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

OFFICE OF
AIR AND RADIATION

April 5, 2022

Mr. Craig Bleth
Minnkota Power Cooperative, Inc.
3401 24th Street SW
PO Box 127
Center, ND 58530

Re: Monitoring, Reporting and Verification (MRV) Plan for Tundra SGS LLC

Dear Mr. Bleth:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Tundra SGS 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 Tundra SGS LLC as the final MRV plan. The MRV Plan Approval Number is 1014103-1. This decision is effective April 10, 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 Tundra SGS LLC at the Milton R. Young Station

March 2022

Contents

<u>**Appendices**</u>

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 for Tundra SGS LLC.

1 Overview of Project

Tundra SGS is a geologic CO_2 storage project located 3.4 miles southeast of Center, North Dakota and owned by Minnkota. Minnkota currently provides wholesale power to the 11 member-owned rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. The two-unit Milton R. Young Station (MRYS), also located within the Tundra SGS area (the geologic storage facility and operation are referred to as Tundra SGS), is Minnkota's primary power generating resource. A nearby mine owned by BNI Coal, Inc. (BNI) supplies lignite coal to the MRYS for power production.

Tundra SGS involves the addition of a carbon capture retrofit and geologic storage program for the MRYS. Minnkota proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 million metric tons (MMt) of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood-Black Island. The Broom Creek is being primarily targeted for the total injection of 77.5 MMt of CO_2; however, the Deadwood-Black Island also has a projected capacity of 23.4 MMt of CO_2 over 20 years, which provides the project with contingent capacity or expansion opportunities. The Deadwood-Black Island Formation is being primarily contemplated as a back-up or redundant storage facility. The Tundra SGS surface facilities, wellsite, and operating location mostly comprise land associated with BNI's coal mining operation.

Minnkota plans to capture and store an average of 4 MMt/yr of CO_2 over the course of 20 years of injection, followed by 10 years of post-injection site care. Minnkota plans to retrofit MRYS Units 1 and 2 with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. After being dehydrated and compressed, the CO_2 will be transported 0.25 miles via pipeline to the storage site, where it will be permanently stored in saline aquifers located within the Broom Creek and Deadwood-Black Island Formations.

Minnkota is planning two phases. Phase 1 will involve the construction and operation of two injection wells (Liberty-1 and Unity-1) in the Broom Creek reservoir, which will inject the captured CO_2 volume. Once operations in Phase 1 have been proven, Minnkota indicates that it will assess the need to construct a third well, the McCall-1. The McCall-1 well would be completed in the Deadwood-Black Island reservoir and would be used to store any excess CO_2 identified in Phase 1 that would require injection and storage. In addition to the three proposed injection wells, Tundra SGS will have one dedicated monitoring well located approximately two miles northeast of the injection site for the lowest underground source of drinking water (USDW). Minnkota also proposes one deep subsurface monitoring well installed on Minnkota property located approximately 2 miles northeast of the injection site.

According to the MRV plan, the Tundra SGS location has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. Furthermore, the MRV plan asserts that the Tundra SGS location is outside of primary oil-producing fields, with little to no well development that would interfere with storage operations and containment.

The Broom Creek Formation, a predominantly sandstone horizon, lies 4,740 feet below the surface. The lower Piper, Opeche, and Spearfish Formations will serve as the primary overlying confining zones for the Broom Creek Formation. The MRV plan states that the confining interval comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation, overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS's Phase 1 operations.

According to the MRV plan, if pursued, the predominantly sandstone horizons of the Black Island and Deadwood Formations, which are approximately 9,280 feet below the surface, will act as the CO_2 storage reservoirs for Phase 2. The Icebox Formation, a shale unit conformably overlying the Black Island Formation with an average thickness of 118 feet, will be used as the overlying confining zone. The continuous shales of the Deadwood Formation B Member will serve as the lower confining zone.

The MRV plan provides a description of the project for Phase 1 and Phase 2, including the site setting, processes, and plans for injection operations. The description of the project is determined to be reasonable and provides information acceptable and in compliance with 40 CFR 98.448(a)(6). Minnkota states in the MRV plan that it will revise the MRV plan, as needed, to reflect changes in monitoring and/or operational parameters of Tundra SGS that are not currently anticipated in the MRV plan. The current MRV plan accounts for all monitoring and reporting obligations under Subpart RR for Phase 2 of Tundra SGS. A revised MRV plan will be submitted to the EPA Administrator within 180 days as required in § 98.448(d). However, Minnkota does not anticipate any material modification to the MRV plan.

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

Minnkota has defined the AMA as the Broom Creek Area of Review (AOR) for both the Broom Creek and the Deadwood-Black Island storage facilities as set forth in Tundra SGS's Class VI Underground Injection Control (UIC) permit application with the state of North Dakota. 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). According to the MRV plan, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

Minnkota has also defined the MMA as the Broom Creek AOR for both the Broom Creek and the Deadwood-Black Island storage facilities because the MRV plan asserts that the AOR exceeds the minimum areal extent of the plume required by Subpart RR. Factors considered include: the extent of free-phase CO_2 within the Broom Creek and Deadwood Formations, fluid pressure and management strategies to retain injected CO_2 within these units, and the geological structure of the units.

The reservoir characterization modeling described in section 1.3 of the MRV plan and the monitoring time frame explained in section 2.3 of the MRV plan indicate that the free phase CO_2 plume will be contained within the NDAC-approved Class VI AOR for the 20-year injection period plus a 10-year post injection monitoring period. This supports the conclusion that the site characterization required by the Class VI permit application is sufficient in delineating the monitoring areas for this MRV plan and no additional site characterization is required. Modeling results indicate no CO_2 migration outside of the storage facility area boundaries for both phases of Tundra SGS.

The MMA and AMA described in the MRV plan are clearly and explicitly delineated and are consistent with the definitions in 40 CFR 98.449. The delineations of the MMA and AMA are acceptable.

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). Minnkota and third-party subject matter experts from Oxy Low Carbon Ventures and the Energy & Environmental Research Center (EERC) identified the following as potential leakage pathways in their MRV plan that required consideration:

- Existing wellbores;
- Faults and fractures;
- Natural or induced seismicity;
- Flowline and surface equipment;
- Lateral migration of CO_2 beyond the AOR;
- Vertical migration: injection and monitoring wells; and
- Vertical migration: diffuse leakage through seal.

3.1 Leakage from Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated in the MRV plan as potential leakage pathways:

1. The **J-ROC1** (North Dakota Industrial Commission (NDIC) No. 37672) well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota Project, Phase III. Although the well is currently in a temporarily plugged and abandoned status, , the MRV plan states that it will be converted to a CO_2 injection well. As a result, the J-ROC1 will be renamed to Liberty-1. According to the MRV plan, Liberty-1 will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.
2. The **J-LOC1** (NDIC No. 37380) well was drilled by Minnkota in 2020 as a stratigraphic well (reaching to the Precambrian rocks). Materials used to construct the well were compatible with Class VI and CO_2 construction and operating standards. The well is currently in a temporarily abandoned status. Abandonment procedures and well schematic details can be found in A2:3, Table 3-5 and Figure 3-8 of the MRV plan. According to the MRV plan, should the J-LOC1 have no future use, it will be permanently plugged and abandoned to ensure integrity. Although the J-LOC1 is slightly outside the delineated AOR for the Broom Creek storage facilities, it is still included in the pressure front delineated for the Deadwood-Black Island Formation storage.
3. The **BNI-1** (NDIC No. 34244) well was drilled in 2018 as a stratigraphic well (reaching the Amsden Formation) by the EERC under North Dakota CarbonSAFE, Phase II. The MRV plan states that the well was plugged and abandoned in 2018.
4. The **Herbert Dresser 1-34** (NDIC No. 4937) well was drilled and plugged in 1970 after being classified as a dry hole. The MRV plan notes that the well was replugged in 2001 and several cement plugs isolate any potential movement of fluids between the different flow units and USDWs.
5. The **Little Boot 15-44** (NDIC No. 8144) well was abandoned as a dry hole in 1981. The MRV plan notes that the well was plugged and abandoned with cement plugs to isolate the different flowing units before the Fox Hill Aquifer. Although the Little Boot 15-44 well is slightly outside the delineated AOR for the Broom Creek storage facility, it is still included in the pressure front delineated for the Deadwood-Black Island Formation storage.

The MRV plan states that there are no other known wellbores that could impact the project and that there is no active or prior production of oil and gas in the vicinity of Tundra SGS. The summary table of existing wellbores can be found in table 3-1 of the MRV plan, which is reproduced in Table 1 below.

Table 1 – Wellbore Summary of Project SGS

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad as the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1,000 feet above the Broom Creek Formation. The MRV plan states that the water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the MRV plan asserts that the risk of leakage is very unlikely. The MRV plan states that the lack of petroleum production and the low likelihood of future drilling activities in the area make potential leakage pathways of injected CO_2 through existing wellbores very unlikely.

Thus, the MRV plan provides adequate characterization of the risk of potential leakage from existing and planned wellbores.

3.2 Leakage through Fractures and Faults

The MRV plan states that there are no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area through site-specific characterization activities, prior studies, or previous oil and gas exploration activities according to the MRV plan. 3D and 2D seismic surveys were acquired in 2019 and 2020, respectively. This seismic data are used for assessment of the geologic structure, interpretation of inter-well heterogeneity, and well placement. No structural features, faults, or discontinuities that would cause concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were found. Therefore, the MRV plan shows that leakage through faults and fractures to be very unlikely to nearly impossible near the MRYS.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage through fractures and faults.

3.3 Leakage due to Natural or Induced Seismicity

According to the MRV plan, between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin. Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin. The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota. This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. Studies completed by the U.S. Geological Survey (USGS) indicate that less than two damaging seismic events are predicted to occur over a 10,000-year period. One study found that a pressure increase of 3,600-4,800 pounds per square inch (psi) would be required to induce shear failure of the Deadwood Formation. According to the MRV plan, injection pressure to the Deadwood Formation is not planned to exceed 1,800 psi. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation. For these reasons, the MRV plan states that leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage due to natural/induced seismic activity.

3.4 Leakage through Flowlines and Surface Equipment

The MRV plan states that surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Potential deterioration through corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in Tundra SGS surface equipment. The Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Independent, 8-inch flow lines will connect each well to M2.

The risk of leakage in this surface equipment is mitigated through:

1. Adhering to regulatory requirements for construction and operation of the site.
2. Implementing highest standards on material selection and construction processes for the flowline and wells.
3. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
4. Continuous monitoring through an automated system and integrated databases.

As a result, the MRV plan concludes that the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed.

Another risk associated with surface equipment is the possibility of catastrophic failure. Natural events or objects striking surface equipment could result in a catastrophic event. Such an event would cause disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the MRV plan states that the project team performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. This leakage scenario could represent thousands of tons of CO_2 released before leakage is stopped. Even though a catastrophic event would be high impact, the likelihood of such an event is extremely unlikely since the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and the equipment is located within a fence on MRYS private property.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage through flowline and surface equipment.

3.5 Leakage due to Lateral Migration

The MRV plan states 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), which confines the CO_2 within the storage facility area. Slow lateral migration of the plume throughout the injection and post-injection period will not likely extend beyond the structure of the storage reservoir, and be contained within the MMA, due to the effects of buoyancy, and the low dipping structure of the storage complexes. 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 Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. For these reasons, the MRV plan identifies potential leakage due to lateral migration of the CO_2 plume as very low likelihood.

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

3.6 Leakage due to Vertical Migration: Injection and Monitoring Wells

The MRV plan states that all Class VI injection wells (Liberty-1, Unity-1, and McCall-1), as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leaks due to loss of integrity in the wellbores. Well instrumentation will have automated data management systems to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program to ensure proper maintenance of the facilities. Once the injection period ceases, the injection wells will be evaluated for mechanical integrity with corrosion and casing inspection logs and will be properly abandoned with CO_2 resistant cement. Following the conclusion of the injection period, the NRDT-1 monitoring well will remain operational until the plume stabilization and the issuance of a certificate of site closure is granted. Finally, the NRDT-1 well will undergo the same plug-and-abandonment protocol as proposed for the injection wells. According to the MRV plan, the risk of leakage due to vertical migration through injection and monitoring wells is unlikely. If such a leak were to occur, the duration of leakage would be minimal due to injection shutoff protocols.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage due to vertical migration through injection and monitoring wells.

3.7 Leakage due to Vertical Migration: Diffuse Leakage Through Seal

The primary mechanism for storing CO_2 within the Broom Creek and Deadwood-Black Island Formations, as stated in the MRV plan, is containment by the cap rock's relative permeability and capillary pressure. For the Broom Creek storage reservoir, the 154 feet thick Opeche-Picard interval will act as the cap rock. The Picard member consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. In addition to the Opeche-Picard interval, 820 feet of impermeable rock formations separate the Broom Creek Formation from the next overlying permeable zone, the Inyan Kara Formation. In regard to USDW, an average of 2,545 feet of impermeable intervals separates the Inyan Kara Formation from the lowest USDW, the Fox Hills Formation.

According to the MRV plan, if Phase 2 is implemented, the Black Island and Deadwood storage reservoirs also have sufficient caprocks. The Icebox Formation consists of impermeable shale that reaches a thickness of 118 feet within the storage facility area. In addition to the primary cap rock consisting of the Icebox Formation, the Roughlock Formation and Red River D member will act as a secondary confining formation to the Black Island and Deadwood storage reservoirs. In total, the Black Island and Deadwood storage reservoirs have up to 612 feet of impermeable rock separating them from the next overlying permeable zone: the Red River A, B, and C members. Above the Red River Formation, more than 1,000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. Below the Black Island and Deadwood storage facilities, the continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite that will also act as a lower confining seal. No known transmissible faults are within these confining systems in the project area according to the MRV plan.

According to the MRV plan, once the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 will gradually be lost after year t+10. Eventual mineralization of the injected CO_2 will ensure its permanent geologic confinement. Overall, the MRV plan explains that leakage through vertical migration through the seal was shown to be very unlikely to nearly impossible.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage due to vertical migration through the seal.

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

40 CFR 98.448(a)(3) requires that an MRV plan 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. Sections 4 and 5 of the MRV plan outline Minnkota's strategy for quantifying surface leakage of CO_2 and their strategy for establishing expected baselines to monitor against. Minnkota's approach includes direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Minnkota's monitoring techniques based on analyzed leakage pathways are summarized in Figure 4-1 in the MRV plan, which is reproduced in Table 2 below.

Table 2 – Tundra SGS monitoring Strategy

Integrated Remote Automated System (SCADA) and Surveillance Protocol

Leak Detection through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and Optical Gas Imaging (OGI) cameras.
- Automated CO_2 sensors in the wellhead.
- Real time (RT) injection performance on surface and downhole (Pressure, Temperature, flow).
- Distribute temperature sensing (DTS) technology to track well integrity and vertical conformance downhole.
- DTS and Distributed acoustic sensing fiber (DAS) for CO_2 flow line monitoring.
- Mechanical Integrity Program.
- Corrosion Monitoring Program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring through:

- Monitoring wells in reservoir .
- Pressure and temperature gauges downhole in injector.
- 4D seismic surveys.
- Interferometric synthetic aperture radar (INSAR).
- History Match Reservoir Simulation.
- Saturation Log in reservoir.
- Real time temperature profile (DTS) on injectors.
- Seismometers network (induced events)

Operational & Near Surface Monitoring through:

- Soil Gas Analysis
- CO_2 stream analysis.
- Water sampling USDW (baseline and during operation)

Tundra SGS will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, distributed temperature sensing (DTS) alongside the casing, and routine maintenance and inspection.

As part of the surveillance protocol, Tundra SGS will use reservoir simulation modeling, based on history-matched data obtained from the monitoring system, to compare the initial numerical model with the measured 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 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 leaking to the surface will be quantified using acceptable emission factors, engineering estimates of 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.

4.1 Leakage from Existing and Planned Wellbores

The MRV plan states that leakage through existing and planned well bores is unlikely due to the lack of any active or prior petroleum production in the vicinity of Tundra SGS, according to section 3.1 of the MRV plan. There are only two known wells in the vicinity of the Tundra SGS that are not plugged: J-ROC1 and J-LOC1. J-ROC1 will eventually be converted to the CO_2 injection well and be renamed Liberty-1. Liberty-1 will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage. The MRV plan does not indicate that the J-LOC1 or the other plugged and abandoned wells in the area will need explicit monitoring. Table 4-2 of the MRV plan lists monitoring strategies for leakage through existing and planned wellbores. For example, wellbores will undergo visual inspections, measurements via handheld CO_2 monitors, 2D/3D time-lapsed surface seismic, and interferometric synthetic aperture radar (InSAR).

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage from existing and planned wellbores as required by 40 CFR 98.448(a)(4).

4.2 Leakage through Fractures and Faults

In the unlikely scenario of leakage through fractures and faults, the MRV plan states that response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E of the MRV plan). Specific leakage event facts and circumstances would be considered when estimating volumetric losses of CO_2. Section 3.2 of the MRV plan states that possible considerations of leakage through fractures and faults might include magnitude and timing of the CO_2 leak and pathway characteristics (fault/fracture permeability, geometry extension, and location). Based on these factors, Minnkota would model CO_2 leakage volume estimates that followed applicable industry standards. Table 4-2 of the MRV plan lists monitoring strategies for leakage through fractures and faults. Some examples include surface seismometers, InSAR, solid gas analysis, and water sampling of surface water and USDW.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage through faults and fractures as required by 40 CFR 98.448(a)(4).

4.3 Leakage due to Natural or Induced Seismicity

Although the MRV plan shows that leakage through natural or induced seismicity is very unlikely to nearly impossible for Tundra SGS, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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. Table 4-2 of the MRV plan lists monitoring strategies for leakage due to natural or induced seismicity. Automated remote systems (SCADA) and surface seismometers will be utilized.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage due to natural or induced seismicity as required by 40 CFR 98.448(a)(4).

4.4 Leakage through Flowline and Surface Equipment

Section 3.4 of the MRV plan states that surface equipment is the likeliest leakage pathway on the Tundra SGS site during its injection period. In order to detect surface equipment leaks, DTS/distributed acoustic-sensing (DAS) fiber optics will be installed along the flowlines as part of the leak detection program and mechanical integrity protocol. Furthermore, each metering station will have flowmeters and temperature and pressure transducers. Pressure gauges will be installed on each 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. Table 4-2 of the MRV plan lists monitoring strategies for leakage through flowline and surface equipment. Some examples include the use of visual inspection, handheld CO_2 monitors, SCADA, and corrosion coupons.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage through flowline and surface equipment as required by 40 CFR 98.448(a)(4).

4.5 Leakage due to Lateral Migration

Section 3.5 of the MRV plan states that there is very low likelihood of CO_2 leakage due to lateral migration. Nevertheless, early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the Storage Facility Permit (SFP) using both observations and history-matched simulation of CO_2 and pressure distribution. Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predicts additional lateral movement of the plume, Tundra SGS would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests. Good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22. Revisions would be made to the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. Table 4-2 of the MRV plan lists monitoring strategies for leakage due to lateral migration. Some examples include downhole (DH) pressure gauges and temperature sensors for injection and monitoring wells, 2D/3D time lapsed surface seismic, and InSAR.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage due to lateral migration as required by 40 CFR 98.448(a)(4).

4.6 Leakage due to Vertical Migration: Injection and Monitoring Wells

According to Section 3.6 of the MRV plan, vertical CO_2 leakage through injection and monitoring wells is unlikely. To measure any possible leakage, well instrumentation connected to an automated data management system will be installed that will provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. The NRDT-1 monitoring well will continue to be operational until plume stabilization and official site closure have occurred. Tundra SGS protocols will be designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. Table 4-2 of the MRV plan lists monitoring strategies for leakage due to vertical migration through injection and monitoring wells. Some examples include annular pressure tests, CO_2 stream analysis, visual inspection, and water sampling.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage due to vertical migration through injection and monitoring wells as required by 40 CFR 98.448(a)(4).

4.7 Leakage due to Vertical Migration through the Seal

As explained in Section 3.7 of the MRV plan, vertical CO_2 leakage through the seal is an unlikely event. Nonetheless, should leakage occur, estimating volumetric losses of CO_2 would require consideration of the 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 on the facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E of the MRV plan). Table 4-2 of the MRV plan lists monitoring strategies for vertical migration through the seal. Some examples include water sampling, handheld CO_2 monitoring, and 2D/3D time-lapsed surface seismic.

Thus, the MRV plan provides adequate characterization of Minnkota's approach to detect potential leakage due to vertical migration through the seal as required by 40 CFR 98.448(a)(4).

4.8 Establishing Baselines for Monitoring

Section 5 of the MRV plan explains Minnkota's strategy for establishing baselines for monitoring any possible CO_2 leakage. Pre-injection baselines will be determined by implementing a monitoring program prior to any CO_2 injection. This monitoring program will take place during each of the four primary seasonal ranges. Measurements taken will target the surface, near-surface, and deep subsurface. Furthermore, the baseline will contain information on the surface water, soil gas in the vadose zone, shallow groundwater, storage reservoir formation water, and gas saturation/oil saturation. These baselines will be used for comparing measurements once injection commences. 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 Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B of the MRV plan.

As explained in section 5.1 of the MRV plan, surface baseline sampling locations will include domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers, as well as one USGS Fox Hills observation well. Measurements taken at these wells will include anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C of the MRV plan.

Section 5.2 of the MRV plan states that pre-operational baseline data will be collected in the injection and monitoring wells to establish subsurface baselines. Furthermore, a 3D seismic survey was conducted on the AOR to establish baseline condition of the storage reservoir. A feasibility study of surface deformation monitoring with InSAR technology will be performed to determine application before injection and to establish a baseline for the future application of this technology. Finally, the project will install seismometer stations a year prior to injection.

The strategy for detecting and quantifying surface leakage of CO_2 and for establishing expected baselines for monitoring is acceptable. 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

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

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

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

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

Tundra SGS will use a volumetric flowmeter 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 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:

$$CO_{2,u} = \Sigma\ Q_{p,u} * D * C_{CO2,p,u}$$

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 (wt percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

5.3 Calculation of 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).

Tundra SGS will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

$$CO_{2E} = \Sigma\ CO_{2,x}$$

Where:

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

6 Summary of Findings

The Subpart RR MRV plan for the Tundra SGS 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 Tundra SGS's MRV plan.

Subpart RR MRV Plan Requirement	**Tundra SGS MRV Plan Explanation**
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. Minnkota has defined the MMA as the Broom Creek AOR for both the Broom Creek and the Deadwood-Black Island storage facilities. Tundra has defined the AMA as the same area as the MMA. The MRV plan indicates that the free phase CO_2 plume will be contained within the NDAC-approved Class VI AOR for the 20-year injection period plus a 10-year post-injection monitoring period. The MMA and AMA delineations consider the extent of free-phase CO_2 within the Broom Creek and Deadwood Formations, fluid pressure and management strategies to retain injected CO_2 within these units, and the geological structure of the units.
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: potential leakage through existing and planned wellbores, faults and fractures, natural or induced seismicity, flowline and surface equipment, lateral migration, vertical migration through injection and monitoring wells, and vertical migration through the seal. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.

	Minnkota determined that the probability of leakage is unlikely, 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 of the MRV plan describes how the facility would detect and quantify CO_2 leakage through the potential pathways described in section 3 of the MRV plan, should leakage occur.
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 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 Minnkota'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.	Attachments 1 and 2 in the MRV plan provide well identification numbers for each applicable injection well. As of the most recent MRV plan submission, Minnkota was still waiting to receive injection well ID numbers. The MRV plan specifies that all injection wells are permitted as UIC Class VI wells.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR12 of this subpart.	Section 7 of the MRV plan states that, "this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion."

Appendix A: Final MRV Plan

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Wells

Facility(GHGRP) ID 579201

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LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT (SFP) DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, Tundra SGS SFPs and their individual sections for Broom Creek and Deadwood are designated as follows:

Attachment 1: Tundra SGS – Carbon Dioxide Geologic SFP (Broom Creek) Case No. 29029-29031

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachment 2: Tundra SGS – Carbon Dioxide Geologic SFP (Deadwood) Case No. 29032-29034

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

*Attachments within this MRV document will follow use the following referencing convention:

- A1 and A2 will refer to the Attachments, A1 being the Broom Creek SFP and A2 being the Deadwood SFP.
- Numbers or letters that appear after the colon will represent the numbered section or appendix of the appropriate Storage Facility Permit. For example:
    - A1:3.1.1 will direct the reader to refer to Section 3.1.1, (Area of Review Section, Written Description Subsection) within the Broom Creek SFP.
    - A2:A will direct the reader to refer to Appendix A (Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations) within the Deadwood SFP

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

1.0 PROJECT DESCRIPTION

Minnkota Power Cooperative, Inc. (Minnkota) is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota also acts as the operating agent of the Northern Municipal Power Agency, which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine, which provides the lignite coal for MRYS, is owned and operated by BNI Coal, Inc. (BNI) and is located adjacent to the MRYS facility. Minnkota prepared this MRV plan in support of the operation, reporting, and accounting for the storage component of Project Tundra, a carbon capture retrofit to MRYS with saline formation geologic storage. Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood–Black Island. The Broom Creek is being primarily targeted for the total injection of 77.5 MMt however the Deadwood-Black Island has a projected capacity of 23.4MMt over 20 years, which provides the project with contingent capacity or expansion opportunities. However, Deadwood-Black Island formation is being primarily contemplated as a back-up or redundant storage facility. The geologic storage facility and operation are referred to as Tundra SGS. The Tundra SGS surface facilities, wellsite, and operating location comprise land mostly associated with the coal-mining operation of BNI, the area where MRYS is located, and the land is primarily industrial and agricultural. The nearest densely populated area is Center, North Dakota, which is approximately 3.4 miles northwest of the Tundra SGS site (Figure 1-1).

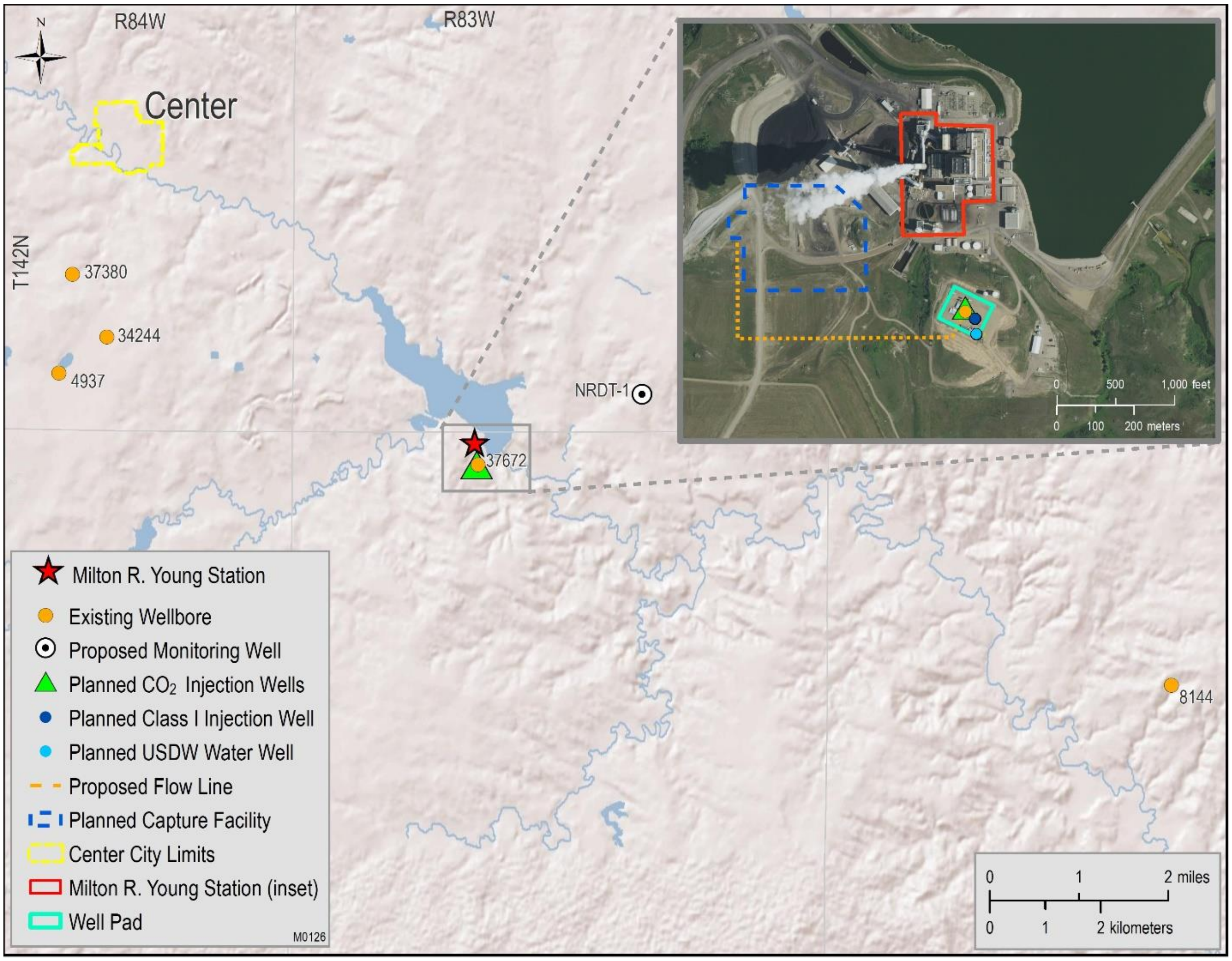

Figure 1-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the proposed CO_2 flowline and well pad layout. The red star denotes MRYS. The existing J-ROC1 wellbore (37672) is the wellbore planned for reentry and conversion to a Class VI injection well, which will be renamed Liberty 1. Offset wells (8144, 37380, 34244, and 4937) are included as they were evaluated in the area of review (AOR) of the Tundra SGS Carbon Dioxide Geologic Storage Facility Permit (SFP) for both Broom Creek and Deadwood storage reservoirs (A1 and A2).

1.1 Operation and Equipment

Tundra SGS plans to capture and store an average of 4 MMt/yr of CO_2 over the course of 20 years of injection, followed by 10 years of post-injection site care. MRYS Units 1 and 2 will be retrofitted with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. The CO_2 captured will be dehydrated and compressed to a supercritical state, then transported via a 0.25-mile flowline to the storage site, where it will be securely and permanently stored in saline geologic formations. Figure 1-2 provides a simplified process flow diagram of the Tundra SGS project, which includes the CO_2 flowline from the metering station (M1) at the outlet of the capture facility compressor and the Phase 1 and Phase 2 injection and monitoring wells (Figure 1-2).

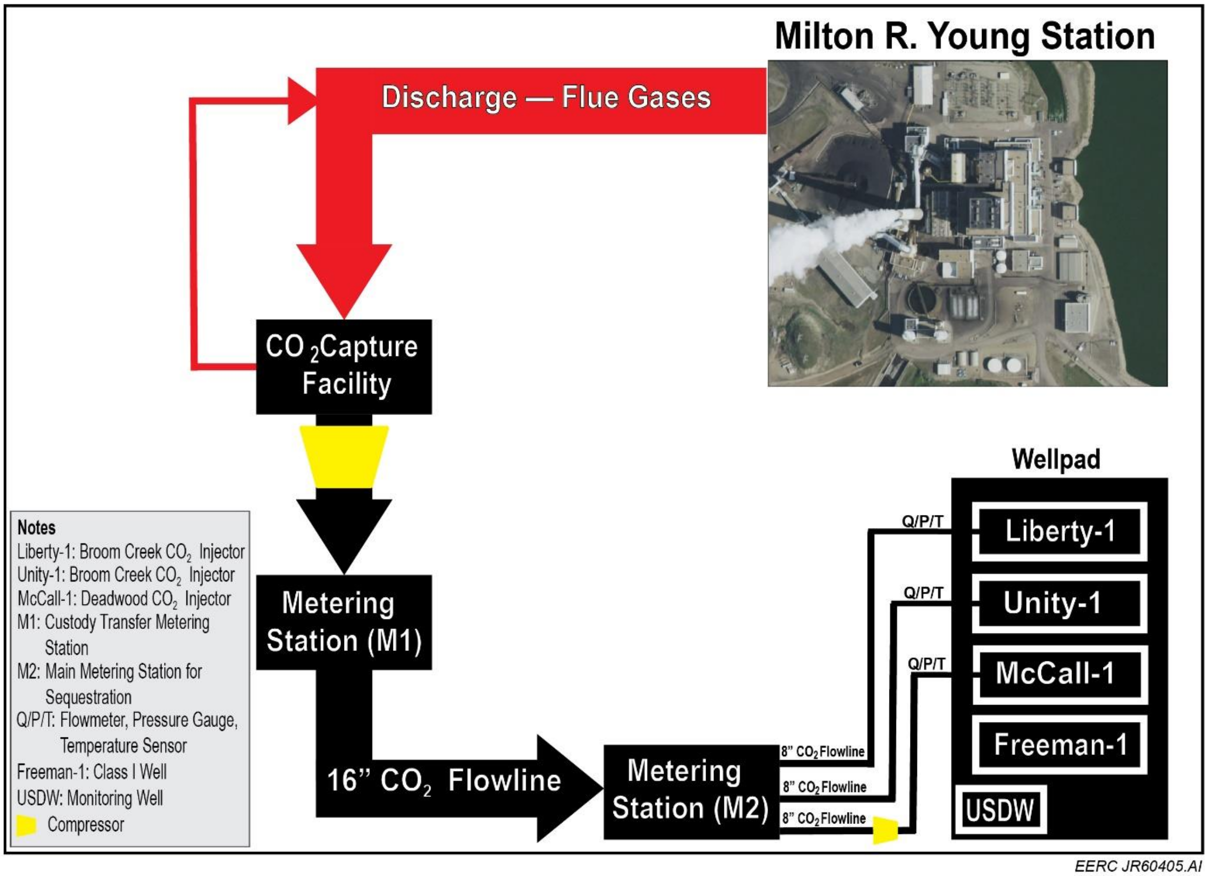

Figure 1-2. Flow diagram for Tundra SGS capture, transport, and storage facilities (USDW is underground source of drinking water).

Tundra SGS will receive captured and dehydrated CO_2 at the compressor outlet (M1), then it will be transported 0.25 miles via CO_2 flowline to the metering station (M2) for distribution to the injection wells for secure and permanent storage in the Broom Creek and Deadwood–Black Island geologic formations. These two storage formations as well as their confining seals have been extensively characterized by Minnkota through local and regional studies led by the Energy & Environmental Research Center (EERC). The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1.

The project proposes a phased development approach, with Phase 1 construction and operation of two injector wells in the Broom Creek reservoir (approximately 5,000 feet in depth), targeting 100% of the captured CO_2 volume. Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well, the McCall-1. This additional well would be completed in the Deadwood–Black Island reservoir (approximately 10,000 feet in depth) to store any excess CO_2 identified in Phase 1. The stacked storage concept and phased development approach allows the project to maximize the areal extent of the storage facilities,

provides operational flexibility and redundancy, and generates further assurance to investors and stakeholders.

In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. Layout of the wells and surface facility infrastructure can be found at Figure 1-2. Minnkota proposes one deep subsurface monitoring well (NRDT-1) installed on Minnkota property located approximately 2 miles northeast of the injection site.

This procedure is applicable to Tundra SGS storage facility operations consisting of the following infrastructure:

SFP Case Number: **29029, 29030, 29031**
UIC Class VI, ADP Form No. 28643[Unity-1]
UIC Class VI, ADP Form No. 30200[Liberty-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]
SFP Case Number: **29032, 29033, 29034**
UIC Class VI, ADP Form No. 28977 [McCall-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]

The current mailing address for the Tundra SGS facility, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

1.2 Environmental Setting/Geology

The Williston Basin lies in the western half of North Dakota; this area has a long history of hydrocarbon exploration and utilization. This region has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. The proposed location of Tundra SGS is approximately 3.4 miles southeast of the town of Center on the eastern flank of the Williston Basin. This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment. Further discussion of potential mineral zones is found at A1:2.6 and A2:2.6.

The target CO_2 storage reservoir for Tundra SGS Phase 1 is the Broom Creek Formation, a predominantly sandstone horizon lying 4,740 feet below the MRYS facility (Figure 1-3). The lower Piper and Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") serve as the primary confining zone overlying the Broom Creek Formation. This confining interval comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS Phase 1 operations.

The target CO_2 storage reservoirs for Tundra SGS Phase 2, if pursued, are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying approximately 9280 feet below MRYS (Figure 1-3). The shales of the Icebox Formation conformably overlie the Black Island and serve as the primary confining zone. The Icebox Formation provides a suitable confining layer, with an average thickness of 118 feet. The continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite. Together, the Icebox (upper confining), Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS Phase 2. For additional details regarding the site characteristics, refer to A1:2 and A2:2.

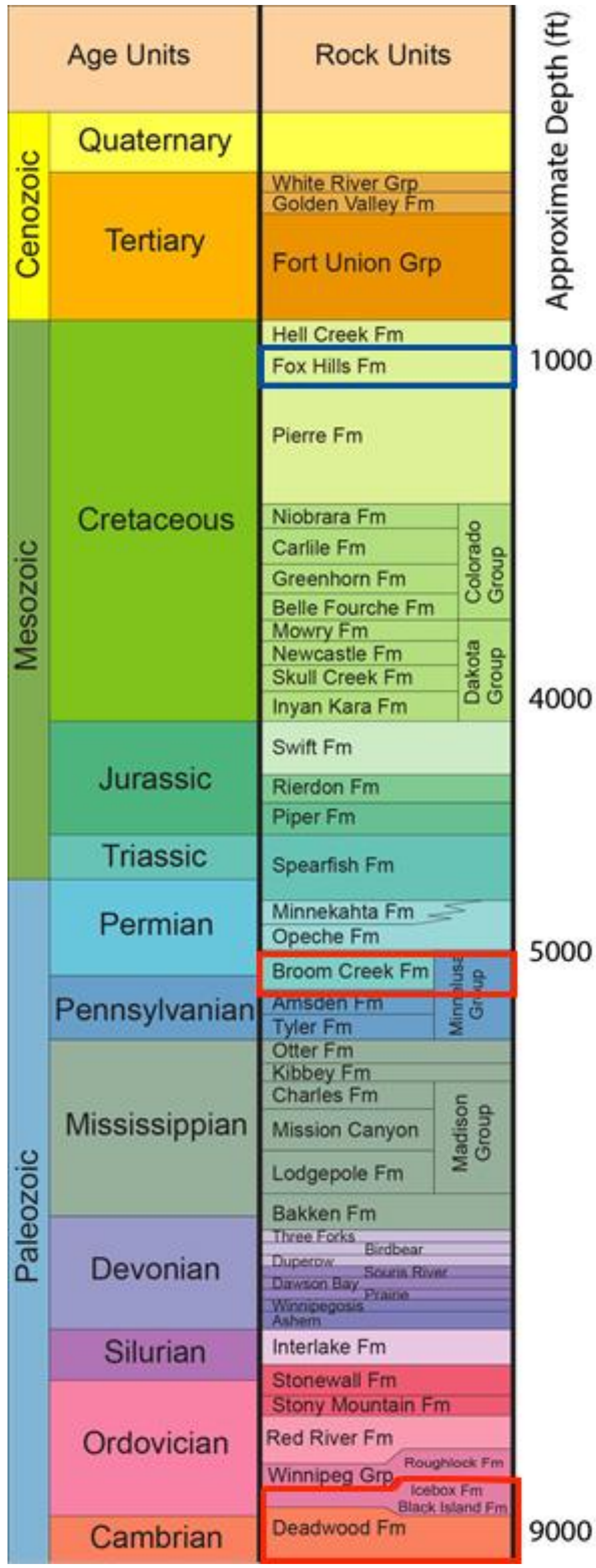

Figure 1-3. Stratigraphic column of North Dakota. Red boxes around the Broom Creek and Deadwood Formations delineate the targeted injection zones.

1.3 Reservoir Model

1.3.1 Broom Creek (Phase 1)

Phase 1 includes two wells: Liberty-1 (originally drilled as J-ROC 1, a stratigraphic well to be converted to a Class VI injector) and Unity-1 (Figure 1-2). Numerical simulation of CO_2 injection in the sandstones of the Broom Creek Formation predicted the wellhead injection pressure (WHP) of both wells would not exceed 1700 psi during injection. Bottomhole pressures (BHPs) reached 3,035.1 and 3,018.3 psi for Liberty-1 and Unity-1 wells, respectively. For the Broom Creek CO_2 plume boundary delineation, the CO_2 plume boundary was modeled using operating assumptions of 20 years at a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 16 through 20. The reservoir simulation model indicated target injection rates were consistently achievable over 20 years of injection. A total of 77.5 MMt of CO_2 would be injected into the Broom Creek Formation with two wells at the end of 20 years. Injected volumes were 41.1 and 36.4 MMt for the Unity-1 and Liberty-1 wells, respectively. A maximum formation pressure increase of 488 psi is estimated in the near-wellbore area during the injection period (A1:A).

1.3.2 Deadwood (Phase 2)

The Deadwood–Black Island reservoir model simulation for Phase 2 includes the McCall-1 well, drilled on the same pad as the Broom Creek wells (Figure 1-2). This model was constrained by WHP and bottomhole fracture gradient without any injection rate constraint. Within the sandstones of the Black Island and Deadwood Formations, numerical simulation of CO_2 injection predicted that injection BHP will not exceed 6,179 psi during injection operations, assuming a WHP limit of 2,800 psi is maintained. Cumulative CO_2 injection at the above-described pressure conditions was 23.4 MMt over the 20 years of injection. The resulting average injection rate of CO_2 into the Black Island and Deadwood Formations was 1.17 MMt/year. Near the wellbore area, a maximum increase of 1620 psi was estimated within the Black Island and Deadwood Formations.

Through numerical simulation efforts, long-term CO_2 migration potential was investigated in each of the Broom Creek and Deadwood models. The results did not indicate migration outside the storage facility area boundaries in either scenario. Storage facility area boundaries were established using a 20-year injection period, with the output boundary at Year 20 identified at a 5% CO_2 saturation rate and then rounded outward to the nearest 40-acre tract (A1:A).

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area

The active monitoring area (AMA) is defined 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" (40 Code of

Federal Regulations [CFR] § 98.449). For purposes of this MRV plan, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (Figure 2-1). Based on review of the data and information of record, and data and information collected in support of A1 and A2, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

2.1.1 Tundra SGS AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

Under North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC) storage facility and Class VI requirements for an AOR, delineation was completed based on the Project Tundra SFP. 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" (NDAC § 43-05-01-01). The NDAC requires the operator develop an AOR and corrective action plan utilizing 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 (NDCC § 38-22-08). Minnkota elected to permit the storage facility area boundaries based on the 20-year reservoir model output discussed in Section 1.3 and then added an additional buffer rounding out to the nearest 40-acre tract.

The Broom Creek proposed AOR was delineated using a risk-based AOR approach (A1:3.1). The risk-based delineation examines the area encompassing the region overlying the injected free-phase CO_2 and the region overlying the extent of increased formation fluid pressure sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or conductive fractures) are present. The risk-based approach established that the CO_2 plume boundary is also the extent of the AOR boundary (A1:3.1). However, in compliance with the NDAC evaluation and monitoring requirements, Minnkota extended the permitted AOR boundary beyond the risk-based delineation to encompass the storage facility boundary plus an additional 1-mile buffer (A1:3.1). Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring from the outset of operations, provides significant assurance that operations can be conducted safely and as contemplated within the permitted storage facility.

The proposed AOR for the Deadwood–Black Island storage facility used EPA Method 1 to establish the AOR (A2:3.1). The Deadwood–Black Island reservoir model simulation discussed in Section 1.1 yielded an annual average injection rate of approximately 1.17 MMt/year for 20 years. Applying EPA Method 1, the Deadwood–Black Island AOR has a larger areal extent, due to the estimated pressure front under EPA Method 1, than the Broom Creek AOR, which applied the risk-based AOR approach; however, the free-phase CO_2 plume for Deadwood is contained in the delineated AOR for Broom Creek. Because of the significant overlap between the two AORs and the phased development approach, the Tundra SGS technical evaluation and proposed monitoring plan were developed to account for monitoring both injection horizons in accordance with the requirements and to the maximum areal extent simulated.

2.1.2 *Tundra SGS AOR Encompasses Subpart RR AMA of both Broom Creek and Deadwood*

AMA minimum delineation requirements are found in 40 CFR § 98.449 and used in Figure 2-1. Using a period of t=20 years, the Broom Creek delineated AMA boundary and the Deadwood–Black Island AMA boundary fall within the Broom Creek AOR. Minnkota proposes that the Broom Creek AOR serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (AOR outlined in black in Figure 2-1), delineation of the AOR is discussed further in A1:3 and A2:3. Aligning the calculated AMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

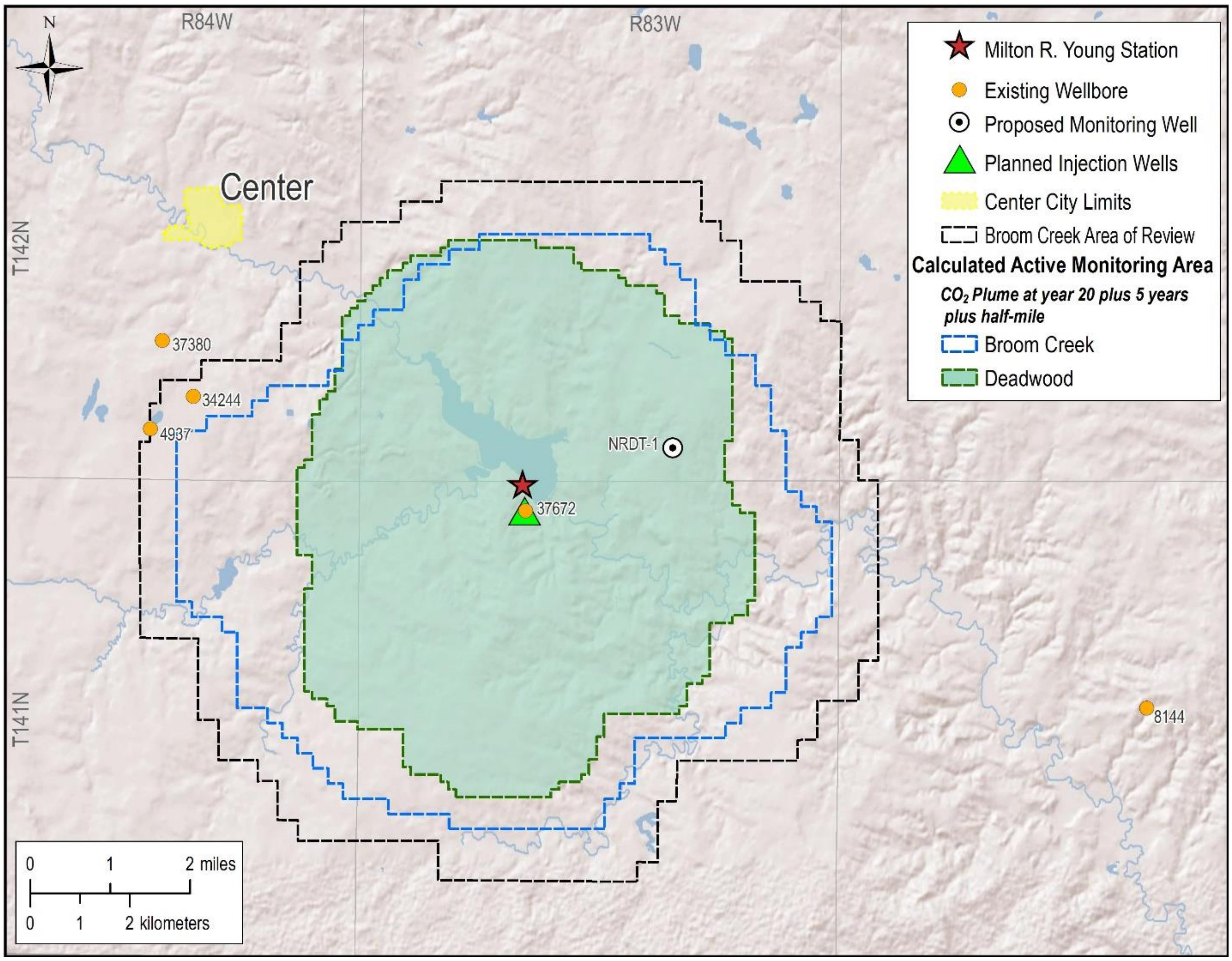

Figure 2-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated AMA in comparison to the permitted AOR. AOR subsumes the calculated AMA for both formations and exceeds requirements for AMA; therefore, the AOR serves as the AMA for Project Tundra.

2.2 Maximum Monitoring Area

The maximum monitoring area (MMA) as defined in 40 CFR § 98.440–449 (Subpart RR) is the area defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The calculated MMA delineated in Figure 2-2 for the Broom Creek and Deadwood–Black Island storage facilities uses a period of t=20 years and represents the period t+10 and a half-mile buffer extending beyond that boundary. The permitted AOR for Broom Creek, as delineated in A1 and A2, exceeds the minimum areal extent required by the Subpart RR approach for delineating the MMA (Figure 2-2); therefore, Minnkota proposes that the Broom Creek AOR serve as the calculated MMA for both the Broom Creek and the Deadwood–Black Island storage facilities.

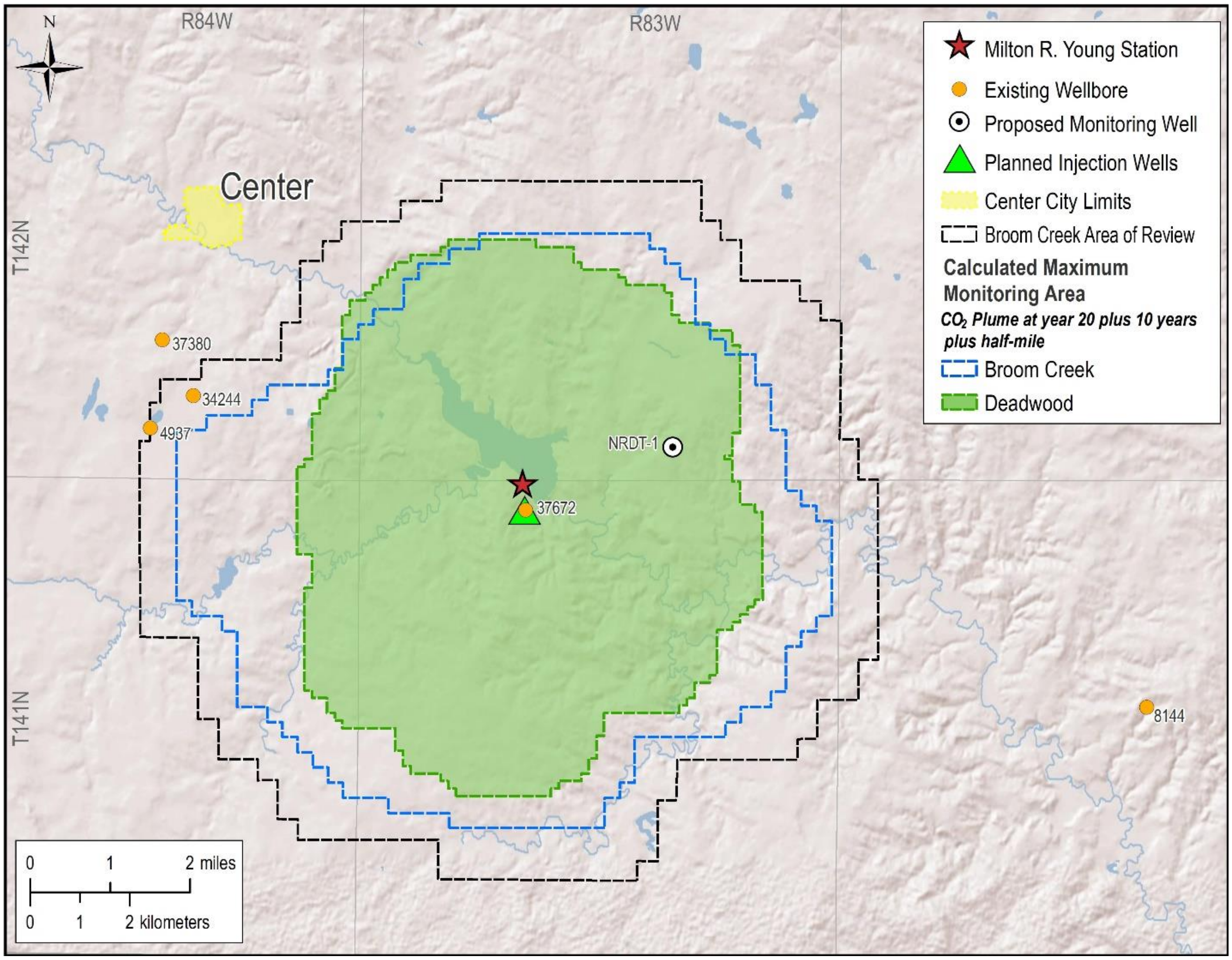

Figure 2-2. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated MMA in comparison to the permitted AoR. AOR subsumes the MMA for both formations and exceeds requirements for the MMA; therefore, the AOR serves as both the AMA and MMA for Project Tundra.

Aligning the calculated AMA and MMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2, as described in A1:4.1 and A2:4.1, comprises three distinct periods: 1) preoperational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. The time frame of these monitoring periods will encompass the entire life cycle of the injection. For purposes of this 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 and frequency of the measurements performed vary. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

Preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and inherent 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 amount of CO_2 that is contained in the formation at any given time. This information will be incorporated into the final Class VI permit. If results from this preoperational monitoring period necessitate changes to this MRV plan, an amendment will be submitted prior to the start of operations.

The operational injection period is focused on validating and updating numerical models of the storage system and ensuring that the geologic storage project is operating safely and is protecting USDWs. Lastly, the purpose of 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 three monitoring periods is a minimum of 1 year, 20 years, and a minimum of 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS AND MECHANISMS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was completed by representatives of Minnkota as well as third-party subject matter experts from Oxy Low Carbon Ventures and the EERC. During these meetings, potential leakage pathways were identified and evaluated for the following:

- Existing wellbores
- Faults and fractures
- Natural or induced seismicity
- Flowline and surface equipment
- Lateral migration of CO_2 beyond the AOR

- Vertical migration: injector and monitoring wells
- Vertical migration: diffuse leakage through seal

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 A1:4.1 and 2:4.1, and summarized in Table 5-2, forms the basis for this MRV plan.

3.1 Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated as potential leakage pathways. There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. A detailed discussion of potential mineral zones is found at A1:2.6 and A2:2.6. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table.

Table 3-1. Wellbore Summary

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

3.1.1 J-ROC1 [NDIC No. 37672]

The J-ROC1 well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota project, Phase III. An entire geologic column from surface to the Precambrian was drilled and core collected, and fluid samples as well as special logs were obtained. The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well. Further discussion of reentry program provided in Supplement-1. Once the well conversion takes place, J-ROC1 will be renamed Liberty-1, on authorization of pending reentry drilling permit. This well will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.

3.1.2 J-LOC1 [NDIC No. 37380]

The J-LOC1 well was drilled by Minnkota in 2020 as a stratigraphic well. The construction materials used were compatible with Class VI and CO_2 operating standards. The well was drilled through the entire geologic column from surface to the Precambrian. The drilling program included collecting core, obtaining fluid samples and special logs, and injectivity testing in the Broom Creek and Deadwood Formations. The well is currently in a temporarily abandoned status, plugged for future use. Abandonment procedure and well schematic details can be found in A2:3, Table 3-5 and Figure 3-8. In case the well has no future potential use, it will be permanently abandoned to ensure integrity. This well is located slightly outside the delineated AOR for the Broom Creek, but it is included in the pressure front delineated for Deadwood–Black Island Formation storage.

3.1.3 BNI-1 [NDIC No. 34244]

The BNI-1 well was drilled in 2018 as a stratigraphic well by the EERC under North Dakota CarbonSAFE Phase II. The well was drilled through the Broom Creek Formation and reached total depth in the Amsden Formation. The well was plugged and abandoned in 2018 in accordance with approved guidance and regulations of the state.

3.1.4 Herbert Dresser 1-34 [NDIC No. 4937]

The Herbert Dresser 1-34 well was drilled and plugged in 1970 after being classified as a dry hole. The well was replugged in 2001 by BNI. It was drilled through the Broom Creek Formation and reached total depth at the Charles Formation. Several cement plugs isolate any potential movement of fluids between the different flow units and USDW aquifers.

3.1.5 Little Boot 15-44 [NDIC No. 8144]

The Little Boot 15-44 well was drilled and abandoned as a dry hole in 1981. The well was drilled through the Broom Creek and reached the Black Island Formation. It was properly plugged and abandoned with cement plugs isolating the different flowing units before the Fox Hill Aquifer. This well is outside the delineated AOR for the Broom Creek Formation but is included in the pressure front delineated for the Deadwood–Black Island Formation.

3.1.6 Future Wells

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad of the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1,000 feet above the Broom Creek Formation. The water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the risk of leakage is very unlikely.

There is no active or prior production of oil and gas in the vicinity of the Tundra SGS area. This fact, combined with the understanding that potential leakage pathways of injected CO_2 through existing wellbores are very unlikely, makes the Tundra SGS site an ideal location for the geologic storage of CO_2.

3.2 Faults and Fractures

No known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area

through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

A 5-mile-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 miles of 2D seismic lines were acquired in 2020 (Figure 3-1). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement (A1:2.5 and A2:2.5). No structural features, faults, or discontinuities that would cause concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data.

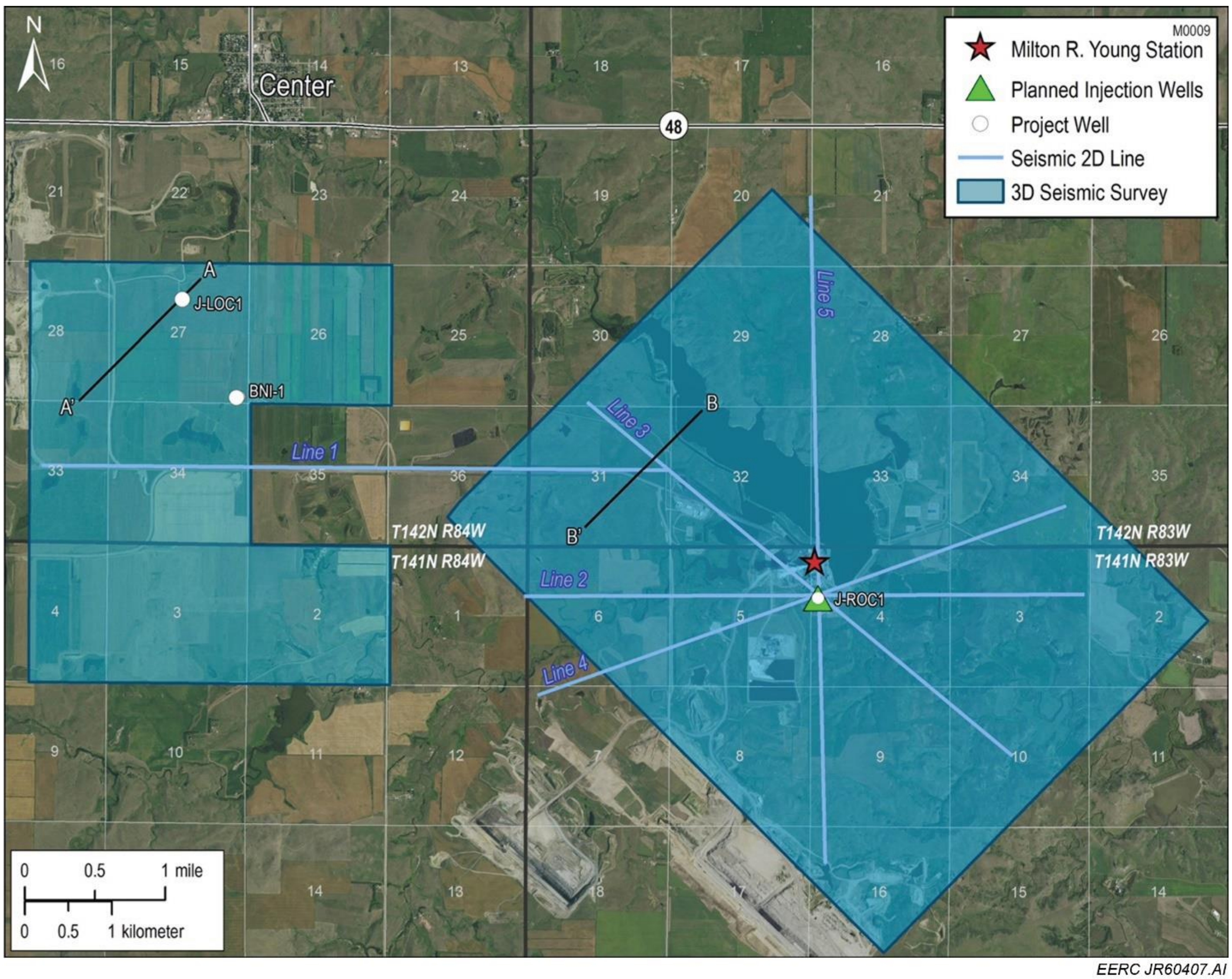

Figure 3-1. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

Leakage through faults and fractures was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the

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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed, and volumetric accounting would follow industry standards as applicable.

3.3 Natural or Induced Seismicity

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 3-2) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 3-2). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota (Table 3-2). This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. The results in Table 3-2 indicate stable geologic conditions in the region surrounding the potential injection site.

Table 3-2. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mile	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mile
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported MMI value.

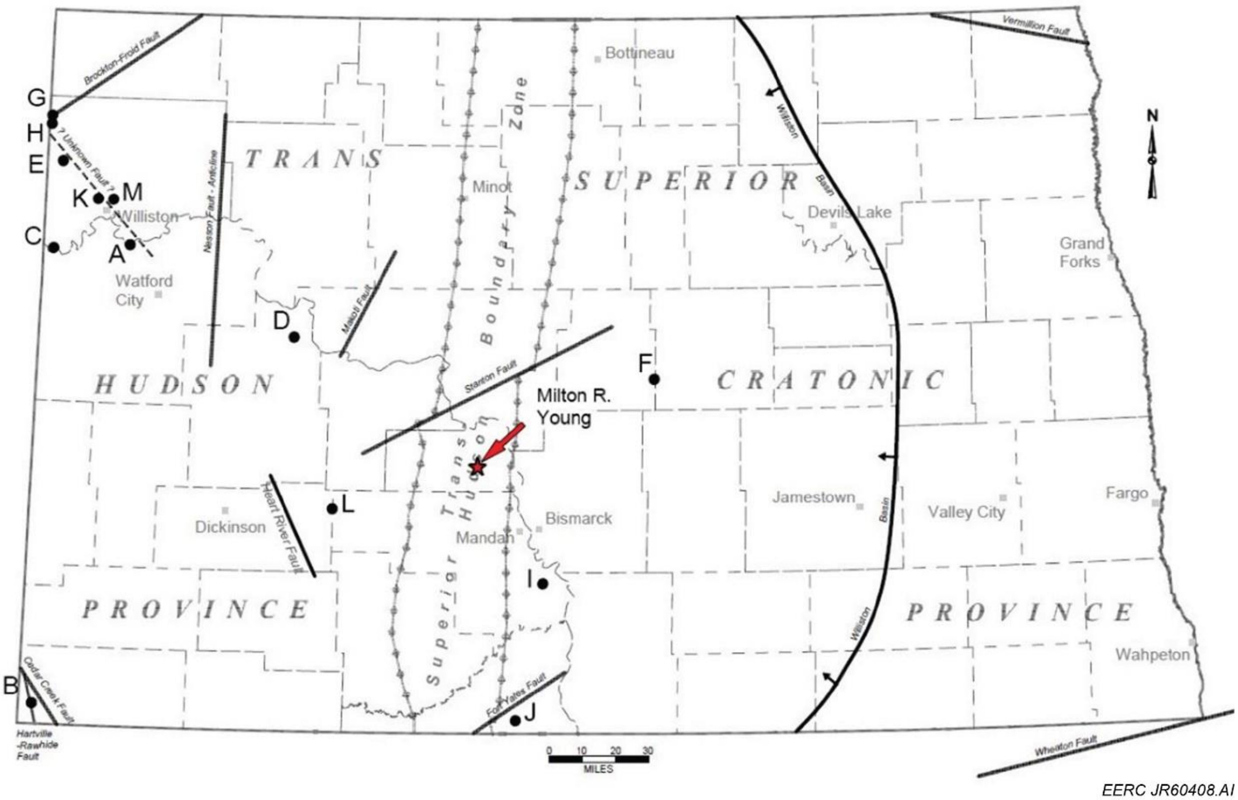

Figure 3-2. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016).

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. 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 time period (Figure 3-3) (U.S. Geological Survey, 2019).

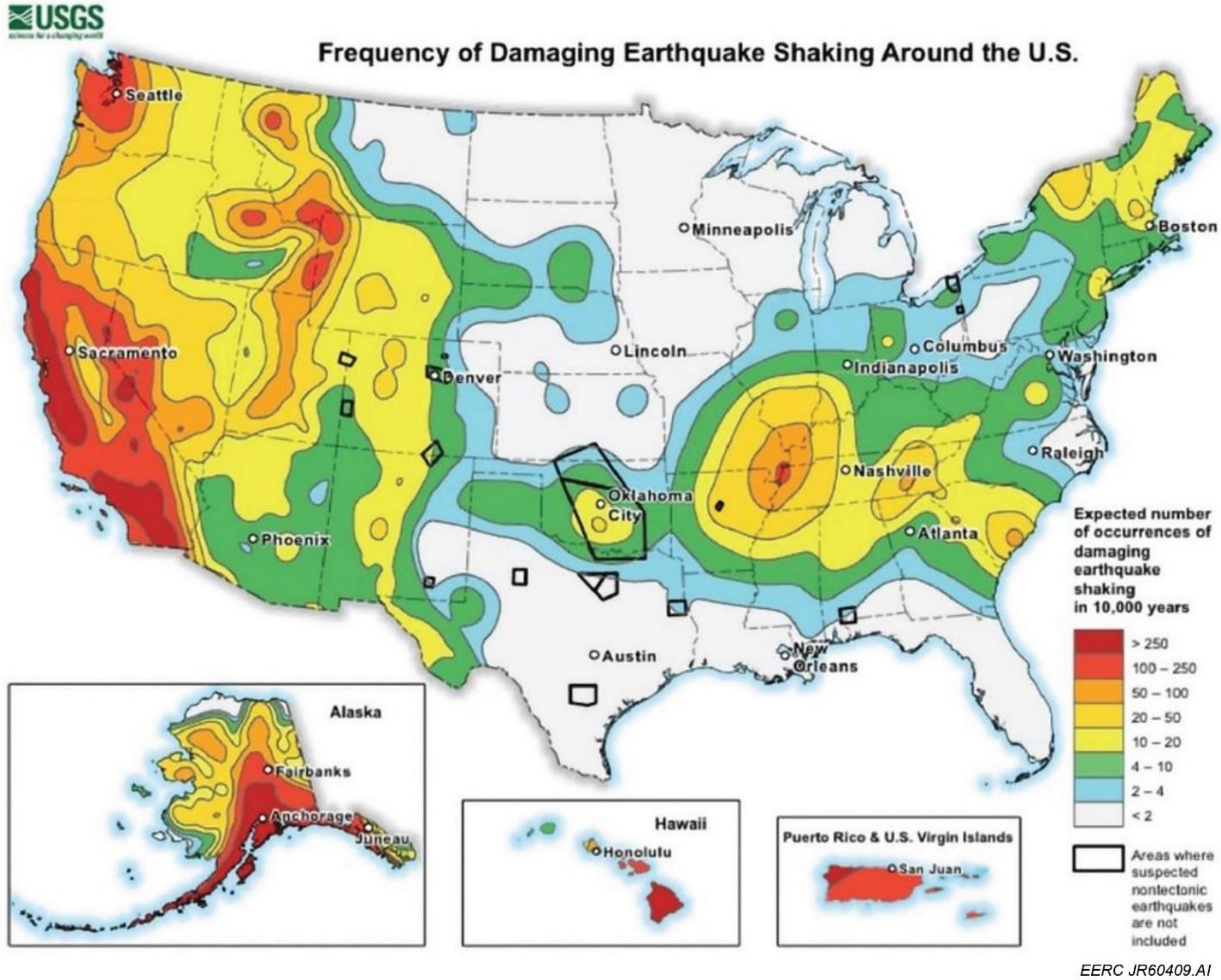

Figure 3-3. Probabilistic map showing how often scientists expect damaging seismic events to occur throughout the United States (U.S. Geological Survey, 2019). The map shows a low probability of damaging seismic events (less than two events per 10,000 years) occurring in North Dakota.

To understand potential induced seismicity, a detailed geomechanical study is described in A1:2.5 and A2:2.5, was carried out to understand the highest possible risk scenario. A scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data suggest that it does not. The failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure.

The maximum expected pressure changes in the Deadwood Formation due to planned injection activities do not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 3-4). Additionally, the injection interval is approximately 120 feet above the Precambrian–Deadwood boundary, and expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results, as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data, suggests planned injection activities will not cause

induced seismicity. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation; therefore, the probability of induced seismicity is minimal.

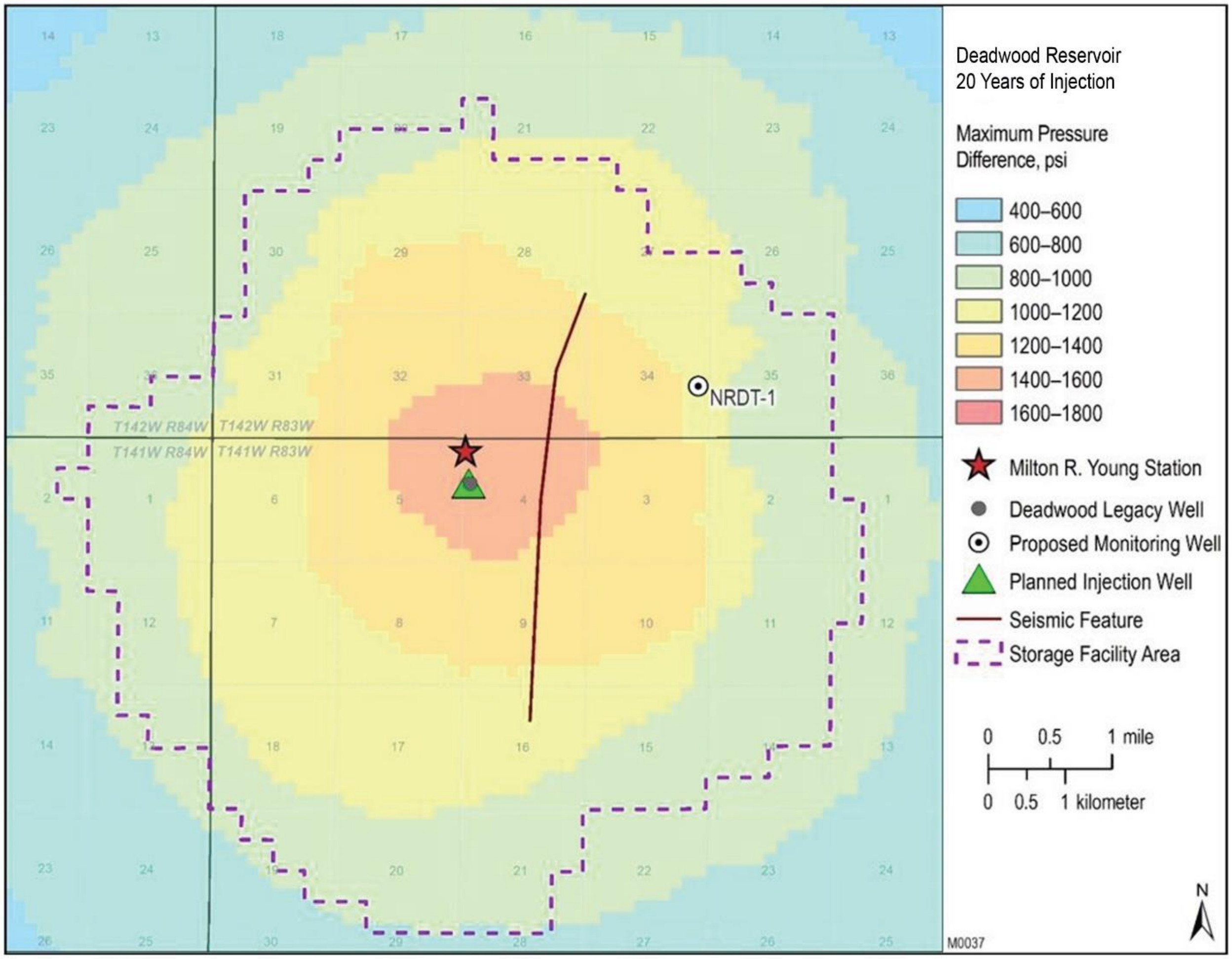

Figure 3-4. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

Leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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.

3.4 Flowline and Surface Equipment

Surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Surface equipment is 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 Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics will be 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.

Each well will be connected independently to the metering station (M2) by 8-inch flowlines equipped with a dedicated flowmeter and pressure and temperature transducers to monitor well performance. Shutoff devices will be installed in the well flowlines 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 Tundra SGS mechanical integrity and monitoring program strives to proactively identify potential surface leak events to ensure the integrity of the facility and minimize the amount of CO_2 released to the ambient air. Maintenance on surface equipment after the delivery point (M2) may require venting cumulated CO_2 volumes before isolating a section of the system; this amount would be quantified and reported.

The risk of leakage in surface equipment is mitigated through:

i. Adhering to regulatory requirements for construction and operation of the site.
ii. Implementing highest standards on material selection and construction processes for the flowline and wells.
iii. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
iv. Continuous monitoring through an automated system and integrated databases.

As a result, the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed. A 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 represent several tons of CO_2 until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply.

The second risk identified was potential leakage at surface equipment through catastrophic damage to surface facilities because of an object striking the equipment or a natural event that causes disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the project team performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. The model is referenced in the risk assessment evaluation matrix and emergency response plan, with the results included in the financial assurance demonstration plan, referenced sections of the applications are found at A1:E, A2:E, and A1:4.3, A2:4.3. This leakage scenario could represent thousands of tons of CO_2 released during the pendency of the response period before the well is controlled and integrity is reestablished. Even though this event is considered high-impact, occurrence is very unlikely since most of the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and will have a fence around the equipment location, located on private MRYS property. Further, containment of any leak is enhanced by the well pad design, including a 4-foot berm and double liner to avoid any brine spill to surface water bodies.

The risk of leakage through surface equipment or major damage is present during the injection phase of the project and 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 and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, NRDT-1, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.5 Lateral Migration of CO_2 Beyond the AOR

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), which confines the CO_2 within the storage facility area. Numerical simulations of CO_2 injection predict slow lateral migration of the plume throughout the injection and post-injection period (A1:A and A2:A). This is the result of the trapping mechanisms combined with the effects of buoyancy and the low dipping structurally characteristic of the storage complexes. 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 Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low-permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at Year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized.

Early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the SFP using both observations and history-matched simulation of CO_2 and pressure distribution. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate the current and predicted future lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predicts additional lateral movement of the plume, Tundra SGS would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests, good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22, and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and post-operational periods.

The risk assessment identifies lateral migration and impact for surface leakage as events with very low likelihood.

3.6 Vertical Migration: Injection and Monitoring Wells

Design and construction of the Class VI injector wells (Liberty-1, Unity-1, and McCall-1) as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leak due to loss of integrity in the wellbores. Material selection complies with CO_2 operating standards, and the wells will be instrumented for continuous, real-time monitoring of well integrity. Well instrumentation will be integrated with an automated data management system to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, described in A1:4.1 and A2:4.1, to ensure proper maintenance of the facilities and timely response in case substandard conditions are detected.

Once the injection period ceases, the injector wells will be evaluated for mechanical condition with corrosion and casing inspection logs and will be properly abandoned with CO_2-resistant cement according to the detailed plugging procedure proposed in A1:4.6 and A2:4.6. The NRDT-1 monitoring well will continue to be operational until plume stabilization and the issuance of a certificate of site closure, then the same rigorous plug-and-abandonment protocol will be followed as proposed for the injector wells.

Based on the design and monitoring program proposed, the project defined the risk of leak through these pathways as unlikely. The amount and timing, if it were to occur, will be minimum since the program is designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. The timing of the leak will be estimated based on the collected data from the monitoring tools until the event is cleared or remediation is completed.

3.7 Vertical Migration: Diffuse Leakage Through Seal

The primary mechanism for geologic confinement of the stored CO_2 in the Broom Creek and Deadwood–Black Island Formations will be containment of the initially buoyant CO_2 by the cap rock (Opeche–Picard, Icebox), under the effects of relative permeability and capillary pressure. Figure 3-5 shows a stratigraphic column with the well schematic for the injector and monitoring wells and highlights the additional secondary seals and buffer formation.

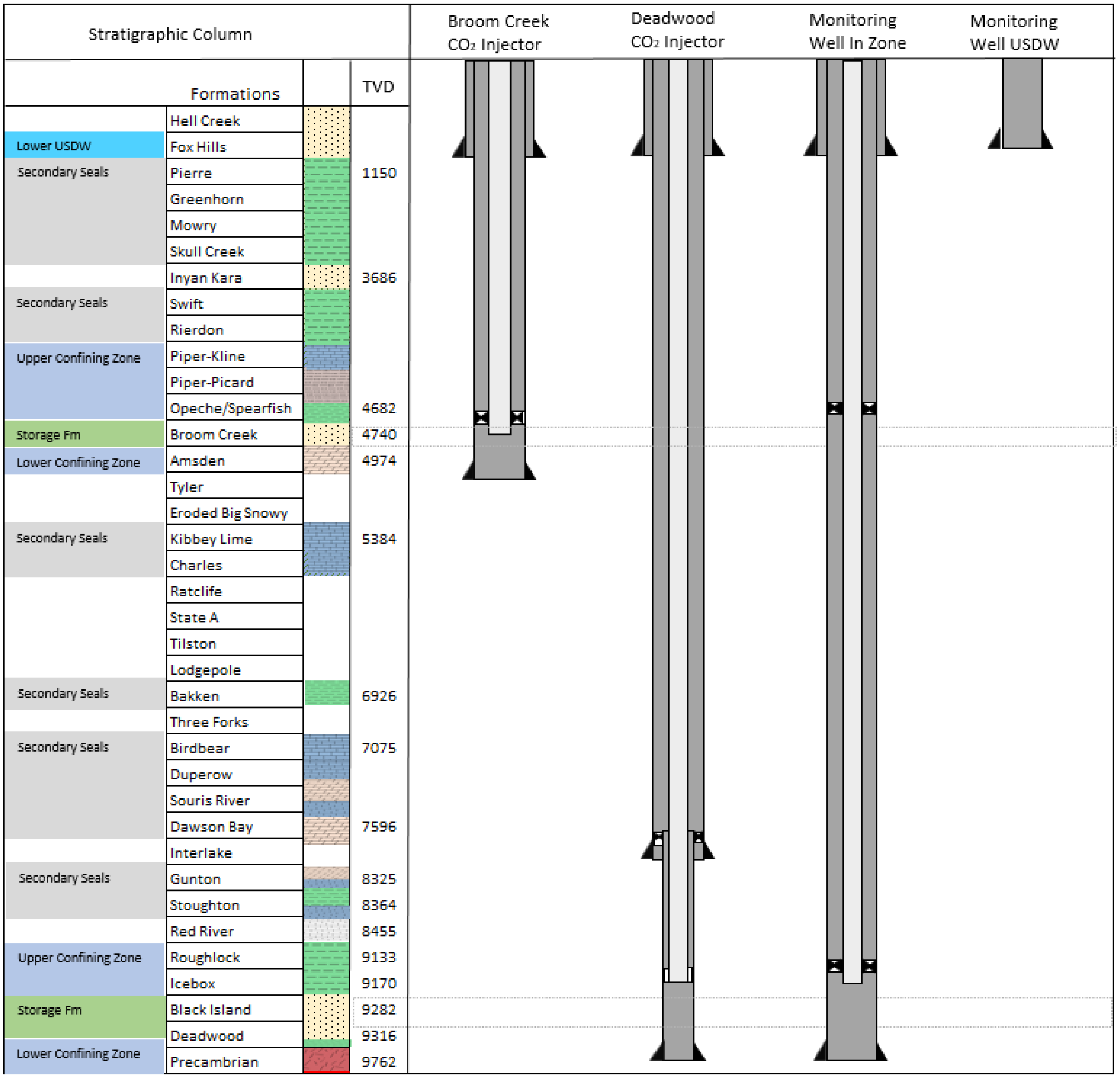

Figure 3-5. Stratigraphic column and well schematic for injector and monitoring wells.

The Picard Member of the Piper Formation within the study area consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. When considered as a single interval, the Opeche–Picard and other formations create an impermeable, laterally extensive cap rock to the Broom Creek Formation capable of containing injected CO_2. The Opeche–Picard interval is 4636 feet below the land surface at the storage site and 154 feet thick at the Tundra SGS site.

In addition to the Opeche–Picard interval, which serves as the cap rock for the Broom Creek Formation, 820 feet of impermeable rock formations separate the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. Surrounding the storage facility area,

an average of 2,545 feet of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation.

Within the Tundra SGS area, the Icebox Formation serves as the upper confining zone of the Black Island and Deadwood Formations. The Icebox Formation consists mostly of impermeable shale, is 9,308 feet below the land surface, and reaches a thickness of 118 feet within the storage facility area. The cap rock has sufficient areal extent and integrity and is free of transmissive faults and fractures to contain injected CO_2.

Impermeable rocks above the primary cap rock include the Roughlock Formation and Red River D Member, which make up the first significant group of secondary confining formations. Together with the Icebox Formation, these formations reach a thickness of 612 feet separating the next overlying permeable zone: the Red River A, B, and C Members. Above the Red River Formation, more than 1,000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. No known transmissible faults are within these confining systems in the project area.

As previously noted, at the same time, 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). As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after Year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure its long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, adsorption is not considered to be a viable trapping mechanism in this project (A1:A and A2:A).

The upper and lower confining zones for the proposed storage formations were largely characterized through core sampling and lab analysis as well as imaging and sonic tools to define the sealing capacity. The great thickness of impermeable rock above each of the storage formations provides a best-in-class secondary seal if the main confining zone were to fail, thereby further reducing the risk of diffusion through the leak to almost zero.

Leakage through vertical migration was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

The risk assessment defined this risk as an unlikely event. Response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses would require consideration of the 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 on the presenting facts

and circumstances, a modeling of the geophysical measurements 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 SURFACE LEAKAGE OF CO_2

Tundra SGS 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 direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous, real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Figure 4-1 summarizes the monitoring techniques proposed based on the leakage pathway analyzed for this MRV plan to provide a vision for the surveillance and management of the site.

These methodologies target early detection of the 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 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 provides a full picture of the monitoring frequency in different periods of the project life, and Table 4-2 summarizes for each technique the leakage path that it is targeting to detect. For additional details regarding strategy for detecting and quantifying surface leakage of CO_2, refer to A1:4.1, E, F and A2:4.1, E, F.

Integrated Remote Automated System (SCADA) and Surveillance Protocol

Leak Detection through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and Optical Gas Imaging (OGI) cameras.
- Automated CO_2 sensors in the wellhead.
- Real time (RT) injection performance on surface and downhole (Pressure, Temperature, flow).
- Distribute temperature sensing (DTS) technology to track well integrity and vertical conformance downhole.
- DTS and Distributed acoustic sensing fiber (DAS) for CO_2 flow line monitoring.
- Mechanical Integrity Program.
- Corrosion Monitoring Program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring through:

- Monitoring wells in reservoir .
- Pressure and temperature gauges downhole in injector.
- 4D seismic surveys.
- Interferometric synthetic aperture radar (INSAR).
- History Match Reservoir Simulation.
- Saturation Log in reservoir.
- Real time temperature profile (DTS) on injectors.
- Seismometers network (induced events)

Operational & Near Surface Monitoring through:

- Soil Gas Analysis
- CO_2 stream analysis.
- Water sampling USDW (baseline and during operation)

Figure 4-1. Tundra SGS monitoring strategy.

Table 4-1. Summary of Tundra SGS Monitoring Strategy

Method	Pre-injection (baseline 1 year)	Injection Period (20 years)	Post-injection (10 years)
CO_2 Stream Analysis – Gas Composition	Pre-injection	Quarterly	NA
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flowline	NA[1]	Real time	NA
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells	NA	Real time	Quarterly
Flowmeters (mass/volume) – Injection Wells and Flowline	NA	Real time	NA
Visual Inspections	Start-up	Weekly	Quarterly
Automated Remote System (SCADA)[2]	Start-up	Real time	NA
OGI[3] Cameras	Start-up	Quarterly	If required
NDIA4 CO_2 Leak Sensors in Wellhead – Injectors	NA	Real time	NA
NDIR CO_2 Leak Sensors in Wellhead – Monitors	NA	Real time	Real time
Handheld CO_2 Monitor	NA	Weekly	Quarterly
Soil Gas Analysis	3–4 seasonal samples per year	Three to four seasonal samples per year	Three to four seasonal samples every 3 years
Water Sampling USDW	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Water Sampling Surface Water	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Cement Bond Logs	After cementing	If needed	Prior to P&A[5]

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Continued . . .

Table 4-1 Summary of Tundra SGS Monitoring Strategy (continued)

Casing Inspection Tool (EM[6]/sonic) – Injection Wells	Baseline	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workover	Prior P&A
Casing Inspection Tool (EM/sonic) – Monitoring Wells	Baseline	Every 5 years	Prior to P&A
Temperature Log – Monitoring Wells	Baseline	Annually	Annually
Annular Pressure Test – Injection Wells	Prior injection	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workovers	Prior to P&A
Annular Pressure Test – Monitoring Wells	During completion	• Every 5 years • During workovers	• Every 5 years • During workovers • Prior to P&A
Corrosion Coupons	NA	Quarterly	NA
DTS/DAS Fiber – Installed on the Casing – Injection Wells	NA	Real time	NA
DTS/DAS Fiber – Main Flowline	NA	Real time	NA
DH[7] Pressure Gauges and Temperature Sensors – Injection Wells	NA	Real time	NA
DH Pressure Gauges and Temperature Sensors – Monitoring Wells	NA	Real time	Bimonthly
RST[8] Log (pulse neutron) – Monitoring Wells	Baseline	Every 5 years	Every 5 years
RST Log (pulse neutron) – Injection Wells	Baseline	As needed	NA
Pressure Falloff Test – Injection Wells	Prior injection	Every 5 years	Prior to P&A
2D/3D Time-Lapsed Surface Seismic	Baseline	Every 5 years	Every 5 years
Interferometric Synthetic Aperture Radar	Baseline	Continuous monitoring	Continuous monitoring
Surface Seismometers	Baseline	Real time	NA

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect CO_2

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis – Gas Composition		X		X	X		
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flow Line				X	X		
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells				X	X	X	
Flowmeters (mass/volume) – Injection Wells and Flowline				X	X		
Visual Inspection	X			X	X		
Automated Remote System (SCADA)			X	X	X		
OGI Cameras				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Injectors				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Monitors				X	X		
Handheld CO_2 Monitor	X			X	X		X
Soil Gas Analysis		X			X		
Water Sampling USDW		X			X		X
Water Sampling Surface Water		X			X		X
Cement Bond Logs					X		
Casing Inspection Tool (EM/sonic) – Injection Wells					X		

Continued . . .

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect (continued)

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
Casing Inspection Tool (EM/sonic) – Monitoring Wells					X		
Temperature Log – Monitoring Wells					X		
Annular Pressure Test – Injection Wells				X	X		
Annular Pressure Test – Monitoring Wells				X	X		
Corrosion Coupons				X	X		
DTS/DAS Fiber Installed on the Casing – Injection Wells		X			X		
DTS/DAS Fiber – Main Flowline				X			
DH Pressure Gauges and Temperature Sensors – Injection Wells		X			X	X	
DH Pressure Gauges and Temperature Sensors – Monitoring Wells		X			X	X	
RST Log (pulse neutron) – Monitoring Wells		X			X	X	X
RST Log (pulse neutron) – Injection Wells		X			X	X	X
Pressure Falloff Test – Injection Wells		X			X	X	
2D/3D Time-Lapsed Surface Seismic	X	X			X	X	X
Interferometric Synthetic Aperture Radar	X	X			X	X	
Surface Seismometers		X	X				

4.1 Leak Verification

Tundra SGS 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, Tundra SGS 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, injector wells 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 CO_2 leakage is occurring. Excursions are not necessarily indicators of 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 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 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 CO_2 surface leak is of lower temperature than ambient, it will often lead to the formation of bright white clouds and ice that are easily visually observed unaided. With this understanding, Tundra SGS will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Tundra SGS project.

Discovery of an event triggers a response, as presented in the A1 and A2, Section 4.2, emergency remedial and response plan. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator 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, Tundra SGS 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 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 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 leaking to the surface will be quantified using acceptable emission factors, engineering estimates of 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.

Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database. For additional details regarding quantification of leakage, refer to A1: 4.3.1 and A2:4.3.1.

5.0 DETERMINATION OF BASELINES

Pre-injection baselines will be established through the Tundra SGS project 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 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 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 Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B.

5.1 Surface Baselines

Baseline sampling includes selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers and one USGS Fox Hills observation well. Verification of the domestic well status, based on viability of the well (existence, depth, access, etc.) and landowner cooperation, has been completed and selected wells sampled August 11–13, 2021.

The locations of these candidate wells are shown in A1:C and A2:C, Figure 4-2. Characterization of selected domestic wells and one USGS Fox Hills observation well will include

the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C.

5.2 Subsurface Baseline

Preoperational baseline data will be collected in the injection and monitoring wells. 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 (interferometric synthetic aperture radar) technology will be performed to determine application before injection and 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 5 km from the injection area a year prior to injection. For additional information regarding surface baseline, refer to A1: 4.1.8 and A2: 4.1.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

Tundra SGS 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 M2 in the facility diagram (Figure 1-2).

CO2I is equal to annual CO2 mass injected (metric tons) through all injection wells) for Tundra SGS, because we are not producing rather Tundra SGS is a permanent geologic sequestration operation. 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:

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

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 surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used

to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Part 98, Subpart W.

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

The Tundra SGS project will use a volumetric flowmeter (M2) (Figure 1-2) 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 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:

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

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 (volume percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

6.2 Annual Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

The Tundra SGS project 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 A1:4 and A2:4, 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 leak to quantify the CO_2 volume to the best of its the capabilities. The process for quantifying leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models among others.

Tundra SGS project will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

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

Where:

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

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

The calculation of CO_{2FI}, the annual mass of CO_2 emitted (in metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead, will comply with the calculation and quality assurance/quality control requirements in Part 98, Subpart W, and will be reconciled with the annual data collected through the monitoring and surveillance plan proposed in A1:4, D and A2:4, D.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

It is proposed that this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 7.0. As discussed under Sections 2.1 and 3.1, this proposed MRV plan was developed to account for both Phase 1 and Phase 2, and thus no modification to the MRV is anticipated if Phase 2 is pursued. Other greenhouse gas (GHG) reports are filed by the end of the third month of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time.

As described in Section 3.3, Tundra SGS anticipates that the MRV program will be in effect during the operational and post-operational monitoring periods, during which time Tundra SGS will operate the storage facilities for the purpose of secure, long-term containment of a measurable quantity of CO_2 in subsurface geologic formations. Tundra SGS anticipates a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, Tundra SGS will prepare a demonstration supporting the long-term containment determination in accordance with North Dakota statutes and regulations and submit a request to discontinue reporting under this MRV plan consistent with the North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Tundra SGS monitoring techniques and data management is provided in the Quality Assurance and Surveillance Plan found in A1:D and A2:D.

Tundra SGS will ensure compliance with the quality assurance requirement in § 98.444.

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 received by pipeline is measured at a receiving meter on the injection well path.

- The CO_2 concentration is measured quarterly upstream or downstream 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 § 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.

Concentration of CO_2:

- CO_2 concentration will be measured using the appropriate standard method. All measured volumes will be converted from CO_2 to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

8.1 Missing Data Procedures

In the event Tundra SGS is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in § 98.445 will be used as follows.

8.1.1 Quarterly Flow Rate of CO_2 Received

- Tundra SGS may use the quarterly flow rate data from the sales contract from the capture facility or invoices associated with the commercial transaction.

- A quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

8.1.2 Quarterly CO_2 Concentration of a CO_2 Stream Received

- Tundra SGS may use the CO_2 concentration data from the sales contract for that quarter if the sales contract was contingent on CO_2 concentration and the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration in accordance with the sales contract terms.

- A quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

8.1.3 Quarterly Quantity of CO_2 Injected

- The quarterly amount of CO_2 injected will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

8.1.4 Values Associated with CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment at the Facility

- Implementation will follow missing data estimation procedures specified in 40 CFR, Part 98, Subpart W.

Any missing data should be followed up with an investigation into issues, whether they are concerned with equipment failure or incorrect estimations.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Tundra SGS project that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Minnkota is the project sponsor of Tundra SGS and will contribute a portion of the total equity for the proposed storage project; other equity participants for the project have not yet been identified. As such, the MRV plan names Minnkota as the sole storage facility owner, operator, and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota plans to contribute all necessary permits to the Tundra SGS project entity, resulting in the transfer of owner and operatorship to the Tundra SGS project. This transfer of ownership will be treated as a minor modification, which will be accomplished through submission of a certificate of representation identifying the change in ownership in accordance with 40 CFR 98.4(h) and will accurately identify and align MRV plan owner/operator/representative designation. Minnkota does not anticipate any material modification to the MRV plan, and as discussed under Section 2.1, if Phase 2 development is pursued, this proposed MRV plan accounts for all monitoring and reporting obligations under Subpart RR.

Tundra SGS reserves the opportunity to submit supplemental revisions to this proposed plan, which take into considerations responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in A1 and A2 and associated Class VI drilling permits.

10.0 RECORDS RECORDING AND RETENTION

Tundra SGS will follow the records retention requirements specified by § 98.3(g). In addition, it will follow the requirements in Subpart RR § 98.447 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 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.

11.0 REFERENCES

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

U.S. Geological Survey, 2016, Induced earthquakes raise chances of damaging shaking in 2016: https://www.usgs.gov/news/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed December 2019).

Appendix B: Submissions and Responses to Requests for Additional Information

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Wells

Facility(GHGRP) ID 579201

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT (SFP) DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, Tundra SGS SFPs and their individual sections for Broom Creek and Deadwood are designated as follows:

Attachment 1: Tundra SGS – Carbon Dioxide Geologic SFP (Broom Creek) Case No. 29029-29031

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachment 2: Tundra SGS – Carbon Dioxide Geologic SFP (Deadwood) Case No. 29032-29034

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

*Attachments within this MRV document will follow use the following referencing convention:

- A1 and A2 will refer to the Attachments, A1 being the Broom Creek SFP and A2 being the Deadwood SFP.
- Numbers or letters that appear after the colon will represent the numbered section or appendix of the appropriate Storage Facility Permit. For example:
    - A1:3.1.1 will direct the reader to refer to Section 3.1.1, (Area of Review Section, Written Description Subsection) within the Broom Creek SFP.
    - A2:A will direct the reader to refer to Appendix A (Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations) within the Deadwood SFP

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

1.0 PROJECT DESCRIPTION

Minnkota Power Cooperative, Inc. (Minnkota) is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota also acts as the operating agent of the Northern Municipal Power Agency, which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine, which provides the lignite coal for MRYS, is owned and operated by BNI Coal, Inc. (BNI) and is located adjacent to the MRYS facility. Minnkota prepared this MRV plan in support of the operation, reporting, and accounting for the storage component of Project Tundra, a carbon capture retrofit to MRYS with saline formation geologic storage. Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood–Black Island. The Broom Creek is being primarily targeted for the total injection of 77.5 MMt however the Deadwood-Black Island has a projected capacity of 23.4MMt over 20 years, which provides the project with contingent capacity or expansion opportunities. However, Deadwood-Black Island formation is being primarily contemplated as a back-up or redundant storage facility. The geologic storage facility and operation are referred to as Tundra SGS. The Tundra SGS surface facilities, wellsite, and operating location comprise land mostly associated with the coal-mining operation of BNI, the area where MRYS is located, and the land is primarily industrial and agricultural. The nearest densely populated area is Center, North Dakota, which is approximately 3.4 miles northwest of the Tundra SGS site (Figure 1-1).

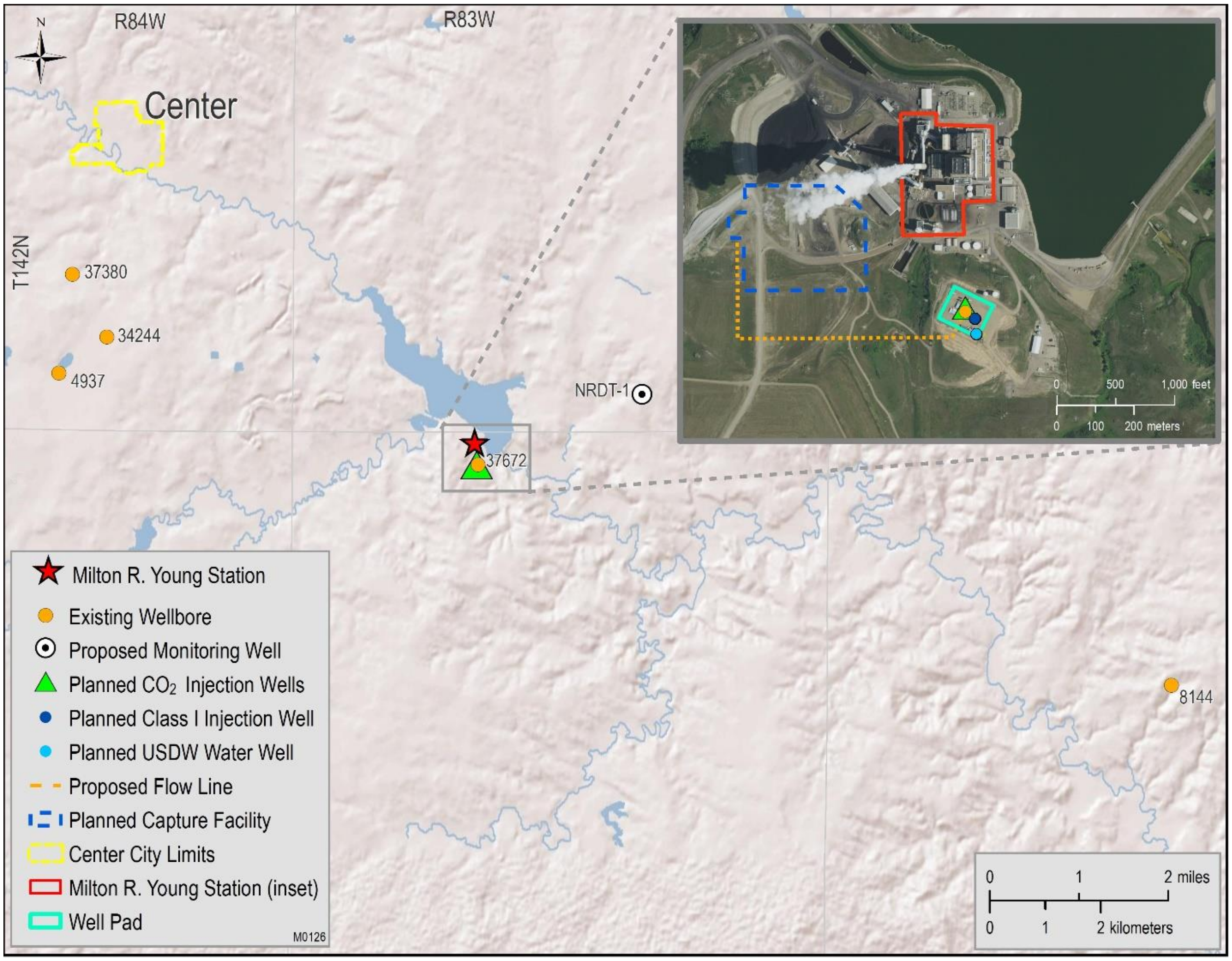

Figure 1-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the proposed CO_2 flowline and well pad layout. The red star denotes MRYS. The existing J-ROC1 wellbore (37672) is the wellbore planned for reentry and conversion to a Class VI injection well, which will be renamed Liberty 1. Offset wells (8144, 37380, 34244, and 4937) are included as they were evaluated in the area of review (AOR) of the Tundra SGS Carbon Dioxide Geologic Storage Facility Permit (SFP) for both Broom Creek and Deadwood storage reservoirs (A1 and A2).

1.1 Operation and Equipment

Tundra SGS plans to capture and store an average of 4 MMt/yr of CO_2 over the course of 20 years of injection, followed by 10 years of post-injection site care. MRYS Units 1 and 2 will be retrofitted with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. The CO_2 captured will be dehydrated and compressed to a supercritical state, then transported via a 0.25-mile flowline to the storage site, where it will be securely and permanently stored in saline geologic formations. Figure 1-2 provides a simplified process flow diagram of the Tundra SGS project, which includes the CO_2 flowline from the metering station (M1) at the outlet of the capture facility compressor and the Phase 1 and Phase 2 injection and monitoring wells (Figure 1-2).

