** This Agreement shall extend to, be binding upon, and inure to the benefit of the Parties hereto and their respective heirs, devisees, legal representatives, successors and assigns and shall constitute a covenant running with the lands, leases and interests covered hereby.

[*Remainder of page intentionally left blank. Signature page follows.*]

Executed the date set opposite each name below but effective for all purposes as provided by Article 14.

Dated: 10/15, 2021

STORAGE OPERATOR

RED TRAIL ENERGY, LLC

By: [signature]

Its: COO

73044007.1

EXHIBIT A

Tract Map

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

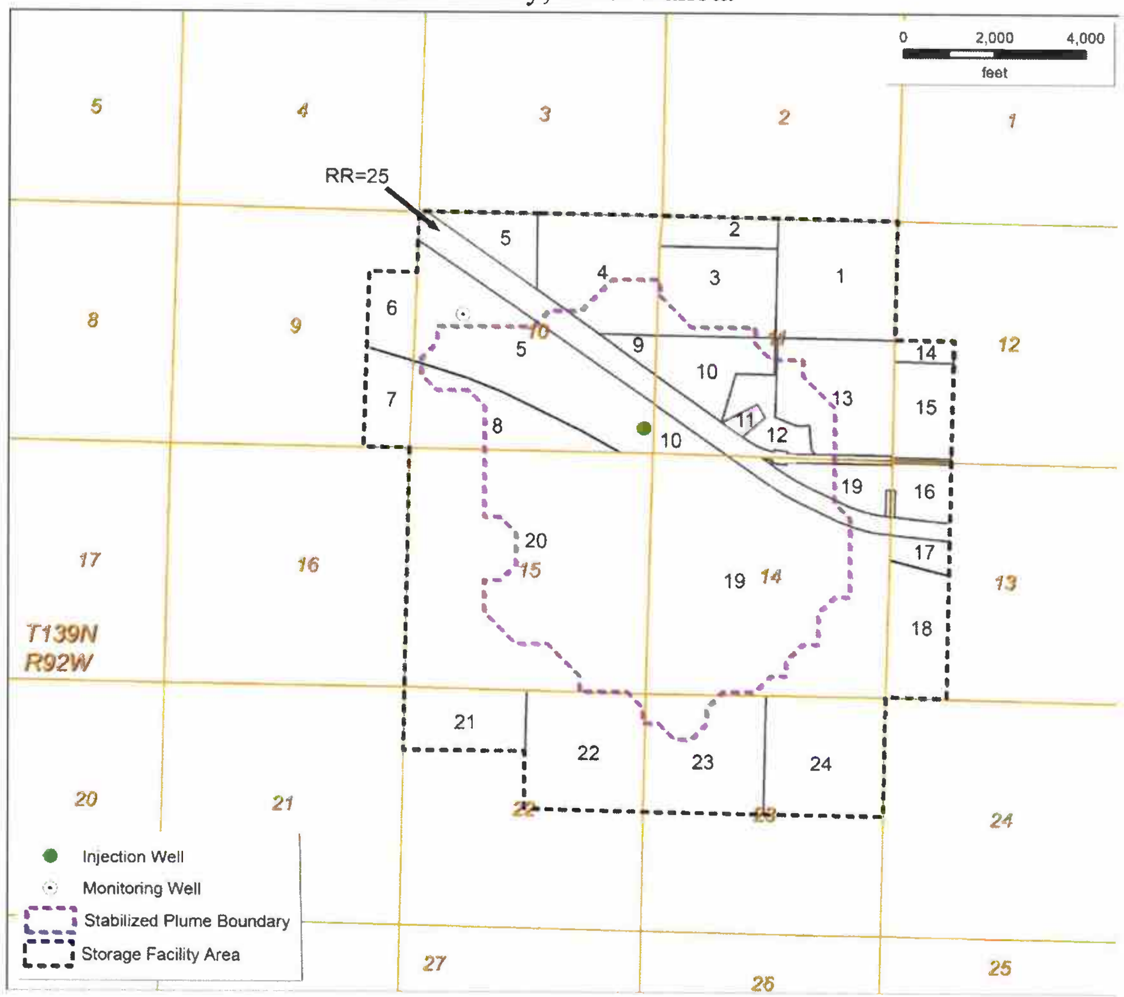

EXHIBIT B

Tract Summary

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 11-T139N-R92W	William S. Hoff Doris Hoff	160.000	100.00000000%	4.59770115%
		Tract Total:	**160.000**		
2	Section 11-T139N-R92W	Jody Hoff Maria Hoff	40.000	100.00000000%	1.14942529%
		Tract Total:	**40.000**		
3	Section 11-T139N-R92W	Ambrose Hoff Charlotte Hoff	120.000	100.00000000%	3.44827586%
		Tract Total:	**120.000**		
4	Section 10-T139N-R92W	Jody Hoff Maria Hoff	150.060	100.00000000%	4.31206897%
		Tract Total:	**150.060**		
5	Section 10-T139N-R92W	Red Trail Energy, LLC	299.078	100.00000000%	8.59419540%
		Tract Total:	**299.078**		
6	Section 9-T139N-R92W	Red Trail Energy, LLC	55.500	100.00000000%	1.59482759%
		Tract Total:	**55.500**		

EXHIBIT B

Tract Summary

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

7	Section 9-T139N-R92W	Karen Messmer	64.500	100.00000000%	1.85344828%
		Tract Total:	**64.500**		
8	Section 10-T139N-R92W	Barbara Hoff	113.314	100.00000000%	3.25614943%
		Tract Total:	**113.314**		
9	Section 10-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	17.878	100.00000000%	0.51373563%
		Tract Total:	**17.878**		
10	Section 11-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	77.850	100.00000000%	2.23706897%
		Tract Total:	**77.850**		
11	Section 11-T139N-R92W	Richard L. Hauck	10.120	100.00000000%	0.29080460%
		Linda Hauck			
		Tract Total:	**10.120**		
12	Section 11-T139N-R92W	William S. Hoff	68.750	100.00000000%	1.97557471%
		Doris Hoff			
		Tract Total:	**68.750**		

EXHIBIT B

Tract Summary

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

13	Section 11-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	143.800	100.00000000%	4.13218391%
		Tract Total:	**143.800**		
14	Section 12-T139N-R92W	Kevin Frederick	15.000	100.00000000%	0.43103448%
		Tract Total:	**15.000**		
15	Section 12-T139N-R92W	Craig S. Fisher	65.000	100.00000000%	1.86781609%
		Tract Total:	**65.000**		
16	Section 13-T139N-R92W	Craig S. Fisher	40.959	100.00000000%	1.17698276%
		Tract Total:	**40.959**		
17	Section 13-T139N-R92W	Sheldon Fisher	18.658	100.00000000%	0.53614943%
		Tract Total:	**18.658**		
18	Section 13-T139N-R92W	Sheldon Fisher	88.223	100.00000000%	2.53514368%
		Tract Total:	**88.223**		
19	Section 14-T139N-R92W	Dwight Schank	607.120	100.00000000%	17.44597701%
		Tract Total:	**607.120**		
20	Section 15-T139N-R92W	Karen Messmer	640.000	100.00000000%	18.39080460%
		Tract Total:	**640.000**		

EXHIBIT B

Tract Summary

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

21	Section 22-T139N-R92W	Messmer Farms LLP	80.000	100.00000000%	2.29885057%
		Tract Total:	**80.000**		
22	Section 22-T139N-R92W	Jeffrey R. Hoff	160.000	100.00000000%	4.59770115%
		Tract Total:	**160.000**		
23	Section 23-T139N-R92W	Lori Hinder	160.000	100.00000000%	4.59770115%
		Tract Total:	**160.000**		
24	Section 23-T139N-R92W	Ambrose Hoff Charlotte Hoff	160.000	100.00000000%	4.59770115%
		Tract Total:	**160.000**		
25	Sections 10,11,13 & 14-T139N-R92W	BNSF Railway Company	124.190	100.00000000%	3.56867816%
		Tract Total:	**124.190**		
		Total Acres:	**3480.000**	**Total Participation:**	**100.00000000%**

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

Tract No.	Acres	Tract Participation Factor
1	160.000	4.59770115%
2	40.000	1.14942529%
3	120.000	3.44827586%
4	150.060	4.31206897%
5	299.078	8.59419540%
6	55.500	1.59482759%
7	64.500	1.85344828%
8	113.314	3.25614943%
9	17.878	0.51373563%
10	77.850	2.23706897%
11	10.120	0.29080460%
12	68.750	1.97557471%
13	143.800	4.13218391%
14	15.000	0.43103448%
15	65.000	1.86781609%
16	40.959	1.17698276%
17	18.658	0.53614943%
18	88.223	2.53514368%
19	607.120	17.44597701%
20	640.000	18.39080460%
21	80.000	2.29885057%
22	160.000	4.59770115%
23	160.000	4.59770115%
24	160.000	4.59770115%
25	124.190	3.56867816%
Total:	**3480.000**	**100.00000000%**