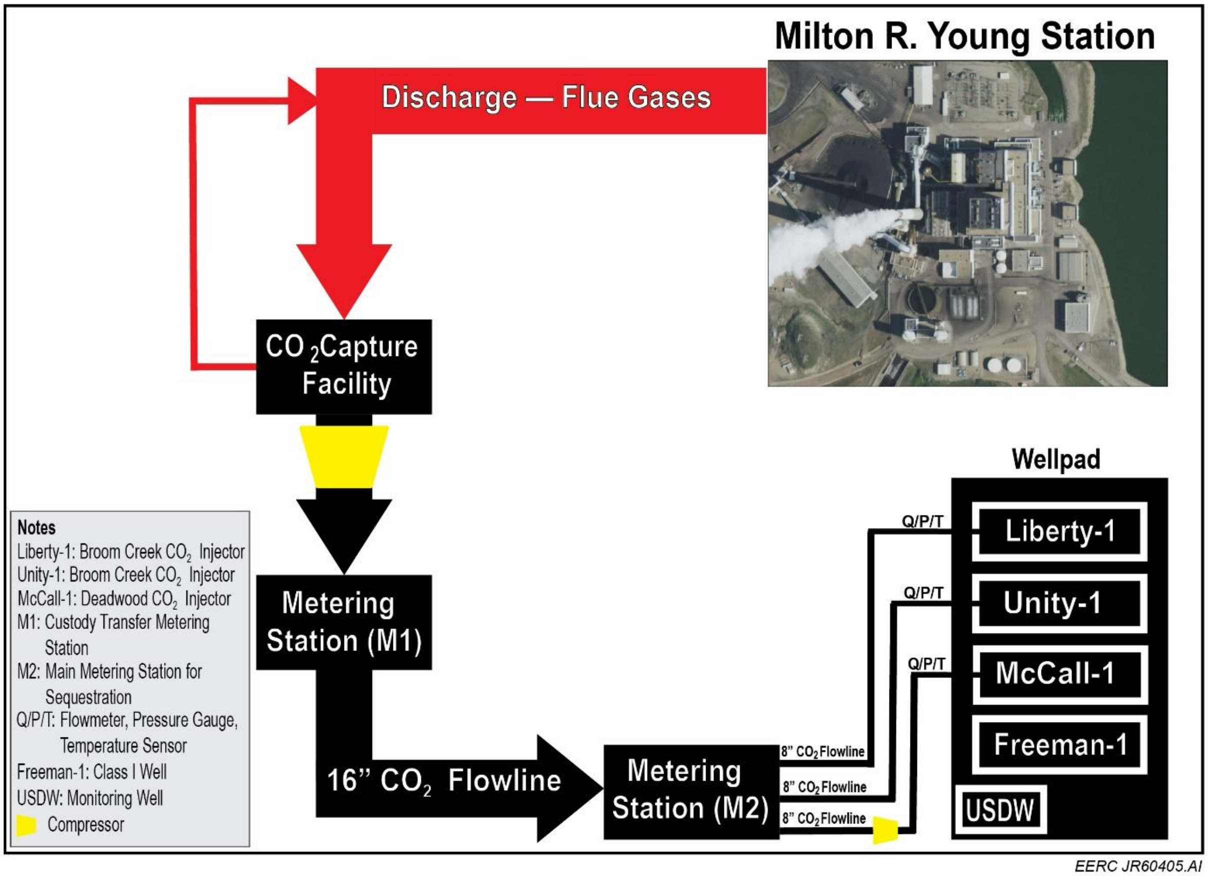

Figure 1-2. Flow diagram for Tundra SGS capture, transport, and storage facilities (USDW is underground source of drinking water).

Tundra SGS will receive captured and dehydrated CO_2 at the compressor outlet (M1), then it will be transported 0.25 miles via CO_2 flowline to the metering station (M2) for distribution to the injection wells for secure and permanent storage in the Broom Creek and Deadwood–Black Island geologic formations. These two storage formations as well as their confining seals have been extensively characterized by Minnkota through local and regional studies led by the Energy & Environmental Research Center (EERC). The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1.

The project proposes a phased development approach, with Phase 1 construction and operation of two injector wells in the Broom Creek reservoir (approximately 5,000 feet in depth), targeting 100% of the captured CO_2 volume. Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well, the McCall-1. This additional well would be completed in the Deadwood–Black Island reservoir (approximately 10,000 feet in depth) to store any excess CO_2 identified in Phase 1. The stacked storage concept and phased development approach allows the project to maximize the areal extent of the storage facilities,

provides operational flexibility and redundancy, and generates further assurance to investors and stakeholders.

In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. Layout of the wells and surface facility infrastructure can be found at Figure 1-2. Minnkota proposes one deep subsurface monitoring well (NRDT-1) installed on Minnkota property located approximately 2 miles northeast of the injection site.

This procedure is applicable to Tundra SGS storage facility operations consisting of the following infrastructure:

SFP Case Number: **29029, 29030, 29031**
UIC Class VI, ADP Form No. 28643[Unity-1]
UIC Class VI, ADP Form No. 30200[Liberty-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]
SFP Case Number: **29032, 29033, 29034**
UIC Class VI, ADP Form No. 28977 [McCall-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]

The current mailing address for the Tundra SGS facility, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

1.2 Environmental Setting/Geology

The Williston Basin lies in the western half of North Dakota; this area has a long history of hydrocarbon exploration and utilization. This region has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. The proposed location of Tundra SGS is approximately 3.4 miles southeast of the town of Center on the eastern flank of the Williston Basin. This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment. Further discussion of potential mineral zones is found at A1:2.6 and A2:2.6.

The target CO_2 storage reservoir for Tundra SGS Phase 1 is the Broom Creek Formation, a predominantly sandstone horizon lying 4,740 feet below the MRYS facility (Figure 1-3). The lower Piper and Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") serve as the primary confining zone overlying the Broom Creek Formation. This confining interval comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS Phase 1 operations.

The target CO_2 storage reservoirs for Tundra SGS Phase 2, if pursued, are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying approximately 9280 feet below MRYS (Figure 1-3). The shales of the Icebox Formation conformably overlie the Black Island and serve as the primary confining zone. The Icebox Formation provides a suitable confining layer, with an average thickness of 118 feet. The continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite. Together, the Icebox (upper confining), Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS Phase 2. For additional details regarding the site characteristics, refer to A1:2 and A2:2.

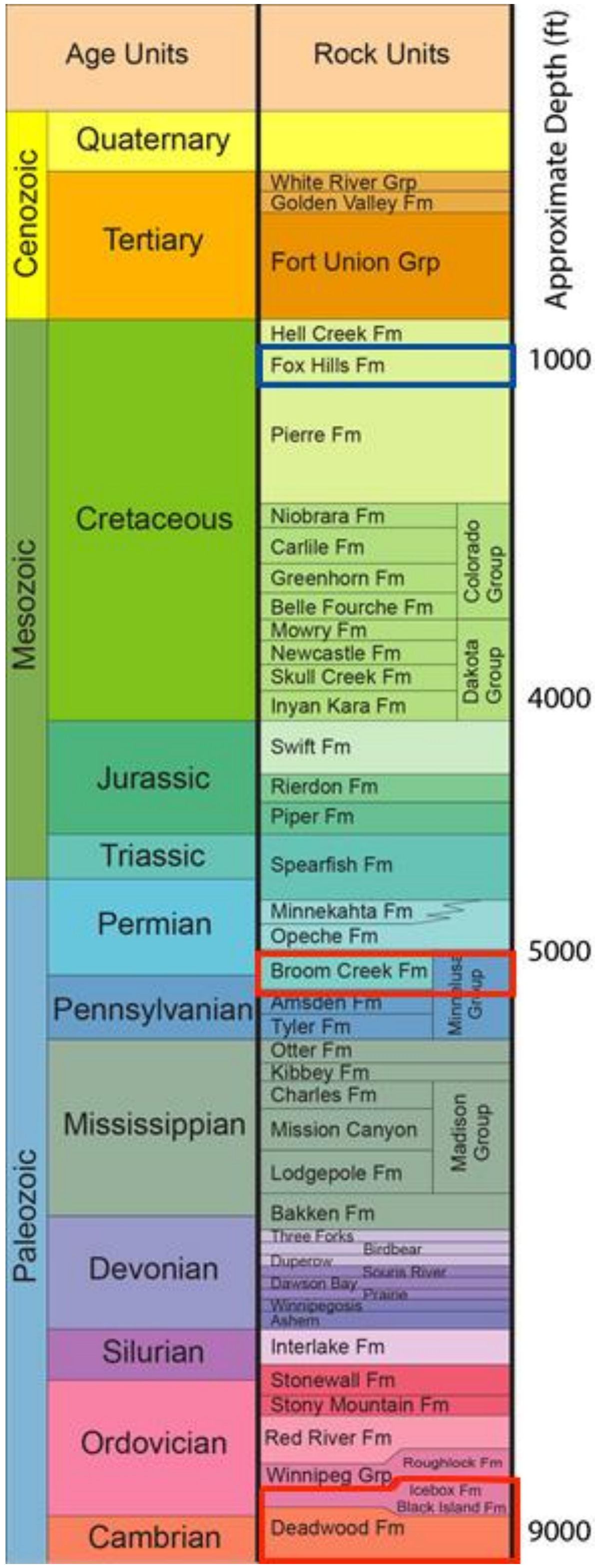

Figure 1-3. Stratigraphic column of North Dakota. Red boxes around the Broom Creek and Deadwood Formations delineate the targeted injection zones.

1.3 Reservoir Model

1.3.1 Broom Creek (Phase 1)

Phase 1 includes two wells: Liberty-1 (originally drilled as J-ROC 1, a stratigraphic well to be converted to a Class VI injector) and Unity-1 (Figure 1-2). Numerical simulation of CO_2 injection in the sandstones of the Broom Creek Formation predicted the wellhead injection pressure (WHP) of both wells would not exceed 1700 psi during injection. Bottomhole pressures (BHPs) reached 3,035.1 and 3,018.3 psi for Liberty-1 and Unity-1 wells, respectively. For the Broom Creek CO_2 plume boundary delineation, the CO_2 plume boundary was modeled using operating assumptions of 20 years at a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 16 through 20. The reservoir simulation model indicated target injection rates were consistently achievable over 20 years of injection. A total of 77.5 MMt of CO_2 would be injected into the Broom Creek Formation with two wells at the end of 20 years. Injected volumes were 41.1 and 36.4 MMt for the Unity-1 and Liberty-1 wells, respectively. A maximum formation pressure increase of 488 psi is estimated in the near-wellbore area during the injection period (A1:A).

1.3.2 Deadwood (Phase 2)

The Deadwood–Black Island reservoir model simulation for Phase 2 includes the McCall-1 well, drilled on the same pad as the Broom Creek wells (Figure 1-2). This model was constrained by WHP and bottomhole fracture gradient without any injection rate constraint. Within the sandstones of the Black Island and Deadwood Formations, numerical simulation of CO_2 injection predicted that injection BHP will not exceed 6,179 psi during injection operations, assuming a WHP limit of 2,800 psi is maintained. Cumulative CO_2 injection at the above-described pressure conditions was 23.4 MMt over the 20 years of injection. The resulting average injection rate of CO_2 into the Black Island and Deadwood Formations was 1.17 MMt/year. Near the wellbore area, a maximum increase of 1620 psi was estimated within the Black Island and Deadwood Formations.

Through numerical simulation efforts, long-term CO_2 migration potential was investigated in each of the Broom Creek and Deadwood models. The results did not indicate migration outside the storage facility area boundaries in either scenario. Storage facility area boundaries were established using a 20-year injection period, with the output boundary at Year 20 identified at a 5% CO_2 saturation rate and then rounded outward to the nearest 40-acre tract (A1:A).

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area

The active monitoring area (AMA) is defined 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" (40 Code of

Federal Regulations [CFR] § 98.449). For purposes of this MRV plan, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (Figure 2-1). Based on review of the data and information of record, and data and information collected in support of A1 and A2, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

2.1.1 Tundra SGS AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

Under North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC) storage facility and Class VI requirements for an AOR, delineation was completed based on the Project Tundra SFP. 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" (NDAC § 43-05-01-01). The NDAC requires the operator develop an AOR and corrective action plan utilizing 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 (NDCC § 38-22-08). Minnkota elected to permit the storage facility area boundaries based on the 20-year reservoir model output discussed in Section 1.3 and then added an additional buffer rounding out to the nearest 40-acre tract.

The Broom Creek proposed AOR was delineated using a risk-based AOR approach (A1:3.1). The risk-based delineation examines the area encompassing the region overlying the injected free-phase CO_2 and the region overlying the extent of increased formation fluid pressure sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or conductive fractures) are present. The risk-based approach established that the CO_2 plume boundary is also the extent of the AOR boundary (A1:3.1). However, in compliance with the NDAC evaluation and monitoring requirements, Minnkota extended the permitted AOR boundary beyond the risk-based delineation to encompass the storage facility boundary plus an additional 1-mile buffer (A1:3.1). Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring from the outset of operations, provides significant assurance that operations can be conducted safely and as contemplated within the permitted storage facility.

The proposed AOR for the Deadwood–Black Island storage facility used EPA Method 1 to establish the AOR (A2:3.1). The Deadwood–Black Island reservoir model simulation discussed in Section 1.1 yielded an annual average injection rate of approximately 1.17 MMt/year for 20 years. Applying EPA Method 1, the Deadwood–Black Island AOR has a larger areal extent, due to the estimated pressure front under EPA Method 1, than the Broom Creek AOR, which applied the risk-based AOR approach; however, the free-phase CO_2 plume for Deadwood is contained in the delineated AOR for Broom Creek. Because of the significant overlap between the two AORs and the phased development approach, the Tundra SGS technical evaluation and proposed monitoring plan were developed to account for monitoring both injection horizons in accordance with the requirements and to the maximum areal extent simulated.

2.1.2 Tundra SGS AOR Encompasses Subpart RR AMA of both Broom Creek and Deadwood

AMA minimum delineation requirements are found in 40 CFR § 98.449 and used in Figure 2-1. Using a period of t=20 years, the Broom Creek delineated AMA boundary and the Deadwood–Black Island AMA boundary fall within the Broom Creek AOR. Minnkota proposes that the Broom Creek AOR serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (AOR outlined in black in Figure 2-1), delineation of the AOR is discussed further in A1:3 and A2:3. Aligning the calculated AMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

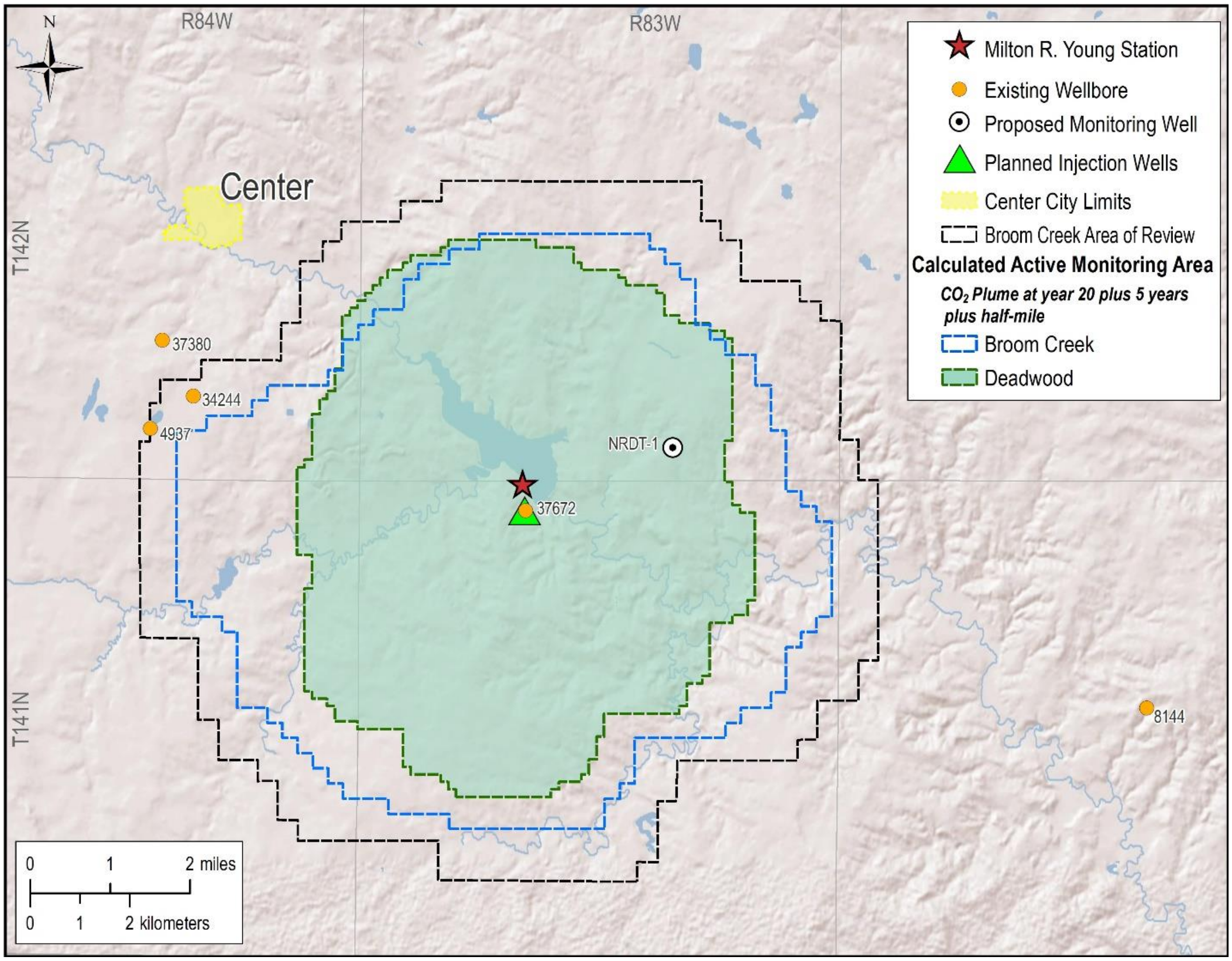

Figure 2-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated AMA in comparison to the permitted AOR. AOR subsumes the calculated AMA for both formations and exceeds requirements for AMA; therefore, the AOR serves as the AMA for Project Tundra.

2.2 Maximum Monitoring Area

The maximum monitoring area (MMA) as defined in 40 CFR § 98.440–449 (Subpart RR) is the area defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The calculated MMA delineated in Figure 2-2 for the Broom Creek and Deadwood–Black Island storage facilities uses a period of t=20 years and represents the period t+10 and a half-mile buffer extending beyond that boundary. The permitted AOR for Broom Creek, as delineated in A1 and A2, exceeds the minimum areal extent required by the Subpart RR approach for delineating the MMA (Figure 2-2); therefore, Minnkota proposes that the Broom Creek AOR serve as the calculated MMA for both the Broom Creek and the Deadwood–Black Island storage facilities.

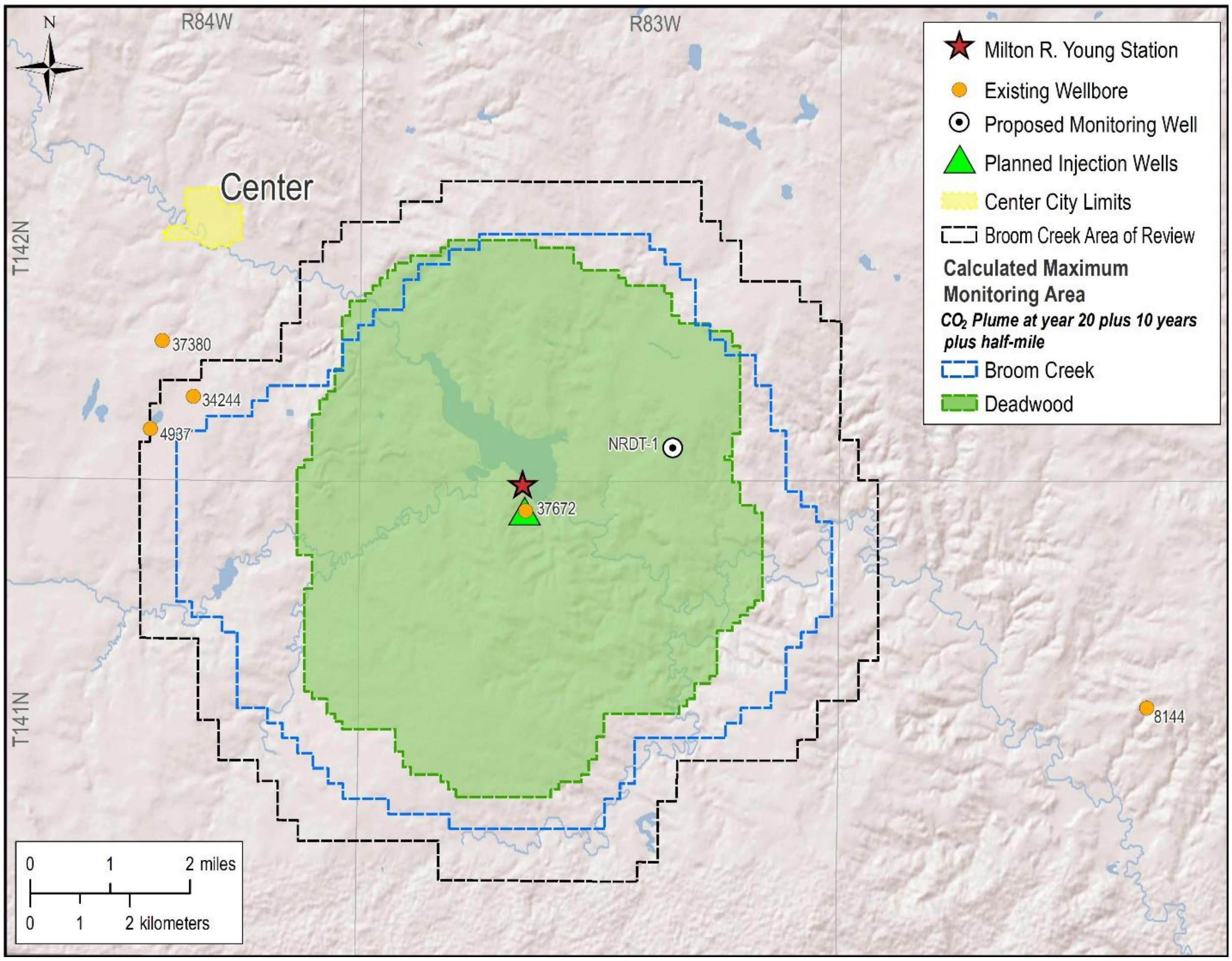

Figure 2-2. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated MMA in comparison to the permitted AoR. AOR subsumes the MMA for both formations and exceeds requirements for the MMA; therefore, the AOR serves as both the AMA and MMA for Project Tundra.

Aligning the calculated AMA and MMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2, as described in A1:4.1 and A2:4.1, comprises three distinct periods: 1) preoperational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. The time frame of these monitoring periods will encompass the entire life cycle of the injection. For purposes of this 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 and frequency of the measurements performed vary. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

Preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and inherent 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 amount of CO_2 that is contained in the formation at any given time. This information will be incorporated into the final Class VI permit. If results from this preoperational monitoring period necessitate changes to this MRV plan, an amendment will be submitted prior to the start of operations.

The operational injection period is focused on validating and updating numerical models of the storage system and ensuring that the geologic storage project is operating safely and is protecting USDWs. Lastly, the purpose of 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 three monitoring periods is a minimum of 1 year, 20 years, and a minimum of 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS AND MECHANISMS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was completed by representatives of Minnkota as well as third-party subject matter experts from Oxy Low Carbon Ventures and the EERC. During these meetings, potential leakage pathways were identified and evaluated for the following:

- Existing wellbores
- Faults and fractures
- Natural or induced seismicity
- Flowline and surface equipment
- Lateral migration of CO_2 beyond the AOR

- Vertical migration: injector and monitoring wells
- Vertical migration: diffuse leakage through seal

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 A1:4.1 and 2:4.1, and summarized in Table 5-2, forms the basis for this MRV plan.

3.1 Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated as potential leakage pathways. There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. A detailed discussion of potential mineral zones is found at A1:2.6 and A2:2.6. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table.

Table 3-1. Wellbore Summary

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

3.1.1 J-ROC1 [NDIC No. 37672]

The J-ROC1 well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota project, Phase III. An entire geologic column from surface to the Precambrian was drilled and core collected, and fluid samples as well as special logs were obtained. The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well. Further discussion of reentry program provided in Supplement-1. Once the well conversion takes place, J-ROC1 will be renamed Liberty-1, on authorization of pending reentry drilling permit. This well will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.

3.1.2 J-LOC1 [NDIC No. 37380]

The J-LOC1 well was drilled by Minnkota in 2020 as a stratigraphic well. The construction materials used were compatible with Class VI and CO_2 operating standards. The well was drilled through the entire geologic column from surface to the Precambrian. The drilling program included collecting core, obtaining fluid samples and special logs, and injectivity testing in the Broom Creek and Deadwood Formations. The well is currently in a temporarily abandoned status, plugged for future use. Abandonment procedure and well schematic details can be found in A2:3, Table 3-5 and Figure 3-8. In case the well has no future potential use, it will be permanently abandoned to ensure integrity. This well is located slightly outside the delineated AOR for the Broom Creek, but it is included in the pressure front delineated for Deadwood–Black Island Formation storage.

3.1.3 BNI-1 [NDIC No. 34244]

The BNI-1 well was drilled in 2018 as a stratigraphic well by the EERC under North Dakota CarbonSAFE Phase II. The well was drilled through the Broom Creek Formation and reached total depth in the Amsden Formation. The well was plugged and abandoned in 2018 in accordance with approved guidance and regulations of the state.

3.1.4 Herbert Dresser 1-34 [NDIC No. 4937]

The Herbert Dresser 1-34 well was drilled and plugged in 1970 after being classified as a dry hole. The well was replugged in 2001 by BNI. It was drilled through the Broom Creek Formation and reached total depth at the Charles Formation. Several cement plugs isolate any potential movement of fluids between the different flow units and USDW aquifers.

3.1.5 Little Boot 15-44 [NDIC No. 8144]

The Little Boot 15-44 well was drilled and abandoned as a dry hole in 1981. The well was drilled through the Broom Creek and reached the Black Island Formation. It was properly plugged and abandoned with cement plugs isolating the different flowing units before the Fox Hill Aquifer. This well is outside the delineated AOR for the Broom Creek Formation but is included in the pressure front delineated for the Deadwood–Black Island Formation.

3.1.6 Future Wells

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad of the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1,000 feet above the Broom Creek Formation. The water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the risk of leakage is very unlikely.

There is no active or prior production of oil and gas in the vicinity of the Tundra SGS area. This fact, combined with the understanding that potential leakage pathways of injected CO_2 through existing wellbores are very unlikely, makes the Tundra SGS site an ideal location for the geologic storage of CO_2.

3.2 Faults and Fractures

No known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area

through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

A 5-mile-long seismic source test and 6.5-mi² 3D seismic survey were acquired in 2019, and a 12-mi² 3D seismic survey and 21 miles of 2D seismic lines were acquired in 2020 (Figure 3-1). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement (A1:2.5 and A2:2.5). No structural features, faults, or discontinuities that would cause concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data.

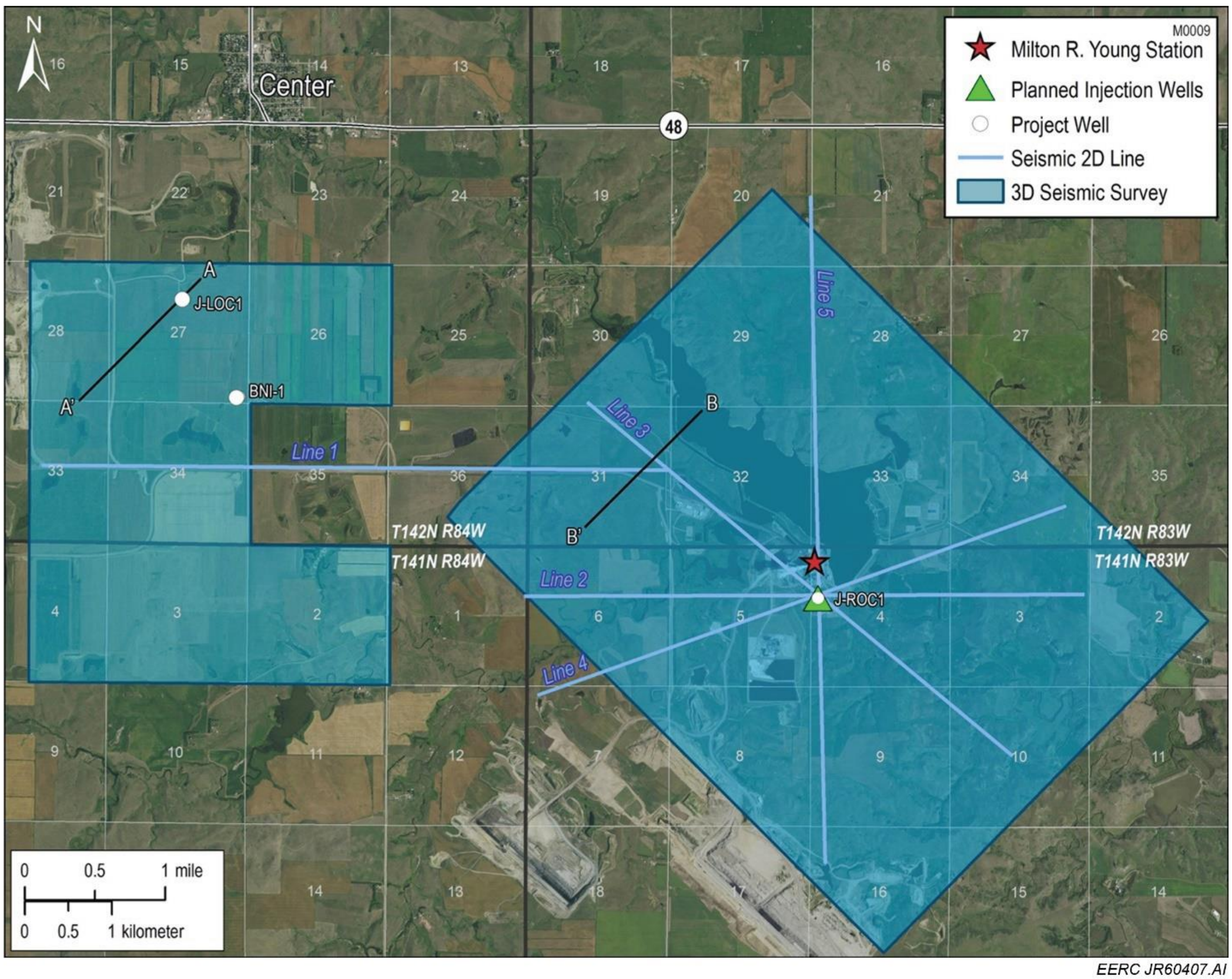

Figure 3-1. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

Leakage through faults and fractures was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the

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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed, and volumetric accounting would follow industry standards as applicable.

3.3 Natural or Induced Seismicity

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 3-2) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 3-2). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota (Table 3-2). This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. The results in Table 3-2 indicate stable geologic conditions in the region surrounding the potential injection site.

Table 3-2. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mile	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mile
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported MMI value.

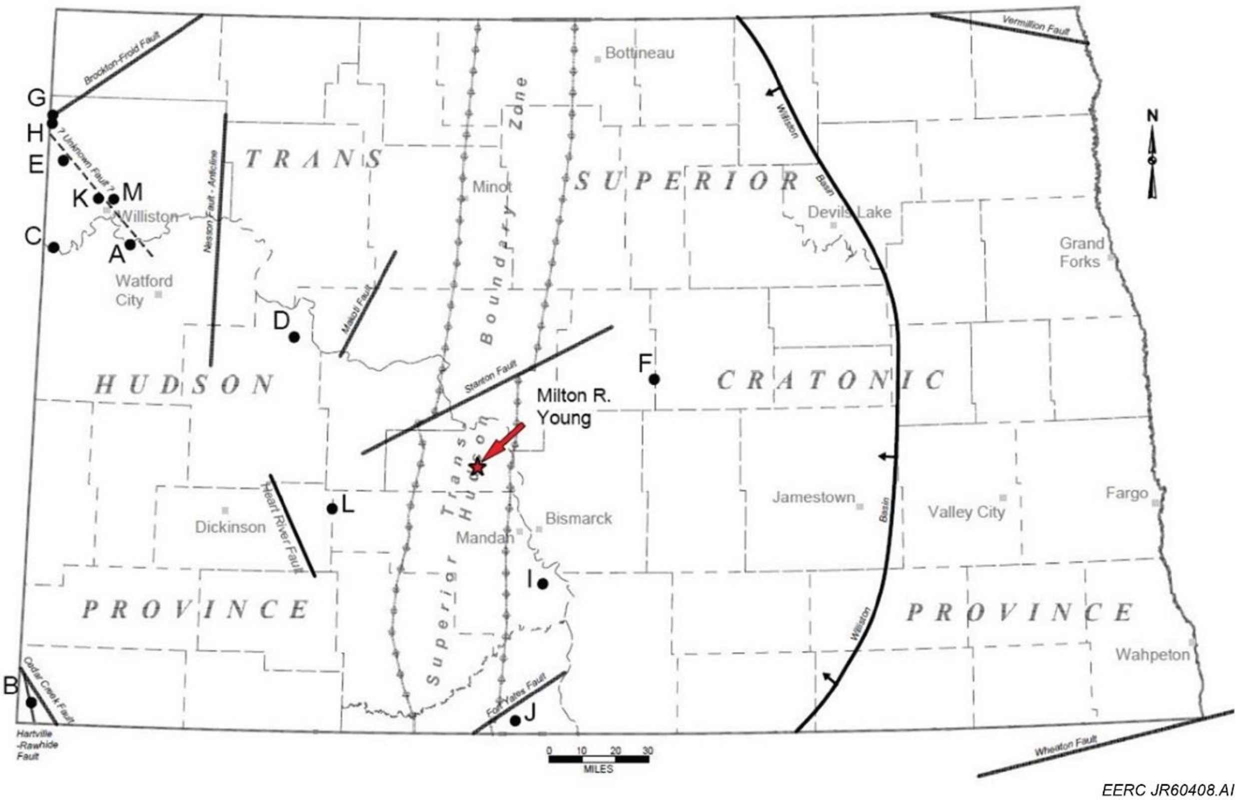

Figure 3-2. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016).

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. 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 time period (Figure 3-3) (U.S. Geological Survey, 2019).

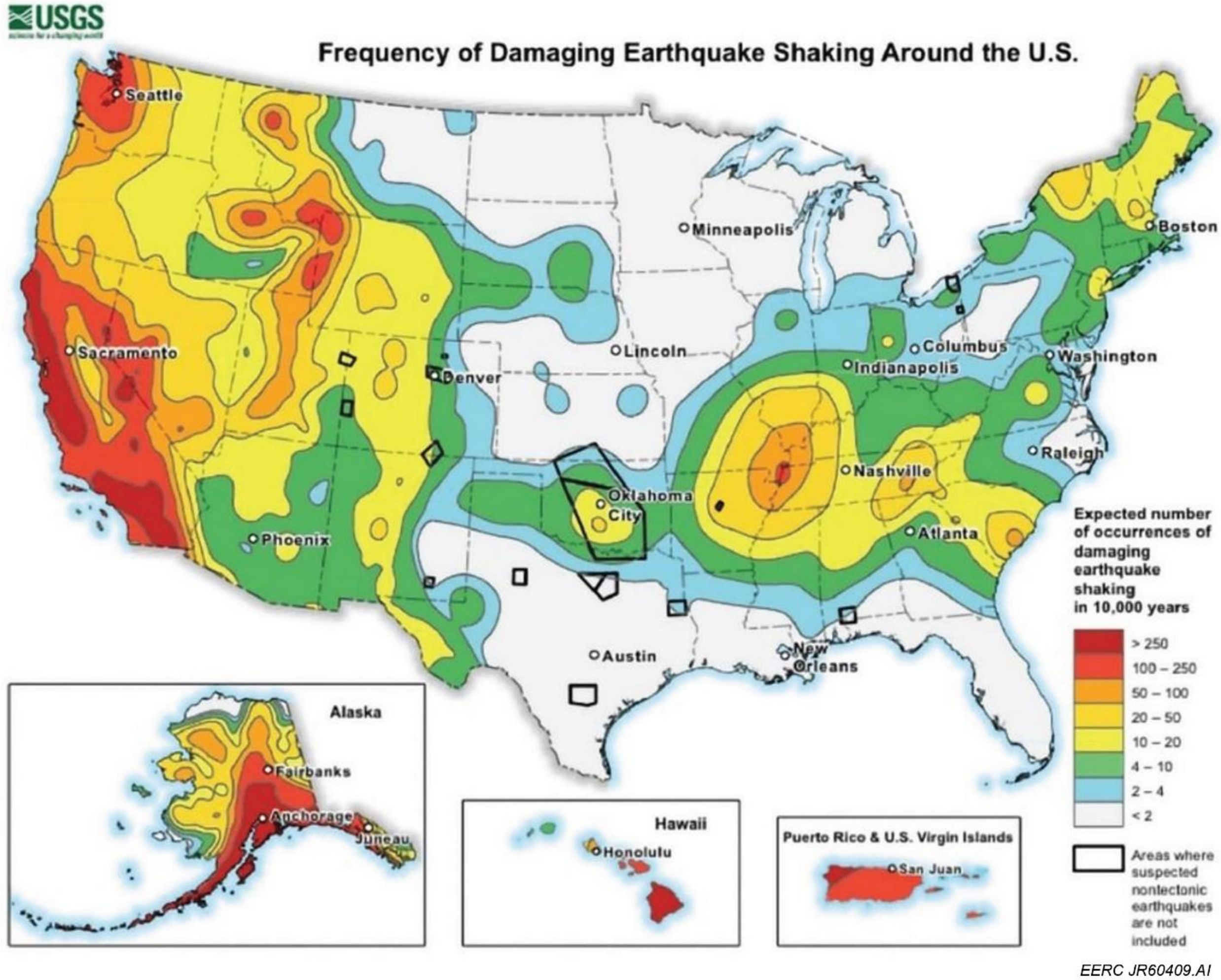

Figure 3-3. Probabilistic map showing how often scientists expect damaging seismic events to occur throughout the United States (U.S. Geological Survey, 2019). The map shows a low probability of damaging seismic events (less than two events per 10,000 years) occurring in North Dakota.

To understand potential induced seismicity, a detailed geomechanical study is described in A1:2.5 and A2:2.5, was carried out to understand the highest possible risk scenario. A scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data suggest that it does not. The failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure.

The maximum expected pressure changes in the Deadwood Formation due to planned injection activities do not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 3-4). Additionally, the injection interval is approximately 120 feet above the Precambrian–Deadwood boundary, and expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results, as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data, suggests planned injection activities will not cause

induced seismicity. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation; therefore, the probability of induced seismicity is minimal.

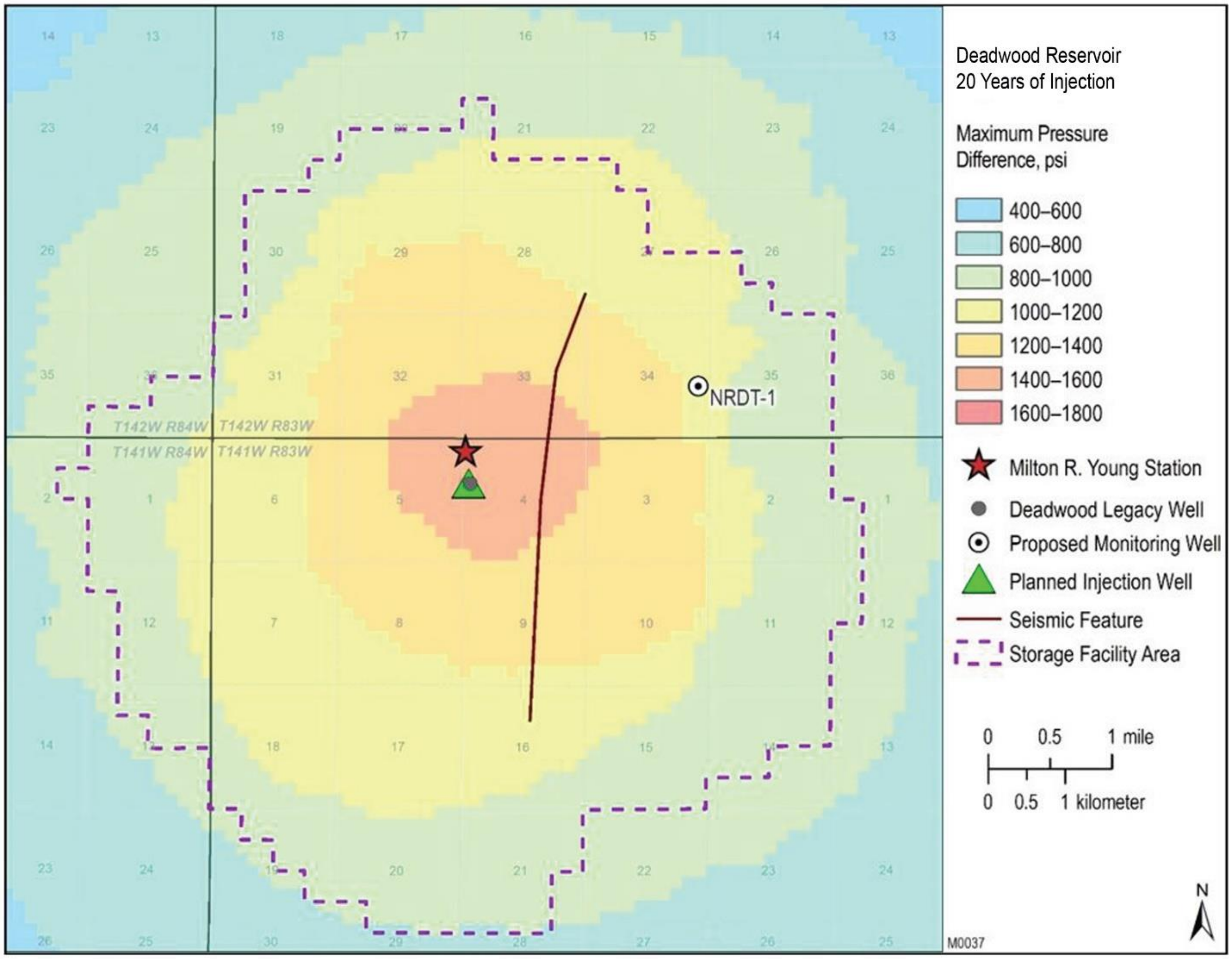

Figure 3-4. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

Leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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.

3.4 Flowline and Surface Equipment

Surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Surface equipment is 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 Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics will be 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.

Each well will be connected independently to the metering station (M2) by 8-inch flowlines equipped with a dedicated flowmeter and pressure and temperature transducers to monitor well performance. Shutoff devices will be installed in the well flowlines 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 Tundra SGS mechanical integrity and monitoring program strives to proactively identify potential surface leak events to ensure the integrity of the facility and minimize the amount of CO_2 released to the ambient air. Maintenance on surface equipment after the delivery point (M2) may require venting cumulated CO_2 volumes before isolating a section of the system; this amount would be quantified and reported.

The risk of leakage in surface equipment is mitigated through:

i. Adhering to regulatory requirements for construction and operation of the site.
ii. Implementing highest standards on material selection and construction processes for the flowline and wells.
iii. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
iv. Continuous monitoring through an automated system and integrated databases.

As a result, the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed. A 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 represent several tons of CO_2 until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply.

The second risk identified was potential leakage at surface equipment through catastrophic damage to surface facilities because of an object striking the equipment or a natural event that causes disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the project team performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. The model is referenced in the risk assessment evaluation matrix and emergency response plan, with the results included in the financial assurance demonstration plan, referenced sections of the applications are found at A1:E, A2:E, and A1:4.3, A2:4.3. This leakage scenario could represent thousands of tons of CO_2 released during the pendency of the response period before the well is controlled and integrity is reestablished. Even though this event is considered high-impact, occurrence is very unlikely since most of the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and will have a fence around the equipment location, located on private MRYS property. Further, containment of any leak is enhanced by the well pad design, including a 4-foot berm and double liner to avoid any brine spill to surface water bodies.

The risk of leakage through surface equipment or major damage is present during the injection phase of the project and 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 and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, NRDT-1, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.5 Lateral Migration of CO_2 Beyond the AOR

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), which confines the CO_2 within the storage facility area. Numerical simulations of CO_2 injection predict slow lateral migration of the plume throughout the injection and post-injection period (A1:A and A2:A). This is the result of the trapping mechanisms combined with the effects of buoyancy and the low dipping structurally characteristic of the storage complexes. 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 Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low-permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at Year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized.

Early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the SFP using both observations and history-matched simulation of CO_2 and pressure distribution. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate the current and predicted future lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predicts additional lateral movement of the plume, Tundra SGS would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests, good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22, and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and post-operational periods.

The risk assessment identifies lateral migration and impact for surface leakage as events with very low likelihood.

3.6 Vertical Migration: Injection and Monitoring Wells

Design and construction of the Class VI injector wells (Liberty-1, Unity-1, and McCall-1) as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leak due to loss of integrity in the wellbores. Material selection complies with CO_2 operating standards, and the wells will be instrumented for continuous, real-time monitoring of well integrity. Well instrumentation will be integrated with an automated data management system to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, described in A1:4.1 and A2:4.1, to ensure proper maintenance of the facilities and timely response in case substandard conditions are detected.

Once the injection period ceases, the injector wells will be evaluated for mechanical condition with corrosion and casing inspection logs and will be properly abandoned with CO_2-resistant cement according to the detailed plugging procedure proposed in A1:4.6 and A2:4.6. The NRDT-1 monitoring well will continue to be operational until plume stabilization and the issuance of a certificate of site closure, then the same rigorous plug-and-abandonment protocol will be followed as proposed for the injector wells.

Based on the design and monitoring program proposed, the project defined the risk of leak through these pathways as unlikely. The amount and timing, if it were to occur, will be minimum since the program is designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. The timing of the leak will be estimated based on the collected data from the monitoring tools until the event is cleared or remediation is completed.

3.7 Vertical Migration: Diffuse Leakage Through Seal

The primary mechanism for geologic confinement of the stored CO_2 in the Broom Creek and Deadwood–Black Island Formations will be containment of the initially buoyant CO_2 by the cap rock (Opeche–Picard, Icebox), under the effects of relative permeability and capillary pressure. Figure 3-5 shows a stratigraphic column with the well schematic for the injector and monitoring wells and highlights the additional secondary seals and buffer formation.

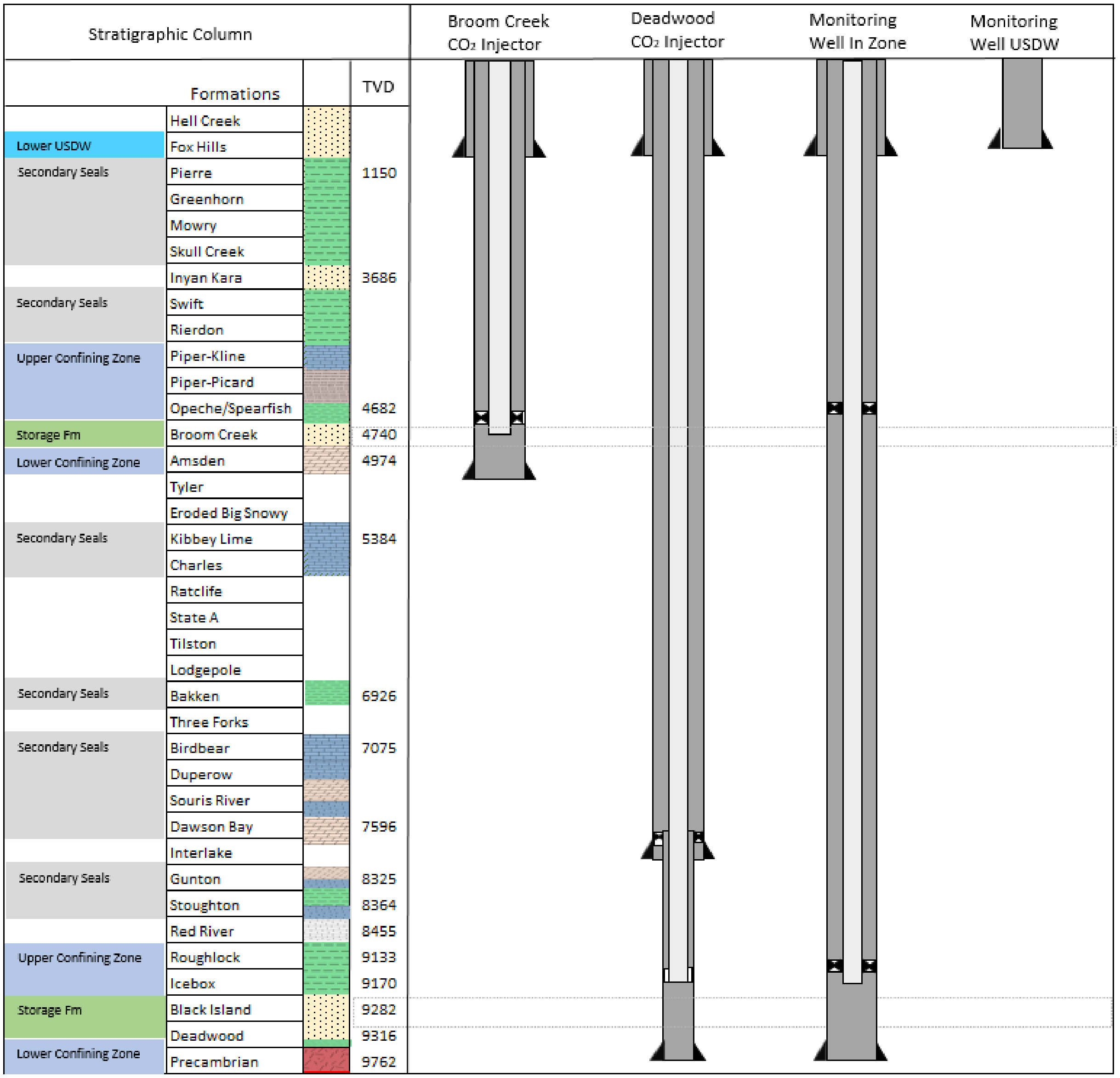

Figure 3-5. Stratigraphic column and well schematic for injector and monitoring wells.

The Picard Member of the Piper Formation within the study area consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. When considered as a single interval, the Opeche–Picard and other formations create an impermeable, laterally extensive cap rock to the Broom Creek Formation capable of containing injected CO_2. The Opeche–Picard interval is 4636 feet below the land surface at the storage site and 154 feet thick at the Tundra SGS site.

In addition to the Opeche–Picard interval, which serves as the cap rock for the Broom Creek Formation, 820 feet of impermeable rock formations separate the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. Surrounding the storage facility area,

an average of 2,545 feet of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation.

Within the Tundra SGS area, the Icebox Formation serves as the upper confining zone of the Black Island and Deadwood Formations. The Icebox Formation consists mostly of impermeable shale, is 9,308 feet below the land surface, and reaches a thickness of 118 feet within the storage facility area. The cap rock has sufficient areal extent and integrity and is free of transmissive faults and fractures to contain injected CO_2.

Impermeable rocks above the primary cap rock include the Roughlock Formation and Red River D Member, which make up the first significant group of secondary confining formations. Together with the Icebox Formation, these formations reach a thickness of 612 feet separating the next overlying permeable zone: the Red River A, B, and C Members. Above the Red River Formation, more than 1,000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. No known transmissible faults are within these confining systems in the project area.

As previously noted, at the same time, 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). As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after Year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure its long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, adsorption is not considered to be a viable trapping mechanism in this project (A1:A and A2:A).

The upper and lower confining zones for the proposed storage formations were largely characterized through core sampling and lab analysis as well as imaging and sonic tools to define the sealing capacity. The great thickness of impermeable rock above each of the storage formations provides a best-in-class secondary seal if the main confining zone were to fail, thereby further reducing the risk of diffusion through the leak to almost zero.

Leakage through vertical migration was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

The risk assessment defined this risk as an unlikely event. Response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses would require consideration of the 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 on the presenting facts

and circumstances, a modeling of the geophysical measurements 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 SURFACE LEAKAGE OF CO_2

Tundra SGS 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 direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous, real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Figure 4-1 summarizes the monitoring techniques proposed based on the leakage pathway analyzed for this MRV plan to provide a vision for the surveillance and management of the site.

These methodologies target early detection of the 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 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 provides a full picture of the monitoring frequency in different periods of the project life, and Table 4-2 summarizes for each technique the leakage path that it is targeting to detect. For additional details regarding strategy for detecting and quantifying surface leakage of CO_2, refer to A1:4.1, E, F and A2:4.1, E, F.

Integrated Remote Automated System (SCADA) and Surveillance Protocol

Leak Detection through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and Optical Gas Imaging (OGI) cameras.
- Automated CO_2 sensors in the wellhead.
- Real time (RT) injection performance on surface and downhole (Pressure, Temperature, flow).
- Distribute temperature sensing (DTS) technology to track well integrity and vertical conformance downhole.
- DTS and Distributed acoustic sensing fiber (DAS) for CO_2 flow line monitoring.
- Mechanical Integrity Program.
- Corrosion Monitoring Program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring through:

- Monitoring wells in reservoir .
- Pressure and temperature gauges downhole in injector.
- 4D seismic surveys.
- Interferometric synthetic aperture radar (INSAR).
- History Match Reservoir Simulation.
- Saturation Log in reservoir.
- Real time temperature profile (DTS) on injectors.
- Seismometers network (induced events)

Operational & Near Surface Monitoring through:

- Soil Gas Analysis
- CO_2 stream analysis.
- Water sampling USDW (baseline and during operation)

Figure 4-1. Tundra SGS monitoring strategy.

Table 4-1. Summary of Tundra SGS Monitoring Strategy

Method	Pre-injection (baseline 1 year)	Injection Period (20 years)	Post-injection (10 years)
CO_2 Stream Analysis – Gas Composition	Pre-injection	Quarterly	NA
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flowline	NA[1]	Real time	NA
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells	NA	Real time	Quarterly
Flowmeters (mass/volume) – Injection Wells and Flowline	NA	Real time	NA
Visual Inspections	Start-up	Weekly	Quarterly
Automated Remote System (SCADA)[2]	Start-up	Real time	NA
OGI[3] Cameras	Start-up	Quarterly	If required
NDIA4 CO_2 Leak Sensors in Wellhead – Injectors	NA	Real time	NA
NDIR CO_2 Leak Sensors in Wellhead – Monitors	NA	Real time	Real time
Handheld CO_2 Monitor	NA	Weekly	Quarterly
Soil Gas Analysis	3–4 seasonal samples per year	Three to four seasonal samples per year	Three to four seasonal samples every 3 years
Water Sampling USDW	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Water Sampling Surface Water	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Cement Bond Logs	After cementing	If needed	Prior to P&A[5]

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Continued . . .

Table 4-1 Summary of Tundra SGS Monitoring Strategy (continued)

Casing Inspection Tool (EM[6]/sonic) – Injection Wells	Baseline	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workover	Prior P&A
Casing Inspection Tool (EM/sonic) – Monitoring Wells	Baseline	Every 5 years	Prior to P&A
Temperature Log – Monitoring Wells	Baseline	Annually	Annually
Annular Pressure Test – Injection Wells	Prior injection	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workovers	Prior to P&A
Annular Pressure Test – Monitoring Wells	During completion	• Every 5 years • During workovers	• Every 5 years • During workovers • Prior to P&A
Corrosion Coupons	NA	Quarterly	NA
DTS/DAS Fiber – Installed on the Casing – Injection Wells	NA	Real time	NA
DTS/DAS Fiber – Main Flowline	NA	Real time	NA
DH[7] Pressure Gauges and Temperature Sensors – Injection Wells	NA	Real time	NA
DH Pressure Gauges and Temperature Sensors – Monitoring Wells	NA	Real time	Bimonthly
RST[8] Log (pulse neutron) – Monitoring Wells	Baseline	Every 5 years	Every 5 years
RST Log (pulse neutron) – Injection Wells	Baseline	As needed	NA
Pressure Falloff Test – Injection Wells	Prior injection	Every 5 years	Prior to P&A
2D/3D Time-Lapsed Surface Seismic	Baseline	Every 5 years	Every 5 years
Interferometric Synthetic Aperture Radar	Baseline	Continuous monitoring	Continuous monitoring
Surface Seismometers	Baseline	Real time	NA

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect CO_2

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis – Gas Composition		X		X	X		
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flow Line				X	X		
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells				X	X	X	
Flowmeters (mass/volume) – Injection Wells and Flowline				X	X		
Visual Inspection	X			X	X		
Automated Remote System (SCADA)			X	X	X		
OGI Cameras				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Injectors				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Monitors				X	X		
Handheld CO_2 Monitor	X			X	X		X
Soil Gas Analysis		X			X		
Water Sampling USDW		X			X		X
Water Sampling Surface Water		X			X		X
Cement Bond Logs					X		
Casing Inspection Tool (EM/sonic) – Injection Wells					X		

Continued . . .

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect (continued)

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
Casing Inspection Tool (EM/sonic) – Monitoring Wells					X		
Temperature Log – Monitoring Wells					X		
Annular Pressure Test – Injection Wells				X	X		
Annular Pressure Test – Monitoring Wells				X	X		
Corrosion Coupons				X	X		
DTS/DAS Fiber Installed on the Casing – Injection Wells		X			X		
DTS/DAS Fiber – Main Flowline				X			
DH Pressure Gauges and Temperature Sensors – Injection Wells		X			X	X	
DH Pressure Gauges and Temperature Sensors – Monitoring Wells		X			X	X	
RST Log (pulse neutron) – Monitoring Wells		X			X	X	X
RST Log (pulse neutron) – Injection Wells		X			X	X	X
Pressure Falloff Test – Injection Wells		X			X	X	
2D/3D Time-Lapsed Surface Seismic	X	X			X	X	X
Interferometric Synthetic Aperture Radar	X	X			X	X	
Surface Seismometers		X	X				

4.1 Leak Verification

Tundra SGS 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, Tundra SGS 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, injector wells 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 CO_2 leakage is occurring. Excursions are not necessarily indicators of 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 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 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 CO_2 surface leak is of lower temperature than ambient, it will often lead to the formation of bright white clouds and ice that are easily visually observed unaided. With this understanding, Tundra SGS will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Tundra SGS project.

Discovery of an event triggers a response, as presented in the A1 and A2, Section 4.2, emergency remedial and response plan. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator 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, Tundra SGS 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 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 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 leaking to the surface will be quantified using acceptable emission factors, engineering estimates of 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.

Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database. For additional details regarding quantification of leakage, refer to A1: 4.3.1 and A2:4.3.1.

5.0 DETERMINATION OF BASELINES

Pre-injection baselines will be established through the Tundra SGS project 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 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 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 Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B.

5.1 Surface Baselines

Baseline sampling includes selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers and one USGS Fox Hills observation well. Verification of the domestic well status, based on viability of the well (existence, depth, access, etc.) and landowner cooperation, has been completed and selected wells sampled August 11–13, 2021.

The locations of these candidate wells are shown in A1:C and A2:C, Figure 4-2. Characterization of selected domestic wells and one USGS Fox Hills observation well will include

the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C.

5.2 Subsurface Baseline

Preoperational baseline data will be collected in the injection and monitoring wells. 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 (interferometric synthetic aperture radar) technology will be performed to determine application before injection and 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 5 km from the injection area a year prior to injection. For additional information regarding surface baseline, refer to A1: 4.1.8 and A2: 4.1.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

Tundra SGS 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 M2 in the facility diagram (Figure 1-2).

CO2I is equal to annual CO2 mass injected (metric tons) through all injection wells) for Tundra SGS, because we are not producing rather Tundra SGS is a permanent geologic sequestration operation. 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:

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

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 surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used

to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Part 98, Subpart W.

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

The Tundra SGS project will use a volumetric flowmeter (M2) (Figure 1-2) 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 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:

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

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 (volume percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

6.2 Annual Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

The Tundra SGS project 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 A1:4 and A2:4, 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 leak to quantify the CO_2 volume to the best of its the capabilities. The process for quantifying leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models among others.

Tundra SGS project will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

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

Where:

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

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

The calculation of CO_{2FI}, the annual mass of CO_2 emitted (in metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead, will comply with the calculation and quality assurance/quality control requirements in Part 98, Subpart W, and will be reconciled with the annual data collected through the monitoring and surveillance plan proposed in A1:4, D and A2:4, D.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

It is proposed that this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 7.0. As discussed under Sections 2.1 and 3.1, this proposed MRV plan was developed to account for both Phase 1 and Phase 2, and thus no modification to the MRV is anticipated if Phase 2 is pursued. Other greenhouse gas (GHG) reports are filed by the end of the third month of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time.

As described in Section 3.3, Tundra SGS anticipates that the MRV program will be in effect during the operational and post-operational monitoring periods, during which time Tundra SGS will operate the storage facilities for the purpose of secure, long-term containment of a measurable quantity of CO_2 in subsurface geologic formations. Tundra SGS anticipates a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, Tundra SGS will prepare a demonstration supporting the long-term containment determination in accordance with North Dakota statutes and regulations and submit a request to discontinue reporting under this MRV plan consistent with the North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Tundra SGS monitoring techniques and data management is provided in the Quality Assurance and Surveillance Plan found in A1:D and A2:D.

Tundra SGS will ensure compliance with the quality assurance requirement in § 98.444.

CO_2 received:

- The quarterly flow rate of CO_2 received by pipeline is measured at a receiving meter on the injection well path.

- The CO_2 concentration is measured quarterly upstream or downstream 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 § 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.

Concentration of CO_2:

- CO_2 concentration will be measured using the appropriate standard method. All measured volumes will be converted from CO_2 to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

8.1 Missing Data Procedures

In the event Tundra SGS is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in § 98.445 will be used as follows.

8.1.1 Quarterly Flow Rate of CO_2 Received

- Tundra SGS may use the quarterly flow rate data from the sales contract from the capture facility or invoices associated with the commercial transaction.

- A quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

8.1.2 Quarterly CO_2 Concentration of a CO_2 Stream Received

- Tundra SGS may use the CO_2 concentration data from the sales contract for that quarter if the sales contract was contingent on CO_2 concentration and the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration in accordance with the sales contract terms.

- A quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

8.1.3 Quarterly Quantity of CO_2 Injected

- The quarterly amount of CO_2 injected will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

8.1.4 *Values Associated with CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment at the Facility*

- Implementation will follow missing data estimation procedures specified in 40 CFR, Part 98, Subpart W.

Any missing data should be followed up with an investigation into issues, whether they are concerned with equipment failure or incorrect estimations.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Tundra SGS project that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Minnkota is the project sponsor of Tundra SGS and will contribute a portion of the total equity for the proposed storage project; other equity participants for the project have not yet been identified. As such, the MRV plan names Minnkota as the sole storage facility owner, operator, and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota plans to contribute all necessary permits to the Tundra SGS project entity, resulting in the transfer of owner and operatorship to the Tundra SGS project. This transfer of ownership will be treated as a minor modification, which will be accomplished through submission of a certificate of representation identifying the change in ownership in accordance with 40 CFR 98.4(h) and will accurately identify and align MRV plan owner/operator/representative designation. Minnkota does not anticipate any material modification to the MRV plan, and as discussed under Section 2.1, if Phase 2 development is pursued, this proposed MRV plan accounts for all monitoring and reporting obligations under Subpart RR.

Tundra SGS reserves the opportunity to submit supplemental revisions to this proposed plan, which take into considerations responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in A1 and A2 and associated Class VI drilling permits.

10.0 RECORDS RECORDING AND RETENTION

Tundra SGS will follow the records retention requirements specified by § 98.3(g). In addition, it will follow the requirements in Subpart RR § 98.447 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 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.

11.0 REFERENCES

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

U.S. Geological Survey, 2016, Induced earthquakes raise chances of damaging shaking in 2016: https://www.usgs.gov/news/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed December 2019).

Request for Additional Information: Tundra SGS LLC
January 27, 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.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>1.</td><td>1.0</td><td>1</td><td><u>Original EPA Question:</u>
“Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood-Black Island.”

According to 1.3, 77.5 MMT will be injected into Broom Creek with an additional 23.4 MMT injected in the Deadwood-Black Island for a total of 100.9 MMt over 20 years. Please clarify.

<u>Project Tundra Response:</u>
Deadwood formation is being contemplated as a back-up or redundant storage facility in the event we need to complete a third well [McCall-1].

<u>New EPA Question:</u>
Please include this clarification in the MRV plan.</td><td>Corrected. Reference included following the identified portion of section 1.0.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	1.0	2	**<u>Original EPA Question:</u>** We suggest removing the detailed callout of MRYS and Tundra SGS and creating a new figure or more clearly delineating the insert in Figure 1-1 to set it apart. Also, please add a scale to the insert as the scale for Figure 1-1 is not applicable to the insert. **<u>Project Tundra Response:</u>** Josh working on this. **<u>New EPA Question:</u>** It appears that a scale was added to the insert in Figure 1-1. However, the meters scale appears to be the same as the one that applies to the larger map. Please ensure the scales are correct.	Corrected.

<table>
<tr><th rowspan="2">No.</th><th colspan="2">MRV Plan</th><th rowspan="2">EPA Questions</th><th rowspan="2">Responses</th></tr>
<tr><th>Section</th><th>Page</th></tr>
<tr><td>3.</td><td>1.1</td><td>3</td><td><u>Original EPA Question:</u>
“The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1, underground injection control (UIC) Permit XX and UIC Permit XX, respectively.”

Does A1:1 refer to Attachment 1, Section 1? Does A2:1 refer to Attachment2, Section 1? What does XX refer to? Please provide clear descriptions of these reference documents.

<u>Project Tundra Response:</u>
Yes, A1:1 refers to Attachment 1, Section 1, A2:1 refers to Attachment 2, Section 1. We used “X” as a numeric place holder. On page iv. Below the contents there is an explanation of the citation approach used.

We have revised “Permit XX” has been removed, however, well file numbers will be assigned to each of the injector wells as well as the subsurface monitoring well, which will be assigned to the each of the wells when agency approves the application for drilling permit. The well file number consists of a four-digit number used by Department of Mineral Resources for tracking the submission of reports and information, and tracking status of the wells. The application for Class VI drilling permits are filed and pending with the North Dakota Industrial Commission staff.

<u>New EPA Question:</u>
We understand that the well file numbers have been issued or are forthcoming. Please add the numbers to the MRV plan where appropriate.</td><td>The Agency has indicated the applications for permit to drill will be assigned a well file number before March 1, 2022. We will submit those numbers through e-GGRT as soon as they are received.</td></tr>
</table>

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	1.1	4	**<u>Original EPA Question:</u>** "In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO2 transported via a CO2 flowline." Is this the USDW in Figure 1-2? If so, please specify. **<u>Project Tundra Response:</u>** Yes. **<u>New EPA Question:</u>** Please add a reference to Figure 1-2 in the referenced passage for clarification.	Corrected. Reference included following the identified portion of section 1.1.
5.	3.1.1	12	**<u>Original EPA Question:</u>** "The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well." Please provide further characterization as to the plugging, abandonment, and conversion processes (cement, is the plug drillable, etc.) **<u>Project Tundra Response:</u>** Supplement 1 is being submitted with MRV Plan Rev.2. **<u>New EPA Question:</u>** Please include a reference to Supplement 1 in the MRV plan.	This was previously included in rev 2 in the sentence following the referenced portion of 3.1.1. Please advise if an alternative reference is being requested.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	3.4	20	**Original EPA Question:** "…the project performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks…" Are the results of this modeling effort presented in the UIC Class VI permit? If so, please reference it here. **Project Tundra Response:** The dispersion model is referenced in the risk assessment evaluation matrix, emergency response plan found at A1:E and A2:E. Results were also considered in the financial assurance demonstration plan found at A1:4.3, A2:4.3. **New EPA Question:** Please include a reference to these appendices in the MRV plan.	Corrected. Reference included following the identified portion of section 3.4.
7.	3.5	21-22	**Original EPA Question:** "If the data predict additional lateral movement of the plume, Tundra SGS will negotiate the additional pore space and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA." Please clarify what is meant by "negotiate the additional pore space." **Project Tundra Response:** If modeling indicates that in the future CO2 may migrate outside of our permitted area, Minnkota would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests, good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22. **New EPA Question:** Please include this information in the MRV plan.	Corrected. Detail consistent with the Response has been incorporated in the referenced portion of Section 3.5

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Wells

Facility(GHGRP) ID 579201

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LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT (SFP) DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, Tundra SGS SFPs and their individual sections for Broom Creek and Deadwood are designated as follows:

Attachment 1: Tundra SGS – Carbon Dioxide Geologic SFP (Broom Creek) Case No. 29029-29031

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachment 2: Tundra SGS – Carbon Dioxide Geologic SFP (Deadwood) Case No. 29032-29034

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

*Attachments within this MRV document will follow use the following referencing convention:

- A1 and A2 will refer to the Attachments, A1 being the Broom Creek SFP and A2 being the Deadwood SFP.
- Numbers or letters that appear after the colon will represent the numbered section or appendix of the appropriate Storage Facility Permit. For example:
  - A1:3.1.1 will direct the reader to refer to Section 3.1.1, (Area of Review Section, Written Description Subsection) within the Broom Creek SFP.
  - A2:A will direct the reader to refer to Appendix A (Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations) within the Deadwood SFP

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

1.0 PROJECT DESCRIPTION

Minnkota Power Cooperative, Inc. (Minnkota) is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota also acts as the operating agent of the Northern Municipal Power Agency, which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine, which provides the lignite coal for MRYS, is owned and operated by BNI Coal, Inc. (BNI) and is located adjacent to the MRYS facility. Minnkota prepared this MRV plan in support of the operation, reporting, and accounting for the storage component of Project Tundra, a carbon capture retrofit to MRYS with saline formation geologic storage. Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood–Black Island. The geologic storage facility and operation are referred to as Tundra SGS. The Tundra SGS surface facilities, wellsite, and operating location comprise land mostly associated with the coal-mining operation of BNI, the area where MRYS is located, and the land is primarily industrial and agricultural. The nearest densely populated area is Center, North Dakota, which is approximately 3.4 miles northwest of the Tundra SGS site (Figure 1-1).

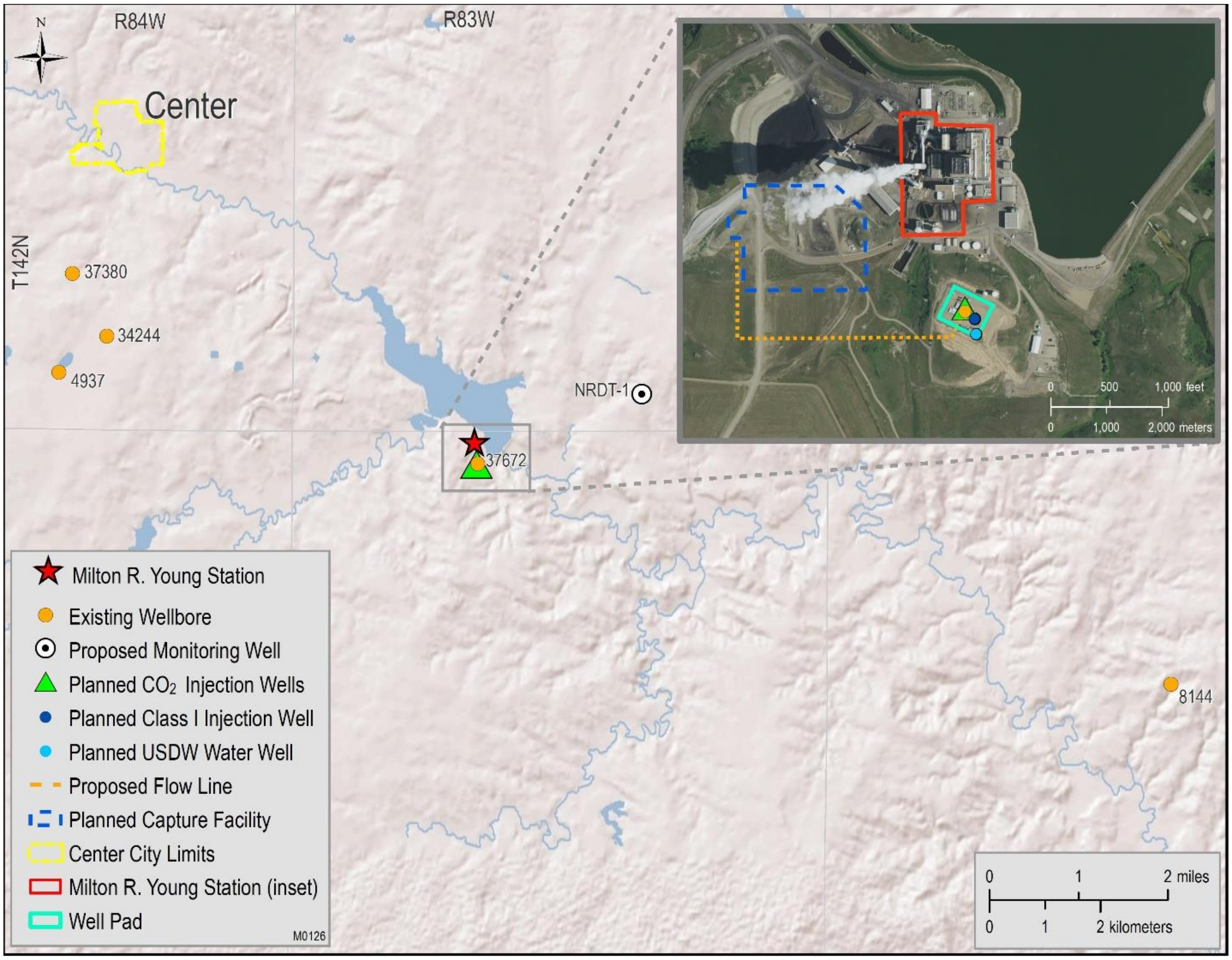


Figure 1-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the proposed CO_2 flowline and well pad layout. The red star denotes MRYS. The existing J-ROC1 wellbore (37672) is the wellbore planned for reentry and conversion to a Class VI injection well, which will be renamed Liberty 1. Offset wells (8144, 37380, 34244, and 4937) are included as they were evaluated in the area of review (AOR) of the Tundra SGS Carbon Dioxide Geologic Storage Facility Permit (SFP) for both Broom Creek and Deadwood storage reservoirs (A1 and A2).

1.1 Operation and Equipment

Tundra SGS plans to capture and store an average of 4 MMt/yr of CO_2 over the course of 20 years of injection, followed by 10 years of post-injection site care. MRYS Units 1 and 2 will be retrofitted with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. The CO_2 captured will be dehydrated and compressed to a supercritical state, then transported via a 0.25-mile flowline to the storage site, where it will be securely and permanently stored in saline geologic formations. Figure 1-2 provides a simplified process flow diagram of the Tundra SGS project, which includes the CO_2 flowline from the metering station (M1) at the outlet of the capture facility compressor and the Phase 1 and Phase 2 injection and monitoring wells (Figure 1-2).

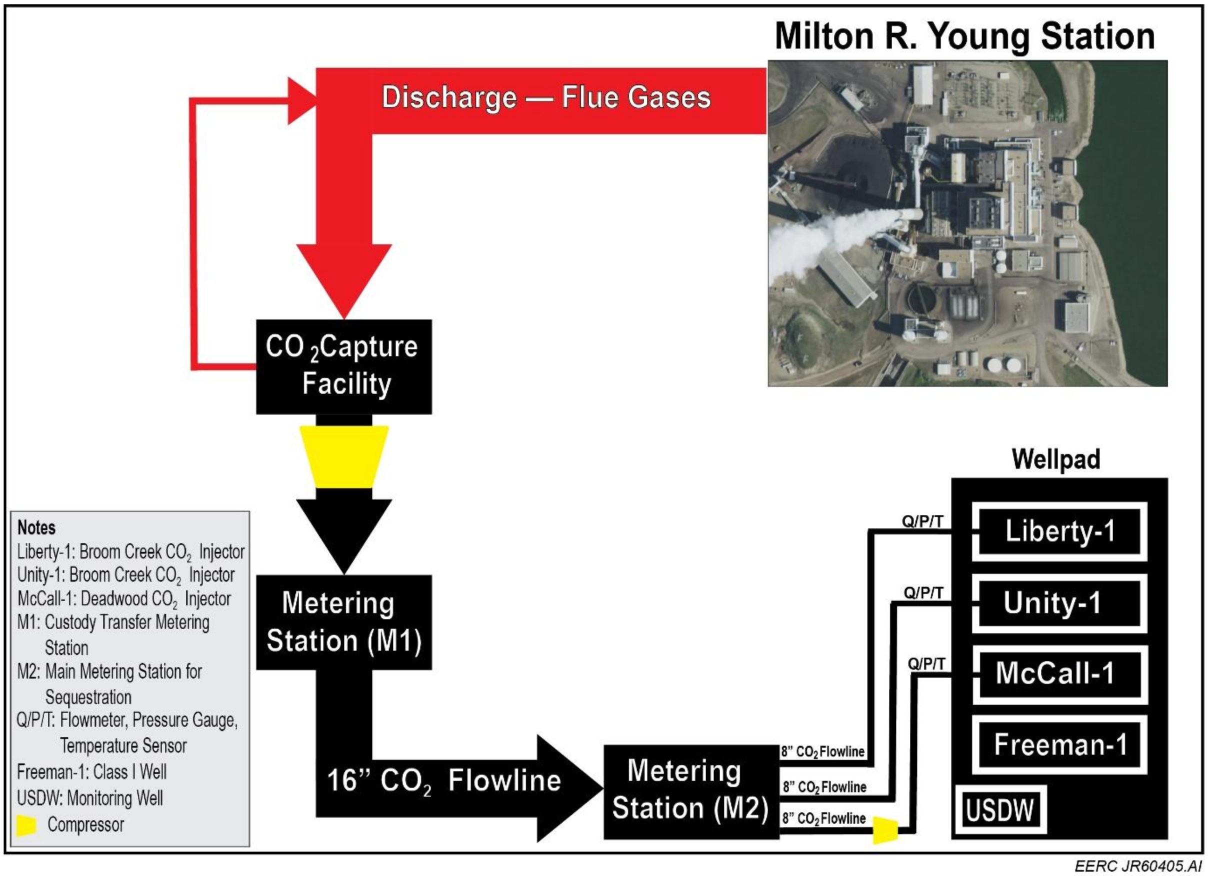


Figure 1-2. Flow diagram for Tundra SGS capture, transport, and storage facilities (USDW is underground source of drinking water).

Tundra SGS will receive captured and dehydrated CO_2 at the compressor outlet (M1), then it will be transported 0.25 miles via CO_2 flowline to the metering station (M2) for distribution to the injection wells for secure and permanent storage in the Broom Creek and Deadwood–Black Island geologic formations. These two storage formations as well as their confining seals have been extensively characterized by Minnkota through local and regional studies led by the Energy & Environmental Research Center (EERC). The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1.

The project proposes a phased development approach, with Phase 1 construction and operation of two injector wells in the Broom Creek reservoir (approximately 5,000 feet in depth), targeting 100% of the captured CO_2 volume. Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well, the McCall-1. This additional well would be completed in the Deadwood–Black Island reservoir (approximately 10,000 feet in depth) to store any excess CO_2 identified in Phase 1. The stacked storage concept and phased development approach allows the project to maximize the areal extent of the storage facilities,

provides operational flexibility and redundancy, and generates further assurance to investors and stakeholders.

In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. Minnkota proposes one deep subsurface monitoring well (NRDT-1) installed on Minnkota property located approximately 2 miles northeast of the injection site.

This procedure is applicable to Tundra SGS storage facility operations consisting of the following infrastructure:

SFP Case Number: **29029, 29030, 29031**
UIC Class VI, ADP Form No. 28643[Unity-1]
UIC Class VI, ADP Form No. 30200[Liberty-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]
SFP Case Number: **29032, 29033, 29034**
UIC Class VI, ADP Form No. 28977 [McCall-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]

The current mailing address for the Tundra SGS facility, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

1.2 Environmental Setting/Geology

The Williston Basin lies in the western half of North Dakota; this area has a long history of hydrocarbon exploration and utilization. This region has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. The proposed location of Tundra SGS is approximately 3.4 miles southeast of the town of Center on the eastern flank of the Williston Basin. This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment. Further discussion of potential mineral zones is found at A1:2.6 and A2:2.6.

The target CO_2 storage reservoir for Tundra SGS Phase 1 is the Broom Creek Formation, a predominantly sandstone horizon lying 4,740 feet below the MRYS facility (Figure 1-3). The lower Piper and Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") serve as the primary confining zone overlying the Broom Creek Formation. This confining interval comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS Phase 1 operations.

The target CO_2 storage reservoirs for Tundra SGS Phase 2, if pursued, are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying approximately 9280 feet below MRYS (Figure 1-3). The shales of the Icebox Formation conformably overlie the Black Island and serve as the primary confining zone. The Icebox Formation provides a suitable confining layer, with an average thickness of 118 feet. The continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite. Together, the Icebox (upper confining), Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS Phase 2. For additional details regarding the site characteristics, refer to A1:2 and A2:2.

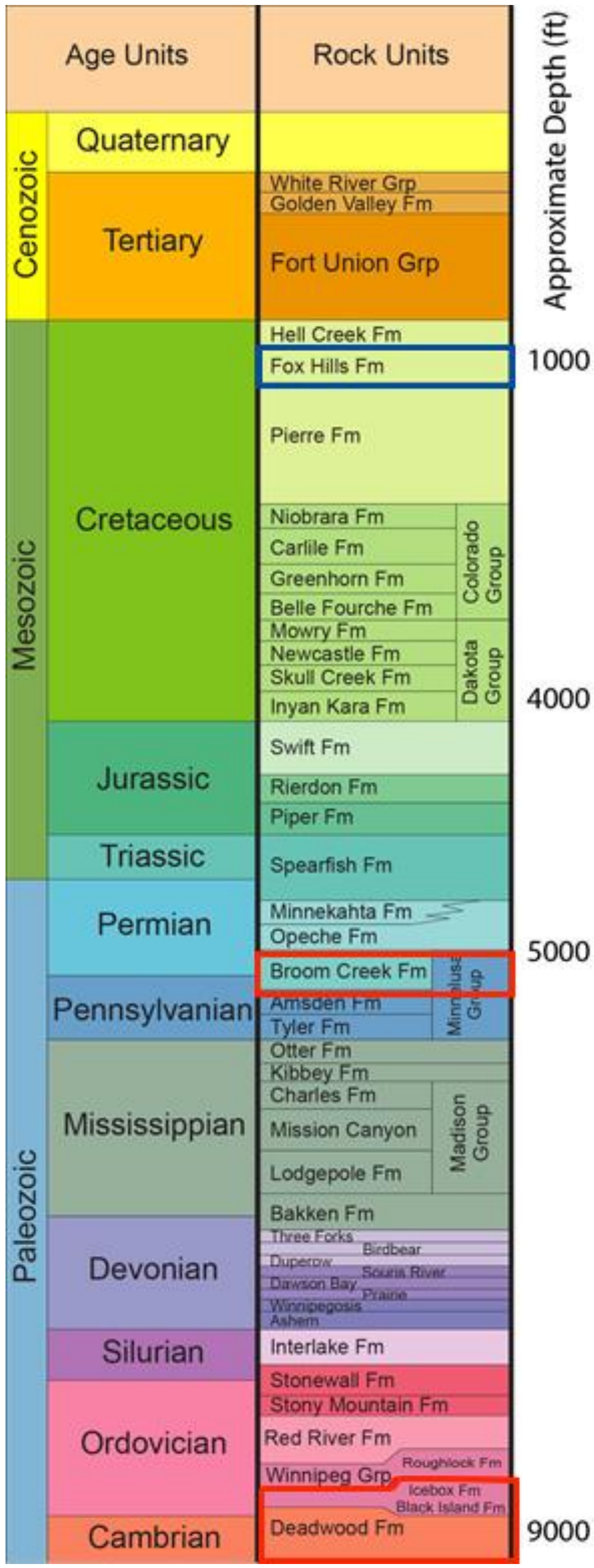


Figure 1-3. Stratigraphic column of North Dakota. Red boxes around the Broom Creek and Deadwood Formations delineate the targeted injection zones.

1.3 Reservoir Model

1.3.1 Broom Creek (Phase 1)

Phase 1 includes two wells: Liberty-1 (originally drilled as J-ROC 1, a stratigraphic well to be converted to a Class VI injector) and Unity-1 (Figure 1-2). Numerical simulation of CO_2 injection in the sandstones of the Broom Creek Formation predicted the wellhead injection pressure (WHP) of both wells would not exceed 1700 psi during injection. Bottomhole pressures (BHPs) reached 3,035.1 and 3,018.3 psi for Liberty-1 and Unity-1 wells, respectively. For the Broom Creek CO_2 plume boundary delineation, the CO_2 plume boundary was modeled using operating assumptions of 20 years at a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 16 through 20. The reservoir simulation model indicated target injection rates were consistently achievable over 20 years of injection. A total of 77.5 MMt of CO_2 would be injected into the Broom Creek Formation with two wells at the end of 20 years. Injected volumes were 41.1 and 36.4 MMt for the Unity-1 and Liberty-1 wells, respectively. A maximum formation pressure increase of 488 psi is estimated in the near-wellbore area during the injection period (A1:A).

1.3.2 Deadwood (Phase 2)

The Deadwood–Black Island reservoir model simulation for Phase 2 includes the McCall-1 well, drilled on the same pad as the Broom Creek wells (Figure 1-2). This model was constrained by WHP and bottomhole fracture gradient without any injection rate constraint. Within the sandstones of the Black Island and Deadwood Formations, numerical simulation of CO_2 injection predicted that injection BHP will not exceed 6,179 psi during injection operations, assuming a WHP limit of 2,800 psi is maintained. Cumulative CO_2 injection at the above-described pressure conditions was 23.4 MMt over the 20 years of injection. The resulting average injection rate of CO_2 into the Black Island and Deadwood Formations was 1.17 MMt/year. Near the wellbore area, a maximum increase of 1620 psi was estimated within the Black Island and Deadwood Formations.

Through numerical simulation efforts, long-term CO_2 migration potential was investigated in each of the Broom Creek and Deadwood models. The results did not indicate migration outside the storage facility area boundaries in either scenario. Storage facility area boundaries were established using a 20-year injection period, with the output boundary at Year 20 identified at a 5% CO_2 saturation rate and then rounded outward to the nearest 40-acre tract (A1:A).

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area

The active monitoring area (AMA) is defined 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” (40 Code of

Federal Regulations [CFR] § 98.449). For purposes of this MRV plan, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (Figure 2-1). Based on review of the data and information of record, and data and information collected in support of A1 and A2, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

2.1.1 Tundra SGS AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

Under North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC) storage facility and Class VI requirements for an AOR, delineation was completed based on the Project Tundra SFP. 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" (NDAC § 43-05-01-01). The NDAC requires the operator develop an AOR and corrective action plan utilizing 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 (NDCC § 38-22-08). Minnkota elected to permit the storage facility area boundaries based on the 20-year reservoir model output discussed in Section 1.3 and then added an additional buffer rounding out to the nearest 40-acre tract.

The Broom Creek proposed AOR was delineated using a risk-based AOR approach (A1:3.1). The risk-based delineation examines the area encompassing the region overlying the injected free-phase CO_2 and the region overlying the extent of increased formation fluid pressure sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or conductive fractures) are present. The risk-based approach established that the CO_2 plume boundary is also the extent of the AOR boundary (A1:3.1). However, in compliance with the NDAC evaluation and monitoring requirements, Minnkota extended the permitted AOR boundary beyond the risk-based delineation to encompass the storage facility boundary plus an additional 1-mile buffer (A1:3.1). Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring from the outset of operations, provides significant assurance that operations can be conducted safely and as contemplated within the permitted storage facility.

The proposed AOR for the Deadwood–Black Island storage facility used EPA Method 1 to establish the AOR (A2:3.1). The Deadwood–Black Island reservoir model simulation discussed in Section 1.1 yielded an annual average injection rate of approximately 1.17 MMt/year for 20 years. Applying EPA Method 1, the Deadwood–Black Island AOR has a larger areal extent, due to the estimated pressure front under EPA Method 1, than the Broom Creek AOR, which applied the risk-based AOR approach; however, the free-phase CO_2 plume for Deadwood is contained in the delineated AOR for Broom Creek. Because of the significant overlap between the two AORs and the phased development approach, the Tundra SGS technical evaluation and proposed monitoring plan were developed to account for monitoring both injection horizons in accordance with the requirements and to the maximum areal extent simulated.

2.1.2 *Tundra SGS AOR Encompasses Subpart RR AMA of both Broom Creek and Deadwood*

AMA minimum delineation requirements are found in 40 CFR § 98.449 and used in Figure 2-1. Using a period of t=20 years, the Broom Creek delineated AMA boundary and the Deadwood–Black Island AMA boundary fall within the Broom Creek AOR. Minnkota proposes that the Broom Creek AOR serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (AOR outlined in black in Figure 2-1), delineation of the AOR is discussed further in A1:3 and A2:3. Aligning the calculated AMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

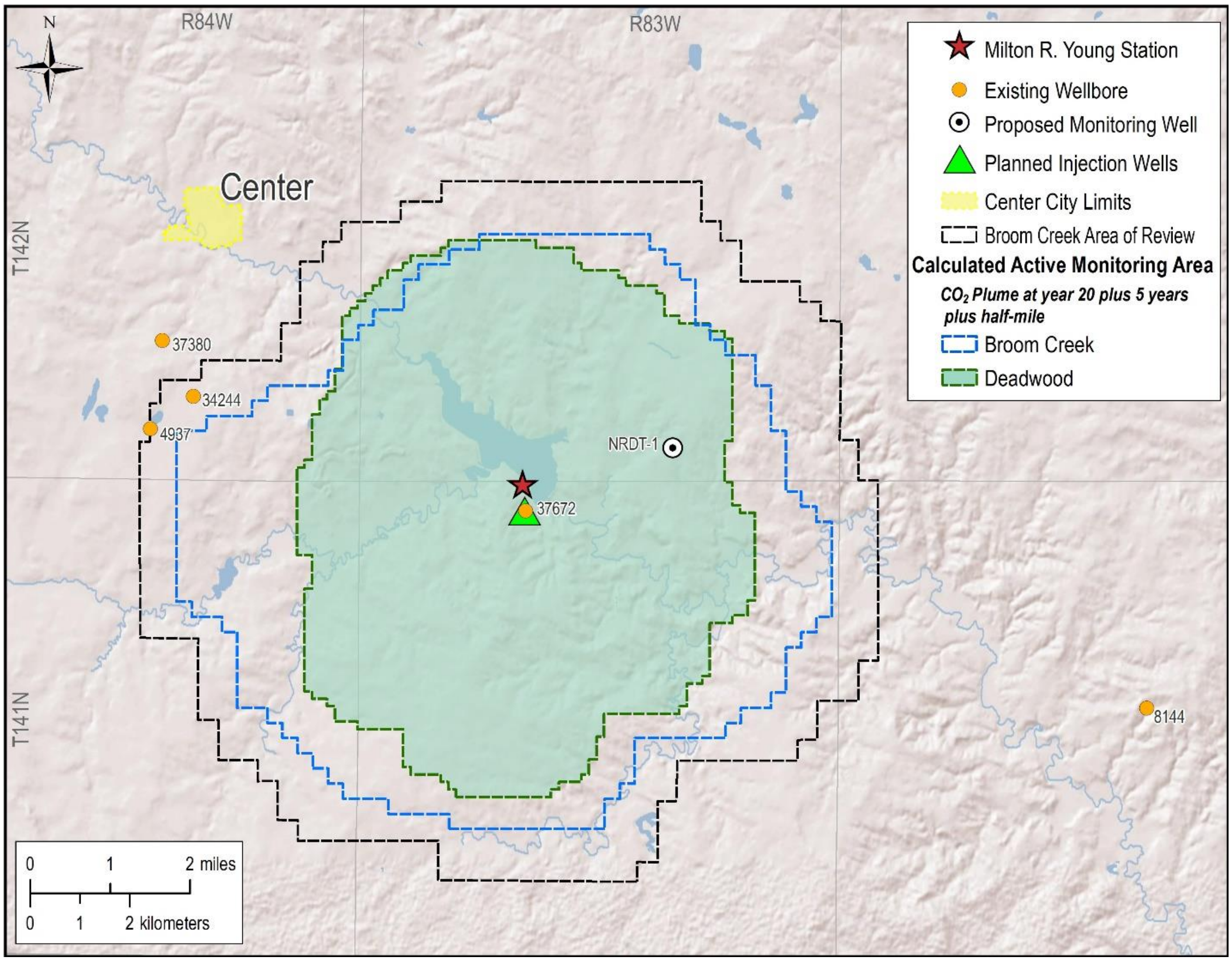


Figure 2-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated AMA in comparison to the permitted AOR. AOR subsumes the calculated AMA for both formations and exceeds requirements for AMA; therefore, the AOR serves as the AMA for Project Tundra.

2.2 Maximum Monitoring Area

The maximum monitoring area (MMA) as defined in 40 CFR § 98.440–449 (Subpart RR) is the area defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The calculated MMA delineated in Figure 2-2 for the Broom Creek and Deadwood–Black Island storage facilities uses a period of t=20 years and represents the period t+10 and a half-mile buffer extending beyond that boundary. The permitted AOR for Broom Creek, as delineated in A1 and A2, exceeds the minimum areal extent required by the Subpart RR approach for delineating the MMA (Figure 2-2); therefore, Minnkota proposes that the Broom Creek AOR serve as the calculated MMA for both the Broom Creek and the Deadwood–Black Island storage facilities.

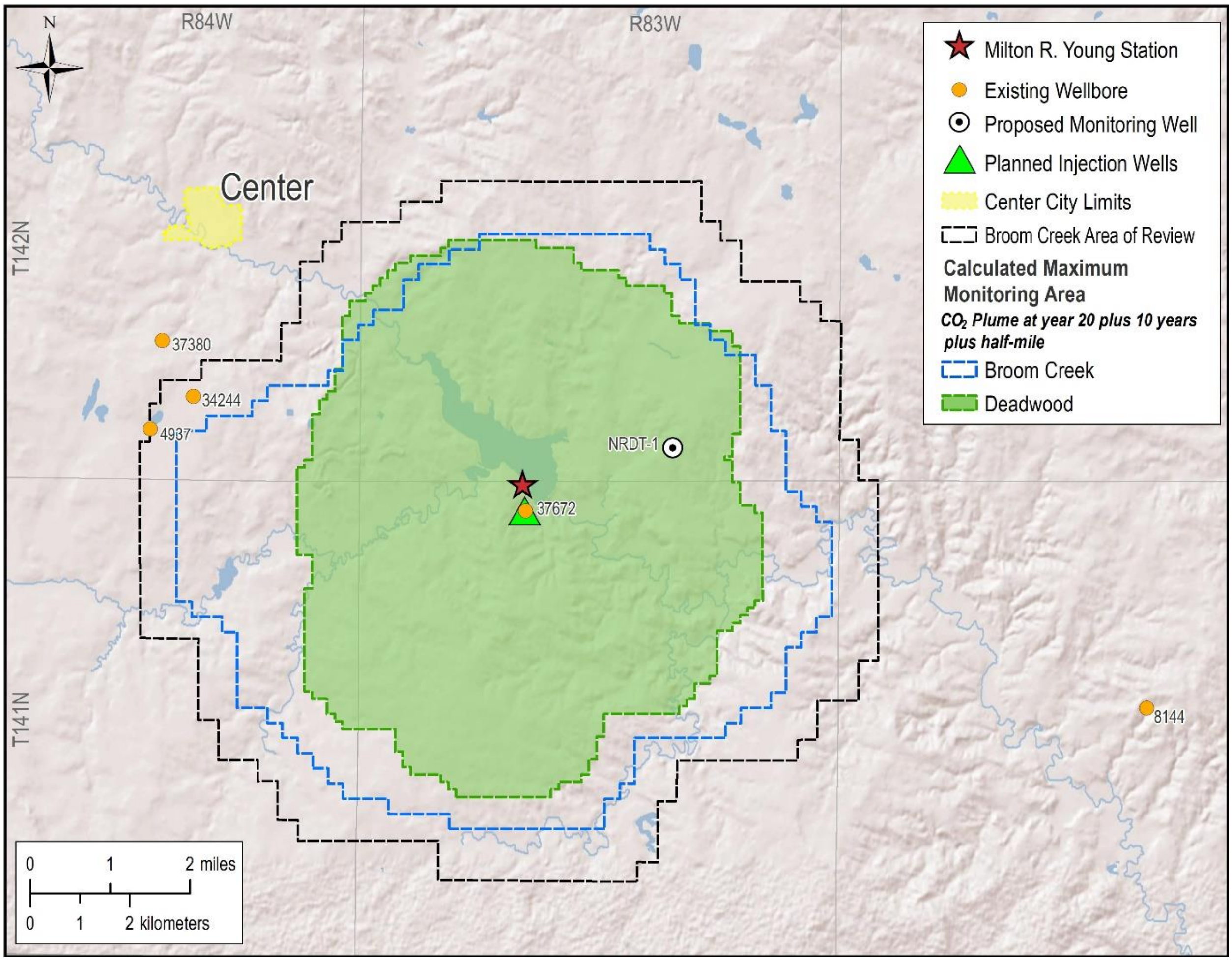


Figure 2-2. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated MMA in comparison to the permitted AoR. AOR subsumes the MMA for both formations and exceeds requirements for the MMA; therefore, the AOR serves as both the AMA and MMA for Project Tundra.

Aligning the calculated AMA and MMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and post-injection periods and avoids unnecessary duplication and complication in reporting.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2, as described in A1:4.1 and A2:4.1, comprises three distinct periods: 1) preoperational (pre-injection of CO_2) baseline monitoring, 2) operational (CO_2 injection) monitoring, and 3) post-operational (post-injection of CO_2) monitoring. The time frame of these monitoring periods will encompass the entire life cycle of the injection. For purposes of this 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 and frequency of the measurements performed vary. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

Preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and inherent 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 amount of CO_2 that is contained in the formation at any given time. This information will be incorporated into the final Class VI permit. If results from this preoperational monitoring period necessitate changes to this MRV plan, an amendment will be submitted prior to the start of operations.

The operational injection period is focused on validating and updating numerical models of the storage system and ensuring that the geologic storage project is operating safely and is protecting USDWs. Lastly, the purpose of 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 three monitoring periods is a minimum of 1 year, 20 years, and a minimum of 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS AND MECHANISMS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was completed by representatives of Minnkota as well as third-party subject matter experts from Oxy Low Carbon Ventures and the EERC. During these meetings, potential leakage pathways were identified and evaluated for the following:

- Existing wellbores
- Faults and fractures
- Natural or induced seismicity
- Flowline and surface equipment
- Lateral migration of CO_2 beyond the AOR

- Vertical migration: injector and monitoring wells
- Vertical migration: diffuse leakage through seal

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 A1:4.1 and 2:4.1, and summarized in Table 5-2, forms the basis for this MRV plan.

3.1 Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated as potential leakage pathways. There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. A detailed discussion of potential mineral zones is found at A1:2.6 and A2:2.6. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table.

Table 3-1. Wellbore Summary

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

3.1.1 J-ROC1 [NDIC No. 37672]

The J-ROC1 well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota project, Phase III. An entire geologic column from surface to the Precambrian was drilled and core collected, and fluid samples as well as special logs were obtained. The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well. Further discussion of reentry program provided in Supplement-1. Once the well conversion takes place, J-ROC1 will be renamed Liberty-1, on authorization of pending reentry drilling permit. This well will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.

3.1.2 J-LOC1 [NDIC No. 37380]

The J-LOC1 well was drilled by Minnkota in 2020 as a stratigraphic well. The construction materials used were compatible with Class VI and CO_2 operating standards. The well was drilled through the entire geologic column from surface to the Precambrian. The drilling program included collecting core, obtaining fluid samples and special logs, and injectivity testing in the Broom Creek and Deadwood Formations. The well is currently in a temporarily abandoned status, plugged for future use. Abandonment procedure and well schematic details can be found in A2:3, Table 3-5 and Figure 3-8. In case the well has no future potential use, it will be permanently abandoned to ensure integrity. This well is located slightly outside the delineated AOR for the Broom Creek, but it is included in the pressure front delineated for Deadwood–Black Island Formation storage.

3.1.3 BNI-1 [NDIC No. 34244]

The BNI-1 well was drilled in 2018 as a stratigraphic well by the EERC under North Dakota CarbonSAFE Phase II. The well was drilled through the Broom Creek Formation and reached total depth in the Amsden Formation. The well was plugged and abandoned in 2018 in accordance with approved guidance and regulations of the state.

3.1.4 Herbert Dresser 1-34 [NDIC No. 4937]

The Herbert Dresser 1-34 well was drilled and plugged in 1970 after being classified as a dry hole. The well was replugged in 2001 by BNI. It was drilled through the Broom Creek Formation and reached total depth at the Charles Formation. Several cement plugs isolate any potential movement of fluids between the different flow units and USDW aquifers.

3.1.5 Little Boot 15-44 [NDIC No. 8144]

The Little Boot 15-44 well was drilled and abandoned as a dry hole in 1981. The well was drilled through the Broom Creek and reached the Black Island Formation. It was properly plugged and abandoned with cement plugs isolating the different flowing units before the Fox Hill Aquifer. This well is outside the delineated AOR for the Broom Creek Formation but is included in the pressure front delineated for the Deadwood–Black Island Formation.

3.1.6 Future Wells

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad of the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1,000 feet above the Broom Creek Formation. The water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the risk of leakage is very unlikely.

There is no active or prior production of oil and gas in the vicinity of the Tundra SGS area. This fact, combined with the understanding that potential leakage pathways of injected CO_2 through existing wellbores are very unlikely, makes the Tundra SGS site an ideal location for the geologic storage of CO_2.

3.2 Faults and Fractures

No known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area

through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

A 5-mile-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 miles of 2D seismic lines were acquired in 2020 (Figure 3-1). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement (A1:2.5 and A2:2.5). No structural features, faults, or discontinuities that would cause concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data.

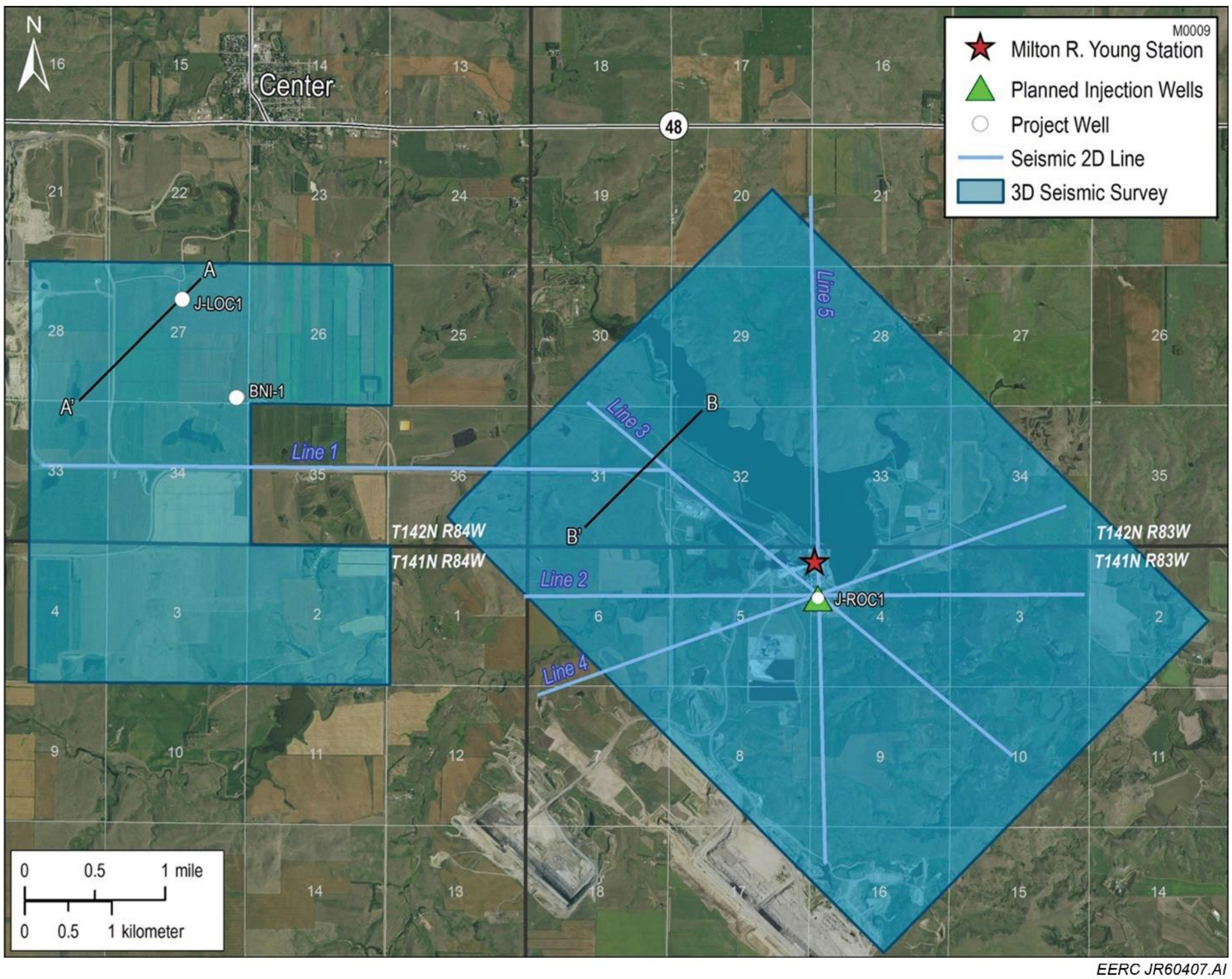


Figure 3-1. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

Leakage through faults and fractures was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the

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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed, and volumetric accounting would follow industry standards as applicable.

3.3 Natural or Induced Seismicity

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 3-2) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 3-2). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota (Table 3-2). This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. The results in Table 3-2 indicate stable geologic conditions in the region surrounding the potential injection site.

Table 3-2. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mile	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mile
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported MMI value.

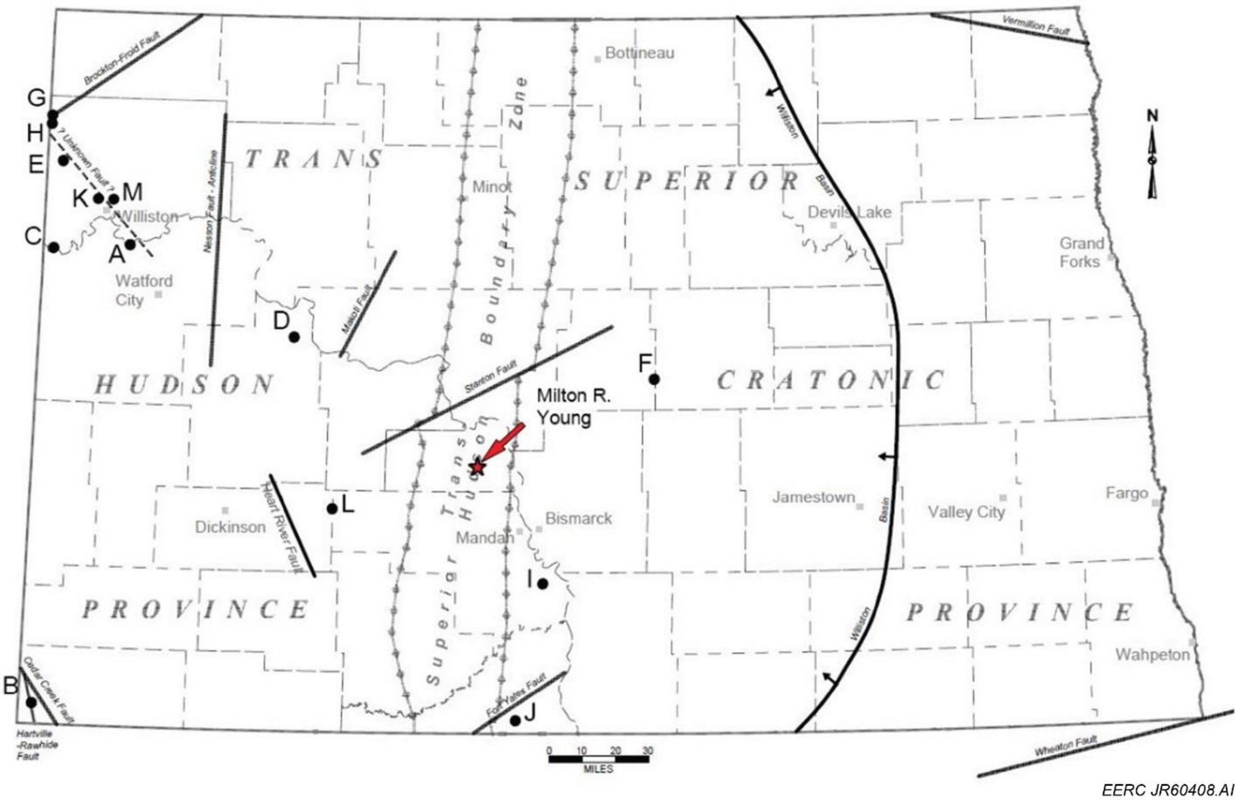


Figure 3-2. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016).

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. 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 time period (Figure 3-3) (U.S. Geological Survey, 2019).

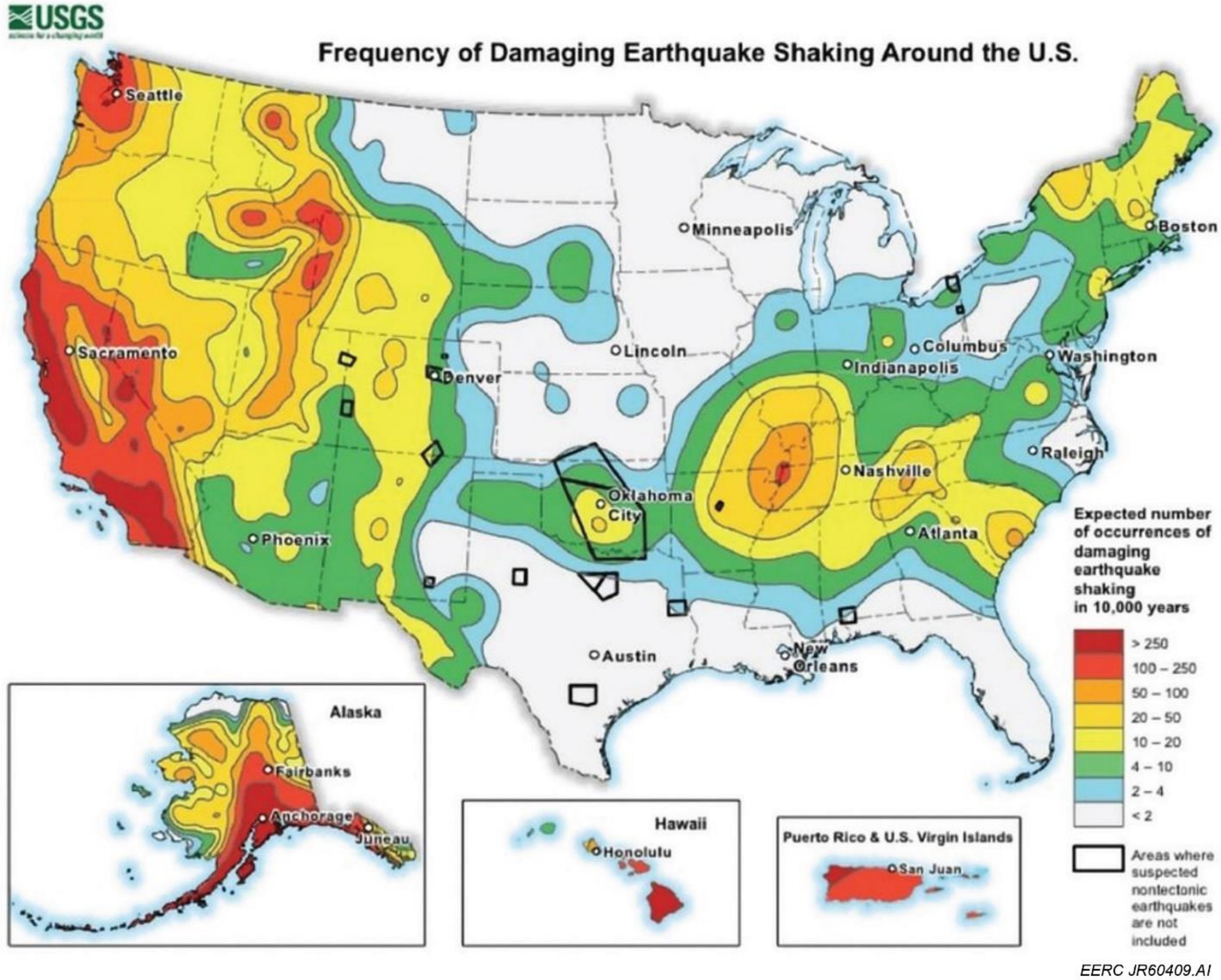
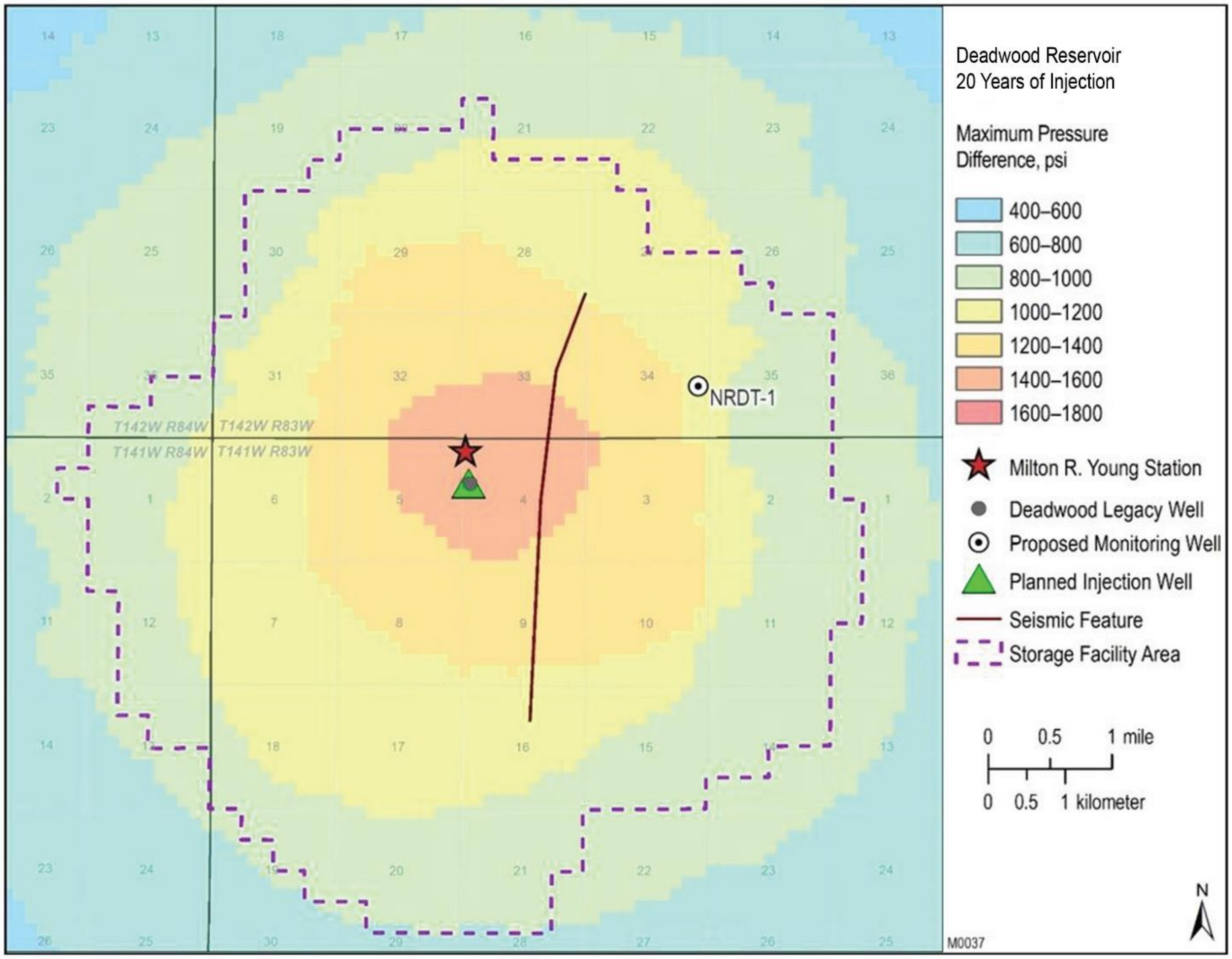


Figure 3-3. Probabilistic map showing how often scientists expect damaging seismic events to occur throughout the United States (U.S. Geological Survey, 2019). The map shows a low probability of damaging seismic events (less than two events per 10,000 years) occurring in North Dakota.

To understand potential induced seismicity, a detailed geomechanical study is described in A1:2.5 and A2:2.5, was carried out to understand the highest possible risk scenario. A scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data suggest that it does not. The failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure.

The maximum expected pressure changes in the Deadwood Formation due to planned injection activities do not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 3-4). Additionally, the injection interval is approximately 120 feet above the Precambrian–Deadwood boundary, and expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results, as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data, suggests planned injection activities will not cause

induced seismicity. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation; therefore, the probability of induced seismicity is minimal.



EERC JR60410.AI

Figure 3-4. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

Leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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.

3.4 Flowline and Surface Equipment

Surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Surface equipment is 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 Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics will be 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.

Each well will be connected independently to the metering station (M2) by 8-inch flowlines equipped with a dedicated flowmeter and pressure and temperature transducers to monitor well performance. Shutoff devices will be installed in the well flowlines 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 Tundra SGS mechanical integrity and monitoring program strives to proactively identify potential surface leak events to ensure the integrity of the facility and minimize the amount of CO_2 released to the ambient air. Maintenance on surface equipment after the delivery point (M2) may require venting cumulated CO_2 volumes before isolating a section of the system; this amount would be quantified and reported.

The risk of leakage in surface equipment is mitigated through:

i. Adhering to regulatory requirements for construction and operation of the site.
ii. Implementing highest standards on material selection and construction processes for the flowline and wells.
iii. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
iv. Continuous monitoring through an automated system and integrated databases.

As a result, the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed. A 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 represent several tons of CO_2 until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply.

The second risk identified was potential leakage at surface equipment through catastrophic damage to surface facilities because of an object striking the equipment or a natural event that causes disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the project performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. This leakage scenario could represent thousands of tons of CO_2 released during the pendency of the response period before the well is controlled and integrity is reestablished. Even though this event is considered high-impact, occurrence is very unlikely since most of the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and will have a fence around the equipment location, located on private MRYS property. Further, containment of any leak is enhanced by the well pad design, including a 4-foot berm and double liner to avoid any brine spill to surface water bodies.

The risk of leakage through surface equipment or major damage is present during the injection phase of the project and 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 and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, NRDT-1, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.5 Lateral Migration of CO_2 Beyond the AOR

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), which confines the CO_2 within the storage facility area. Numerical simulations of CO_2 injection predict slow lateral migration of the plume throughout the injection and post-injection period (A1:A and A2:A). This is the result of the trapping mechanisms combined with the effects of buoyancy and the low dipping structurally characteristic of the storage complexes. 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 Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low-permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at Year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized.

Early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the SFP using both observations and history-matched simulation of CO_2 and pressure distribution. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate the current and predicted future lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predict additional lateral movement of the plume, Tundra SGS will negotiate the additional pore space and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. The time frame of these monitoring efforts will encompass the entire life cycle of the injection site, which includes the preoperational (baseline), operational, and post-operational periods.

The risk assessment identifies lateral migration and impact for surface leakage as events with very low likelihood.

3.6 Vertical Migration: Injection and Monitoring Wells

Design and construction of the Class VI injector wells (Liberty-1, Unity-1, and McCall-1) as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leak due to loss of integrity in the wellbores. Material selection complies with CO_2 operating standards, and the wells will be instrumented for continuous, real-time monitoring of well integrity. Well instrumentation will be integrated with an automated data management system to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, described in A1:4.1 and A2:4.1, to ensure proper maintenance of the facilities and timely response in case substandard conditions are detected.

Once the injection period ceases, the injector wells will be evaluated for mechanical condition with corrosion and casing inspection logs and will be properly abandoned with CO_2-resistant cement according to the detailed plugging procedure proposed in A1:4.6 and A2:4.6. The NRDT-1 monitoring well will continue to be operational until plume stabilization and the issuance of a certificate of site closure, then the same rigorous plug-and-abandonment protocol will be followed as proposed for the injector wells.

Based on the design and monitoring program proposed, the project defined the risk of leak through these pathways as unlikely. The amount and timing, if it were to occur, will be minimum since the program is designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. The timing of the leak will be estimated based on the collected data from the monitoring tools until the event is cleared or remediation is completed.

3.7 Vertical Migration: Diffuse Leakage Through Seal

The primary mechanism for geologic confinement of the stored CO_2 in the Broom Creek and Deadwood–Black Island Formations will be containment of the initially buoyant CO_2 by the cap rock (Opeche–Picard, Icebox), under the effects of relative permeability and capillary pressure. Figure 3-5 shows a stratigraphic column with the well schematic for the injector and monitoring wells and highlights the additional secondary seals and buffer formation.

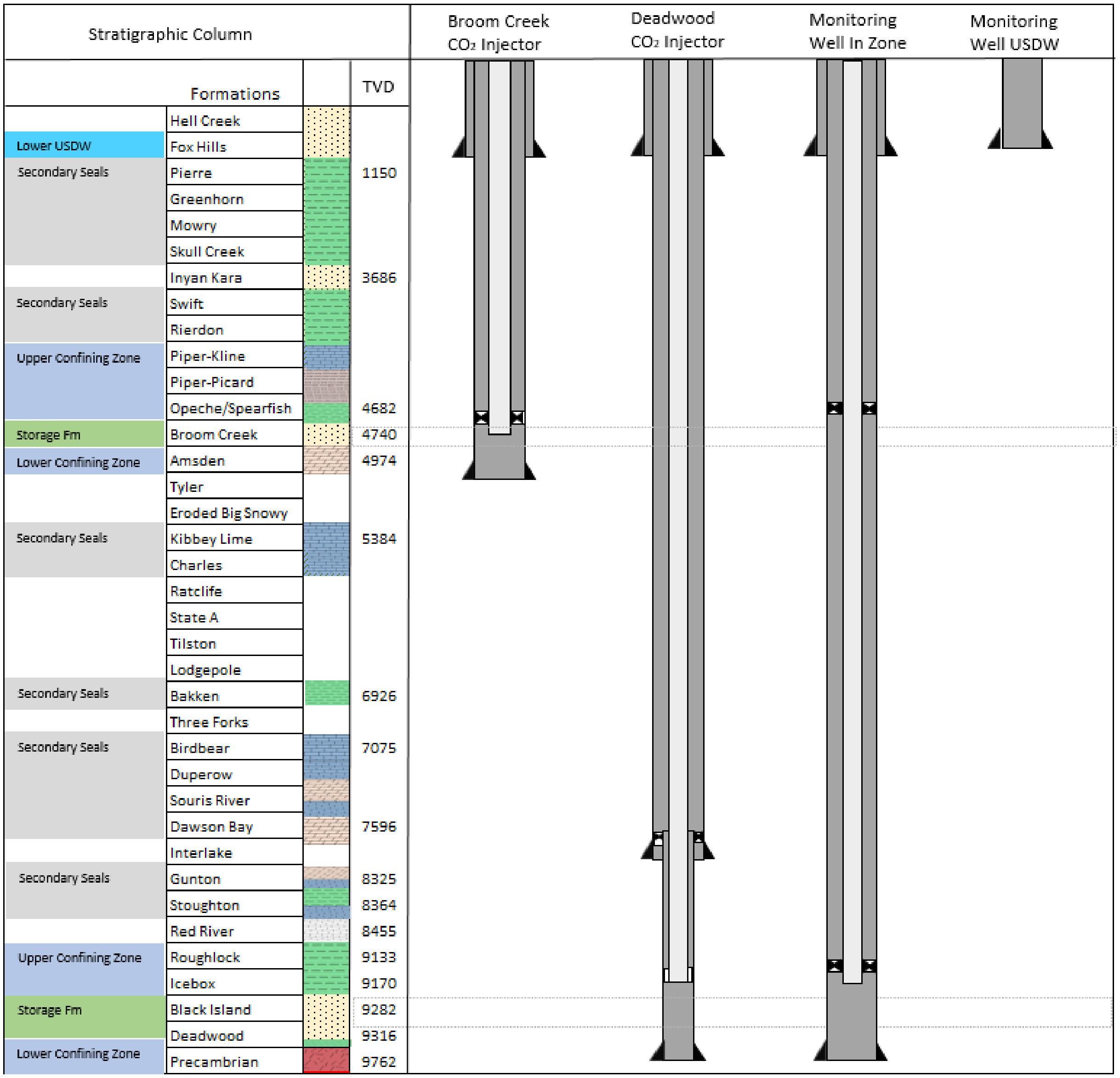


Figure 3-5. Stratigraphic column and well schematic for injector and monitoring wells.

The Picard Member of the Piper Formation within the study area consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. When considered as a single interval, the Opeche–Picard and other formations create an impermeable, laterally extensive cap rock to the Broom Creek Formation capable of containing injected CO_2. The Opeche–Picard interval is 4636 feet below the land surface at the storage site and 154 feet thick at the Tundra SGS site.

In addition to the Opeche–Picard interval, which serves as the cap rock for the Broom Creek Formation, 820 feet of impermeable rock formations separate the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. Surrounding the storage facility area,

an average of 2,545 feet of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation.

Within the Tundra SGS area, the Icebox Formation serves as the upper confining zone of the Black Island and Deadwood Formations. The Icebox Formation consists mostly of impermeable shale, is 9,308 feet below the land surface, and reaches a thickness of 118 feet within the storage facility area. The cap rock has sufficient areal extent and integrity and is free of transmissive faults and fractures to contain injected CO_2.

Impermeable rocks above the primary cap rock include the Roughlock Formation and Red River D Member, which make up the first significant group of secondary confining formations. Together with the Icebox Formation, these formations reach a thickness of 612 feet separating the next overlying permeable zone: the Red River A, B, and C Members. Above the Red River Formation, more than 1,000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. No known transmissible faults are within these confining systems in the project area.

As previously noted, at the same time, 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). As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after Year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure its long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, adsorption is not considered to be a viable trapping mechanism in this project (A1:A and A2:A).

The upper and lower confining zones for the proposed storage formations were largely characterized through core sampling and lab analysis as well as imaging and sonic tools to define the sealing capacity. The great thickness of impermeable rock above each of the storage formations provides a best-in-class secondary seal if the main confining zone were to fail, thereby further reducing the risk of diffusion through the leak to almost zero.

Leakage through vertical migration was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

The risk assessment defined this risk as an unlikely event. Response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses would require consideration of the 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 on the presenting facts

and circumstances, a modeling of the geophysical measurements 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 SURFACE LEAKAGE OF CO_2

Tundra SGS 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 direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous, real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Figure 4-1 summarizes the monitoring techniques proposed based on the leakage pathway analyzed for this MRV plan to provide a vision for the surveillance and management of the site.

These methodologies target early detection of the 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 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 provides a full picture of the monitoring frequency in different periods of the project life, and Table 4-2 summarizes for each technique the leakage path that it is targeting to detect. For additional details regarding strategy for detecting and quantifying surface leakage of CO_2, refer to A1:4.1, E, F and A2:4.1, E, F.

Integrated Remote Automated System (SCADA) and Surveillance Protocol

Leak Detection through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and Optical Gas Imaging (OGI) cameras.
- Automated CO_2 sensors in the wellhead.
- Real time (RT) injection performance on surface and downhole (Pressure, Temperature, flow).
- Distribute temperature sensing (DTS) technology to track well integrity and vertical conformance downhole.
- DTS and Distributed acoustic sensing fiber (DAS) for CO_2 flow line monitoring.
- Mechanical Integrity Program.
- Corrosion Monitoring Program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring through:

- Monitoring wells in reservoir .
- Pressure and temperature gauges downhole in injector.
- 4D seismic surveys.
- Interferometric synthetic aperture radar (INSAR).
- History Match Reservoir Simulation.
- Saturation Log in reservoir.
- Real time temperature profile (DTS) on injectors.
- Seismometers network (induced events)

Operational & Near Surface Monitoring through:

- Soil Gas Analysis
- CO_2 stream analysis.
- Water sampling USDW (baseline and during operation)

Figure 4-1. Tundra SGS monitoring strategy.

Table 4-1. Summary of Tundra SGS Monitoring Strategy

Method	Pre-injection (baseline 1 year)	Injection Period (20 years)	Post-injection (10 years)
CO_2 Stream Analysis – Gas Composition	Pre-injection	Quarterly	NA
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flowline	NA[1]	Real time	NA
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells	NA	Real time	Quarterly
Flowmeters (mass/volume) – Injection Wells and Flowline	NA	Real time	NA
Visual Inspections	Start-up	Weekly	Quarterly
Automated Remote System (SCADA)[2]	Start-up	Real time	NA
OGI[3] Cameras	Start-up	Quarterly	If required
NDIA4 CO_2 Leak Sensors in Wellhead – Injectors	NA	Real time	NA
NDIR CO_2 Leak Sensors in Wellhead – Monitors	NA	Real time	Real time
Handheld CO_2 Monitor	NA	Weekly	Quarterly
Soil Gas Analysis	3–4 seasonal samples per year	Three to four seasonal samples per year	Three to four seasonal samples every 3 years
Water Sampling USDW	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Water Sampling Surface Water	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Cement Bond Logs	After cementing	If needed	Prior to P&A[5]

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Continued . . .

Table 4-1 Summary of Tundra SGS Monitoring Strategy (continued)

Casing Inspection Tool (EM[6]/sonic) – Injection Wells	Baseline	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workover	Prior P&A
Casing Inspection Tool (EM/sonic) – Monitoring Wells	Baseline	Every 5 years	Prior to P&A
Temperature Log – Monitoring Wells	Baseline	Annually	Annually
Annular Pressure Test – Injection Wells	Prior injection	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workovers	Prior to P&A
Annular Pressure Test – Monitoring Wells	During completion	• Every 5 years • During workovers	• Every 5 years • During workovers • Prior to P&A
Corrosion Coupons	NA	Quarterly	NA
DTS/DAS Fiber – Installed on the Casing – Injection Wells	NA	Real time	NA
DTS/DAS Fiber – Main Flowline	NA	Real time	NA
DH[7] Pressure Gauges and Temperature Sensors – Injection Wells	NA	Real time	NA
DH Pressure Gauges and Temperature Sensors – Monitoring Wells	NA	Real time	Bimonthly
RST[8] Log (pulse neutron) – Monitoring Wells	Baseline	Every 5 years	Every 5 years
RST Log (pulse neutron) – Injection Wells	Baseline	As needed	NA
Pressure Falloff Test – Injection Wells	Prior injection	Every 5 years	Prior to P&A
2D/3D Time-Lapsed Surface Seismic	Baseline	Every 5 years	Every 5 years
Interferometric Synthetic Aperture Radar	Baseline	Continuous monitoring	Continuous monitoring
Surface Seismometers	Baseline	Real time	NA

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect CO_2

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis – Gas Composition		X		X	X		
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flow Line				X	X		
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells				X	X	X	
Flowmeters (mass/volume) – Injection Wells and Flowline				X	X		
Visual Inspection	X			X	X		
Automated Remote System (SCADA)			X	X	X		
OGI Cameras				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Injectors				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Monitors				X	X		
Handheld CO_2 Monitor	X			X	X		X
Soil Gas Analysis		X			X		
Water Sampling USDW		X			X		X
Water Sampling Surface Water		X			X		X
Cement Bond Logs					X		
Casing Inspection Tool (EM/sonic) – Injection Wells					X		

Continued . . .

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect (continued)

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
Casing Inspection Tool (EM/sonic) – Monitoring Wells					X		
Temperature Log – Monitoring Wells					X		
Annular Pressure Test – Injection Wells				X	X		
Annular Pressure Test – Monitoring Wells				X	X		
Corrosion Coupons				X	X		
DTS/DAS Fiber Installed on the Casing – Injection Wells		X			X		
DTS/DAS Fiber – Main Flowline				X			
DH Pressure Gauges and Temperature Sensors – Injection Wells		X			X	X	
DH Pressure Gauges and Temperature Sensors – Monitoring Wells		X			X	X	
RST Log (pulse neutron) – Monitoring Wells		X			X	X	X
RST Log (pulse neutron) – Injection Wells		X			X	X	X
Pressure Falloff Test – Injection Wells		X			X	X	
2D/3D Time-Lapsed Surface Seismic	X	X			X	X	X
Interferometric Synthetic Aperture Radar	X	X			X	X	
Surface Seismometers		X	X				

4.1 Leak Verification

Tundra SGS 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, Tundra SGS 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, injector wells 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 CO_2 leakage is occurring. Excursions are not necessarily indicators of 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 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 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 CO_2 surface leak is of lower temperature than ambient, it will often lead to the formation of bright white clouds and ice that are easily visually observed unaided. With this understanding, Tundra SGS will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Tundra SGS project.

Discovery of an event triggers a response, as presented in the A1 and A2, Section 4.2, emergency remedial and response plan. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator 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, Tundra SGS 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 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 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 leaking to the surface will be quantified using acceptable emission factors, engineering estimates of 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.

Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database. For additional details regarding quantification of leakage, refer to A1: 4.3.1 and A2:4.3.1.

5.0 DETERMINATION OF BASELINES

Pre-injection baselines will be established through the Tundra SGS project 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 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 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 Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B.

5.1 Surface Baselines

Baseline sampling includes selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers and one USGS Fox Hills observation well. Verification of the domestic well status, based on viability of the well (existence, depth, access, etc.) and landowner cooperation, has been completed and selected wells sampled August 11–13, 2021.

The locations of these candidate wells are shown in A1:C and A2:C, Figure 4-2. Characterization of selected domestic wells and one USGS Fox Hills observation well will include

the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C.

5.2 Subsurface Baseline

Preoperational baseline data will be collected in the injection and monitoring wells. 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 (interferometric synthetic aperture radar) technology will be performed to determine application before injection and 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 5 km from the injection area a year prior to injection. For additional information regarding surface baseline, refer to A1: 4.1.8 and A2: 4.1.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

Tundra SGS 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 M2 in the facility diagram (Figure 1-2).

CO2I is equal to annual CO2 mass injected (metric tons) through all injection wells) for Tundra SGS, because we are not producing rather Tundra SGS is a permanent geologic sequestration operation. 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:

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

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 surface leakage.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used

to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Part 98, Subpart W.

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

The Tundra SGS project will use a volumetric flowmeter (M2) (Figure 1-2) 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 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:

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

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 (volume percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

6.2 Annual Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

The Tundra SGS project 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 A1:4 and A2:4, 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 leak to quantify the CO_2 volume to the best of its the capabilities. The process for quantifying leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models among others.

Tundra SGS project will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

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

Where:

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

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

The calculation of CO_{2FI}, the annual mass of CO_2 emitted (in metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead, will comply with the calculation and quality assurance/quality control requirements in Part 98, Subpart W, and will be reconciled with the annual data collected through the monitoring and surveillance plan proposed in A1:4, D and A2:4, D.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

It is proposed that this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 7.0. As discussed under Sections 2.1 and 3.1, this proposed MRV plan was developed to account for both Phase 1 and Phase 2, and thus no modification to the MRV is anticipated if Phase 2 is pursued. Other greenhouse gas (GHG) reports are filed by the end of the third month of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time.

As described in Section 3.3, Tundra SGS anticipates that the MRV program will be in effect during the operational and post-operational monitoring periods, during which time Tundra SGS will operate the storage facilities for the purpose of secure, long-term containment of a measurable quantity of CO_2 in subsurface geologic formations. Tundra SGS anticipates a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, Tundra SGS will prepare a demonstration supporting the long-term containment determination in accordance with North Dakota statutes and regulations and submit a request to discontinue reporting under this MRV plan consistent with the North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Tundra SGS monitoring techniques and data management is provided in the Quality Assurance and Surveillance Plan found in A1:D and A2:D.

Tundra SGS will ensure compliance with the quality assurance requirement in § 98.444.

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 received by pipeline is measured at a receiving meter on the injection well path.

- The CO_2 concentration is measured quarterly upstream or downstream of the receiving meter on the injection well path.

<u>Flowmeter provision</u>:

- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in § 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.

<u>Concentration of CO_2</u>:

- CO_2 concentration will be measured using the appropriate standard method. All measured volumes will be converted from CO_2 to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

8.1 Missing Data Procedures

In the event Tundra SGS is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in § 98.445 will be used as follows.

8.1.1 Quarterly Flow Rate of CO_2 Received

- Tundra SGS may use the quarterly flow rate data from the sales contract from the capture facility or invoices associated with the commercial transaction.

- A quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

8.1.2 Quarterly CO_2 Concentration of a CO_2 Stream Received

- Tundra SGS may use the CO_2 concentration data from the sales contract for that quarter if the sales contract was contingent on CO_2 concentration and the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration in accordance with the sales contract terms.

- A quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

8.1.3 Quarterly Quantity of CO_2 Injected

- The quarterly amount of CO_2 injected will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

8.1.4 Values Associated with CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment at the Facility

- Implementation will follow missing data estimation procedures specified in 40 CFR, Part 98, Subpart W.

Any missing data should be followed up with an investigation into issues, whether they are concerned with equipment failure or incorrect estimations.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Tundra SGS project that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Minnkota is the project sponsor of Tundra SGS and will contribute a portion of the total equity for the proposed storage project; other equity participants for the project have not yet been identified. As such, the MRV plan names Minnkota as the sole storage facility owner, operator, and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota plans to contribute all necessary permits to the Tundra SGS project entity, resulting in the transfer of owner and operatorship to the Tundra SGS project. This transfer of ownership will be treated as a minor modification, which will be accomplished through submission of a certificate of representation identifying the change in ownership in accordance with 40 CFR 98.4(h) and will accurately identify and align MRV plan owner/operator/representative designation. Minnkota does not anticipate any material modification to the MRV plan, and as discussed under Section 2.1, if Phase 2 development is pursued, this proposed MRV plan accounts for all monitoring and reporting obligations under Subpart RR.

Tundra SGS reserves the opportunity to submit supplemental revisions to this proposed plan, which take into considerations responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in A1 and A2 and associated Class VI drilling permits.

10.0 RECORDS RECORDING AND RETENTION

Tundra SGS will follow the records retention requirements specified by § 98.3(g). In addition, it will follow the requirements in Subpart RR § 98.447 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 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.

11.0 REFERENCES

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

U.S. Geological Survey, 2016, Induced earthquakes raise chances of damaging shaking in 2016: https://www.usgs.gov/news/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed December 2019).

Request for Additional Information: Tundra SGS LLC
December 13, 2021

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Throughout the MRV plan there is a consistent lack of thousands place separators in numeric integers. We recommend adding commas to numbers where appropriate to improve clarity.	Corrected, for all thousands place carving out four-figure file and permit identification numbers.
2.	1	1	"…a **minemouth** lignite coal-fired power plant." Minemouth is typically written as two separate words or as a hyphenated phrase. We recommend editing the MRV plan to reflect this.	Corrected.
3.	1	1	"Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood-Black Island." According to 1.3, 77.5 MMT will be injected into Broom Creek with an additional 23.4 MMT injected in the Deadwood-Black Island for a total of 100.9 MMt over 20 years. Please clarify.	Deadwood formation is being contemplated as a back-up or redundant storage facility in the event we need to complete a third well [McCall-1].
4.	1	1	"Reporting Number(s) XX" The reporting number is incomplete. We recommend either (1) adding the relevant facility ID number to the MRV plan, or (2) deleting this reference.	Corrected including the Facility ID (GHGRP ID).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	1	1	"…the area where MRYS is located, and the land is primarily industrial or agriculture." We recommend editing the above phrase to "… the land is primarily industrial <u>and</u> agricultur<u>al</u>."	Corrected.
6.	1	2	We suggest removing the detailed callout of MRYS and Tundra SGS and creating a new figure or more clearly delineating the insert in Figure 1-1 to set it apart. Also, please add a scale to the insert as the scale for Figure 1-1 is not applicable to the insert.	Josh working on this.
7.	1	2	"….Geologic Storage Facility Permit (SFP) for both **Broom Creek and Deadwood** (A1 and A2)." We recommend editing the above phrase to "the Broom Creek and Deadwood storage reservoirs" to improve clarity.	Corrected.
8.	1.1	2	"Tundra SGS plans to capture and store an average of 4 MMt/yr over the course of 20 years…" It is not clear what Tundra intends to capture and store in the above phrase. We recommend specifying CO_2 in order to improve clarity.	Corrected.
9.	1.1	2	"The CO_2 captured will be dehydrated and **compressed to supercritical state**…" We recommend changing the above phrase to "compressed to a supercritical state" to improve clarity.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
10.	1.1	3	"The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1, underground injection control (UIC) Permit XX and UIC Permit XX, respectively." Does A1:1 refer to Attachment 1, Section 1? Does A2:1 refer to Attachment2, Section 1? What does XX refer to? Please provide clear descriptions of these reference documents.	Yes, A1:1 refers to Attachment 1, Section 1, A2:1 refers to Attachment 2, Section 1. We used "X" as a numeric place holder. On page iv. Below the contents there is an explanation of the citation approach used. We have revised "Permit XX" has been removed, however, well file numbers will be assigned to each of the injector wells as well as the subsurface monitoring well, which will be assigned to the each of the wells when agency approves the application for drilling permit. The well file number consists of a four-digit number used by Department of Mineral Resources for tracking the submission of reports and information, and tracking status of the wells. The application for Class VI drilling permits are filed and pending with the North Dakota Industrial Commission staff.
11.	1.1	3	"Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well." Is this the McCall-1? If so, please specify.	Yes, McCall-1 would be our primary option for a third well. Another option might be making application for and completing a third well in the Broom Creek. Corrected to add clarification.
12.	1.1	3-4	"This additional well would be **constructed** in the Deadwood-Black Island reservoir…" We recommend changing "constructed" in the above phrase to "completed" to improve clarity.	Corrected.
13.	1.1	4	"In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline." Is this the USDW in Figure 1-2? If so, please specify.	Yes.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	1.1	4	"Minnkota proposes one deep subsurface monitoring well installed on Minnkota property located approximately 2 miles northeast of the injection site." Is this the NRDT-1 well? If so, please specify.	Corrected.
15.	1.2	4	"The proposed location of Tundra SGS is approximately 3.4 miles southwest of the town of Center on the eastern flank of the Williston Basin." Figure 1-1 shows that the Tundra SGS is southeast, not southwest, of the town of Center. Please make sure the geographic description and Figure 1-1 are consistent.	Corrected.
16.	1.2	4	"This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment." Although this is currently the case, are there mid-term or longer-term prospects for oil and gas exploration and production activities, including the drilling of exploratory well, that could impact the Tundra SGS? Please explain and/or state if this is unlikely, and why.	There are no mid-term or longer-term prospects that Minnkota is aware of for oil and gas exploration or production activities within 20 miles of the storage facility area, please see further detailed discussion of potential mineral zones found at A1:2.6 and A2:2.6. Added citation A1:2.6 and A2:2.6 to text.
17.	1.2	5-6	Figure 1.3 and its caption are currently on separate pages. We recommend editing the document so that they are on the same page to improve readability.	Corrected.
18.	1.2	5-6	"This confining interval…..Comprises 56 feet of mudstones, siltstones, and interbedded evaporites…." The above sentence is split in two by Figure 1-3 making it difficult to follow. Please correct.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
19.	1.2	6	"….comprise this CO_2 storage complex for Tundra SGS." We recommend adding "Phase 2" to the end of the sentence above as clarification.	Corrected.
20.	1.2	6	"For additional details regarding the site characteristics, refer to A1:2 and A2:2)." Please remove extraneous parenthesis and clarify whether A1:2 and A2:2 are appendices.	Corrected. A1:2 is Attachment 1, Section 2 and Attachment 2, Section 2.
21.	1.3	6	"...plume boundary was modeled using operating assumptions of 20 years at **a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 15 through 20**." We recommend changing the above phrase to "an annual rate of 4 MMT/year for the first 15 years and 3.5 MMt/year for Years 16 through 20" to improve clarity.	Corrected.
22.	1.3.1 - 1.3.2	6,7	For references to "A1:A", please clarify whether A1:A is an appendix.	Attachment 1, Appendix A is correct.
23.	1.3.2	7	"Through numerical simulation efforts**, Long**-term CO_2…." We do not believe "Long" needs to be capitalized in the phrase above. If this is an error, then please correct it.	Corrected.
24.	2.1	7	"For purposes of this **MRV**, Minnkota proposes…." Please change the above phrase to "MRV plan" rather than "MRV".	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
25.	2.1	7	"For purposes of this MRV, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood‑Black Island storage facilities (Figure 2-1)." To ensure consistency, we recommend amending the legend in Figure 2-2 to refer to the Broom Creek Area of Review or Broom Creek AOR rather than the Permitted Area of Review or amend the text in this sentence to reference the Permitted Area of Review rather than the Broom Creek AOR.	Corrected.
26.	2.1	7	"Based on review of the data and information of record and collected…" It appears there is a typo in the above phrase, please correct it if so.	Corrected.
27.	2.1.1	8	"The risk-based delineation examines the area encompassing the region overlying the injected freephase **CO2 and region** overlying the extent of increased formation fluid pressure sufficient to drive formation fluids…" It appears there is a missing word in the highlighted phrase above, please correct if so.	Corrected.
28.	2.1.1	8	"Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring outside of operations, **provides a significant assurance**…." We recommend changing the end of the phrase above to "provides significant assurance" to improve readability.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
29.	2.3	10	"1) preoperational (preinjection of CO2) baseline monitoring, 2) operational (CO2 injection) monitoring, and 3) postoperational (postinjection of CO2)" Preinjection, postinjection, or postoperational are not words. This error is consistent throughout the MRV plan. We recommend hyphenating them to improve clarity and consistency.	Corrected
30.	3.1	11-12	"There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table." Although this is currently the case, are there mid-term or longer-term prospects for oil and gas exploration and production activities, including the drilling of exploratory well, that could impact the Tundra SGS? Please elaborate.	There are no mid-term or longer-term prospects that Minnkota is aware of for oil and gas exploration or production activities within 20 miles of the storage facility area, please see further detailed discussion of potential mineral zones found at A1:2.6 and A2:2.6. Added citation A1:2.6 and A2:2.6 to text.
31.	3.1.1	12	"The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well." Please provide further characterization as to the plugging, abandonment, and conversion processes (cement, is the plug drillable, etc.)	Supplement 1 is being submitted with MRV Plan Rev.2.
32.	3.1.2	12	"The well is currently in a temporarily abandoned status, plugged for future use." Please provide further characterization of the plugging procedure for this well.	Corrected. Details of the abandonment are described in A2 table 3-5, and the well schematic Figure 3-8.
33.	3.3	18	"To understand potential induced seismicity, **a geomechanics detailed study**…" It appears there is a typo in the phrase above, please correct it if so.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
34.	3.3	19	"…the probability of induced seismicity is **minimized**." We recommend changing "minimized" to "minimal" to improve clarity.	Corrected.
35.	3.4	21	"…the project performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks…" Are the results of this modeling effort presented in the UIC Class VI permit? If so, please reference it here.	The dispersion model is referenced in the risk assessment evaluation matrix, emergency response plan found at A1:E and A2:E. Results were also considered in the financial assurance demonstration plan found at A1:4.3, A2:4.3.
36.	3.4	21	"…the wellhead, valves, and instrumentation will be protected by barriers; **and a fence with the equipment** is located on private MRYS property." The highlighted portion of the above phrase is unclear. We recommend editing it to improve readability.	Corrected.
37.	3.5	22	"If the data predict additional lateral movement of the plume, Tundra SGS will negotiate the additional pore space and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA." Please clarify what is meant by "negotiate the additional pore space."	If modeling indicates that in the future CO2 may migrate outside of our permitted area, Minnkota would proactively meet with landowners to negotiate in good faith terms for leasing the pore space interests, good faith attempt to obtain consent is required under North Dakota Century Code, Chapter 38-22.
38.	3.6	22	"Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, **describe** in..." It appears there is a typo in the phrase above; please correct it if so.	Corrected.
39.	3.7	23	"The **initial** mechanism for geologic confinement of the stored CO_2..." We recommend changing "initial" to "primary" in the phrase above to improve clarity.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
40.	3.7	23	"Stratigraphic column and well **schematic** for injector and monitoring wells." It appears there is a typo in the phrase above; please correct it if so. Specifically, there are multiple well schematics shown in the figure.	Corrected.
41.	3.7	24	"….while the Opeche/Spearfish Formation consists of tight, silty mudstone." The Spearfish Formation is not in the stratigraphic column provided in Figure 3-5. If this is a unique unit then it should be on the stratigraphic column, and if it is an alternate name for the Opeche Formation then we recommend explicitly stating so.	Left the Spearfish and Opeche undifferentiated because the Minnekahta (limestone between them) doesn't extend across the study area. The top of the Opeche (as shown) is the top of the combined (undifferentiated) Opeche and Spearfish. Corrected to "Opeche/Spearfish"
42.	3.7	25	"Based on the presenting facts and circumstances, **modeling geophysical measurement** to estimate…." It appears there is a typo or missing word in the phrase above; please correct it if so.	Corrected.
43.	4	25	"….leakage pathway analyzed for this **MRV** to provide a vision for the surveillance and management of the site." Please change the above phrase to "MRV plan" rather than "MRV".	Corrected.
44.	4	26	The acronyms "OGI" and "RT" are used in figure 4-1 prior to being defined.	Corrected.
45.	6.1	34	"The Tundra SGS project **will to** use a volumetric flowmeter…" It appears there is a typo in the above phrase, please correct it if so.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
46.	6.1	34	You have defined CCO2,p,u as the Quarterly CO2 concentration measurement in flow for Flowmeter u in Quarter p (wt percent CO2, expressed as a decimal fraction). Per 40 CFR 98.443, this data element should be defined as the Quarterly CO2 concentration measurement in flow for Flowmeter u in Quarter p (volume percent CO2, expressed as a decimal fraction). We recommend noting that CO2,u is equal to CO2I (Equation RR-7; Total annual CO2 mass injected (metric tons) through all injection wells) for Tundra SGS. In general, please make sure any Subpart RR equations are consistent with the regulatory text.	Corrected.
47.	6.2	34	"The Tundra SGS **site** characterized, in detail, potential leakage pathways…." We recommend changing "site" to "project" or a similar term in the above phrase because the site itself is not doing the characterization.	Corrected.
48.	6.2	34	"If the monitoring and surveillance plan detects a deviation of the threshold established for each method…." Is it the threshold that is deviating, or is it a deviation from/above/below the threshold?	Corrected.
49.	6.2	34	"Tundra SGS will calculate the total annual mass of CO_2 emitted…." "We recommend editing the above phrase to read "The Tundra SGS Project…" to improve clarity.	Corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
50.	7	35	"Tundra SGS anticipates establishing a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage." The word "establishing" in the phrase above is not needed and may lead to confusion. We recommend removing it to improve clarity.	Corrected.

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

Class VI Wells

Reporting Number(s) XX

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LIST OF FIGURES

LIST OF TABLES

STORAGE FACILITY PERMIT (SFP) DESIGNATIONS

Within the text of this monitoring, reporting, and verification plan, Tundra SGS SFPs and their individual sections for Broom Creek and Deadwood are designated as follows:

Attachment 1: Tundra SGS – Carbon Dioxide Geologic SFP (Broom Creek) Case No. 29029-29031

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachment 2: Tundra SGS – Carbon Dioxide Geologic SFP (Deadwood) Case No. 29032-29034

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 – Well and Well Formation Fluid-Sampling Laboratory Analysis
Appendix C – Near-Surface Monitoring Parameters and Baseline Data
Appendix D – Testing and Monitoring: Quality Control and Surveillance Plan
Appendix E – Risk Assessment Emergency Remedial and Response Plan
Appendix F – Corrosion Control Matrix
Appendix G – Financial Assurance Demonstration Plan
Appendix H – Storage Agreement Tundra Broom Creek: Secure Geologic Storage Oliver County, North Dakota
Appendix I – Storage Facility Permit Regulatory Compliance Table

Attachments within this MRV document will follow use the following referencing convention:

- A1 and A2 will refer to the Attachments, A1 being the Broom Creek SFP and A2 being the Deadwood SFP.
- Numbers or letters that appear after the colon will represent the numbered section or appendix of the appropriate Storage Facility Permit. For example:
    - A1:3.1.1 will direct the reader to refer to Section 3.1.1, (Area of Review Section, Written Description Subsection) within the Broom Creek SFP.
    - A2:A will direct the reader to refer to Appendix A (Data, Processing, Outcomes of CO_2 Storage Geomodeling and Simulations) within the Deadwood SFP

TUNDRA SGS
SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

1.0 PROJECT DESCRIPTION

Minnkota Power Cooperative, Inc. (Minnkota) is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota also acts as the operating agent of the Northern Municipal Power Agency, which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a minemouth lignite coal-fired power plant. The mine, which provides the lignite coal for MRYS, is owned and operated by BNI Coal, Inc. (BNI) and is located adjacent to the MRYS facility. Minnkota prepared this MRV plan in support of the operation, reporting, and accounting for the storage component of Project Tundra, a carbon capture retrofit to MRYS with saline formation geologic storage. Project Tundra proposes 20 years of operation and the secure geologic storage of an approximate cumulative total of 77.5 MMt of carbon dioxide (CO_2) over the course of the 20 years of injection into two saline aquifer reservoirs: the Broom Creek and Deadwood–Black Island. The geologic storage facility and operation are referred to as Tundra SGS. The Tundra SGS surface facilities, wellsite, and operating location comprise land mostly associated with the coal-mining operation of BNI, the area where MRYS is located, and the land is primarily industrial or agriculture. The nearest densely populated area is Center, North Dakota, which is approximately 3.4 miles northwest of the Tundra SGS site (Figure 1-1).

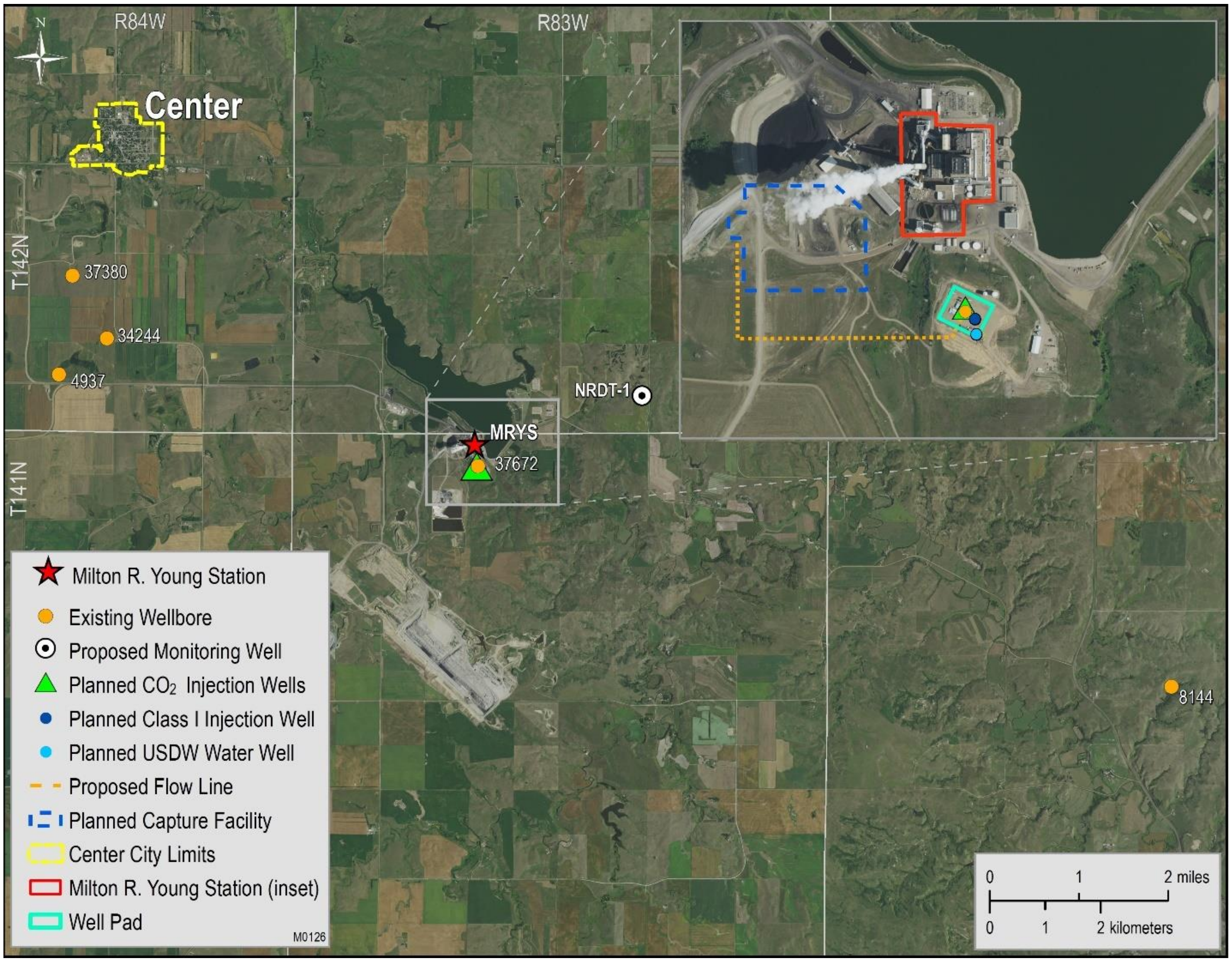

Figure 1-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the proposed CO_2 flowline and well pad layout. The red star denotes MRYS. The existing J-ROC1 wellbore (37672) is the wellbore planned for reentry and conversion to a Class VI injection well, which will be renamed Liberty 1. Offset wells (8144, 37380, 34244, and 4937) are included as they were evaluated in the area of review (AOR) of the Tundra SGS Carbon Dioxide Geologic Storage Facility Permit (SFP) for both Broom Creek and Deadwood (A1 and A2).

1.1 Operation and Equipment

Tundra SGS plans to capture and store an average of 4 MMt/yr over the course of 20 years of injection, followed by 10 years of postinjection site care. MRYS Units 1 and 2 will be retrofitted with a capture facility system that utilizes amine absorption technology to generate a high-purity stream of CO_2 from the flue gas. The CO_2 captured will be dehydrated and compressed to supercritical state, then transported via a 0.25-mile flowline to the storage site, where it will be securely and permanently stored in saline geologic formations. Figure 1-2 provides a simplified process flow diagram of the Tundra SGS project, which includes the CO_2 flowline from the metering station (M1) at the outlet of the capture facility compressor and the Phase 1 and Phase 2 injection and monitoring wells (Figure 1-2).

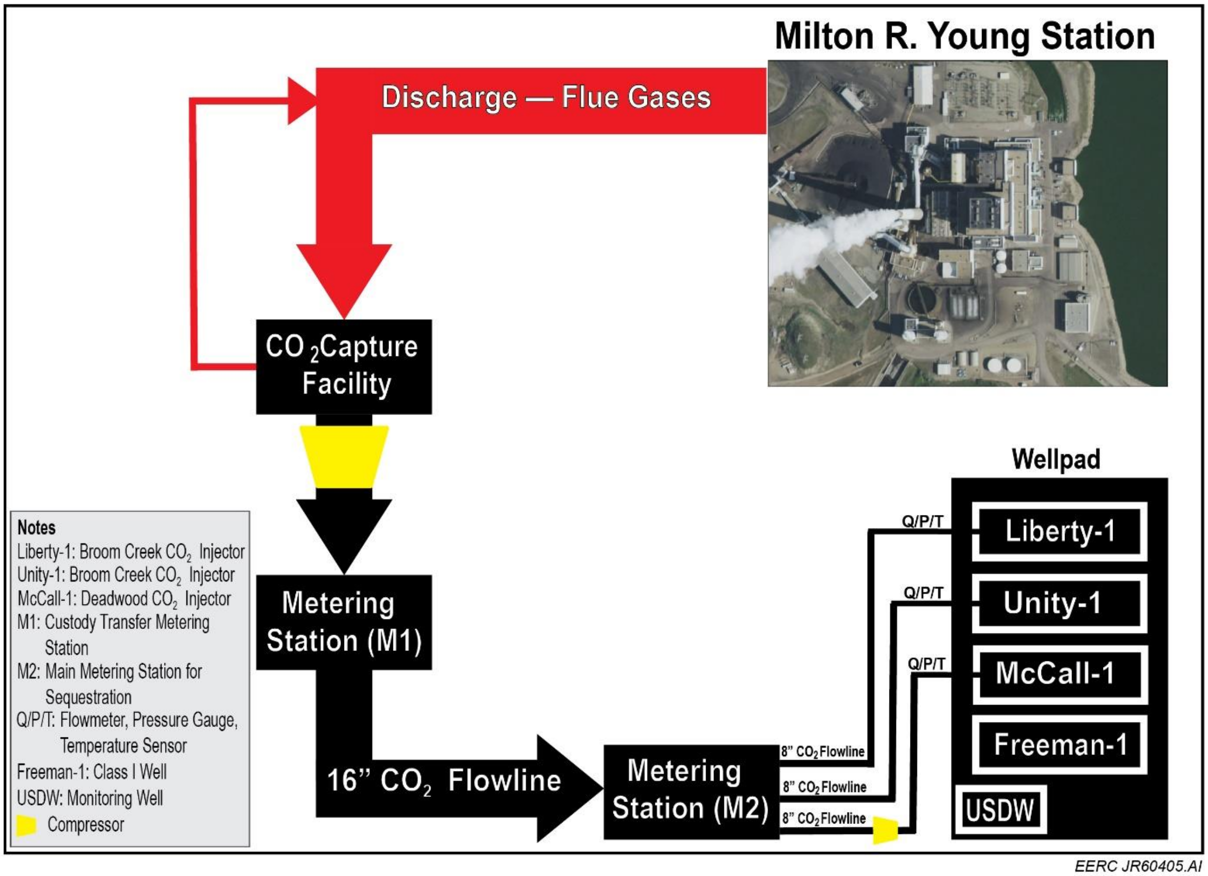

Figure 1-2. Flow diagram for Tundra SGS capture, transport, and storage facilities (USDW is underground source of drinking water).

Tundra SGS will receive captured and dehydrated CO_2 at the compressor outlet (M1), then it will be transported 0.25 miles via CO_2 flowline to the metering station (M2) for distribution to the injection wells for secure and permanent storage in the Broom Creek and Deadwood–Black Island geologic formations. These two storage formations as well as their confining seals have been extensively characterized by Minnkota through local and regional studies led by the Energy & Environmental Research Center (EERC). The focus of these studies includes North Dakota geology, results of three stratigraphic wells drilled on-site, special logs, coring, fluid sampling, seismic surveys, and an advanced numerical model, as described in A1:1 and A2:1, underground injection control (UIC) Permit XX and UIC Permit XX, respectively.

The project proposes a phased development approach, with Phase 1 construction and operation of two injector wells in the Broom Creek reservoir (approximately 5000 feet in depth), targeting 100% of the captured CO_2 volume. Following validation through operations in Phase 1, the owner and operator will assess the need to construct a third well. This additional well would be constructed in the Deadwood–Black Island reservoir (approximately 10,000 feet in depth) to store any excess CO_2 identified in Phase 1. The stacked storage concept and phased development approach allows the project to maximize the areal extent of the storage facilities, provides operational flexibility and redundancy, and generates further assurance to investors and stakeholders.

In addition to the three proposed injection wells, the injection pad, located within the MRYS fence line, will include one dedicated monitoring well for the lowest USDW as well as associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. Minnkota proposes one deep subsurface monitoring well installed on Minnkota property located approximately 2 miles northeast of the injection site.

This procedure is applicable to Tundra SGS storage facility operations consisting of the following infrastructure:

SFP Case Number: **29029, 29030, 29031**
UIC Class VI, ADP Form No. 28643[Unity-1]
UIC Class VI, ADP Form No. 30200[Liberty-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]
SFP Case Number: **Case No. 29032, 29033, 29034**
UIC Class VI, ADP Form No. 28977 [McCall-1]
UIC Class VI, ADP Form No. 29077 [NRDT-1]

The current mailing address for the Tundra SGS facility, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

1.2 Environmental Setting/Geology

The Williston Basin lies in the western half of North Dakota; this area has a long history of hydrocarbon exploration and utilization. This region has been identified as an excellent candidate for long-term CO_2 storage because of the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability. The proposed location of Tundra SGS is approximately 3.4 miles southwest of the town of Center on the eastern flank of the Williston Basin. This proposed facility location serves as a suitable site for an injection operation, as it is located outside of the primary oil-producing fields, with little to no well development that would interfere with storage operations and containment.

The target CO_2 storage reservoir for Tundra SGS Phase 1 is the Broom Creek Formation, a predominantly sandstone horizon lying 4740 feet below the MRYS facility (Figure 1-3). The lower Piper and Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") serve as the primary confining zone overlying the Broom Creek Formation. This confining interval

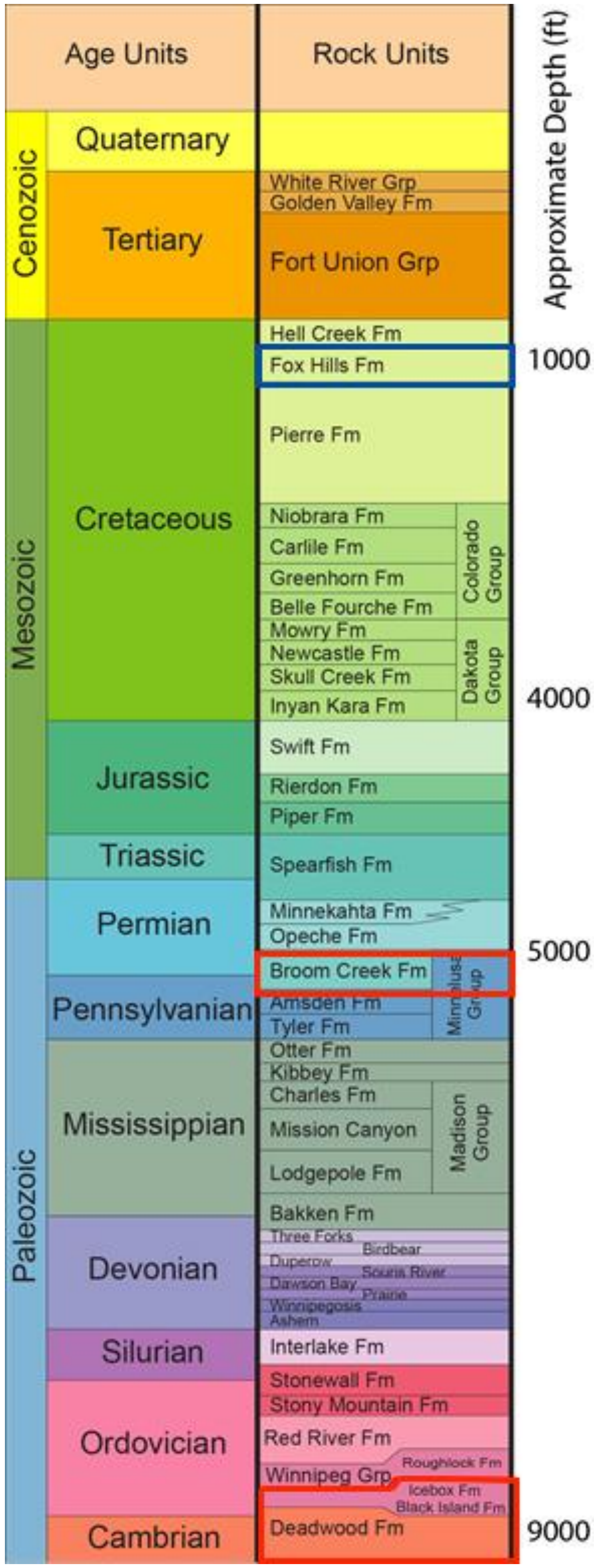

Figure 1-3. Stratigraphic column of North Dakota. Red boxes around the Broom Creek and Deadwood Formations delineate the targeted injection zones.
Comprises 56 feet of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche/Spearfish Formation overlain by 90 feet of mudstones and siltstones of the lower Piper Formation (Picard Member and lower). The Amsden Formation (dolostone, limestone, and anhydrite) underlies the Broom Creek Formation and serves as the lower confining zone. Together, the Opeche–Picard (upper confining), Broom Creek, and Amsden Formations (lower confining) make up the CO_2 storage complex for Tundra SGS Phase 1 operations.

The target CO_2 storage reservoirs for Tundra SGS Phase 2, if pursued, are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying approximately 9280 feet below MRYS (Figure 1-3). The shales of the Icebox Formation conformably overlie the Black Island and serve as the primary confining zone. The Icebox Formation provides a suitable confining layer, with an average thickness of 118 feet. The continuous shales of the Deadwood Formation B Member serve as the lower confining zone. One hundred and fifty-five feet below the lower injection horizon in the Deadwood Formation B is Precambrian metamorphosed granite. Together, the Icebox (upper confining), Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS. For additional details regarding the site characteristics, refer to A1:2 and A2:2).

1.3 Reservoir Model

1.3.1 Broom Creek (Phase 1)

Phase 1 includes two wells: Liberty-1 (originally drilled as J-ROC 1, a stratigraphic well to be converted to a Class VI injector) and Unity-1 (Figure 1-2). Numerical simulation of CO_2 injection in the sandstones of the Broom Creek Formation predicted the wellhead injection pressure (WHP) of both wells would not exceed 1700 psi during injection. Bottomhole pressures (BHPs) reached 3035.1 and 3018.3 psi for Liberty-1 and Unity-1 wells, respectively. For the Broom Creek CO_2 plume boundary delineation, the CO_2 plume boundary was modeled using operating assumptions of 20 years at a rate of an annual 4 MMt/year for the first 15 years and 3.5 MMt/year for Years 15 through 20. The reservoir simulation model indicated target injection rates were consistently achievable over 20 years of injection. A total of 77.5 MMt of CO_2 would be injected into the Broom Creek Formation with two wells at the end of 20 years. Injected volumes were 41.1 and 36.4 MMt for the Unity-1 and Liberty-1 wells, respectively. A maximum formation pressure increase of 488 psi is estimated in the near-wellbore area during the injection period (A1:A).

1.3.2 Deadwood (Phase 2)

The Deadwood–Black Island reservoir model simulation for Phase 2 includes the McCall-1 well, drilled on the same pad as the Broom Creek wells (Figure 1-2). This model was constrained by WHP and bottomhole fracture gradient without any injection rate constraint. Within the sandstones of the Black Island and Deadwood Formations, numerical simulation of CO_2 injection predicted that injection BHP will not exceed 6179 psi during injection operations, assuming a WHP limit of 2800 psi is maintained. Cumulative CO_2 injection at the above-described pressure conditions was 23.4 MMt over the 20 years of injection. The resulting average injection rate of CO_2 into the Black Island and Deadwood Formations was 1.17 MMt/year. Near the wellbore area, a maximum increase of 1620 psi was estimated within the Black Island and Deadwood Formations.

Through numerical simulation efforts, Long-term CO_2 migration potential was investigated in each of the Broom Creek and Deadwood models. The results did not indicate migration outside the storage facility area boundaries in either scenario. Storage facility area boundaries were established using a 20-year injection period, with the output boundary at Year 20 identified at a 5% CO_2 saturation rate and then rounded outward to the nearest 40-acre tract (A1:A).

2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

2.1 Active Monitoring Area

The active monitoring area (AMA) is defined 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" (40 Code of Federal Regulations [CFR] § 98.449). For purposes of this MRV, Minnkota proposes that the Broom Creek AOR, as delineated in Attachment 1, Section 3, serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (Figure 2-1). Based on review of the data and information of record and collected in support of A1 and A2, there are no known or suspected lateral leakage pathways within the area projected to contain free-phase CO_2 and the default one-half mile buffer zone.

2.1.1 Tundra SGS AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

Under North Dakota Century Code (NDCC) and North Dakota Administrative Code (NDAC) storage facility and Class VI requirements for an AOR, delineation was completed based on the Project Tundra SFP. 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" (NDAC § 43-05-01-01). The NDAC requires the operator develop an AOR and corrective action plan utilizing 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 (NDCC § 38-22-08). Minnkota elected to permit the storage facility area boundaries based on the 20-year reservoir model output discussed in Section 1.3 and then added an additional buffer rounding out to the nearest 40-acre tract.

The Broom Creek proposed AOR was delineated using a risk-based AOR approach (A1:3.1). The risk-based delineation examines the area encompassing the region overlying the injected free-phase CO_2 and region overlying the extent of increased formation fluid pressure sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or conductive fractures) are present. The risk-based approach established that the CO_2 plume boundary is also the extent of the AOR boundary (A1:3.1). However, in compliance with the NDAC evaluation and monitoring requirements, Minnkota extended the permitted AOR boundary beyond the risk-based delineation to encompass the storage facility boundary plus an additional 1-mile buffer (A1:3.1). Utilizing the 20-year operating output, plus a 1-mile buffer for monitoring from the outset of operations, provides a significant assurance that operations can be conducted safely and as contemplated within the permitted storage facility.

The proposed AOR for the Deadwood–Black Island storage facility used EPA Method 1 to establish the AOR (A2:3.1). The Deadwood–Black Island reservoir model simulation discussed in Section 1.1 yielded an annual average injection rate of approximately 1.17 MMt/year for 20 years. Applying EPA Method 1, the Deadwood–Black Island AOR has a larger areal extent, due to the estimated pressure front under EPA Method 1, than the Broom Creek AOR, which applied the risk-based AOR approach; however, the free-phase CO_2 plume for Deadwood is contained in the delineated AOR for Broom Creek. Because of the significant overlap between the two AORs and the phased development approach, the Tundra SGS technical evaluation and proposed monitoring plan were developed to account for monitoring both injection horizons in accordance with the requirements and to the maximum areal extent simulated.

2.1.2 Tundra SGS AOR Encompasses Subpart RR AMA of both Broom Creek and Deadwood

AMA minimum delineation requirements are found in 40 CFR § 98.449 and used in Figure 2-1. Using a period of t=20 years, the Broom Creek delineated AMA boundary and the Deadwood–Black Island AMA boundary fall within the Broom Creek AOR. Minnkota proposes that the Broom Creek AOR serve as the AMA for both the Broom Creek and the Deadwood–Black Island storage facilities (AOR outlined in black in Figure 2-1), delineation of the AOR is discussed further in A1:3 and A2:3. Aligning the calculated AMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and postinjection periods and avoids unnecessary duplication and complication in reporting.

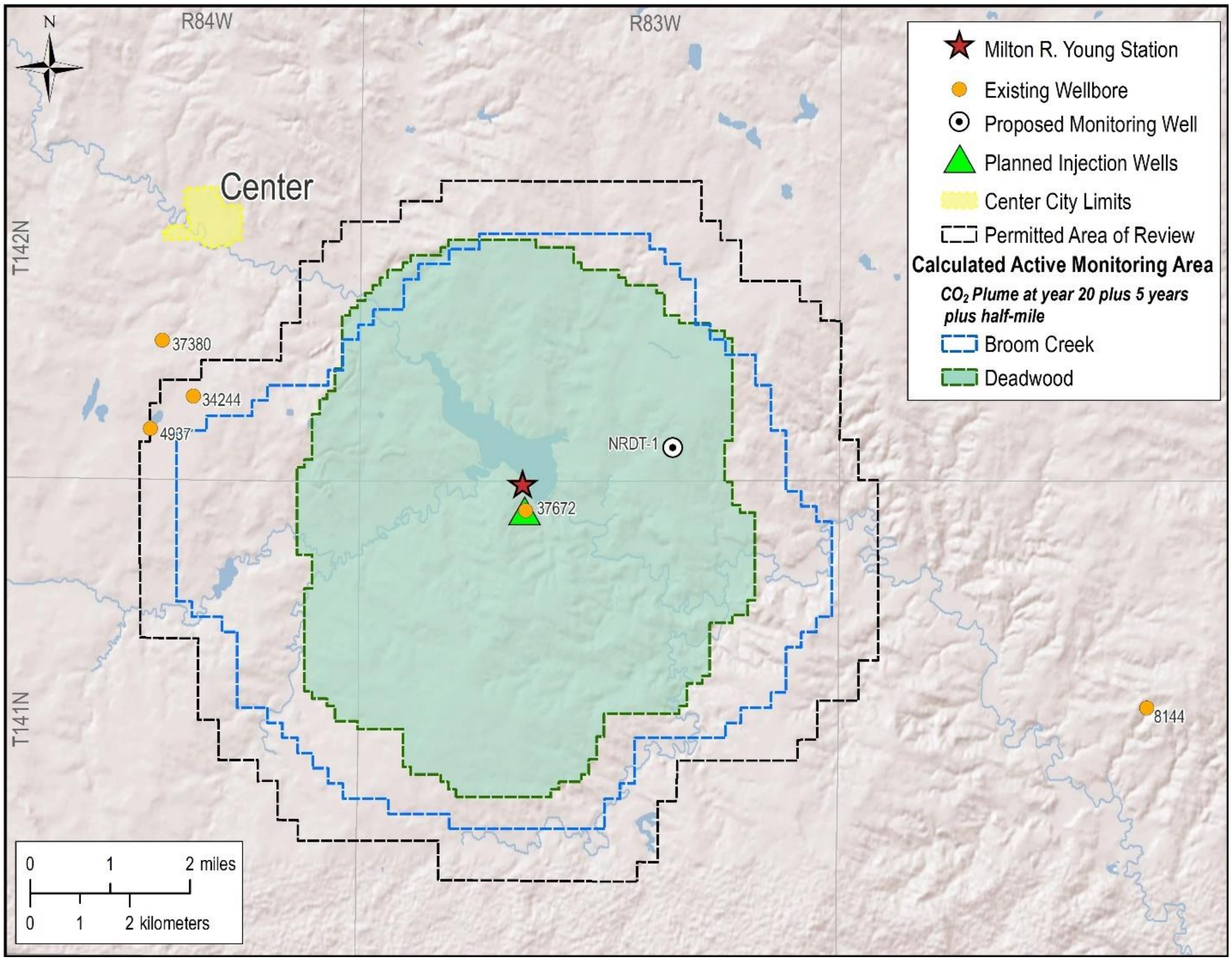

Figure 2-1. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated AMA in comparison to the permitted AOR. AOR subsumes the calculated AMA for both formations and exceeds requirements for AMA; therefore, the AOR serves as the AMA for Project Tundra.

2.2 Maximum Monitoring Area

The maximum monitoring area (MMA) as defined in 40 CFR § 98.440–449 (Subpart RR) is the area defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The calculated MMA delineated in Figure 2-2 for the Broom Creek and Deadwood–Black Island storage facilities uses a period of t=20 years and represents the period t+10 and a half-mile buffer extending beyond that boundary. The permitted AOR for Broom Creek, as delineated in A1 and A2, exceeds the minimum areal extent required by the Subpart RR approach for delineating the MMA (Figure 2-2); therefore, Minnkota proposes that the Broom Creek AOR serve as the calculated MMA for both the Broom Creek and the Deadwood–Black Island storage facilities.

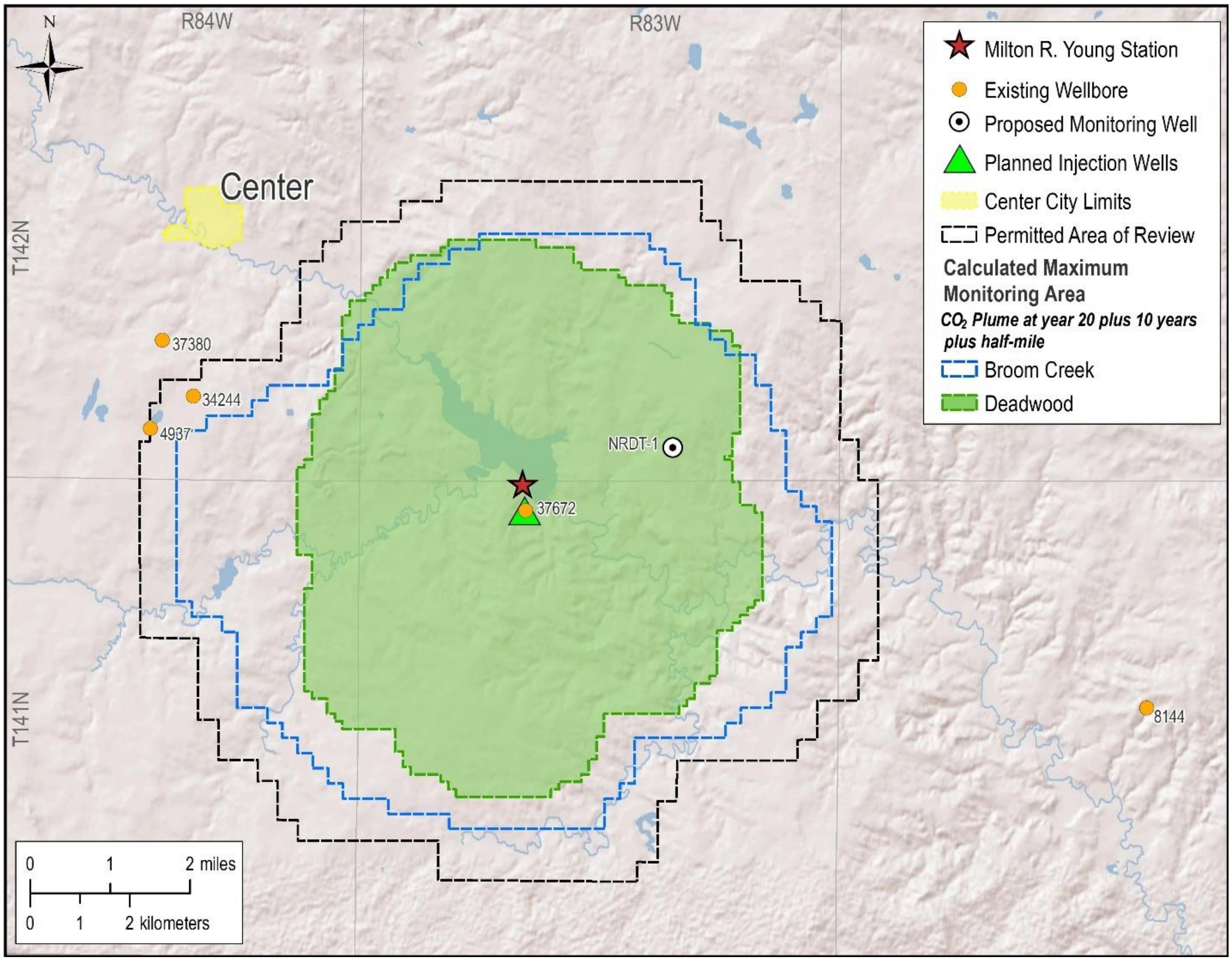

Figure 2-2. Map showing the location of Tundra SGS, NRDT-1, offset wells (orange dots), and the calculated MMA in comparison to the permitted AoR. AOR subsumes the MMA for both formations and exceeds requirements for the MMA; therefore, the AOR serves as both the AMA and MMA for Project Tundra.

Aligning the calculated AMA and MMA under the more expansive Broom Creek AOR allows for consistent monitoring and recording throughout the proposed injection and postinjection periods and avoids unnecessary duplication and complication in reporting.

2.3 Monitoring Time Frames

The monitoring program for the geologic storage of CO_2, as described in A1:4.1 and A2:4.1, 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. The time frame of these monitoring periods will encompass the entire life cycle of the injection. For purposes of this 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 and frequency of the measurements performed vary. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

Preoperational baseline monitoring establishes the pre-CO_2 injection conditions of the storage system and inherent 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 amount of CO_2 that is contained in the formation at any given time. This information will be incorporated into the final Class VI permit. If results from this preoperational monitoring period necessitate changes to this MRV plan, an amendment will be submitted prior to the start of operations.

The operational injection period is focused on validating and updating numerical models of the storage system and ensuring that the geologic storage project is operating safely and is protecting USDWs. Lastly, the purpose of 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 three monitoring periods is a minimum of 1 year, 20 years, and a minimum of 10 years, respectively.

3.0 EVALUATION OF POTENTIAL PATHWAYS AND MECHANISMS FOR LEAKAGE TO THE SURFACE

An evaluation of potential pathways for CO_2 leakage to the surface during the implementation of the project was completed by representatives of Minnkota as well as third-party subject matter experts from Oxy Low Carbon Ventures and the EERC. During these meetings, potential leakage pathways were identified and evaluated for the following:

- Existing wellbores
- Faults and fractures
- Natural or induced seismicity
- Flowline and surface equipment
- Lateral migration of CO_2 beyond the AOR
- Vertical migration: injector and monitoring wells
- Vertical migration: diffuse leakage through seal

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 A1:4.1 and 2:4.1, and summarized in Table 5-2, forms the basis for this MRV plan.

3.1 Existing and Planned Wellbores

Five existing wellbores and one potential wellbore were evaluated as potential leakage pathways. There are no other known wellbores that could impact the project because there is no active or prior production of oil and gas in the vicinity of the Tundra SGS project. Table 3-1 summarizes the existing wellbore names and status and future actions. Additional explanation is provided after the table.

Table 3-1. Wellbore Summary

	Well Name	Current Status	Future Status
a	J-ROC1 [NDIC[1] No. 37672]	Openhole plugged (surface casing installed)	Reenter and construct Class VI injection well
b	J-LOC1 [NDIC No. 37380]	Temporarily abandoned (cased hole)	TBD[2]
c	BNI-1 [NDIC No. 34244]	Openhole plugged	NA[3]
d	Herbert Dresser 1-34 [NDIC No. 4937]	Openhole plugged	NA
e	Little Boot 15-44 [NDIC No. 8144]	Openhole plugged	NA
f	Future Wells (Freeman-1)	NA	Class I injection well

[1] North Dakota Industrial Commission.
[2] To be determined.
[3] Not applicable.

3.1.1 J-ROC1 [NDIC No. 37672]

The J-ROC1 well was drilled by Minnkota and the EERC in 2020 as part of the CarbonSAFE North Dakota project, Phase III. An entire geologic column from surface to the Precambrian was drilled and core collected, and fluid samples as well as special logs were obtained. The well is currently in a plugged and abandoned status openhole in the injection section, which will be reentered and converted to a CO_2 injector well. Once the well conversion takes place, J-ROC1 will be renamed Liberty-1, on authorization of pending reentry drilling permit. This well will be monitored in real time during injection to detect any potential mechanical integrity issues associated with potential leakage, and once the injection period ceases, the well will be properly plugged and abandoned.

3.1.2 J-LOC1 [NDIC No. 37380]

The J-LOC1 well was drilled by Minnkota in 2020 as a stratigraphic well. The construction materials used were compatible with Class VI and CO_2 operating standards. The well was drilled through the entire geologic column from surface to the Precambrian. The drilling program included collecting core, obtaining fluid samples and special logs, and injectivity testing in the Broom Creek and Deadwood Formations. The well is currently in a temporarily abandoned status, plugged for future use. In case the well has no future potential use, it will be permanently abandoned to ensure integrity. This well is located slightly outside the delineated AOR for the Broom Creek, but it is included in the pressure front delineated for Deadwood–Black Island Formation storage.

3.1.3 BNI-1 [NDIC No. 34244]

The BNI-1 well was drilled in 2018 as a stratigraphic well by the EERC under North Dakota CarbonSAFE Phase II. The well was drilled through the Broom Creek Formation and reached total depth in the Amsden Formation. The well was plugged and abandoned in 2018 in accordance with approved guidance and regulations of the state.

3.1.4 Herbert Dresser 1-34 [NDIC No. 4937]

The Herbert Dresser 1-34 well was drilled and plugged in 1970 after being classified as a dry hole. The well was replugged in 2001 by BNI. It was drilled through the Broom Creek Formation and reached total depth at the Charles Formation. Several cement plugs isolate any potential movement of fluids between the different flow units and USDW aquifers.

3.1.5 Little Boot 15-44 [NDIC No. 8144]

The Little Boot 15-44 well was drilled and abandoned as a dry hole in 1981. The well was drilled through the Broom Creek and reached the Black Island Formation. It was properly plugged and abandoned with cement plugs isolating the different flowing units before the Fox Hill Aquifer. This well is outside the delineated AOR for the Broom Creek Formation but is included in the pressure front delineated for the Deadwood–Black Island Formation.

3.1.6 Future Wells

Minnkota is planning to drill Freeman-1, a Class I well, on the same well pad of the injection site to dispose of the residual water from the capture process. The Inyan Kara is the proposed geologic formation for disposal and is stratigraphically located approximately 1000 feet above the Broom Creek Formation. The water disposal zone is separated from the Phase 1 Broom Creek target by a series of impermeable rocks. Since the Class I well will not penetrate the primary or secondary confining seals of the Broom Creek storage facility, the risk of leakage is very unlikely.

There is no active or prior production of oil and gas in the vicinity of the Tundra SGS area. This fact, combined with the understanding that potential leakage pathways of injected CO_2 through existing wellbores are very unlikely, makes the Tundra SGS site an ideal location for the geologic storage of CO_2.

3.2 Faults and Fractures

No known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified in the Tundra SGS area through site-specific characterization activities, prior studies, or previous oil and gas exploration activities.

A 5-mile-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 miles of 2D seismic lines were acquired in 2020 (Figure 3-1). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement (A1:2.5 and A2:2.5). No structural features, faults, or discontinuities that would cause concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data.

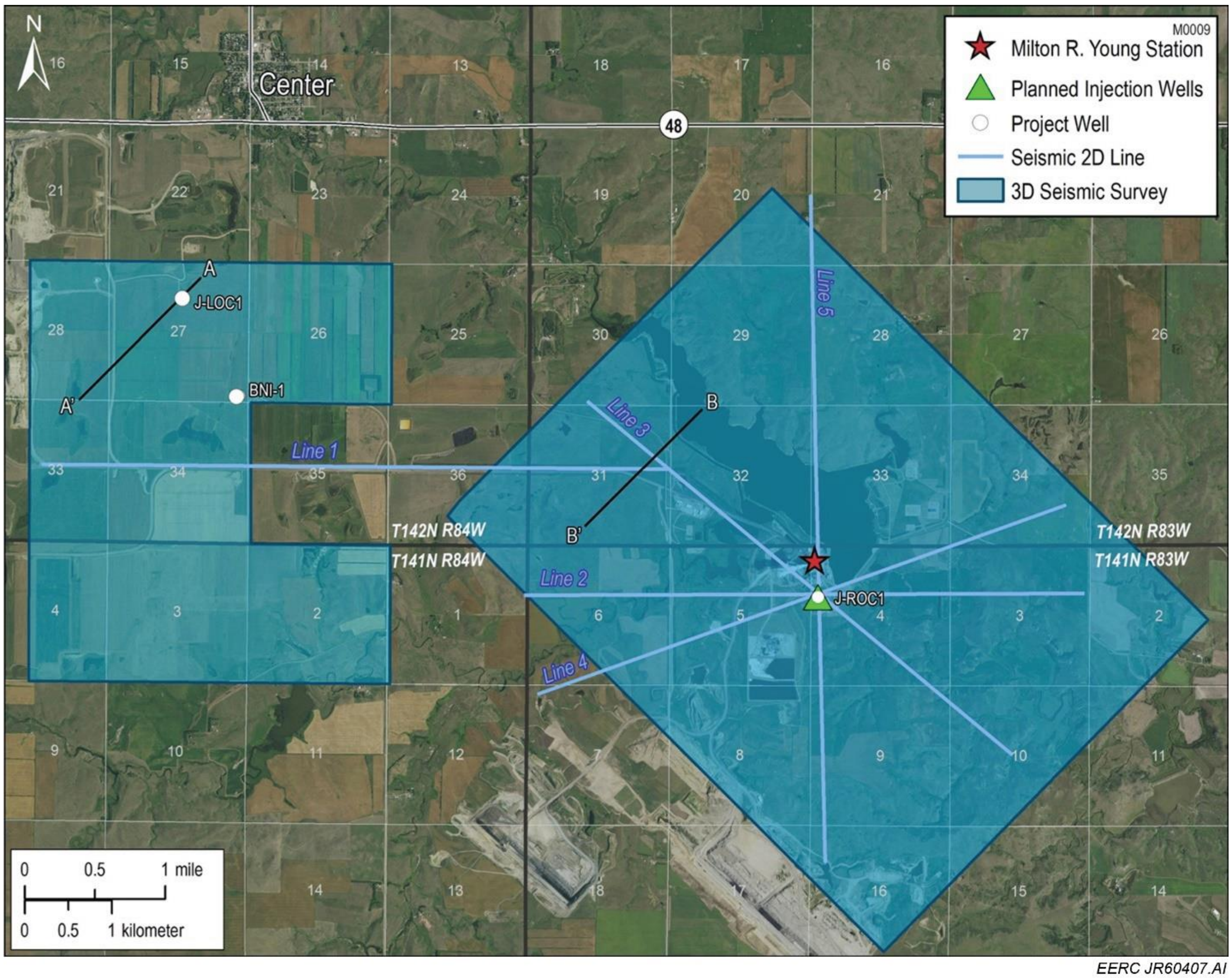

Figure 3-1. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

Leakage through faults and fractures was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the emergency remedial and response plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed, and volumetric accounting would follow industry standards as applicable.

3.3 Natural or Induced Seismicity

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 3-2) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 3-2). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 miles from the J-ROC1 well in Huff, North Dakota (Table 3-2). This seismic event is estimated to have been a 4.4 magnitude from the reported modified Mercalli intensity (MMI) value. The results in Table 3-2 indicate stable geologic conditions in the region surrounding the potential injection site.

Table 3-2. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mile	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mile
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported MMI value.

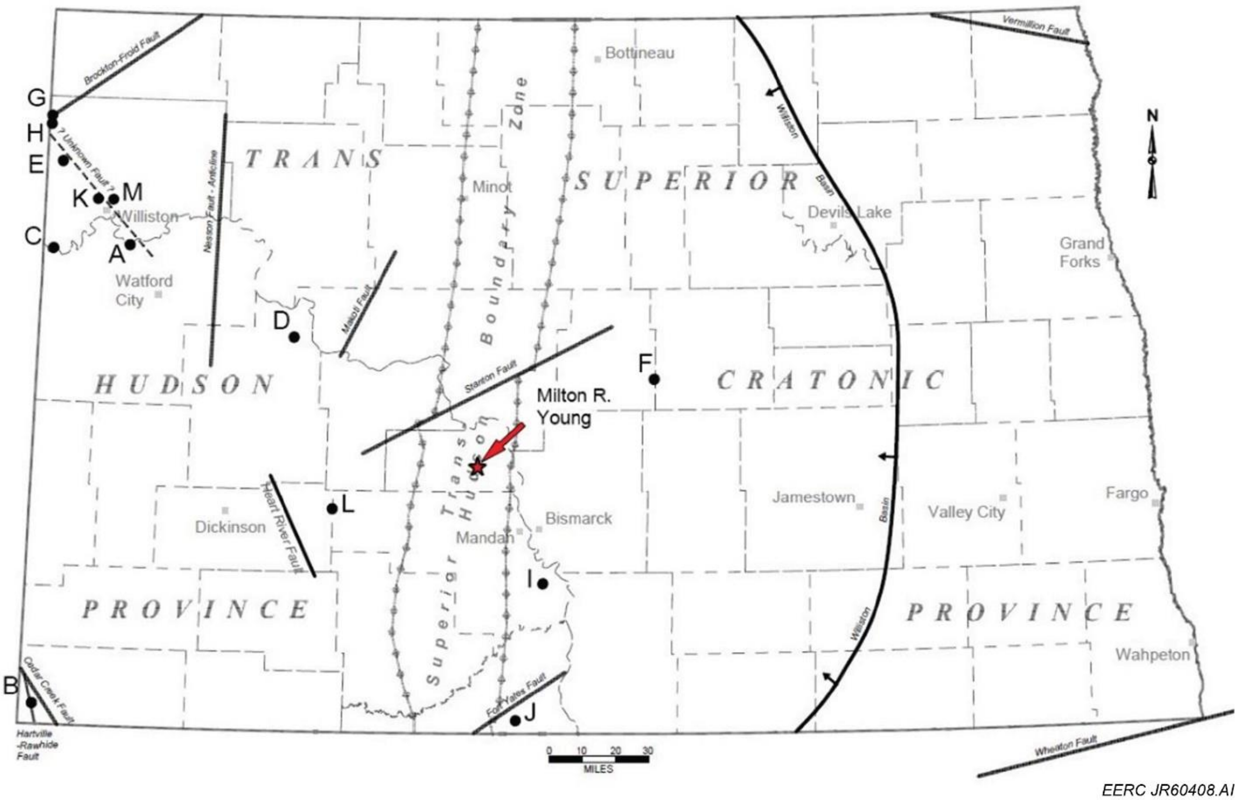

Figure 3-2. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016).

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment. 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 time period (Figure 3-3) (U.S. Geological Survey, 2019).

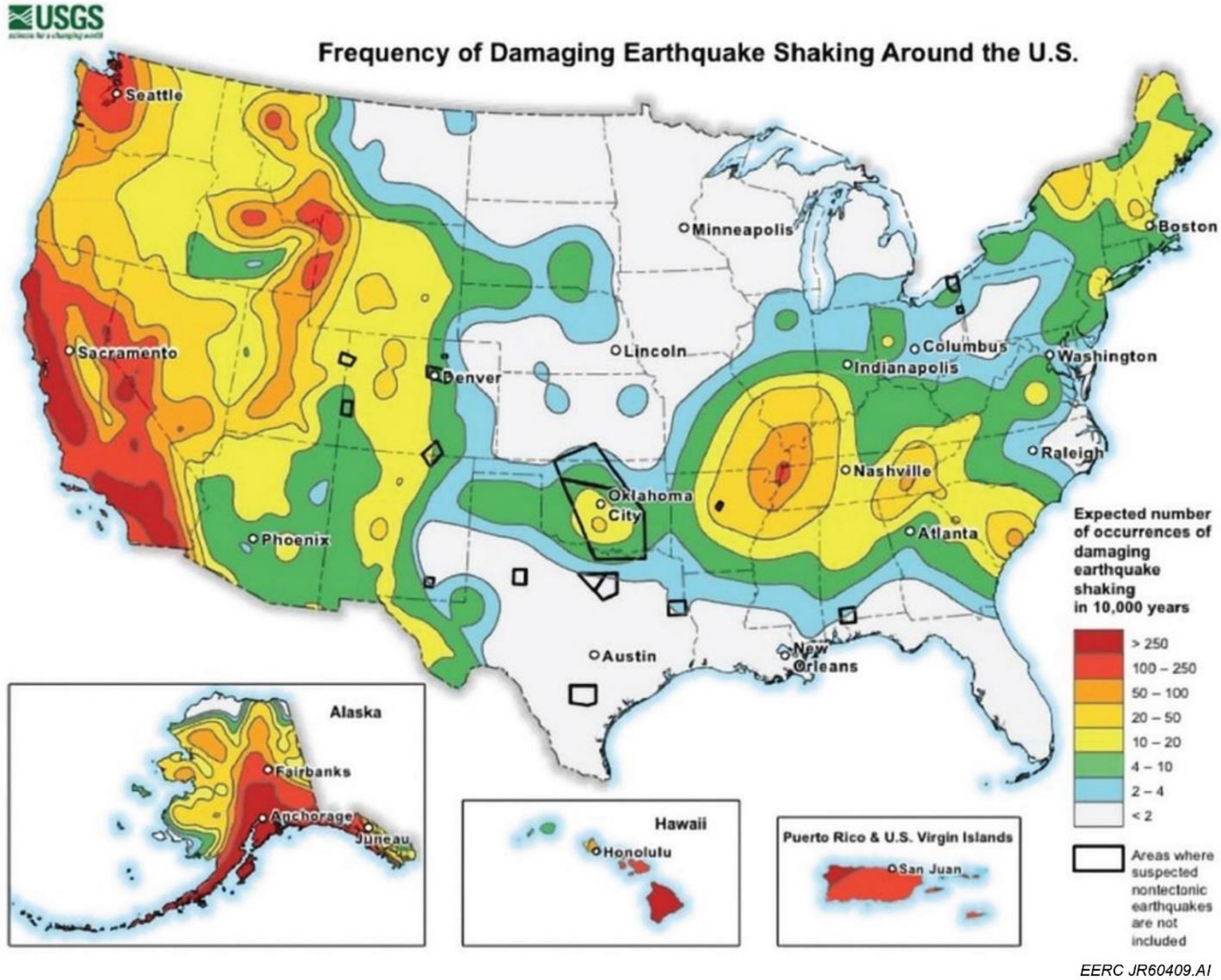

Figure 3-3. Probabilistic map showing how often scientists expect damaging seismic events to occur throughout the United States (U.S. Geological Survey, 2019). The map shows a low probability of damaging seismic events (less than two events per 10,000 years) occurring in North Dakota.

To understand potential induced seismicity, a geomechanics detailed study described in A1:2.5 and A2:2.5, was carried out to understand the highest possible risk scenario. A scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data suggest that it does not. The failure analysis indicated that a pressure increase of 3600–4800 psi would be required to induce shear failure.

The maximum expected pressure changes in the Deadwood Formation due to planned injection activities do not exceed 1800 psi, which is well below the 3600–4800-psi pressure threshold for failure (Figure 3-4). Additionally, the injection interval is approximately 120 feet above the Precambrian–Deadwood boundary, and expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results, as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data, suggests planned injection activities will not cause induced seismicity. Furthermore, no faults interpreted in the AOR would affect the Broom Creek Formation; therefore, the probability of induced seismicity is minimized.

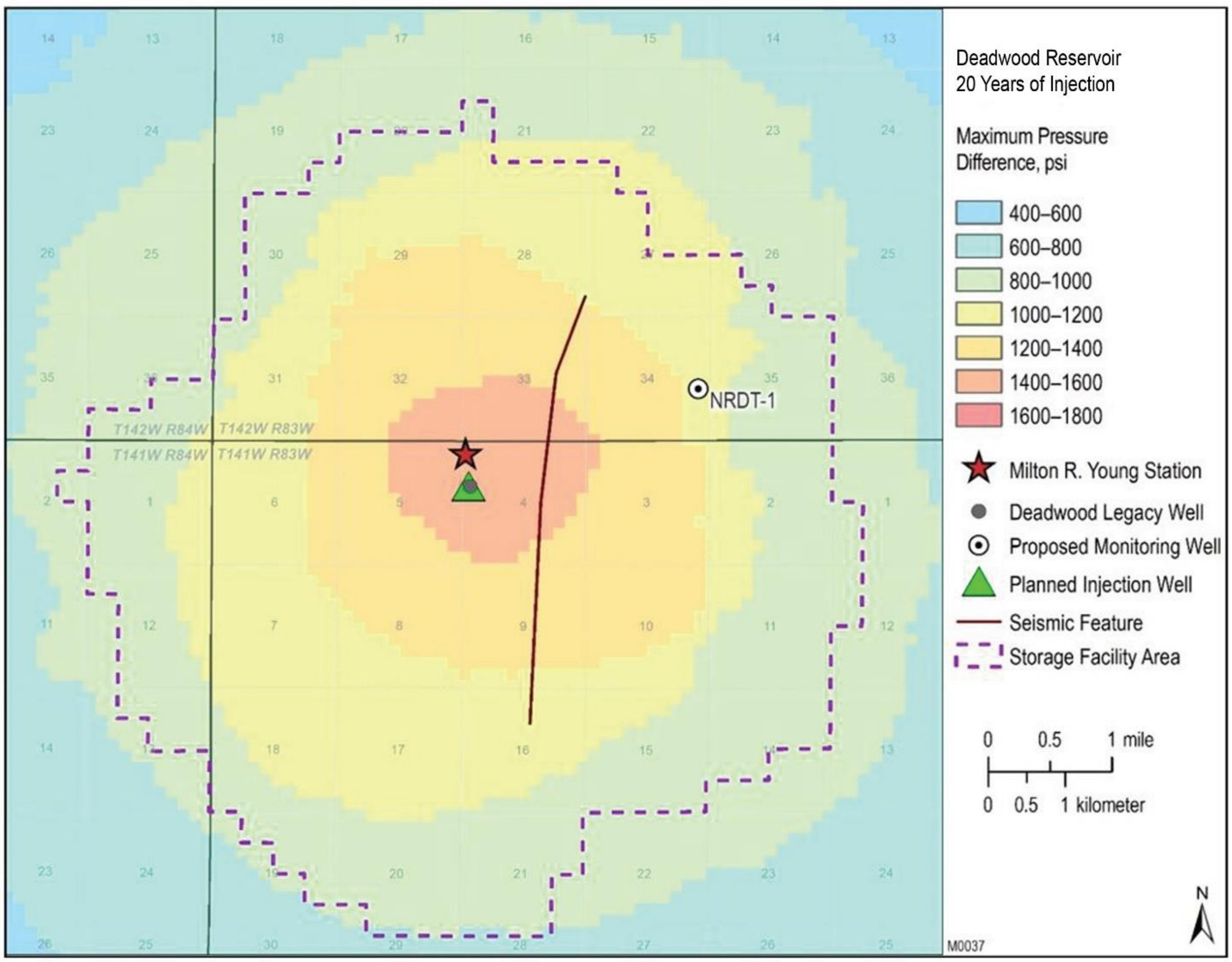

Figure 3-4. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

Leakage through natural or induced seismicity was shown to be very unlikely to nearly impossible through the risk assessment. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:E and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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.

3.4 Flowline and Surface Equipment

Surface equipment is the likeliest leakage pathway on the Tundra SGS site during the injection period. Surface equipment is 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 Tundra SGS system includes a 16-inch surface flowline buried 4 feet to transport CO_2 from the capture facility to the sequestration site (0.25 miles). The flowline will be connected to the metering station (M2), which is located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics will be 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.

Each well will be connected independently to the metering station (M2) by 8-inch flowlines equipped with a dedicated flowmeter and pressure and temperature transducers to monitor well performance. Shutoff devices will be installed in the well flowlines 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 Tundra SGS mechanical integrity and monitoring program strives to proactively identify potential surface leak events to ensure the integrity of the facility and minimize the amount of CO_2 released to the ambient air. Maintenance on surface equipment after the delivery point (M2) may require venting cumulated CO_2 volumes before isolating a section of the system; this amount would be quantified and reported.

The risk of leakage in surface equipment is mitigated through:

i. Adhering to regulatory requirements for construction and operation of the site.
ii. Implementing highest standards on material selection and construction processes for the flowline and wells.
iii. The implementation of best practices and a robust mechanical integrity program as well as operating procedures.
iv. Continuous monitoring through an automated system and integrated databases.