EXHIBIT D

Form of Surface Use and Pore Space Lease

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

FORM OF SURFACE USE AND PORE SPACE LEASE

THIS SURFACE USE AND PORE SPACE LEASE (this "Lease") is made and entered into this ____ day of ________________, 2018, by and between ______________________________, whose address is ______________________________ (whether one or more, "Lessor"), and Red Trail Energy, LLC, a North Dakota limited liability company, whose address is 3682 Hwy 8 S., Richardton, North Dakota 58652 (whether one or more, "Lessee"). Lessor and Lessee may be individually referred to herein as a "Party" and collectively as the "Parties".

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee's geologic storage operations and other purposes set forth herein, the following-described lands situated in Stark County, North Dakota:

Township ___ North, Range ___ West
Section ____: ____

containing ____ acres, more or less (the "Leased Premises"), subject to the terms and conditions set forth herein.

2. Term. The initial term of this Lease shall be for fifty (50) years. Lessee shall have the option, but not the obligation, to extend this lease for an additional fifty (50) year term by paying a bonus of __________ and No/100 Dollars ($_____.__) per net acre before the end of the initial ten (10) year term. This Lease shall continue beyond the second ten (10) year term for so long as any portion of the Leased Premises or Lessee's storage facilities are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") or under the ownership or control of the State of North Dakota; *provided, however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a certificate of project completion pursuant to Ch. 38-22 of the North Dakota Century Code.

3. Annual Rentals. Lessee shall pay to Lessor an annual rental of ________ dollars ($__.__) per net acre for as long as this Lease is in effect. The annual rental shall be paid each year prior to the anniversary date of this Lease. The first year's rental has been paid to Lessor, the receipt of which is hereby acknowledged. The rentals paid under this lease shall not be deducted from the royalties as they accrue. Lessee shall have the right to prepay in a lump sum the annual rentals payable during the terms of this Lease or any extension thereof. Prepaid annual rental shall be refunded on a pro-rata basis in the event this Lease is terminated due to no fault of Lessee. Lessee shall no longer be liable to Lessee for annual rentals upon (i) the termination of this Lease or, (ii) the issuance of a certificate of project completion and transfer of title and custody of Lessor's storage facilities to the State of North Dakota in accordance with Ch. 38-22 of the North Dakota Century Code. For avoidance of doubt, Lessee shall continue to pay Lessor the annual rental for the duration of the ten (10) year period following the date injection operations have ceased in accordance with Ch. 38-22 of the North Dakota Century Code.

4. Royalty. In addition to the annual rental, Lessee shall pay to Lessor a royalty of ____ cents ($0.__) per ton of carbon dioxide (CO_2) injected into the reservoirs and pore spaces underlying the Leased Premises. The quantity of carbon dioxide injected into the reservoirs and pore spaces underlying the Leased Premises shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Leased Premises during any calendar quarter shall be paid to Lessor by the last day of the following month after the calendar quarter.

5. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide (CO_2) and other gaseous substances, from whatever source or sources obtained, into the reservoirs and subsurface pore spaces (as such terms are defined in Ch. 38-22 and Ch. 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises, together with the right to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of, abandon in place any such pipelines, reservoirs, electric and telephone lines, roadways, underground equipment, surface facilities and equipment, buildings and structures Lessee determines reasonably necessary to carry out the purpose of this Lease.

6. Right of Ways. Lessor grants Lessee the rights of ingress and egress over the Leased Premises together with the right of way over, under and across the Leased Premises and the right from time to time to lay, maintain, replace repair, and remove roads, pipelines, tanks, fences, or other facilities and appurtenances on the Leased Premises for the purposes herein granted to Lessee. Lessee shall have the further right to fence the perimeter of any facility on the Leased Premises and sufficiently illuminate the site for the safety of operations. Lessee shall utilize "dark sky" lighting fixtures or shades so as to minimize or reduce night light pollution.

7. Lessee Obligations. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the reservoirs and subsurface pore spaces of the Leased Premises, and (ii) all equipment, buildings, structures, facilities and other property constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Ch. 38-22 of the North Dakota Century Code.

9. Surrender of Leased Premises. Lessee shall have the right at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the subsurface pore pace is not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release.

10. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

11. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall give Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property of Lessee located on the Leased Premises.

12. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes, assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

13. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee's interpretation of the same, pending final determination.

14. Force Majeure. Should Lessee be prevented from complying with any express or implied covenant of this Lease, from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

15. Surface Damage Compensation Act. The annual rental amounts and any and all other compensation contemplated and paid to Lessor hereunder is compensation for, among other things, damages sustained by Lessor for the lost use of and access to Lessor's land, pore space (to the extent required under North Dakota law), and any other damages which are contemplated under Ch. 38-11.1 of the North Dakota Century Code. Lessor agrees that such compensation is just and adequate for any and all damages contemplated under said Chapter 38-11.1 and all other damages which Lessor may sustain as a result of Lessee's use of the property for its storage operations.

16. Warranty of Title. Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises. Lessor hereby warrants and agrees to defend title to the Leased Premises and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the

Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such lien with the right to enforce the same and apply annual rental payments or any other such payments due to Lessor toward satisfying the same.

17. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however,* that an assigning party's failure to deliver written notice of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional.

18. Change of Ownership. No change of ownership in the Leased Premises shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership.

19. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

20. No Waiver. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

21. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county in which the Leased Premises are situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

22. Counterparts. This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

23. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

24. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in Bismarck, North Dakota.

25. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

[*Remainder of page intentionally left blank. Signature page follows.*]

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the date first set forth above.

LESSOR:

By:____________________________________
Print:__________________________________

By:____________________________________
Print:__________________________________

LESSEE:

RED TRAIL ENERGY, LLC

By:____________________________________
Print:__________________________________
Its:____________________________________

EXHIBIT B

Summary of Surface Owners Who Have Ratified

Attached to and made part of the Geologic Storage Agreement
Broom Creek Formation
Stark County, North Dakota

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation	Acreage Leased (Y/N)	RATIFIED
1	Section 11-T139N-R92W	William S. Hoff Doris Hoff	160.000	100.00000000%	4.59770115%	Y	
		Tract Total:	**160.000**				
2	Section 11-T139N-R92W	Jody Hoff Maria Hoff	40.000	100.00000000%	1.14942529%	Y	1.14942529%
		Tract Total:	**40.000**				
3	Section 11-T139N-R92W	Ambrose Hoff Charlotte Hoff	120.000	100.00000000%	3.44827586%	Y	3.44827586%
		Tract Total:	**120.000**				
4	Section 10-T139N-R92W	Jody Hoff Maria Hoff	150.060	100.00000000%	4.31206897%	Y	4.31206897%
		Tract Total:	**150.060**				
5	Section 10-T139N-R92W	Red Trail Energy, LLC	299.078	100.00000000%	8.59419540%	Y	8.59419540%
		Tract Total:	**299.078**				
6	Section 9-T139N-R92W	Red Trail Energy, LLC	55.500	100.00000000%	1.59482759%	Y	1.59482759%
		Tract Total:	**55.500**				
7	Section 9-T139N-R92W	Karen Messmer	64.500	100.00000000%	1.85344828%	Y	1.85344828%
		Tract Total:	**64.500**				
8	Section 10-T139N-R92W	Barbara Hoff	113.314	100.00000000%	3.25614943%	Y	
		Tract Total:	**113.314**				
9	Section 10-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	17.878	100.00000000%	0.51373563%	Y	
		Tract Total:	**17.878**				
10	Section 11-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	77.850	100.00000000%	2.23706897%	Y	
		Tract Total:	**77.850**				