As a result, the risk of leakage through surface equipment (under normal operating conditions) is unlikely and the magnitude will vary according to the failure observed. A 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 represent several tons of CO_2 until the shutoff device stops the injection automatically or the operator ceases the CO_2 supply.

The second risk identified was potential leakage at surface equipment through catastrophic damage to surface facilities because of an object striking the equipment or a natural event that causes disconnection and loss of containment during the injection period at or before the wellhead. To account for such a hypothetical event, the project performed a leak model simulating a worst-case blowout scenario and a dispersion model to evaluate risks and potential mass of CO_2 released. This leakage scenario could represent thousands of tons of CO_2 released during the pendency of the response period before the well is controlled and integrity is reestablished. Even though this event is considered high-impact, occurrence is very unlikely since most of the flowline will be buried; the wellhead, valves, and instrumentation will be protected by barriers; and a fence with the equipment is located on private MRYS property. Further, containment of any leak is enhanced by the well pad design, including a 4-foot berm and double liner to avoid any brine spill to surface water bodies.

The risk of leakage through surface equipment or major damage is present during the injection phase of the project and 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 and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, NRDT-1, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

3.5 Lateral Migration of CO_2 Beyond the AOR

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), which confines the CO_2 within the storage facility area. Numerical simulations of CO_2 injection predict slow lateral migration of the plume throughout the injection and postinjection period (A1:A and A2:A). This is the result of the trapping mechanisms combined with the effects of buoyancy and the low dipping structurally characteristic of the storage complexes. 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 Deadwood Formations and then outward. The free-phase CO_2 plume migrates outward, favoring relatively high permeabilities and low pressure bounded vertically by the low-permeability cap rock. This process results in a higher concentration of CO_2 at the center, which gradually spreads to the edge of the plume at Year t, where the CO_2 saturation is lower.

As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized.

Early monitoring and operational data will be used to evaluate conformance of the operating storage system with the requirements of the SFP using both observations and history-matched simulation of CO_2 and pressure distribution. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate the current and predicted future lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tundra SGS will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure front for comparison to the information provided in the storage reservoir permit. If the data predict additional lateral movement of the plume, Tundra SGS will negotiate the additional pore space and revise the monitoring area to appropriately establish equivalent monitoring protocols implemented in the original AMA. 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 risk assessment identifies lateral migration and impact for surface leakage as events with very low likelihood.

3.6 Vertical Migration: Injection and Monitoring Wells

Design and construction of the Class VI injector wells (Liberty-1, Unity-1, and McCall-1) as well as the in-zone monitoring well, NRDT-1, will follow the standards required for UIC Class VI wells to minimize any potential leak due to loss of integrity in the wellbores. Material selection complies with CO_2 operating standards, and the wells will be instrumented for continuous, real-time monitoring of well integrity. Well instrumentation will be integrated with an automated data management system to provide alerts and activate the shutoff device if the threshold for controlling parameters is exceeded. Additionally, the wells will follow a rigorous corrosion and mechanical integrity program, describe in A1:4.1 and A2:4.1, to ensure proper maintenance of the facilities and timely response in case substandard conditions are detected.

Once the injection period ceases, the injector wells will be evaluated for mechanical condition with corrosion and casing inspection logs and will be properly abandoned with CO_2-resistant cement according to the detailed plugging procedure proposed in A1:4.6 and A2:4.6. The NRDT-1 monitoring well will continue to be operational until plume stabilization and the issuance of a certificate of site closure, then the same rigorous plug-and-abandonment protocol will be followed as proposed for the injector wells.

Based on the design and monitoring program proposed, the project defined the risk of leak through these pathways as unlikely. The amount and timing, if it were to occur, will be minimum since the program is designed to shut off injection or alert the operator to manually shut off injection until the alarm is clear or remediation is complete. The timing of the leak will be estimated based on the collected data from the monitoring tools until the event is cleared or remediation is completed.

3.7 Vertical Migration: Diffuse Leakage Through Seal

The initial mechanism for geologic confinement of the stored CO_2 in the Broom Creek and Deadwood–Black Island Formations will be containment of the initially buoyant CO_2 by the cap rock (Opeche–Picard, Icebox), under the effects of relative permeability and capillary pressure. Figure 3-5 shows a stratigraphic column with the well schematic for injector and monitoring wells and highlights the additional secondary seals and buffer formation.

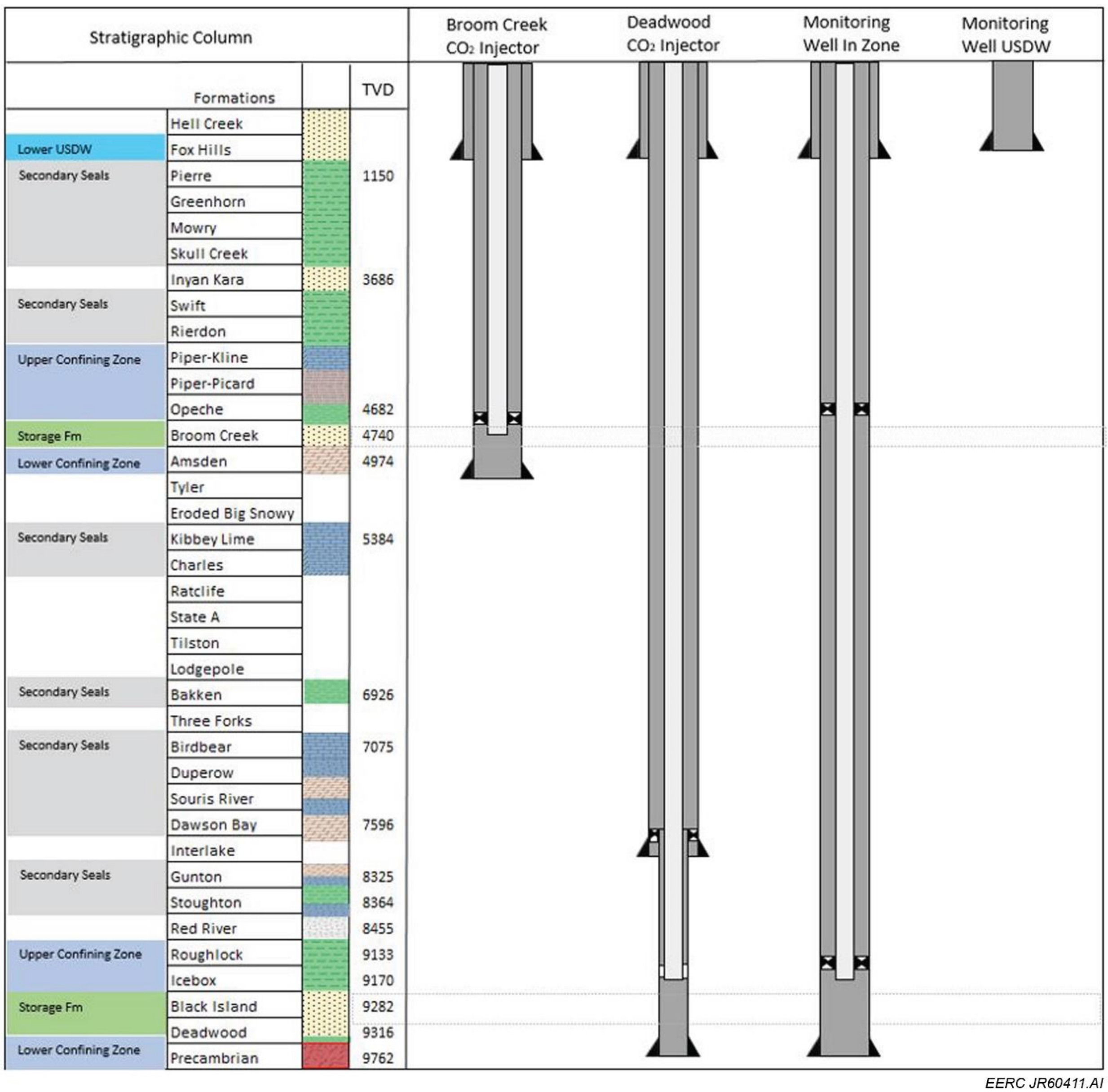

Figure 3-5. Stratigraphic column and well schematic for injector and monitoring wells.

The Picard Member of the Piper Formation within the study area consists of siltstone, while the Opeche/Spearfish Formation consists of tight, silty mudstone. Both intervals are free of transmissive faults and fractures. When considered as a single interval, the Opeche–Picard and other formations create an impermeable, laterally extensive cap rock to the Broom Creek Formation capable of containing injected CO_2. The Opeche–Picard interval is 4636 feet below the land surface at the storage site and 154 feet thick at the Tundra SGS site.

In addition to the Opeche–Picard interval, which serves as the cap rock for the Broom Creek Formation, 820 feet of impermeable rock formations separate the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. Surrounding the storage facility area, an average of 2545 feet of impermeable intervals separates the Inyan Kara Formation and the lowest USDW, the Fox Hills Formation.

Within the Tundra SGS area, the Icebox Formation serves as the upper confining zone of the Black Island and Deadwood Formations. The Icebox Formation consists mostly of impermeable shale, is 9308 feet below the land surface, and reaches a thickness of 118 feet within the storage facility area. The cap rock has sufficient areal extent and integrity and is free of transmissive faults and fractures to contain injected CO_2.

Impermeable rocks above the primary cap rock include the Roughlock Formation and Red River D Member, which make up the first significant group of secondary confining formations. Together with the Icebox Formation, these formations reach a thickness of 612 feet separating the next overlying permeable zone: the Red River A, B, and C Members. Above the Red River Formation, more than 1000 feet of impermeable rock acts as an additional seal between the Red River and Broom Creek Formations. No known transmissible faults are within these confining systems in the project area.

As previously noted, at the same time, 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). As the free-phase CO_2 plume spreads out within the reservoir, the potential energy of the buoyant CO_2 is gradually lost after Year t+10. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. Over a much longer period (>100 years), mineralization of the injected CO_2 will ensure its long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation; therefore, adsorption is not considered to be a viable trapping mechanism in this project (A1:A and A2:A).

The upper and lower confining zones for the proposed storage formations were largely characterized through core sampling and lab analysis as well as imaging and sonic tools to define the sealing capacity. The great thickness of impermeable rock above each of the storage formations provides a best-in-class secondary seal if the main confining zone were to fail, thereby further reducing the risk of diffusion through the leak to almost zero.

Leakage through vertical migration was shown to be very unlikely to nearly impossible in the risk assessment carried out. In an unlikely scenario of leakage through any pathway, response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses of CO_2 would require consideration of the 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 on the presenting facts and circumstances, modeling to estimate the CO_2 loss would be performed and volumetric accounting would follow industry standards as applicable.

The risk assessment defined this risk as an unlikely event. Response and remediation would be performed in accordance with the Emergency Remedial and Response Plan (A1:4.2, A1:E, A2:4.2, and A2:E). Estimating volumetric losses would require consideration of the 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 on the presenting facts and circumstances, modeling geophysical measurement 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 SURFACE LEAKAGE OF CO_2

Tundra SGS 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 direct and indirect monitoring of the CO_2 plume, a corrosion and mechanical integrity protocol, and monitoring of near-surface conditions as well as induced seismicity and continuous, real-time surveillance of injection performance. Tundra SGS also proposes a detailed emergency remedial and response plan that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk.

Figure 4-1 summarizes the monitoring techniques proposed based on the leakage pathway analyzed for this MRV to provide a vision for the surveillance and management of the site.

These methodologies target early detection of the 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 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 provides a full picture of the monitoring frequency in different periods of the project life, and Table 4-2 summarizes for each technique the leakage path that it is targeting to detect. For additional details regarding strategy for detecting and quantifying surface leakage of CO_2, refer to A1:4.1, E, F and A2:4.1, E, F.

Integrated Remote Automated System and Surveillance Protocol

Surface Monitoring Through:

- Routine visual inspections conducted by field personnel.
- Facilities inspection with handheld and OGI cameras.
- Automated CO_2 sensors in the wellhead.
- RT injection performance on surface and downhole (pressure, temperature, flow).
- DTS technology.
- DTS and DAS for CO_2 flowline monitoring.
- Mechanical integrity program.
- Corrosion monitoring program.
- Annular pressure test on injectors and monitoring wells.

Reservoir Monitoring Through:

- Monitoring wells in reservoir.
- Pressure and temperature gauges downhole in injector.
- 3D/2D time-lapse seismic surveys.
- Interferometric synthetic aperture radar (InSAR).
- History-match reservoir simulation.
- Saturation log in reservoir.
- Real-time temperature profile (DTS) on injectors.
- Seismometer network (induced events).

Operational and Near-Surface Monitoring Through:

- Soil gas analysis.
- CO_2 stream analysis.
- Water-sampling USDW (baseline and during operation).

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Figure 4-1. Tundra SGS monitoring strategy.

Table 4-1. Summary of Tundra SGS Monitoring Strategy

Method	Preinjection (baseline 1 year)	Injection Period (20 years)	Postinjection (10 years)
CO_2 Stream Analysis – Gas Composition	Preinjection	Quarterly	NA
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flowline	NA[1]	Real time	NA
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells	NA	Real time	Quarterly
Flowmeters (mass/volume) – Injection Wells and Flowline	NA	Real time	NA
Visual Inspections	Start-up	Weekly	Quarterly
Automated Remote System (SCADA)[2]	Start-up	Real time	NA
OGI[3] Cameras	Start-up	Quarterly	If required
NDIA4 CO_2 Leak Sensors in Wellhead – Injectors	NA	Real time	NA
NDIR CO_2 Leak Sensors in Wellhead – Monitors	NA	Real time	Real time
Handheld CO_2 Monitor	NA	Weekly	Quarterly
Soil Gas Analysis	3–4 seasonal samples per year	Three to four seasonal samples per year	Three to four seasonal samples every 3 years
Water Sampling USDW	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Water Sampling Surface Water	Three to four sample events per selected wells (baseline)	One sample in each selected well at the following frequency: • Year 1 to 3: once a year • At Year 5 • Every 5 years after that	• Three to four sample events at cessation of injection • Three to four sample events before site closure
Cement Bond Logs	After cementing	If needed	Prior to P&A[5]

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Continued . . .

Table 4-1 Summary of Tundra SGS Monitoring Strategy (continued)

Casing Inspection Tool (EM[6]/sonic) – Injection Wells	Baseline	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workover	Prior P&A
Casing Inspection Tool (EM/sonic) – Monitoring Wells	Baseline	Every 5 years	Prior to P&A
Temperature Log – Monitoring Wells	Baseline	Annually	Annually
Annular Pressure Test – Injection Wells	Prior injection	• Every 5 years for Broom Creek • Annually for Deadwood─Black Island • During workovers	Prior to P&A
Annular Pressure Test – Monitoring Wells	During completion	• Every 5 years • During workovers	• Every 5 years • During workovers • Prior to P&A
Corrosion Coupons	NA	Quarterly	NA
DTS/DAS Fiber – Installed on the Casing – Injection Wells	NA	Real time	NA
DTS/DAS Fiber – Main Flowline	NA	Real time	NA
DH[7] Pressure Gauges and Temperature Sensors – Injection Wells	NA	Real time	NA
DH Pressure Gauges and Temperature Sensors – Monitoring Wells	NA	Real time	Bimonthly
RST[8] Log (pulse neutron) – Monitoring Wells	Baseline	Every 5 years	Every 5 years
RST Log (pulse neutron) – Injection Wells	Baseline	As needed	NA
Pressure Falloff Test – Injection Wells	Prior injection	Every 5 years	Prior to P&A
2D/3D Time-Lapsed Surface Seismic	Baseline	Every 5 years	Every 5 years
Interferometric Synthetic Aperture Radar	Baseline	Continuous monitoring	Continuous monitoring
Surface Seismometers	Baseline	Real time	NA

[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Optical gas imaging.
[4] Nondispersive infrared.
[5] Plugged and abandoned.
[6] Electromagnetic.
[7] Downhole.
[8] Reservoir saturation tool.

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect CO_2

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
CO_2 Stream Analysis – Gas Composition		X		X	X		
Pressure Gauges and Temperature Sensors at Surface – Injection Wells and Flow Line				X	X		
Pressure Gauges and Temperature Sensors at Surface – Monitoring Wells				X	X	X	
Flowmeters (mass/volume) – Injection Wells and Flowline				X	X		
Visual Inspection	X			X	X		
Automated Remote System (SCADA)			X	X	X		
OGI Cameras				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Injectors				X	X		
NDIR CO_2 Leak Sensors in Wellhead – Monitors				X	X		
Handheld CO_2 Monitor	X			X	X		X
Soil Gas Analysis		X			X		
Water Sampling USDW		X			X		X
Water Sampling Surface Water		X			X		X
Cement Bond Logs					X		
Casing Inspection Tool (EM/sonic) – Injection Wells					X		

Continued . . .

Table 4-2. Monitoring Strategies and Leakage Pathway Associated to Detect (continued)

Method	Existing Wellbores	Faults and Fractures	Natural and Induced Seismicity	Flowline and Surface Equipment	Vertical Migration Injectors and Monitoring Wells	Lateral Migration	Diffuse Leakage Through Seal
Casing Inspection Tool (EM/sonic) – Monitoring Wells					X		
Temperature Log – Monitoring Wells					X		
Annular Pressure Test – Injection Wells				X	X		
Annular Pressure Test – Monitoring Wells				X	X		
Corrosion Coupons				X	X		
DTS/DAS Fiber Installed on the Casing – Injection Wells		X			X		
DTS/DAS Fiber – Main Flowline				X			
DH Pressure Gauges and Temperature Sensors – Injection Wells		X			X	X	
DH Pressure Gauges and Temperature Sensors – Monitoring Wells		X			X	X	
RST Log (pulse neutron) – Monitoring Wells		X			X	X	X
RST Log (pulse neutron) – Injection Wells		X			X	X	X
Pressure Falloff Test – Injection Wells		X			X	X	
2D/3D Time-Lapsed Surface Seismic	X	X			X	X	X
Interferometric Synthetic Aperture Radar	X	X			X	X	
Surface Seismometers		X	X				

4.1 Leak Verification

Tundra SGS 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, Tundra SGS 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, injector wells 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 CO_2 leakage is occurring. Excursions are not necessarily indicators of 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 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 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 CO_2 surface leak is of lower temperature than ambient, it will often lead to the formation of bright white clouds and ice that are easily visually observed unaided. With this understanding, Tundra SGS will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the Tundra SGS project.

Discovery of an event triggers a response, as presented in the A1 and A2, Section 4.2, emergency remedial and response plan. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator 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, Tundra SGS 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 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 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 leaking to the surface will be quantified using acceptable emission factors, engineering estimates of 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.

Leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in an electronic central database. For additional details regarding quantification of leakage, refer to A1: 4.3.1 and A2:4.3.1.

5.0 DETERMINATION OF BASELINES

Preinjection baselines will be established through the Tundra SGS project 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 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 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 Tundra SGS project area are provided in A1: 4.1.6, A, B and A2: 4.1.6, A, B.

5.1 Surface Baselines

Baseline sampling includes selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek Aquifers and one USGS Fox Hills observation well. Verification of the domestic well status, based on viability of the well (existence, depth, access, etc.) and landowner cooperation, has been completed and selected wells sampled August 11–13, 2021.

The locations of these candidate wells are shown in A1:C and A2:C, Figure 4-2. Characterization of selected domestic wells and one USGS Fox Hills observation well will include

the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in A1:C and A2:C.

5.2 Subsurface Baseline

Preoperational baseline data will be collected in the injection and monitoring wells. 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 (interferometric synthetic aperture radar) technology will be performed to determine application before injection and 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 5 km from the injection area a year prior to injection. For additional information regarding surface baseline, refer to A1: 4.1.8 and A2: 4.1.8.

6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

Tundra SGS 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 M2 in the facility diagram (Figure 1-2).

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:

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

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 surface leakage.

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

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

The Tundra SGS project will to use a volumetric flowmeter (M2) (Figure 1-2) 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 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:

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

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 (wt percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flowmeter.

6.2 Annual Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

The Tundra SGS site 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 A1:4 and A2:4, 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 leak to quantify the CO_2 volume to the best of its the capabilities. The process for quantifying leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the leak, and numerical and predictive models among others.

Tundra SGS will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98, Subpart RR:

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

Where:

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

The calculation of CO_{2FI}, the annual mass of CO_2 emitted (in metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead, will comply with the calculation and quality assurance/quality control requirements in Part 98, Subpart W, and will be reconciled with the annual data collected through the monitoring and surveillance plan proposed in A1:4, D and A2:4, D.

7.0 MRV PLAN IMPLEMENTATION SCHEDULE

It is proposed that this MRV plan will be implemented within 90 days of the placed-in-service date of the capture and storage equipment, including the Class VI injection wells. The project will not be placed in service until successfully completing performance testing, an essential milestone in achieving substantial completion. At the placed-in-service date, the project will commence collecting data for calculating total amount sequestered according to equations outlined in Section 7.0. As discussed under Sections 2.1 and 3.1, this proposed MRV plan was developed to account for both Phase 1 and Phase 2, and thus no modification to the MRV is anticipated if Phase 2 is pursued. Other greenhouse gas (GHG) reports are filed by the end of the third month of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time.

As described in Section 3.3, Tundra SGS anticipates that the MRV program will be in effect during the operational and postoperational monitoring periods, during which time Tundra SGS will operate the storage facilities for the purpose of secure, long-term containment of a measurable quantity of CO_2 in subsurface geologic formations. Tundra SGS anticipates establishing a measurable amount of CO_2 injected during the operational period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, Tundra SGS will prepare a demonstration supporting the long-term containment determination in accordance with North Dakota statutes and regulations and submit a request to discontinue reporting under this MRV plan consistent with the North Dakota and Subpart RR requirements (see 40 CFR § 98.441[b][2][ii]).

8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for Tundra SGS monitoring techniques and data management is provided in the Quality Assurance and Surveillance Plan found in A1:D and A2:D.

Tundra SGS will ensure compliance with the quality assurance requirement in § 98.444.

<u>CO_2 received</u>:

- The quarterly flow rate of CO_2 received by pipeline is measured at a receiving meter on the injection well path.
- The CO_2 concentration is measured quarterly upstream or downstream 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 § 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.

Concentration of CO_2:

- CO_2 concentration will be measured using the appropriate standard method. All measured volumes will be converted from CO_2 to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

8.1 Missing Data Procedures

In the event Tundra SGS is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in § 98.445 will be used as follows.

8.1.1 Quarterly Flow Rate of CO_2 Received

- Tundra SGS may use the quarterly flow rate data from the sales contract from the capture facility or invoices associated with the commercial transaction.

- A quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

8.1.2 Quarterly CO_2 Concentration of a CO_2 Stream Received

- Tundra SGS may use the CO_2 concentration data from the sales contract for that quarter if the sales contract was contingent on CO_2 concentration and the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration in accordance with the sales contract terms.

- A quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

8.1.3 Quarterly Quantity of CO_2 Injected

- The quarterly amount of CO_2 injected will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

8.1.4 Values Associated with CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment at the Facility

- Implementation will follow missing data estimation procedures specified in 40 CFR, Part 98, Subpart W.

Any missing data should be followed up with an investigation into issues, whether they are concerned with equipment failure or incorrect estimations.

9.0 MRV PLAN REVISIONS

In the event there is a material change to the monitoring and/or operational parameters of the Tundra SGS project that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in § 98.448(d). Minnkota is the project sponsor of Tundra SGS and will contribute a portion of the total equity for the proposed storage project; other equity participants for the project have not yet been identified. As such, the MRV plan names Minnkota as the sole storage facility owner, operator, and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota plans to contribute all necessary permits to the Tundra SGS project entity, resulting in the transfer of owner and operatorship to the Tundra SGS project. This transfer of ownership will be treated as a minor modification, which will be accomplished through submission of a certificate of representation identifying the change in ownership in accordance with 40 CFR 98.4(h) and will accurately identify and align MRV plan owner/operator/representative designation. Minnkota does not anticipate any material modification to the MRV plan, and as discussed under Section 2.1, if Phase 2 development is pursued, this proposed MRV plan accounts for all monitoring and reporting obligations under Subpart RR.

Tundra SGS reserves the opportunity to submit supplemental revisions to this proposed plan, which take into considerations responses, inquiries, and final determinations from the regulatory agencies having jurisdiction in A1 and A2 and associated Class VI drilling permits.

10.0 RECORDS RECORDING AND RETENTION

Tundra SGS will follow the records retention requirements specified by § 98.3(g). In addition, it will follow the requirements in Subpart RR § 98.447 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 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.

11.0 REFERENCES

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U.S. Geological Survey, 2016, Induced earthquakes raise chances of damaging shaking in 2016: https://www.usgs.gov/news/induced-earthquakes-raise-chances-damaging-shaking-2016 (accessed December 2019).

Attachment 1

TUNDRA SGS – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO_2 Storage Facility Permit Application – Corrected

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NOMENCLATURE

AES	atomic emission spectrometry
AMS	accelerator mass spectrometry
ANSI	American National Standards Institute
AOR	area of review
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	ASTM (American Society for Testing and Materials) International
AVO	amplitude variation with offset
AZMI	above-zone monitoring interval
bbl	barrel
BHA	bottomhole assembly
BHP	bottomhole pressure
BHT	borehole temperature
BNI	BNI Coal, Inc.
BOP	blowout preventer
BOPE	blowout preventer equipment
bpm	barrels per minute
BTC	buttress-thread and coupled
CBL	cement bond log
CCP	corrosion control program
CCS	carbon capture and storage
CF	continuous flow
CFR	Code of Federal Regulations
cm	centimeter
CMG	Computer Modelling Group Ltd.
CMP	corrosion management program
CMR	combinable magnetic resonance
CO_2	carbon dioxide
C-ODTR	coherent optical time domain reflectometry
COW	control of well
CRDS	cavity ring down spectrometry
CSE	confined space entry
CVAA	cold-vapor atomic absorption
DAS	distributed acoustic sensing
dB	decibel
DIC	dissolved inorganic carbon
DMR	Department of Mineral Resources
DO	dissolved oxygen
DOC	dissolved organic carbon
DOT	U.S. Department of Transportation

Continued . . .

NOMENCLATURE (continued)

DSS	distributed strain sensing
DTS	distributed temperature sensing
EERC	Energy & Environmental Research Center
EM	electromagnetic
EOR	enhanced oil recovery
EOS	equation of state
EPA	U.S. Environmental Protection Agency
ERR	emergency or remedial response
ERRP	emergency and remedial response plan
°F	degree Fahrenheit
FADP	financial assurance demonstration plan
FID	flame ionization detector
FMI	formation microimaging
FOSV	full opening safety valve
FPD	flame photometric detector
FS	field superintendent
ft	foot
GC	gas chromatography
g/cm^3	gram per cubic centimeter
GEM	Generalized Equation-of-State Model
GFCI	ground fault circuit interrupter
GPa	gigapascal
GPS	global positioning system
GR	gamma ray
h	hour
HCR	high closing ratio
HID	helium ionization detector
HNBR	hydrogenated nitrile butadiene rubber
HPMI	high-pressure mercury injection
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
IBOPSV	inside BOP safety valve
ICEA	Insulated Cable Engineers Association
ICP	inductively coupled plasma
ID	inside diameter

Continued . . .

NOMENCLATURE (continued)

IEPA	Illinois Environmental Protection Agency
in.	inch
InSAR	interferometric synthetic aperture radar
IRMS	isotope-ratio mass spectrometry
JSA	job safety analysis
kg/m^3	kilogram per cubic meter
kHz	kilohertz
Klb	thousand pound
km	kilometer
L	liter
lb	pound
LCS	laboratory control sample
LEL	lower explosive limit
LOC	loss of containment
m	meter
mA	milliampere
m amsl	meter above mean sea level
MASP	maximum anticipated surface pressure
mD	millidarcy
MD	measured depth
MDT	modular dynamics testing
MEM	mechanical earth model
mg	milligram
mg/L	milligram per liter
mi	mile
mi^2	square mile
MI	move in
MICP	mercury injection capillary pressure
Minnkota	Minnkota Power Cooperative, Inc.
ML	local magnitude
mm	millimeter
MMI	modified Mercalli intensity
MMscf/d	million standard cubic foot per day
MMt	million tonne
MMt/yr	million tonne per year
MOC	management of change
mol%	mole percent
MPa	megapascal
MRV	monitoring, reporting, and verification
MRYS	Milton R. Young Station
m/s	meter per second
m/s^2	meter per square second

Continued . . .

NOMENCLATURE (continued)

ms	millisecond
MS	mass spectrometry
MVA	monitoring, verification, and accounting
MVTL	Minnesota Valley Testing Laboratories
NACE	National Institute of Corrosion Engineers
NAICS	North American Industry Classification System
NDAC	North Dakota Administrative Code
NDCC	North Dakota Century Code
NDDH	North Dakota Department of Health
NDIC	North Dakota Industrial Commission
NDSWC	North Dakota State Water Commission
NEC	National Electrical Code
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
nm	nanometer
NMPA	Northern Municipal Power Agency
NU	nipple up
O_2	oxygen
OD	outside diameter
OEM	original equipment manufacturer
O&G	oil and gas
OLCV	Oxy Low Carbon Ventures
ORP	oxidation reduction potential
OSHA	Occupational Safety and Health Administration
P&A	plug and abandon
PCOR	Plains CO_2 Reduction (Partnership)
PISC	postinjection site care
PLT	production logging tool
PM	project manager
PNC	pulsed-neutron capture
PNL	pulsed-neutron log
PPE	personal protective equipment
ppf	pound per foot
ppg	pound per gallon
ppm	part per million
ppmv	part per million volume
psi	pound per square inch
P/T	pressure/temperature
QA	quality assurance
QASP	quality assurance and surveillance plan
QC	quality control
QCSP	quality control and surveillance plan
RTD	resistance temperature detector

Continued . . .

NOMENCLATURE (continued)

RTU	remote terminal unit
RU	rig up
RWP	rated working pressure
§	section
s	second
SCADA	supervisory control and data acquisition
SDS	safety data sheet
SFP	storage facility permit
SGS	secure geologic storage
SIMOPS	simultaneous operations
SLRA	screening-level risk assessment
SMEs	subject matter experts
SP	spontaneous potential
Spf	shots per foot
ST	surveillance technician
SWC	sidewall coring
T&A	temporarily plugged and abandoned
TCD	thermal conductivity detector
TD	total depth
TDS	total dissolved solids
TF	task force
TIC	total inorganic carbon
TIH	trip in hole
TOC	total organic carbon
Tundra SGS	Tundra Secure Geologic Storage Site
TVD	true vertical depth
UCS	uniaxial compressive strength
UIC	underground injection control
μL	microliter
USDW	underground source of drinking water
USGS	U.S. Geological Survey
USIT	ultrasonic imaging tool
VDL	variable density log
VFD	variable-frequency drive
VOA	volatile organic analysis
VSP	vertical seismic profile
WHP	wellhead pressure
WSP	worker safety plan
wt%	weight percent
XRD	x-ray diffraction
XRF	x-ray fluorescence

TUNDRA SGS – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PERMIT APPLICATION SUMMARY

General Applicant and Project Information. Minnkota Power Cooperative, Inc. (Minnkota) and its partners prepared this supporting documentation for its storage facility and underground injection control (UIC) Class VI permit applications to establish two storage reservoirs and phased construction and operation of up to three injection wells located in Oliver County, North Dakota. The project for secure geologic storage (SGS) of carbon dioxide (CO_2) will be operated over a 20-year injection period and be named Tundra SGS. Minnkota is the project sponsor of Tundra SGS. Minnkota anticipates contributing a portion of the total equity of the proposed storage project, but the other equity participants have not yet been identified. As such, the application names Minnkota as the sole storage facility operator and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota anticipates contributing these permits to the Tundra SGS project entity. Minnkota intends such a contribution to effect a transfer of owner and operatorship to the Tundra SGS project entity. Further, a transfer of ownership is treated as a minor modification upon filing of an application to amend for change in ownership in accordance with North Dakota Administrative Code (NDAC) §§ 43-05-01-06 and 12.1. The current mailing address for the Tundra SGS facility and Minnkota, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

Minnkota is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota is also affiliated with the Northern Municipal Power Agency (NMPA), which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners. Minnkota serves as the operating agent of the NMPA. Figure PS-1 provides a map showing the Minnkota and NMPA service territory.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine which provides the lignite coal for MRYS is owned and operated by BNI Coal, Inc. (BNI) and is adjacent to the MRYS facility. The lignite used as the fuel for electrical generation also serves as the primary source of the captured CO_2 that will be securely stored by Tundra SGS. The operation of Tundra SGS together with the carbon capture project are commonly referred to as Project Tundra. The standard industrial classification code for the principal products and services provided Minnkota is best reflected as North American Industry Classification System (NAICS) 221112, Fossil Fuel Electric Power Generation.

An organizational chart showing the relationships between Minnkota and its affiliated organizations is provided in Figure PS-2.

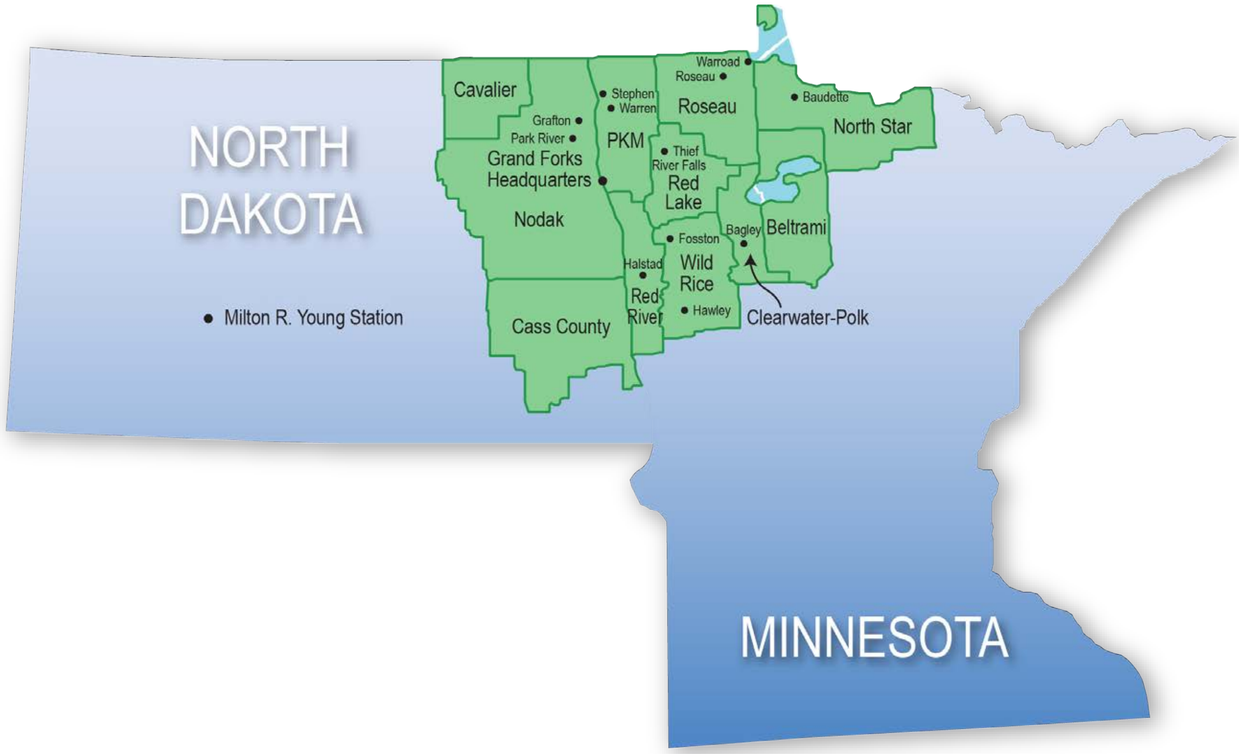

Figure PS-1. Map of the Minnkota and NMPA service territory.

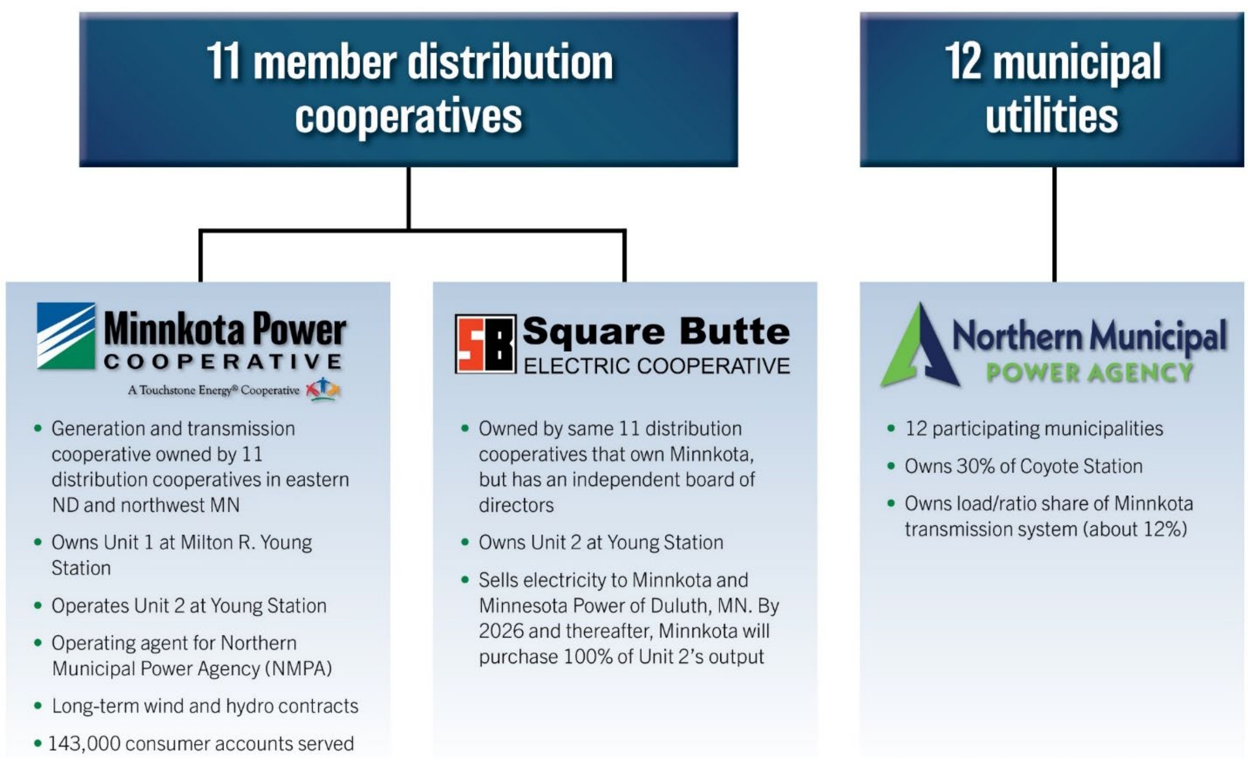

Figure PS-2. Chart showing the relationships between Minnkota and its affiliated organizations.

Minnkota proposes to initially conduct CO_2 storage operations in the Broom Creek Formation as Phase 1 of construction and operation of Tundra SGS. Two wells are proposed for Phase 1 injection of CO_2 into the Broom Creek Formation. Upon construction and operation of the two Broom Creek injection wells, validation of the Phase 1 operation and need for additional capacity will be considered in the decision to proceed with Phase 2 of development. Phase 2 of construction and operation may consist of one additional well for injection of CO_2 into the Black Island–Deadwood Formation. Alternatively, depending on the outcome of Phase 1 operation in the Broom Creek, a third injection well may be considered into the Broom Creek. Permit applications for the two proposed Phase 1 injection wells for the Broom Creek have been prepared and submitted. Since Tundra SGS is proposing a phased development approach for the site, the supporting documentation for the Phase 1 wells in the Broom Creek, as well as the Phase 2 injection well (one in the Black Island–Deadwood) is collectively provided within the application and attachments. This application and its supporting documents have been prepared in accordance with the North Dakota Century Code~~,~~ and NDAC. The applications and supporting documentation are based on currently available data, including regional and site-specific data derived from two stratigraphic test wells drilled by Minnkota in 2020 and one stratigraphic test well drilled by the Energy & Environmental Research Center (EERC) in 2015, all located within 5 mi of the proposed injection wells.

The proposed Tundra SGS injection site is approximately 3.4 mi southwest of the town of Center (Figure PS-3) and will include up to three injection wells, one dedicated monitoring well for the lowest underground source of drinking water (USDW), and associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. In addition, one deep subsurface monitoring well is proposed to be installed approximately 2 mi northeast of the Tundra SGS injection site. All the aforementioned surface facilities and underground equipment will be contained on Minnkota-owned property, and the injection site is within the MRYS fence line (Figure PS-3).

Storage Reservoir Boundary/Area of Review. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Black Island–Deadwood storage facilities. Minnkota defines the storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start of injection until the end of injection. The storage reservoir boundary is identified based on the computational model output of the areal extent of the subsurface CO_2 volume at the end of the injection period (20 years), in which a CO_2 saturation is predicted to be greater than or equal to 5%. To identify the storage reservoir boundaries, reservoir simulation software was used to model the coupled hydrologic, chemical, and thermal processes and chemical interactions of CO_2 with the aqueous fluids and rock minerals. The storage reservoir extent is determined from the numerical model, and the resulting map area is displayed in Figure PS-3.

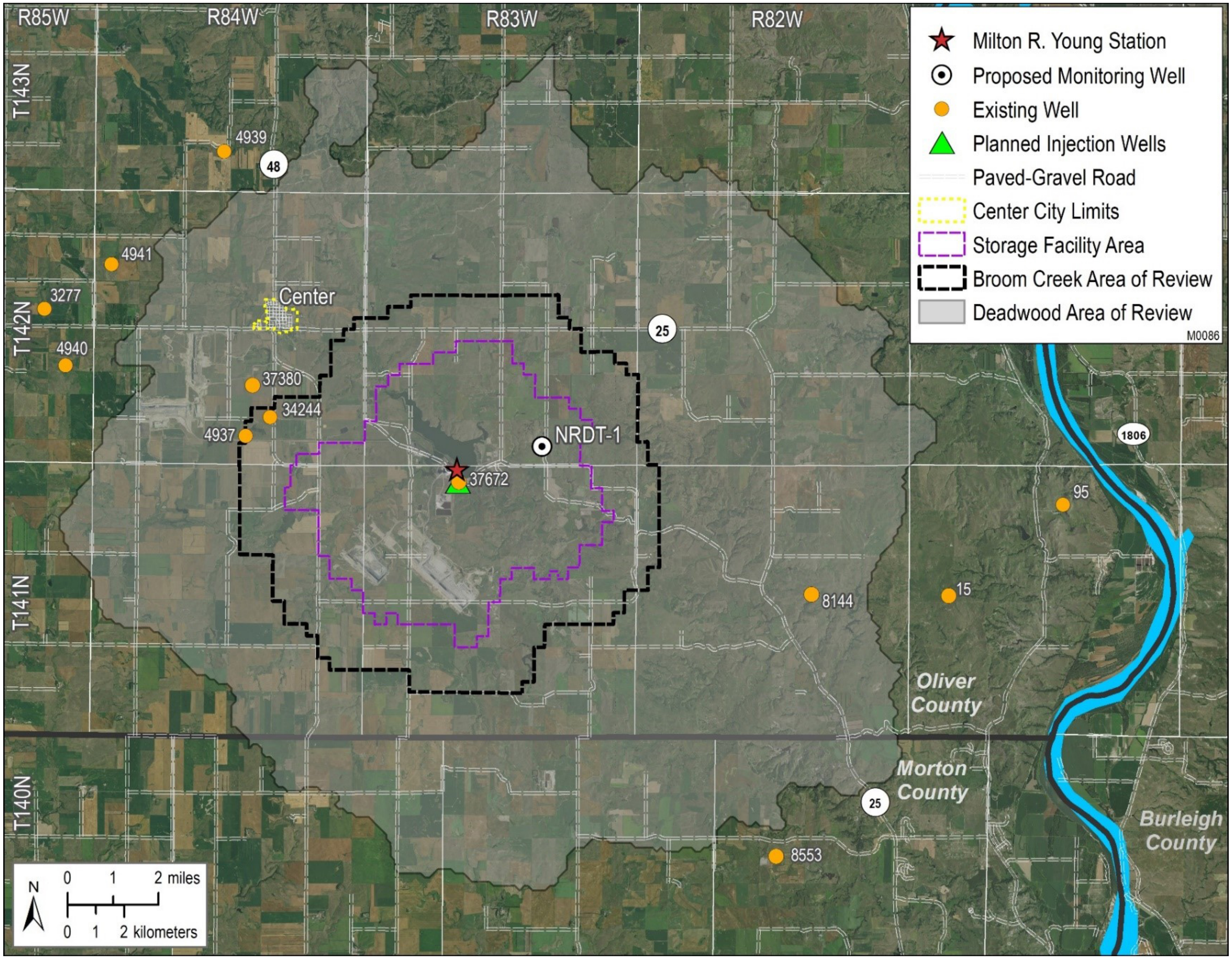

Figure PS-3. Project Tundra geologic storage of CO_2 project map.

The primary objective of the area of review (AOR) is to delineate the region encompassing the Tundra SGS site where USDWs may be endangered by the injection activity (NDAC § 43-05-01-01[4]). The AOR is generally defined as the horizontal extent of a pressure front and plume.

As shown in Figure PS-3, an AOR has been defined for each of the two targeted CO_2 storage horizons. These areas are used to identify the existence of any confining zone penetrations (i.e., existing wells that may penetrate the cap rock). There are five existing wellbores in the Black Island–Deadwood Formation AOR region. Three of those wellbores are the stratigraphic test holes drilled in the past 5 years as part of Tundra SGS geologic characterization efforts. Of these five existing wellbores, only three penetrated the cap rock of the Black Island–Deadwood Formation. Two of the wellbores that penetrate the Deadwood are two of the three stratigraphic test holes drilled for Tundra SGS characterization.

Of these existing wellbores, the remaining two do not penetrate the Black Island–Deadwood Formation. Within the Broom Creek Formation AOR, there are two existing wellbores, one of which is the same stratigraphic test well within the Black Island–Deadwood Formation AOR. This existing wellbore penetrates the Broom Creek Formation, and as discussed in Section 5.0, is proposed to be reentered and completed as one of the two Broom Creek Formation injectors, Liberty-1. Surface bodies of water and other pertinent surface features (including structures intended for human occupancy), administrative boundaries, and roads within the AOR are shown in Figure PS-3.

Minnkota also incorporated the AOR assessments into the proposed corrective action and monitoring plans. The deep subsurface-monitoring plan is tailored to each individual proposed AOR, while the near-surface-monitoring plan for the Broom Creek Formation extends to the boundary of the proposed Deadwood Formation AOR. The AOR assessments of these penetrating wells indicate that none could serve as conduits for the movement of fluids from the injection zone into USDWs. Therefore, no corrective actions on existing wells will need to be taken. Additionally, there are no subsurface cleanup sites, quarries, or Tribal lands within this area.

Construction and Operations Plan. The Tundra SGS project is designed to securely store the injected CO_2 within the storage reservoirs. At MRYS, the captured CO_2 stream will be at least 99% purity, dehydrated, and compressed to 1,800 psi before entering the CO_2 flowline. At these conditions, the CO_2 will be in a dense fluid phase, noncorrosive, and nonflammable. The approximately 0.25-mi (0.40-km) flowline will be 16 in. (40.64 cm) in outside diameter (OD) and have a maximum design flow rate of 4.3 MMT/yr (224 MMscf/d). Because of the short distance between the compressor and wellsite (0.25 mi), the CO_2 pressure is not anticipated to decrease significantly as the CO_2 travels the length of the flowline to the Tundra SGS site. The Broom Creek Formation injector wellhead pressure does not exceed 1,600 psi. Surface injection pressure into the Black Island–Deadwood storage zone will be increased to 2,800 psi using a booster pump downstream of the custody transfer metering station.

The Tundra SGS site design was optimized to receive CO_2 at an average operating rate of 4 MMt/yr, which represents an average annual capacity factor of 90% for the carbon capture plant. The operational design considers the need for redundancy for planned or unplanned outage of any of the wells for maintenance or repair. Two wells are proposed for Phase 1 in the Broom Creek storage reservoir (to be named Liberty-1 and Unity-1) in a twin-well design. Liberty-1 will be a reentry into one of Minnkota's former stratigraphic test wells (J-ROC1, NDIC File No. 37672, now plugged and abandoned) and will be completed as a vertical injector. Unity-1, the twin well to Liberty-1, will be completed as a deviated injector with bottomhole location offset 1000 ft from Liberty-1. These two wells will be operated together to receive CO_2 at an annual average of 4.0 MMt/yr, with a maximum rate of 4.3 MMt/yr.

The optional Phase 2 of construction and operation contemplates a third injector as a vertical injector for the Black Island–Deadwood Formation and will be operated to receive CO_2 at a maximum rate of 1.3 MMT/yr. The phased approach to construction and the maximum rates of the three injector wells and associated equipment are based on operational flexibility, which includes consideration of the planned maintenance, outage, and operating capacity of MRYS and carbon capture equipment, along with the planned maintenance and testing requirements of the Tundra SGS site equipment.

The injection wells will be built with a protection system that will control the injection of the CO_2 and provide a means to safely stop CO_2 injection in the event of an injection well or equipment failure. The injection process will be monitored by an integrated system of equipment and instrumentation that will be capable of detecting whether injection conditions are out of permitted limits and responding by either adjusting conditions or ceasing injection. The system is designed to operate automatically with manual overrides. Additionally, Minnkota has prepared a detailed worker safety plan, which provides the minimum safety programs, permit activities, and training requirements to implement during the construction, operation, and postinjection site care activities of the Tundra SGS site.

Testing and Monitoring Plan. An extensive monitoring, verification, and accounting (MVA) system will be implemented to verify that injected CO_2 is effectively contained within the injection zone. The objectives of the MVA program are to proactively account for corrosion and leakage in the well equipment and surface facilities, track the lateral extent of CO_2 within the injection zones, characterize any geochemical or geomechanical changes that occur within the injection and confining zones that may affect containment, and track the areal extent of the injected CO_2 through indirect monitoring techniques such as geophysical and surveillance methods. The monitoring network, shown in Figure PS-3 and described in Section 4.0, will be designed to account for and verify the location of CO_2 injected.

Emergency and Remedial Response Plan (ERRP). Minnkota developed a comprehensive ERRP for the Tundra SGS site, delineating what actions would be necessary in the unlikely event of an emergency at the Tundra SGS site or within the AOR. The ERRP describes the potential affected resources and provides that site operators know which entities and individuals are to be notified and what actions need to be taken to expeditiously mitigate any emergency and protect human health and safety and the environment, including USDWs. An attachment to the ERRP identifies and categorizes potential adverse event scenarios, and if an adverse event occurred, a variety of emergency or remedial responses are outlined, to be deployed depending on the circumstances (e.g., the location, type, and volume of a release) to protect USDWs.

Postinjection Site Care and Site Closure Plan (PISC). Postinjection monitoring will include a combination of groundwater monitoring, storage zone pressure monitoring, and geophysical monitoring of the Tundra SGS site. The monitoring locations, methods, and schedule are designed to show the position of the CO_2 plume and demonstrate that the CO_2 injected is within the storage reservoir and there is no endangerment to the USDWs.

The proposed monitoring program includes one monitoring well, which covers each of the injection and above confining zones to verify that CO_2 has not migrated into that interval. In addition, a groundwater well will be completed at the Tundra SGS site in the Fox Hills Formation to monitor this lowermost federal USDW. Monitoring of the site will continue for a minimum of 10 years after injection has ceased.

Financial Responsibility Plan. Minnkota has developed a plan to maintain financial responsibility for the construction, operation, closure, and monitoring of the proposed injection wells and undertake any emergency or remedial actions that may be necessary. To ensure that sufficient funds will be available, Minnkota has obtained an estimate for the cost of hiring a third party to undertake any necessary actions to protect USDWs within the AOR. Funding for performing any needed corrective actions will be deposited in a Tundra SGS trust fund that will be available during all phases of the project. Minnkota will also obtain a third-party insurance policy that would be available for conducting any emergency or remedial response actions.

Summary. Minnkota prepared its storage facility and Class VI UIC permit applications and supporting documentation to demonstrate that 1) the proposed Tundra SGS site comprises injection zones of sufficient areal extent, thickness, porosity, and permeability to safely receive the planned injection volume and rates of CO_2 over 20 years and 2) the confining and secondary confining zones are free of transmissive faults and fractures and of sufficient areal extent and integrity to vertically contain the injected CO_2at the proposed pressures and volumes without initiating or propagating fractures in the reservoir or confining zones. These findings are supported by the data and information gathered from coring, logging, sampling, and testing the subsurface characteristics in the three stratigraphic wells that provided site-specific geologic data as well as available regional data.

Minnkota has developed comprehensive construction and operations, testing and monitoring, injection well-plugging, and postinjection site care and site closure plans as well as an emergency and remedial response plan to protect USDWs. To ensure that sufficient funds are available to undertake these actions, Minnkota has also developed a financial responsibility plan.

Minnkota is confident that its permit applications and supporting documentation demonstrate compliance with the North Dakota Industrial Commission (NDIC) Underground Storage of Carbon Dioxide Rules and North Dakota Legislature's authorizing statute. Table PS-1 provides a crosswalk between the regulatory requirements in that rule and organization of Minnkota's supporting documentation.

Table PS-1. Crosswalk Between Applicable Regulatory Provisions in NDIC Rule and Tundra SGS Permit Application and Supporting Documents

NDIC Rule – Regulatory Requirements	Tundra SGS Permit Application
43-05-01-05. Storage Facility Permit Information	Sections 1.0, 2.0, 4.0, 5.0, and Appendixes A–C
43-05-01-05.1 Area of Review and Corrective Action	Sections 3.0, 4.2–4.3, and Appendixes A–B
43-05-01-13 Emergency Remedial Response	Section 4.2 and Appendix E
43-05-01-09 Well Permit Application Requirements	Sections 4.0, 5.0, and Form 25 (Northstar)
43-05-01-09.1 Financial Responsibility	Section 4.3 and Appendix G
43-05-01-11 Injection Well Construction and Completion Standards	Section 5.0
43-05-01-11.1 Mechanical Integrity	Sections 4.1 and 5.0
43-05-01-11.2 Logging, Sampling and Testing Prior to Injection Well Operation	Sections 2.1, 2.2, 5.0, and Appendix B
43-05-01-11.3 Injection Well Operating Requirements	Section 5.0
43-05-01-11.4 Testing and Monitoring Requirements	Section 4.1
43-05-01-11.5 Injection Well Plugging	Section 4.6
43-05-01-11.6 Injection Depth Waiver Requirements	*Not Applicable*
43-05-01-15 Storage Facility Corrosion Monitoring and Prevention Requirements	Section 4.1 and Appendix F
43-05-01-19 Post-Injection Site Care and Facility Closure Requirements	Section 4.7

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 required by North Dakota statute for geologic storage of carbon dioxide (CO_2) to make a good faith attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith attempt, it was able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of the pore space. 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, Minnkota submits the form of storage agreement attached hereto as Appendix H 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.

1.1 Storage Reservoir Pore Space

Minnkota Power Cooperative, Inc. (Minnkota) defines the proposed storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start until the end of injection. The storage reservoir vertical and horizontal boundaries are identified based on the computational model output of the areal extent of the CO_2 plume volume at the end of the injection period (20 years), in which a CO_2 saturation is predicted to be greater than or equal to 5%. The model utilizes applicable geologic and reservoir engineering information and analysis as detailed in Section 2.0 and Appendix A.

The operation inputs for the simulation scenarios assumes storage at the average designed injection rates, approximately 4.0 MMt/year injected into the Broom Creek storage reservoir for the first 15 years of operation and 3.5 MMt/year for year 15 through year 20 of operation. These maximum rates were based on Minnkota's consideration of the planned maintenance, outage, and operating capacity of the Milton R. Young Station (MRYS) and carbon capture equipment along with the planned maintenance requirements and testing requirements of the Tundra SGS (secure geologic storage) site equipment.

1.1.1 Horizontal Boundaries

The proposed horizontal boundaries of the storage reservoirs, including an adequate buffer area, are defined by the simulated migration of the CO_2 plume, using the actual rate of injection from the start until the end of injection. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Deadwood storage facilities if needed. The horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off the maximum design life of the carbon capture equipment. The reservoir models will be updated regularly with operating data, and the operator will provide evidence of the CO_2 plume migration as part of the reevaluations required under NDAC §§ 43-05-01-05.1 and 43-05-01-11.4. These reevaluations are to occur no later than every 5 years, thus the simulation output at 5 years of operation is indicated in Figure 1-1 to exemplify the buffer existing within the proposed storage facility area, allowing safe operation as proposed and contemplated. The stacked storage operations scenario option allows for coordination of the capacity of the Black–Island Deadwood with the Broom Creek capacity and provides further assurance of the contemplated operation within the defined storage reservoir boundary.

The simulated horizontal storage reservoir boundary results proposed for the Broom Creek Formation are depicted in Figure 1-1.

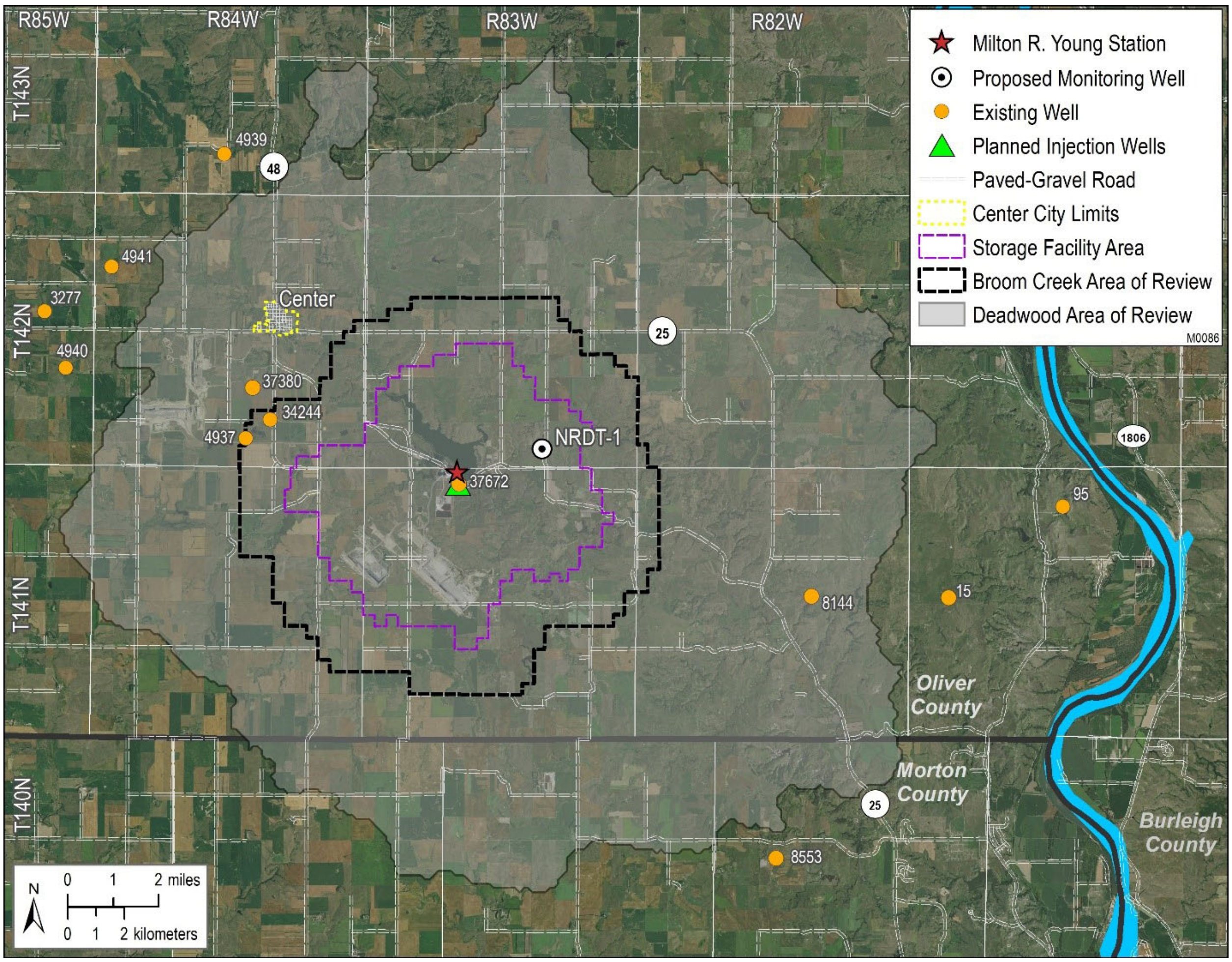

Figure 1-1. Broom Creek storage facility area map.

1.1.2 Vertical Boundaries

The Tundra SGS site was designed using a stacked storage concept, where two storage reservoirs identified with varying vertical depths could be accessed by a common wellsite. A key benefit of this development approach is to minimize the surface land use impact by reducing the amount of surface facilities required for operation. Despite the significant overlap of pore space area between the Broom Creek and Deadwood reservoirs, two distinct SFPs are being requested, with the distinct vertical boundaries based upon geologic analysis and simulations, which are further detailed and described in Section 2.0 of the respective SFP application supporting information.

The applicant requests amalgamation of the injection zone pore space within the Broom Creek interval, as identified in Section 2.0, Figure 2-3. In addition to the injection zone, the applicant requests the permitted storage facility consist of the Opeche–Picard interval as the upper confining zone and Amsden Formation as the lower confining zone (Section 2.0, Figure 2-3).

1.2 Persons Notified

Minnkota will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 mi of its outside boundary. Minnkota will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to 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 in accordance with North Dakota law (NDCC Chapter 47-31):

- A map showing the extent of the pore space that will be occupied by the CO_2 plume over the injection period, including the storage reservoir boundary and 0.5 mi (0.8 km) outside of the storage reservoir boundary, with a description of the pore space ownership, surface owner, and pore space lessees of record (Figure 1-1).

- A table identifying all pore space (surface) owners, and lessees of pore space of record, their mailing addresses, and legal descriptions of their pore space landownership (Table 1-1).

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

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

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S., Grand Forks, ND 58201	Sec. 3-T141N-R83W Sec. 4-T141N-R83W Sec. 5-T141N-R83W Sec. 9-T141N-R83W Sec. 10-T141N-R83W Sec. 32-T142N-R83W Sec. 33-T142N-R83W Sec. 34-T142N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S., Grand Forks, ND 58201	Sec. 4-T141N-R83W Sec. 5-T141N-R83 Sec. 33-T142N-R83W
Oliver County Attn: County Auditor	Oliver County Courthouse, PO Box 188, Center, ND 58530	Sec. 5-T141N-R83W Sec. 34-T142N-R83W
BNI Coal, Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897	Sec. 8-T141N-R83W Sec. 17-T141N-R83W Sec. 31-T142N-R83W Sec. 32-T142N-R83W
Five D's, LLP	3009 Bayside Drive, Mandan, ND 58554	Sec. 8-T141N-R83W
Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 7-T141N-R83W Sec. 1-T141N-R84W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Larry F. & Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 16-T141N-R83W
Kasper J. Kraft & Donna M. Kraft	2845 35th Avenue SW, New Salem, ND 58563	Sec. 16-T141N-R83W
Kasper J. Kraft, Jr.	305 9th Street NW, Mandan, ND 58554	Sec. 16-T141N-R83W
Steve Kraft	2847 35th Avenue, New Salem, ND 58563	Sec. 16-T141N-R83W
Susan Henke	4235 20th Street SW, Stanton, ND 58571	Sec. 16-T141N-R83W
Allen Kraft	6155 12th Street SE, Bismarck, ND 58504	Sec. 16-T141N-R83W
Robin Schimke	9115 Paige Drive, Bismarck, ND 58503	Sec. 16-T141N-R83W
Oliver County	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 16-T141N-R83W
State of North Dakota - Dept. of Trust Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T141N-R83W
Five D's LLP	4609 Borden Harbor Drive SE, Mandan, ND 58554	Sec. 17-T141N-R83W
Jerald O. Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 17-T141N-R83W
Wayne A. Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W Sec. 19-T141N-R83W
Karen L. Reuther	1411 Pocatello Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Jeanette M. Reuther	P. O. Box 304, Center, ND 58530	Sec. 17-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 17-T141N-R83W
Brian Reinke	1106 East Highland Acres Road, Bismarck, ND 58501	Sec. 6-T141N-R83W
Benjamin Reinke	1215 Columbia Drive, Bismarck, ND 58504	Sec. 6-T141N-R83W
Elizabeth Wagendorf	948 Stryker Avenue, West St. Paul, MN 55118	Sec. 6-T141N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 6-T141N-R83W Sec. 1-T141N-R84W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 6-T141N-R83W
Heirs or Devisees of Alex Sorge, deceased	Center ND 58530	Sec. 32-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	**Mailing Address**	**Legal Description**
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W Sec. 32-T142N-R83W
Oliver County Attn: Chairman	P.O. Box 188, Center, ND 58530	Sec. 4-T141N-R83W Sec. 32-T142N-R83W
ALLETE, INC.	30 W Superior St., Duluth, MN 55802-2030	Sec. 33-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 34-T142N-R83W
State of North Dakota	1707 N 9th St., Bismarck, ND 58501-5523	Sec. 34-T142N-R83W
Robert Reinke	1144 College Drive #201, Bismarck, ND 58501	Sec. 31-T142N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 2-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 11-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 11-T141N-R83W
Nancy Henke	P.O. Box 90, Hazen, ND 58545	Sec. 11-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 11-T141N-R83W
Peggy Gobar	504 Garden Avenue NW, West Fargo, ND 58078	Sec. 11-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Randy Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Janet K. Dohrmann and L.J. Dohrmann, as Trustees of The Janet and L.J. Fast Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 18-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Kent Reutherfkuf	3610 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Keith Reuther	3594 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Karen Shulz	13720 Chamy Dr., Reno, NV 89521	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Martha Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Ave. SW, Center, ND, 58530	Sec. 18-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 19-T141N-R83W
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 19-T141N-R83W
Charles H. Kuether	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Charles H. Kuether	3555 28th Street, New Salem, ND 58563	Sec. 19-T141N-R83W
Erick G. Larson	50 Avalon Dr Unit 7323, Milford, CT 06460-8957	Sec. 19-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 22-T141N-R83W Sec. 27-T141N-R83W
Travis Klatt and Jessica Klatt, as joint tenants	2438 37th Ave. SW, Center, ND 58530	Sec. 1-T141N-R84W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 20-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 20-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 20-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 20-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 20-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 20-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 20-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 20-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 20-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 20-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 5850	Sec. 20-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 20-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Doll Farm Enterprises	3997 36th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 28-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Clementine Freisz	710 Pine Avenue, New Salem, ND 58563	Sec. 28-T141N-R83W
Sandra K. Orgaard	2810 26th Street, Center, ND 58530	Sec. 28-T141N-R83W
Roger A. Friesz	797 7th Street, Idaho Falls, ID 83401	Sec. 28-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Duane M. Friesz	4465 34th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Karen M. Porsborg	2720 37th Avenue SW, New Salem, ND 58563	Sec. 28-T141N-R83W
Michael J. Friesz	3463 County Road 87, New Salem ND, 58563	Sec. 28-T141N-R83W
Audrey A. Peterson	12719 Doris Drive, Black Hawk, SD 57718	Sec. 28-T141N-R83W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 21-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 21-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 21-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 21-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 21-T141N-R83W
Michael Pazdernik	P.O. Box 194, New Salem, ND 58563	Sec. 21-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 21-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 21-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 21-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 21-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 21-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 21-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 21-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 21-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 21-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 21-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 21-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 21-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
City of Center Park District	Center, ND 58530	Sec. 2-T141N-R84W
Barry A. Berger and Carrie Berger, as joint tenants	809 Main Street E, Center, ND 58530	Sec. 2-T141N-R84W
Dwight Wrangham and Linda Wrangham, as joint tenants	301 52nd St. SE, Bismarck, ND 58501	Sec. 2-T141N-R84W
BNI Coal, Ltd.	1637 Burnt Boat Drive, P.O. Box 897, Bismarck, ND 58502-0897	Sec. 2-T141N-R84W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Eugene Yantzer and Betty Yantzer, as joint tenants	2745 18th St. SW, Center, ND 58530	Sec. 2-T141N-R84W
Delmar Hagerott Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust under the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 2492	Sec. 29-T141N-R83W
Steven P. Kraft and Julie F. Kraft, as joint tenants	2847 35th Avenue, New Salem, ND 58563	Sec. 29-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 13-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R83W
Nancy Henke and Dwight Henke	P.O. Box 90, Hazen, ND 58545	Sec. 13-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane, Mandan, ND 58554	Sec. 13-T141N-R83W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 13-T141N-R83W
Rodney Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 13-T141N-R83W
Delvin Bueligen	709A 3rd Avenue SE, Mandan, ND 58554	Sec. 13-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 13-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 13-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 13-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 13-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 13-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R83W
Arline Orgaardz	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R83W
Mark Leischner and Susan Leischner	2866 Woodland Place, Bismarck, ND 58504-8922	Sec. 13-T141N-R83W
Mark Erhardt	P.O. Box 132, Center, ND 58530	Sec. 13-T141N-R83W
Burton & Etheleen Enterprises, LLC	3655 County Road 139, New Salem, ND 58563	Sec. 14-T141N-R84W
Lee Dresser	P.O. Box 683, Riverdale, ND 58565	Sec. 14-T141N-R84W
Jesse L. Lackman and Darcy J. Lackman Revocable Living Trust	2647 37th Avenue SW, Center, ND 58530	Sec. 14-T141N-R84W
David Porsborg and Karen Porsborg	2720 37th Avenue, New Salem, ND 58563	Sec. 24-T141N-R84W
Beverly Faul	1420 9th Avenue NE, McClusky, ND 58463	Sec. 24-T141N-R84W
Brad Bonnet	3444 110th Avenue NE, Bismarck, ND 58504	Sec. 24-T141N-R84W
Justin Kessler	6045 Lyndale Avenue S, #255, Minneapolis, MN 55419	Sec. 24-T141N-R84W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Adam Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Andrew Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Chad Porsborg	3206 Stonewall Drive, Bismarck, ND 58501	Sec. 24-T141N-R84W
Heather Bullinger	2602 10th Avenue SE, Mandan, ND 58554	Sec. 24-T141N-R84W
Christie Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Tina Sorge	4412 E Mulberry, #312, Ft. Collins, CO, 80524	Sec. 24-T141N-R84W
Jerald Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 24-T141N-R84W
Wayne Reuther	476 Glenwood Drive, Bismarck, ND 58504	Sec. 24-T141N-R84W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 24-T141N-R84W
Kent Reuther and Pam Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Kenneth W. Reinke and Darlene Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Minnkota Power Cooperative, Inc.	P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 3-T141N-R84W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 3200, Grand Forks, ND 58208-3200	Sec. 3-T141N-R84W
Agnes Dockter	2424 South 121st Street, Seattle, WA 98101	Sec. 15-T142N-R83W
Steve Schmidt and Julie Schmidt, as joint tenants	P.O. Box 1936, Center, ND 58530	Sec. 15-T142N-R83W
Mike Saba a/k/a Michael P. Saba	26560 N. Shore Pl., Hartford, SD 57033	Sec. 15-T142N-R83W
State of North Dakota, for the use and benefit of the State Highway Department	608 East Boulevard Avenue, Bismarck, ND 58505-0700	Sec. 15-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 23-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
State of North Dakota Board of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 36-T142N-R84W
Oliver County Attn: County Auditor	P.O. Box 188, Center, ND 58530-0188	Sec. 36-T142N-R84W
Minnkota Power Cooperative, Inc.	1822 State Mill Road, P. O. Box 13200", Grand Forks, ND 58208-3200	Sec. 36-T142N-R84W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 36-T142N-R84W
BNI Coal, Ltd.	P.O. Box 897, Bismarck, ND 58502	Sec. 36-T142N-R84W
Larry J. Doll and Faye Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 25-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Haag Brothers, a partnership consisting of Thomas Haag, Donald Haag, and Conrad Haag	3051 Highway 25, Center, ND 58530	Sec. 24-T142N-R84W
Wayne Haag and Jennifer Haag, as joint tenants	P.O. Box 184, Center, ND 58530	Sec. 24-T142N-R84W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Kenneth Schmidt	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt	3581 22 Street SW, Center, ND 58530	Sec. 19-T142N-R83W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Matthias A. Erhardt, trustee, or successor trustee(s), of the Matthias A. Erhardt Trust dated December 27, 1994	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Josephine Erhardt, trustee, or successor trustee(s), of the Josephine Erhardt Trust dated December 27, 1994	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Joey Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Jerry Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 1-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 1-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 1-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 12-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan, ND 58554	Sec. 12-T141N-R83W
Fred Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Raynold Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Walter Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 12-T141N-R83W
Nancy Henke and Dwight Henke, as joint life tenants	P.O. Box 90, Hazen, ND 58545	Sec. 12-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane N, Mandan, ND 58554	Sec. 12-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 12-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 12-T141N-R83W
Peggy Gobar	504 Garden Ave. NW, West Fargo, ND 58078	Sec. 12-T141N-R83W
Annette Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W
Brent Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W
Randy Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Reda Renee Clinton and Stephanie A. Clarys, as joint tenants	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Michael P. Hilton	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Oliver County	Oliver County Courthouse, P.O. Box 188, Center, ND 58530	Sec. 14-T141N-R83W
John Barnhardt	1511 North 21st Street, Bismarck, ND 58501	Sec. 14-T141N-R83W
Gail M. Hilton	3195 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 14-T141N-R83W
Lowell Bueligen	13621 Homestead Lane Riverton, UT 84065	Sec. 14-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 14-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 14-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 14-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Dale Barnhardt	3199 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Jeff Erhardt ad Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 20-T142N-R83W
Matthias A. Erhardt, as trustee of the Matthias A. Erhardt Trust dated December 27, 1994	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Josephine Erhardt, as trustee of the Josephine Erhardt Trust dated December 27, 1994	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 20-T142N-R83W
Raymond Friedig, as personal representative of the Estate of Magdalen F. Friedig, deceased	523 South Anderson Street, Bismarck, ND 58504	Sec. 26-T142N-R83W
Carl Schwalbe	Center, ND 58530	Sec. 26-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Heirs or Devisees of the Estate of Loren Schwalbe, deceased	3520 81st Ave. SE, Unit 15, Jamestown, ND 58401	Sec. 26-T142N-R83W
Rolland Schwalbe	Center, ND 58530	Sec. 26-T142N-R83W
Randolph Middleton and Mary Middleton, as joint tenants	2298 32nd Ave SW, Center, ND 58530	Sec. 26-T142N-R83W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 27-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 28-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 28-T142N-R83W
Dale Barth	2255 33rd Ave SW, Center, ND 58530	Sec. 28-T142N-R83W
Dusty Backer	PO Box 411, Underwood, ND 58576	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 29-T142N-R83W
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Terrie Nehring	2234 35th Ave. SW, Center, ND, 58530	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 30-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 30-T142N-R83W
Ryan J. Weber	2241 29th Ave. SW, Center, ND 58530	Sec. 30-T142N-R83W
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 30-T142N-R83W
Bradley Dahl	602 Lehmkuhl St., PO Box 276, Center, ND 58530	Sec. 30-T142N-R83W
Brennan Price	3074 Highway 25, Center, ND 58530-1015	Sec. 35-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 36-T142N-R83W
Michelle Marie Ternes	3721 W Regent Drive, Bismarck, ND 58504	Sec. 35-T142N-R84W
Michael P. Dresser	3731 24th Street SW, Center, ND 58530	Sec. 35-T142N-R84W
BNI Coal, Ltd.	P.O. Box 897, Bismarck, ND 58502	Sec. 35-T142N-R84W
Oliver County, Attn: County Auditor & Hwy Dept.	P.O. Box 188, Center, ND 58530-0188	Sec. 34-T142N-R84W
BNI Coal, Ltd	P.O. Box 879, Minot, ND 58702	Sec. 34-T142N-R84W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 16-T142N-R83W
State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T142N-R83W
Luella C. Isaak	3347 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Burton Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Burton Lee Isaak, individually	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brenda Kitzan	3313 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brent J. Isaak	2065 33rd Avenue SW, Center, ND 58530	Sec. 16-T142N-R83W
Luella C. Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brent Isaak	2065 33rd Avenue SW, Center, ND 58530	Sec. 16-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 17-T142N-R83W
The State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T142N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 12-T141N-R84W
Brian Dresser	2574 37th Avenue SW, Center, ND 58530	Sec. 12-T141N-R84W
Frances Fuchs	2475 37th Avenue NW, Center, ND 58530	Sec. 12-T141N-R84W
Rosalie A. Dingus	400 Augsburg Avenue, Bismarck, ND 58504	Sec. 12-T141N-R84W
Mark R. Fuchs	18671 Fairweather, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jack B. Fuchs	15409 Rhododendron Drive, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jeff Erhardt and Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt and Kelly Jo Erhardt, as joint tenants	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Melvin Schoepp and Caroline Schoepp, as joint tenants	2023 Northridge Drive, Bismarck, ND 58503	Sec. 21-T142N-R83W
Larry Doll and Fay Doll, as joint tenants	3155 49th Ave., New Salem, ND 58563	Sec. 21-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND, 58501-5523	Sec. 21-T142N-R83W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 11-T141N-R84W
David O. Berger and Debra A. Berger, as joint tenants	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Melvin Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Caroline K. Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Larry Doll and Fay Doll, as joint tenants	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Larry Doll	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Grealing Starck and Deborah Stark, as joint tenants	3244 Highway 25, Center, ND 58530	Sec. 22-T142N-R83W
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 22-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 22-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 22-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 22-T142N-R83W

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

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 5-T141N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1415 Louisiana Street, Suite 2400, Houston, TX 77002-7361	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1658 Cole Boulevard, Building #6; Suite 2, Golden, CO 80401	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1101 N 27th Street, Suite 201, Billings, MT, 59101	Sec. 5-T141N-R83W
Susanna Skubinna	Egeland ND 58331	Sec. 5-T141N-R83W
Mildred Meili Miran	21500 Miran Farm Lane, Aldie, VA 20105	Sec. 5-T141N-R83W
Marilyn Meili	7681 East Vista Drive, Scottsdale, AZ 85250-6824	Sec. 5-T141N-R83W
Douglas L. Franklin	4409 S 292nd Street, Auburn, WA 98002	Sec. 5-T141N-R83W
R. C. Newkirk	4208 Lone Oak Drive, Fort Worth, TX 76107	Sec. 5-T141N-R83W
Vernon R. Young	2954 Chevy Chase Drive, Houston, TX 77019Z	Sec. 5-T141N-R83W
Charles W. LaGrave and Louis G. Kravits, as joint tenants	118 Weiss Court, Hercules, CA 94547	Sec. 5-T141N-R83W
Richard Haddaway	109 Estates Drive, Santa Fe, NM 87506	Sec. 5-T141N-R83W
Percy Lee Henderson	3032 Willing Avenue, Fort Worth, TX 76110	Sec. 5-T141N-R83W
W. H. Henderson	1016 S Main Street, Fort Worth, TX 76104	Sec. 5-T141N-R83W
K. C. Kyle, Jr.	P. O. Box 253, Carthage, TX 75633	Sec. 5-T141N-R83W
Catherine Westbrook	12 North Park, Randolph AFB, TX 78148	Sec. 5-T141N-R83W
Joseph Harrison Shelton, Jr.	18629 Reamer Road, Castro Valley, CA 94546	Sec. 5-T141N-R83W
Katherine S. Fulcher	1120 N Golder, Odessa, TX 79761	Sec. 5-T141N-R83W
C. H. Kopp and Blanche Kopp, as joint tenants	1609 E Cypress, Enid, OK 73701	Sec. 5-T141N-R83W
Stanley T. Staggs and Cora Staggs, as joint tenants	2233 NW 31 St., Oklahoma City, OK 73112	Sec. 5-T141N-R83W
Wyman Orlin Meigs	2408 Zion Park, Yukon, OK 73099-5939	Sec. 5-T141N-R83W
Robert Michael Westfall	No address of record	Sec. 5-T141N-R83W
Don Walter Westfall	No address of record	Sec. 5-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
First National Bank and Trust Company of Oklahoma City, Trustee under Agreement with Othel D. Westfall	c/o Boatmen's National Bank of Oklahoma, Bank of America, National Association (3510), Charlotte, NC, 100 North Tryon Street, Suite 170, Charlotte, NC 28202	Sec. 5-T141N-R83W
Charyl W. Loveridge and Margaret A. Loveridge, as joint tenants	701 Vandehei Avenue, Cheyenne, WY 82009-2553	Sec. 5-T141N-R83W
Dierdre A. (Reynolds) Shipman	6501 Deerview Trail, Durham, NC 27712	Sec. 5-T141N-R83W
John T. Reynolds	2835 Pond Apple, Schertz, TX 78154	Sec. 5-T141N-R83W
Mary L. (Reynolds) Hamlin	#9 Hickory Ridge, Texarkana, TX 75503	Sec. 5-T141N-R83W
Shauna I. (Reynolds) Lee	1127 Felicity Street, New Orleans, LA 70130	Sec. 5-T141N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 5-T141N-R83W
Red Crown Royalties, LLC	P. O. Box 888, Littleton, CO 80160-0888	Sec. 5-T141N-R83W
Tenneco Oil Company	P. O. Box 2511, Houston, TX 77252	Sec. 5-T141N-R83W
Tenneco Oil Company	1001 Louisiana, P. O. Box 2511, Houston, TX 77252-2511	Sec. 5-T141N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 5-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 5-T141N-R83W
United States of America	Unknown address	Sec. 8-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 8-T141N-R83W
Great River Energy Attn: Eric J. Olsen	12300 Elm Creek Boulevard N, Maple Grove, MN 55369-4718	Sec. 8-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 8-T141N-R83W
David Erhardt	13906 Round Oak Court. Houston, TX 77059	Sec. 8-T141N-R83W
Delphine Vetter	2317 79th Street SE, Linton, ND 58552	Sec. 8-T141N-R83W
Doretta Bornemann	511 County 27, Hazen, ND 58545	Sec. 8-T141N-R83W
Danita Deichert	3009 Bayside Drive, Mandan, ND 58554	Sec. 8-T141N-R83W
Dean P. Erhardt	120 Tennessee Walker Way, St. Peters, MO 63376	Sec. 8-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 8-T141N-R83W
Donna Barnhardt	8050 17th Avenue NE, Bismarck, ND 58501	Sec. 8-T141N-R83W
Linda Kilber	2928 Avenue B East, Bismarck, ND 58501	Sec. 8-T141N-R83W
Loretta Tabor	7100 Country Hills Drive, Bismarck, ND 58503	Sec. 8-T141N-R83W
John L. Kautzman	1314 22nd Street W, Williston, ND 58801-2139	Sec. 8-T141N-R83W
W. T. Brown	No street address of record, Newton, KS 67114	Sec. 8-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph MO 64501	Sec. 8-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 8-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Clay E. Kedrick	306 Morningside Lane, Newton, KS, 67114	Sec. 8-T141N-R83W
Clay E. Kedrick	P. O. Box 205, Newton, KS, 67114	Sec. 8-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 8-T141N-R83W
O. Sutorius	No address of record	Sec. 8-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS, 67114	Sec. 8-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 8-T141N-R83W
PEC Minerals LP	14860 Montfort Drive Suite 209, Dallas, TX, 75254	Sec. 8-T141N-R83W
Black Stone Minerals Company, L. P.	1001 Fannin, Suite 2020, Houston, TX, 77002-6709	Sec. 8-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-8006	Sec. 8-T141N-R83W
J. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 8-T141N-R83W
J. L. McMullen	127 N 4th St., Okemah, OK 74859-2456 AND 215 S 5th St., Okemah, OK 74859-3808	Sec. 8-T141N-R83W
Lily Stamper	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
George R. McKown	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 8-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 8-T141N-R83W
O. C. Fore	303 S Okfuskee Avenue, Wewoka, ND 74884	Sec. 8-T141N-R83W
Carl Files	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 8-T141N-R83W
Irene Kautzman	Center, ND 58530	Sec. 8-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 8-T141N-R83W
Breene Associates	1005 Ash Coulee Place, Bismarck, ND 58503	Sec. 8-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 8-T141N-R83W
Penelope Files	3387 W Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 8-T141N-R83W
Carolyn K. Files	P. O. Box 154, Bunn, NC 27508	Sec. 8-T141N-R83W
Kurt Von Files	143 Lake Royale, Louisburg, NC 27549	Sec. 8-T141N-R83W
Erika Lee Files	HC5, Box 103-1, Gainesville, MO 65655	Sec. 8-T141N-R83W
Robert Carl Files	1720 1/2 Reed Avenue, San Diego, CA, 92109	Sec. 8-T141N-R83W
Richard Irwin Files	1720 1/2 Reed Avenue, San Diego, CA, 92109	Sec. 8-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Janet K. Dohrmann and Jamie A. Fast, Co-Trustees of the Opp Family Mineral Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Great Northern Properties LP	601 Jefferson Street; Suite 3600, Houston, TX 77002	Sec. 7-T141N-R83W
BNI Coal, Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897	Sec. 7-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 7-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO, 80111	Sec. 7-T141N-R83W
Meridian Minerals Company	2919 Allen Parkway, Houston, TX, 77019-2142	Sec. 7-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 7-T141N-R83W
James Schneider	RR #1 Box 56, Center, ND 58530	Sec. 7-T141N-R83W
Gail Schneider	RR #1 Box 56, Center, ND 58530	Sec. 7-T141N-R83W
Ida Schwalbe Estate c/o Rolland Schwalbe	3160 25th Street, Center, ND 58530	Sec. 7-T141N-R83W
Wilma Lueneburg Estate c/o Linda Lueneburg	3730 Lockport St., Bismarck, ND 58503	Sec. 7-T141N-R83W
Alvin Hagerott	3190 27th Ave., Center, ND 58530	Sec. 7-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 15-T141N-R83W
Delvin Bueligen/Delvin Bueligen and Jill Bueligen, as joint tenant	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 15-T141N-R83W
Lowell Bueligen/Lowell Bueligen and Tammy Bueligen, as joint tenants	13621 Homestead Lane, Riverton, UT 84065	Sec. 15-T141N-R83W
Rodella Hausauer/Rodella Hausauer and Barry Hausauer, as joint tenants	1611 Castillian Way, Mundelein, IL 60060	Sec. 15-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO, 80126	Sec. 15-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 15-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 15-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 15-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 15-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 15-T141N-R83W
Albert Hagerott	3190 27th St, Center, ND 58530-9559	Sec. 15-T141N-R83W
Mary Hagerott	1719 N Bell St, Bismarck, ND 58501-1531	Sec. 15-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 15-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 15-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 82647	Sec. 15-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 15-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 15-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 15-T141N-R83W
State of North Dakota - Dept. of Trust Lands - Board of University & School Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T141N-R83W
State of North Dakota - Board of University & School Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T141N-R83W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 17-T141N-R83W
Central Dakota Humane Society	2104 37th St., Mandan, ND 58554	Sec. 17-T141N-R83W
David Erhardt	13906 Round Oak Court, Houston, TX 77059	Sec. 17-T141N-R83W
Delphine Vetter	2317 79th Street SE, Linton, ND 58552	Sec. 17-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Doretta Bornemann	511 County 27, Hazen, ND 58545	Sec. 17-T141N-R83W
Danita Deichert	3009 Bayside Drive, Mandan, ND 58554	Sec. 17-T141N-R83W
Dean P. Erhardt	120 Tennessee Walker Way, St. Peters, MO 63376	Sec. 17-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 17-T141N-R83W
Jerald O. Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 17-T141N-R83W
Wayne A. Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Karen L. Reuther	1411 Pocatello Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Jeanette M. Reuther	P. O. Box 304, Center, ND 58530	Sec. 17-T141N-R83W
Donna Barnhardt	8050 17th Avenue NE, Bismarck, ND 58501	Sec. 17-T141N-R83W
Linda Kilber	2928 Avenue B East, Bismarck, ND 58501	Sec. 17-T141N-R83W
Loretta Tabor	7100 Country Hills Drive, Bismarck, ND 58503	Sec. 17-T141N-R83W
John L. Kautzman	1314 22nd Street W, Williston, ND 58801-2139	Sec. 17-T141N-R83W
W. T. Brown	No street address of record, Newton, KS 67114	Sec. 17-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph MO 64501	Sec. 17-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 17-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 17-T141N-R83W
O. Sutorius	No address of record	Sec. 17-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS 67114	Sec. 17-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 17-T141N-R83W
PEC Minerals LP	14860 Montfort Drive, Suite 209, Dallas, TX 75254	Sec. 17-T141N-R83W
Black Stone Minerals Company, L. P.	1001 Fannin, Suite 2020, Houston, TX 77002-6709	Sec. 17-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-6709	Sec. 17-T141N-R83W
J. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W
J. L. McMullen	127 N 4TH ST, Okemah OK 74859-2456 AND 215 S 5TH ST Okemah OK 74859-3808	Sec. 17-T141N-R83W
Lily Stamper	No street address of record, Okemah OK 74859	Sec. 17-T141N-R83W
George R. McKown	No street address of record, Okemah OK 74859	Sec. 17-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 17-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W
O. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Carl Files	No street address of record, Okemah, OK 74859	Sec. 17-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 17-T141N-R83W
Irene Kautzman	Center, ND 58530	Sec. 17-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 17-T141N-R83W
Breene Associates	1005 Ash Coulee Place, Bismarck, ND 58503	Sec. 17-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 17-T141N-R83W
Penelope Files	3387 W Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 17-T141N-R83W
Carolyn K. Files	P. O. Box 154, Bunn, NC 27508	Sec. 17-T141N-R83W
Kurt Von Files	143 Lake Royale, Louisburg, NC 27549	Sec. 17-T141N-R83W
Erika Lee Files	HC5, Box 103-1, Gainesville, MO 65655	Sec. 17-T141N-R83W
Robert Carl Files	1720 1/2 Reed Avenue, San Diego, CA 92109	Sec. 17-T141N-R83W
Richard Irwin Files	1720 1/2 Reed Avenue, San Diego, CA 92109	Sec. 17-T141N-R83W
James Schneider	RR #1, Box 56, Center, ND 58530	Sec. 6-T141N-R83W
Gail Schneider	RR #1, Box 56, Center, ND 58530	Sec. 6-T141N-R83W
Ida Schwalbe Estate c/o Rolland Schwalbe	3160 25th Street, Center, ND 58530	Sec. 6-T141N-R83W
Wilma Lueneburg Estate c/o Linda Lueneburg	3730 Lockport St., Bismarck, ND 58503	Sec. 6-T141N-R83W
Alvin Hagerott	3190 27th Ave., Center, ND 58530	Sec. 6-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 6-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 6-T141N-R83W
Brian Reinke	1106 East Highland Acres Road, Bismarck, ND 58501	Sec. 6-T141N-R83W
Benjamin Reinke	1215 Columbia Drive, Bismarck, ND 58504	Sec. 6-T141N-R83W
Elizabeth Wagendorf	948 Stryker Avenue, West St. Paul, MN 55118	Sec. 6-T141N-R83W
United States of America	Unknown address	Sec. 6-T141N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 6-T141N-R83W
Tenneco Oil Company	P. O. Box 2511, Houston, TX 77252	Sec. 6-T141N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 6-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 6-T141N-R83W
Duane C. Anderson	1321 Whispering Hill, Ada, OK 74820	Sec. 9-T141N-R83W
Corrine L. Dockter	507 S 8th Street, Lot #10, Bismarck, ND 58504	Sec. 9-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Vi Ann Olson	2130 27th Avenue S, Grand Forks, ND 58201	Sec. 9-T141N-R83W
Gary A. Anderson	110 Lakota Avenue, Center, ND 58530	Sec. 9-T141N-R83W
Willard C. Anderson	No address of record (Check with Duane, Corrine, Vi or Gary)	Sec. 9-T141N-R83W
Wallace R. Anderson	No address of record (Check with Duane, Corrine, Vi or Gary), Star Prairie, WI 54026	Sec. 9-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 32-T142N-R83W
Heirs or Devisees of Alex Sorge, deceased	Center ND 58530	Sec. 32-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 32-T142N-R83W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 32-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 32-T142N-R83W
Spindletop Exploraton Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 32-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 32-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 32-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 32-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 32-T142N-R83W
United States of America	Unknown address	Sec. 32-T142N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec.4-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec.4-T141N-R83W
Anna Manny	Center, ND 58530	Sec.4-T141N-R83W
United States of America	Unknown address	Sec.4-T141N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 33-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 33-T142N-R83W
ALLETE, INC.	30 W Superior St., Duluth, MN 55802-2030	Sec. 33-T142N-R83W
Anna Manny	Center, ND 58530	Sec. 33-T142N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 33-T142N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 33-T142N-R83W
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 33-T142N-R83W
AgriBank, FCB (f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul)	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 33-T142N-R83W
Floyd B. Sperry	No street address of record, Bismarck, ND 58501	Sec. 33-T142N-R83W
State of North Dakota N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 33-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Great Northern Properties Limited Partnership Attn: Steven K. Shirley	1101 N. 27th Street, Suite 201, Billings, MT 59101	Sec. 33-T142N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 33-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 34-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 34-T142N-R83W
Nick Ferderer	Flasher, ND 58535 AND 912 Summit Blvd, Bismarck ND 58504-5277	Sec. 34-T142N-R83W
Harry H. Ferderer	907 Cowl Street, Milton Freewater OR 97862-1682	Sec. 34-T142N-R83W
John R. Ferderer	115 C Street North, Richardton ND 58652	Sec. 34-T142N-R83W
Eleanor Falstad	Eleanor Falstad Estate, c/o Valerie Fast, 2495 15th St. NW, Coleharbor ND 58531-9449	Sec. 34-T142N-R83W
Joyce Ervin, as personal representative of the Estate of Marie M. McGirl, deceased	2073 Rayshire Street, Thousand Oaks CA 91362-2460	Sec. 34-T142N-R83W
Esther Ferderer, as personal representative of the Estate of Jake H. Ferderer, deceased	No address of record	Sec. 34-T142N-R83W
Dorene Rambur	500 North 17th Street, Bismarck ND 58501	Sec. 34-T142N-R83W
Norman D. Bunch	6900 Wedgewood Ct., Black Hawk, SD 57718-9680	Sec. 34-T142N-R83W
Kaspar Barth	Center ND 58530	Sec. 34-T142N-R83W
United States of America	Unknown address	Sec. 34-T142N-R83W
County of Oliver	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 34-T142N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 34-T142N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 34-T142N-R83W
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 34-T142N-R83W
Floyd B. Sperry	No street address of record, Bismarck, ND 58501	Sec. 34-T142N-R83W
AgriBank, FCB (f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul)	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 34-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 3-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 3-T141N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 3-T141N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 3-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 3-T141N-R83W
Florian Emineth	No street address of record, Mandan, ND 58554	Sec. 3-T141N-R83W
Wm. M. Mutz	No street address of record, Mandan, ND 58554	Sec. 3-T141N-R83W
William K. Engelter	202 15th Street NW, Apt. 6, Mandan ND 58554-2075	Sec. 3-T141N-R83W
Great Northern Properties Limited Partnership Attn: Steven K. Shirley	1101 N. 27th Street, Suite 201, Billings, MT 59101	Sec. 3-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 3-T141N-R83W
Duane C. Anderson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Corrine L. Dockter	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Vi Ann Olson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Gary A. Anderson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Robert Reinke	1144 College Drive #201, Bismarck, ND 58501	Sec. 31-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 31-T142N-R83W
Nellie Dietz	New Salem ND 58563	Sec. 31-T142N-R83W
Eldon Reinke	Eldon Reinke Estate, c/o Colleen Reinke, 13239 71st Street SE, Lisbon ND 58054	Sec. 31-T142N-R83W
Lyle Reinke	c/o Colleen Reinke, 13239 71st Street SE, Lisbon ND 58054	Sec. 31-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 31-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 31-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 31-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 31-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 31-T142N-R83W
C. D. Griggs	230 Park Avenue, New York, NY 10169	Sec. 31-T142N-R83W
Lebert Lesch	Rt. 1, Box 134, Sheridan, WY 82801	Sec. 31-T142N-R83W
Lavern Heid	New Salem, ND 58563	Sec. 31-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
State of North Dakota N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 2-T141N-R83W
United States of America	Unknown address	Sec. 2-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 10-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Gertrude Schwalbe Estate c/o Susan Bohn, PR	16710 NE 41st Street, Redmond, WA 98052	Sec. 10-T141N-R83W
United States of America	Unknown address	Sec. 10-T141N-R83W
Duane C. Anderson	1321 Whispering Hill, Ada, OK 74820	Sec. 10-T141N-R83W
Corrine L. Dockter	624 S Hannifin Street; Apt. 3, Bismarck, ND 58504	Sec. 10-T141N-R83W
Vi Ann Olson	2130 27th Avenue S, Grand Forks, ND 58201	Sec. 10-T141N-R83W
Gary A. Anderson	315 Olier Avenue N, Center, ND 58530	Sec. 10-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 10-T141N-R83W
Delvin Bueligen/Delvin Bueligen and Jill Bueligen, as joint tenant	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 10-T141N-R83W
Lowell Bueligen/Lowell Bueligen and Tammy Bueligen, as joint tenants	13621 Homestead Lane, Riverton, UT 84065	Sec. 10-T141N-R83W
Rodella Hausauer/Rodella Hausauer and Barry Hausauer, as joint tenants	1611 Castillian Way, Mundelein, IL 60060	Sec. 10-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 10-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 10-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 10-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Lynn C. Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 10-T141N-R83W
Dollie Hagerot	744 Lake Avenue, Ortonville, MN 56278	Sec. 10-T141N-R83W
Albert Hagerott	3190 27th St, Center, ND 58530-9559	Sec. 10-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 10-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 10-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 10-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92674	Sec. 10-T141N-R83W
Alvin Hagerott	HC2 Box 244, Center ND 58530	Sec. 10-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 10-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 10-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 10-T141N-R83W
AgriBank, FCB f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 10-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 11-T141N-R83W
Great Northern Properties L.P.	1415 Louisiana Street, Suite 2400, Houston, TX 77002-7361	Sec. 11-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 11-T141N-R83W
State of North Dakota - Board of University and School Lands	1707 N 9th Street, Bismarck, ND 58501-5523	Sec. 11-T141N-R83W
Julie Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 11-T141N-R83W
Nancy Henke	P. O. Box 90, Hazen, ND 58545	Sec. 11-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 11-T141N-R83W
Peggy Gobar	504 Garden Avenue NW, West Fargo, ND 58078	Sec. 11-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Randy Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Janet K. Dohrmann and Jamie A. Fast, as Co-Trustees of The Opp Family Mineral Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 18-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 18-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Kent Reuther	3610 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W
Keith Reuther	3594 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Karen Shulz	13720 Chamy Dr., Reno, NV 89521	Sec. 18-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 18-T141N-R83W
Martha Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Ave. SW Center ND 58530	Sec. 18-T141N-R83W
Peter Pfleger Jr.	No address of record	Sec. 18-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 18-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 18-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 18-T141N-R83W
Sandra Ohlhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 18-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 18-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Wittmann, AZ 85361	Sec. 18-T141N-R83W
Holli K. Taylor	28827 N. 254th Lane, Wittmann, AZ 85361	Sec. 18-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 18-T141N-R83W
Darrell Ray Buntin III	P.O. Box 167, Chino Valley, AZ 86323	Sec. 18-T141N-R83W
Amanda Marie Minick	4332 S. Fireside Trail, Gilbert, AZ 85297	Sec. 18-T141N-R83W
Lisa F. Pulse, as a purported heir to Angeline Bonogofsky, deceased	405 William Street, Miles City MT 59301-2336	Sec. 18-T141N-R83W
Donald Perry Bonogofsky, as a purported heir to Angeline Bonogofsky, deceased	1117 Palmer Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Gary Blase Bonogofsky, as a purported heir to Angeline Bonogofsky, deceased	1117 Palmer Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Brittany E. Bonogofsky	1820 N. Merriam Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Duane J. Siegel	C65 100 3rd Street SW, Mandan, ND 58554	Sec. 18-T141N-R83W
Susan Jones	33800 NE Kern Court, Scappoose, OR 97056	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 18-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 18-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 18-T141N-R83W
Carolyn Files	P.O. Box 154, Bunn, NC 27508	Sec. 18-T141N-R83W
Robert Files	1720-1/2 Reed Avenue, San Diego, CA 92109	Sec. 18-T141N-R83W
Richard Files	1720-1/2 Reed Avenue, San Diego, CA 92109	Sec. 18-T141N-R83W
Kurt Files	143 Lake Royale, Louisburg, NC 27549	Sec. 18-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Penney Files	3387 West Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 18-T141N-R83W
Erika Files Hilliard	HC 5, Box 103-1, Gainesville, MO 65655	Sec. 18-T141N-R83W
J.C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
J.L. McMullen	127 N 4TH ST, Okemah OK 74859-2456 AND 215 S 5TH ST Okemah OK 74859-3808	Sec. 18-T141N-R83W
Lily Stamper	No street address of record, Okemah, OK 74859	Sec. 18-T141N-R83W
George R. McKown	No street address of record, Okemah, OK 74859	Sec. 18-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 18-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
Mrs. O.C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph, MO 64501	Sec. 18-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 18-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 18-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS 67114	Sec. 18-T141N-R83W
W.T. Brown	No street address of record, Newton, KS 67114	Sec. 18-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 18-T141N-R83W
PEC Minerals LP	14860 Montfort Drive, Suite 209, Dallas, TX 75254	Sec. 18-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-8006	Sec. 18-T141N-R83W
Black Stone Minerals Company, L.P.	1001 Fannin, Suite 2020, Houston, TX 77002-6709	Sec. 18-T141N-R83W
Barbara Endres	11449 SW 68th Court, Ocala, FL 34476	Sec. 18-T141N-R83W
Ellen Emley	6871 South Spotswood Street, Littleton, CO 80120	Sec. 18-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 19-T141N-R83W
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 19-T141N-R83W
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 19-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 19-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 19-T141N-R83W
Kent Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 19-T141N-R83W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 19-T141N-R83W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 19-T141N-R83W
Charles H. Kuether	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Charles H. Kuether	3555 28th Street, New Salem, ND 58563	Sec. 19-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert A Fryhling and Janice F. Fryhling, Trustees of the Fryhling Family Trust, dated August 15, 2002	2595 Calle Tres Lomas, San Diego, CA 92139	Sec. 19-T141N-R83W
Lila Wilson	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Lois Hohimer	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Madalyn Kraft	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Central Dakota Humane Society	2104 37th Street, Mandan, ND 58554	Sec. 19-T141N-R83W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 19-T141N-R83W
Earl Bodner	No address of record	Sec. 19-T141N-R83W
Erick G. Larson	50 Avalon Drive – Unit 7323, Milford CT 06460-8957	Sec. 19-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 27-T141N-R83W
Edward J. Koch	3359 Campstool Road, Cheyenne, WY 82007	Sec. 27-T141N-R83W
Randy L. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jacey Lee Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Gregory M. Messer	116 Pheasant Street, Bismarck, ND 58504	Sec. 27-T141N-R83W
Jennifer M. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jamie N. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jesse C. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Ronald F. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Heather A. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Ashley M. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Debra L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Dominic J. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Dayton L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Magdalena Koch	1205 Sunset Drive, Mandan, ND 58554	Sec. 27-T141N-R83W
John R. Hatzenbuhler and Ida Hatzenbuhler, as joint tenants	Route 1, Mandan, ND 58554	Sec. 27-T141N-R83W
Roberts' Royalty LLC	12239 Treeview Lane, Farmers Branch, TX 75234-7809	Sec. 27-T141N-R83W
James H. Luther Royalty, LLC	717 S View Terrace, Alexandria, VA 22314	Sec. 27-T141N-R83W
BM Marcus Royalty LLC	3948 SW Greencastle Avenue, Oxford, IA 52322	Sec. 27-T141N-R83W
Mary Langdon	11707 Monica Lane, Houston, TX 77024	Sec. 27-T141N-R83W
Martha Bauman	1513 Gaston, Austin, TX 78703	Sec. 27-T141N-R83W
El Campo Energy Partners, LLC	8815 Chalk Knoll Drive, Austin, TX 78735	Sec. 27-T141N-R83W
Graham Shinnick	No street address or zip code of record, Detroit, MI	Sec. 27-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Moody, Trustee of the Alice H. Cordes Revocable Trust, dated January 11, 2007	2343 E Sierra Street, Phoenix, AZ 85028	Sec. 27-T141N-R83W
Jane Z. Hooker	4743 N 54th Street, Phoenix, AZ 85018-1905	Sec. 27-T141N-R83W
V. G. Perry	No street address, Detroit, MI 48127	Sec. 27-T141N-R83W
United States of America	No address of record	Sec. 22-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 22-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 22-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 22-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 22-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 22-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 22-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 22-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 22-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 22-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 22-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 22-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 22-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 22-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 22-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 22-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 22-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 22-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 22-T141N-R83W
Edward J. Koch	3359 Campstool Road, Cheyenne, WY 82007	Sec. 22-T141N-R83W
Randy L. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jacey Lee Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Gregory M. Messer	116 Pheasant Street, Bismarck, ND 58504	Sec. 22-T141N-R83W
Jennifer M. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jamie N. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jesse C. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Ronald F. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Heather A. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Ashley M. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Debra L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Dominic J. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Dayton L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Magdalena Koch	1205 Sunset Drive, Mandan, ND 58554	Sec. 22-T141N-R83W
John R. Hatzenbuhler and Ida Hatzenbuhler, as joint tenants	Route 1, Mandan, ND 58554	Sec. 22-T141N-R83W
Roberts' Royalty LLC	12239 Treeview Lane, Farmers Branch, TX 75234-7809	Sec. 22-T141N-R83W
James H. Luther Royalty, LLC	717 S View Terrace, Alexandria, VA 22314	Sec. 22-T141N-R83W
BM Marcus Royalty LLC	3948 SW Greencastle Avenue, Oxford, IA 52322	Sec. 22-T141N-R83W
Mary Langdon	11707 Monica Lane, Houston, TX 77024	Sec. 22-T141N-R83W
Martha Bauman	1513 Gaston, Austin, TX 78703	Sec. 22-T141N-R83W
El Campo Energy Partners, LLC	8815 Chalk Knoll Drive, Austin, TX 78735	Sec. 22-T141N-R83W
Graham Shinnick	No street address, Detroit, MI 48127	Sec. 22-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Moody, Trustee of the Alice H. Cordes Revocable Trust, dated January 11, 2007	2343 E Sierra Street, Phoenix, AZ 85028	Sec. 22-T141N-R83W
Jane Z. Hooker	4743 N 54th Street, Phoenix, AZ 85018-1905	Sec. 22-T141N-R83W
V. G. Perry	No street address, Detroit, MI 48127	Sec. 22-T141N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 1-T141N-R84W
Travis Klatt and Jessica Klatt, as joint tenants	2438 37th Ave. SW, Center, ND 58530	Sec. 1-T141N-R84W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 1-T141N-R84W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 1-T141N-R84W
Red Crown Royalties, LLC	1490 W. Canal Court, Suite 3000, Littleton, CO 80120	Sec. 1-T141N-R84W
Ida Schwable	HC02 Box 258, Center, ND 58530	Sec. 1-T141N-R84W
Alvin Hagerott	HC2 Box 244, Center, ND 58530	Sec. 1-T141N-R84W
Ernst R. Lueneburg	2903 Manitoba Lane, Bismarck, ND 58501	Sec. 1-T141N-R84W
Glacier Park Company	801 Cherry Street, Fort Worth, TX 76102	Sec. 1-T141N-R84W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 1-T141N-R84W
Tenneco Oil Company	P.O. Box 2511, Houston, TX 77252	Sec. 1-T141N-R84W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 20-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 20-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 20-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 20-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 20-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 20-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 20-T141N-R83W
Joseph Edwin Marcy	2133 SE 57th Avenue, Portland, OR 97214	Sec. 20-T141N-R83W
Nancy L. Carr	219 Mariners Way, Savannah, GA 31419-9308	Sec. 20-T141N-R83W
Charles L. Marsters	3903 Gershwin Avenue N, St. Paul, MN 55128-3010	Sec. 20-T141N-R83W
Beverly R. Buttram	5176 N Blackbird Way, Boise, ID 83714-1780	Sec. 20-T141N-R83W
Sandra Kaye Gish	1654 SW Sagebrush Court, Dallas, TX 97338-1262	Sec. 20-T141N-R83W
Michael Charles Marsters	3920 Miranda Drive, Paris, TX 75462-6648	Sec. 20-T141N-R83W
David S. Marsters	4205 Saint Andrews Place, New Albany, IN 47150-9691	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Ronald P. Tuning	13300 NE Whitlow Lane, Newberg, OR 97132-6723	Sec. 20-T141N-R83W
Daniel R. Cottrell, Surviving Trustee of The Cottrell Trust, a revocbale living trust, dated September 26, 1996, as restated on August 25, 2014	8330 Cason Road, Unit 219, Gladstone, OR 97027	Sec. 20-T141N-R83W
L. D. Jenkins c/o Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Willow Point Corporation c/o Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Daniel Landeis and Carol Landeis	2735 Boundary Road, Bismarck, ND 58503	Sec. 20-T141N-R83W
Jessica Oakland	2218 LaForrest, Bismarck, ND 58501	Sec. 20-T141N-R83W
Jonica Norick	615 East Wachter Avenue, Bismarck, ND 58504	Sec. 20-T141N-R83W
Judy Dick and Brian T. Dick	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Jodi Gragg	4487 South Ireland Lane, Aurora, Co 80015	Sec. 20-T141N-R83W
Jeremiah Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Benjamen Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Garrett Dick	598 East Dry Creek Place, Littleton, CO 80122	Sec. 20-T141N-R83W
Mandy Davis	8394 South Everett Way, #F, Littleton, CO 80128	Sec. 20-T141N-R83W
Roger Landeis and Diane Landeis	7752 South Columbine Street, Centennial, CO 80122	Sec. 20-T141N-R83W
Tamara Landeis	2836 Mount Carmel Road, Newnan, GA 30263	Sec. 20-T141N-R83W
Randy Landeis and Susan Corine	11096 W 104th Drive, Westminster, CO 80021	Sec. 20-T141N-R83W
Cory Lee Landeis	11625 Community Center Drive, Apt. 1311, Northglenn, CO 80233	Sec. 20-T141N-R83W
Carisa Nicole Landeis	436 North 5th Avenue, Brighton, CO 80601	Sec. 20-T141N-R83W
Donald Roerich and Justine Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Mason Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Memphis Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Katherine Mosbrucker	404 NW 13th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 20-T141N-R83W
Irene Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 20-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 20-T141N-R83W
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 20-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 20-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 20-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 20-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 20-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 20-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 28-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 28-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 28-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 28-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Manda, ND 58554	Sec. 28-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Whitman, AZ 85361	Sec. 28-T141N-R83W
Holli K. Taylor	28827 N 254th Lane, Whitman, AZ 85361	Sec. 28-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 28-T141N-R83W
Darrell Ray Buntin III	P. O. Box 167, Chino Valley, AZ 86323	Sec. 28-T141N-R83W
Marie Pfleger	717 Solano Drive, Prescott, AZ86301	Sec. 28-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 28-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Clementine Freisz	710 Pine Avenue, New Salem, ND 58563	Sec. 28-T141N-R83W
Sandra K. Orgaard	2810 26th Street, Center, ND 58530	Sec. 28-T141N-R83W
Roger A. Friesz	797 7th Street, Idaho Falls, ID 83401	Sec. 28-T141N-R83W
Duane M. Friesz	4465 34th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Karen M. Porsborg	2720 37th Avenue SW, New Salem, ND 58563	Sec. 28-T141N-R83W
Michael J. Friesz	3463 County Road 87, New Salem, ND 58563	Sec. 28-T141N-R83W
Audrey A. Peterson	12719 Doris Drive, Black Hawk, SD 57718	Sec. 28-T141N-R83W
Marshall & Winston, Inc.	P. O. Box 50880, Midland, TX 79710-0880	Sec. 28-T141N-R83W
Hancock Enterprises	P. O. Box 2527, Billings, MT 59103	Sec. 28-T141N-R83W
Fortin Enterprises, Inc.	P.O. Box 3129, Palm Beach, FL 33480	Sec. 28-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
DeKalb Energy Company	1625 Broadway Suite 1300, Denver, CO 80202-4713	Sec. 28-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 21-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 21-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 21-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 21-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 21-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 21-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Whitman, AZ 85361	Sec. 21-T141N-R83W
Holli K. Taylor	28827 N 254th Lane, Whitman, AZ 85361	Sec. 21-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 21-T141N-R83W
Darrell Ray Buntin III	P. O. Box 167, Chino Valley, AZ 86323	Sec. 21-T141N-R83W
Amanda Marie Minick	4332 S Fireside Trail, Gilbert, AZ 85297	Sec. 21-T141N-R83W
Marie Pfleger	717 Solano Drive, Prescott, AZ 86301 AND 1487 Horseshoe Bend Drive, #37, Camp Verde, AZ 86322	Sec. 21-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 21-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 21-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 21-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 21-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 21-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 21-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 21-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center, ND 58530	Sec. 21-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 21-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 21-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 21-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 21-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 21-T141N-R83W
Grace Ellen Janssen	204 Juniper Dr., Bismarck, ND 58503-0292	Sec. 21-T141N-R83W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 21-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 21-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 21-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 21-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 21-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 21-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 21-T141N-R83W
Daniel Landeis and Carol Landeis	2735 Boundary Road, Bismarck, ND 58503	Sec. 21-T141N-R83W
Jessica Oakland	2218 LaForrest, Bismarck, ND 58501	Sec. 21-T141N-R83W
Jonica Norick	615 East Wachter Avenue, Bismarck, ND 58504	Sec. 21-T141N-R83W
Judy Dick and Brian T. Dick	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W
Jodi Gragg	4487 South Ireland Lane, Aurora, CO 80015	Sec. 21-T141N-R83W
Jeremiah Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W
Benjamen Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Garrett Dick	598 East Dry Creek Place, Littleton, CO 80122	Sec. 21-T141N-R83W
Mandy Davis	8394 South Everett Way, #F, Littleton, CO 80128	Sec. 21-T141N-R83W
Roger Landeis and Diane Landeis	7752 South Columbine Street, Centennial, CO 80122	Sec. 21-T141N-R83W
Tamara Landeis	2836 Mount Carmel Road, Newnan, GA 30263	Sec. 21-T141N-R83W
Randy Landeis and Susan Corine	11096 W 104th Drive, Westminster, CO 80021	Sec. 21-T141N-R83W
Cory Lee Landeis	11625 Community Center Drive, Apt. 1311, Northglenn, CO 80233	Sec. 21-T141N-R83W
Carisa Nicole Landeis	436 North 5th Avenue, Brighton, CO 80601	Sec. 21-T141N-R83W
Donald Roerich and Justine Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Mason Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Memphis Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Katherine Mosbrucker	404 NW 13th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Ralph P. Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 21-T141N-R83W
Irene Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 21-T141N-R83W
Mrs. Emanuel Kautzman	No address of record, Yakima WA 98901	Sec. 21-T141N-R83W
Estate of George Hagel, deceased	P.O. Box 223, Center, ND 58530	Sec. 2-T141N-R84W
City of Center Park District	No street address and zip code of record, Center ND	Sec. 2-T141N-R84W
James Hagel	746 E. 4th Ave., Kennewick, WA 99336	Sec. 2-T141N-R84W
Gene Hagel	9131 Prairie Vista Dr. NE, Albuquerque, NM 87113	Sec. 2-T141N-R84W
Kathy Lipp	4744 Thornburg Dr., Bismarck, ND 58504	Sec. 2-T141N-R84W
Loretta Rath	2606 Village Drive, Bismarck, ND 58505	Sec. 2-T141N-R84W
Julie Zahn	404 1st St. SW, Beulah, ND 58523	Sec. 2-T141N-R84W
Betty Yantzer	2745 18th St. SW, Center, ND 58530	Sec. 2-T141N-R84W
Jackie Schwab	938 Elbowoods Dr., Hazen, ND 58545	Sec. 2-T141N-R84W
Janice Matthews	P.O. Box 626, Washburn, ND 58577	Sec. 2-T141N-R84W
United States of America	No address of record	Sec. 2-T141N-R84W
Estate of Nick M. Berger, deceased	2529 37th Avenue SW, Center, ND 58530	Sec. 2-T141N-R84W
State Treasurer, as Trustee of the State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 2-T141N-R84W
Karmen Boehm	907 Nishu Place, Hazen, ND 58545	Sec. 2-T141N-R84W
Karle Boehm	1017 Fayette Drive, Hazen, ND 58545	Sec. 2-T141N-R84W
Dwight Wrangham and Linda Wrangham, as joint tenants	301 52nd St. SE, Bismarck, ND 58501	Sec. 2-T141N-R84W
Eileen Rooney Hewgley, L.L.C.	427 South Boston Avenue, Suite 304, Tulsa, OK 74103	Sec. 2-T141N-R84W
RLand, L.L.C.	401 South Boston Avenue, Suite 2400, Tulsa, OK 74103	Sec. 2-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The L.F. Rooney III Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Patrick T. Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	No address of record	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Timothy P. Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The James Harris Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees The Lucy Rooney Kapples Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 2-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Rebecca Finch Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 2-T141N-R84W
Osprey Resources, Inc.	P.O. Box 56449, Houston, TX 77256-6449	Sec. 2-T141N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, West Lake Hills, TX 78746	Sec. 2-T141N-R84W
Gonzaga University Law Dept. Scholarship	22H E. Euclid, Spokane, WA 99207	Sec. 2-T141N-R84W
J.C. Miller	508 Beacon Building, Tulsa, OK 74103	Sec. 2-T141N-R84W
Ralph M. Fahrenwald and Edna M. Fahrenwald, as joint tenants	3737 E. 45th Street, Tulsa, OK 74135	Sec. 2-T141N-R84W
Noah W. Millsap and Nell Rose Millsap, as joint tenants	1927 E. 33rd Place, Tulsa, OK 74105	Sec. 2-T141N-R84W
W.A. Dean and Fonda G. Dean, as joint tenants	1316 East 35th Place, Tulsa, OK 74105	Sec. 2-T141N-R84W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 29-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 29-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 29-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 29-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 29-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 29-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 29-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 29-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 29-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 29-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 29-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 29-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 29-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 29-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 29-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 29-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 29-T141N-R83W
Alvin Hagerott	HC2, Box 244, Center, ND 58530	Sec. 29-T141N-R83W
Dora Porsborg	Mandan Villa, Mandan, ND 58554	Sec. 29-T141N-R83W
Nels Porsborg	Mandan Villa, Mandan, ND 58554	Sec. 29-T141N-R83W
Dora Porsborg and Nels Porsborg c/o Kenneth Porsborg and Myron Porsborg	Route 1, Box 47A, Mandan, ND 58554	Sec. 29-T141N-R83W
Great Northern Properties LP	601 Jefferson Street; Suite 3600, Houston, TX 77002	Sec. 29-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 29-T141N-R83W
Meridian Minerals Company	2919 Allen Parkway, Houston, TX 77019-2142	Sec. 29-T141N-R83W
Fern Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 29-T141N-R83W
Steven P. Kraft and Julie F. Kraft, as joint tenants	2847 35th Avenue, New Salem, ND 58563	Sec. 29-T141N-R83W
Robert Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 29-T141N-R83W
Sandra Smith, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	1320 County Road 80, Mandan, ND 58558	Sec. 29-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Collette Friedt, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	802 Wagon Trail Street, Gillette, WY 82718	Sec. 29-T141N-R83W
Stacy Kautzman, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	9301 Wentworth Drive, Bismarck, ND 58503	Sec. 29-T141N-R83W
Jean L. Kautzman	2130 41st Avenue SW, Center, ND 58530	Sec. 29-T141N-R83W
Jay Kautzman	2024 N 5th Street, Bismarck, ND 58501	Sec. 29-T141N-R83W
Julie Frye	1853 N 23rd Street, Bismarck, ND 58501	Sec. 29-T141N-R83W
Janet Anderson	15537 East Radcliffe Place, Aurora, CO 80015	Sec. 29-T141N-R83W
Jeanine Marcolina	3938 East San Pedro, Gilbert, AZ 85234	Sec. 29-T141N-R83W
Douglas H. Kautzman	3450 County Road 138, Mandan, ND 58554	Sec. 29-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 13-T141N-R84W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 13-T141N-R84W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 13-T141N-R84W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 13-T141N-R84W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 13-T141N-R84W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 13-T141N-R84W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 13-T141N-R84W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Lynn C. Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Fern Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 13-T141N-R84W
Richard Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 13-T141N-R84W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 13-T141N-R84W
Dollie Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 13-T141N-R84W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R84W
Nancy Henke and Dwight Henke	P. O. Box 90, Hazen, ND 58545	Sec. 13-T141N-R84W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R84W
Melissa Hatlestad	2372 Harmon Lane, Mandan, ND 58554	Sec. 13-T141N-R84W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 13-T141N-R84W
Rodney Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 13-T141N-R84W
State of North Dakota Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 13-T141N-R84W
Mark Erhardt	P. O. Box 132, Center, ND 58530	Sec. 13-T141N-R84W
Margaret Erhardt	3685 27th Street, New Salem, ND 58563-9617	Sec. 13-T141N-R84W
Kathryn Erhardt	P. O. Box 132, Center, ND 58530	Sec. 13-T141N-R84W
Agnes Phagan	419 Mathias Street, Taft, TX 78390	Sec. 13-T141N-R84W
Isabelle Forster	851 4th Avenue E, Dickinson, ND 58601	Sec. 13-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Evangeline Bolton	1951 Carbon Ridge Street, Enumclaw, WA 98022	Sec. 13-T141N-R84W
Lorraine Bosch	851 4th Avenue E, Dickinson, ND 58601	Sec. 13-T141N-R84W
Ann Pasley	13838 162nd Avenue NE, Woodinville, WA 98072	Sec. 13-T141N-R84W
Scott Erhardt	3101 85M Avenue SW, Richardton, ND 58657	Sec. 13-T141N-R84W
Laura Kordonowy	2329 Main Street, Dickinson, ND 58601	Sec. 13-T141N-R84W
Alice Christianson	2585 Dakota Boulevard, Apt. 323, Dickinson, ND 58601	Sec. 13-T141N-R84W
Alice Frederick	Route 2 24C, Dickinson, ND 58601	Sec. 13-T141N-R84W
Marcus C. Erhardt	332 Wehrle Drive, Richardton, ND 58652	Sec. 13-T141N-R84W
Perry Erhardt	597 Twin Oaks Lane, Dallas, GA 30157	Sec. 13-T141N-R84W
Edward Erhardt	3105 85M Avenue SW, Richardton, ND 58652	Sec. 13-T141N-R84W
Wallace Erhardt	119 East Calgary Avenue, Bismarck, ND 58503	Sec. 13-T141N-R84W
Gloria Ciavarella	119 East Calgary Avenue, Bismarck, ND 58503	Sec. 13-T141N-R84W
Rose Erhardt	No street address of record, Dickinson, ND 58601	Sec. 13-T141N-R84W
Ronald P. Erhardt	No street address of record, Williston, ND 58801/58802/58803	Sec. 13-T141N-R84W
Rhoda P. Erhardt	2379 Snowshoe Court E, St. Paul, MN 55119	Sec. 13-T141N-R84W
Dorothy Mae Erhardt	Dickinson, ND 58601	Sec. 13-T141N-R84W
United States of America	No address of record	Sec. 14-T141N-R84W
Donald C. Erhard and Kathleen Erhardt	2955 37th Avenue SW, New Salem, ND 58563	Sec. 14-T141N-R84W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 14-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Raymond Schmidt, Sr. Estate	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 14-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 14-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 14-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655	Sec. 14-T141N-R84W
JoAnne Snow	329 Bedford Blvd., Bismarck, ND 58504	Sec. 14-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Rose Royalty, LLC	6730 N Scottsdale Road; Ste. 270, Scottsdale, AZ 85253	Sec. 14-T141N-R84W
Cooper Land Family, LLC	460 Oak Hill Road, Chaska, MN 55318	Sec. 14-T141N-R84W
Kristoffer J. Land	12275 Berea Court, Poway, CA 92064	Sec. 14-T141N-R84W
Solveig K. Land, Trustee of the Solveig K. Land Revocable Trust Agreement, dated August 2, 2008	310 Parkway Court, Minneapolis, MN 55419	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Mike Golden	P. O. Box 2734, Bismarck, ND 58502	Sec. 14-T141N-R84W
A. G. Golden	P. O. Box 1853, Bismarck, ND 58502	Sec. 14-T141N-R84W
Peter Mosbrucker	No street address of record, New Salem, ND 58563	Sec. 14-T141N-R84W
Jesse L. Lackman and Darcy J. Lackman Revocable Living Trust	2647 37th Avenue SW, Center, ND 58530	Sec. 14-T141N-R84W
Raymond Mizak and Phyllis F. Mizak	794 E Gemini Place, Chandler, AZ 85249	Sec. 14-T141N-R84W
Armstrong Minerals, LLC	P. O. Box 1999, Dickinson, ND 58602	Sec. 14-T141N-R84W
Julie M. Fadden and Gordon W. Schnell, Co-Trustees of the Patrick Fadden Residuary Trust	1007 Highland Place, Bismarck, ND 58501	Sec. 14-T141N-R84W
Richard E. Haug	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
W. R. Everett	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
Michelle M. Miller	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
Dennis W. Yockim	P. O. Box 477, Williston, ND 58801	Sec. 14-T141N-R84W
Douglas C. McLeod	518 17th Street, Ste. 1525, Denver, CO 80202	Sec. 14-T141N-R84W
O. W. E. Oil Company	P. O. Box 422, Pauma Valley, CA 92061	Sec. 14-T141N-R84W
Crescent Energy, Inc.	Box 1413, Scottsdale, AZ 85252-1413	Sec. 14-T141N-R84W
TurmOil, Inc.	P. O. Box 5, Bismarck, ND 58502	Sec. 14-T141N-R84W
The Carter Investment Company	333 Clay Street, Ste. 3439, Houston, TX 77002	Sec. 14-T141N-R84W
Black Stone Minerals Company, L.P.	1001 Fannin, Ste. 2020, Houston, TX 77002	Sec. 14-T141N-R84W
William G. Seal and Marcellyn J. Seal	4662 S Troost, Tulsa, OK 74170	Sec. 14-T141N-R84W
Robert C. Simpson, Trustee of the Robert C. Simpson Living Trust created by declaration of trust dated April 5, 1999	P. O. Box 700216 Tulsa, OK, 74170-0216	Sec. 14-T141N-R84W
John Williard Forsyth c/o Benjamin Forsyth	3301 9th Street E Great Falls, MT, 59404	Sec. 14-T141N-R84W
Martha Ann Forsyth Thomas	34 Creekside Close, Nellysford, VA 22958	Sec. 14-T141N-R84W
Benjamin Ripley Forsyth	3301 9th Street E, Great Falls, MT 59404	Sec. 14-T141N-R84W
L. R. Forsyth	L. R. Boughton (f.k.a. L. R. Forsyth), 1566 Texakoma Park Road, Kingston OK 73439-9324	Sec. 14-T141N-R84W
Thomas D. Selby	P. O. Box 2344, Williston, ND 58801	Sec. 14-T141N-R84W
M. Sue Bruce and Clifford R. Bruce, Sr., as Co-Trustees of the M. Sue Bruce Declaration of Trust dated January 30, 2015	36 Greenridge Drive, Decatur, IL 62526-1404	Sec. 14-T141N-R84W
Charles F. Smith c/o Mary Sue Bruce	36 Greenridge Drive, Decatur, IL 62526-1404	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Al Nick	111 Church Street, Ferguson, MO 63135	Sec. 14-T141N-R84W
Al E. Nick, Trustee of the Modak Trust A	111 Church Street, Ferguson, MO 63135	Sec. 14-T141N-R84W
Michael J. Wetzel	7880 Shelbyville Road, Indianapolis, IN 45259	Sec. 14-T141N-R84W
Aqua Purple Reef, LLC	7582 Mulholland Drive, Los Angeles, CA 9004	Sec. 14-T141N-R84W
Mary Catherine Watson	8136 Bishops Lane, Indianapolis, IN 46217	Sec. 14-T141N-R84W
Arkoma Bakken, LLC	203 E Interstate 30, Rockwall, TX 75087-5402	Sec. 14-T141N-R84W
Jean M. Voltz	9006 River Ridge Drive, Texarkana TX, 75503	Sec. 14-T141N-R84W
Rial Genre and Lynnette Genre	367 5th Street SW, Dickinson, ND 58601	Sec. 14-T141N-R84W
Margaret Leone Sutton Revocable Trust Agreement dated April 10, 1993	201 W Gibson Street, West Liberty, IA 52776	Sec. 14-T141N-R84W
Lynn C. Wright c/o Marjorie E. McKim	911 East Madison, Mt. Pleasant, IA 52641	Sec. 14-T141N-R84W
Pledge Resources, LLC	P. O. Box 1032, Bismarck, ND 58502	Sec. 14-T141N-R84W
Herbert Weder	Highland, IL 62249	Sec. 14-T141N-R84W
Jay W. Boulanger	9th and Lemon Streets, Highland, IL 62249	Sec. 14-T141N-R84W
Wray Boulanger	9th and Lemon Streets, Highland, IL 62249	Sec. 14-T141N-R84W
Orville A. Winet and Nelda E. Winet, as joint tenants	R. R. 3, Highland, IL 62249	Sec. 14-T141N-R84W
Susan Kim Ballinger, Successor Trustee of the Sutton Family Revocable Trust dated January 10, 1985/Jane Sutton	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of The Deborah Lynn Sutton Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of The David Keith Sutton Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of, The Ashley and Steven Ballinger Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger	P. O. Box 1271, Catoosa, OK74015	Sec. 14-T141N-R84W
Steven Ballinger	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Missouri River Royalty Corporation	919 S 7th Street, Ste. 405, Bismarck, ND 58504	Sec. 14-T141N-R84W
Northern Pacific Royalties, LLC	P. O. Box 572, Bismarck, ND 58502	Sec. 14-T141N-R84W
Northern Energy Corporation	P. O. Box 2283, Bismarck, ND 58502	Sec. 14-T141N-R84W
Jane Ogilvie	23 Geneva Drive, Muscatine, IA 52761	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Mason W. Potter Estate, c/o Jane Ogilvie	23 Geneva Drive, Muscatine, IA 52761	Sec. 14-T141N-R84W
LARCO Resources, LLC	P. O. Box 821, Bismarck, ND 58502-0821	Sec. 14-T141N-R84W
Clark James Crawford	1930 Riverwood Drive, Bismarck, ND 58504	Sec. 14-T141N-R84W
Eliza A. Burkholder	111 Bellemont Road, Bloomington, IL 61701	Sec. 14-T141N-R84W
Chester C. Alexander and Ralph E. Alexander	1590 Martha Drive, Elgin, IL 60123	Sec. 14-T141N-R84W
Yank Litzelman	Olney, IL 62450	Sec. 14-T141N-R84W
Mabel Litzelman	Olney, IL 62450	Sec. 14-T141N-R84W
Bavendick Minerals & Royalty, LLC	P. O. Box 313, Bismarck, ND 58502-0313	Sec. 14-T141N-R84W
C. R. Hippard and Chas F. Hippard	108 Locust Street, Maroa, IL 61756	Sec. 14-T141N-R84W
Valerian L. Roberts	2921 Cronin Drive, Springfield, I, 62711	Sec. 14-T141N-R84W
Michael D. Glaspey and Joyce A. Glaspey	P. O. Box 77, Lignite, ND 58752	Sec. 14-T141N-R84W
Joe E. Harrison, Jr.	778 W Decatur Street, Decatur, I, 62522	Sec. 14-T141N-R84W
William C. Clements	Highland, IL 62249	Sec. 14-T141N-R84W
Sherry D. Wilkin and Paul W. Wilken	285 Falcon Drive E, Highland, IL, 62249	Sec. 14-T141N-R84W
Amelia R. Clements	No street address of record, Highland, IL 62249	Sec. 14-T141N-R84W
Shari R. Weber, Trustee of the Shari R. Weber Trust dated August 10, 2008	75-6100 Alii Drive, Kona Isle E 22, Kailua-Kona, HI 96740	Sec. 14-T141N-R84W
Betty Eileen Ferrel	3740 Pinebrook Circle, #107, Bradenton, FL 34209	Sec. 14-T141N-R84W
Rikki P. Doyle	3740 Pinebrook Circle, #207, Bradenton, FL 34209	Sec. 14-T141N-R84W
Marcy P. Stacy	5619 Open Gate Court, Cincinnati, OH 45247	Sec. 14-T141N-R84W
Bobby Gene Story	8749 N 600th Street, Newton, IL 62448	Sec. 14-T141N-R84W
Lee Eugene Story	7711 N 500th Street, Newton, IL 62448	Sec. 14-T141N-R84W
Paul D. Johnson, Trustee of the Declaration of Trust of Paul D. Johnson, dated April 5, 1996	105 N Lafayette, Newton, IL 62448	Sec. 14-T141N-R84W
Sandra K. Hartrich	13 Carriage Lane, Newton, IL 62448	Sec. 14-T141N-R84W
Lana Dhom	107 N Maple Street, Newton, IL 62448	Sec. 14-T141N-R84W
Bruce Hartrich	1209 Seasons Drive, Godrey, IL 62035	Sec. 14-T141N-R84W
Eric Hartrich	1137 Drewsbury Court, Smyrna, GA 30080	Sec. 14-T141N-R84W
Judith Ann Hartrich and Dennis Hartrich	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Julie Burns	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Bradley Hartrich	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Jill Han	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Edward Kocher	16295 E 700th Avenue, Newton, IL 62448	Sec. 14-T141N-R84W
Scott A. Kocher	832 W 90th Avenue N, Conway Springs, KS 67031	Sec. 14-T141N-R84W
Matthew E. Kocher	4214 E State Hwy 234, Greenfield, IN 46140	Sec. 14-T141N-R84W
Gary Henry	257 Addison Way, Titisville, FL 32780	Sec. 14-T141N-R84W
Monica Snook	3406 Antietam Court, Edwardsville, IL 62025	Sec. 14-T141N-R84W
Melissa Cruz	13008 Pingry Place, Town & Country, MO 63131	Sec. 14-T141N-R84W
Melanie Byrkit	204 Magnolia Trace Drive, Ballwin, MO 63021	Sec. 14-T141N-R84W
Georgia Ann Upton	1783 Avenida Alta Mira, Oceanside, CA 92056	Sec. 14-T141N-R84W
John C. McElhiney	1720 Landisburg Road, Landisburg, PA 17040	Sec. 14-T141N-R84W
SHARK VENTURES, LLC	P. O. Box 2714, Bentonville, AR 72712	Sec. 14-T141N-R84W
Kent Littlejohn and Brenda Littlejohn	10777 N Friendship Road, Casey, IL 62420	Sec. 14-T141N-R84W
Jack L. Pitcher	6653 E 1800 Avenue, Montrose, IL 62445	Sec. 14-T141N-R84W
Melvin E. Pitcher	1065 Co. Rd. 000 N, Jewett IL 62436	Sec. 14-T141N-R84W
Marilyn J. James	24 Co. Rd. 1125 E, Jewett IL 62436	Sec. 14-T141N-R84W
Joyce Etnire	18931 Westfield Road, Charleston, IL, 61920	Sec. 14-T141N-R84W
Wayne Pitcher	11777 Destination Lane, Carthege, MO 64836	Sec. 14-T141N-R84W
Richard Pitcher	9000 U. S. Highway, Lot 575, Clermont, FL 34711	Sec. 14-T141N-R84W
Pam Goess	20 Lido Boulevard, Lake Grove, NY 11755	Sec. 14-T141N-R84W
Beverly Rosalee Shupe	206 N Marietta Street, Greenup, IL 62428	Sec. 14-T141N-R84W
Norma Elaine Edwards	262 Oak Avenue, Neoga, IL 62447	Sec. 14-T141N-R84W
Terry Eugene Warner	2537 Georgetown Road, Danville, IL 61832	Sec. 14-T141N-R84W
Stewart J. Schutte	6592 N 1075th Street, Robinson, IL 62454	Sec. 14-T141N-R84W
Tyler R. Tedford	10250 Wicklow Court, Fishers, IN 46040	Sec. 14-T141N-R84W
Kent A. Tedford	3823 N Ashland Avenue, #203, Chicago IL 60613	Sec. 14-T141N-R84W
David Porsborg and Karen Porsborg	2720 37th Avenue, New Salem, ND 58563	Sec. 24-T141N-R84W
Beverly Faul	1420 9th Avenue NE, McClusky, ND 58463	Sec. 24-T141N-R84W
Brad Bonnet	3444 110th Avenue NE, Bismarck, ND 58504	Sec. 24-T141N-R84W
Justin Kessler	6045 Lyndale Avenue S, #255, Minneapolis, MN 55419	Sec. 24-T141N-R84W
Adam Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Andrew Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Chad Porsborg	3206 Stonewall Drive, Bismarck, ND 58501	Sec. 24-T141N-R84W
Heather Bullinger	2602 10th Avenue SE, Mandan, ND 58554	Sec. 24-T141N-R84W
Christie Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Tina Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Jerald Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 24-T141N-R84W
Wayne Reuther	476 Glenwood Drive, Bismarck, ND 58504	Sec. 24-T141N-R84W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 24-T141N-R84W
Kent Reuther and Pam Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Dorothy Kessler	800 N Sewell Avenue, Miles City, MT 59301	Sec. 24-T141N-R84W
Dorothy Willem	1808 N Strevell, Miles City, MT 59301	Sec. 24-T141N-R84W
Jeannette Bonnet	1420 9th Avenue NW, McClusky, ND 58463	Sec. 24-T141N-R84W
Darlene Sorge	63 Lakeview Drive, Wheatland, WY 82201	Sec. 24-T141N-R84W
Robert Porsborg	415 1st Street E, Center, ND 58530	Sec. 24-T141N-R84W
Martha Reuther Estate, c/o Jerald Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 24-T141N-R84W
United States of America	No address of record	Sec. 10-T141N-R84W
Kenneth W. Reinke and Darlene Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
August W. Reinke Estate, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Lawrence Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Dora Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Walford Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Ervin Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Dora Schulte, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Grace Weiss, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
B. W. Henderscheid and Alice Henderscheid	3635 Hwy 200A, Center, ND 58530	Sec. 3-T141N-R84W
Gloria R. Albers	852 Bermuda Drive, Hemet, CA, 92543	Sec. 3-T141N-R84W
Shannon Wade Henke	8921 Island Road, Bismarck, ND 58503	Sec. 3-T141N-R84W
Karla Rae Henke	1238 Hyacinth Lane, Peachtree City, GA 30269	Sec. 3-T141N-R84W
Verlaine Gullickson	701 33rd Avenue N, Unit 411, Fargo, ND 58102	Sec. 3-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Agnes Dockter	2424 South 121st Street, Seattle, WA 98101	Sec. 15-T142N-R83W
Josephine McAdoo	No street address of record, Froid, MT 59226	Sec. 15-T142N-R83W
Anna Friesz	203 5th Avenue NE, Mandan, ND 58554	Sec. 15-T142N-R83W
Keith Vitek, as purported successor to the Estate of Clarence Vitek, deceased	P.O. Box 1214, Center, ND 58530	Sec. 15-T142N-R83W
Brenda Vitek, as purported successor to the Estate of Clarence Vitek, deceased	P.O. Box 1214, Center, ND 58530	Sec. 15-T142N-R83W
John Vitek	3002 South 208 Street, No. 8, Seattle WA, 98188	Sec. 15-T142N-R83W
Denisa Iwata f/k/a Denise Vitek	1458 Columbia Way 6, Seattle, WA 98178	Sec. 15-T142N-R83W
Sheila K. Naglich	11034 Crestwood Drive S, Seattle, WA 98178	Sec. 15-T142N-R83W
Gloria Iwata	1321 S. Puget Drive, E14, Renton, WA 98055	Sec. 15-T142N-R83W
Kathleen A. Rusich	4308 Lake Road, Apt. G, Killeen, WA 98146	Sec. 15-T142N-R83W
Sandra L. Vitek	10405 5th Avenue Southwest, Seattle, WA 98146	Sec. 15-T142N-R83W
Sacred Heart Hospice Donatory Corporation	1200 12th Street SW, Austin, MN 55912	Sec. 15-T142N-R83W
Karen O. Van Amburg, life tenant	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Jana Van Amburg, remainderman	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Matthew Van Amburg, remainderman	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Anne Cerulli, life tenant	13641 Alderwood Lane, 35B, Seal Beach, CA 90740	Sec. 15-T142N-R83W
Anthony James Cerulli, remainderman	2227 E. Everett Place, Orange, CA 92867	Sec. 15-T142N-R83W
Nathan Raymond Cerulli, remainderman	2227 E. Everett Place, Orange, CA 92867	Sec. 15-T142N-R83W
Black Stone Minerals Company, L.P.	1001 Fannin, Suite 2020, Houston, TX 77002	Sec. 15-T142N-R83W
Dorchester Minerals, L.P.	3838 Oak Lawn Avenue, Suite 300, Dallas, TX 75219	Sec. 15-T142N-R83W
Mike Saba a/k/a Michael P. Saba	26560 N. Shore Pl., Hartford, SD 57033	Sec. 15-T142N-R83W
State of North Dakota, for the use and benefit of the State Highway Department	608 East Boulevard Avenue, Bismarck, ND 58505-0700	Sec. 15-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 23-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Williston Projects, Inc.	3345 Highway 132, Rayville, LA 71269	Sec. 23-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Nick Freidig	17220 Schuch Lane, Stanwood, WA 56201	Sec. 23-T142N-R83W
Leo Freidig	1106 W. 14th St., Willmar, MN no zip code of record56201	Sec. 23-T142N-R83W
Johanna Rambur Jackson	3420 11th Place N., Renton, WA 98056	Sec. 23-T142N-R83W
Murex Petroleum Corporation	515 N. Sam Houston Parkway East, Suite 485, Houston, TX 77060	Sec. 23-T142N-R83W
Alan G. Cypert	6467 Glennox St., Dallas, TX 75214	Sec. 23-T142N-R83W
Missiana L.L.C.	15311 Vantage Parkway West, Suite 201, Houston, TX 77032	Sec. 23-T142N-R83W
Matt Freidig Jr.	2202 E. Rosser, Bismarck, ND 58501	Sec. 23-T142N-R83W
Cynthia C. Fowler, as Trustee of The Cotton 4 Mineral Trust	1411 North Boulevard, Houston, TX 77006	Sec. 23-T142N-R83W
Michael H. Dunn	1128 South 7th Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
James M. Dunn	116 Center Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
Alice R. Dunn Thompson	116 Center Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
Cynthia C. Fowler, as Trustee of The Cotton 6 Mineral Trust	1411 North Boulevard, Houston, TX 77006	Sec. 23-T142N-R83W
George E. Moss Jr. and John K. Moss, as joint tenants	4360 Worth Street, Los Angeles, CA 90063	Sec. 23-T142N-R83W
Alexander F. Rolle and Andrew Rolle, as Trustees of The Andrew Rolle O & G Trust	2105 Adair, San Marino, CA 91108	Sec. 23-T142N-R83W
Henry O. Bergloff	606 North Addison, Villa Park, IL 60181	Sec. 23-T142N-R83W
Raymond A. Bergloff	22712 Brenford Street, Woodland Hills, CA 91364	Sec. 23-T142N-R83W
Cleone I. Fredrickson	Box 9116, Brooks, OR 97305	Sec. 23-T142N-R83W
Laurence S. Bergloff	9900 Oakland Avenue South, Bloomington, MN 55420	Sec. 23-T142N-R83W
Beatrice L. Ottema	9901 Oakland Avenue South, Bloomington, MN 55420	Sec. 23-T142N-R83W
Alfred O. Bergloff	2528 Atlas Drive, Bismarck, ND 58501	Sec. 23-T142N-R83W
Mardi Albers, as purported successor to the Estate of Joyce Albers	P.O. Box 164, Grass Range, MT 59032	Sec. 23-T142N-R83W
Claudette Yantzer, as purported successor to the Estate of Joyce Albers	P.O. Box 180, Killdeer, ND 58640	Sec. 23-T142N-R83W
Daniel Bergloff	1232 W. 450 #46, Clearfield, UT 84015	Sec. 23-T142N-R83W
Norman Berglof	1232 W. 450 #46, Clearfield, UT 84015	Sec. 23-T142N-R83W
Vylo Raye Glasgow	2029 Canyon Drive, Billings, MT 59102	Sec. 23-T142N-R83W
Renee K. Hicks	16690 S.W. Vincent St., Aloha, OR 97007	Sec. 23-T142N-R83W
Constance M. Russell and Robert L. Russell, as Trustees of The Constance M. Russell Trust executed March 15, 1993	6000 NE Livingston Road, Camas, WA 98607	Sec. 23-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Keith H. Albers	2333 Portola Drive #46, Santa Cruz, CA 95062	Sec. 23-T142N-R83W
Roberta L. Herman	20247 Homestead Drive, Oregon City, OR 97045	Sec. 23-T142N-R83W
State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 36-T142N-R84W
John M. Haag and Beata Haag	P. O. Box 353, Center ND 58530	Sec. 36-T142N-R84W
Larry J. Doll and Faye Doll	5801 Lake Shore Est., Lot 9, Beulah, ND 58523	Sec. 25-T142N-R83W
Monsadius J. Hatzenbihler Estate, c/o Denise Brorby and Jill Bosch	265 93rd Street SE, Strasburg, ND 58573	Sec. 25-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court; Ste. 3000, Littleton, CO 80120	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W

Mineral Owners, Lessees and Operators	**Mailing Address**	**Legal Description**
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Eileen Rooney Hewgley, L.L.C.	427 S Boston Avenue; Ste. 304, Tulsa, OK 74103	Sec. 25-T142N-R83W
RLand, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 25-T142N-R83W
Osprey Rersources, Inc.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 25-T142N-R83W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 25-T142N-R83W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 25-T142N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 25-T142N-R83W
Tenneco Oil Company	P. O. Box 3119, Englewood, CO 80155 AND 1001 Louisiana, P. O. Box 2511, Houston, TX 77252-2511	Sec. 25-T142N-R83W
John M. Haag and Beata Haag	P. O. Box 353, Center, ND 58530	Sec. 24-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Eileen Rooney Hewgley, L.L.C.	427 S Boston Avenue; Ste. 304, Tulsa, OK 74103	Sec. 24-T142N-R84W
RLand, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 24-T142N-R84W
Osprey Rersources, Inc.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 24-T142N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 24-T142N-R84W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 24-T142N-R84W
Carlotta B. Tyler	Elk River MN 55330	Sec. 25-T142N-R84W
E. L. Gunberg	No street address, Minneapolis, MN 55111	Sec. 25-T142N-R84W
O. P. Curry	No street address, Minneapolis, MN 55111	Sec. 25-T142N-R84W
P. H. Phillips	5444 Fremont Ave S, Minneapolis, MN 55419-1625	Sec. 25-T142N-R84W
Albert A. Reed	No street address or zip code of record, Minneapolis, MN	Sec. 25-T142N-R84W
Frances R. Kary	1709 Linda Drive, Mandan, ND 58554	Sec. 25-T142N-R84W
Cecelia Hatzenbihler	P. O. Box 283, Center, ND 58530	Sec. 25-T142N-R84W
Elizabeth Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 25-T142N-R84W
Joyce Barrick	835 Harrington Street SW, Hutchinson, MN 55350-3013	Sec. 25-T142N-R84W
Richard Himmelspach	8983 Sheridan Lake Road, Rapid City, SD 57702-9064	Sec. 25-T142N-R84W
Gary Himmelspach	4201 Old Red Trail NW, Mandan, ND 58554-1352	Sec. 25-T142N-R84W
Michele Curtis	710 3rd Avenue SE, Jamestown, ND 58401	Sec. 25-T142N-R84W
Robert Himmelspach	6298 Fox Run Drive, Idaho Falls, ID 83402-5876	Sec. 25-T142N-R84W
Mary Nelson	5004 Cornice Drive, Bismarck, ND 58503	Sec. 25-T142N-R84W
Becky Martin	10049 N 27th E, Idaho Falls, ID 83401-6437	Sec. 25-T142N-R84W
Beverly Moon	#4 Manor Lane, Rossville, GA 30741	Sec. 25-T142N-R84W
Jeanette Brown	HC 2, Box 154, Hensler, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt c/o Kenneth Schmidt	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Kenneth J. Schmidt, Personal Representative of the Monica Schmidt Estate	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt	3581 22 Street SW, Center, ND 58530	Sec. 19-T142N-R83W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Robert A. Wilbrandt, Executor of Harold M. Tripp Estate	P. O. Box 85, Crystal Lake, IL 60039	Sec. 19-T142N-R83W
Mary S. Tripp	P. O. Box 85, Crystal Lake, IL 60039	Sec. 19-T142N-R83W
Matthias A. Erhardt and Josephine Erhardt, as co-trustees of the Erhardt Family Trust dated June 13, 2006	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
June T. Nelson	15100 Interlachen Drive, # 212, Silver Springs, MD 20906	Sec. 19-T142N-R83W
Anna I. V. Kiebert	No address of record	Sec. 19-T142N-R83W
William V. Kiebert	No address of record	Sec. 19-T142N-R83W
Mary E. Tripp	No street address or zip of record. USPS.com for zip, Faribault, MN 55021	Sec. 19-T142N-R83W
Joey Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Jerry Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 1-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 1-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 1-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 1-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan ND 58554	Sec. 1-T141N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 12-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan, ND 58554	Sec. 12-T141N-R83W
Fred Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Raynold Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Walter Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 12-T141N-R83W
Nancy Henke and Dwight Henke, as joint life tenants	P.O. Box 90, Hazen, ND 58545	Sec. 12-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane N, Mandan, ND 58554	Sec. 12-T141N-R83W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 12-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 12-T141N-R83W
Peggy Gobar	504 Garden Ave. NW, West Fargo, ND 58078	Sec. 12-T141N-R83W
Annette Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Brent Hatzenbihler	310 W. Tonk, Gillette, WY, 82718	Sec. 12-T141N-R83W
Randy Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523z	Sec. 12-T141N-R83W
United States of America	No address of record	Sec. 12-T141N-R83W
Reda Renee Clinton and Stephanie A. Clarys, as joint tenants	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Michael P. Hilton	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Oliver County	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 14-T141N-R83W
John Barnhardt	1511 North 21st Street, Bismarck, ND 58501	Sec. 14-T141N-R83W
Gail M. Hilton	3195 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND, 58530	Sec. 14-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 14-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 14-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 14-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 14-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 14-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Dale Barnhardt	3199 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 14-T141N-R83W
United States of America	No address of record	Sec. 14-T141N-R83W
Jeff Erhardt ad Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 20-T142N-R83W
"State of North Dakota N.D. Dept. of Trust Lands"	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 20-T142N-R83W
Federal Land Bank of Saint Paul	375 Jackson Street, P.O. Box 64949, St. Pau, MN 55164-0949	Sec. 20-T142N-R83W
General Council of the Assemblies of God	1445 N. Boonville Avenue, Springfield MO 65802-1894	Sec. 20-T142N-R83W
North Dakota District Council of the Assemblies of God	1724 North Grandview Lane, Bismarck ND 58503	Sec. 20-T142N-R83W
Matthias A. Erhardt and Josephine Erhardt, as co-trustees of the Erhardt Family Trust dated June 13, 2006	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
United States of America	No address of record	Sec. 20-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 26-T142N-R83W
Heirs or Devisees of the Estate of Loren Schwalbe, deceased	3520 81st Ave. SE, Unit 15, Jamestown, ND 58401	Sec. 26-T142N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 26-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 26-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 26-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 26-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 26-T142N-R83W
Sacred Heart Hospice Donatory Corporation	1200 12th Street SW, Austin, MN 55912	Sec. 26-T142N-R83W
John J. Krauth	Dumont MN 56236	Sec. 26-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 26-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 26-T142N-R83W
T. F. Hodge	1113 Continental Bank Building, Fort Worth, TX No zip code of record	Sec. 26-T142N-R83W
Pierce Exploration & Production Corporation	1133 Bal Harbor Blvd., #1139, Punta Gorda, FL 33950	Sec. 26-T142N-R83W
Marshall & Winston, Inc.	P.O. Box 50880, Midland, TX 79710-0880	Sec. 26-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 26-T142N-R83W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 27-T142N-R83W
Kathryn S. Wilson	1941 St. Johns Road, Apt. #34, Seal Beach, CA 90740	Sec. 27-T142N-R83W
Margaret A. Flavin	1240 Fourth Avenue, Los Angeles, CA 90019	Sec. 27-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 28-T142N-R83W
Nick Ferderer	Flasher, ND 58535 AND 912 Summit Blvd, Bismarck ND 58504-5277	Sec. 28-T142N-R83W
Harry H. Ferderer	907 Cowl Street, Milton Freewater, OR 97862-1682	Sec. 28-T142N-R83W
John R. Ferderer	115 C Street North Richardton ND 58652	Sec. 28-T142N-R83W
Eleanor Falstad	2495 15th St. NW Coleharbor, ND 58531-9449	Sec. 28-T142N-R83W
Joyce Ervin, as personal representative of the Estate of Marie M. McGirl, deceased	2073 Rayshire Street, Thousand Oaks CA 91362-2460	Sec. 28-T142N-R83W
Esther Ferderer, as personal representative of the Estate of Jake H. Ferderer, deceased	No address of record	Sec. 28-T142N-R83W
Dorene Rambur	500 North 17th Street Bismarck ND 58501	Sec. 28-T142N-R83W
Norman D. Bunch	6900 Wedgewood Ct., Black Hawk, SD 57718-9680	Sec. 28-T142N-R83W
Kasper Barth	Center ND 58530	

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Dale Barth	2255 33rd Ave SW, Center, ND 58530	Sec. 28-T142N-R83W
Dusty Backer	PO Box 411, Underwood, ND 58576	Sec. 28-T142N-R83W
United States of America	No address of record	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S., Grand Forks, ND 58208-3200 AND 1822 Mill Road, P. O. Box 13200, Grand Forks, ND 58208-3200	Sec. 29-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 29-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 29-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 29-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 29-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 29-T142N-R83W
J. F. Millard	5100 Aldrich Avenue South, Minneapolis, MN 55419	Sec. 29-T142N-R83W
Benischek Management, L.L.C.	3600 N. Harvey Parkway, Oklahoma City, OK 73118	Sec. 29-T142N-R83W
H. Gordon Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 29-T142N-R83W
Margaret W. Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 29-T142N-R83W
John H. Carton	Wolverine Tower, Battle Creek, MI	Sec. 29-T142N-R83W
Mack K. Lowrey	P. O. Box 393, Lancaster, TX 75146	Sec. 29-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 29-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312 AND 1822 Mill Road, P. O. Box 13200, Grand Forks, ND 58208-3200	Sec. 30-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 30-T142N-R83W
John M. Haag and Beata Haag, as joint tenants	P. O. Box 353, Center ND 58530	Sec. 30-T142N-R83W
Osprey Resources, Inc.	PO Box 56449, Houston, TX 77256-6449	Sec. 30-T142N-R83W
Mary Michael Genung	885 Live Oak Ridge Road, West Lake Hills, TX 78746	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the L. F. Rooney III Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Patrick T. Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Timothy P. Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the James Harris Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Lucy Rooney Kapples Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Rebecca Finch Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Eileen Rooney Hewgley, L.L.C.	427 South Boston Avenue, Suite 304, Tulsa, OK 74103	Sec. 30-T142N-R83W
RLand, L.L.C.	401 South Boston Avenue, Suite 2400, Tulsa, OK 74103	Sec. 30-T142N-R83W
Gonzaga University Law Dept.	1224 E Euclid, Spokane, WA 99207	Sec. 30-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 30-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 30-T142N-R83W
Benischek Management, L.L.C.	3600 N. Harvey Parkway, Oklahoma City, OK 73118	Sec. 30-T142N-R83W
H. Gordon Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 30-T142N-R83W
Margaret W. Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 30-T142N-R83W
John H. Carton	Wolverine Tower, Battle Creek, MI 49017	Sec. 30-T142N-R83W
Mack K. Lowrey	P. O. Box 393, Lancaster, TX 75146	Sec. 30-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 30-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 30-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 30-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY No zip code of record	Sec. 30-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 30-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 30-T142N-R83W
Unknown trustee of the Frederick W. McCoy, Jr. Revocable Trust	PO Box 11215, St. Louis, MO 63105	Sec. 30-T142N-R83W
Hymen Cohen and Janis M. Cohen, as joint tenants	7301 Shaftesbury, University City, MO 63130	Sec. 30-T142N-R83W
Martha Buchheister	1748 Fremont Court, Ft. Collins, CO 80526	Sec. 30-T142N-R83W
DGHJLW Holdings, LLC	P.O. Box 33, Cleveland, NM 87715-0033	Sec. 30-T142N-R83W
Groundswell 45, LLC	P.O. Box 121, Kiowa, CO 80117	Sec. 30-T142N-R83W
AWerdel Minerals, LLC	1419 17th Street, Greeley, CO 80631	Sec. 30-T142N-R83W
J. Byron Werdel Resources, LLC	1419 17th Street, Greeley, CO 80631	Sec. 30-T142N-R83W
Shari R. Weber, as trustee of the Shari R. Weber Trust dated August 10, 2008	107 W. Cedar, P O Box 137, Robinson, IL 62454	Sec. 30-T142N-R83W
Betty Eileen Ferrel	3740 Pinebrook Circle, #107, Bradenton, FL 34209	Sec. 30-T142N-R83W
Rikkie P. Doyle	3740 Pinebrook Circle, #207, Bradenton, FL 34209	Sec. 30-T142N-R83W
Marcy P. Stacy	5619 Open Gate Court, Cincinnati, OH 45247	Sec. 30-T142N-R83W
Guy M. Simmons and Ruby P. Simmons, as joint tenants	820 North Cross St., Robinson, IL 62454	Sec. 30-T142N-R83W
Thomas E. Eaton, Sr.	7817 North 1150th Street, Newton, IL 62448	Sec. 30-T142N-R83W
Jacqueline R. Blakley	3207 Florence Drive, Champaign, IL, 61822-8011	Sec. 30-T142N-R83W
Lee. R. Martin	1602 South Lamar Street, Lakewood, CO 80226	Sec. 30-T142N-R83W
Kent Littlejohn and Brenda Littlejohn, as joint tenants	10777 N. Friendship Road, Casey, IL 62420	Sec. 30-T142N-R83W
O. E. Benefiel and Isabel Benefiel, as joint tenants	No street address of record, Newton, IL 62448	Sec. 30-T142N-R83W
Jerome Maginn and Mary Maginn, as joint tenants	Route #3, Newton, IL 62448	Sec. 30-T142N-R83W
Timothy J. Pulliam, as Trustee of the Timothy J. Pulliam Family Legacy Trust dated December 14, 2017	27701 Sycamore Creek Drive, Valencia, CA 91354	Sec. 30-T142N-R83W
Alonzo Walden and Buerryl Walden, as joint tenants	No street address of record, Hidalgo, IL No zip code of record	Sec. 30-T142N-R83W
Donald L. Long and Ledora M. Long, as joint tenants	R. R. 3, Newton, IL 62448	Sec. 30-T142N-R83W
Arnold L. Colpitts and Esther M. Colpitts, as joint tenants	No street address of record, Newton, IL No zip code of record	Sec. 30-T142N-R83W
Irma J. Goeckner, as Trustee of the Goeckner Living Trust dated January 24, 2011	7202 Torrington Way, Springfield, IL 62711	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Alice Marlene Heaton	863 County Road 500 East, Toledo, IL 62468	Sec. 30-T142N-R83W
Todd David Clark	3301 Avondale Avenue, Knoxville, TN 37917	Sec. 30-T142N-R83W
David Deatherage and Myrtle Deatherage, as joint tenants	No street address of record, Oblong, IL 62449	Sec. 30-T142N-R83W
Estate of Belva L. Dalrymple, deceased	8929 State Route 555, Cutler OH 45724-5167	Sec. 30-T142N-R83W
Robert Lynn Dalrymple and Elizabeth J. Feuerstein, as joint tenants	5 West Fairview Street, Arlington Heights, IL 60005-2551	Sec. 30-T142N-R83W
Barbara Breen, as PR of the Estate of William Wallace Dalrymple, deceased	4 Stuart on Oxford, Rolling Meadows, IL 60008	Sec. 30-T142N-R83W
Kay Kirkpatrick	430 S. Elmwood, Oak Park, IL 60302	Sec. 30-T142N-R83W
Karen Quinn	518 S. Euclid, Oak Park, IL 60304	Sec. 30-T142N-R83W
Kathy Simandl	R.R. #2, Box 210, Menomonie, WI 54751	Sec. 30-T142N-R83W
George G. Vaught, Jr.	P.O. Box 13557, Denver, CO 80201-3557	Sec. 30-T142N-R83W
Paul L. McCulliss	P.O. Box 3248, Littleton, CO 80161-3248	Sec. 30-T142N-R83W
Glengarry Oil Company	PO Box 267, Lima, OH 45802	Sec. 30-T142N-R83W
Stewart J. Schutte	6592 N. 1075th Street, Robinson, IL 62454	Sec. 30-T142N-R83W
Tyler R. Tedford	10250 Wicklow Court, Fishers, IN 46040	Sec. 30-T142N-R83W
Kent A. Tedford	3823 N. Ashland Avenue, #203, Chicago, IL 60613	Sec. 30-T142N-R83W
Charles Sanders	301 North Wolfenberger Street, #1, Sullivan IN 47882-7211	Sec. 30-T142N-R83W
Thomas L. Frichtl and Elizabeth Frichtl, as joint tenants	11681 North 1300th Street, Newton IL 62448-3622	Sec. 30-T142N-R83W
Frank G. Mefford, Emogene Mefford, and Cheryl A. Mefford, as joint tenants	Rt. 1, Palestine, IL 62451	Sec. 30-T142N-R83W
James D. Stout, as trustee of the Carl H. Zwermann Trust	PO Box 714, Robinson IL 62454	Sec. 30-T142N-R83W
United States of America	No address of record	Sec. 30-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 35-T142N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan ND 58554	Sec. 35-T142N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 35-T142N-R83W
T. F. Hodge	1113 Continental Bank Building, Fort Worth, TX No zip code of record	Sec. 35-T142N-R83W
Pierce Exploration & Production Corporation	1133 Bal Harbor Blvd., #1139, Punta Gorda, FL 33950	Sec. 35-T142N-R83W
Marshall & Winston, Inc.	P.O. Box 50880 Midland, TX 79710-0880	Sec. 35-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 36-T142N-R83W
Michelle Marie Ternes	3721 W Regent Drive, Bismarck, ND 58504	Sec. 35-T142NR84W
Michael P. Dresser	3731 24th Street SW, Center, ND 58530	Sec. 35-T142NR84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Linda L. Ash	411B 32nd Avenue NW, Underwood, ND 58576	Sec. 35-T142NR84W
Thomas Dresser, Sr.	HC 2, Box 218", Center, ND 58530	Sec. 35-T142NR84W
USA - Dept. of Interior, Bureau of Land Management	1245 N 29th Street, Billings, MT 59101-0122	Sec. 34-T142N-R84W
Larry Bernard Dresser and Mary Dresser	RR 1, Box 80A", Washburn, ND 58577	Sec. 34-T142N-R84W
Thomas Dresser, Jr.	609 N Almon, #2028, Moscow, ID 83843	Sec. 34-T142N-R84W
Tammy L. Dresser	4810 16th Avenue SW, Apt. #206, Fargo, ND 58103	Sec. 34-T142N-R84W
Laura Ann Dresser	4810 Highway 7, Apt. #102, St. Louis Park, MN 55416	Sec. 34-T142N-R84W
Paul Ash	HC 1, Box 34", Underwood, ND 58576	Sec. 34-T142N-R84W
Dean Ash	HC 1, Box 34", Underwood, ND 58576	Sec. 34-T142N-R84W
Theresa Ash	HC 1, Box 34, Underwood, ND 58576	Sec. 34-T142N-R84W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 16-T142NR83W
State of North Dakota		Sec. 16-T142NR83W
Luella C. Isaak	3347 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Burton Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Bruce Isaak	1819 Xavier Street, Bismarck, ND 58501	Sec. 16-T142NR83W
Byron Isaak	2132 Terra Ridge Drive, Highlands Ranch, CO 80126	Sec. 16-T142NR83W
Brenda Kitzan	3313 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 17-T142N-R83W
The State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T142N-R83W
United States of America	No address of record	Sec. 12-T141N-R84W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 12-T141N-R84W
Brian Dresser	2574 37th Avenue SW, Center, ND 58530	Sec. 12-T141N-R84W
Frances Fuchs	2475 37th Avenue NW, Center, ND 58530	Sec. 12-T141N-R84W
Rosalie A. Dingus	400 Augsburg Avenue, Bismarck, ND 58504	Sec. 12-T141N-R84W
Mark R. Fuchs	18671 Fairweather, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jack B. Fuchs	15409 Rhododendron Drive, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 12-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 12-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 12-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 12-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655 AND 203 S Prairie Lane, Mandan, ND 58554	Sec. 12-T141N-R84W
JoAnne Snow	329 Bedford Boulevard, Bismarck, ND 58504 AND 902 S Woodland Drive, Mandan, ND 58554	Sec. 12-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 12-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Eileen Rooney Hewgley, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 12-T141N-R84W
RLand, L.L.C.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 12-T141N-R84W
Osprey Rersources, Inc.	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 12-T141N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 12-T141N-R84W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 12-T141N-R84W
J. C. Miller	508 Beacon Building, Tulsa, OK 74103	Sec. 12-T141N-R84W
Ralph M. Fahrenwald and Edna M. Fahrenwald	3737 E 45th Street, Tulsa, OK 74135	Sec. 12-T141N-R84W
Noah W. Millsap and Nell Rose Millsap	1927 E 33rd Place, Tulsa, OK 74105	Sec. 12-T141N-R84W
W. A. Dean and Fonda G. Dean	1316 E 35th Place, Tulsa, OK 74105	Sec. 12-T141N-R84W
Regina Husfloen	240 Bridge Avenue, Center, ND 58530	Sec. 12-T141N-R84W
Judith McNulty	P. O. Box 1173, Center, ND 58530	Sec. 12-T141N-R84W
Gary Hagel	3453 Thunderbird Lane, Bismarck, ND 58503	Sec. 12-T141N-R84W
Scott Hagel	275 Poplar Drive , Shoreview, MN 55126	Sec. 12-T141N-R84W
Dennis Hagel	506 W Main, Hazen, ND 58545	Sec. 12-T141N-R84W
Jay Kautzman	2024 N 5th Street, Bismarck, ND 58501	Sec. 12-T141N-R84W
Julie Fry	1853 N 23rd Street, Bismarck, ND 58501	Sec. 12-T141N-R84W
Janet Anderson	15537 E Radcliffe Place, Aurora, CO 80015	Sec. 12-T141N-R84W
Jeanine Marcolina	3938 E San Pedro, Gilbert, AZ 85234	Sec. 12-T141N-R84W
John Kautzman	P. O. Box 82, Center, ND 58530	Sec. 12-T141N-R84W
Jeff Erhardt and Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt and Kelly Jo Erhardt, as joint tenants	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Melvin Schoepp and Caroline Schoepp, as joint tenants	2023 Northridge Drive, Bismarck, ND 58503	Sec. 21-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 21-T142N-R83W
AgriBank, FCB	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 21-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Sacred Heart Hospice Donatory Corporation (as apparent successor to Robert Dunn)	1200 12th Street SW, Austin, MN 55912	Sec. 21-T142N-R83W
Richard E. Armentrout and Margaret Ann Armentrout, as joint tenants	255 Lynn Ave., Satellite Beach, FL 32937	Sec. 21-T142N-R83W
Burtis B. Conyne	No street address of record, Bismarck ND, No zip code of record	Sec. 21-T142N-R83W
Mary Dunn Lynch	No street address of record Austin, MN 55912	Sec. 21-T142N-R83W
Margaret E. Hagerott	No street address of record, Mandan ND 58554	Sec. 21-T142N-R83W
Michael H. Dunn	1128 South 7th Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
James M. Dunn	116 Center Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
Alice R. Dunn Thompson	116 Center Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 21-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 21-T142N-R83W
United States of America	No address of record	Sec. 11-T141N-R84W
State of North Dakota, Department of Trust Lands	1707 N 9th Street, Bismarck, ND 58501-5523	Sec. 11-T141N-R84W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 11-T141N-R84W
David O. Berger and Debra A. Berger, as joint tenants	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Great Northern Properties LP	1101 N 27th Street; Suite 201, Billings, MT 59101 AND 1658 Cole Boulevard, Building #6, Suite 2, Golden, CO 80401	Sec. 11-T141N-R84W
Meridian Land & Mineral Company	5613 DTC Parkway; Suite 1100, Englewood, CO 80111 AND 2919 Allen Parkway, Houston, TX 77019-2142	Sec. 11-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 11-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 11-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 11-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655 AND 203 S Prairie Lane, Mandan, ND 58554	Sec. 11-T141N-R84W
JoAnne Snow	329 Bedford Boulevard, Bismarck, ND 58504 AND 902 S Woodland Drive, Mandan, ND 58554	Sec. 11-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Matt Berger and Rose Berger c/o David O. Berger"	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Raymond Schmidt Estate c/o Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Melvin Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Caroline K. Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Larry Doll	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Grealing Starck and Deborah Stark, as joint tenants	3244 Highway 25, Center, ND 58530	Sec. 22-T142N-R83W
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 22-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 22-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 22-T142N-R83W
Richard C. Baulder, as Personal Representative of the Estate of Winifred M. Dunn, deceased	No street address of record, Austin, MN 55912	Sec. 22-T142N-R83W
Ryan Oil Company, LLC	P.O. Box 507, Evansville, IN 47703	Sec. 22-T142N-R83W
Derby Energy, L.L.C.	6420 Richmond Avenue, Suite 210, Houston, TX 77057	Sec. 22-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 22-T142N-R83W
United States of America	No address of record	Sec. 22-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
BNI Coal Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897 AND P. O. Box 897, Bismarck, ND 58502 AND 16400 Saybrook Lane, Huntington, CA 92649	Sec. 3-T141N-R83W Sec. 5-T141N-R83W Sec. 6-T141N-R83W Sec. 7-T141N-R83W Sec. 8-T141N-R83W Sec. 9-T141N-R83W Sec. 15-T141N-R83W Sec. 16-T141N-R83W Sec. 17-T141N-R83W Sec. 18-T141N-R83W Sec. 19-T141N-R83W Sec. 20-T141N-R83W Sec. 21-T141N-R83W Sec. 22-T141N-R83W Sec. 28-T141N-R83W Sec. 29-T141N-R83W Sec. 3-T141N-R84W Sec. 10-T141N-R84W Sec. 11-T141N-R84W Sec. 12-T141N-R84W Sec. 13-T141N-R84W Sec. 14-T141N-R84W Sec. 24-T141N-R84W Sec. 15-T142N-R83W Sec. 16-T142N-R83W Sec. 17-T142N-R83W Sec. 19-T142N-R83W Sec. 20-T142N-R83W Sec. 21-T142N-R83W Sec. 22-T142N-R83W Sec. 28-T142N-R83W Sec. 29-T142N-R83W Sec. 30-T142N-R83W Sec. 32-T142N-R83W Sec. 33-T142N-R83W Sec. 25-T142N-R84W Sec. 34-T142N-R84W Sec. 35-T142N-R84W Sec. 36-T142N-R84W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 32-T142N-R83W
L. D. Jenkins c/o Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Willow Point Corporation c/o Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Otter Creek Mining Company, L.L.C.	2000 Schafer Street, Suite D, Bismarck, ND 58501	Sec. 15-T142N-R83W
Consolidation Coal Company	1800 Washington Road, Pittsburgh, PA 15241 AND Koppers Building, 436 7th Avenue, Pittsburgh, PA 15219	Sec. 11-T141N-R84W
William Coal Corporation	801 Wilmington Trust Building Wilmington, DE 19801	Sec. 11-T141N-R84W

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed Tundra SGS (secure geologic storage) carbon dioxide (CO_2) storage project will be situated near the Milton R. Young Station (MRYS) located south of Center, North Dakota (Figures 2-1 and 2-2). This project site is on the eastern flank of the Williston Basin.

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 (Peck and others, 2014; Glazewski and others, 2015).

A target CO_2 storage reservoir for Tundra SGS is the Broom Creek Formation, a predominantly sandstone horizon lying 4,740 ft below the MRYS facility. Fifty-six ft of mudstones, siltstones, and interbedded evaporites of the undifferentiated Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation") unconformably overlie the Broom Creek Formation. Ninety ft of mudstones and siltstones of the lower Piper Formation (Picard Member and lower) overlie the undifferentiated Opeche and Spearfish Formations. Together, the lower Piper and Opeche/Spearfish Formations (hereafter "Opeche–Picard interval" serve as the primary confining zone (Figure 2-3). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-3). Together, the Opeche–Picard, Broom Creek, and Amsden Formations make up the CO_2 storage complex for Tundra SGS (Table 2-1).

In addition to the Opeche–Picard interval, there is 820 ft (average thickness across the simulated area) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2,545 ft (average over simulation area) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-3).

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 (sources and uses are discussed within Section 2.2) and site-specific data acquired by the applicant specifically to characterize the storage complex.

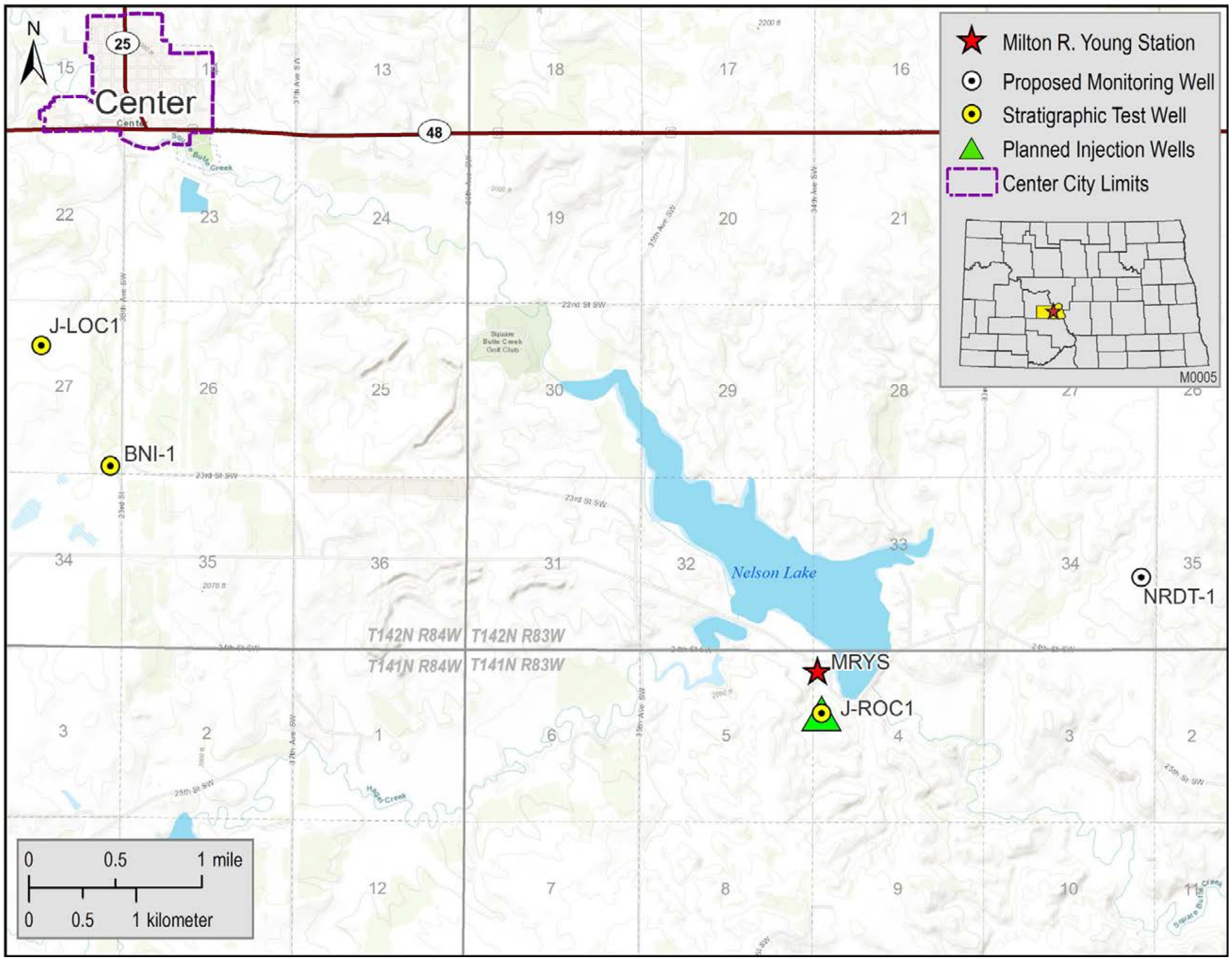

Figure 2-1. Topographic map of the Tundra SGS area showing well locations and MRYS.

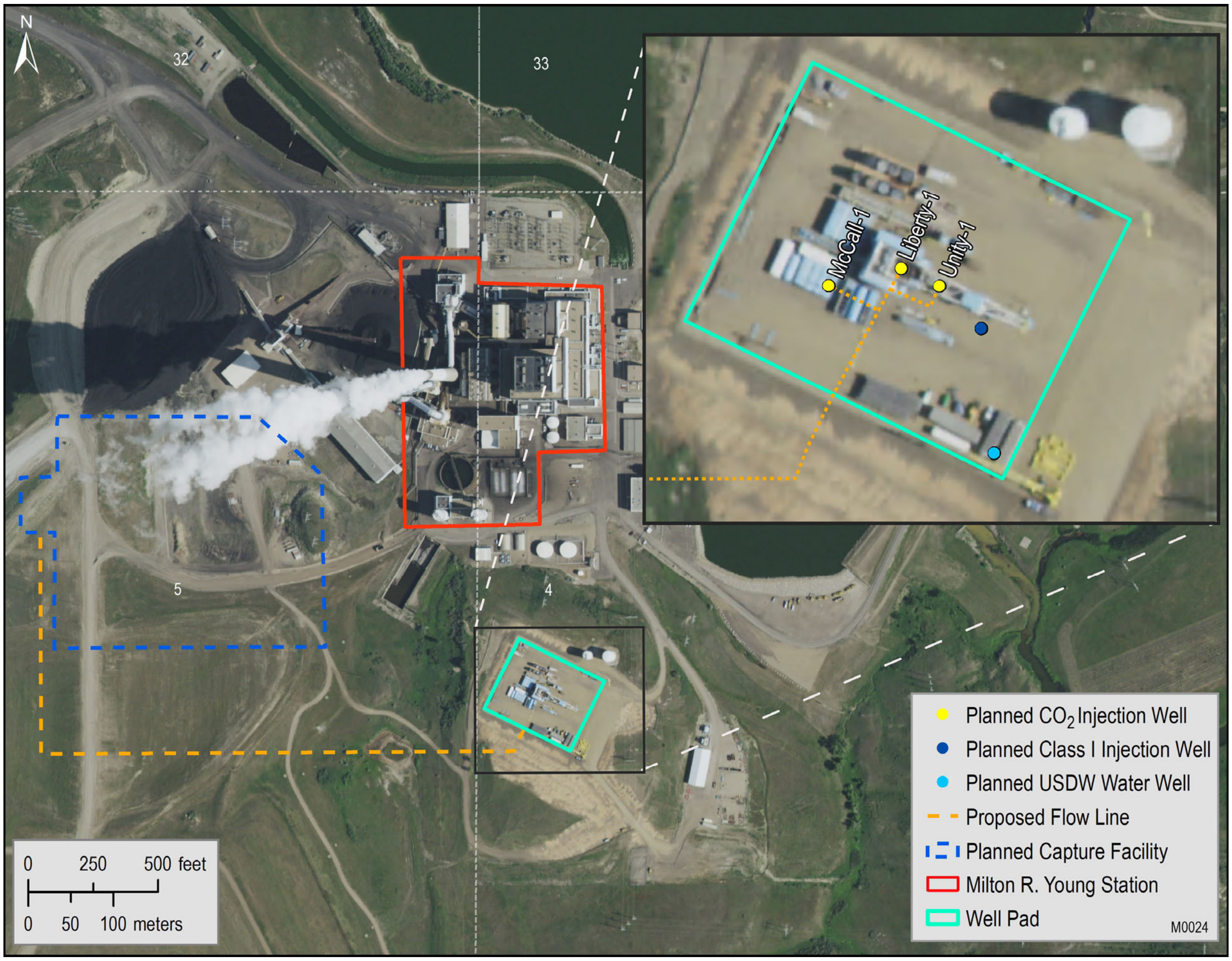

Figure 2-2. Map of the proposed CO_2 flowlines and well pad layout.

2.2.1 Existing Data

The existing data used to characterize the geology beneath the Tundra SGS 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 109 wellbores within a 5,500-mi^2 (74 × 74-mi) area centered on the proposed storage site (Figure 2-4). Well 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 shown in Figure 2-5: Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), and ANG 1 (ND-UIC-101) (Figure 2-5). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with newly acquired site specific data. Ten mi^2 of legacy 3D seismic data from Mercer County, encompassing the Flemmer-1 wellsite, was examined to understand the heterogeneity and geologic structure of the Broom Creek Formation interval.

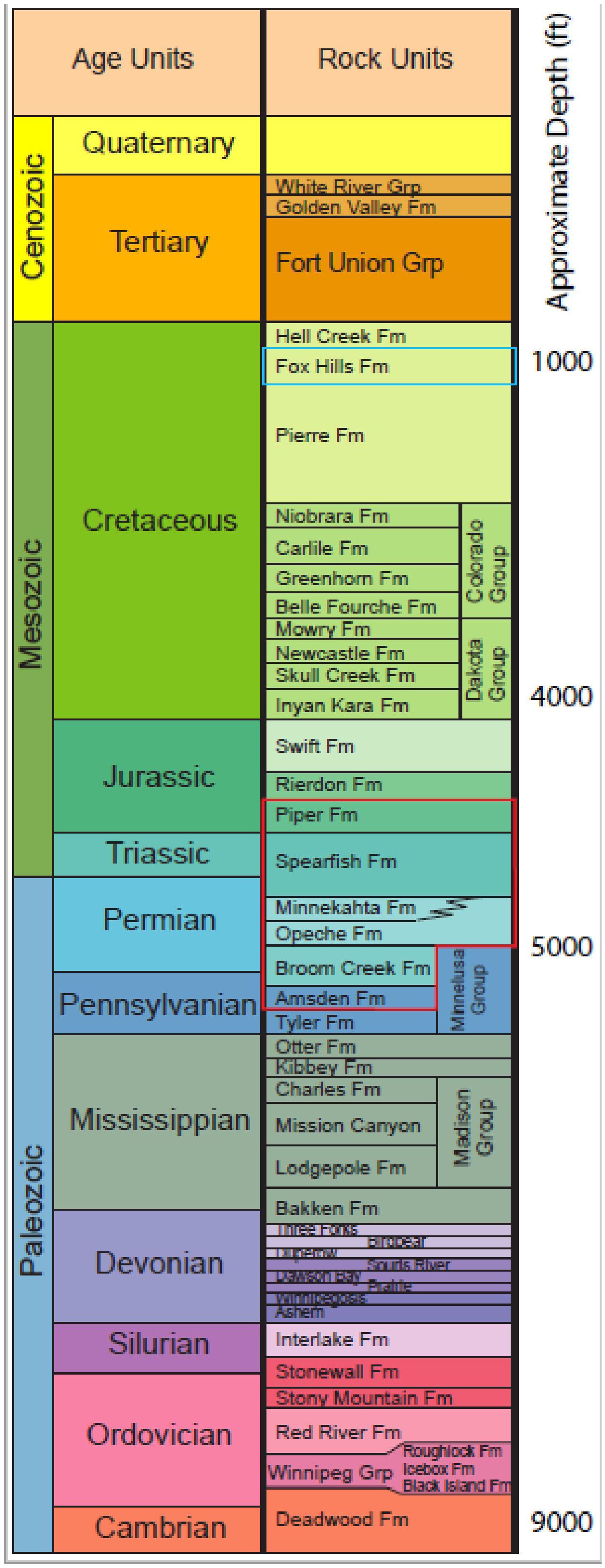

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for Tundra SGS.

Table 2-1. Formations Making up the Tundra SGS CO_2 Storage Complex (average values calculated from the simulation model and well log data)

	Formation	Purpose	Average Thickness, ft	Average Depth, ft	Lithology
Storage Complex	Opeche–Picard	Upper confining zone	154	4,712	Siltstone, mudstone evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	249	4,915	Sandstone, dolostone, dolomitic sandstone, anhydrite
	Amsden	Lower confining zone	270	5,175	Dolostone, limestone, anhydrite

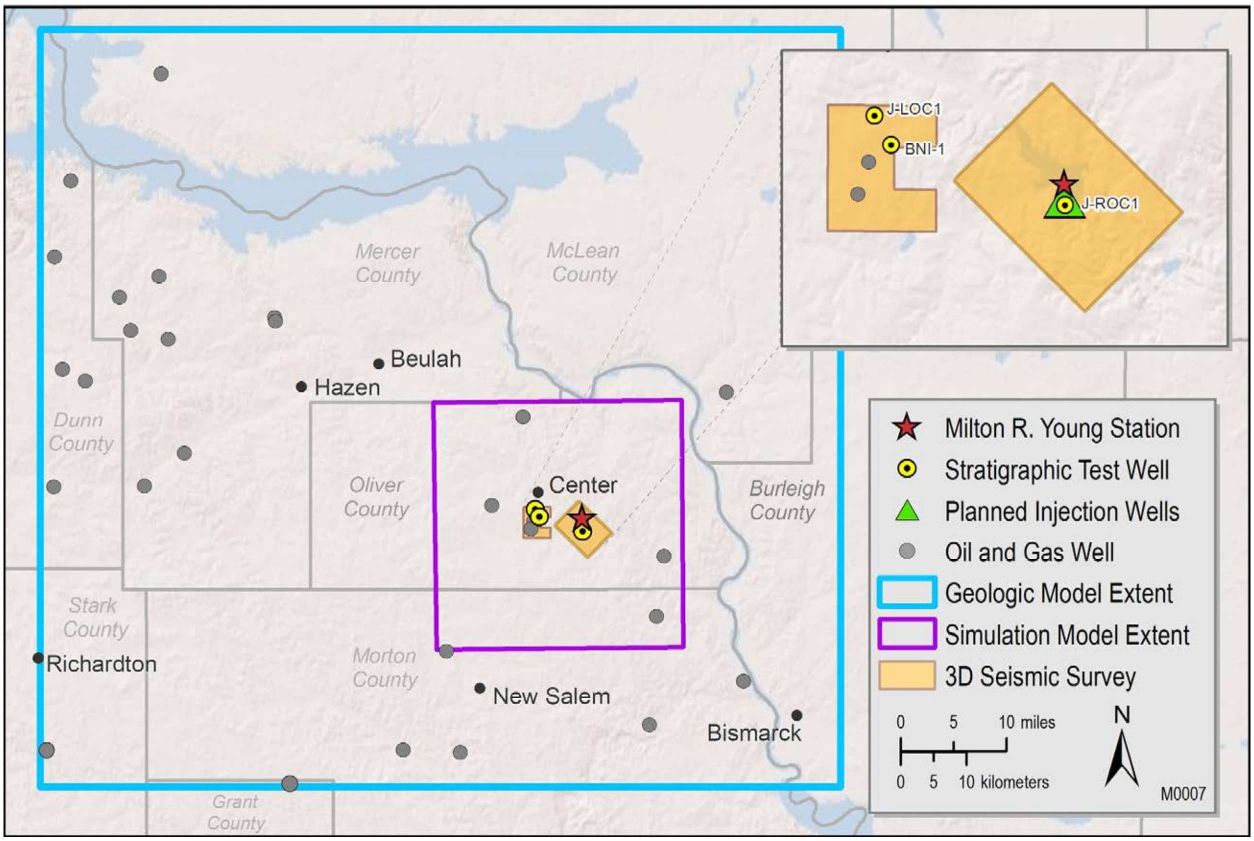

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

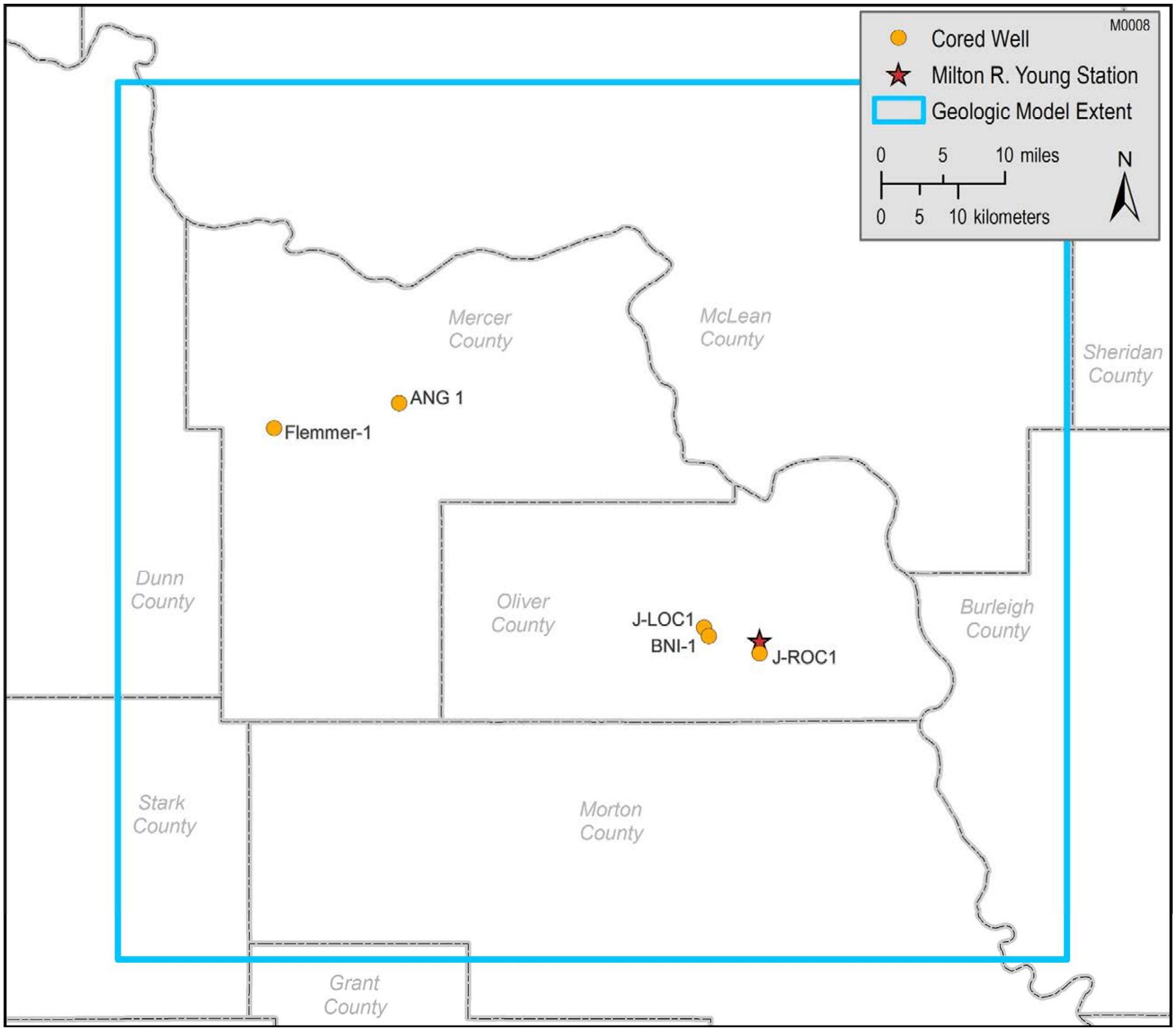

Figure 2-5. Map showing the spatial relationship between the Tundra SGS area and wells where the Broom Creek Formation core samples were collected. Wells with core data include the Flemmer-1 (NDIC File No. 34243), BNI-1 (NDIC File No. 34244), ANG 1 (ND-UIC-101), J-LOC1(NDIC File No. 37380) and J-ROC1 (NDIC File No. 37672).

2.2.2 Site-Specific Data

Site-specific efforts to characterize the proposed Broom Creek storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, and 3D seismic data. The BNI-1 well was drilled in 2018 to a depth of 5,316 ft in the Amsden Formation. In 2020, the J-LOC1(NDIC File No. 37380) and J-ROC1 (NDIC File No. 37672) wells were drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility. The J-LOC1 and J-ROC1 wells were drilled to a depth of 10,470 ft and 9,871 ft, respectively. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche–Picard, Broom Creek, and Amsden Formations) (Figures 2-6a and 2-6b).

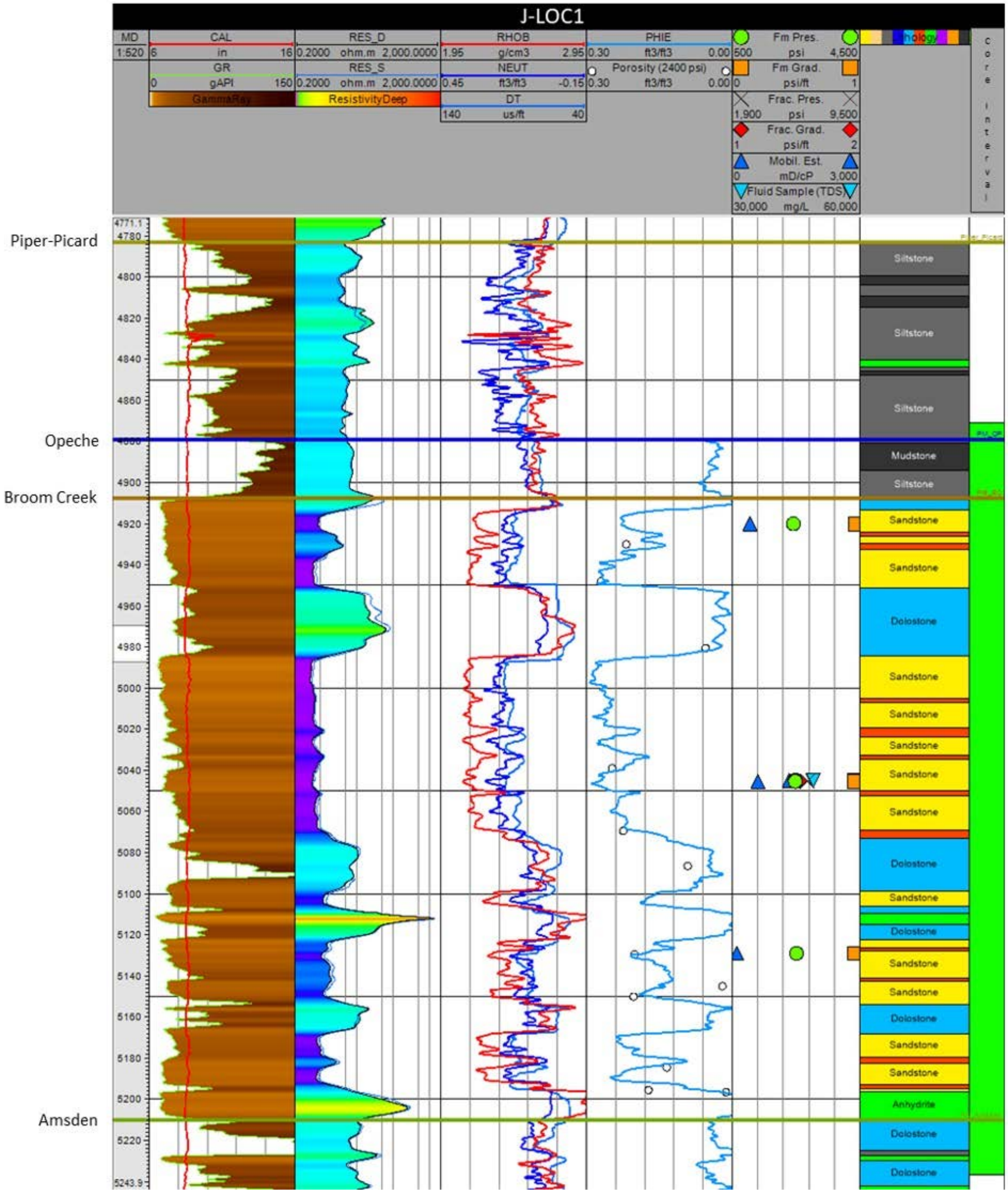

Figure 2-6a. Schematic showing vertical relationship of coring (rightmost track) and testing (third track from right) intervals in the Opeche/Spearfish, Broom Creek, and Amsden Formations in the J-LOC1 well.

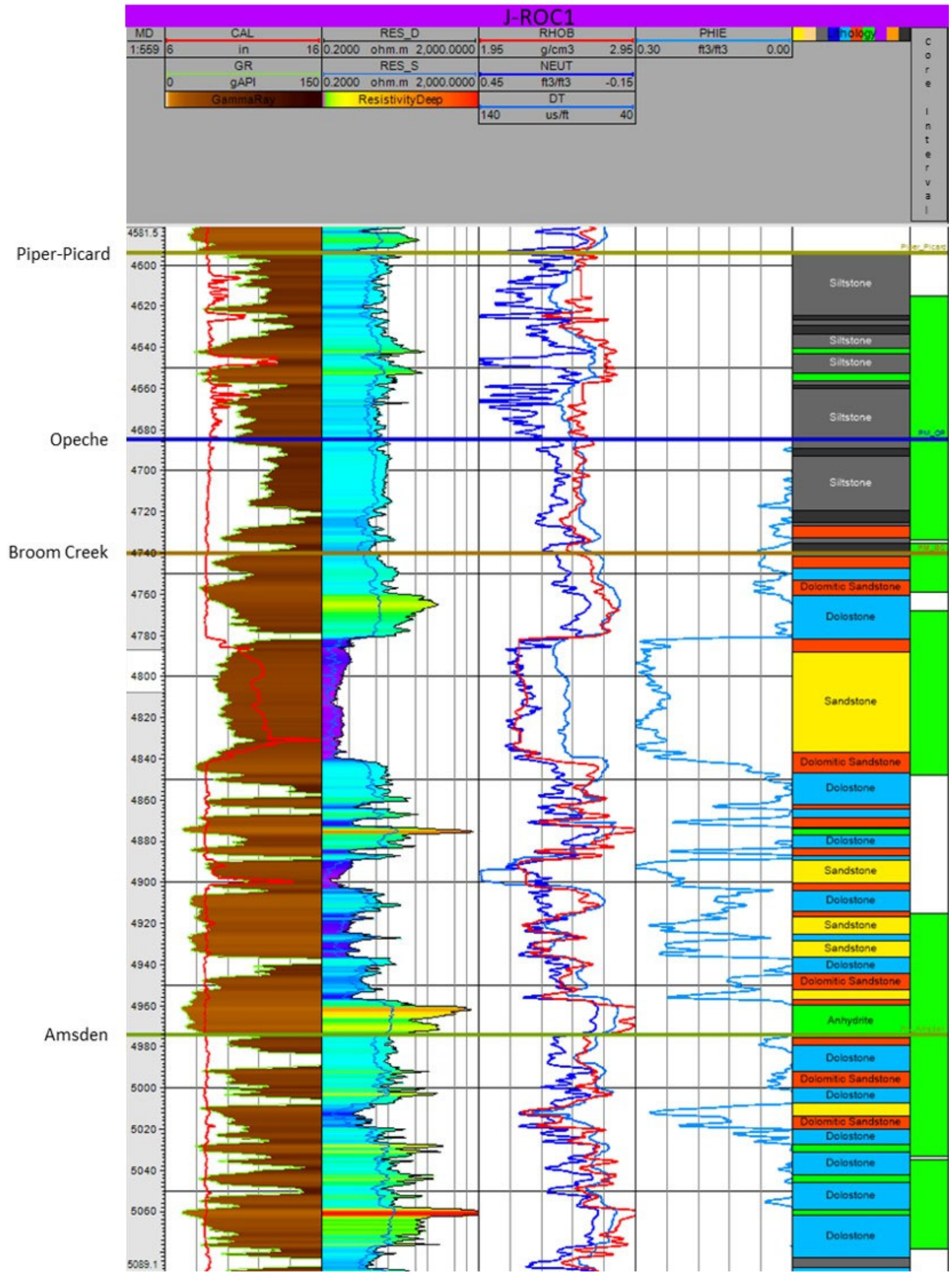

Figure 2-6b. Schematic showing vertical relationship of coring intervals (rightmost track) in the Opeche/Spearfish, Broom Creek, and Amsden Formations in the J-ROC1 well.

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 also 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 site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced 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 J-LOC1 and J-ROC1 wells along the entire open section of the wellbore. The logging suite included caliper, gamma ray (GR), density, porosity, dipole sonic, resistivity, combinable magnetic resonance (CMR) spectroscopy, and fracture finder or image log. A similar logging suite was acquired from the BNI-1 well, except that the CMR and image logs were not collected, but a spontaneous potential (SP) log was included.

The acquired well logs were used to pick formation top depths and interpret lithology and petrophysical properties and create synthetic seismic traces for tying depth to time. 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 109 wellbores within the 5,500-mi^2 area covered by the model to understand the geologic extent, depth, and thickness of the subsurface geologic strata. The formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

Three hundred six ft of core was collected from the Broom Creek storage complex in the J-LOC1 well. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche/Spearfish, 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 J-LOC1 and BNI-1 wellbores were used to derive a temperature gradient for the proposed injection site (Tables 2-2 and 2-3). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the geologic model of the Tundra SGS 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 the J-LOC1 and BNI-1 wells was performed with the Schlumberger MDT (modular formation dynamics testing) tool. The MDT is a wireline-conveyed tool assembly incorporated with 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 (Appendix D, "Schlumberger MDT"). The MDT tool formation pressure measurements from the Broom Creek Formation are included in Tables 2-4 and 2-5. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-2. Description of J-LOC1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	4,889.2	143.90
Broom Creek	4,920.0	136.26
	5,045.1	136.60
	5,129.1	137.26
Mean Broom Creek Temp., °F	136.71	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT tool-measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-3. Description of BNI-1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	4,874.4	126.88
	4,897.5	127.92
Broom Creek	4,986.0	128.52
	5,041.0	133.42
	5,104.0	135.44
	5,124.0	137.60
Mean Broom Creek Temp., °F	133.75	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT tool-measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-4. Description of J-LOC1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	4,920.0	2,415.86
Broom Creek	5,045.1	2,471.43
Broom Creek	5,129.1	2,509.60
Mean Broom Creek Pressure, psi	2,465.63	
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is an average of the MDT tool-measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

Table 2-5. Description of BNI-1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Broom Creek	5,041.0	2,470.60
Broom Creek	5,124.0	2,507.79
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is an average of the MDT tool-measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.2.2.4 Microfracture In Situ Stress Tests

Using the Schlumberger MDT, microfracture in situ stress tests were performed in the J-LOC1 and BNI-1 wellbores. In situ reservoir stress-testing measurements provided real-time formation pressure and formation temperature, as well as formation, fracture breakdown, propagation, and closure pressures. Microfracture in situ stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

Microfracture in situ stress tests were performed in the Opeche/Spearfish and Broom Creek Formations (Table 2-6). 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. Fracture propagation pressures determined from the microfracture test were used to calculate pressure constraints related to the maximum allowable bottomhole pressure.

Table 2-6. Description of J-LOC1 Microfracture In Situ Stress Tests

	Test Depth	Breakdown Pressure		Propagation Pressure		Closure Pressure		Initial Shut-In Pressure	
Formation	ft	psi	Gradient, psi/ft	Avg., psi	Gradient, psi/ft	Avg., psi	Gradient, psi/ft	Avg., psi	Avg. Gradient, psi/ft
Opeche/ Spearfish	4,887.7	No observed formation breakdown. Maximum applied injection pressure = 8,162.49 psi							
	4,888.8	No observed formation breakdown. Maximum applied injection pressure = 8,150.95psi							
Broom Creek	5,045.4	6,384.5	1.265	3,592.5	0.712	3,203.42	0.635	3,594.19	0.712

In the J-LOC1 wellbore, two microfracture in situ stress tests were performed in the Opeche/ Spearfish Formation, at 4,887.7 and 4,888.8 ft, with the interpretation of the results provided in Section 2.4 Storage Reservoir Confinement Zone. Of the two tests attempted in the Opeche/ Spearfish Formation, in which a formation breakdown was not achieved, one predominant reason included limitations with the dual-packer mechanical specifications, with a maximum differential pressure between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Opeche/Spearfish Formation at the two depths indicated that the formation is very tight competent rock and exhibits sufficient geologic integrity to contain the injected CO_2 stream. One microfracture in situ stress test was performed in the Broom Creek Formation, at 5,045.4 ft, with interpretation of the results provided in Table 2-6.

In the BNI-1 wellbore, two microfracture in situ stress tests were performed in the Opeche/Spearfish Formation, at 4,873.0 and 4,897.5 ft, with the interpretation of the results provided in Section 2.4 Storage Reservoir Confinement Zone. For one of the two tests attempted in the Opeche/Spearfish Formation, in which a formation breakdown was not achieved, one reason is the 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/Spearfish Formation at the upper depth is consistent with the formation being very tight, competent rock. One microfracture in situ stress test was performed in the Broom Creek Formation, at 5,041.6 ft, with interpretation of the results provided in (Table 2-7).