11	Section 11-T139N-R92W	Richard L. Hauck Linda Hauck	10.120	100.00000000%	0.29080460%	N	
		Tract Total:	**10.120**				
12	Section 11-T139N-R92W	William S. Hoff Doris Hoff	68.750	100.00000000%	1.97557471%	Y	
		Tract Total:	**68.750**				
13	Section 11-T139N-R92W	Neal C. & Bonnie M. Messer Farm Properties LLLP	143.800	100.00000000%	4.13218391%	Y	
		Tract Total:	**143.800**				
14	Section 12-T139N-R92W	Kevin Frederick	15.000	100.00000000%	0.43103448%	N	
		Tract Total:	**15.000**				
15	Section 12-T139N-R92W	Craig S. Fisher	65.000	100.00000000%	1.86781609%	Y	1.86781609%
		Tract Total:	**65.000**				
16	Section 13-T139N-R92W	Craig S. Fisher	40.959	100.00000000%	1.17698276%	Y	1.17698276%
		Tract Total:	**40.959**				
17	Section 13-T139N-R92W	Sheldon Fisher	18.658	100.00000000%	0.53614943%	Y	0.53614943%
		Tract Total:	**18.658**				
18	Section 13-T139N-R92W	Sheldon Fisher	88.223	100.00000000%	2.53514368%	Y	2.53514368%
		Tract Total:	**88.223**				
19	Section 14-T139N-R92W	Dwight Schank	607.120	100.00000000%	17.44597701%	Y	17.44597701%
		Tract Total:	**607.120**				
20	Section 15-T139N-R92W	Karen Messmer	640.000	100.00000000%	18.39080460%	Y	18.39080460%
		Tract Total:	**640.000**				
21	Section 22-T139N-R92W	Messmer Farms LLP	80.000	100.00000000%	2.29885057%	Y	
		Tract Total:	**80.000**				
22	Section 22-T139N-R92W	Jeffrey R. Hoff	160.000	100.00000000%	4.59770115%	Y	
		Tract Total:	**160.000**				
23	Section 23-T139N-R92W	Lori Linder	160.000	100.00000000%	4.59770115%	N	
		Tract Total:	**160.000**				
24	Section 23-T139N-R92W	Ambrose Hoff Charlotte Hoff	160.000	100.00000000%	4.59770115%	Y	4.59770115%
		Tract Total:	**160.000**				
25	Sections 10,11,13 & 14-T139N-R92W	BNSF Railway Company	124.190	100.00000000%	3.56867816%	N	
		Tract Total:	**124.190**				
		Total Acres:	**3480.000**	**Total Participation:**	**100.00000000%**	**91.11178161%**	**67.50281609%**

RATIFICATION AND JOINDER OF GEOLOGIC STORAGE AGREEMENT
BROOM CREEK FORMATION
STARK COUNTY, NORTH DAKOTA

In consideration of the execution of the Geologic Storage Agreement, Broom Creek Formation, Stark County, North Dakota, dated August 1, 2021 ("Storage Agreement"), the undersigned (whether one or more) hereby expressly joins said Storage Agreement and ratifies, consents and agrees to the terms of said Storage Agreement as fully as though the undersigned had executed the original instrument, as the same is finally approved by order of the North Dakota Industrial Commission.

This Ratification and Joinder shall be effective as to the undersigned's Pore Space Interest and any other interest necessary for the geologic storage of carbon dioxide in and under lands within the Storage Facility in which the undersigned has a Pore Space Interest.

This Ratification and Joinder shall be binding upon the undersigned, his, her, or its heirs, devisees, assigns, or successors in interest. All capitalized terms not defined herein shall have the meanings ascribed to such terms in the Storage Agreement, a copy of which has been made available to the undersigned.

EXECUTED this 15th day of October, 2021.

Jody Hoff and Marla Hoff
3729 86th Ave. SW
Richardton ND 58652

By: Jody Hoff Marla Hoff

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

RATIFICATION AND JOINDER OF GEOLOGIC STORAGE AGREEMENT
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STARK COUNTY, NORTH DAKOTA

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EXECUTED this 15th day of October, 2021.

Ambrose Hoff and Charlotte Hoff
3713 36th Ave. SW
Richardton ND 58652

By: Ambrose J. Hoff
Charlotte Hoff

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

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EXECUTED this 15th day of October, 2021.

Karen L. Messmer
1990 Mesquite Lp
Bismarck ND 58503

By: Karen Messmer

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

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EXECUTED this 15th day of October, 2021.

Craig S. Fisher
8330 39th St. SW
Richardton ND 58652

By: [signature]

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

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EXECUTED this 15th day of October, 2021.

Sheldon Fisher
8330 39th St SW
Richardton ND 58652

By: [signature] POA

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

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EXECUTED this 15 day of October, 2021.

Dwight F. Schank
868 17th ST E
Dickinson, ND 58601-3458

By: Dwight Schank

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

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EXECUTED this 18th day of October, 2021.

Messmer Farms LLP
10844 E Queensborough Ave
Mesa AZ 85212

By: Chet Messmer

PLEASE RETURN ONE (1) EXECUTED COPY TO:

Red Trail Energy, LLC
3682 Hwy 8 S.
Richardton, ND 58652

74147828.1

EXHIBIT B

Summary of Surface Owners Who Have Ratified

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Stark County, North Dakota

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		Tract Total:	**124.190**				
		Total Acres:	**3480.000**	**Total Participation:**	**100.00000000%**	**91.11178161%**	**69.80166667%**