Table 2-7. Description of BNI-1 Microfracture In Situ Stress Tests

	Test Depth	Breakdown Pressure		Propagation Pressure		Closure Pressure		Initial Shut-In Pressure	
Formation	**ft**	**psi**	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**	**Avg., psi**	**Gradient, psi/ft**
Opeche/ Spearfish	4,873.0	No observed formation breakdown. Maximum applied injection pressure = 7561psi							
	4,897.5	5,897	1.204	N/A	N/A	4,273.58	0.873	4,503.25	0.920
Broom Creek	5,041.6	7,089	1.406	3,586.32	0.711	3,270.84	0.649	3,382.15	0.671

2.2.2.5 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the J-LOC1 wellbore via an MDT tool (Appendix D, "Schlumberger Saturn 3D Radial Probe") as shown in Table 2-8. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab, and confirmed by the Energy & Environmental Research Center (EERC). A fluid sample from the Broom Creek Formation was also collected from the BNI-1 well and analyzed by the 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 2-8. Description of Fluid Sample Tests and Corresponding Total Dissolved Solids (TDS) Values for Each Sample

Formation	Well	Test Depth, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	J-LOC1	5,044.8	49,000	49,000
Broom Creek	BNI-1	5,124.0	N/A	64,100

In situ fluid pressure testing was performed in the Opeche/Spearfish Formation with the MDT tool. This test utilized the tool's large-diameter probe to test both the mobility and reservoir pressure (Appendix D). The probe (MDT) was unable to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample, and the formation was unable to rebound (build pressure) because of low to almost zero permeability. The testing results provide further evidence of the confining properties of the Opeche/Spearfish Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

2.2.2.6 Seismic Survey

A 5-mi-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 mi of 2D seismic lines were acquired in 2020 (Figure 2-7). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement. Data products generated from the interpretation and inversion of the 3D seismic data were used as inputs into the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 4).

The 3D seismic data and J-LOC1 and J-ROC1 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 J-LOC1 and J-ROC1 sonic logs. 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 Tundra SGS area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data.

The 3D seismic data were also used to gain a better understanding of interwell heterogeneity across the Tundra SGS area for petrophysical property distributions. Acoustic impedance volumes were created using the 3D seismic and petrophysical data from the J-LOC1 and J-ROC1 wells (e.g., dipole sonic and density logs), as shown in Figure 2-8. The acoustic impedance volumes were 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.

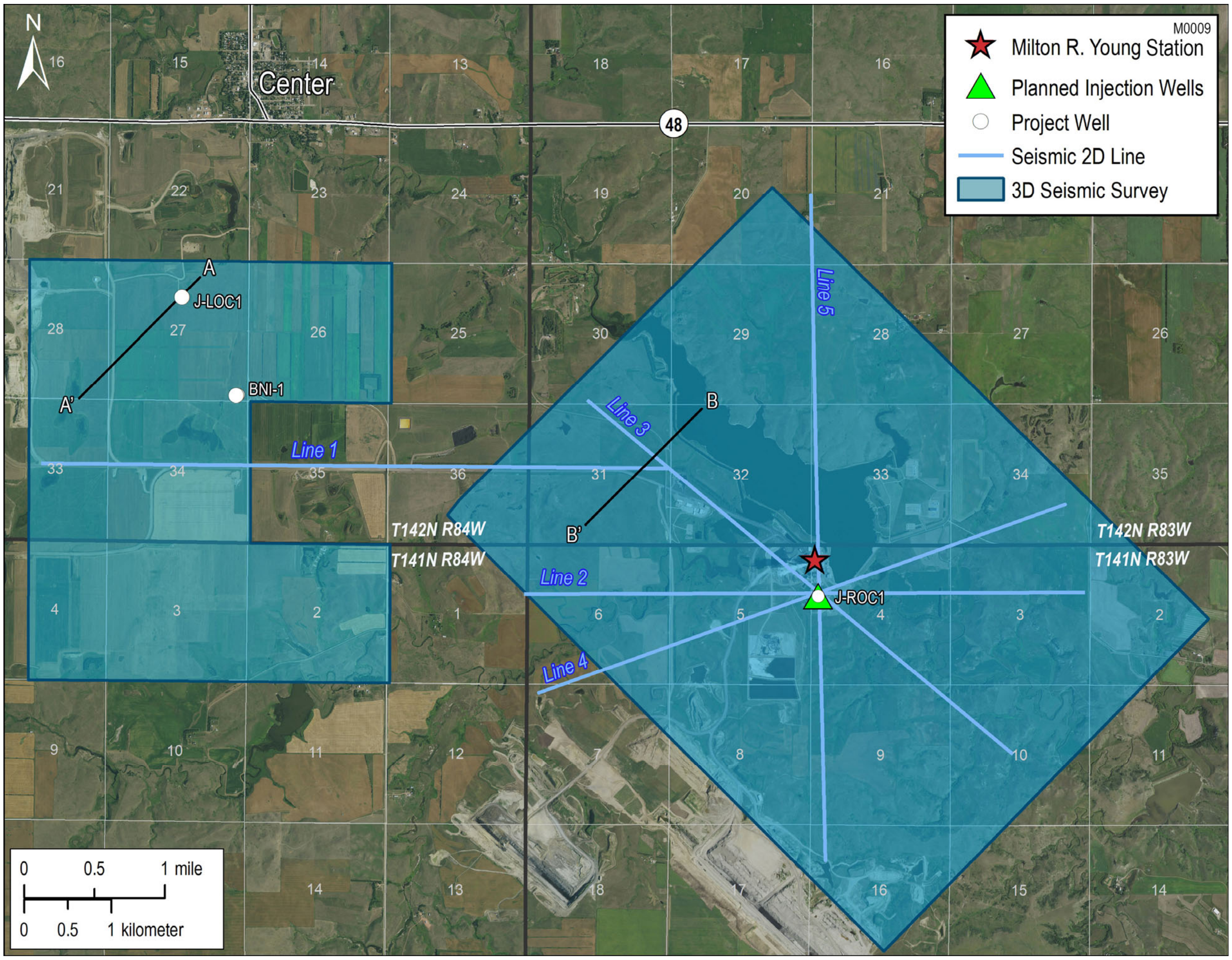

Figure 2-7. Map showing the 2D and 3D seismic surveys in the Tundra SGS area. Cross section A-A' and B-B' are shown in Figure 2-8.

2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3).

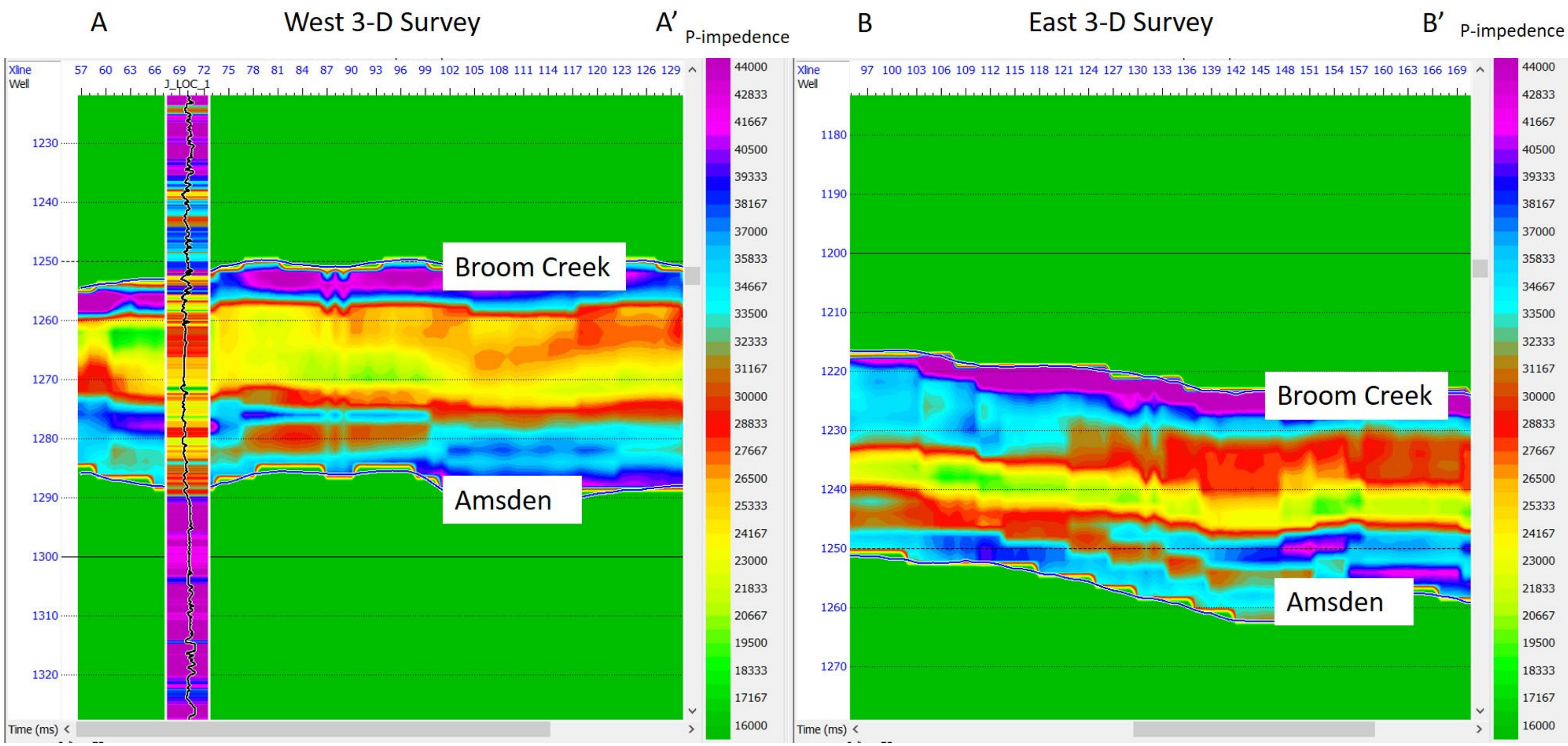

Figure 2-8. Left: cross section of the inverted acoustic impedance volume for the western seismic 3D survey that transects the J-LOC1 well. The acoustic impedance log calculated from the J-LOC1 sonic and density logs is shown on the inset panel. Right: cross section of the inverted acoustic impedance volume for the eastern 3D survey. Figure 2-7 shows the location of these two cross sections.

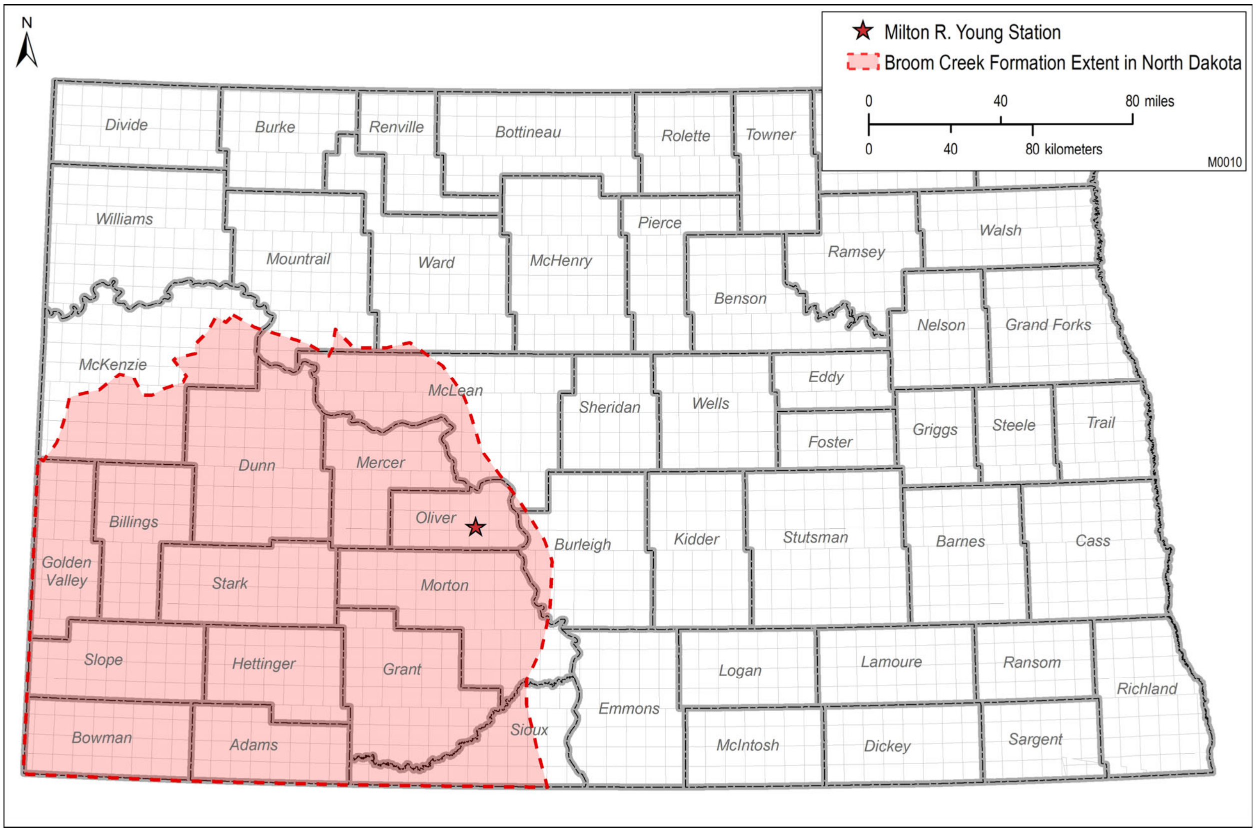

Figure 2-9. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh, 1990).

At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft.

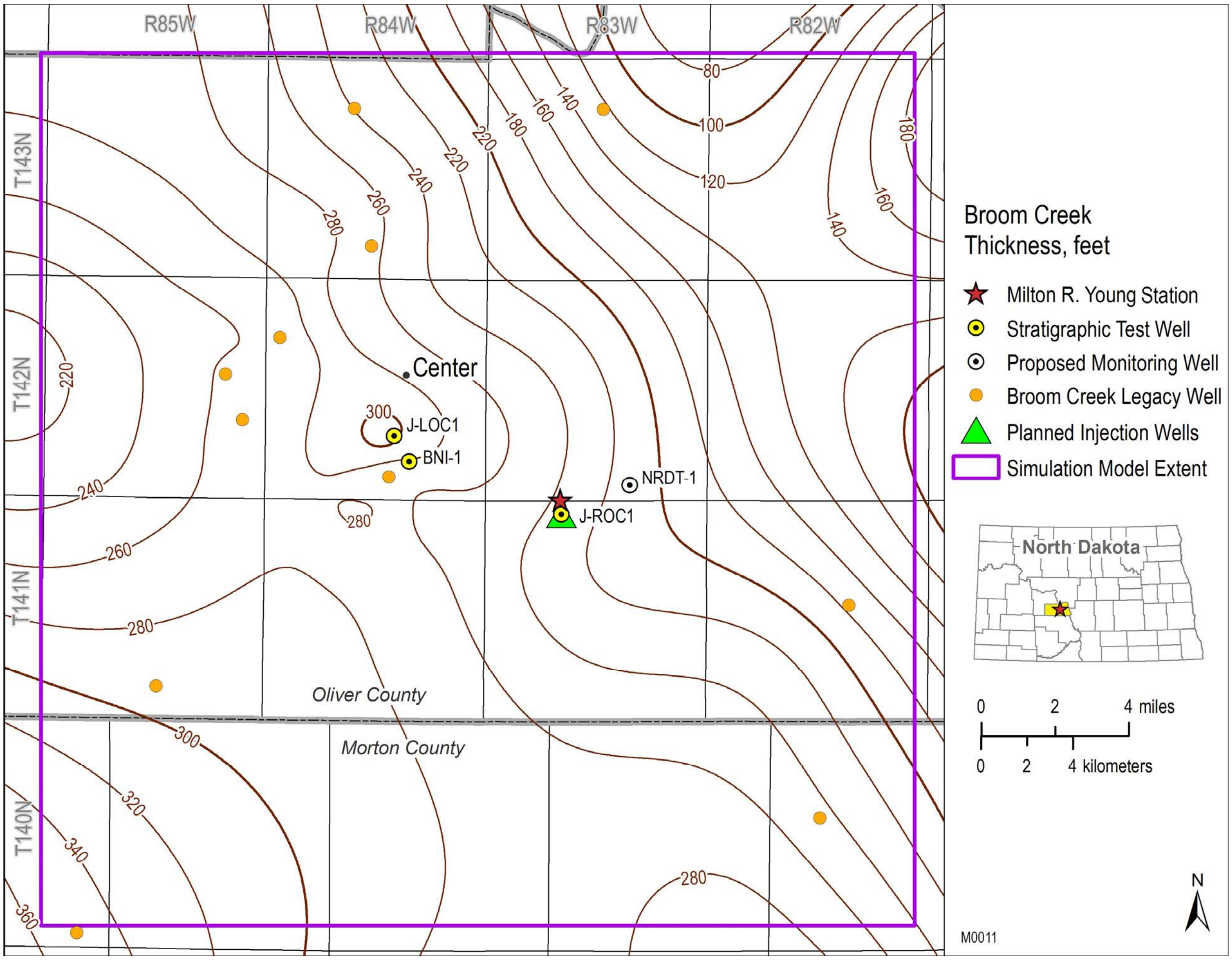

Figure 2-10. Isopach map of the Broom Creek Formation in the Tundra SGS area.

The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14).

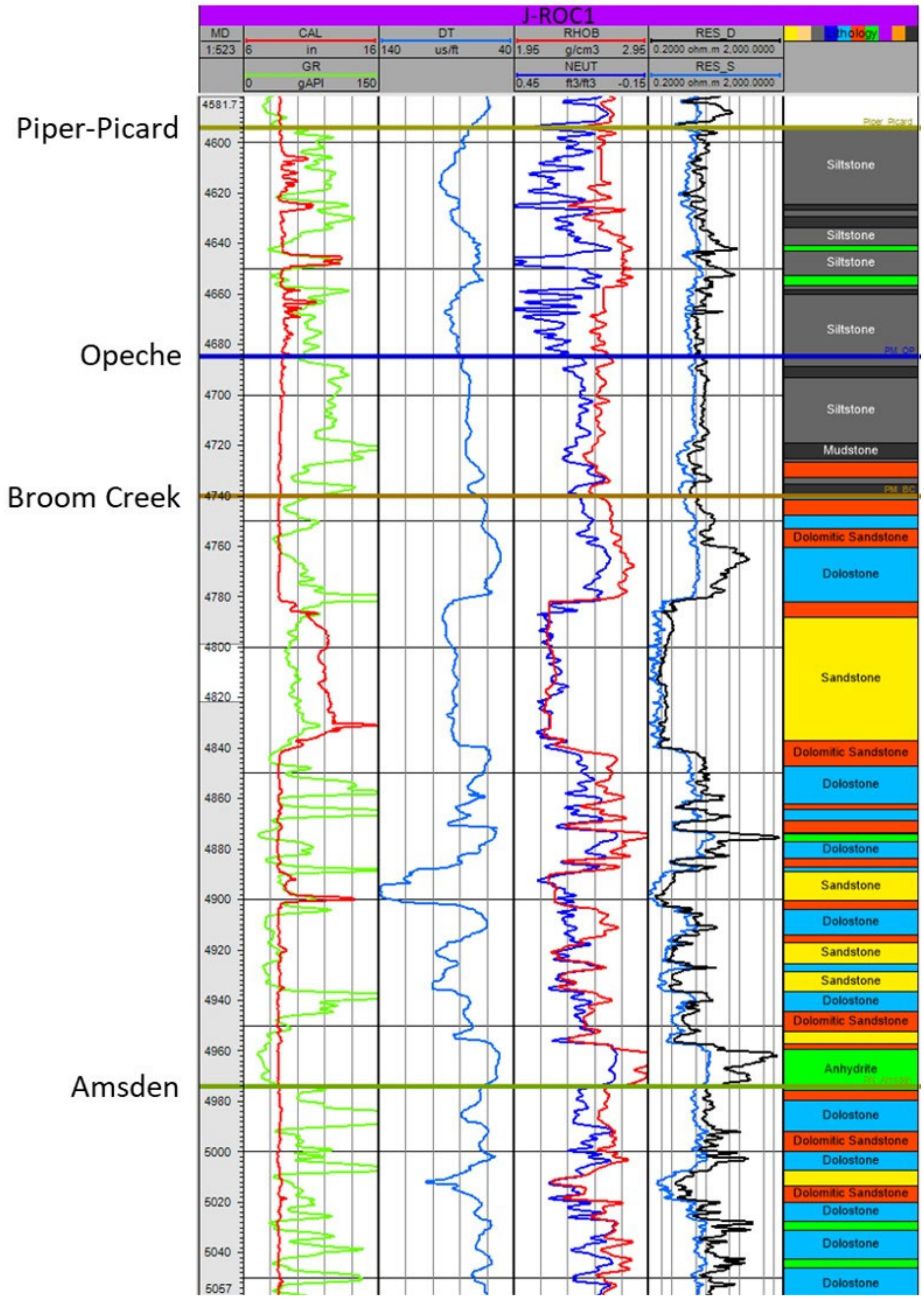

Figure 2-11. Well log display of the interpreted lithologies of the Opeche–Picard, Broom Creek, and upper Amsden Formations in J-ROC1.

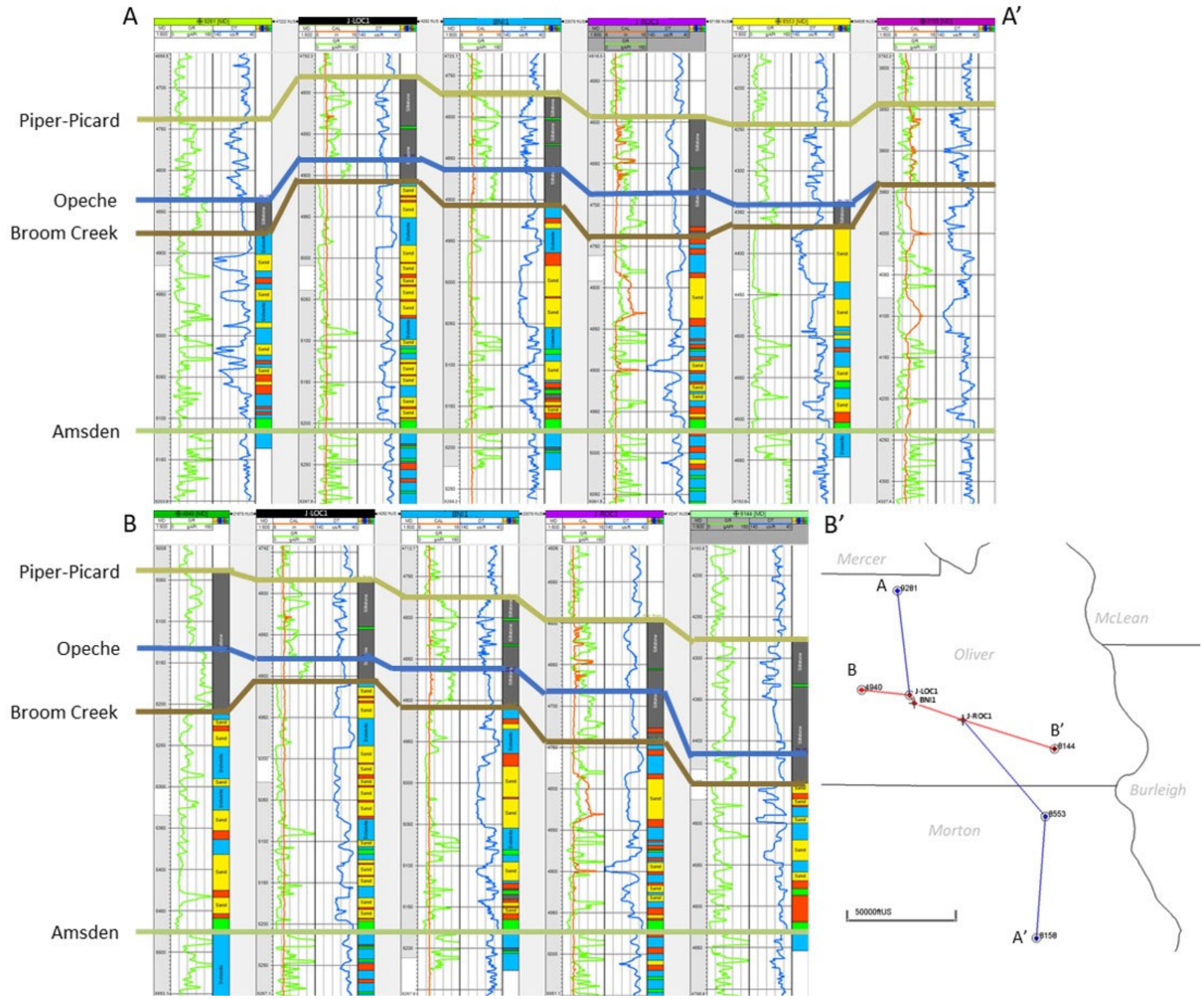

Figure 2-12a. Regional well log stratigraphic cross sections of the Opeche–Picard and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

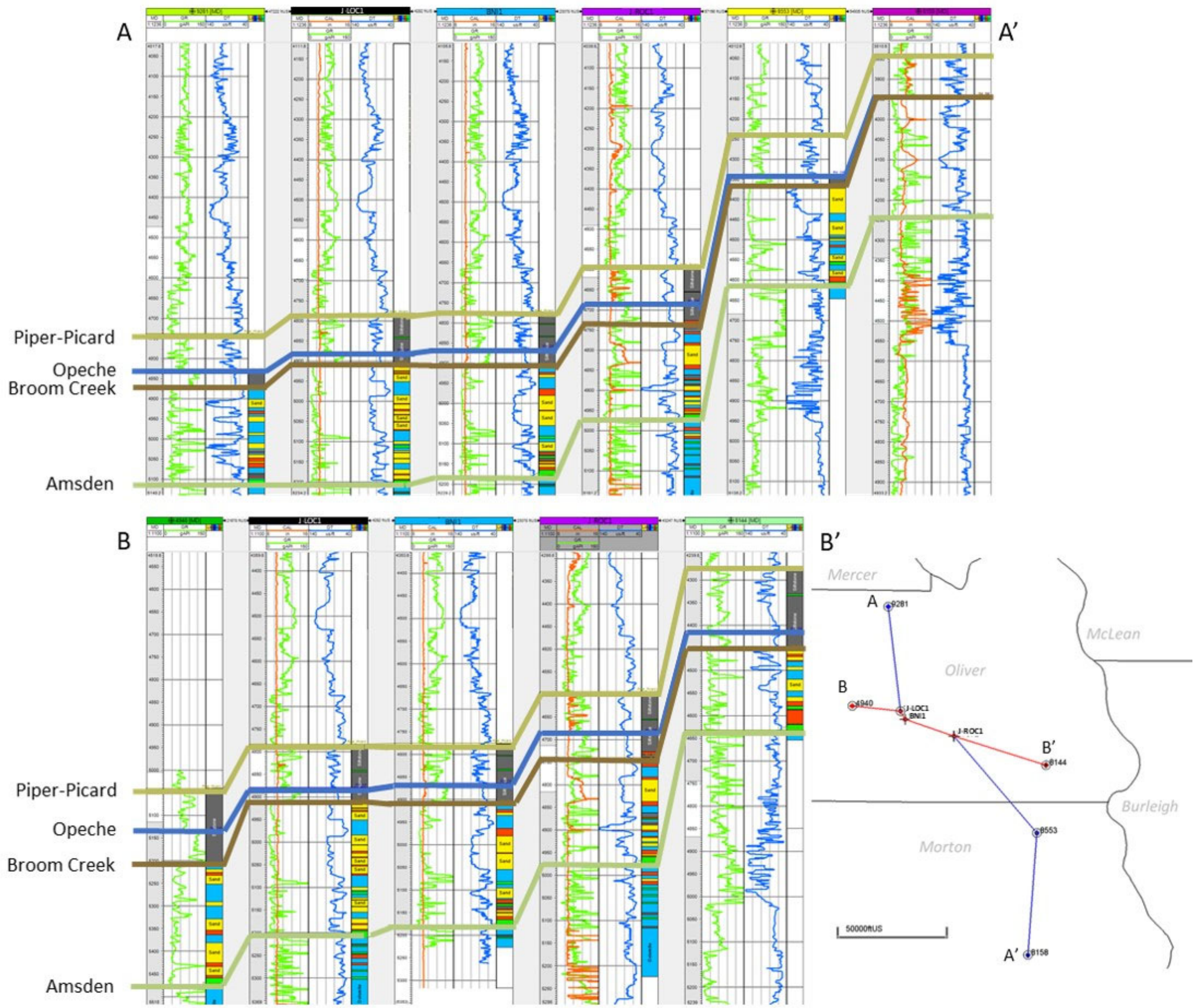

Figure 2-12b. Regional well log cross sections showing the structure of the Opeche–Picard, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

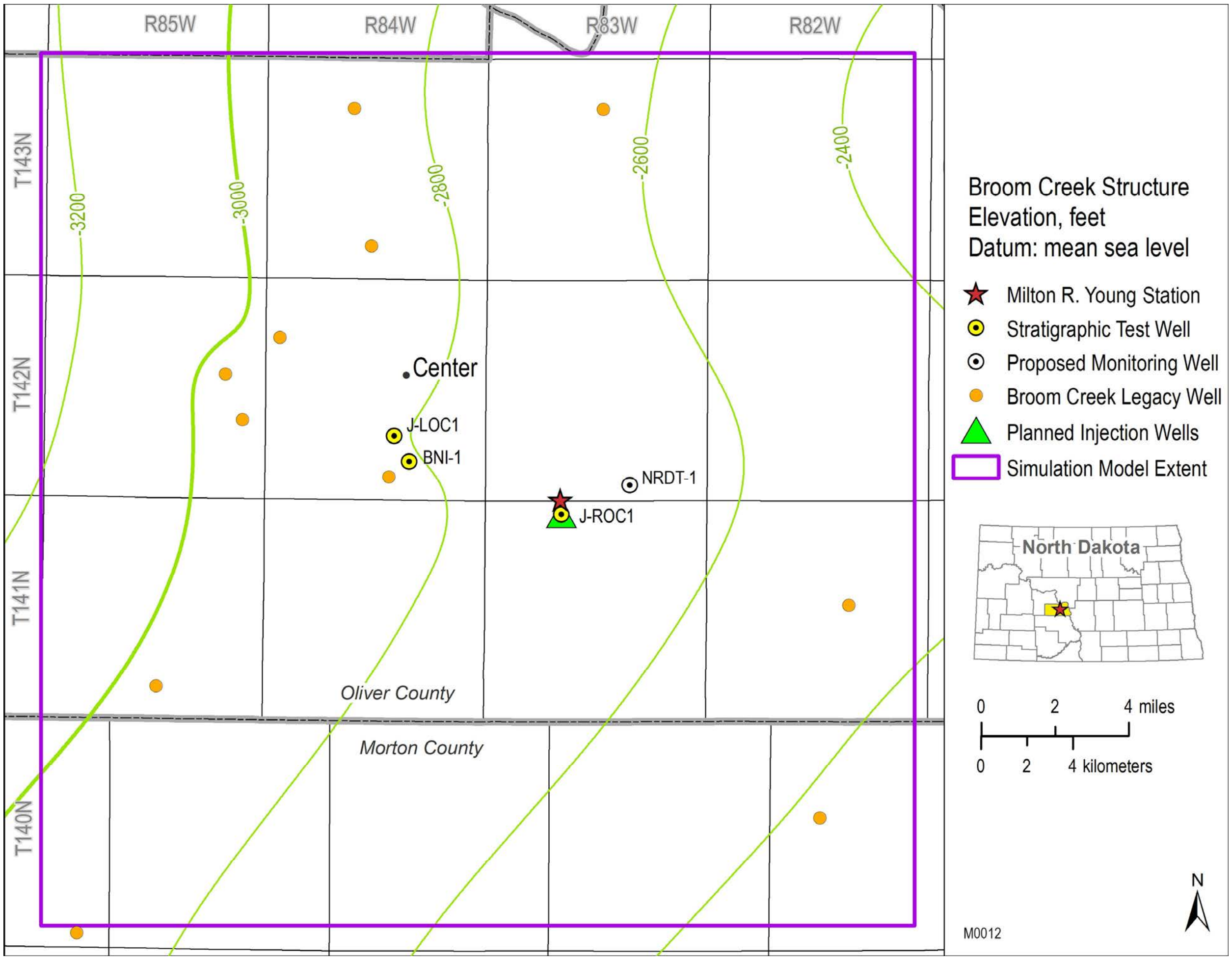

Figure 2-13. Structure map of the Broom Creek Formation across the Tundra SGS area.

Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone.

Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15).

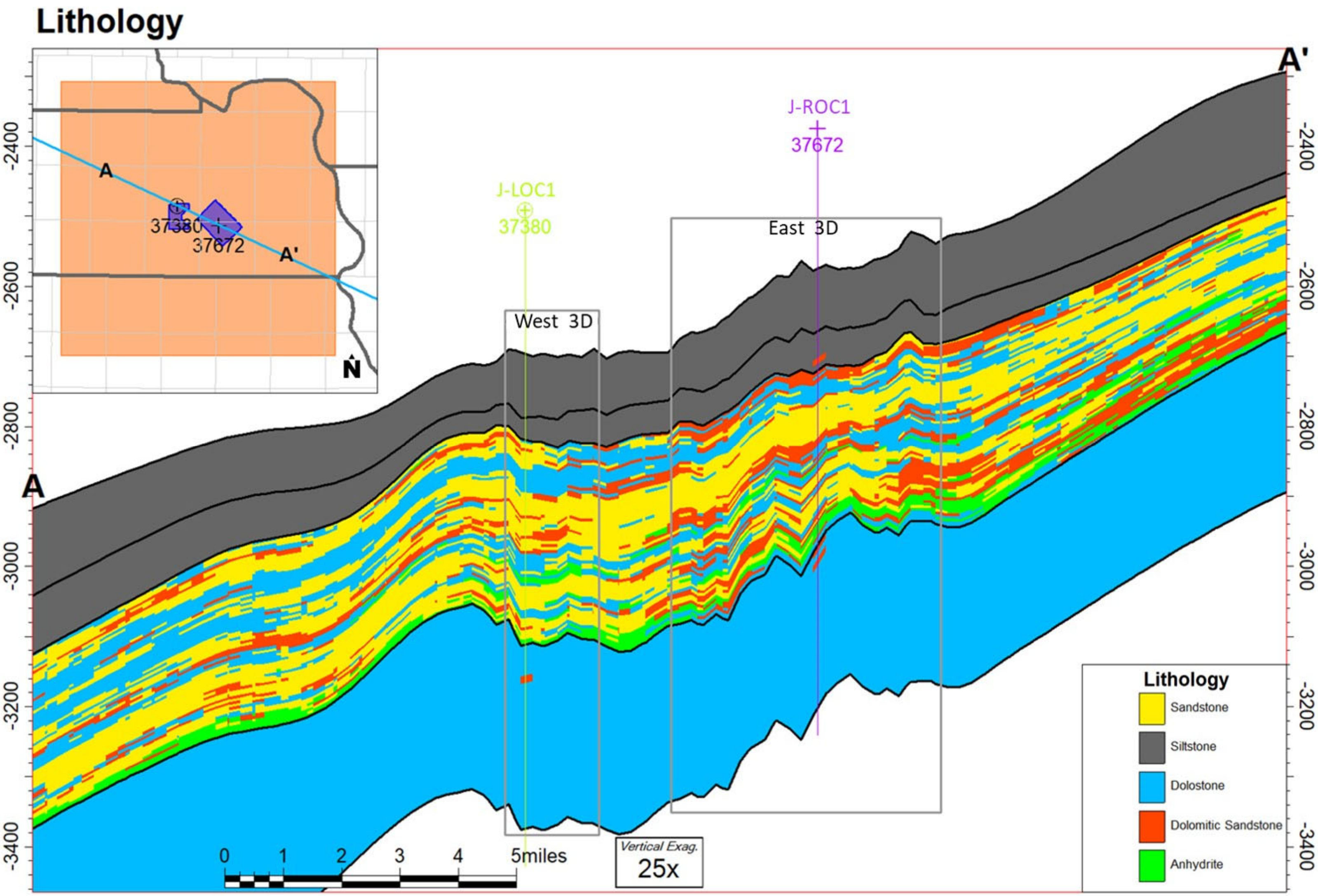

Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

Table 2-9. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties

Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite
Formation Top Depth, ft	4,906
Thickness, ft	Sandstone 168 Dolostone 103 Dolomitic Sandstone 26 Anhydrite 19
Capillary Entry Pressure (CO_2/brine), psi	0.20

Geologic Properties

Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	19.51 (2.46–27.38)	21.4 (1.0–36.0)
	Permeability, mD**	69.29 (0.06–2,690)	168.8 (0.0–8,601.1)
Broom Creek (dolostone)	Porosity, %	8.11 (5.48–8.97)	5.8 (0.0–18.0)
	Permeability, mD	0.03 (0.02–0.05)	0.13 (0.0–2,259.6)

* 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.

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 the J-LOC1 well. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-9 are derived from a combination of the core analysis and larger data set derived from offset well logs. A 2.5 multiplier for permeability was applied to the geologic model based on injection test results (Appendix A).

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.

Pressure testing in the Broom Creek Formation included a total of seven pressure measurements via an MDT tool at the J-LOC1 and BNI-1 wells. All tests resulted in good

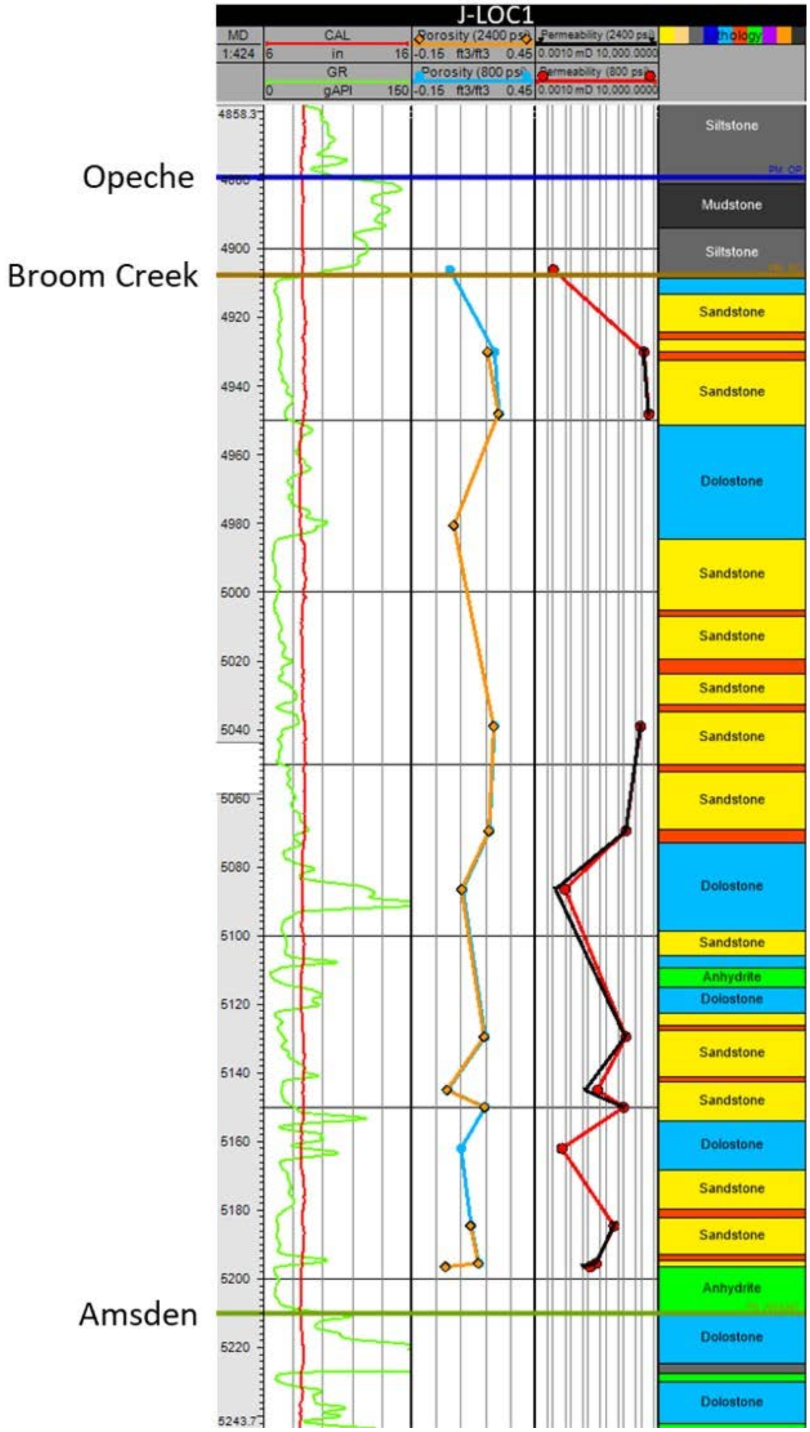

Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex.

agreement, with reservoir pressures recorded that ranged from 2,415.86 to 2,509.60 psi. These pressures were used to derive an average pressure gradient of 0.49 psi/ft.

Microfracture in situ stress tests were performed within the Broom Creek Formation in the J-LOC1 and BNI-1 wells (Table 2-10). These tests were conducted at 5,045.4 and 5,041.6 ft, respectively, which is 137.4 and 134.6 ft below the top of the formation, respectively. The average pressures of the stress test results are shown in Table 2-10, with a supporting graph for derivation of averages in Figure 2-16.

Table 2-10. Broom Creek Microfracture Results from J-LOC1 and BNI-1

	J-LOC1		BNI-1	
Depth, ft	5,045.4		5,041.6	
Pressure/Gradient	**psi**	**psi/ft**	**psi**	**psi/ft**
Breakdown	6,384.5	1.265	7,089.00	1.406
Avg. Fracture Propagation	3,592.5	0.712	3,586.32	0.711
Avg. Closure	3,203.4	0.635	3,270.84	0.649

The measured temperature of the Broom Creek Formation in the J-LOC1 well was 136.60°F at a depth of 5,045.1 ft. Using an average surface temperature of 40°F, the resulting temperature gradient for the Broom Creek Formation is 0.02°F/ft.

$$\frac{136.60°\text{F} - 40°\text{F}}{5045.1 \text{ ft}} = 0.02°\text{F/ft} \qquad \text{[Eq. 1]}$$

Fluid samples were collected via an MDT tool in the J-LOC1 well from the Broom Creek Formation and analyzed by a state-certified lab, with results confirmed by the EERC, as discussed earlier in Table 2-8.

2.3.1 J-LOC1 Injectivity Tests

The J-LOC1 formation well testing was performed specifically to characterize the injectivity and obtain the breakdown pressure of the Broom Creek Formation in December 2020. The well testing consisted of a step rate test, extended injection test, and pressure falloff test. The well was perforated from 4,912 to 4,922 ft with 4 shots per foot (spf) and 90° phasing. To record the bottomhole pressure, a tandem downhole memory gauge was installed at a depth of 4,862 and 4,868 ft. The well test data were interpreted by GeothermEx, a Schlumberger Company.

The step rate test was performed with a total of ten injection rates. The initial injection rate was 1.27 barrels per minute (bpm), and final injection rate was 16 bpm. From the step rate test evaluation, the fracture opening pressure was observed at 3,424 psi, as shown in Figure 2-17.

A 12-hour extended injection rate was performed at a constant rate of 5 bpm followed by a 24-hour pressure falloff test. The interpretation of the pressure falloff data interpretation shows a permeability of 4,485 mD with reservoir pressure of 2,410 psi. No lateral boundary was observed from the pressure falloff test within the radius of investigation of 24,804 ft, as shown in Figures 2-18 and 2-19. Broom Creek Formation well testing is summarized in Table 2-11.

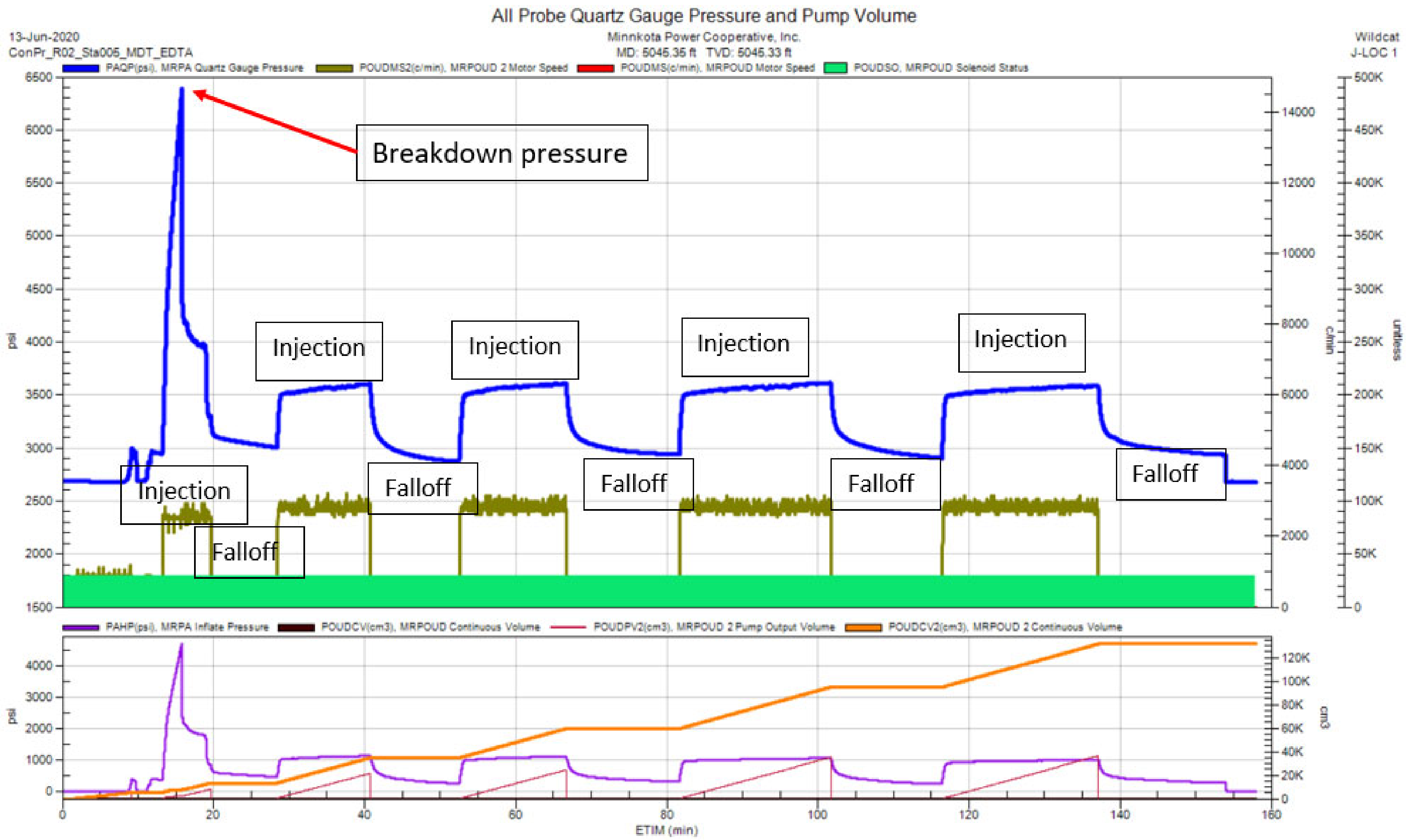

Figure 2-16. J-LOC1 Broom Creek Formation MDT microfracture in situ stress pump cycle graph at 5,045.4 ft.

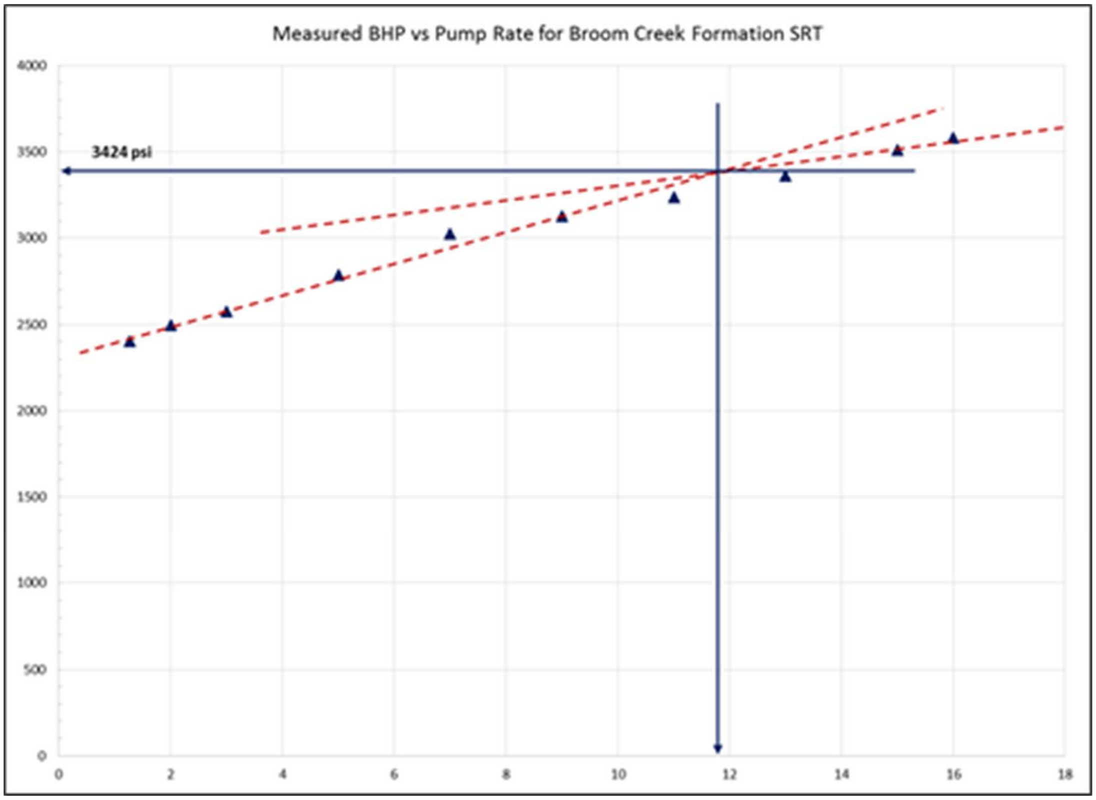

Figure 2-17. Step rate test data of the Broom Creek Formation with fracture opening pressure observed at 3,424 psi (courtesy of GeothermEx, a Schlumberger Company). The x-axis is injection rate in barrels per minute while the y-axis is bottomhole injection pressure in psi.

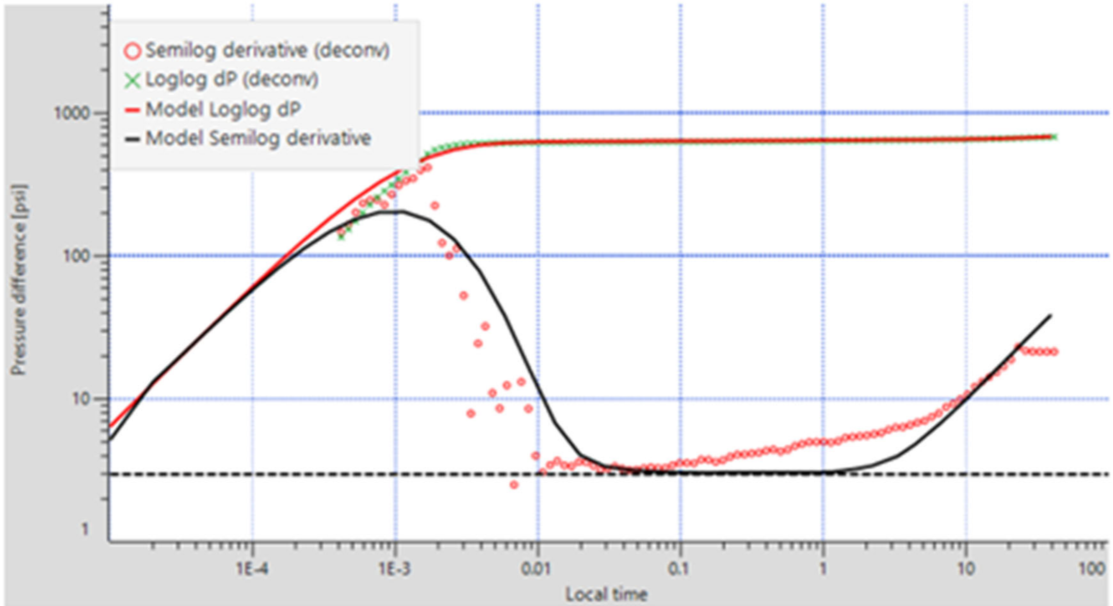

Figure 2-18. GeothermEx interpretation of the Broom Creek pressure formation falloff test using Saphir – Kappa (courtesy of GeothermEx, a Schlumberger Company).

Formation	**Broom Creek**
Perforation Interval (ft)	4,912 to 4,922
Estimated Formation Thickness (ft)	38
Tested Interval Thickness (ft)	38
Formation Transmissibility (mD.ft)	170,458
Formation Permeability (mD)	4,485
Skin Factor	89.6
Investigation Radius (ft)	24,804
Boundary Condition	Infinite Acting
Comments	Quality PFO test, good confidence in formation parameters assessed with numerical model. Noted skin damage changing between the step rate and constant rate test.

Figure 2-19. Broom Creek well test summary of J-LOC1 well (modified from Schlumberger presentation).

Table 2-11. J-LOC1 Broom Creek Formation Test Summary

Parameters	Value	Unit
Reservoir Pressure	2,410	psi
Permeability	4,485	mD
Radius of Investigation	24,804	ft
Type of Boundary	Infinite acting	
Fracture Opening Pressure	3,424	psi

2.3.2 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 carbonate and anhydrite. Seventeen 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. Thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals shows that quartz (~85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (~4%), dolomite (~5%), and anhydrite as cement (~6%). 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 from 15% to 25%.

Two distinct carbonate intervals are notable. The first is the presence of a very fine- to fine-grained dolostone (75%), with quartz (16%) and feldspar (9%) present. The porosity is intercrystalline and not well-developed, averaging 5.5%. Diagenesis is expressed by dolomitization of the original calcite grains. The second carbonate interval comprises fine-grained dolomite (78%), quartz (10%), feldspar (8%), and clay (4%). Diagenesis is expressed by the dissolution of dolomite, resulting in vuggy porosity. The porosity averages 9%. The anhydrite intervals are expressed as thin beds that separate different sand bodies and cement. The porosity ranges from 1.5% to 2.5%.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, dolomite, anhydrite, feldspar, clay, and iron oxides (Figure 2-20). XRD data show illite is the most prominent type of clay within the formation.

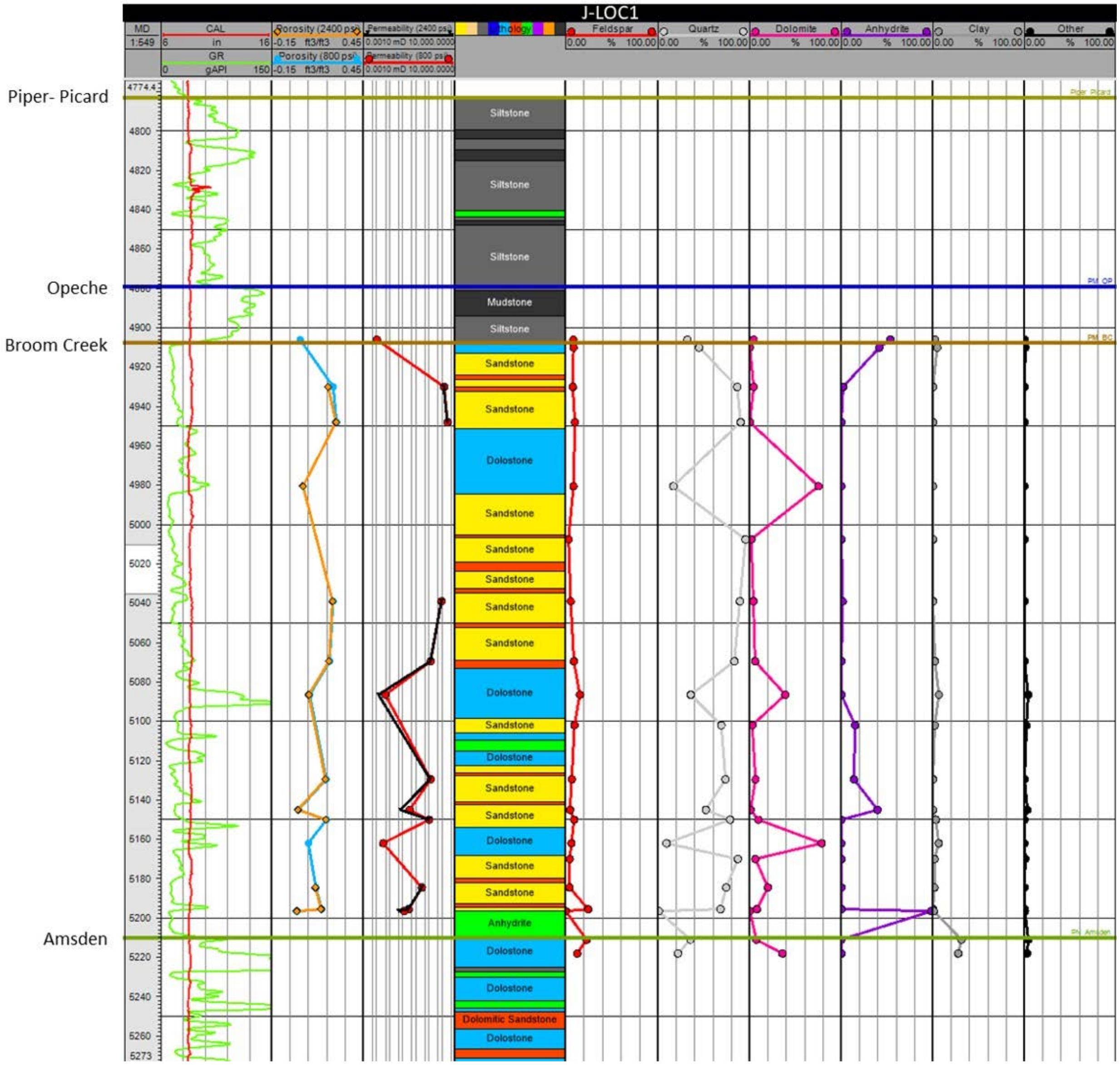

Figure 2-20. Laboratory-derived mineralogic characteristics of the Broom Creek Formation.

XRF data are shown in Figure 2-21 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%–80%), CaO (0%–30%), and MgO (0%–20%). The high percentage of CaO and SO_3 at 5,196 and 5,111 ft indicate a presence of a thin layer of anhydrite. The formation shows very little clay, with a range of 0% to 6% being the highest detected.

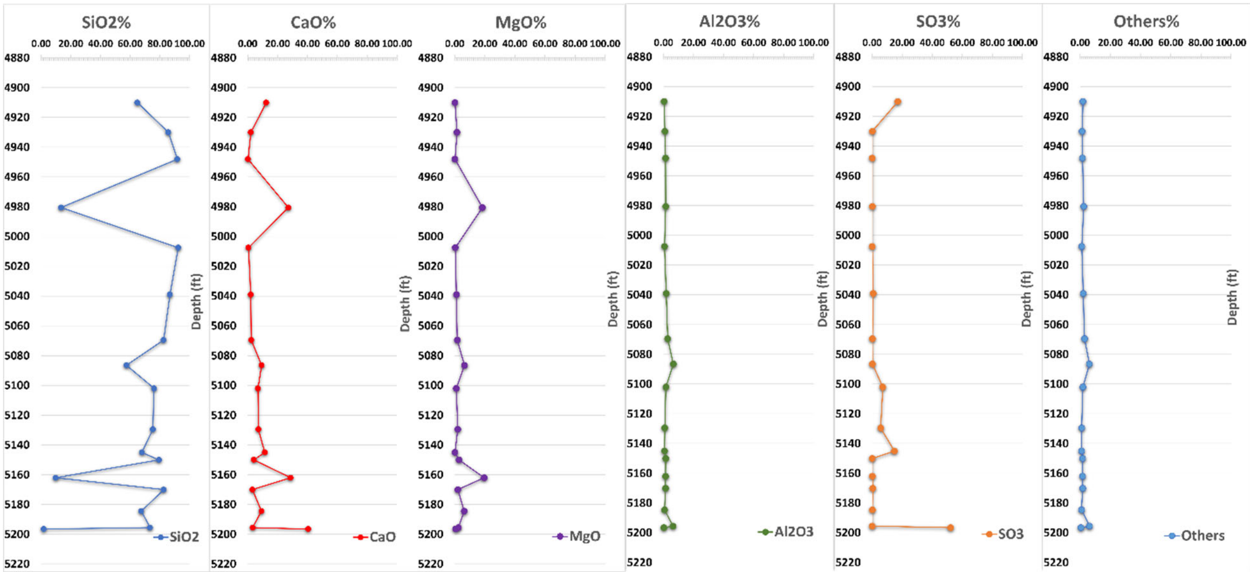

Figure 2-21. XRF data from the Broom Creek from J-LOC1.

2.3.3 Mechanism of Geologic Confinement

For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche–Picard interval), 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), which confines the CO_2 within the proposed storage reservoir as identified in (Figure 2-3). 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. However, adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.3.4 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 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. For this geochemical modeling study, the injection scenario consisted of a 20-year injection period with BHP (bottomhole pressure) and WHP (wellhead pressure) constraints of 3,005.4 and 1,700 psi, resulting in an annual injection rate of 3.35–3.67 MM tonnes/year. This scenario was run with and without the geochemical analysis option included, 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 meaningful change to storage reservoir performance or mechanical properties (porosity) of the storage formation.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (87% of bulk reservoir volume) and average formation brine composition (13% of bulk reservoir volume). XRD data from the JLOC-1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-12). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the formation water is listed in Table 2-13. The injection stream is expected to be 99.9% CO_2. Other constituents represent 0.1% of the stream and are expected to include nitrogen (N_2) and water vapor (H_2O). However, 100% CO_2 was assumed for computational efficiency in the geochemical simulation to investigate rock and fluid interaction in the saline storage formation. N_2 is known to be an inert gas, and water is already in the saline storage formation and will have little to no impact on the geochemical reactions. In the injection stream, argon (Ar) and oxygen vapor (O_2) may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation. The geochemistry case was run for the 20-year injection period followed by 22 years of postinjection monitoring.

Table 2-12. XRD Results for JLOC-1 Broom Creek Core Samples

Mineral Data	%
Dolomite	14.98
Quartz	53.78
Illite	2.20
K-Feldspar	5.52
Anhydrite	23.48
Albite	0.04

Table 2-13. Broom Creek Water Ionic Composition, expressed as molality

Component	Molality
SO_4^{2-}	0.02865
K^+	0.005135
Na^+	0.70365
Ca^{2+}	0.04809
Mg^{2+}	0.01546
CO_3^{2-}	3.1657E-4
Cl^-	0.79259
HCO_3^-	0.001193
Al^{3+}	9.6107E-06
$SiO_2(aq)$	1.0E-08

Figure 2-22 shows that reservoir performance results for the two cases are essentially identical. As a result of geochemical reactions in the reservoir, there is no observable difference in cumulative injection. The wellhead injection pressure is unchanged for both cases: 1,700 psi. Figure 2-23 shows the concentration of CO_2, in molality, in the reservoir after 20 years of injection. The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-24. The pH of the Broom Creek native brine is 7.3 whereas the fluid pH declines to approximately 5.0 in the CO_2-flooded areas.

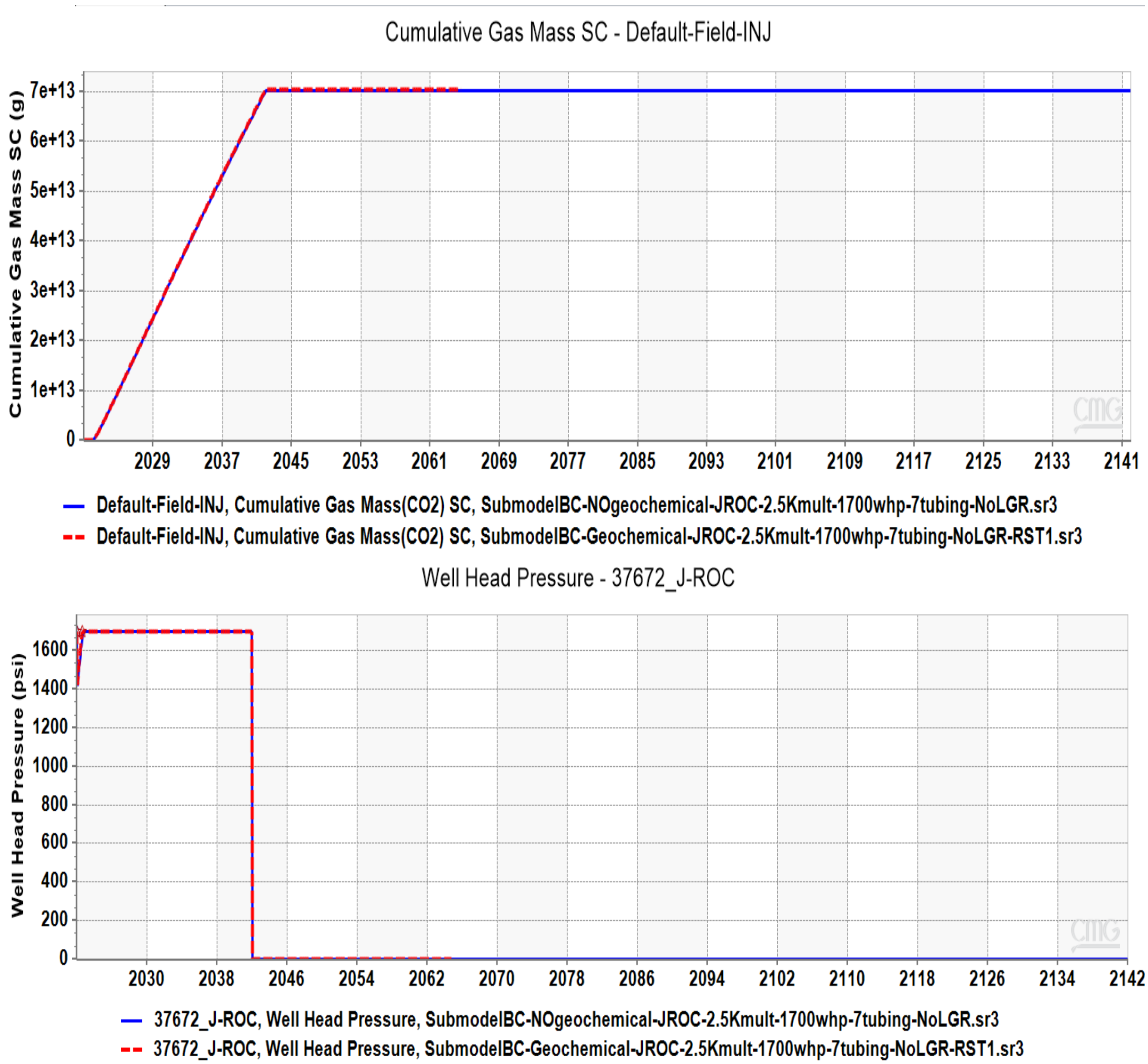

Figure 2-22. Upper graph shows cumulative injection vs. time. There is no observable difference in injection due to geochemical reactions. Lower graph shows wellhead injection pressure for the two cases is the same, 1,700 psi.

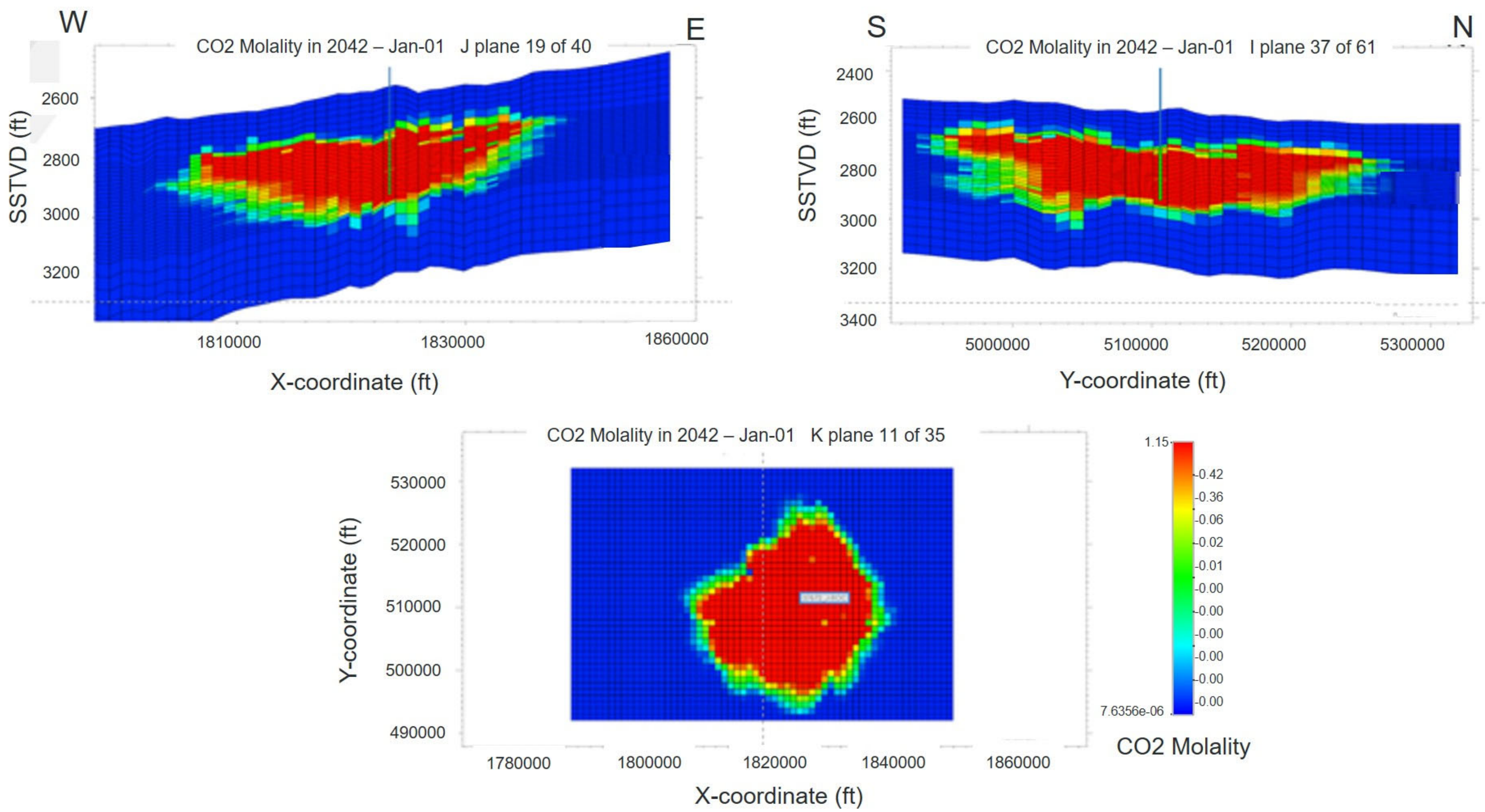

Figure 2-23. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality with a log scale. Upper image is a north-south cross section. Lower image is a planar view of Simulation Layer 11.

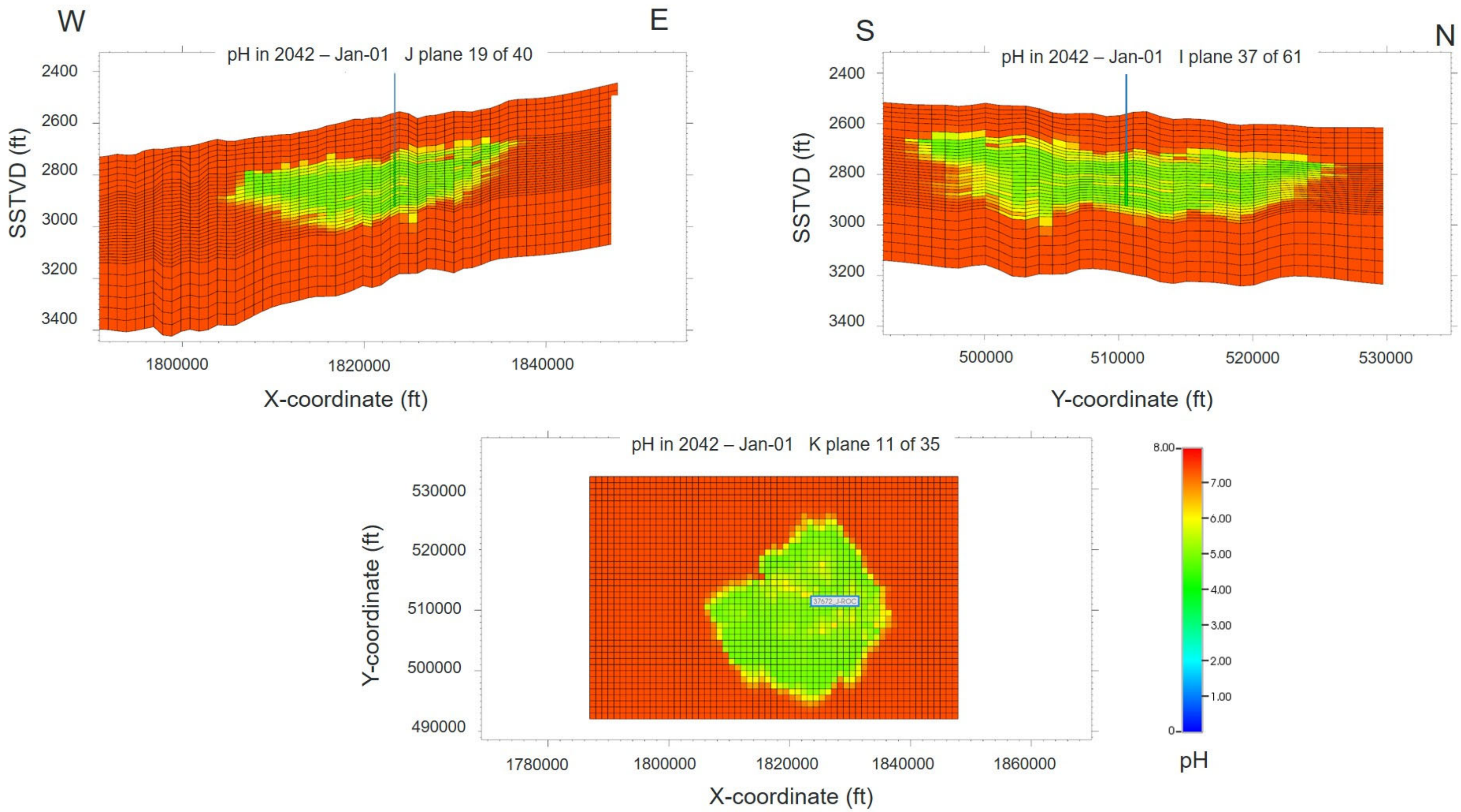

Figure 2-24. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine.

Figure 2-25 shows the mass of mineral dissolution and precipitation due to geochemical reactions in the Broom Creek Formation. Illite is the most prominent dissolution mineral, followed by K-feldspar. K-feldspar dissolution slows after Year 2042, the year in which injection ends. Quartz and dolomite are the primary precipitation minerals. There is a small amount of net dissolution during the simulation period as somewhat larger quantities of minerals are dissolved rather than precipitated. Figures 2-26 and 2-27 provide an indication of the change in distribution of the mineral that experienced the most dissolution, illite, and mineral that has experienced significant precipitation, quartz, respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-25, there is an associated net increase in porosity of the affected area, as shown in Figure 2-28. However, the porosity change is small, less than 0.4% porosity units, equating to a maximum increase in average porosity from 12.8% to 13.2% after the 20-year injection period.

Results of the simulation show that geochemical processes will be at work in the Broom Creek Formation 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 from 7.3 to approximately 5.0, and there will be a slight net increase in system porosity. However, these changes are not significant enough to create observable change in the reservoir performance parameters such as injection rate or wellhead injection pressure.

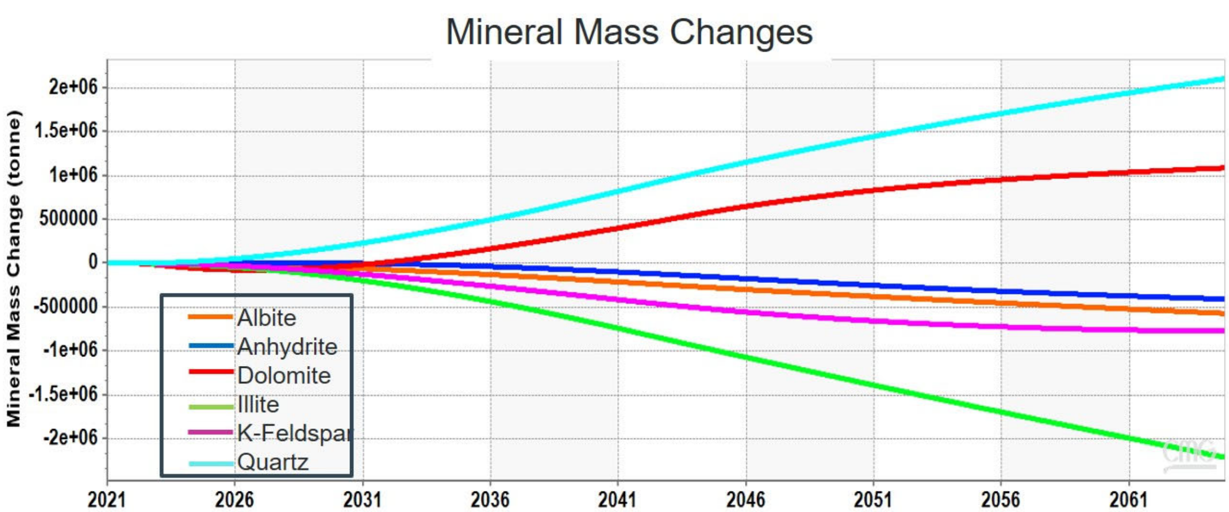

Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of illite, anhydrite, and K-feldspar with precipitation of calcite, quartz, and dolomite was observed.

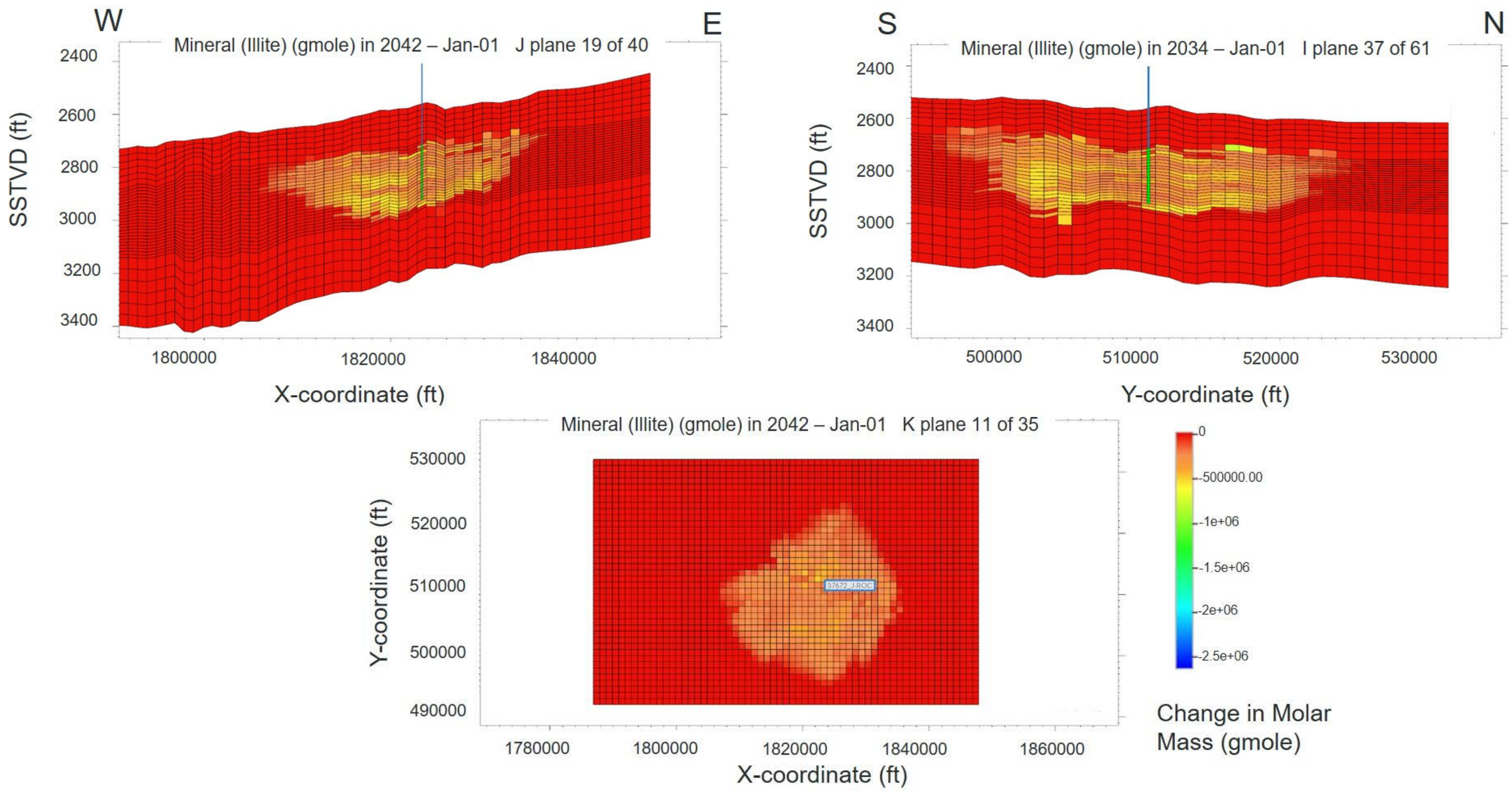

Figure 2-26. Change in molar distribution of illite, the most prominent dissolved mineral at the end of the injection period, shown in orange/yellow color. Compare to the molar CO_2 distribution in Figure 2-23.

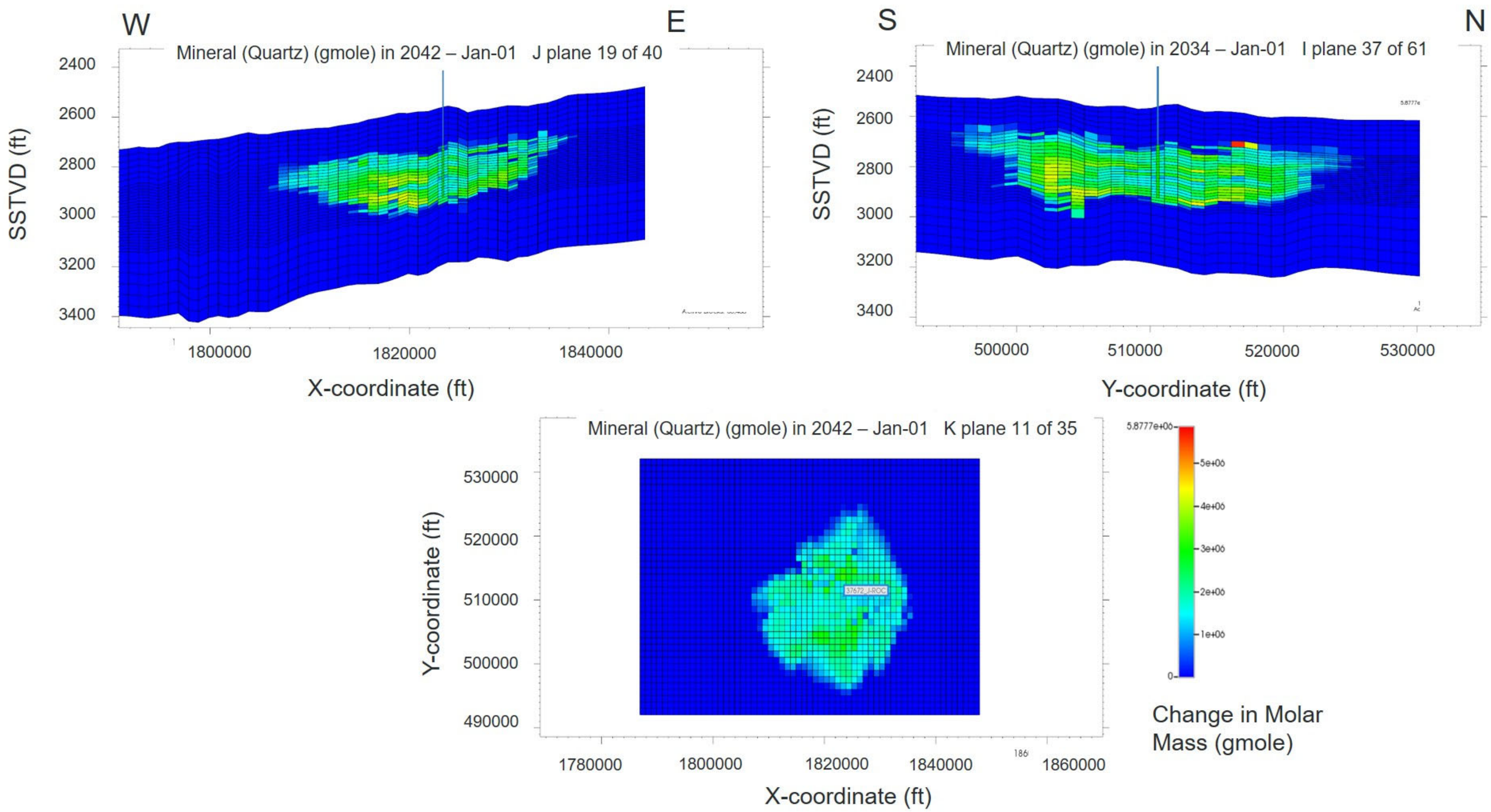

Figure 2-27. Change in molar distribution of quartz, a prominent precipitated mineral at the end of the injection period, shown in orange/yellow color. Compare to the molar CO_2 distribution in Figure 2-23.

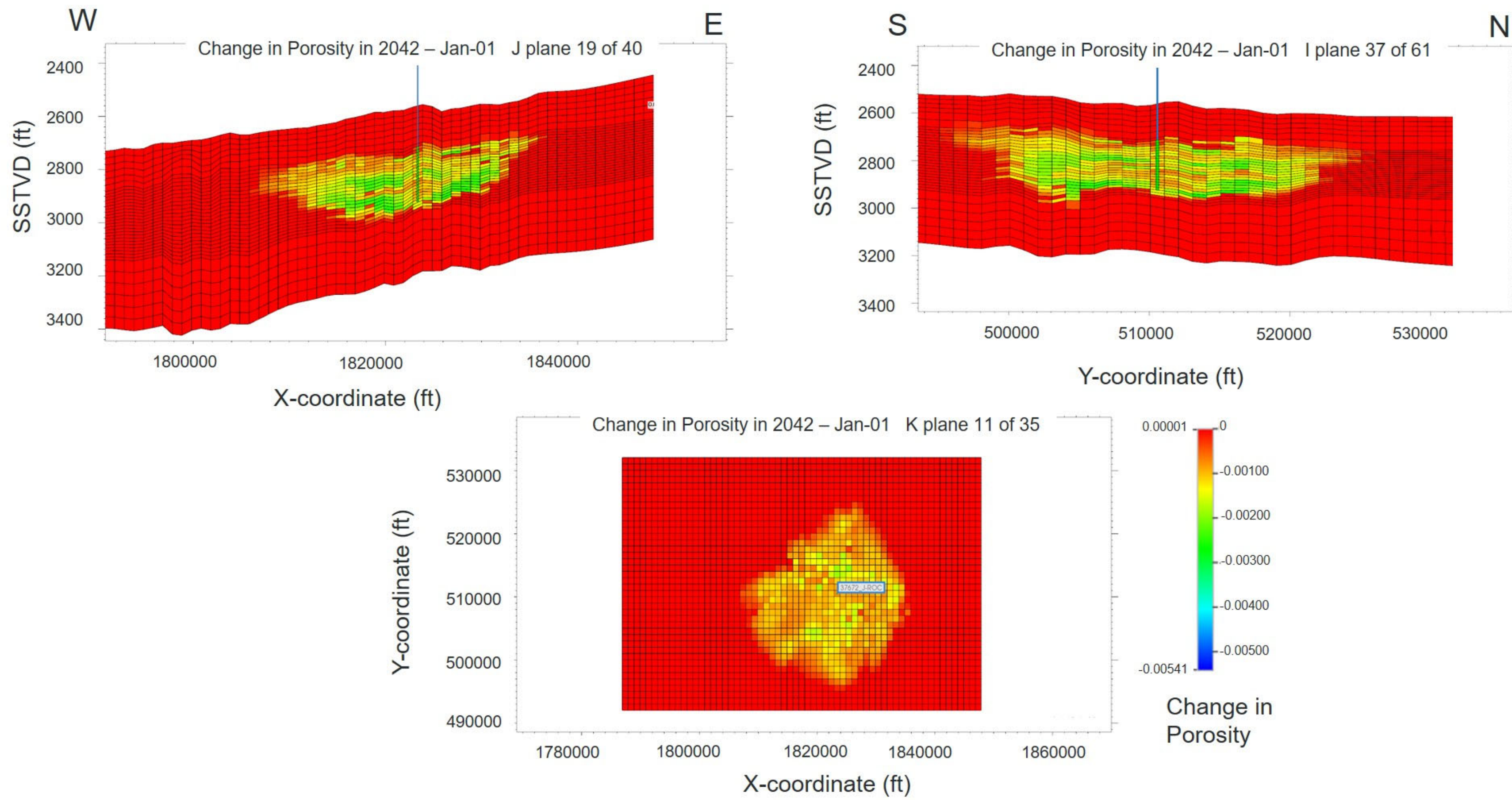

Figure 2-28. Change in porosity due to net geochemical dissolution after the 20-year injection period. Maximum porosity change is less than 0.4%. Compare to the molar CO_2 distribution in Figure 2-23.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche–Picard interval and underlying Amsden Formation (Figure 2-3, Table 2-14). Both the Amsden and Opeche–Picard intervals consist of impermeable rock layers.

Table 2-14. Properties of Upper and Lower Confining Zones in Simulation Area

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche–Picard	Amsden
Lithology	Siltstone	Dolostone
Formation Top Depth, ft	4,636	5,040
Thickness, ft	154	270
Porosity, % (core data)*	6.55	7.04
Permeability, mD (core data)**	0.112	0.017
Capillary Entry Pressure (CO_2/brine), psi	20.59	69.03
Depth below Lowest Identified USDW, ft	3,409	3,813

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35).

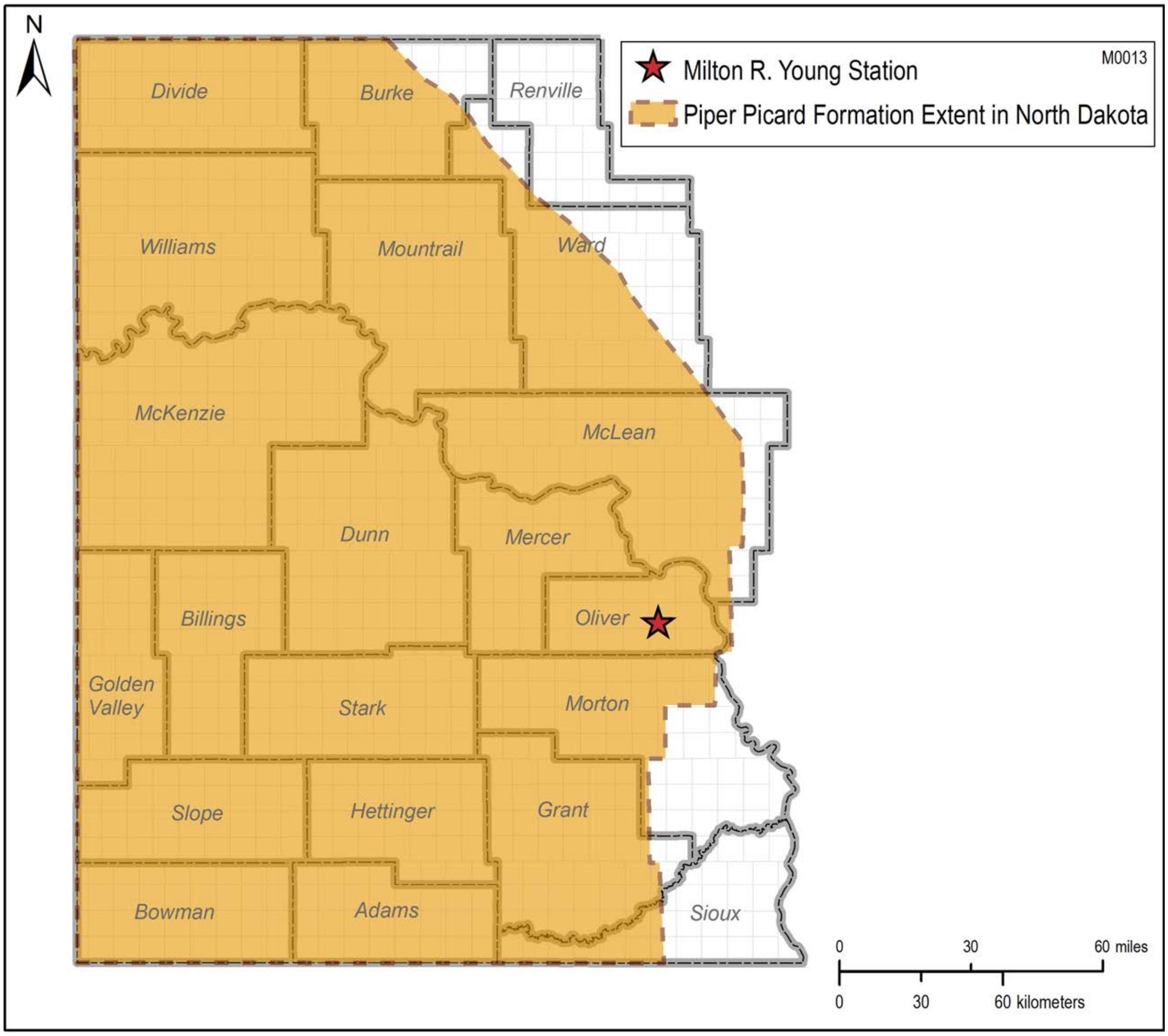

Figure 2-29. Areal extent of the Piper Picard in western North Dakota (modified from Carlson, 1993).

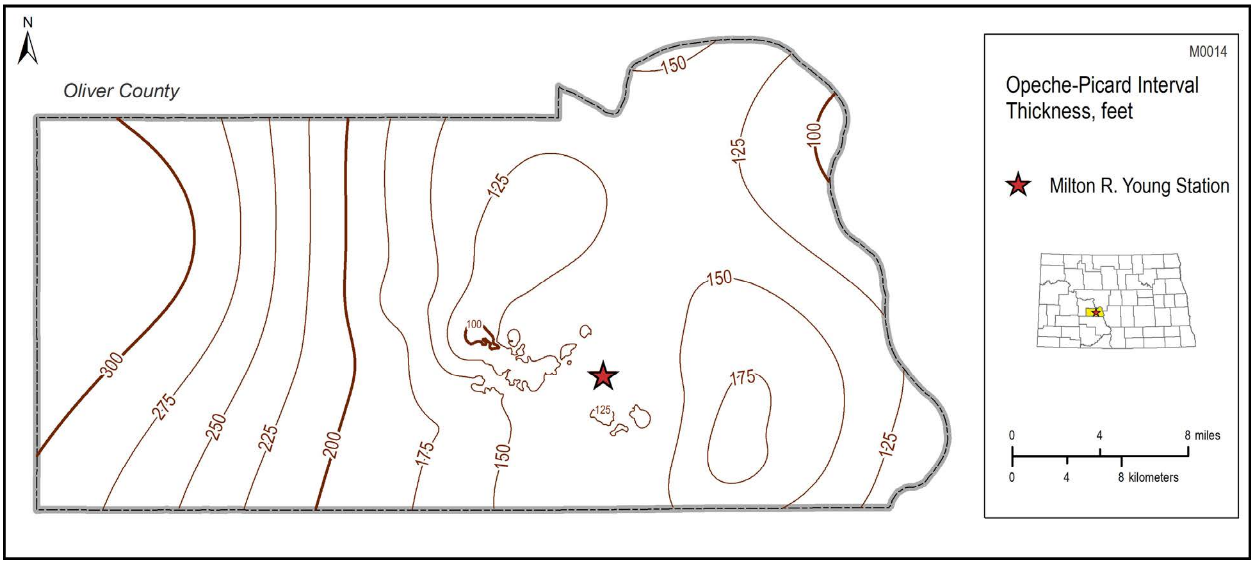

Figure 2-30. Thickness of the Opeche–Picard interval in Oliver County derived from well log data.

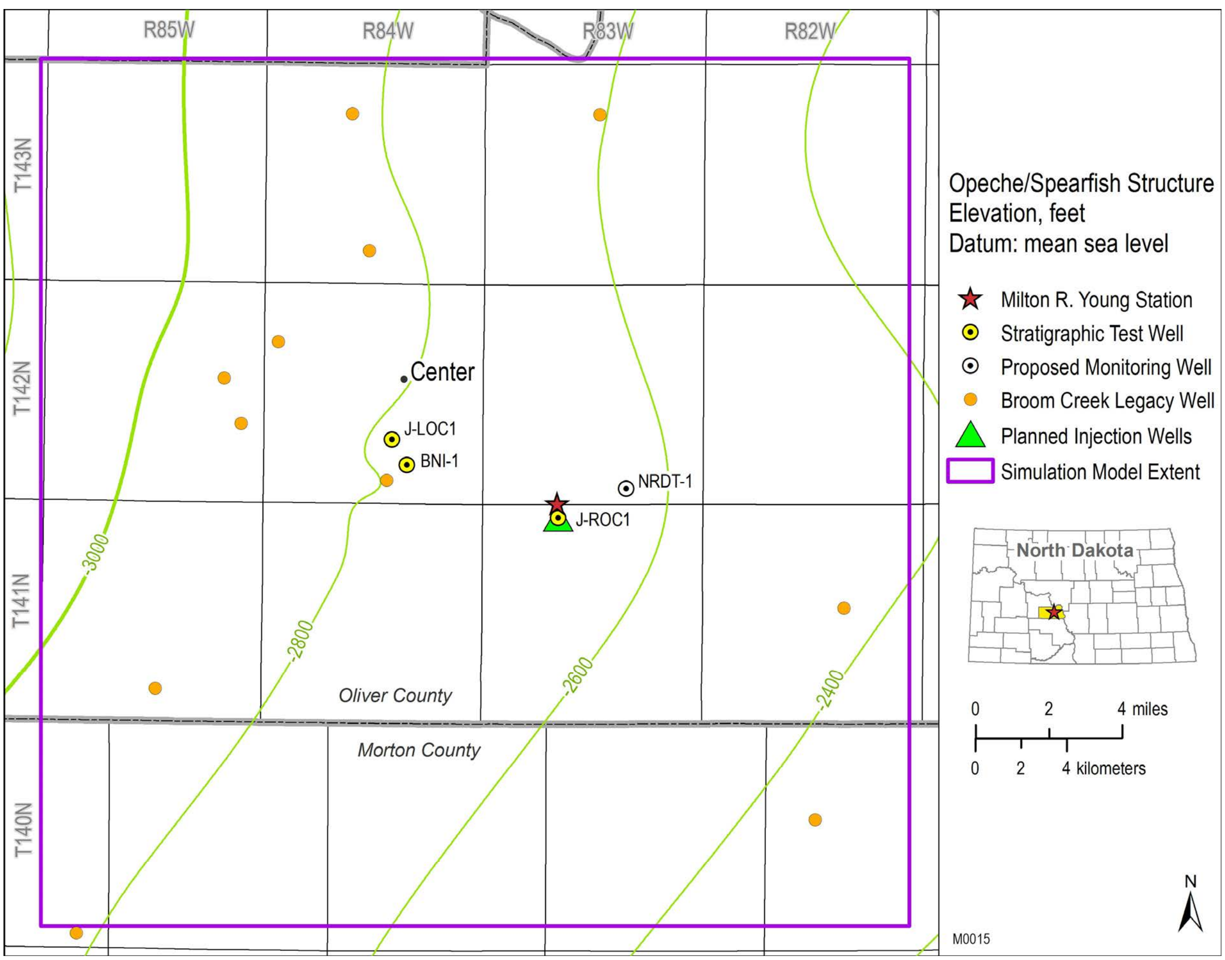

Figure 2-31. Structure map of the Opeche/Spearfish interval of the upper confining zone across the greater Tundra SGS area.

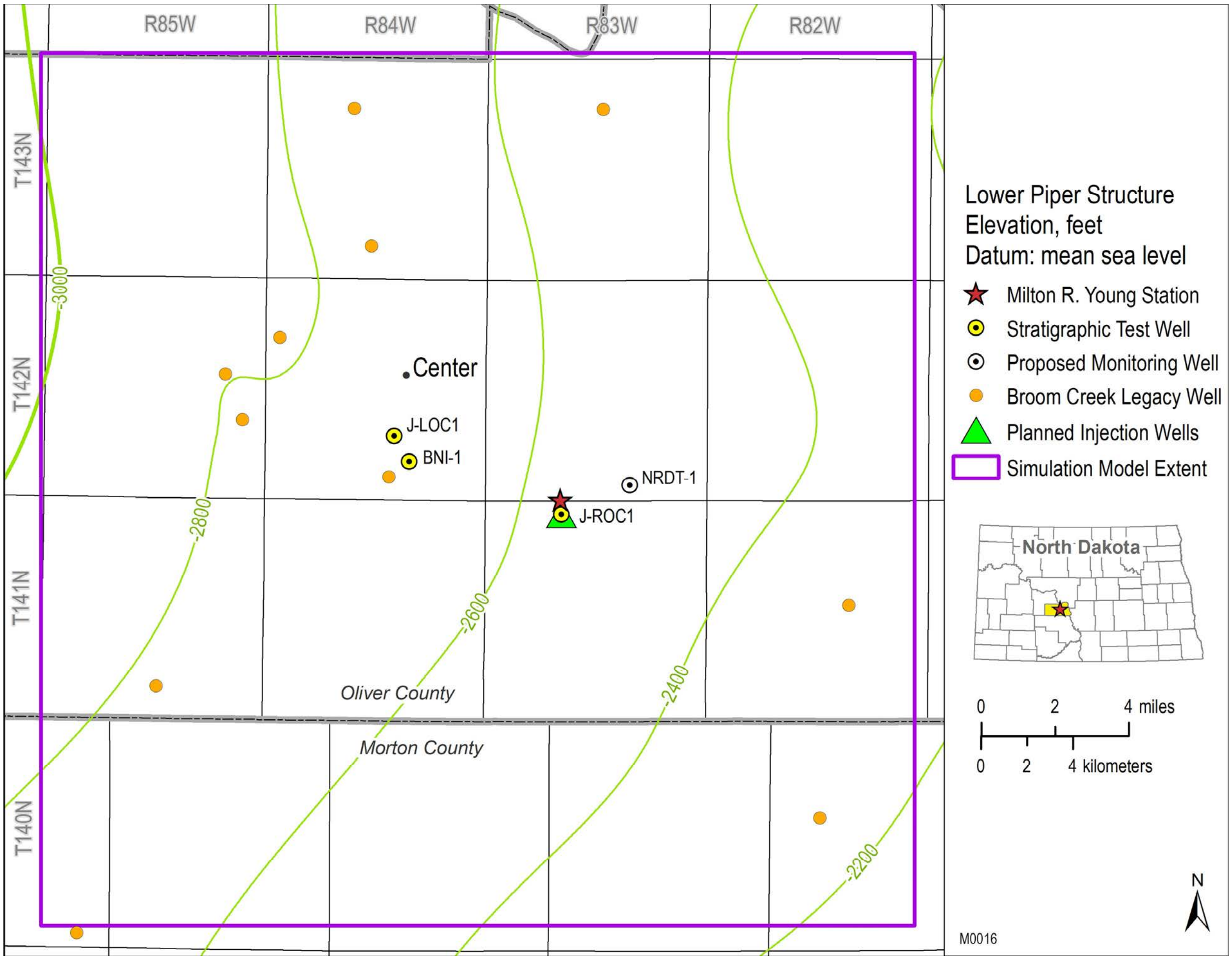

Figure 2-32. Structure map of the lower Piper interval of the upper confining zone across the greater Tundra SGS area.

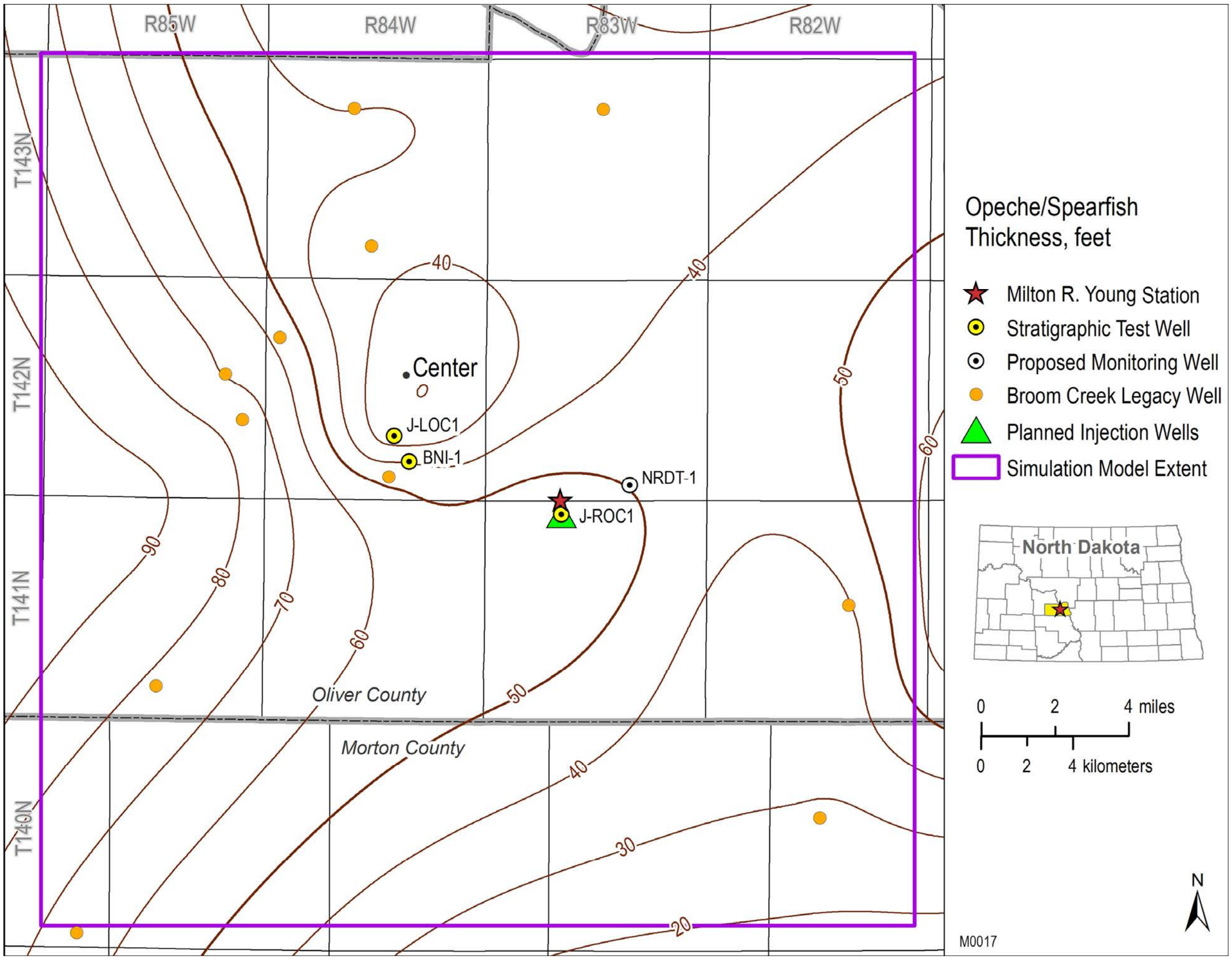

Figure 2-33. Isopach map of the Opeche/Spearfish interval of the upper confining zone in the Tundra SGS area.

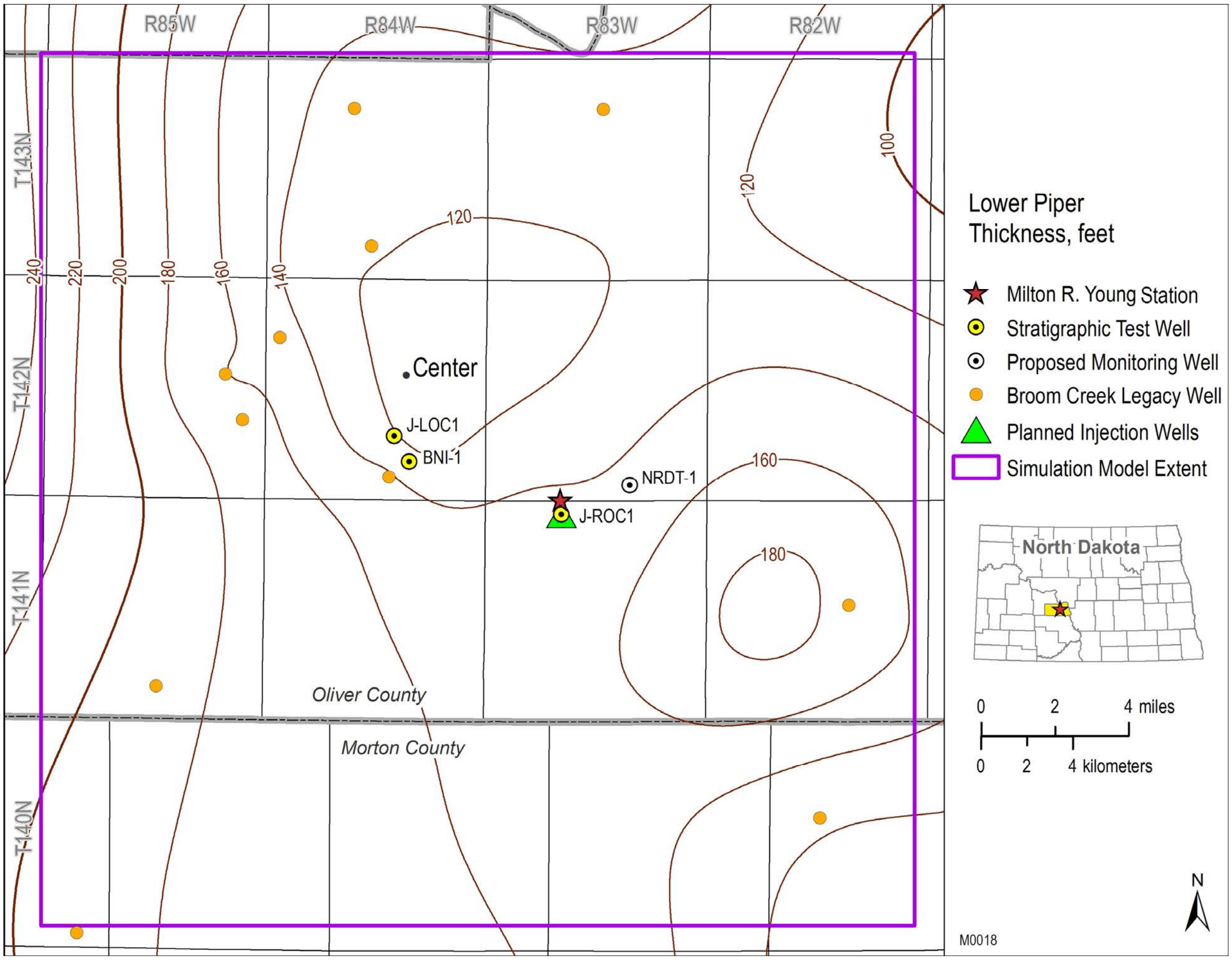

Figure 2-34. Isopach map of the lower Piper interval of the upper confining zone in the Tundra SGS area.

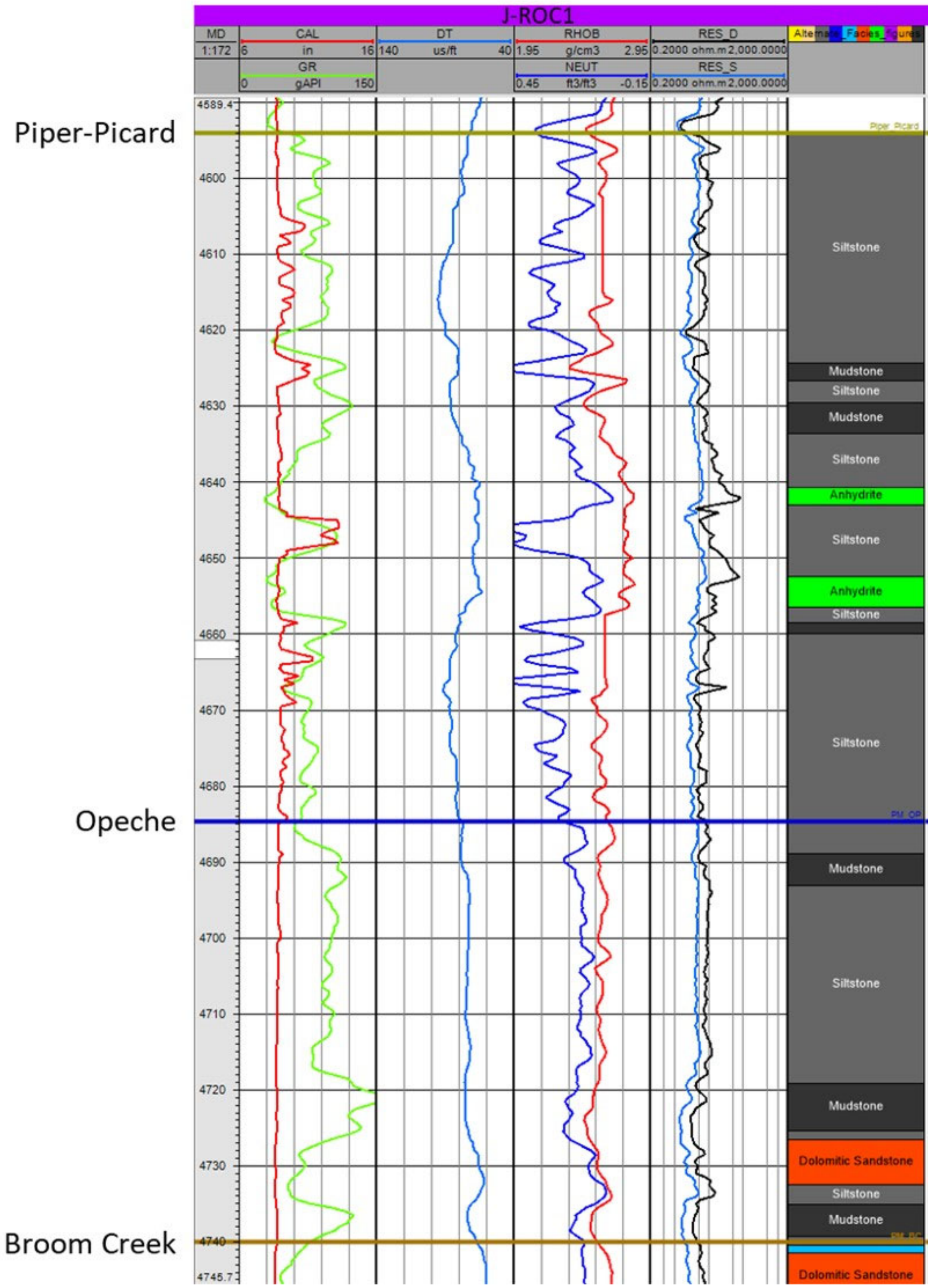

Figure 2-35. Well log display of the upper confining zone at the J-ROC1 well.

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool.

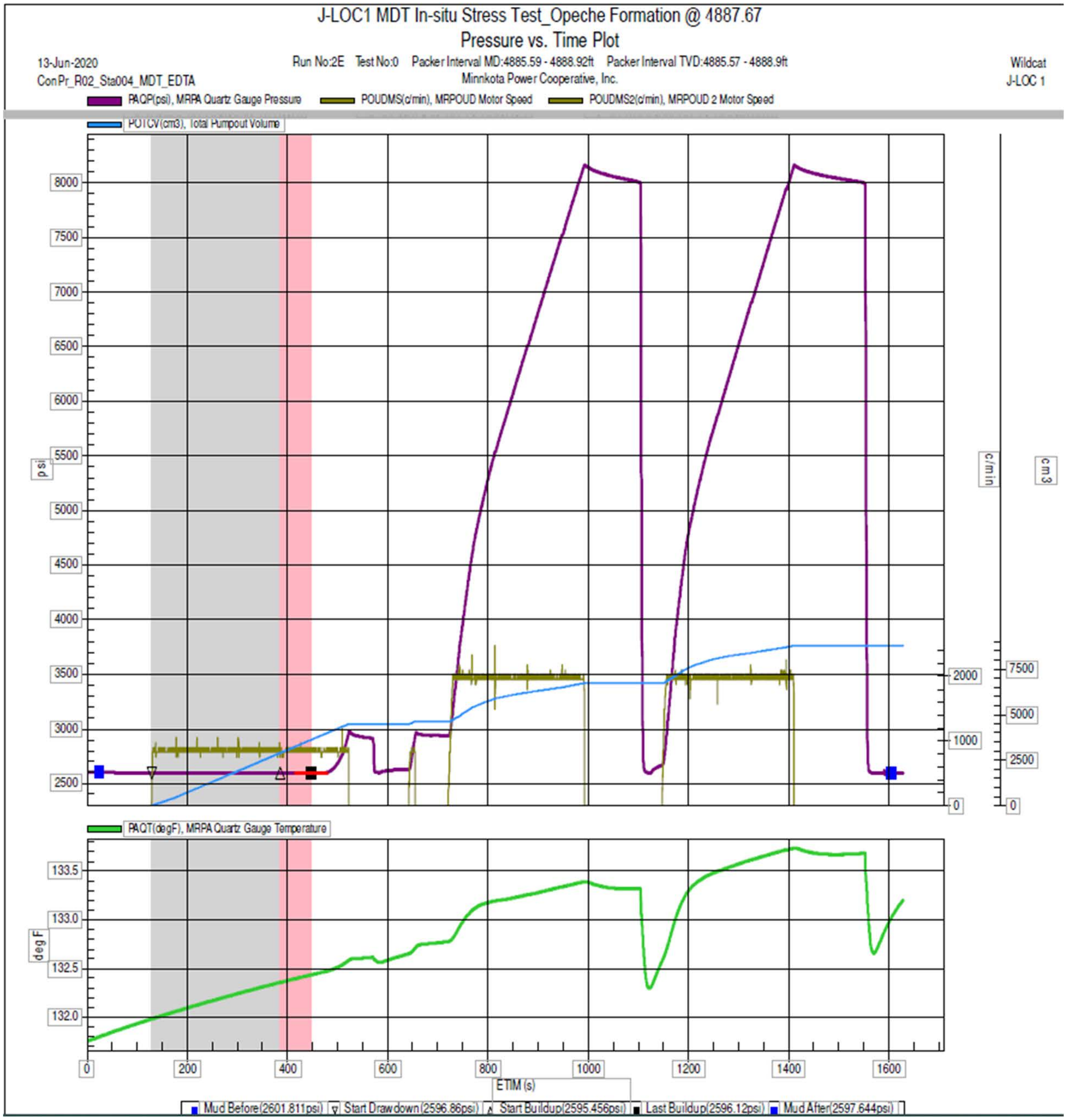

Figure 2-36. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,887.7 ft.

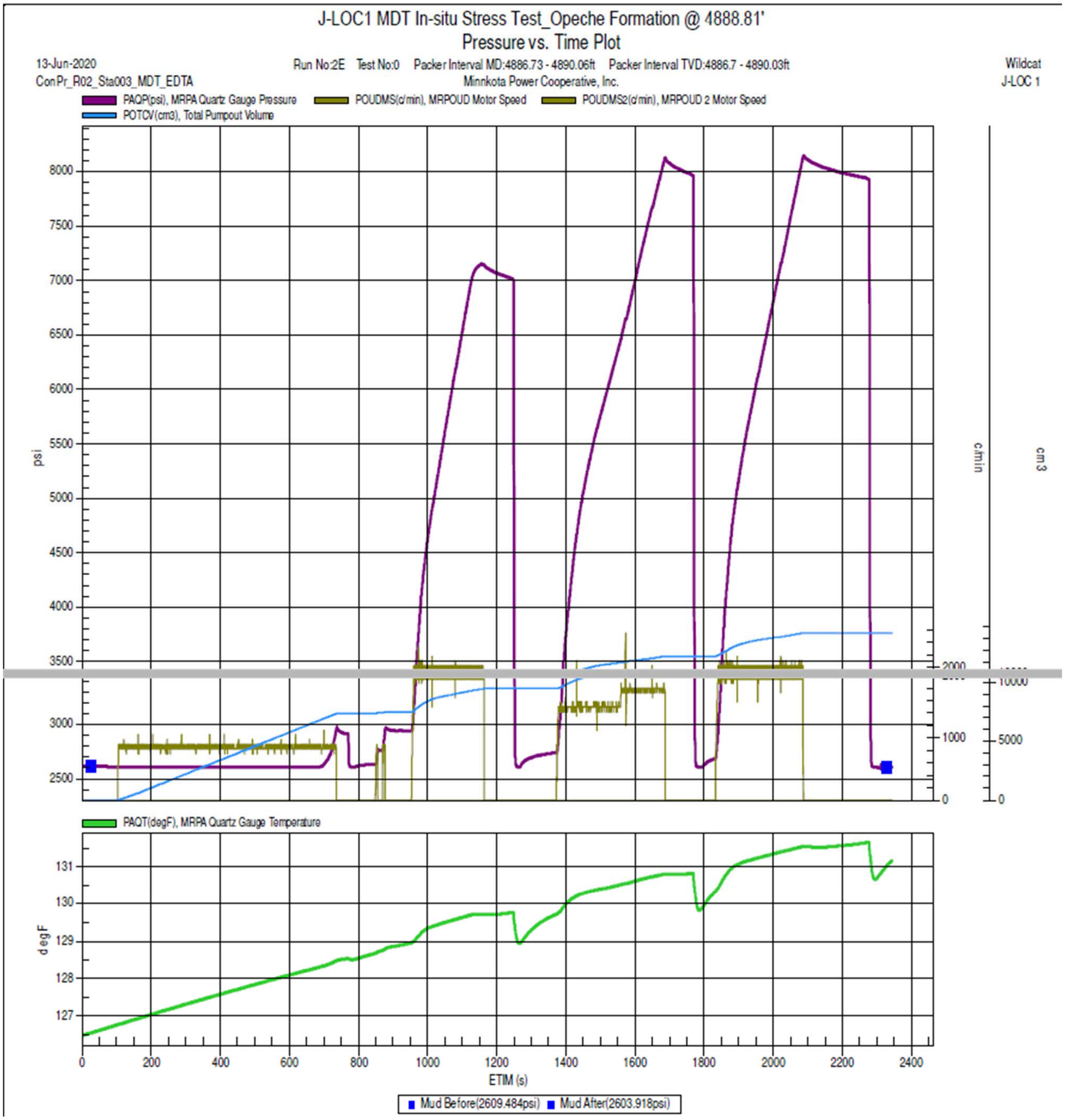

Figure 2-37. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,888.8 ft.

For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish.

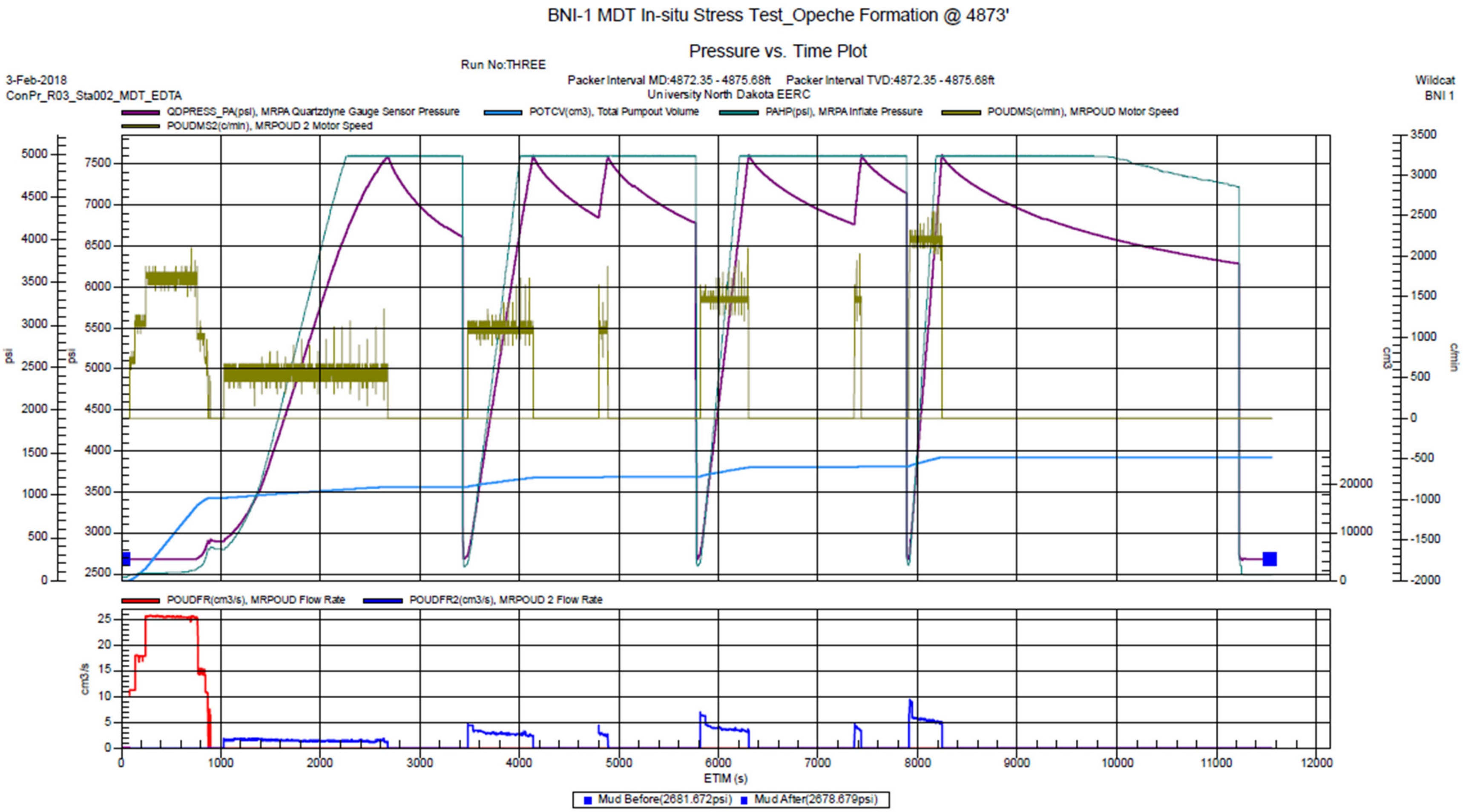

Figure 2-38. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,873 ft.

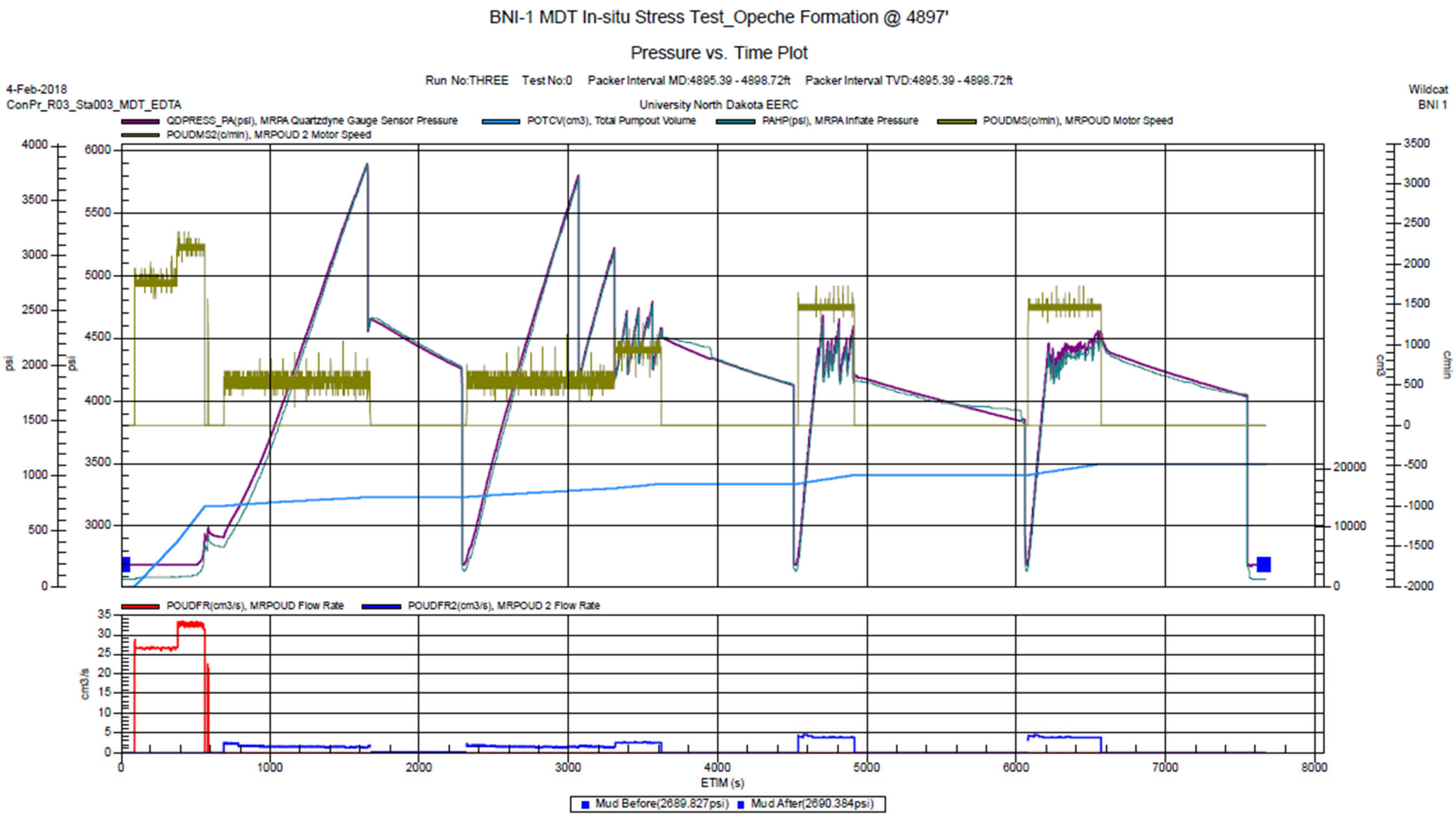

Figure 2-39. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,897 ft.

Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche/Spearfish Formation comprises alternating intervals of silty mudstone, argillaceous siltstone, mudstone, and anhydrite. Thin sections were created from the base of the Opeche/Spearfish and the transition zone present at the top of the Broom Creek which comprises clay-rich siltstone. The transition zone has similar characteristics as the Opeche/Spearfish Formation and will also act as a seal. The mineral components present in these samples are anhydrite, quartz, feldspar, dolomite, clay, and iron oxides. The grains are typically surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. The porosity equals 3.5%. Log interpretations and visual inspection of the collected core validate consistent mineral assemblage within the Opeche/Spearfish Formation.

XRD data from samples in the J-LOC1 well core supported facies interpretations from core descriptions and thin-section analysis. The Opeche/Spearfish Formation mainly comprises anhydrite, quartz, clay, and dolomite.

XRF analysis of the Opeche/Spearfish Formation identifies the major chemical constituents to be dominated by SiO_2 (47%), SO_3 (18%), CaO (16%), Al_2O_3 (4%), and MgO (2%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by the XRD (Table 2-15). Thus these results correlate with XRD, core description, and thin-section analysis.

Table 2-15. XRF Data for the Opeche/Spearfish Formation from J-LOC1

Sample Depth 4,906 ft	
Component	**Percentage**
SiO_2	47.41
Al_2O_3	3.78
CaO	16.58
MgO	2.17
SO_3	18.26
Others	11.8

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 on the Opeche/Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche/Spearfish Formation was honored (Table 2-16). Formation brine composition was assumed as the same as the known composition from the Broom Creek injection zone below (Table 2-17). The CO_2 stream composition was as described by Minnkota (Table 2-18). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/yr. This overestimate 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 of postinjection. The simulations were performed at reservoir pressure and temperature conditions.

Table 2-16. Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of JLOC-1 Core Samples

Minerals, wt%	
Illite	2.2
K-Feldspar	5.6
Albite	2.7
Quartz	31.9
Dolomite	4.3
Anhydrite	53.3

Table 2-17. Formation Water Chemistry from Broom Creek Fluid Samples from JLOC-1

pH	7.3	TDS	49,000 mg/L
Total Alkalinity	67 mg/L $CaCO_3$	Calcium	1,990 mg/L
Bicarbonate	67 mg/L $CaCO_3$	Magnesium	376 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	16,300 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	223 mg/L
Selenium	0.1204 mg/L	Iron	<2 mg/L
Sulfate	2,620 mg/L	Manganese	<2 mg/L
Chloride	29,900 mg/L	Barium	<2 mg/L
Nitrate	25.1 mg/L	Strontium	45.2 mg/L

Table 2-18. Proposed Composition of the Injection Stream (Minnkota)

Component Flows	ppmv	mol%
CO_2	804,195	0.999
H_2O	632	7.85E-04
N_2	163	2.02E-04
O_2	6	7.45E-06
H_2	0	0.00E+00
Ar	4	4.97E-06

Results showed geochemical processes at work. Figures 2-40, 2-41, and 2-42 show results from geochemical modeling. Figure 2-40 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.25 and stabilizes at a level of 5.3 after 14 years of injection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 25. Lastly, the pH is unaffected in Cell C3, indicating CO_2 does not penetrate this cell within the first 45 years. Figure 2-41 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1, solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 500 grams per cubic meter per year during active injection, with little to no precipitation or dissolution taking place after injection ceases in Year 2044. Any effects in cell C3 are too small to represent at this scale. Figure 2-42 shows change in porosity of the cap rock. Cell 1 experiences an initial increase in porosity as it is first exposed to CO_2 because of dissolution. The porosity decreases to nearly its initial condition after Year 14 because of precipitation. As dissolution occurs in Cell 1, reaction products move into Cell 2, where they precipitate, causing the porosity to slightly decrease. No significant change in porosity is seen in Cell 3 during the 45-year duration of the simulation. Note the scale of percent porosity change, E-05 to E-04. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results suggest that geochemical change from exposure to CO_2 is minor and will not cause substantive deterioration of the Opeche/Spearfish cap rock.

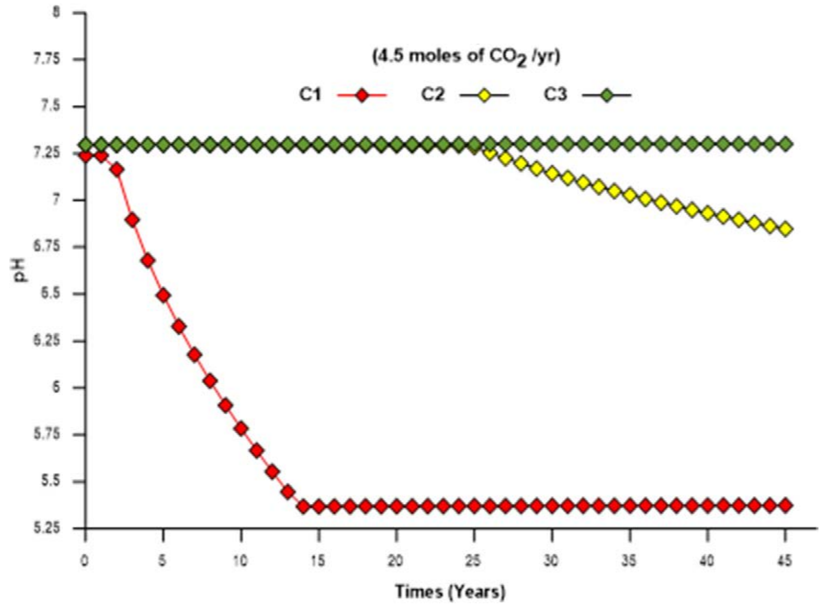

Figure 2-40. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Opeche/Spearfish cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 25.

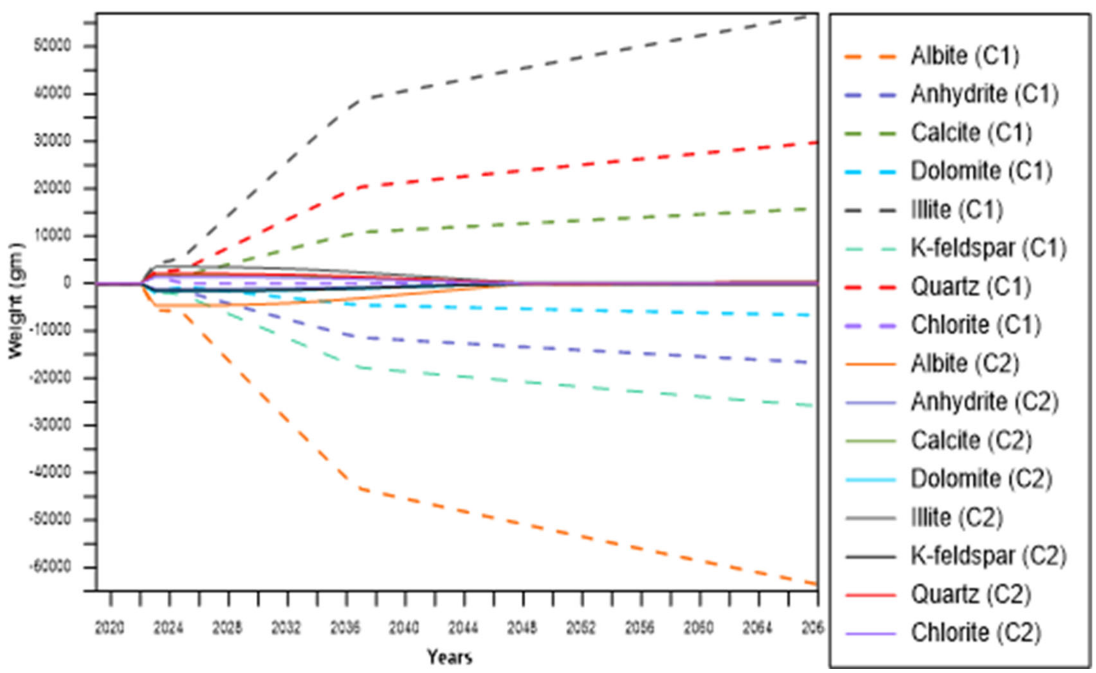

Figure 2-41. Dissolution and precipitation of minerals in the Opeche/Spearfish cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

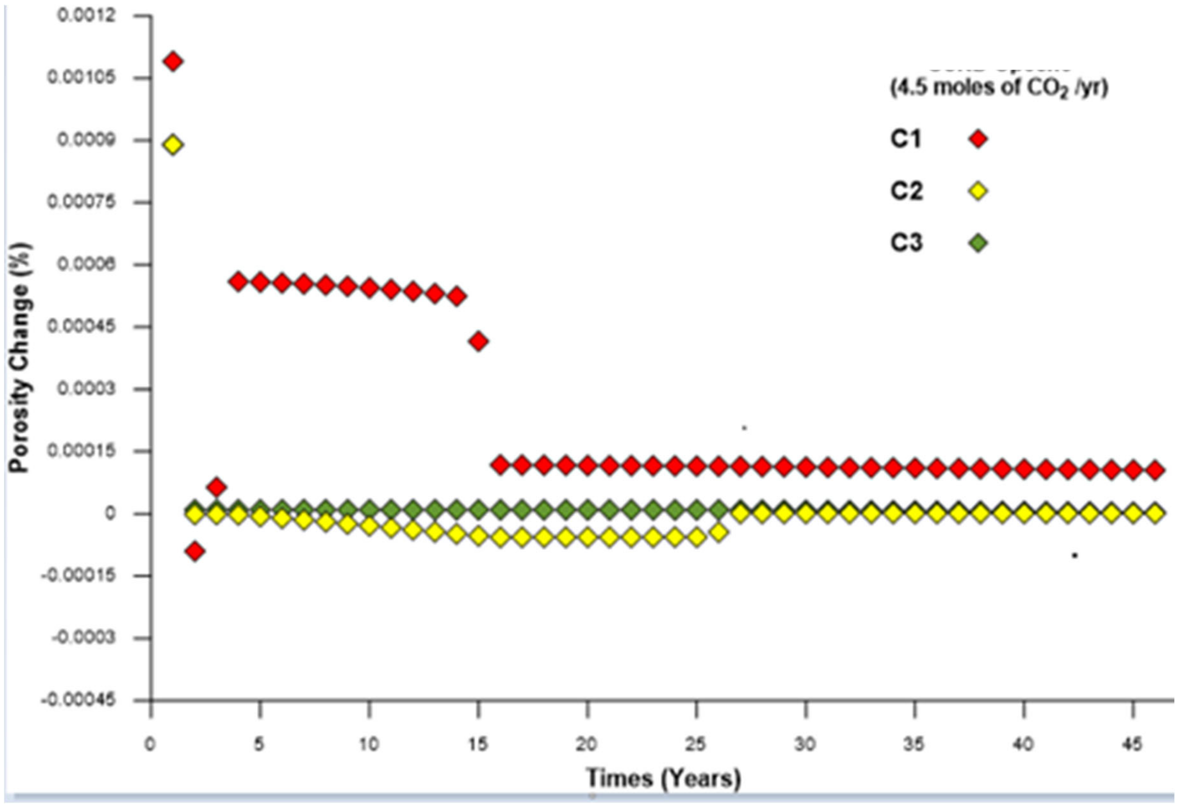

Figure 2-42. Change in percent porosity of the Opeche/Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to precipitation of minerals and negative change is due to mineral dissolution.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Piper–Picard interval. Impermeable rocks above the primary seal include the Upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-19). Together with the Opeche–Picard interval, these formations are 154 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-43). Including the Opeche–Picard there is over 850 ft of impermeable rocks that separate the Broom Creek from the Inyan Kara. Above the Inyan Kara Formation, 2,545 ft of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (see Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-19).

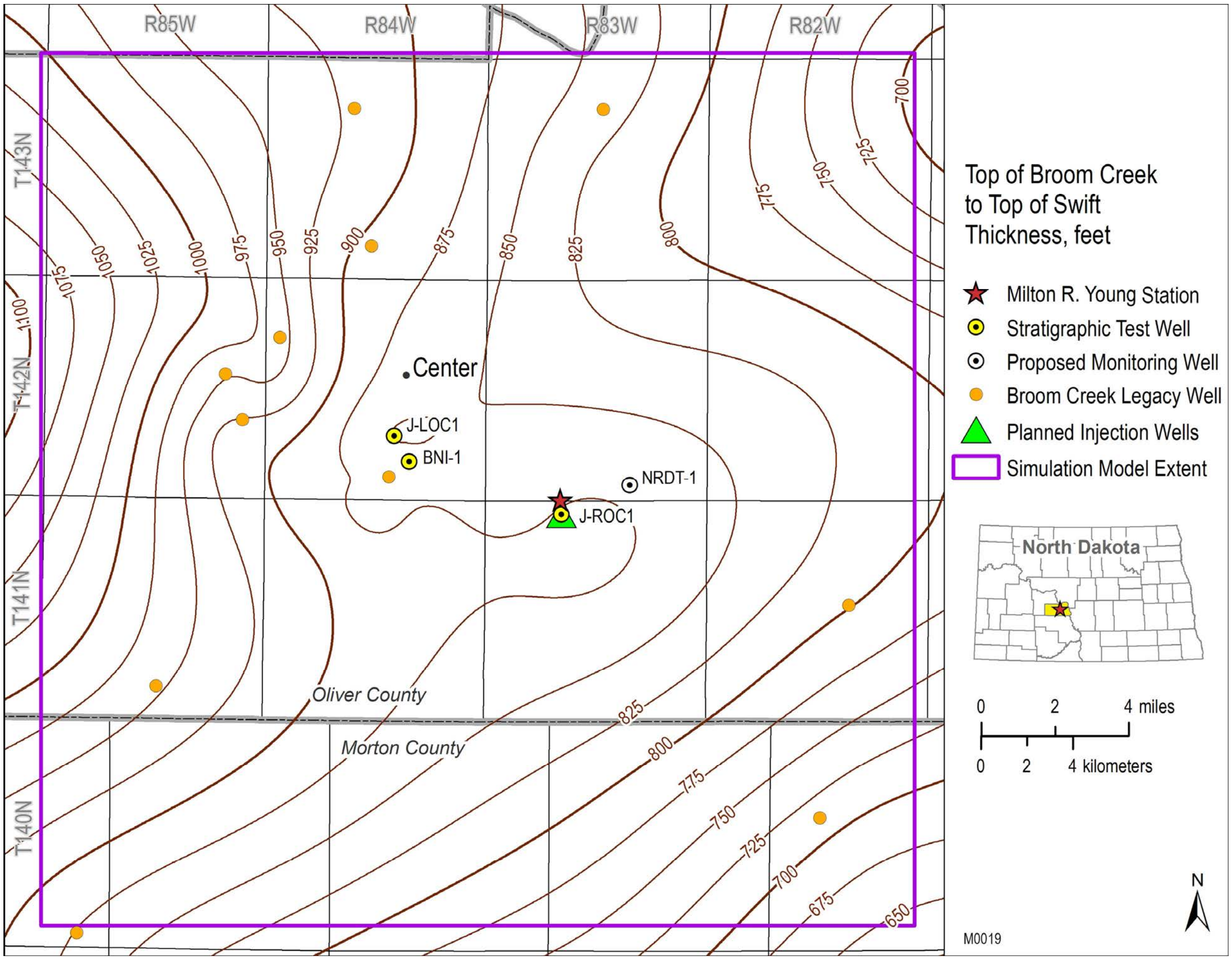

Figure 2-43. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

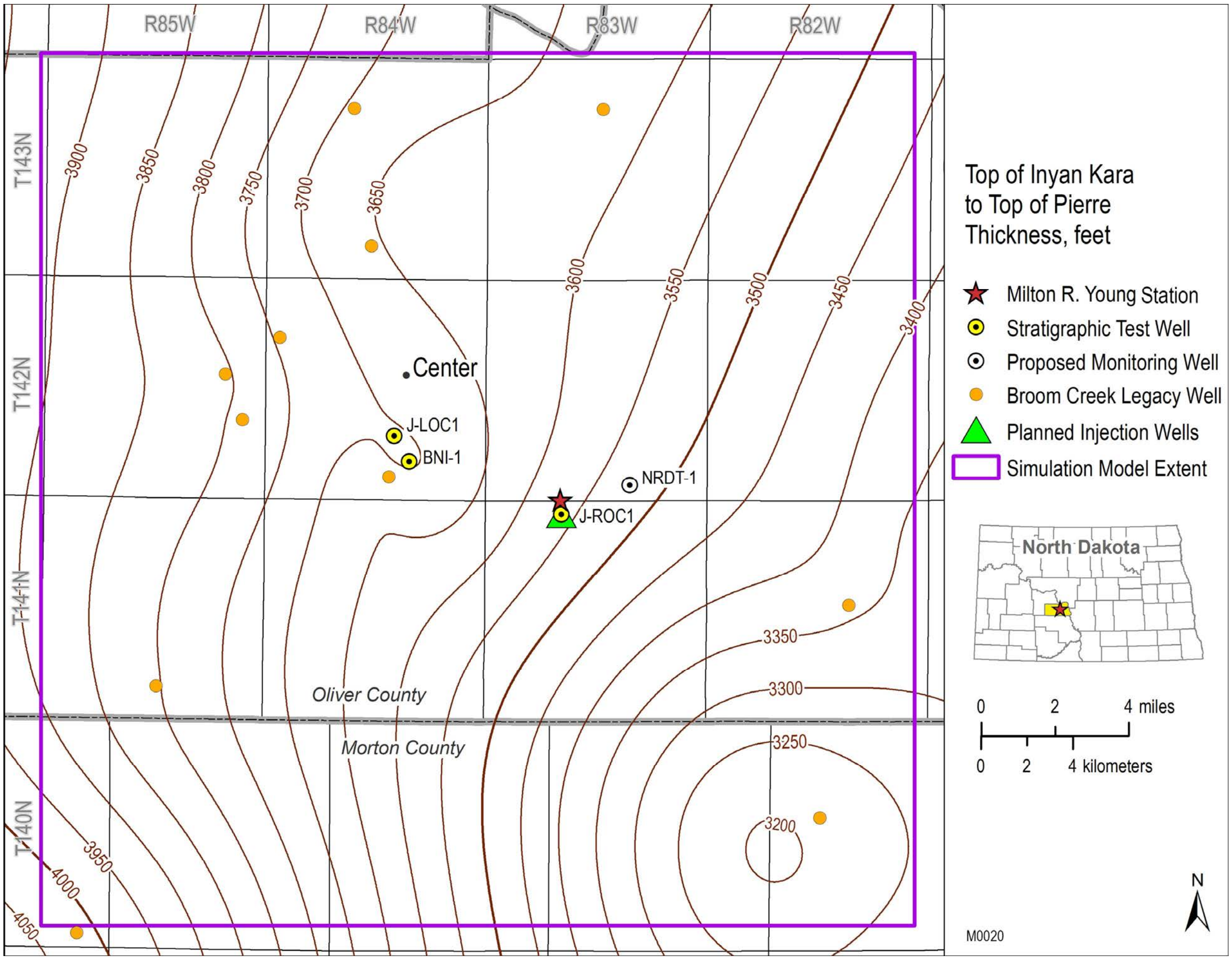

Figure 2-44. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

Table 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1,862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334

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 (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensing (DTS) data for the Inyan Kara Formation using the downhole fiber optic cable provides an additional opportunity for mitigation and remediation (Section 4). 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 Formation. The depth to the Inyan Kara Formation in the Tundra SGS area is 3,714 ft, and the formation itself is 294 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 can be correlated across the Tundra SGS area (Figures 2-45 and 2-46). The Amsden Formation is 5,040 ft below land surface and 270 ft thick at the Tundra SGS site (Table 2-14).

The contact between the overlying Broom Creek and Amsden Formations 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 the J-LOC1 well. The lithology of the cored section of the Amsden Formation from the J-LOC1well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the two core plug samples taken from the Amsden Formation show porosity values ranging from 5.4% to 7.3% and permeability values from 0.0053 to 0.0062 mD (Table 2-20).

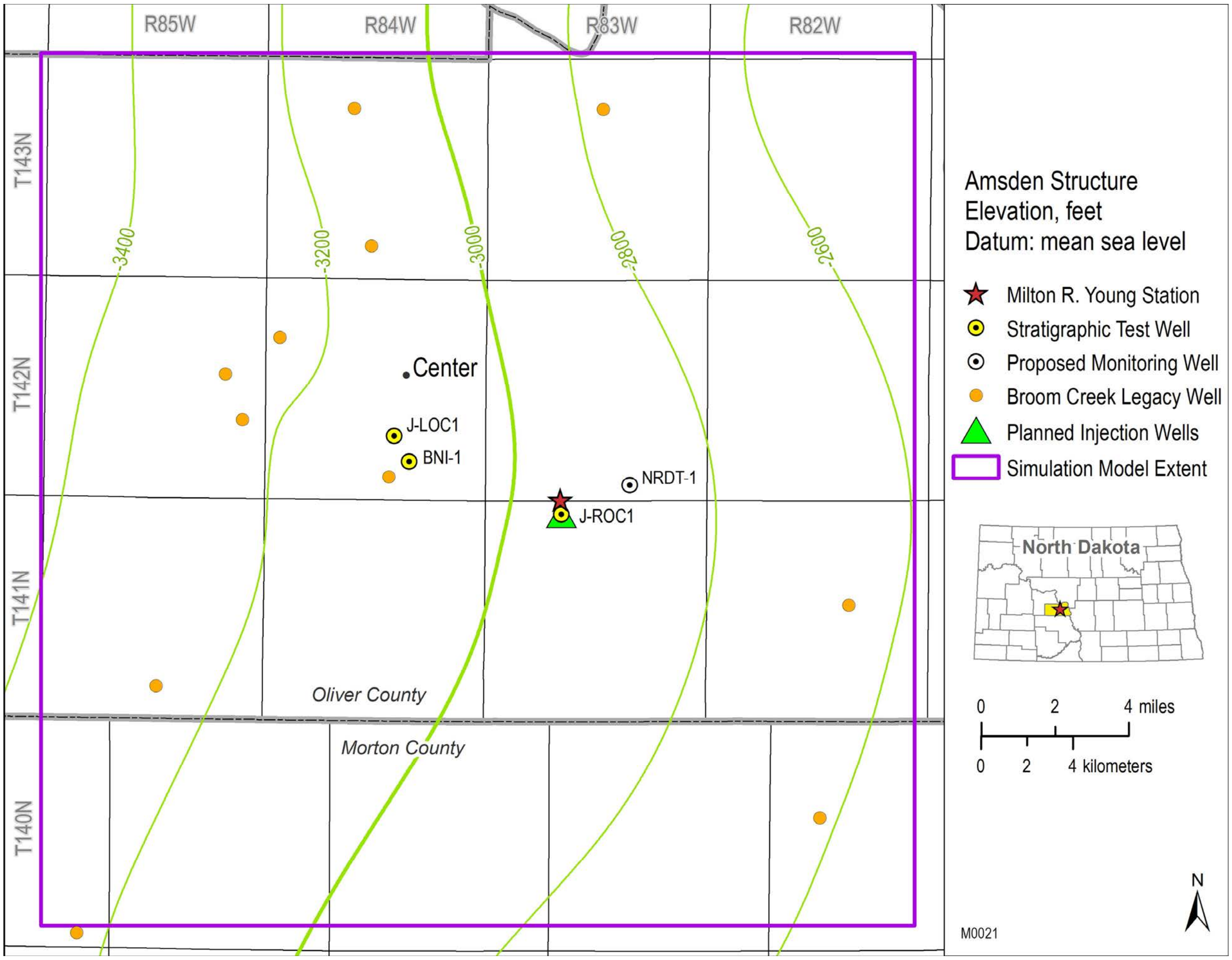

Figure 2-45. Structure map of the Amsden Formation across the greater Tundra SGS area.

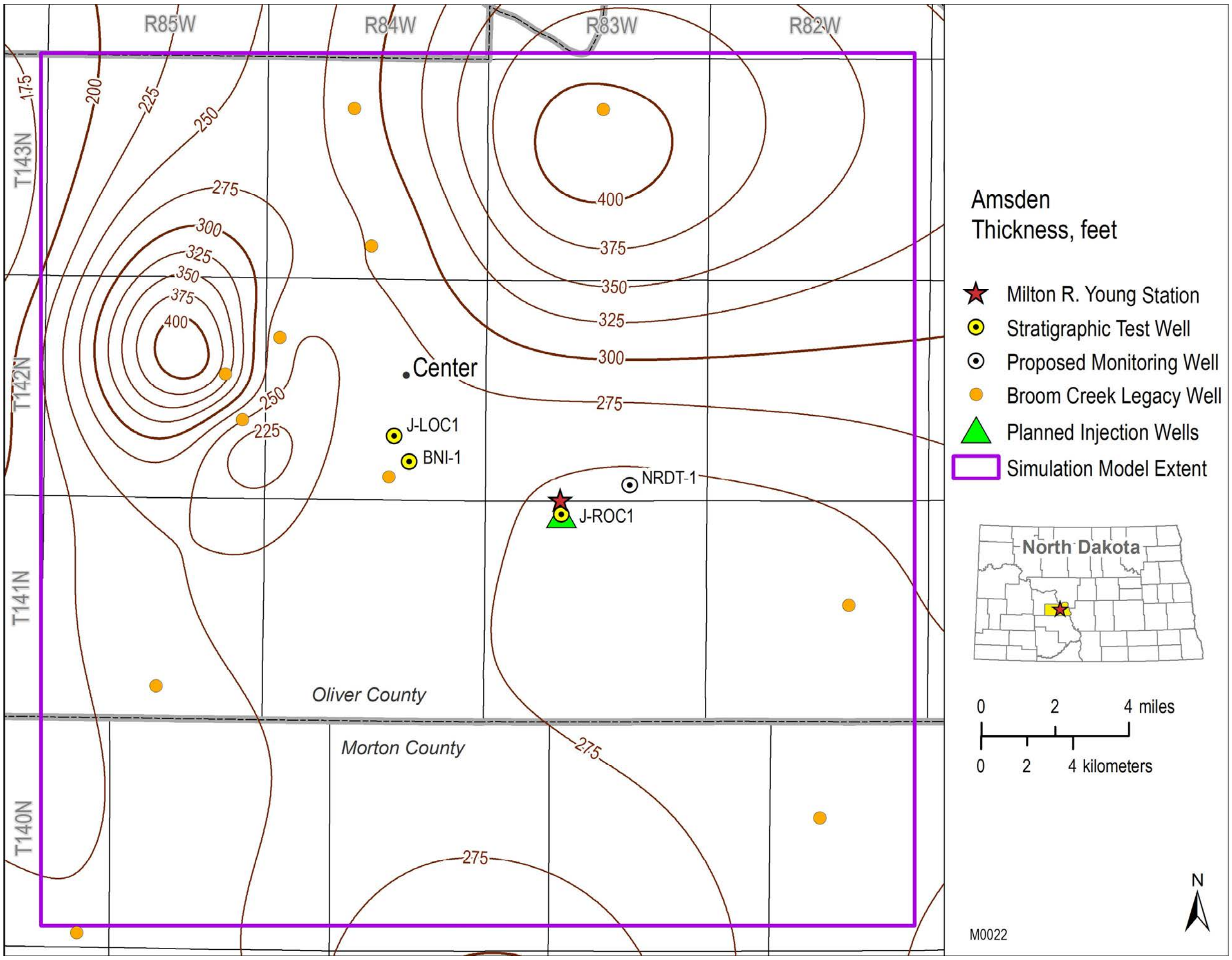

Figure 2-46. Isopach map of the Amsden Formation across the Tundra SGS area.

Table 2-20. Amsden Core Sample Porosity and Permeability from J-LOC1

Sample Depth, ft	Porosity %	Permeability, mD
5211	7.3	0.0062
5218	5.4	0.0053

2.4.3.1 Mineralogy

The well logs and thin-section analyses show that the Amsden Formation comprises dolomite, sandy dolomite, shaly sandstone, and anhydrite. The dolomite is expressed by very fine- to fine-grained dolostone (35%), with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. Quartz overgrowth and the absence of intercrystalline porosity were observed in thin sections (Figure 2-47). The existing porosity (secondary porosity) is mainly due to the dissolution of feldspar and quartz and averages 5% (Figure 2-47, Table 2-21).

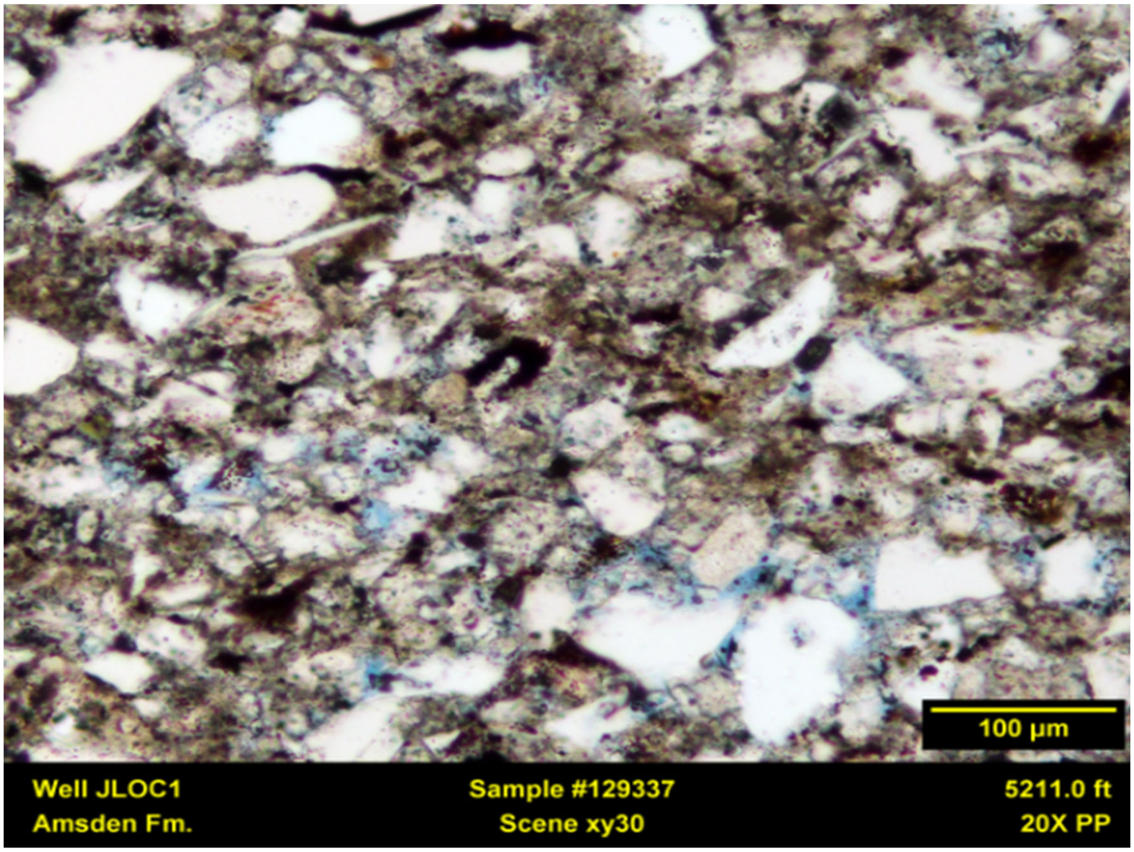

Figure 2-47. Plane-polarized light thin-section images from the J-LOC1 well Amsden Formation. This image shows the dolomite-quartz-rich nature of this interval of the Amsden Formation. The example shows dolomite, corroded quartz grains, and iron oxides. Porosity is due to the dissolution.

Table 2-21. XRF Data for the Amsden Formation from the J-LOC1 Well

Sample Depth			
5,211 ft		5,218 ft	
Component	**Percentage**	**Component**	**Percentage**
SiO_2	62.84	SiO_2	29.48
Al_2O_3	9.24	Al_2O_3	4.93
Fe_2O_3	2.85	Fe_2O_3	2.19
CaO	5.13	CaO	19.43
MgO	3.95	MgO	13.45
K_2O	4.79	K_2O	2.42
Other	9.08	Other	5.41

Anhydrite is present as beds that separate the dolomite intervals and cement and mineral components. It comprises anhydrite minerals with minor inclusions of iron oxides. The porosity is almost null.

The sandy dolomite mainly comprises 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 quartz 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 frequently separated by clay cement. The porosity is very low, averaging 7%, and is mainly due to the dissolution of feldspar and quartz.

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

XRF data show the Amsden Formation has the same major chemical constituents as the Opeche/Spearfish Formation (Table 2-21). However, the interval at the contact with the Broom Creek Formation is underlain by 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.

2.4.3.2 Geochemical Interaction

The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of nineteen cells, each cell 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation, and CO_2 was allowed to enter the system by advection and dispersion processes. Results were calculated at the center of each cell below the confining layer– CO_2 exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-22). Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above (Table 2-17). The CO_2 stream composition was as described by Minnkota (Table 2-18). The Amsden Formation temperature and pressure were extrapolated from regional temperature and pressure gradients. Two different pressure levels, 2,360 and 3,675 psi, were applied to the CO_2 saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. These simulations were run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Table 2-22. Mineral Composition of the Amsden Derived from XRD Analysis of JLOC1 Core Samples at a Depth of 5,211 ft and 5,218 ft MD

Samples Depth			
5,211 ft		5,218 ft	
Mineral	**wt%**	**Mineral**	**wt%**
Smectite	7	Smectite	9
Illite/Muscovite	18.6	Illite/Muscovite	13.7
Chlorite	1.6	Chlorite	0.7
K-Feldspar	16.4	K-Feldspar	7.9
P-Feldspar	6.2	P-Feldspar	4.5
Quartz	35.2	Quartz	21.6
Dolomite	7.1	Dolomite	35.6
Others	7.9	Others	7

Results show geochemical processes at work. Figures 2-48, 2-49, 2-50, and 2-51 show results from the geochemical modeling. Figure 2-48 shows change in fluid pH over 45 years of simulation time as CO_2 enters the system. Initial change in pH in all the cells from 7.3 to 7 is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines to a level of 5.4 after 20 years of injection and slowly declines further to 5.2 after an additional 25 years of postinjection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2 interface. The pH for Cells 15–19 did not decline over the 45 years of simulation time. Figure 49 shows that CO_2 does not penetrate more than 14 meters (represented by Cell C14) within the 45 years simulated.

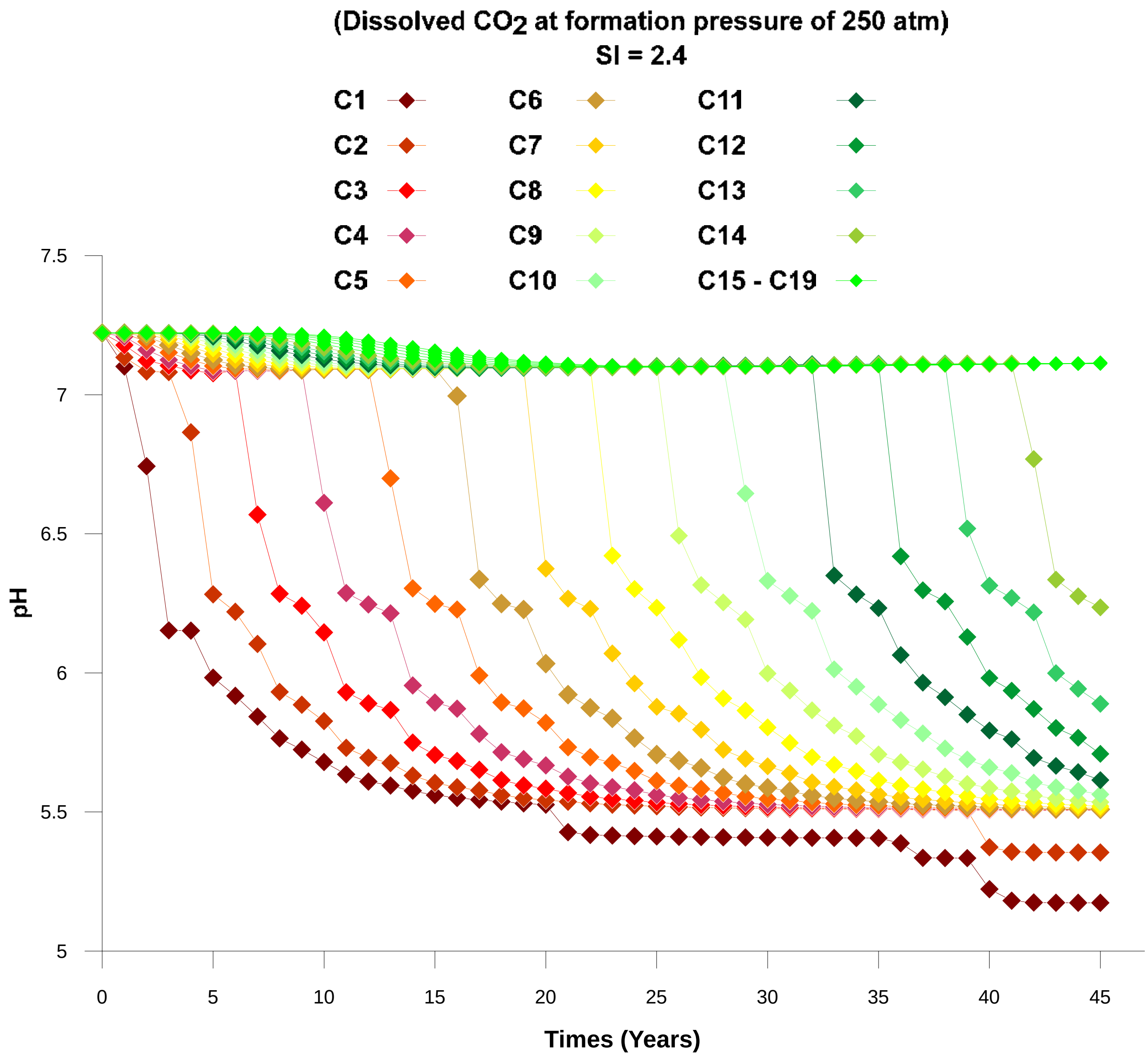

Figure 2-48. Change in fluid pH in the Amsden underlying confining layer for Cells C1–C19.

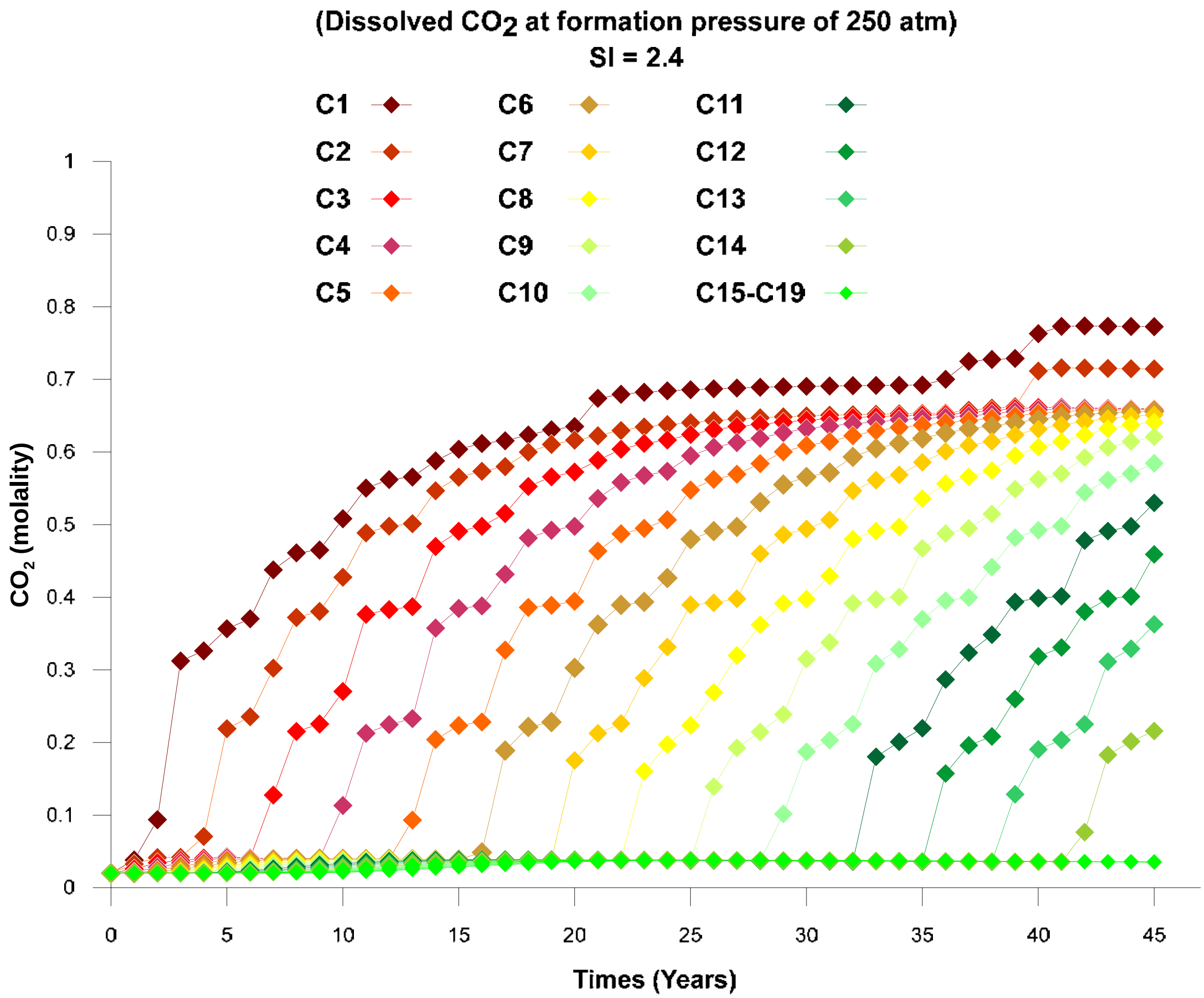

Figure 2-49. CO_2 concentration (molality) in the Amsden underlying confining layer for Cells C1–C19.

Figure 2-50 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz begins to precipitate. Montmorillonite (smectite) and illite clays largely follow mirror image paths of dissolution and precipitation during the time of the simulation.

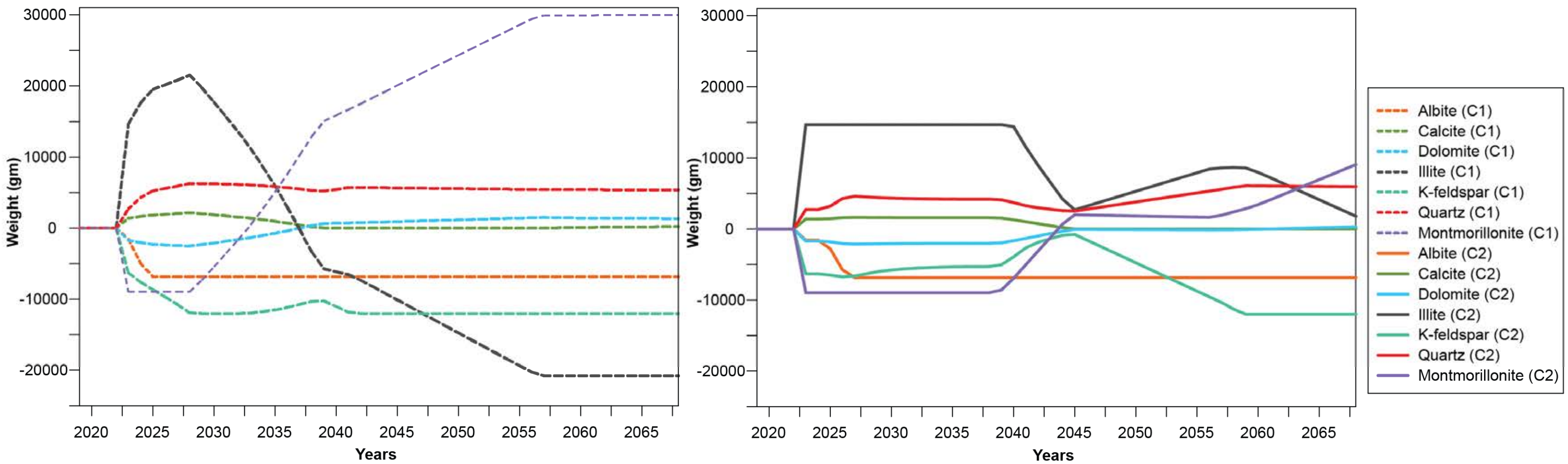

Figure 2-50. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

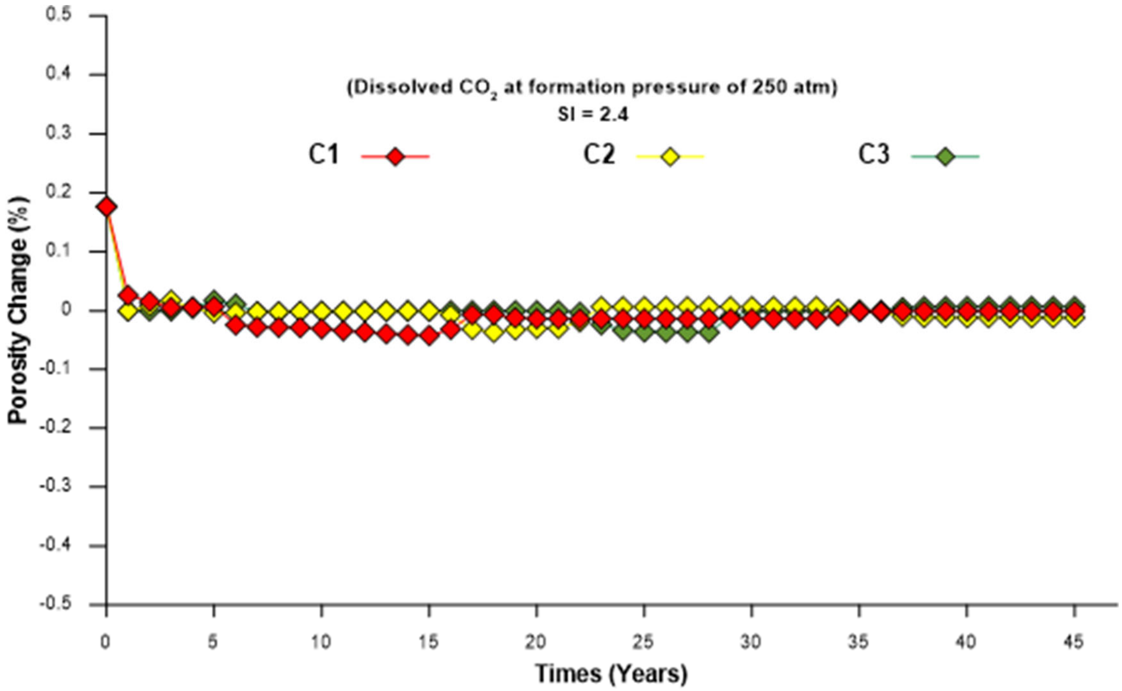

Figure 2-51. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to precipitation of minerals, and negative change is due to mineral dissolution.

Change in porosity (% units) of the Amsden underlying confining layer is displayed in Figure 2-51 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. Cell C1 shows an initial porosity increase, of 0.17%, but this change is temporary, and the cell quickly returns to its near initial porosity value of 7.5%. At later times, no significant porosity changes were observed. Cells C4–C19 showed similar results with net porosity change being less than 0.1%.

2.4.4 Geomechanical Information of Confining Zones

2.4.4.1 Fracture Analysis

Fractures within the Opeche/Spearfish Formation, the overlying confining zone, and Amsden Formation, the underlying confining zone, have been assessed during the description of the J-LOC1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stress were assessed through the interpretation of the QuantaGeo log acquired during the drilling of the J-LOC1 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche/Spearfish Formation are primarily resistive and mixed. They are commonly filled with anhydrite. However, some conductive fractures are highlighted. 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, resistive fractures are commonly coincident with the horizontal compaction features (stylolite) observed. On the other hand, few mixed fractures are highlighted. 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 J-LOC1 well.

2.4.4.3 Borehole Image Fracture Analysis (QuantaGeo)

Schlumberger's QuantaGeo 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 2-52a and 2-52b show two sections of the interpreted borehole imagery and primary features observed. The far-right track on Figure 2-52a notes the presence of electrically resistive features. These are interpreted as minor anhydrite-filled fractures. Figure 2-52b demonstrates that the tool provides information on surface boundaries and bedding features. Some isolated fractures are identified in Figure 2-51b and are likely clay-filled because of their electrically conductive signal. Figures 2-53a and 2-53b show two thin-section images and give an indication of different minerals within the reservoir with observed change in the electrical response shown on the QuantaGeo log.

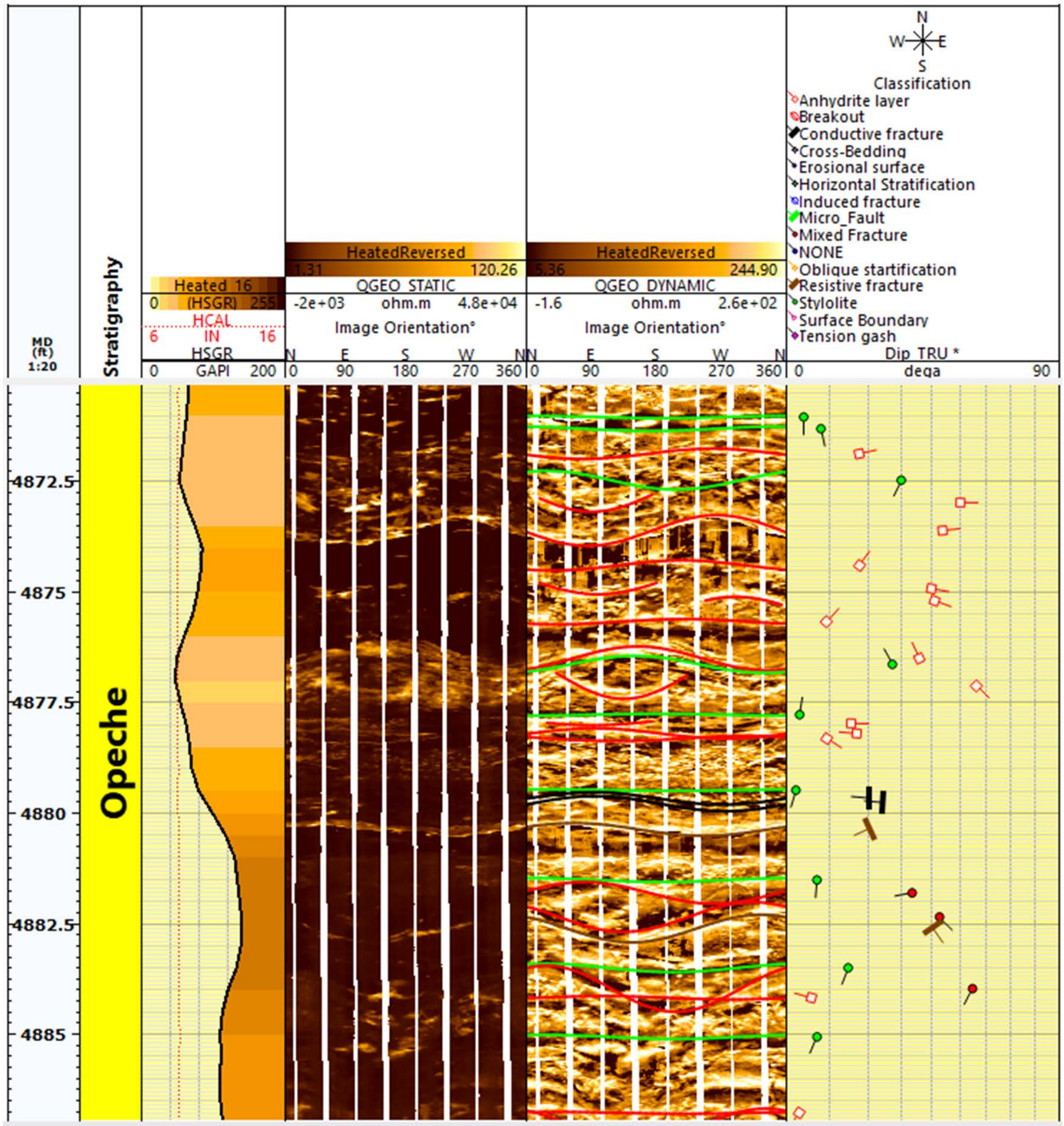

Figure 2-52a. Examples of the interpreted QuantaGeo log for the J-LOC1 well. Two examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche/Spearfish QuantaGeo borehole image analysis.

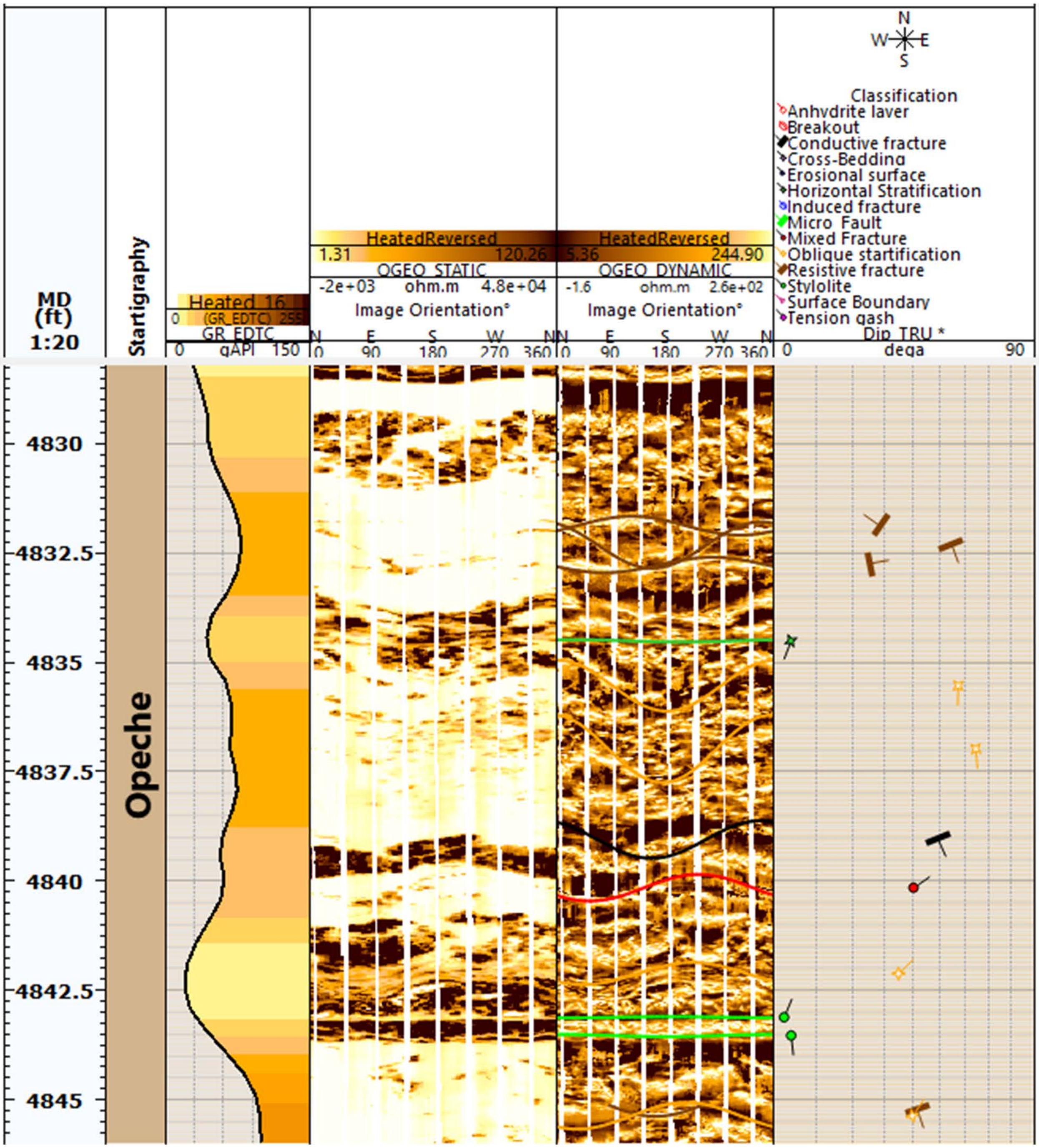

Figure 2-52b. Examples of the interpreted QuantaGeo log for the J-LOC1 well. Two examples show the traces of features observed and their interpreted feature type. This example shows the common feature types seen in the Opeche/Spearfish QuantaGeo borehole image analysis.

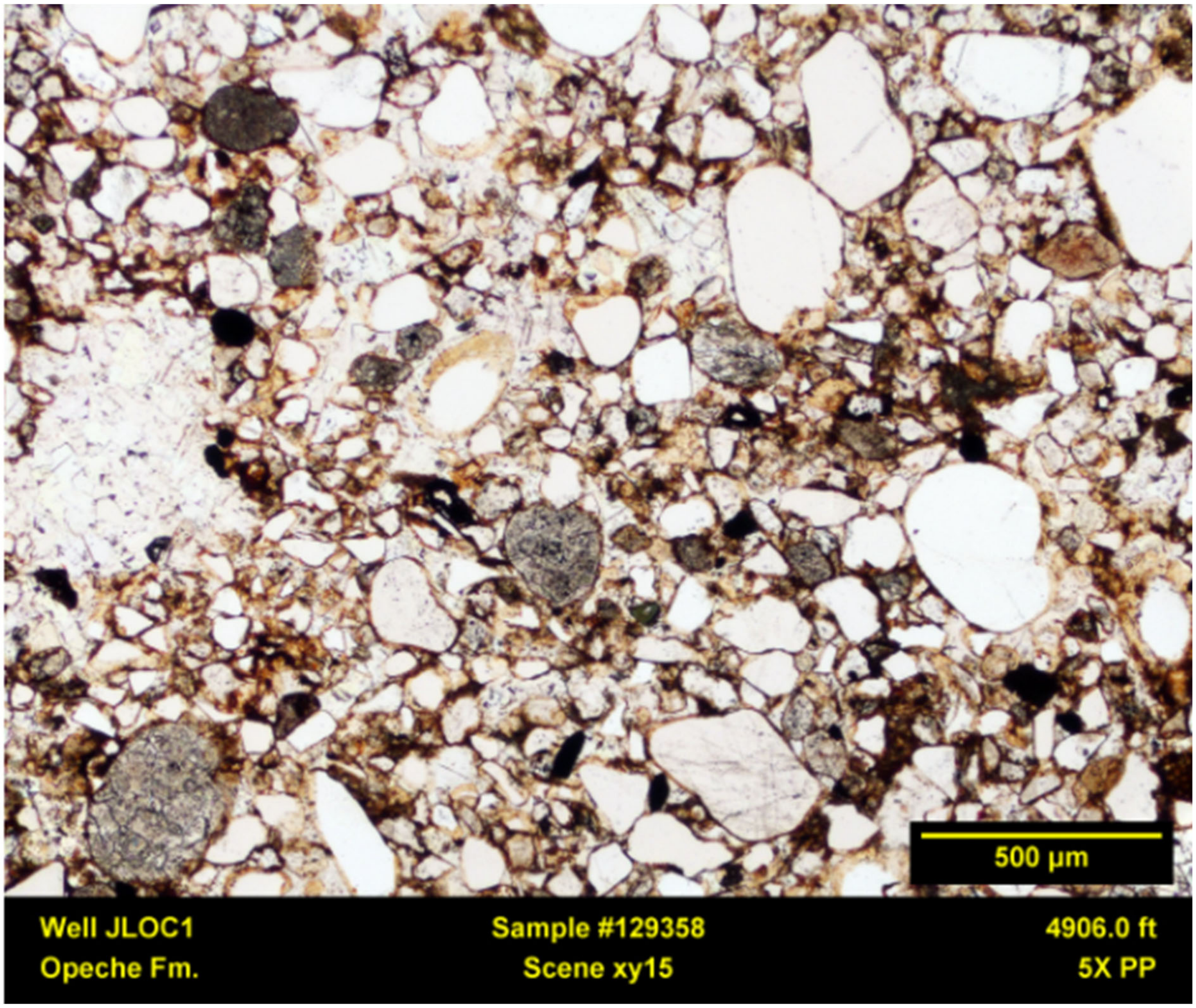

Figure 2-53a. Plane-polarized light thin-section images from the J-LOC1 well Opeche/Spearfish Formation. This image shows the silt-rich nature of this interval of the Opeche/Spearfish Formation. On the example shown, the quartz grains (white) are rimmed by anhydrite and iron.

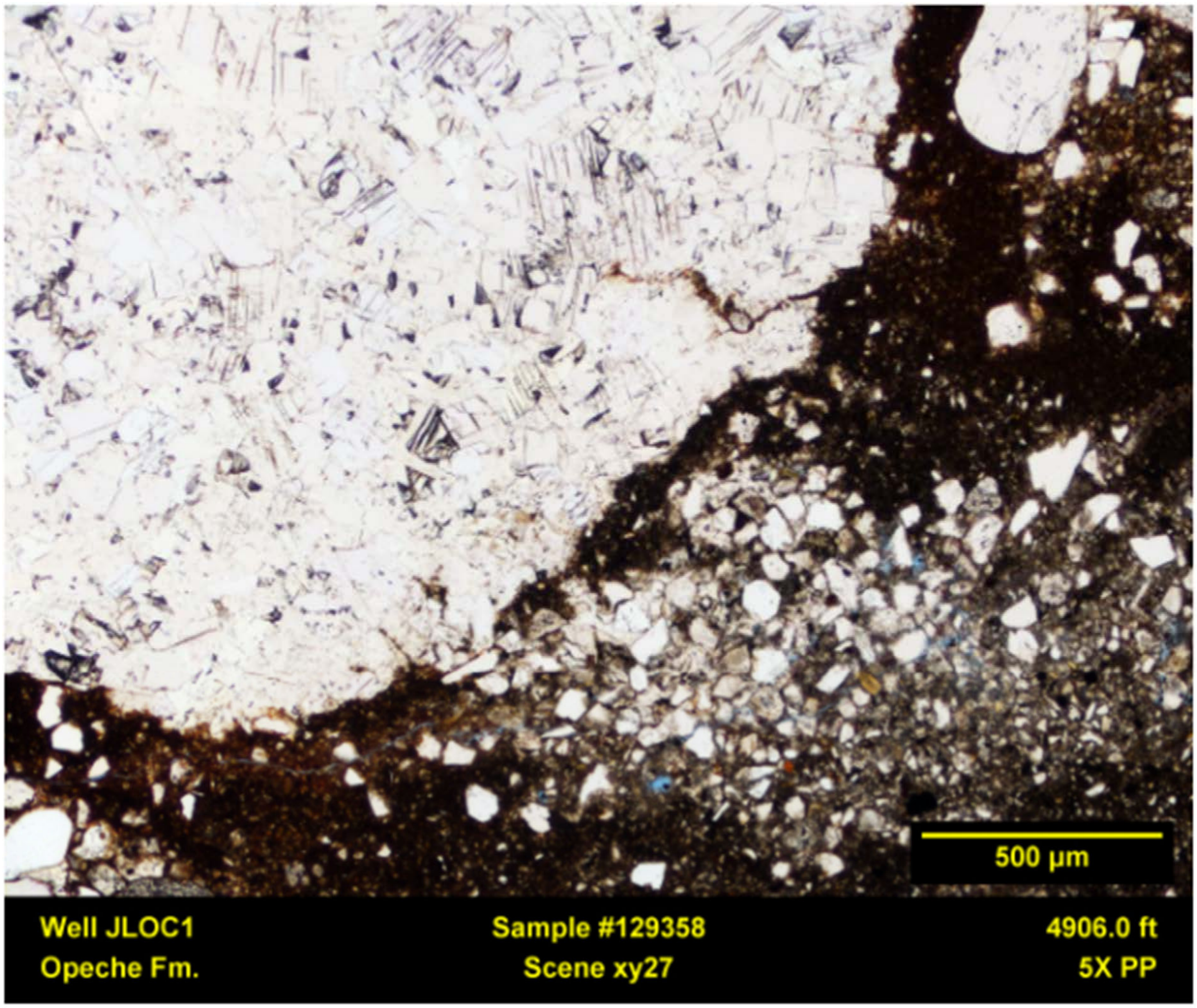

Figure 2-53b. Plane-polarized light thin-section images from the J-LOC1 well Opeche/Spearfish Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the QuantaGeo log.

Figure 2-54 shows the logged interval for the entire Opeche/Spearfish Formation at the J-LOC1 well. As shown, the section closest to the Broom Creek Formation (4,900 ft) is dominated by anhydrite layers and compaction features (stylolites) and has corresponding tensional features, as noted in the core description analysis. The observed stylolites are parallel to bedding and 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. The rose diagrams shown in Figures 2-55, 2-56, and 2-57 provide the orientation of the conductive, resistive, and mixed features in the Opeche/Spearfish Formation.

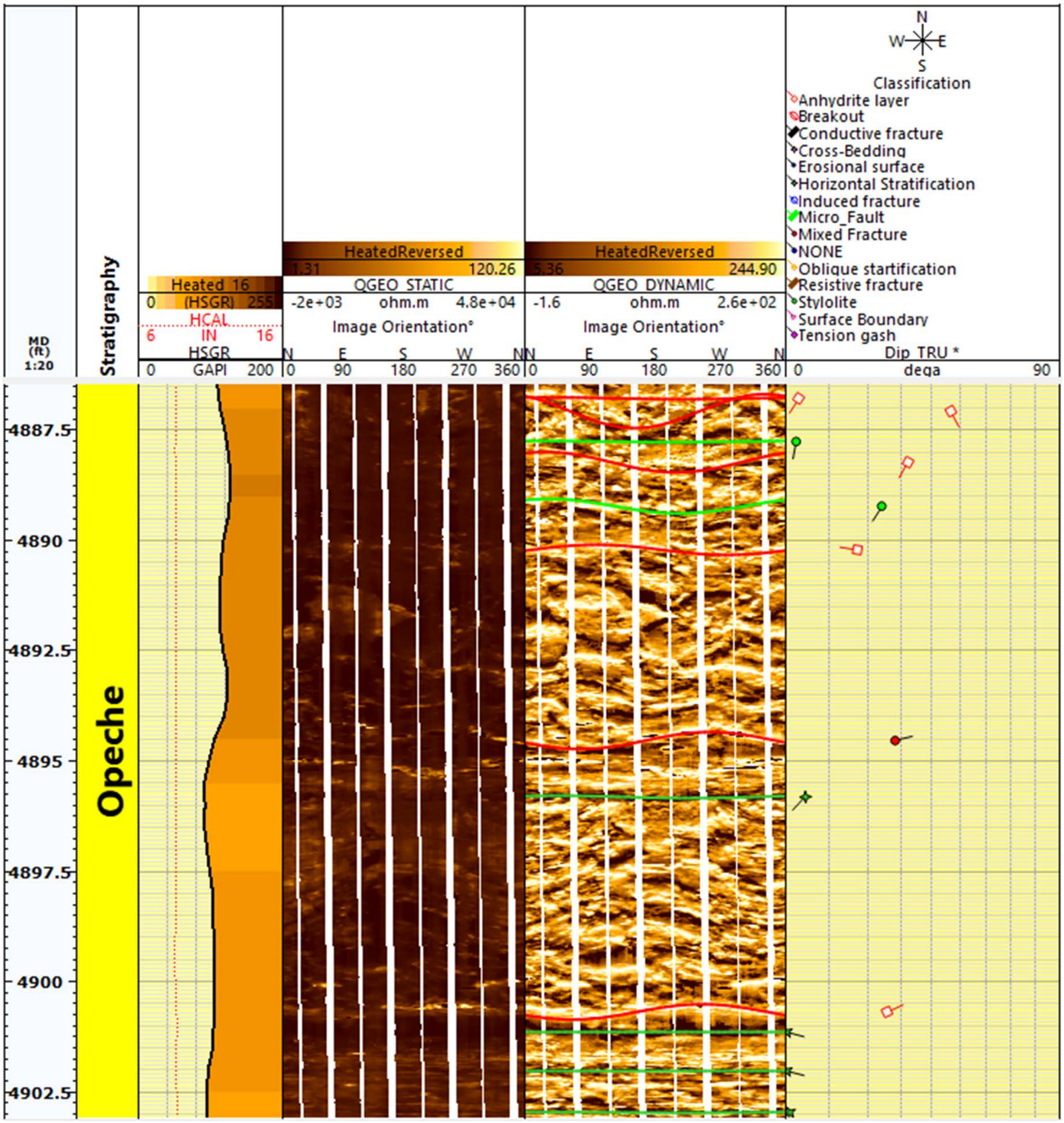

Figure 2-54. Interpreted QuantaGeo log through the lower Opeche/Spearfish Formation.

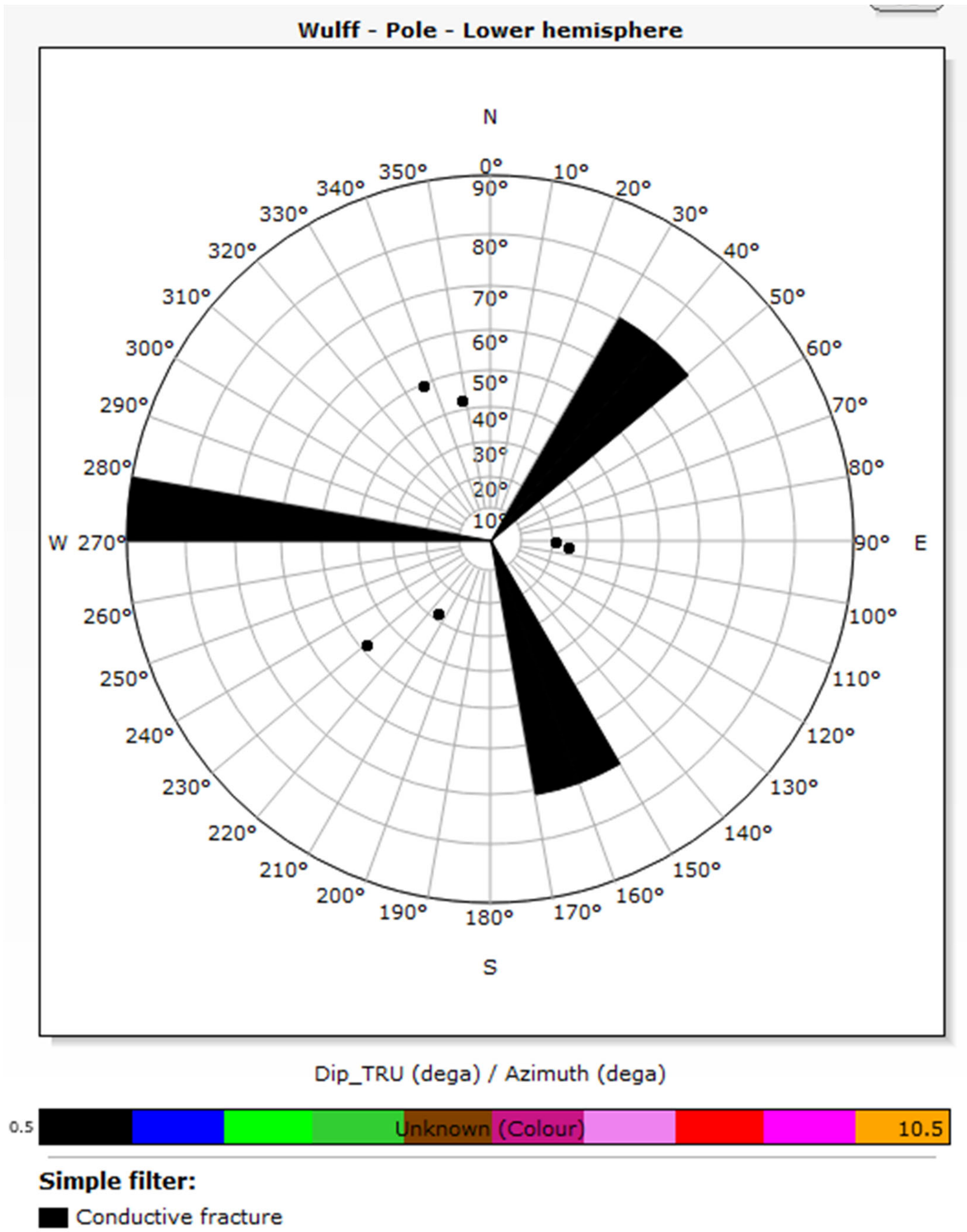

Figure 2-55. Conductive fracture dip orientation in the Opeche/Spearfish Formation.

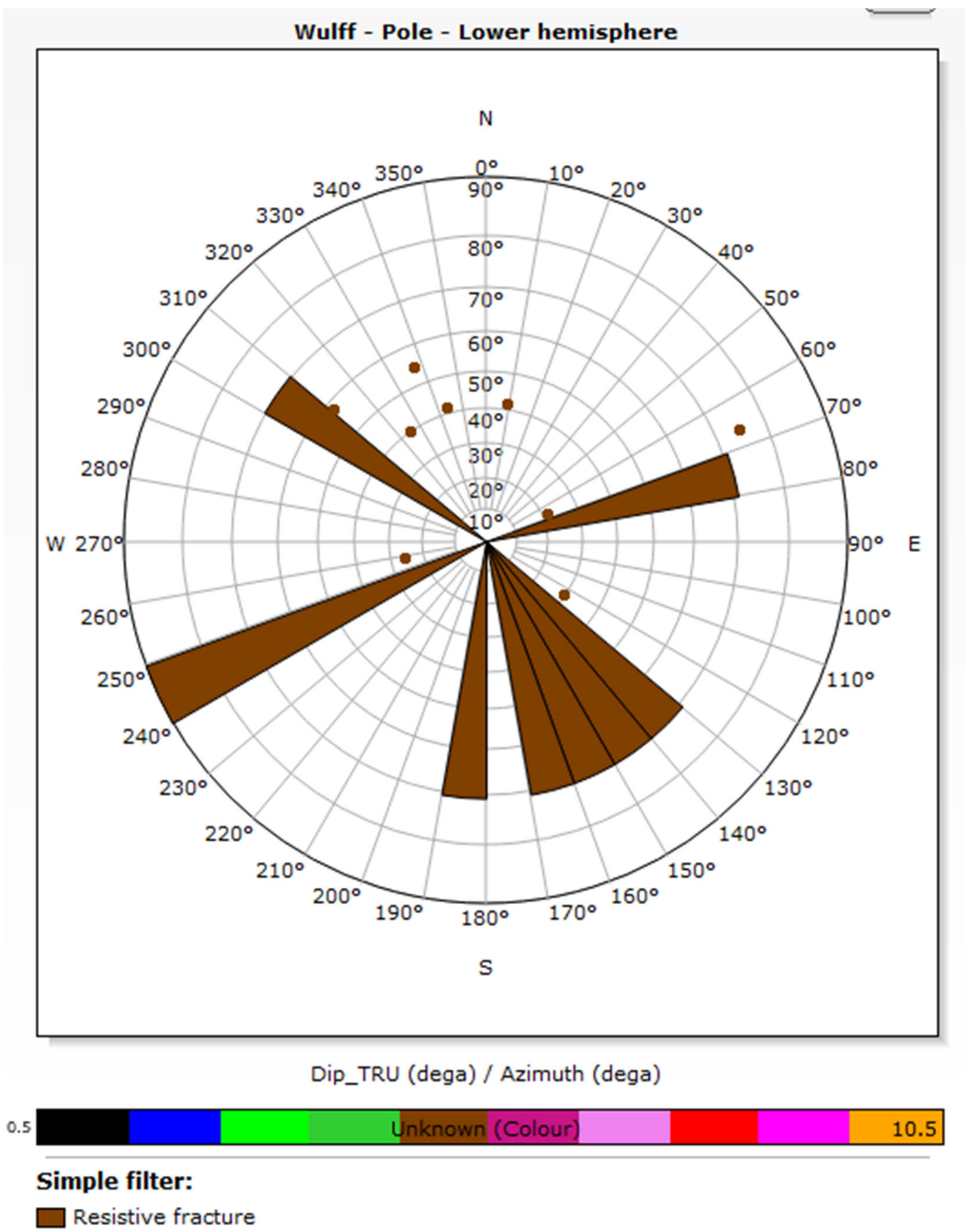

Figure 2-56. Resistive fracture dip orientation in the Opeche/Spearfish Formation.

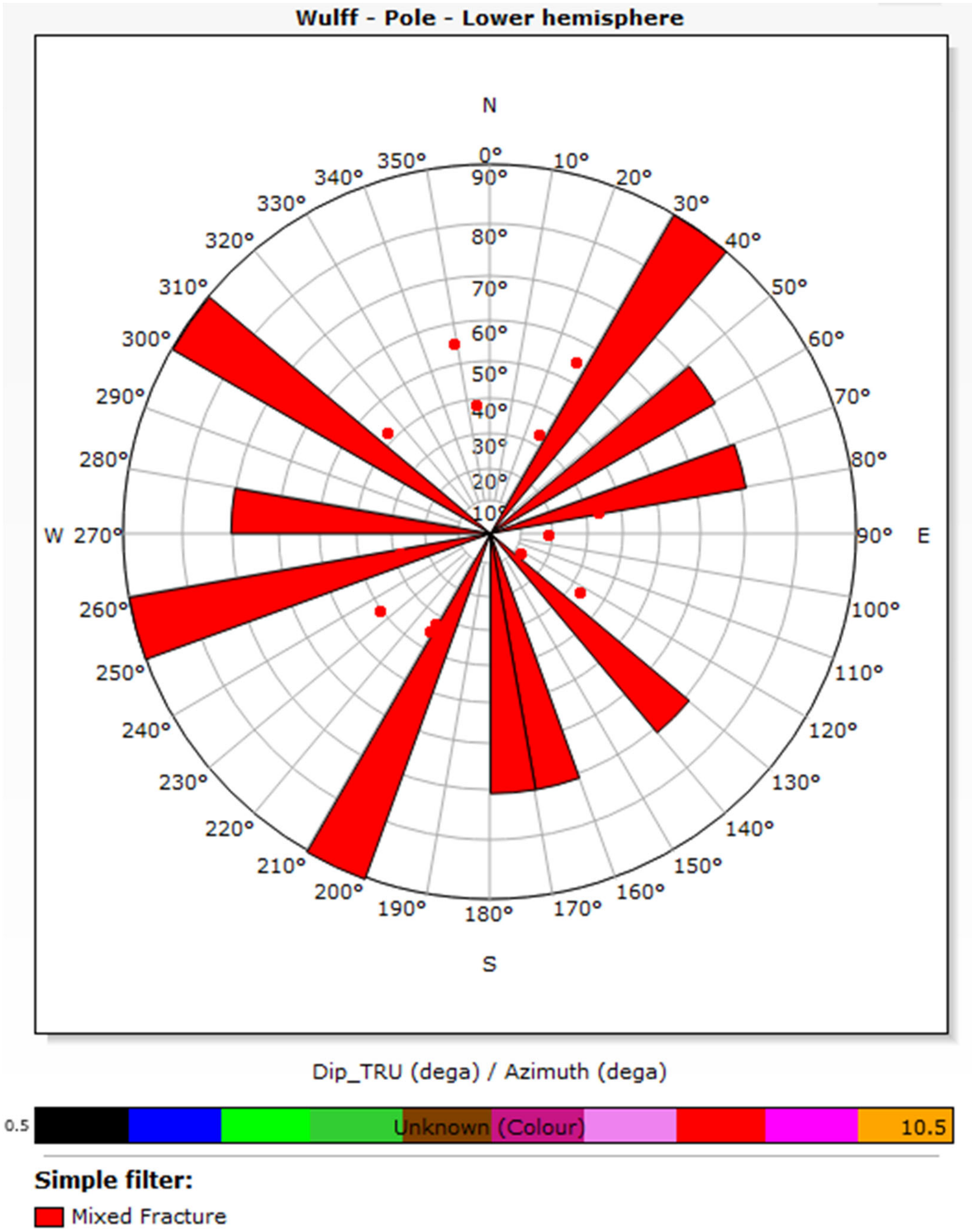

Figure 2-57. Mixed fracture dip orientation in the Opeche/Spearfish Formation.

The logged interval of the Amsden Formation shows that the main features present are stylolite–tension pairs, which are an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. One zone between 5,220 and 5,222.5 ft shows some evidence of resistive fractures (Figure 2-58). 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 2-59 and 2-60 provide the orientation of the mixed and resistive features in the Amsden Formation. As shown in Figure 2-61, only one electrically mixed feature was picked in the Amsden interval with an azimuth-oriented NW. Some electrically resistive features are present with an azimuth-oriented NE–SW and E–W. Drilling-induced fractures were not identified in the Amsden Formation.

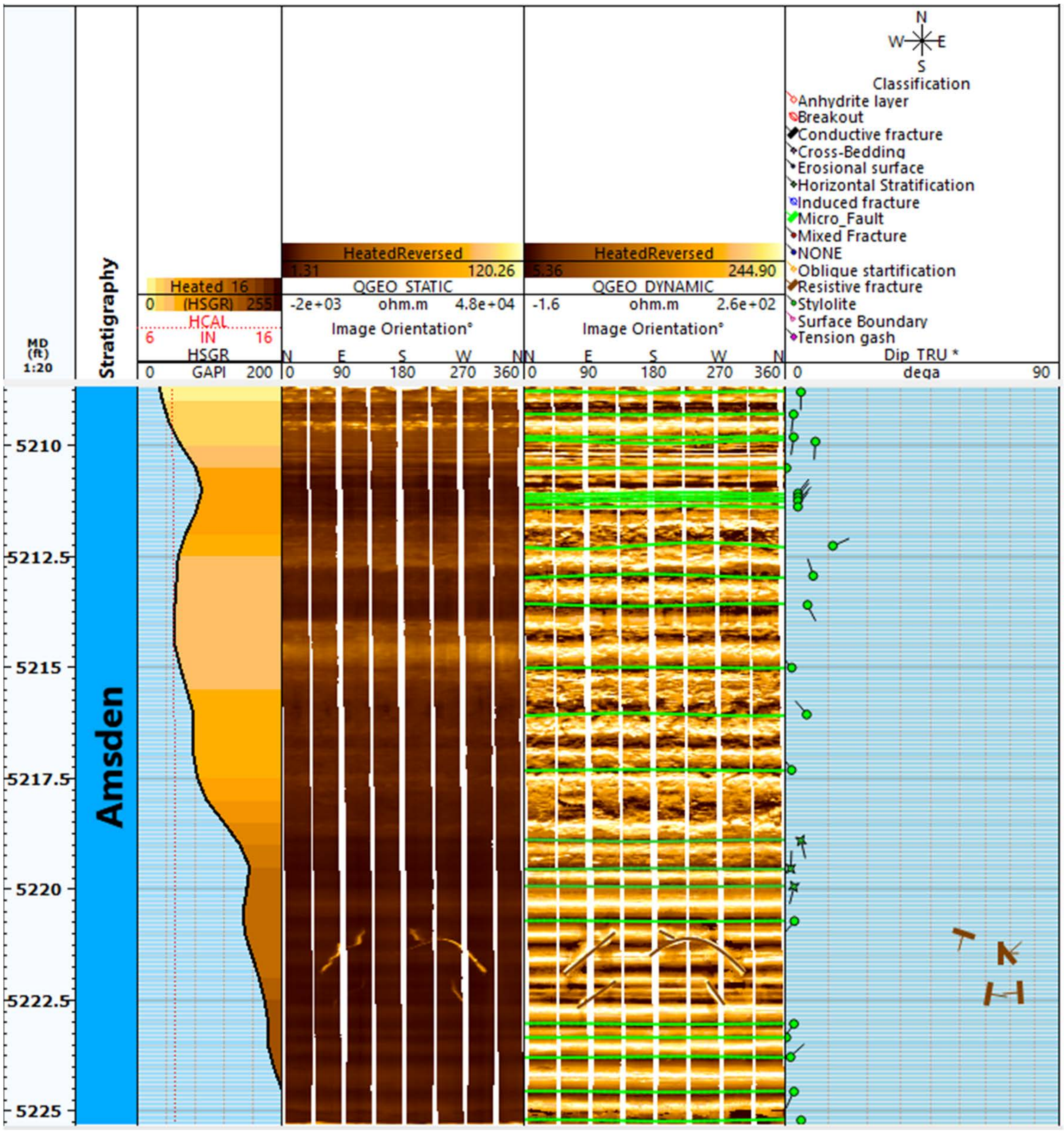

Figure 2-58. Interpreted QuantaGeo log through the upper Amsden Formation.

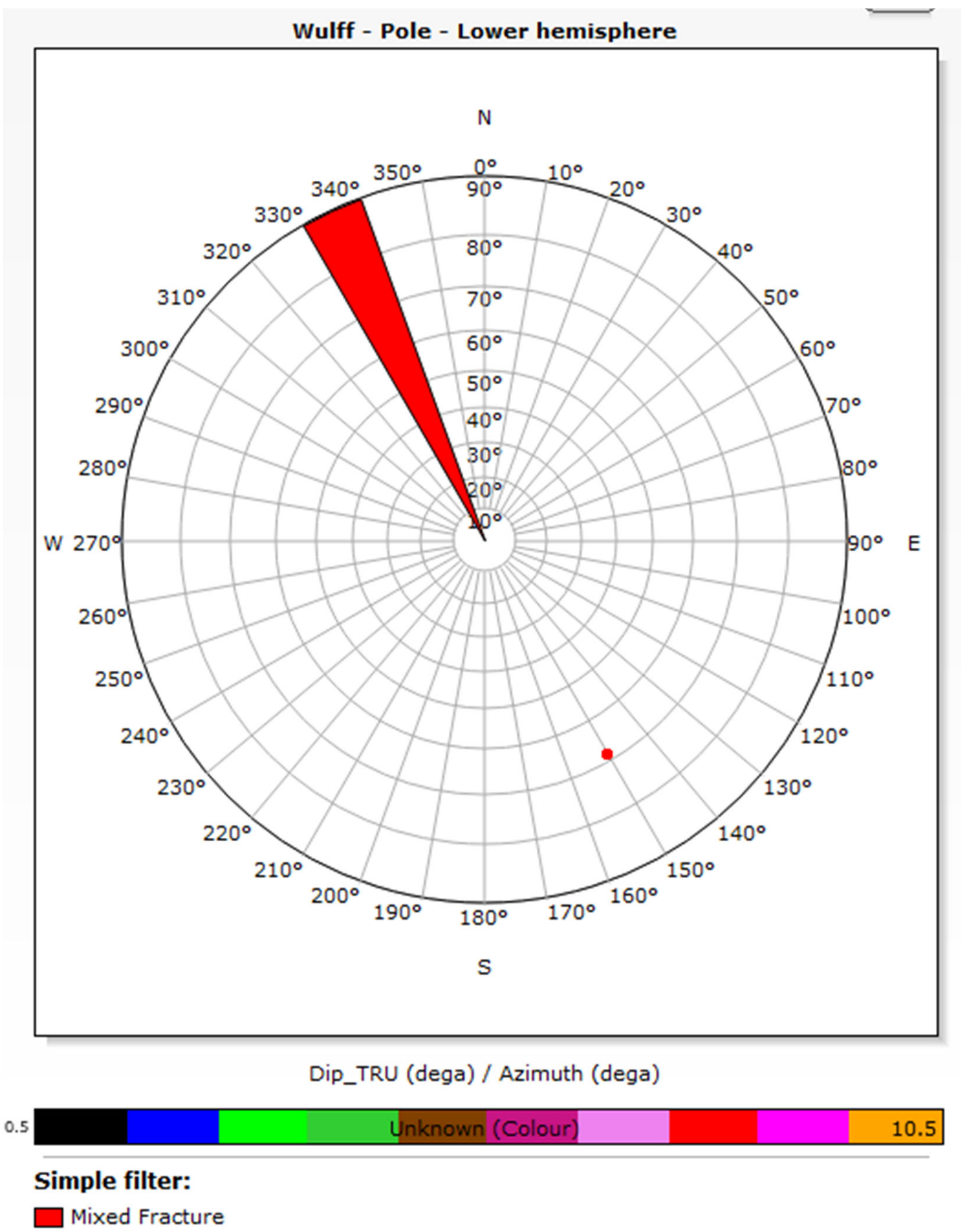

Figure 2-59. Mixed fracture dip orientation in the Amsden Formation.

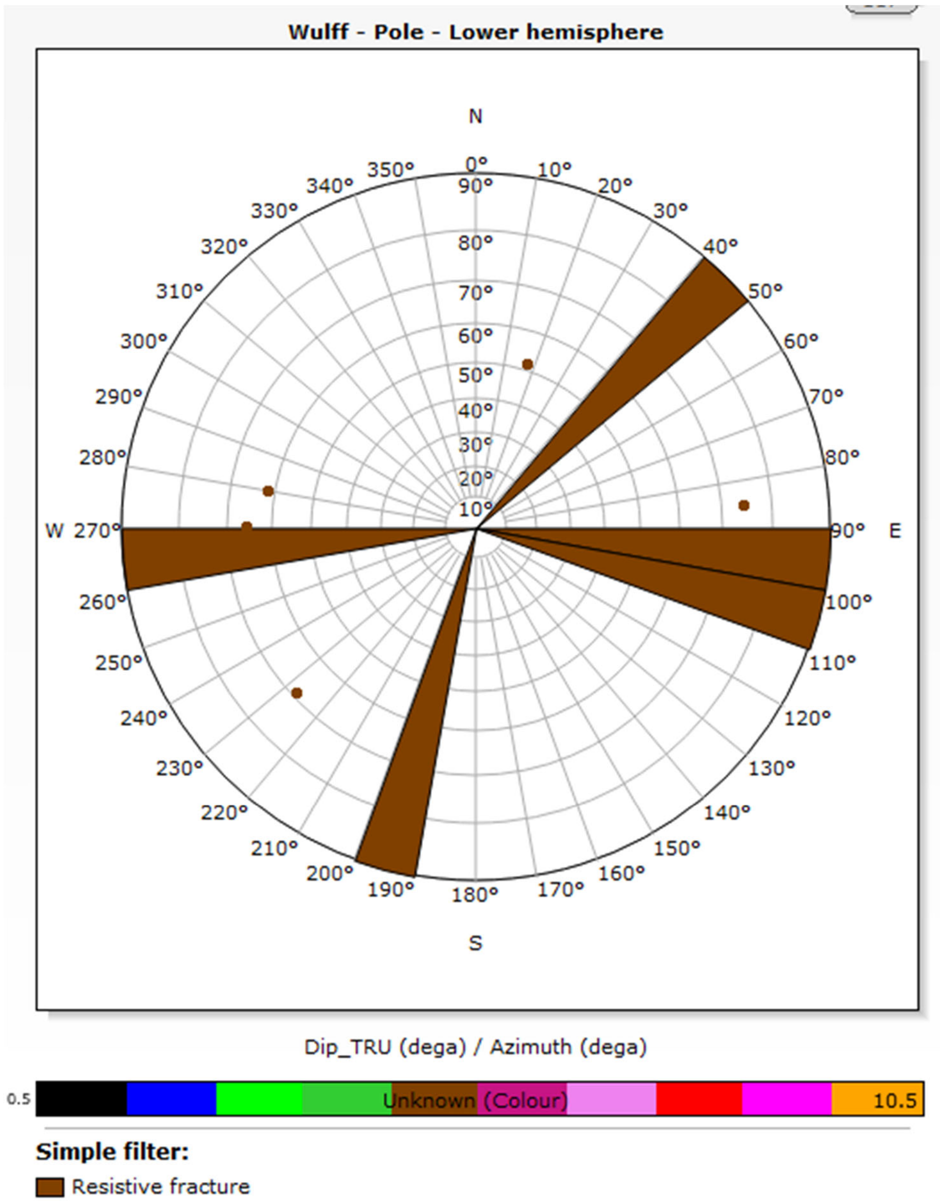

Figure 2-60. Resistive fracture dip orientation in the Amsden Formation.

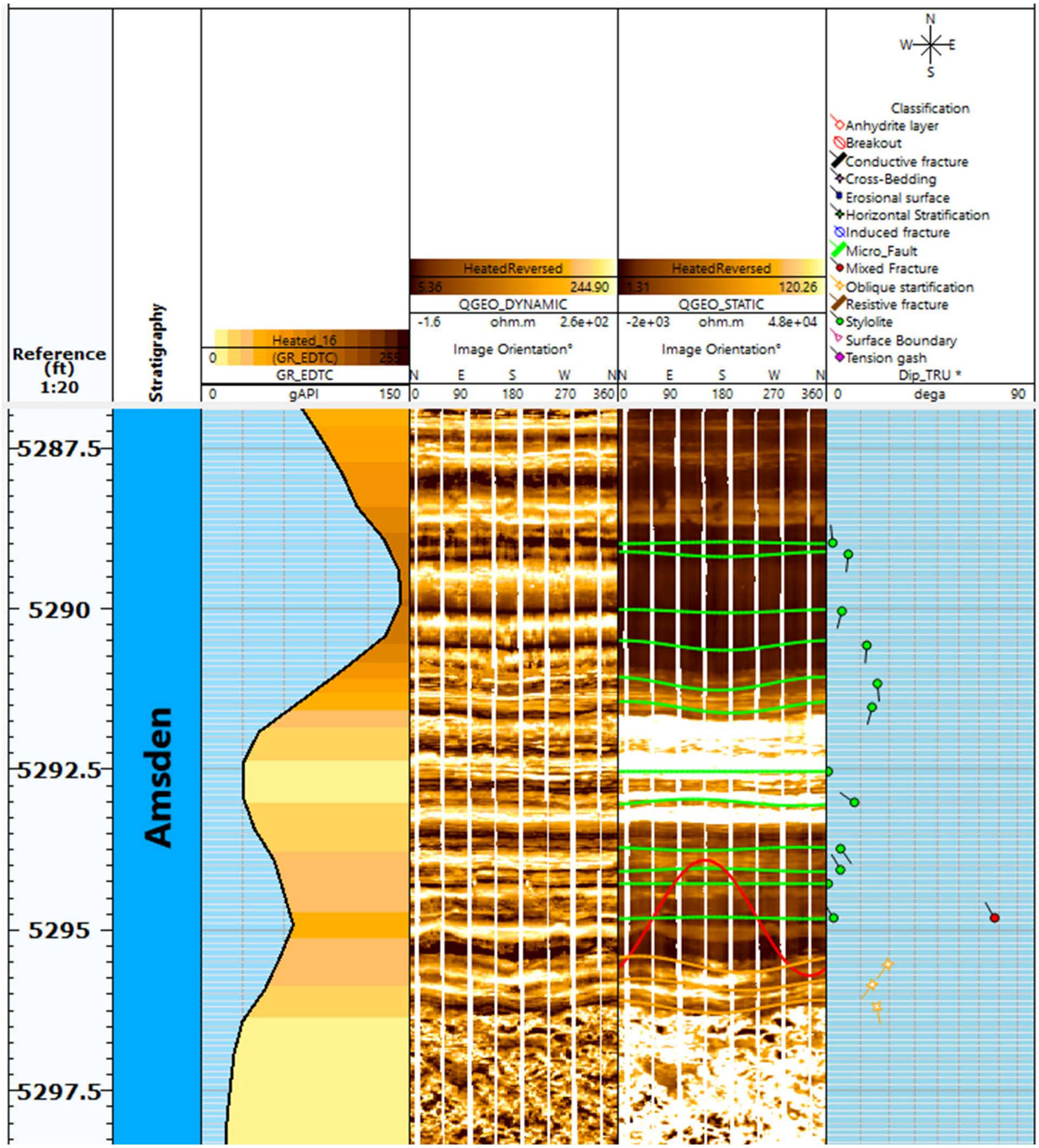

Figure 2-61. Interpreted QuantaGeo log through the Amsden Formation.

2.4.4.4 Stress

During drilling of the J-LOC1 well, an openhole MDT microfracture in situ stress test was completed to determine a formation breakdown pressure and minimum horizontal stress. The microfracture in situ stress test operation was performed using the MDT dual-packer module to obtain the formation breakdown pressure followed by multiple injection–falloff cycles to determine formation geomechanics properties. Within the Opeche/Spearfish Formation confining zone, two attempts were made at a depth of 4,888.78 and 4,887.66 ft to determine the formation breakdown pressure and closure pressure, which corresponds to the minimum horizontal stress. Unfortunately, the two attempts were unsuccessful to achieve the formation breakdown pressure with an applied maximum injection pressure of 8,150.95 and 8,162.95 psi (Figure 2-62 and Figure 2-63). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module."

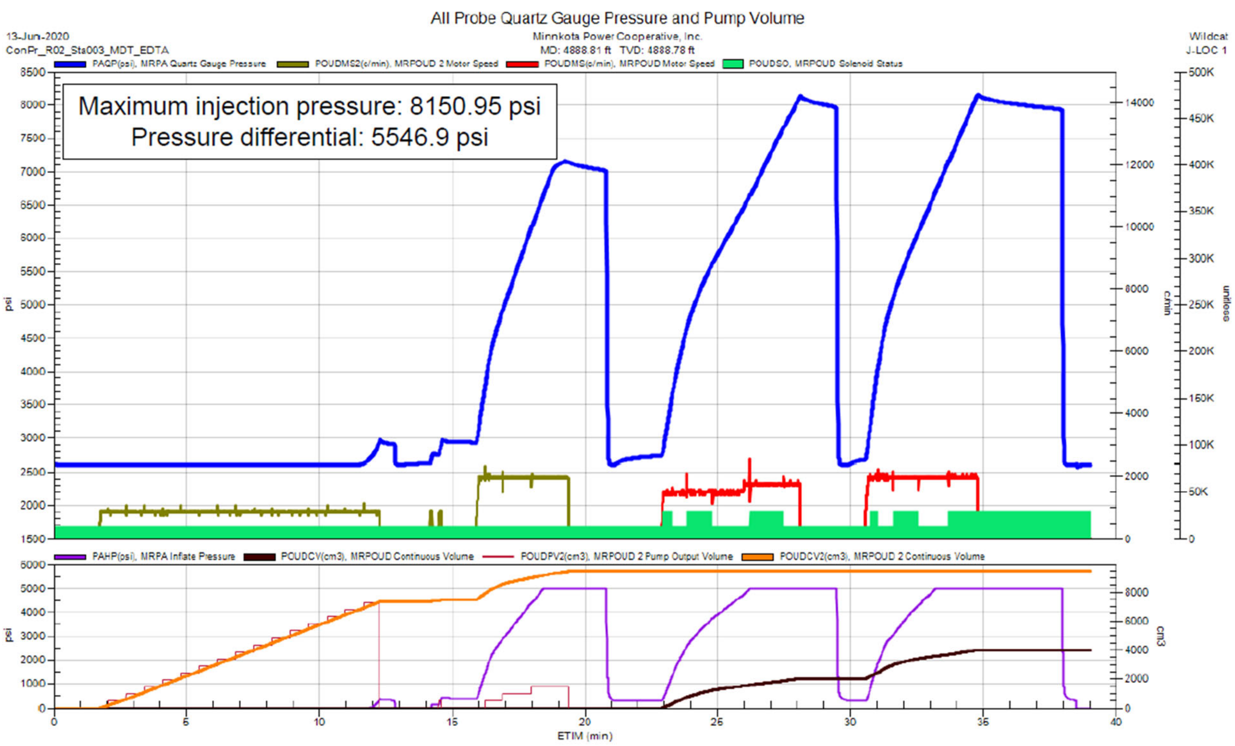

Figure 2-62. J-LOC1 Spearfish/Opeche MDT microfracture in situ stress test (first attempt) at 4,888.78 ft.

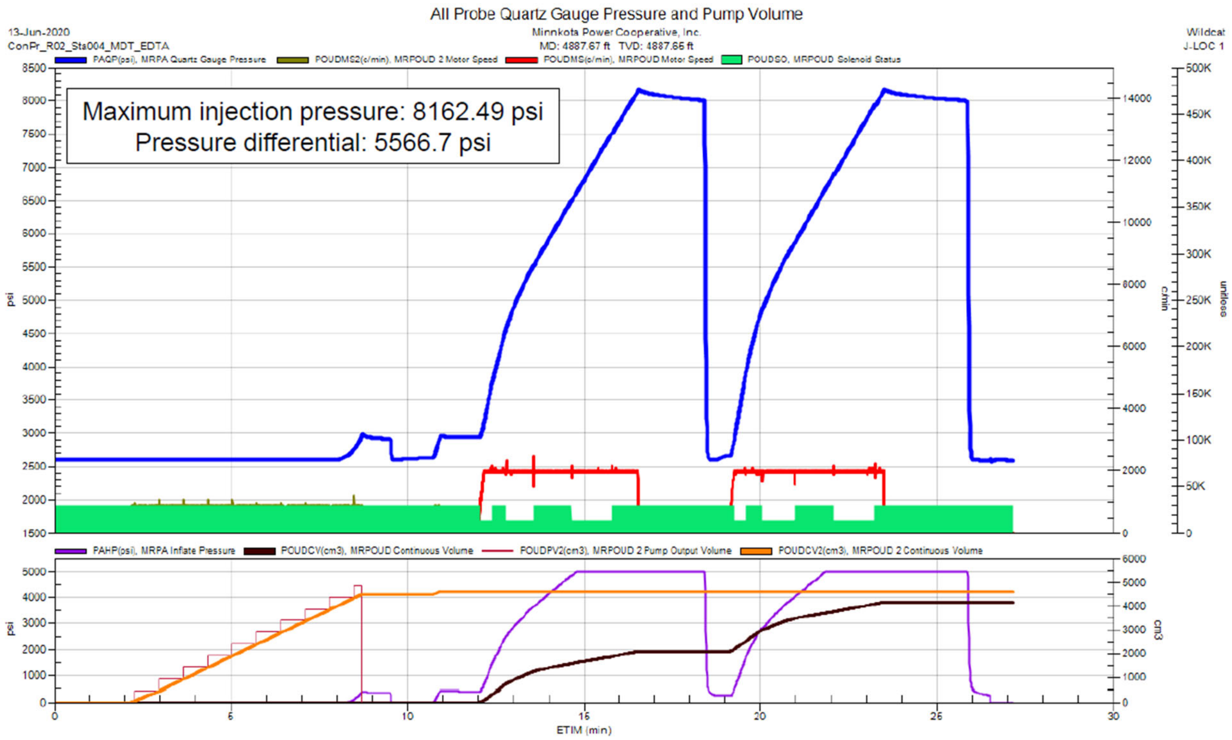

Figure 2-63. J-LOC1 Spearfish/Opeche MDT microfracture in situ stress test (second attempt) at 4,887.66 ft.

J-LOC1 openhole logging data were used to construct a 1D mechanical earth model (1D MEM) for different formations, including the Spearfish/Opeche Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties, such as Young's modulus, Poisson's ratio, shear modulus, and bulk modulus, were calculated based on the available well logs. The formation strength properties, like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion, were also estimated from the available data (Figure 2-64). Table 2-23 provides the summary of stresses in the Spearfish/Opeche Formation generated using 1D MEM.

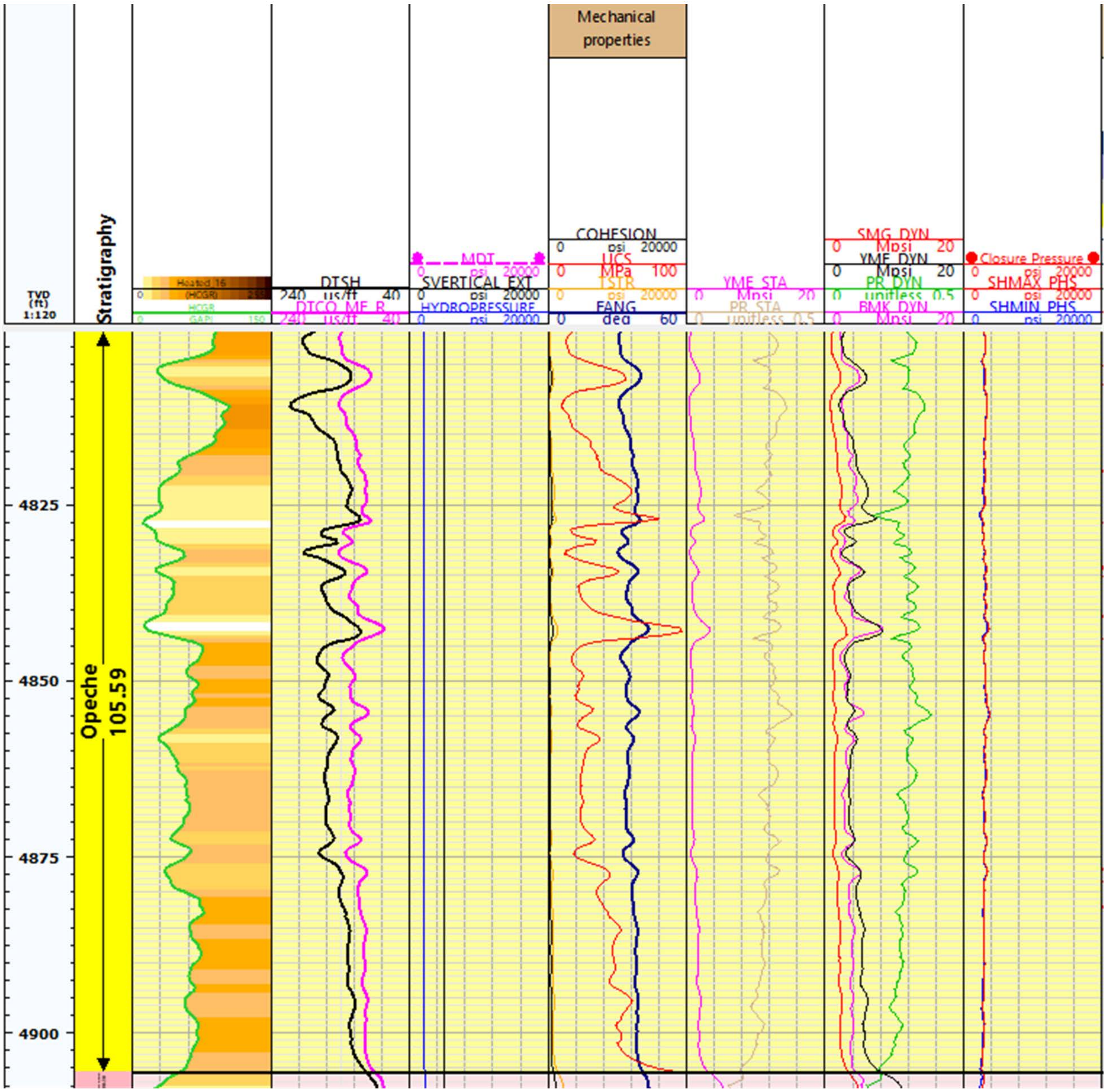

Figure 2-64. 1D MEM of the Spearfish/Opeche Formation.

Table 2-23. Summary of Stresses in Spearfish/Opeche Formation

Depth, ft	Hydrostatic Pressure, psi	Vertical Stress, psi	Minimum Stress, psi
4,800	2,064	4,957	2,922
4,904	2,108	5,073	2,623

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/Spearfish Formation core in the J-LOC1 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 2-24 shows the sample parameters, and Table 2-25 shows the elastic parameters obtained.

Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-63, the sample failed at a maximum stress of 113.8 MPa (16,505.295 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 2-24. Sample Parameters

Sample and Experiment Information			
Depth:	4,905.8 ft	Rock Type:	Anhydrite
Formation:	Opeche/Spearfish	Porosity:	3.5%
Dry Bulk Density:	2.660 g/cm^3	Pore Fluids:	None
Diameter:	25.40 mm	Entered Length:	62.99 mm

Table 2-25. Elastic Properties Obtained Through Experimentation: E = Young's 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	10.2	10.0	55.14	0.140	25.51	24.19	57.76
2	20.3	20.2	58.07	0.150	27.65	25.25	61.32
3	30.2	30.1	60.84	0.161	29.93	26.20	64.86
4	40.3	40.0	60.94	0.195	33.35	25.49	67.34

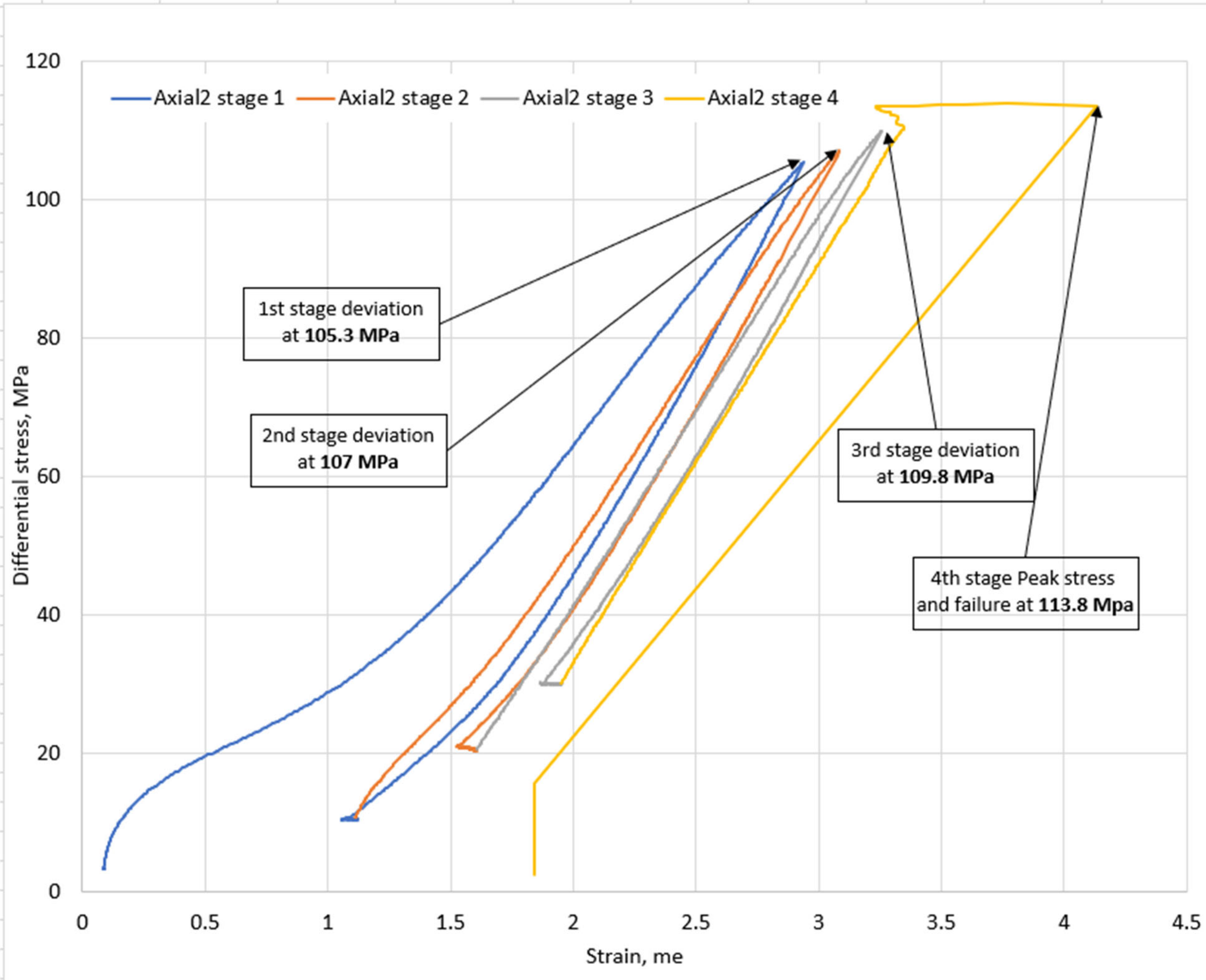

Figure 2-65. Results of multistage triaxial test performed at confining pressures exceeding 40 MPa (5,800 psi), providing information regarding the elastic parameters and peak strength of the rock sample. Failure occurred at the fourth-stage peak stress of 113.8 MPa.

2.5 Faults, Fractures, and Seismic Activity

2.5.1 Faults and Fractures

In the Tundra SGS 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. The following section discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment.

2.5.2 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 seismic events have been detected within the North Dakota portion of the Williston Basin (Table 2-26) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-64). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 mi from the J-ROC1 well near Huff, North Dakota (Table 2-26). The magnitude of this seismic event is estimated to have been 4.4.

Table 2-26. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mi	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mi
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct. 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug. 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.

** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

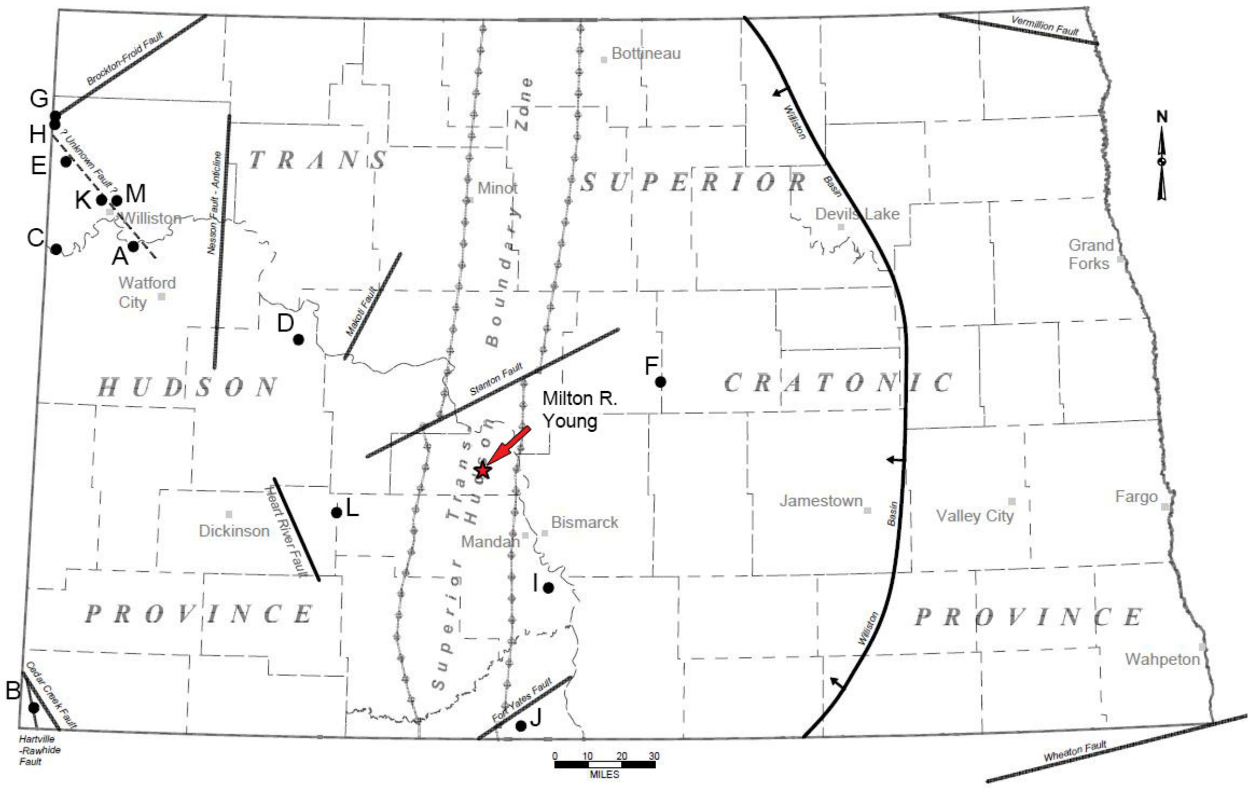

Figure 2-66. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations listed in Table 2-26.

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 damaging seismic events predicted to occur over a 10,000-year time period (Figure 2-65) (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 seismic events in North Dakota that could be associated with nearby oil and gas activities. These results indicate relatively stable geologic conditions in the region surrounding the potential injection site. Based upon the review and assessment of 1) the USGS studies, 2) the characteristics of the Broom Creek injection zone and upper and lower confining zones, 3) the low risk of induced seismicity due to the basin stress regime, and 4) history of recorded seismic events, seismic activity will not interfere with containment of the maximum volume of CO_2 proposed to be injected annually over the life of this project.

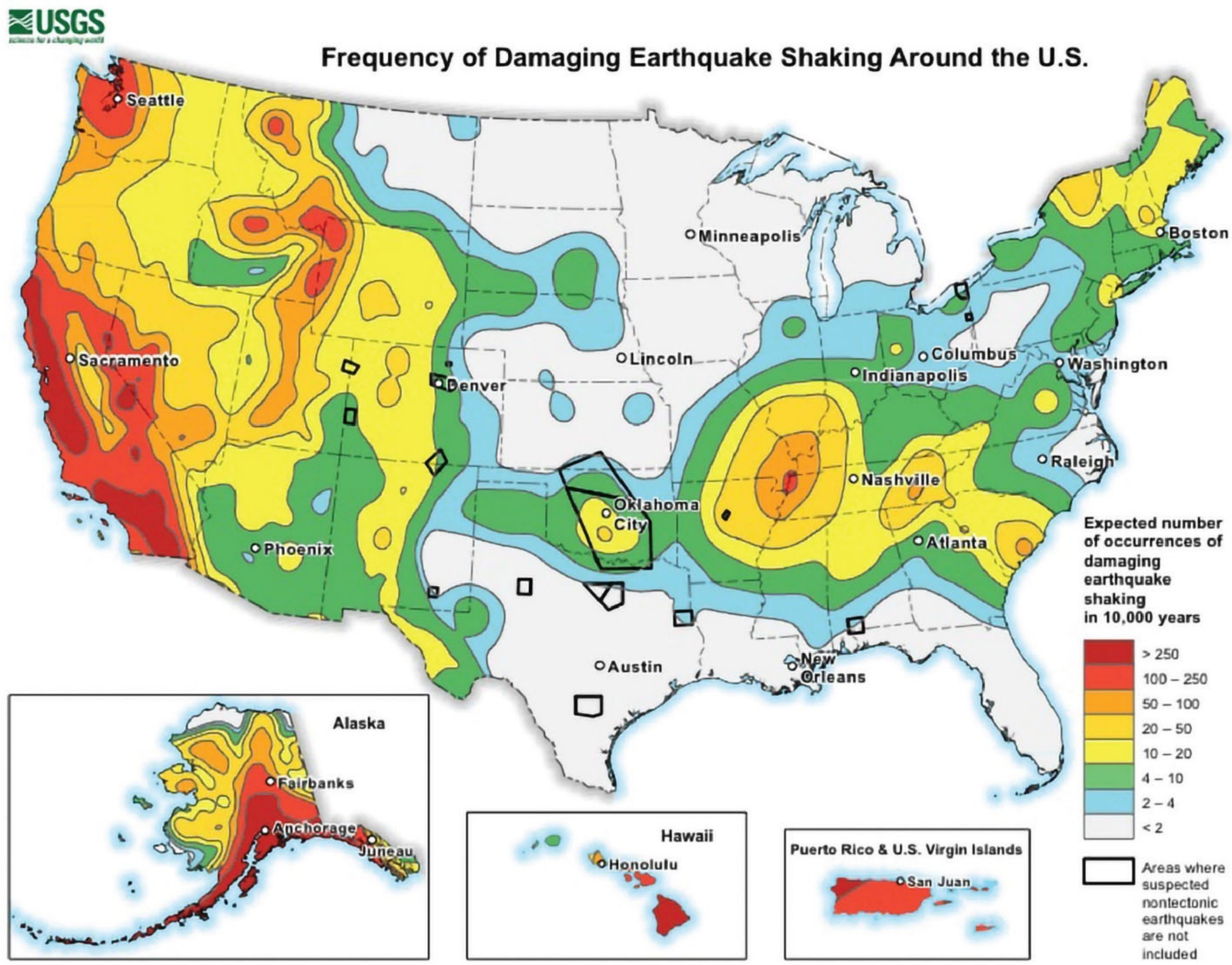

Figure 2-67. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging seismic events occurring in North Dakota.

2.6 Potential Mineral Zones

The North Dakota Geological Survey recognizes the Spearfish Formation 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 2-68). There has been no exploration for, nor development of, hydrocarbon resource from the Spearfish Formation in the Tundra SGS area.

There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. The only hydrocarbon exploration well near the storage facility area, the Herbert Dresser 1-34 (NDIC File No. 4937) was drilled in 1970 to explore potential hydrocarbons in the Charles Formation. The well was dry and did not suggest the presence of hydrocarbons. There are no known producible accumulations of hydrocarbons in the storage facility area.

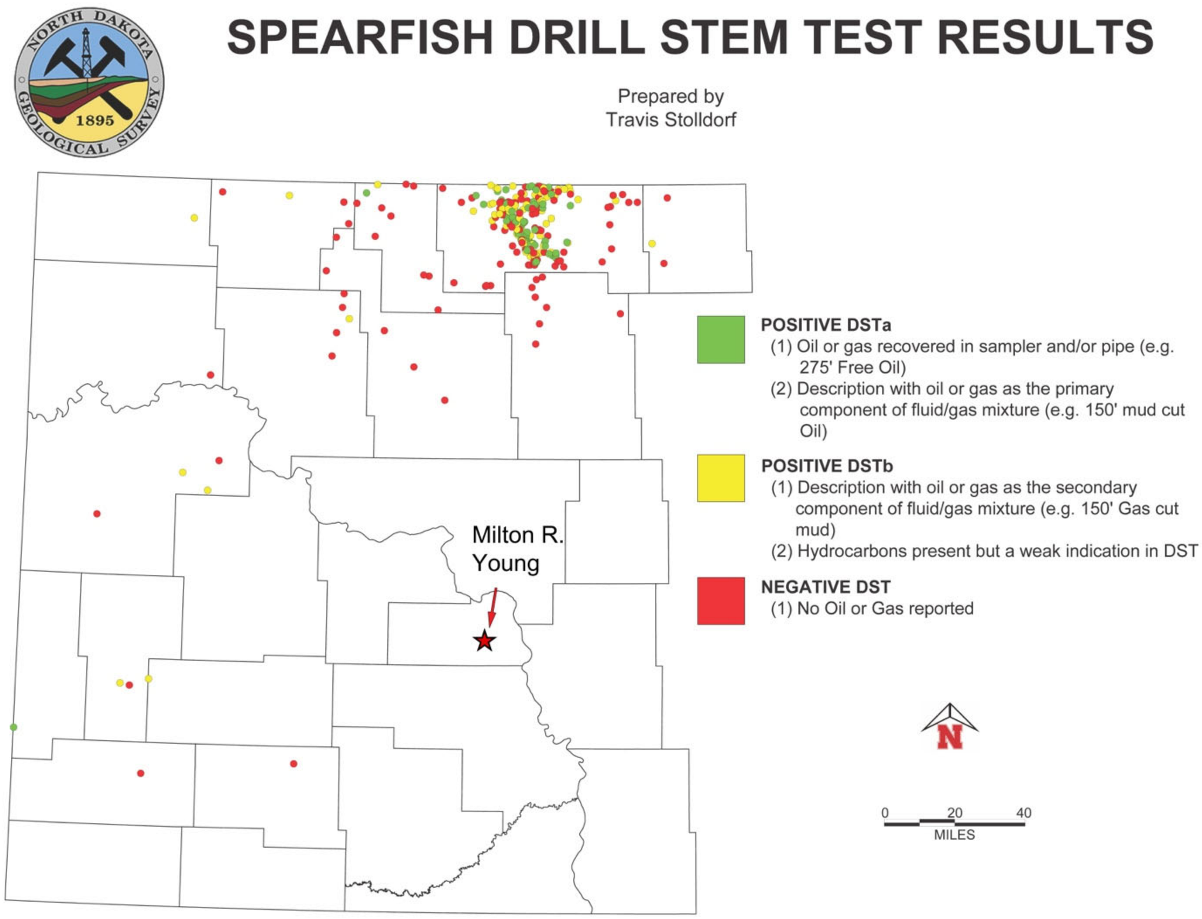

Figure 2-68. Drillstem test results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020).

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations (NDCC 57-51-01) define shallow gas resources as "gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced."

Lignite coal currently is mined in the area of the Center Coal Mine, operated by BNI Coal. The Center Mine currently mines the Hagel coal seam for use as fuel at Minnkota Power Cooperative's MRYS. The Hagel coal seam is the lowermost major lignite present in this area of the Sentinel Butte Formation.

Thickness of the Hagel coal seam averages 7.8 ft in the area permitted to be mined but varies, with some areas exceeding 10 ft in thickness (Figure 2-67) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam, but currently the Hagel is the only economically minable seam with its thickness and overburden of 100 ft or less (Figures 2-69 and 2-70). The Hagel and other coal seams in the Fort Union Group thicken and deepen to the west. The overlying Beulah-Zap coal seam has pinched out farther to the west but is economically minable in the central part of Mercer County at North American Coal's Coteau Mine. The Hagel seam pinches out to the east, and no other coal seams are mined farther east than the Hagel.

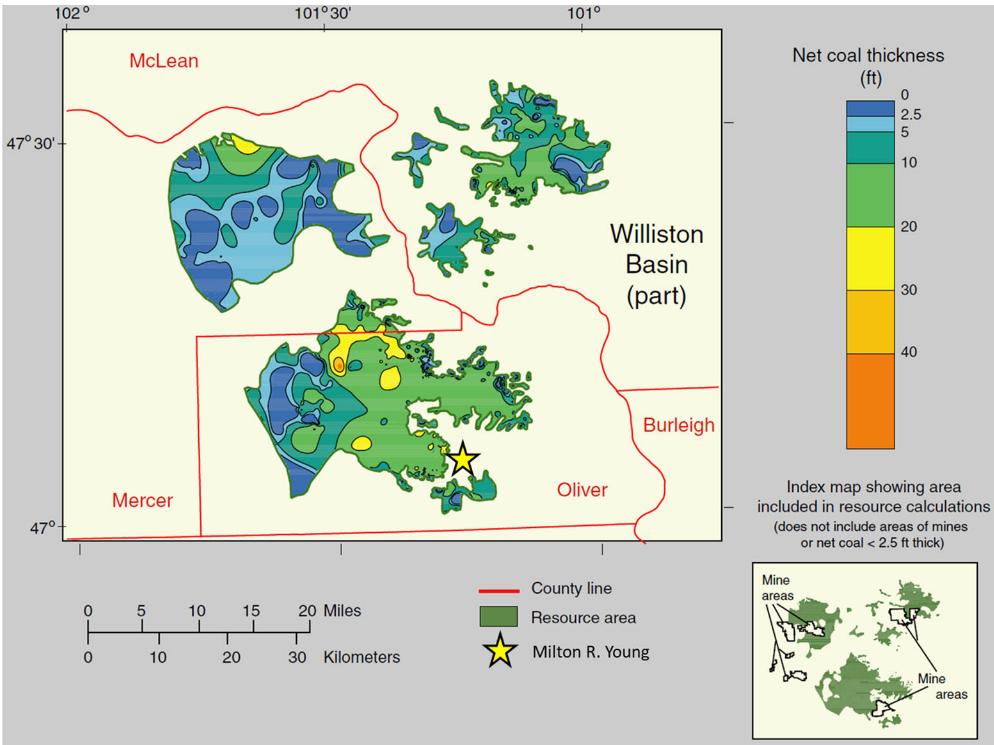

Figure 2-69. Hagel net coal isopach map (modified from Ellis and others, 1999).

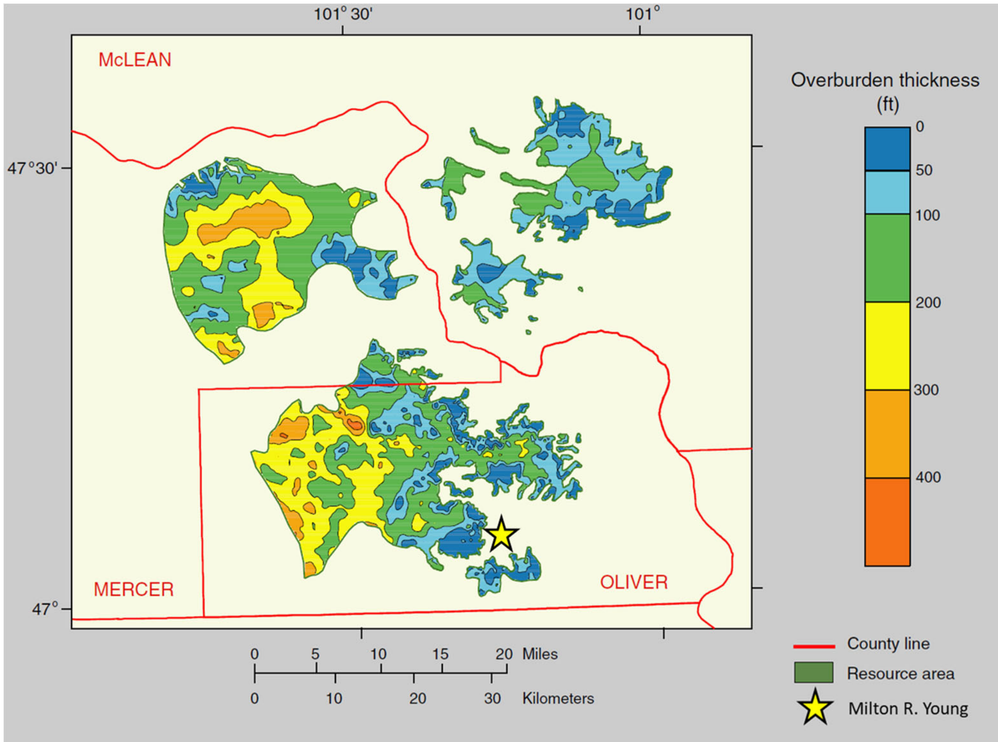

Figure 2-70. Hagel overburden isopach map (modified from Ellis and others, 1999).

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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[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 resultant pressure as the "critical threshold pressure." Application of risk-based methods using site-specific data from the J-LOC1 and J-ROC1 wells shows that the storage reservoir in the project area is overpressurized with respect to the deepest USDW (i.e., the critical threshold pressure increase is less than zero [Appendix A, Table A-4]).

Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR.

NDAC § 43-05-01-05 subsection 1)(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1)(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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.

This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 3-1.

3.1.2 Supporting Maps

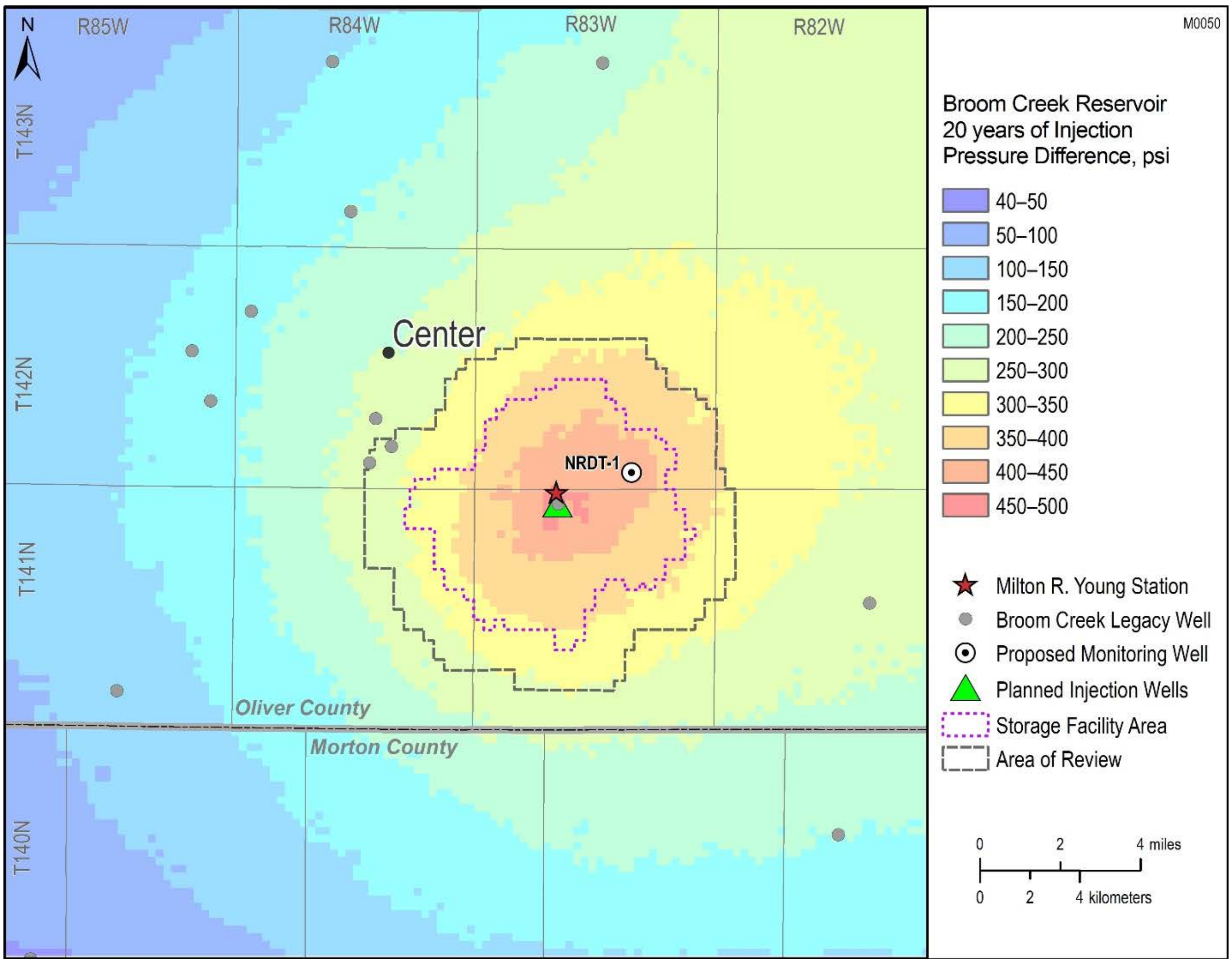


Figure 3-1. Pressure map showing the subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation. Shown is the storage facility area and AOR boundary in relation to the subsurface pressure influence. Subsurface pressure subsides at the cessation of injection.

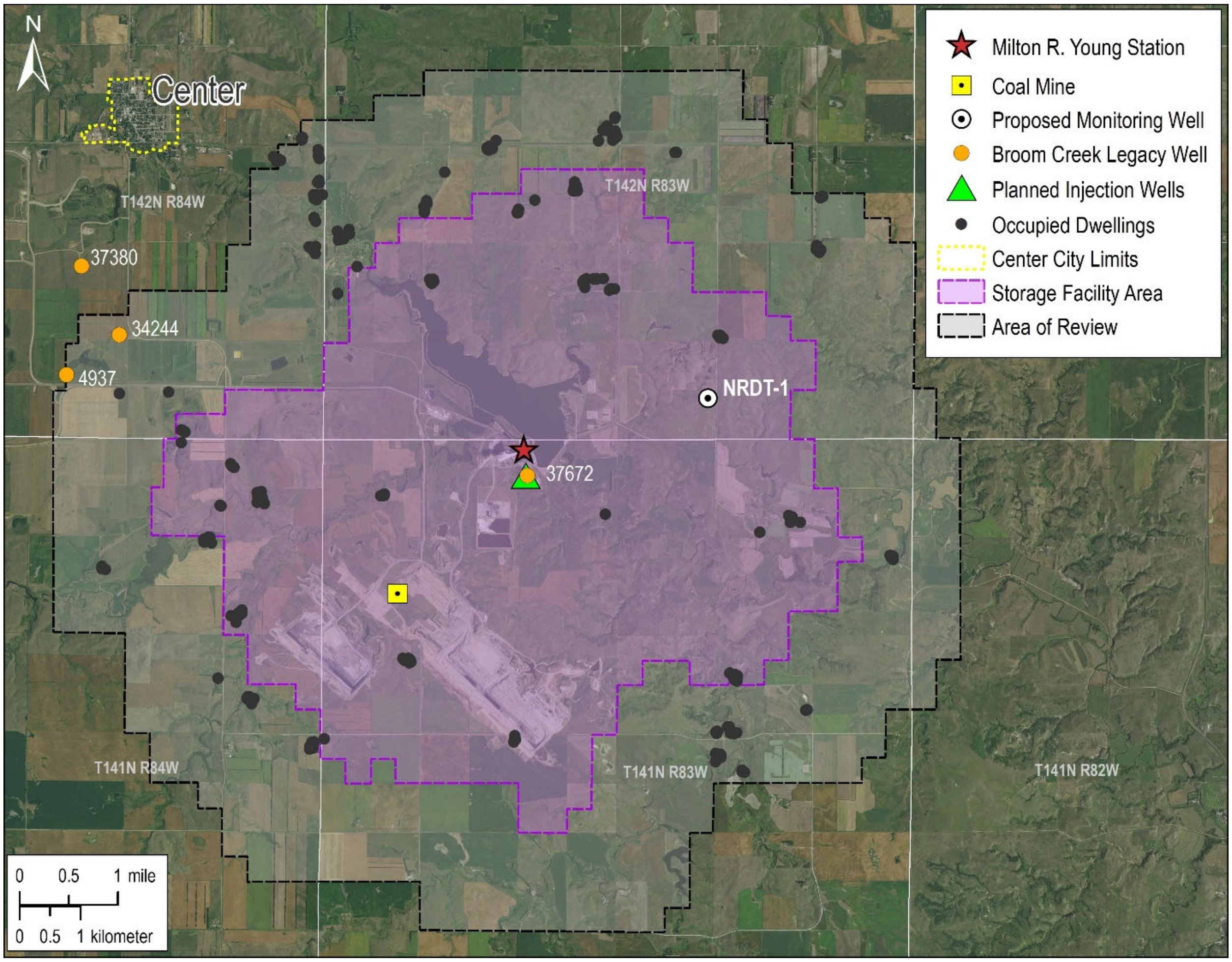


Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings.

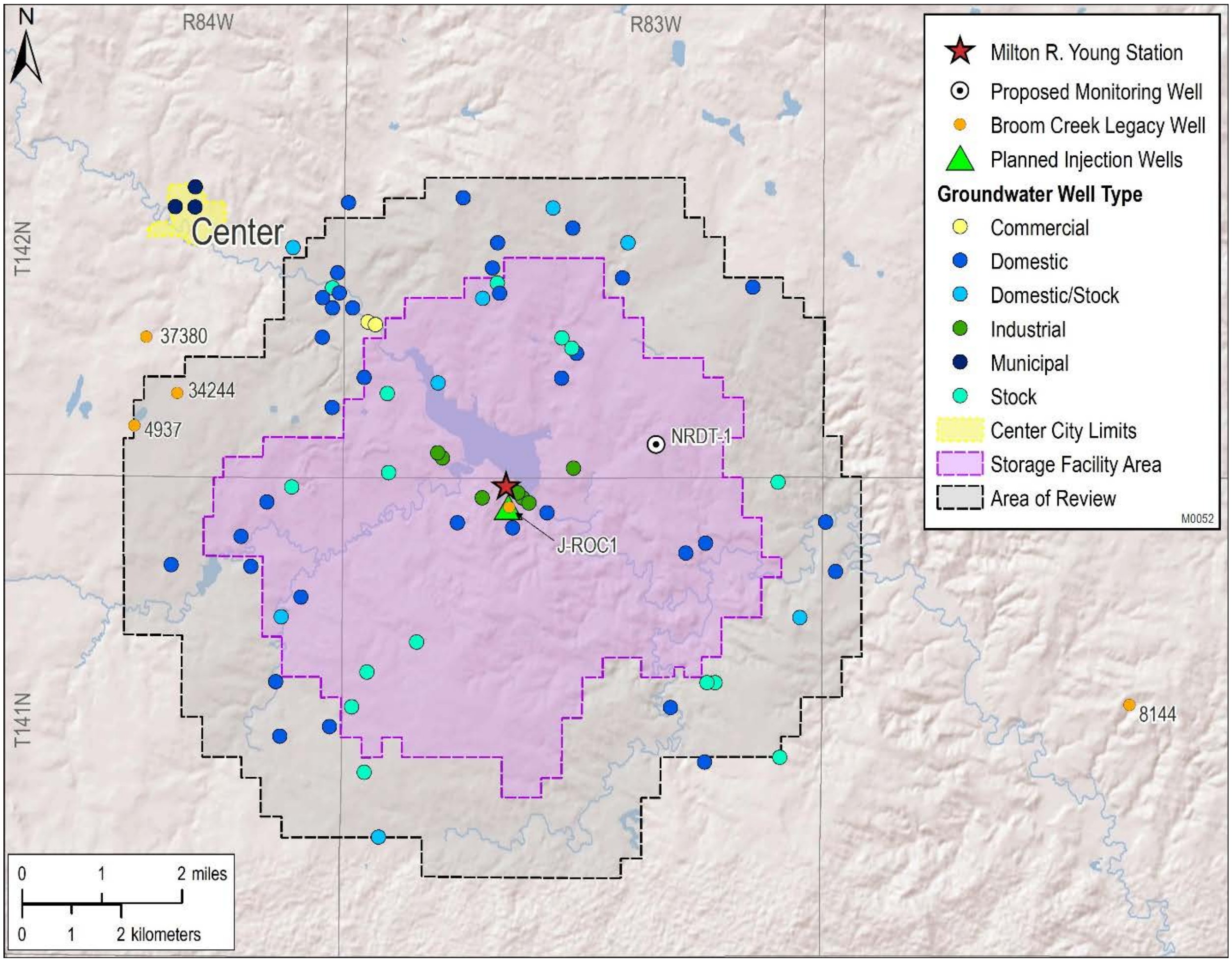


Figure 3-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the storage facility area and AOR boundaries.

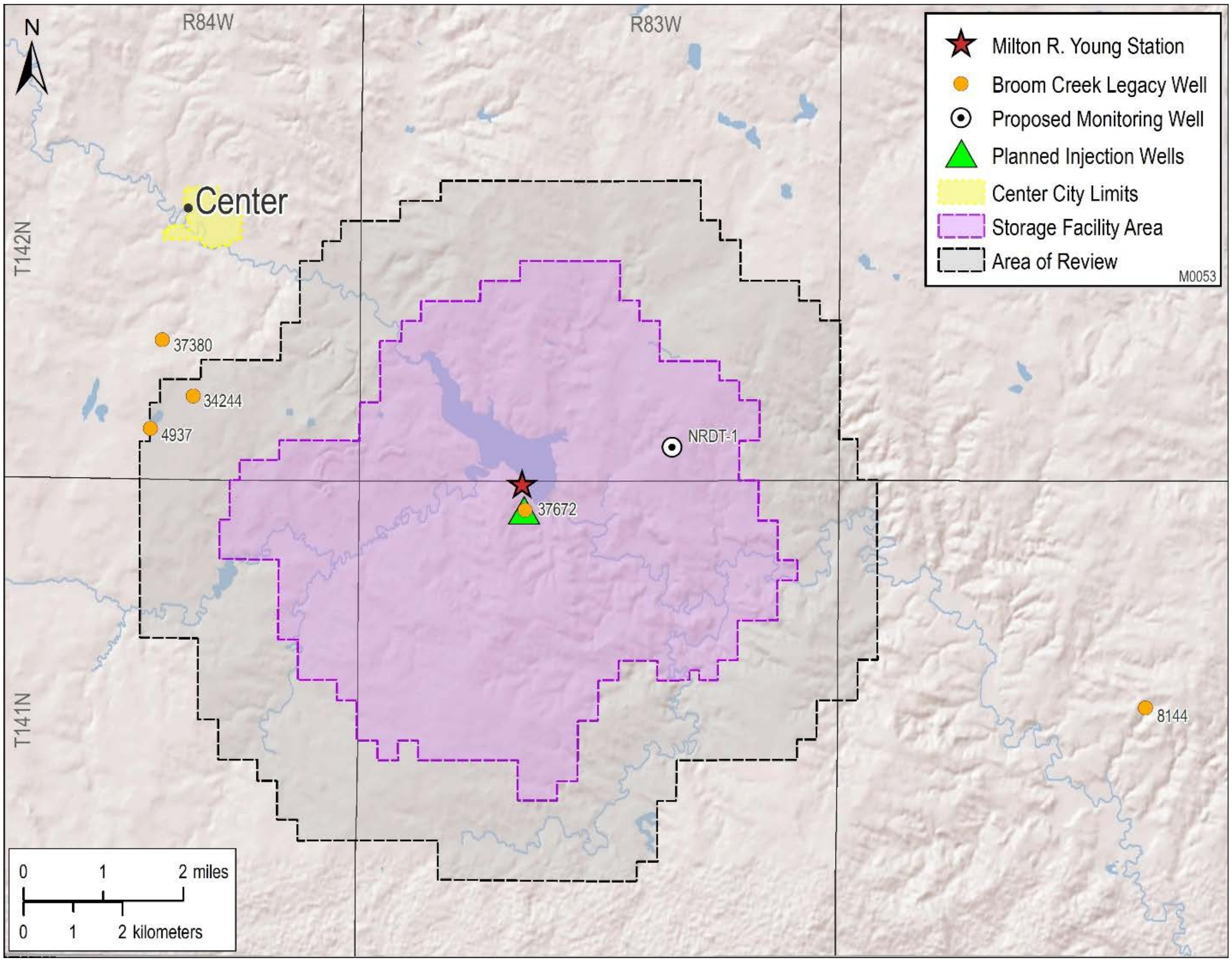


Figure 3-4. The AOR map in relation to nearby legacy wells. Shown are the storage facility area (purple boundary), Center city limits (yellow dotted boundary), and AOR (gray boundary). Orange circles represent nearby legacy wells near the project area, including within the AOR.

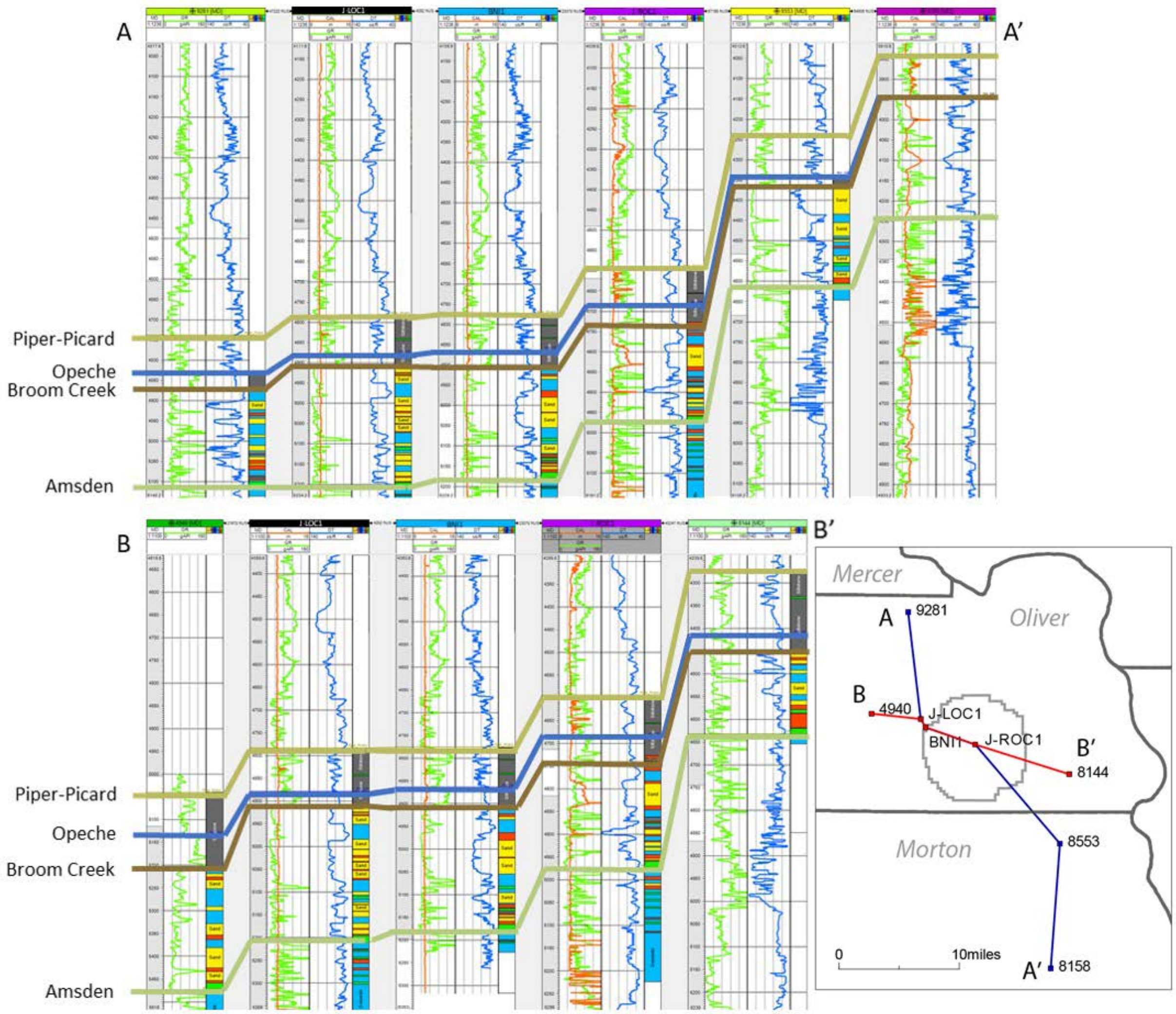


Figure 3-5. Regional well log stratigraphic cross sections of the Opeche, Piper–Picard, and Broom Creek Formations flattened on the top of the Amsden Formation, with inset map demonstrating the location of the J-ROC1 and J-LOC1 wells within the AOR boundary. The logs displayed in tracks from left to right are 1) gamma ray (GR, green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

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 through 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*		X
Any Existing Aboveground Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines	X	
Indian Boundary Lines		X
Other Pertinent Surface Features**	X	

* Cathodic protection planned with location TBD.
** Center, North Dakota, city limit boundary.

3.2 Corrective Action Evaluation

Table 3-2. Wells in AOR Evaluated for Corrective Action

NDIC[1] Well File No.	Operator	Well Name	Spud Date	Surface Casing OD, in.	Surface Casing Seat, ft	Long-String Casing, in.	Hole Direction	TD,[2] ft	TVD,[3] ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
37672	Minnkota Power Cooperative, Inc. (Minnkota)	J-ROC1	9/8/2020	13.375	2,000	Openhole	Vertical	9,871	9,871	TA	10/27/2020	141 N	83 W	4	SW/NW	Oliver	No
34244	University of North Dakota EERC	BNI-1	1/17/2018	9.625	1,386	Openhole	Vertical	5,316	5,315	P&A	2/6/2018	142 N	84 W	27	SE/SE	Oliver	No
4937	General American Oil Company of Texas	Herbert Dresser 1-34	8/25/1970	8.625	300	Openhole	Vertical	6,042	6,042	P&A	9/8/1970	142 N	84 W	34	SE/NW	Oliver	No

[1] North Dakota Industrial Commission.
[2] Total depth.
[3] True vertical depth.

Table 3-3. J-ROC1 (NDIC File No. 37672) Well Evaluation

Well Name: J-ROC1 (NDIC File No. 37672)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	9,030	9,375	345	241
2	7,830	8,550	720	212
3	7,361	7,830	469	272
4	6,516	7,200	684	241
5	5,215	5,600	385	147
6	4,430	4,770	340	160
7	3,400	3,715	315	145
8	1,715	2,050	335	221
9	28	90	62	46

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
Pierre	1,150	Cement Plug 9 isolates the surface.
$13^{3}/_{8}$" Casing Shoe	2,000	Cement Plug 8 isolates the surface casing shoe.
Mowry	3,404	Cement Plug 7 isolates above the Inyan Kara Formation.
Inyan Kara	3,686	
Swift	3,865	
Spearfish/Opeche	4,688	Cement Plug 6 isolates above the Broom Creek and Spearfish/Opeche Formations.
Broom Creek	4,740	
Amsden	4,974	Cement Plug 5 isolates below the Broom Creek and Amsden Formations.

Spud Date: 9/8/2020
Total Depth: 9,871 ft (Precambrian Basement)

Surface Casing:
$13^{3}/_{8}$" 61# K-55 casing set at 2,000 ft, cement to surface with 1,207 sacks Class C cement.

Openhole TA

Corrective Action: No corrective action is necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs. Minnkota plans to convert this well into an injection well named Liberty-1 (J-ROC1 NDIC File No. 37672).

Table 3-4. BNI-1 (NDIC File No. 34244) Well Evaluation

Well Name: BNI-1 (NDIC File No. 34244)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	4,739	5,199	460	170
2	3,466	3,623	157	60
3	1,277	1,447	170	75
4	68	125	57	25

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
Pierre	1,225	Cement Plug 3 isolates the 9⅝" casing shoe with 61' and 109' cement below and above the casing shoe, respectively.
9⅝" Casing Shoe	1,386	
Greenhorn	3,170	
Mowry	3,568	
Newcastle	3,628	
Inyan Kara	3,840	Cement Plug 2 isolates above the Inyan Kara Formation.
Swift	4,104	
Rierdon	4,522	
Broom Creek	4,900	Cement Plug 1 isolates 161’ above and completely across the Broom Creek Formation, respectively.

Spud Date: 1/17/2018
Total Depth: 5,316 ft (Amsden Formation)

Surface Casing:
9⅝" 36# J-55 casing set at 1,386 ft, cement to surface with 465 sacks Class G cement.

Openhole P&A

Corrective Action: No corrective action is necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs and is located near the outside edge of the AOR. Monitoring at this location may be necessary depending on actual plume growth.

Table 3-5. Herbert Dresser 1-34 (NDIC File No. 4937) Well Evaluation

Well Name: Herbert Dresser 1-34 (NDIC File No. 4937)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	5,738	5,823	85	25
2	4,874	4,959	85	25
3	3,975	4,060	85	25
4	3,809	3,894	85	25
5	265	343	78	25
6	4	14	10	5

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	300	Cement plug 5 isolates the 8⅝" casing shoe with 43' and 35' cement below and above the casing shoe, respectively.
Pierre	1,282	
Greenhorn	3,223	
Mowry	3,593	Cement Plug 4 isolates the Inyan Kara Formation with 4' within the Inyan Kara and 81' within the Mowry. Cement Plug 3 isolates across the Inyan Kara Formation.
Inyan Kara	3,890	
Swift	4,105	
Broom Creek	4,940	Cement Plug 2 isolates 19’ of the Broom Creek Formation and its upper-confining layer with a total cement plug thickness of 85’.

Spud Date: 8/25/1970
Total Depth: 6,042 ft (Charles Formation)

Surface Casing:
8⅝" 36# K-55 casing set at 300 ft, cement to surface with 225 sacks Class G cement.

Openhole P&A

Corrective Action: No corrective action is necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs and is on the edge of the AOR boundary. Monitoring this location may be necessary depending on actual plume growth.

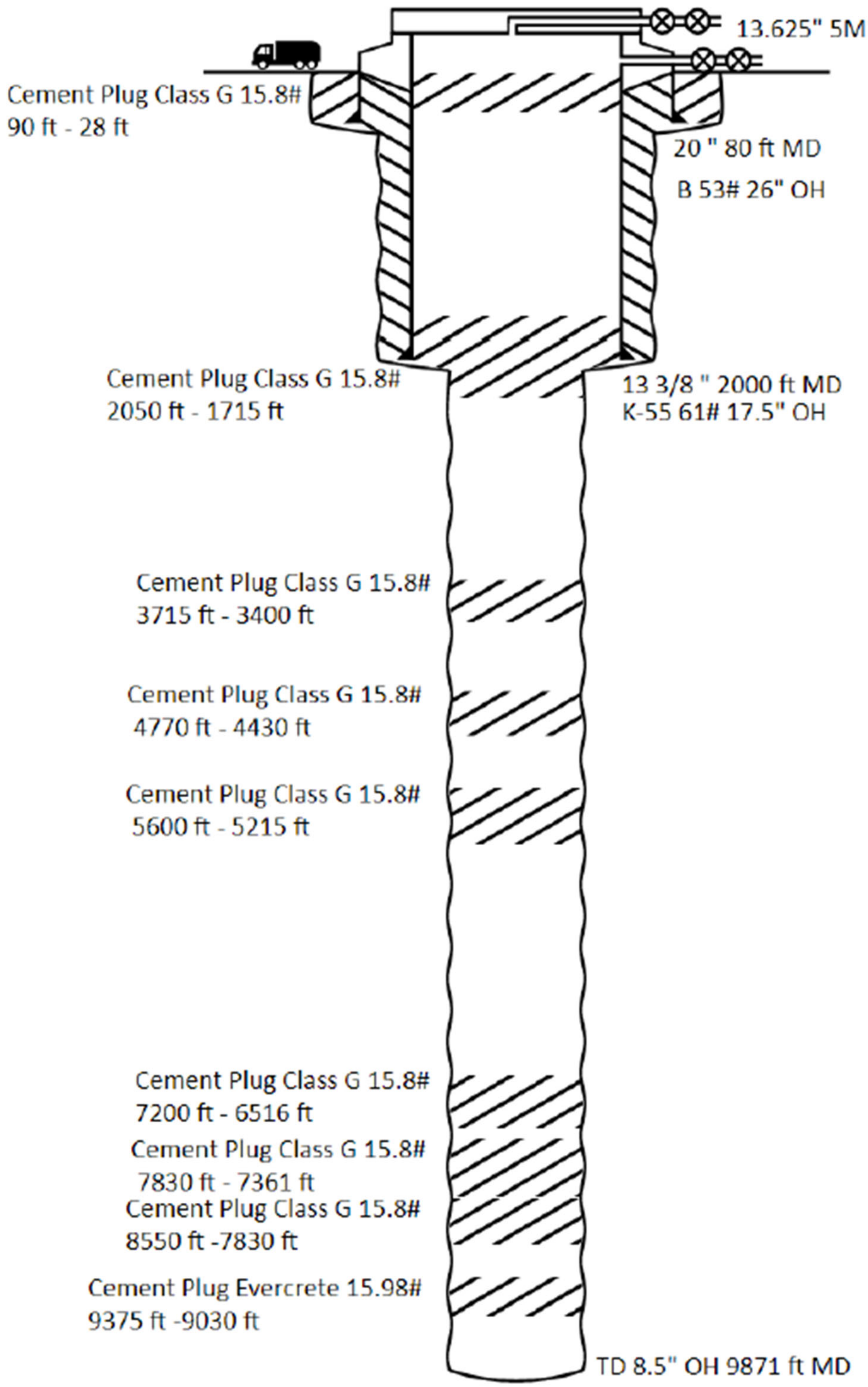


Figure 3-6. J-ROC1 (NDIC File No. 37672) well schematic showing the location and thickness of cement plugs.

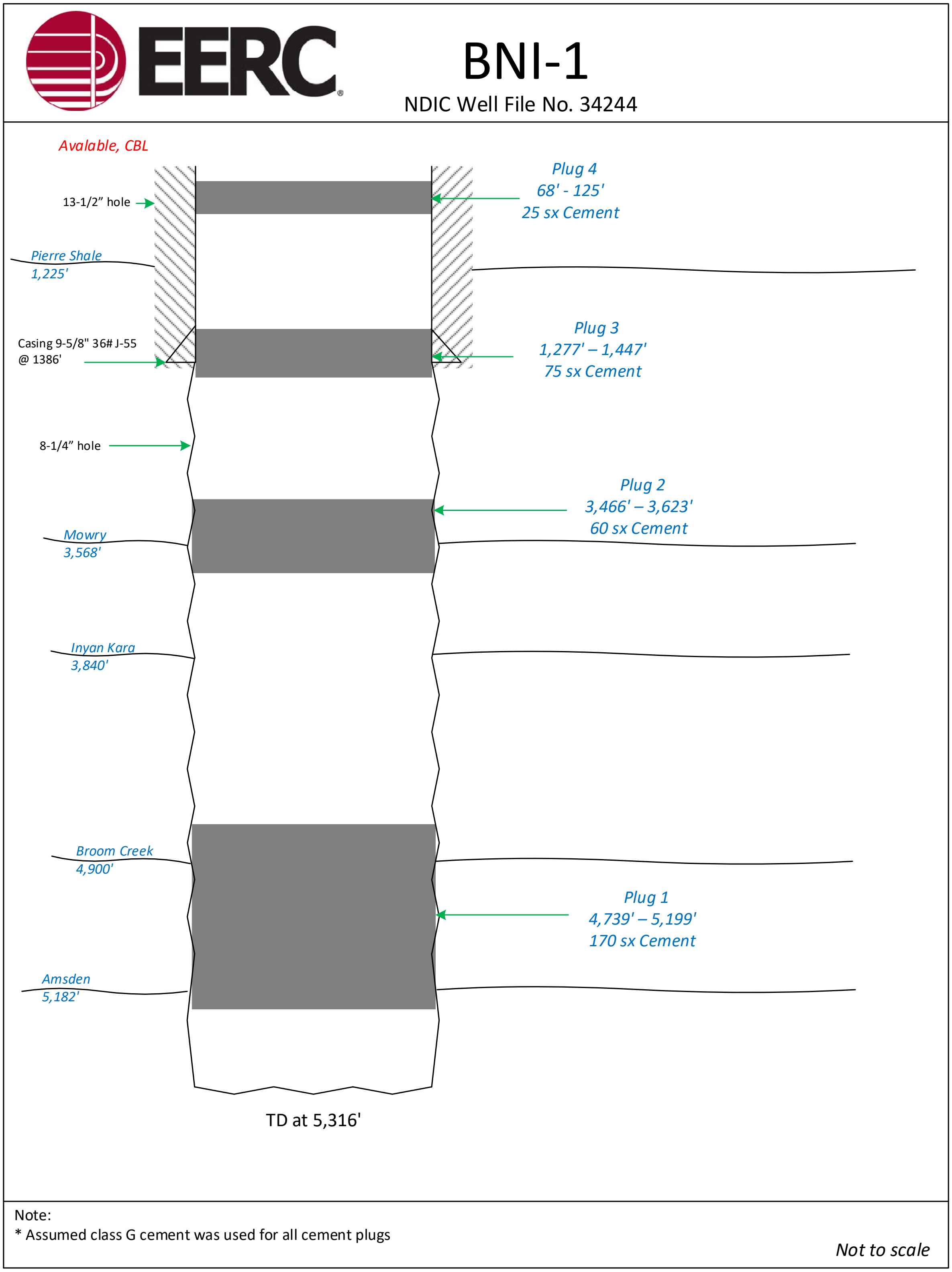


Figure 3-7. BNI-1 (NDIC File No. 34244) well schematic showing the location and thickness of cement plugs.

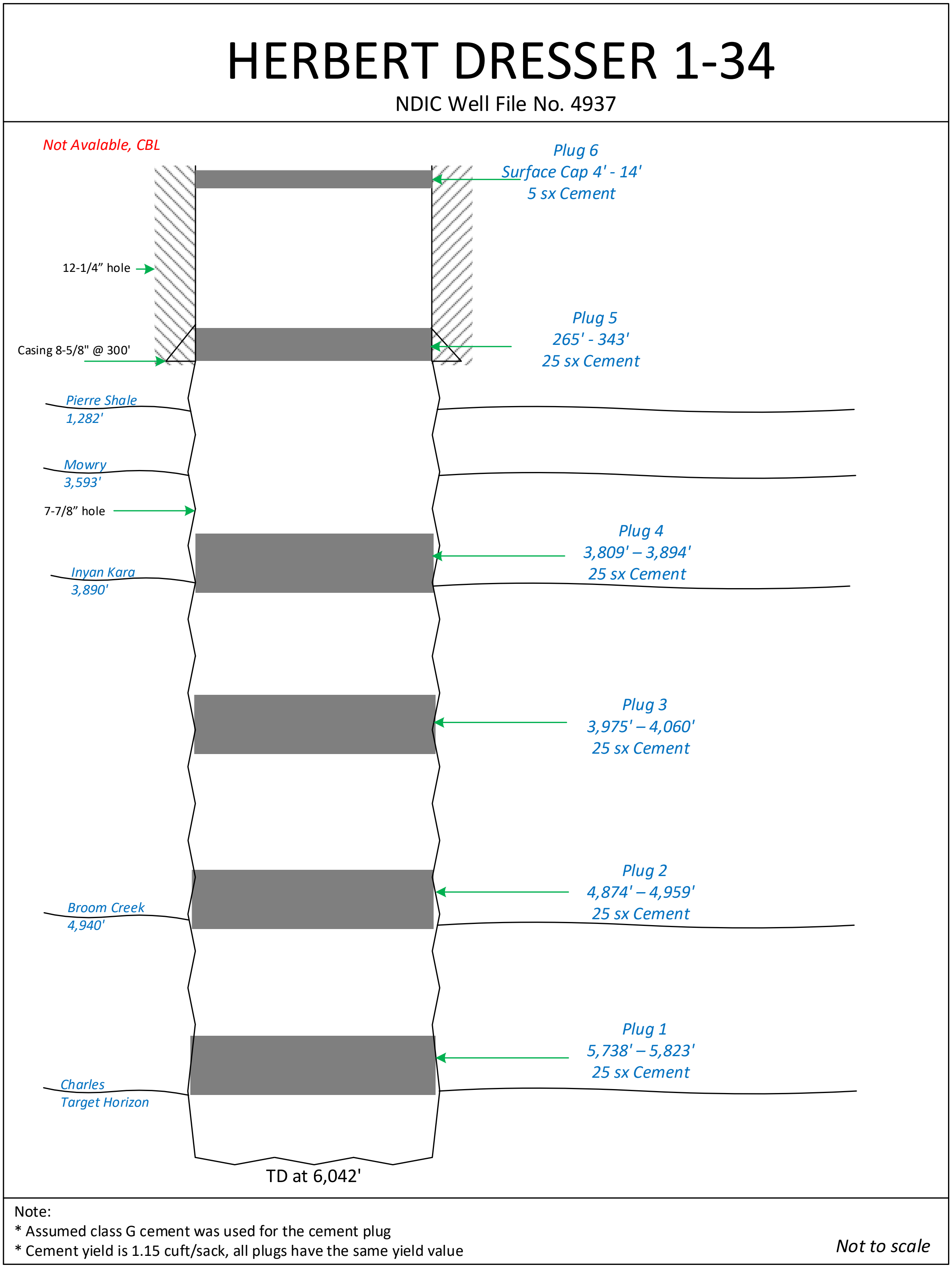


Figure 3-8. Herbert Dresser 1-34 (NDIC File No. 4937) well schematic showing the location and thickness of cement plugs.

3.3 Reevaluation of AOR and Corrective Action Plan

Minnkota will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date.

- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.

- The protocol to conduct corrective action, if necessary, will be determined, 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 deepest USDW in the AOR. The Opeche Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6).

Table 3-6. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1,862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444

3.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises 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 3-9). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and Tertiary Golden Valley Formation (Figure 3-10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973).

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 700 to 900 ft deep and 200 to 350 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 3-11).

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 1000 ft thick in the AOR (Thamke and others, 2014).

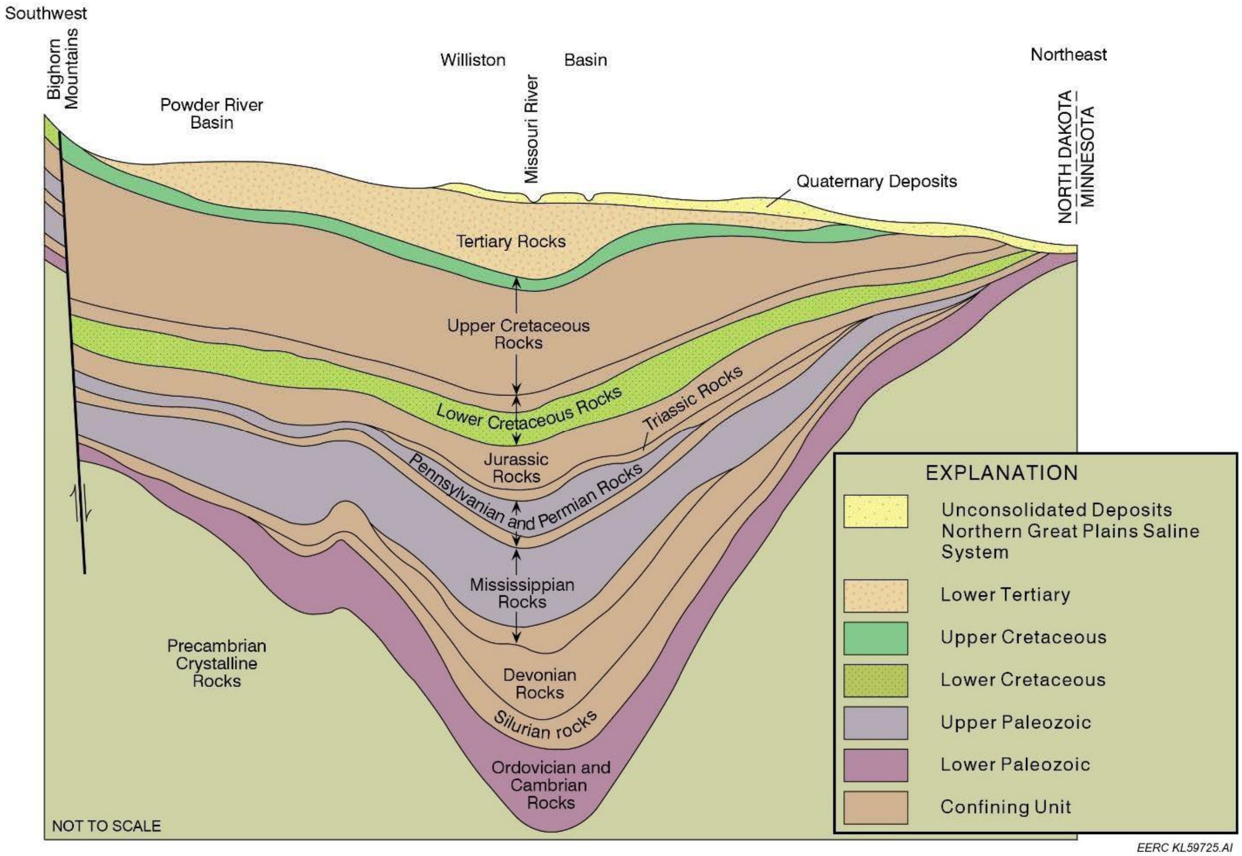


Figure 3-9. Major aquifer systems of the Williston Basin.

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
	Tertiary		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

Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

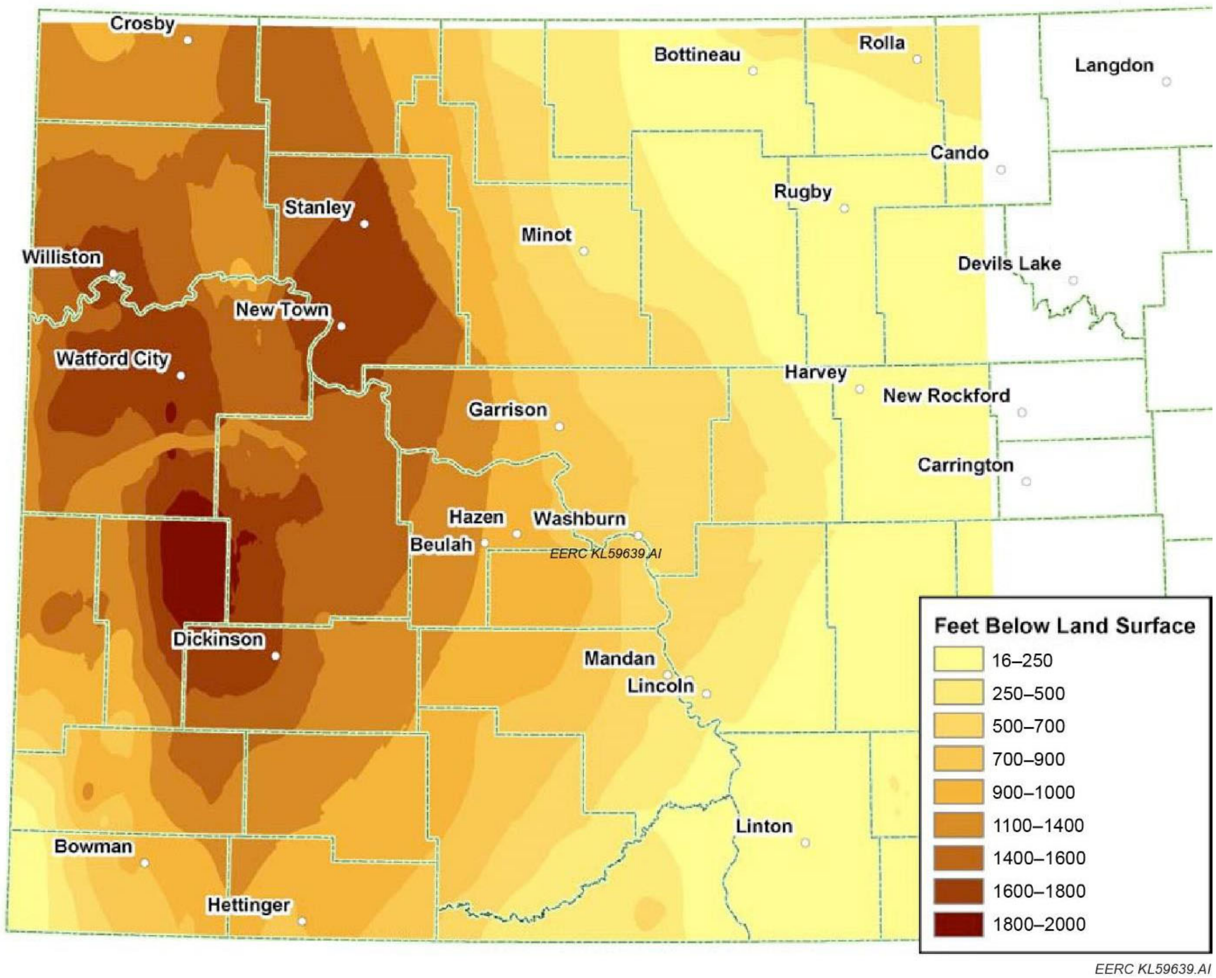


Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

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, which isolates 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 east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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.

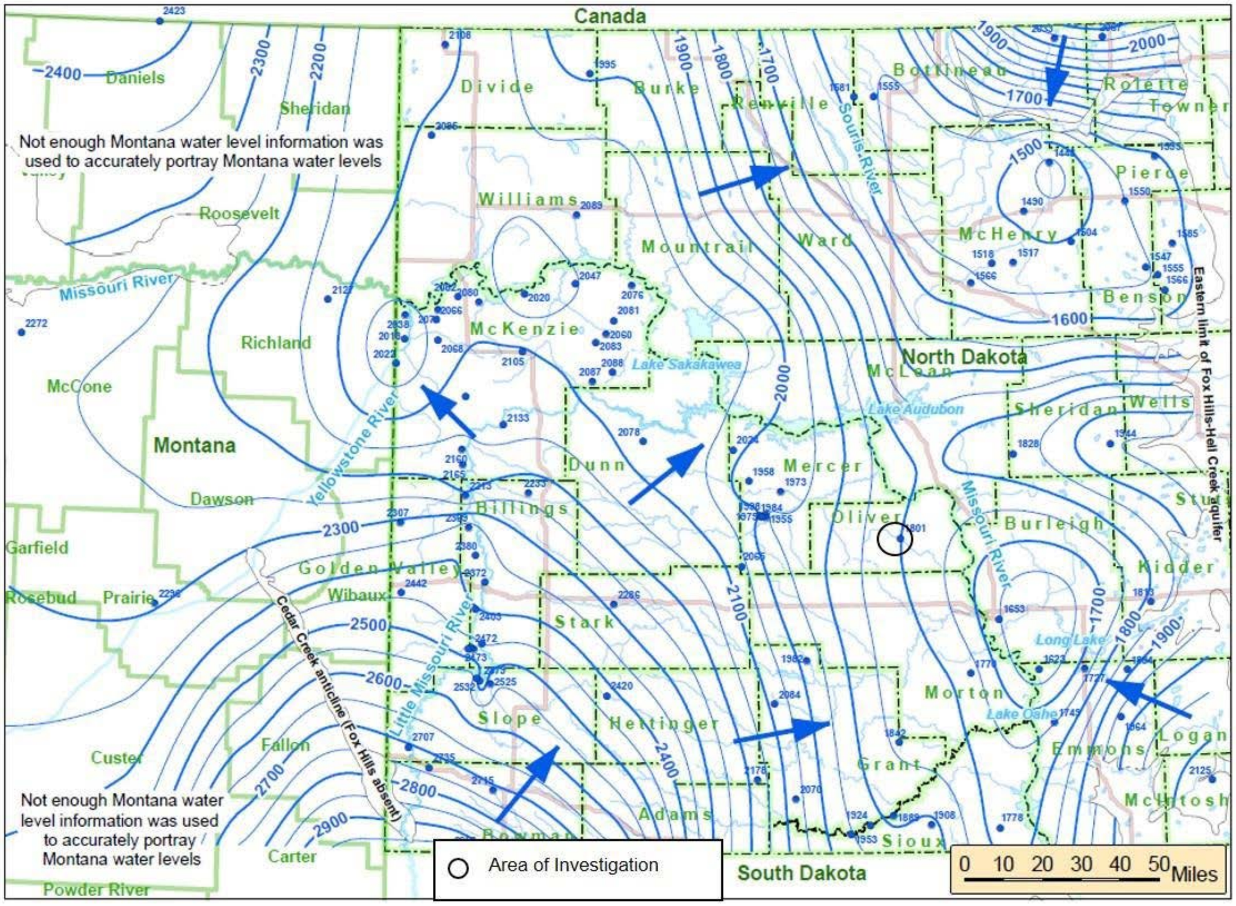


Figure 3-12. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Oliver County (modified from Fischer, 2013).

Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown.

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

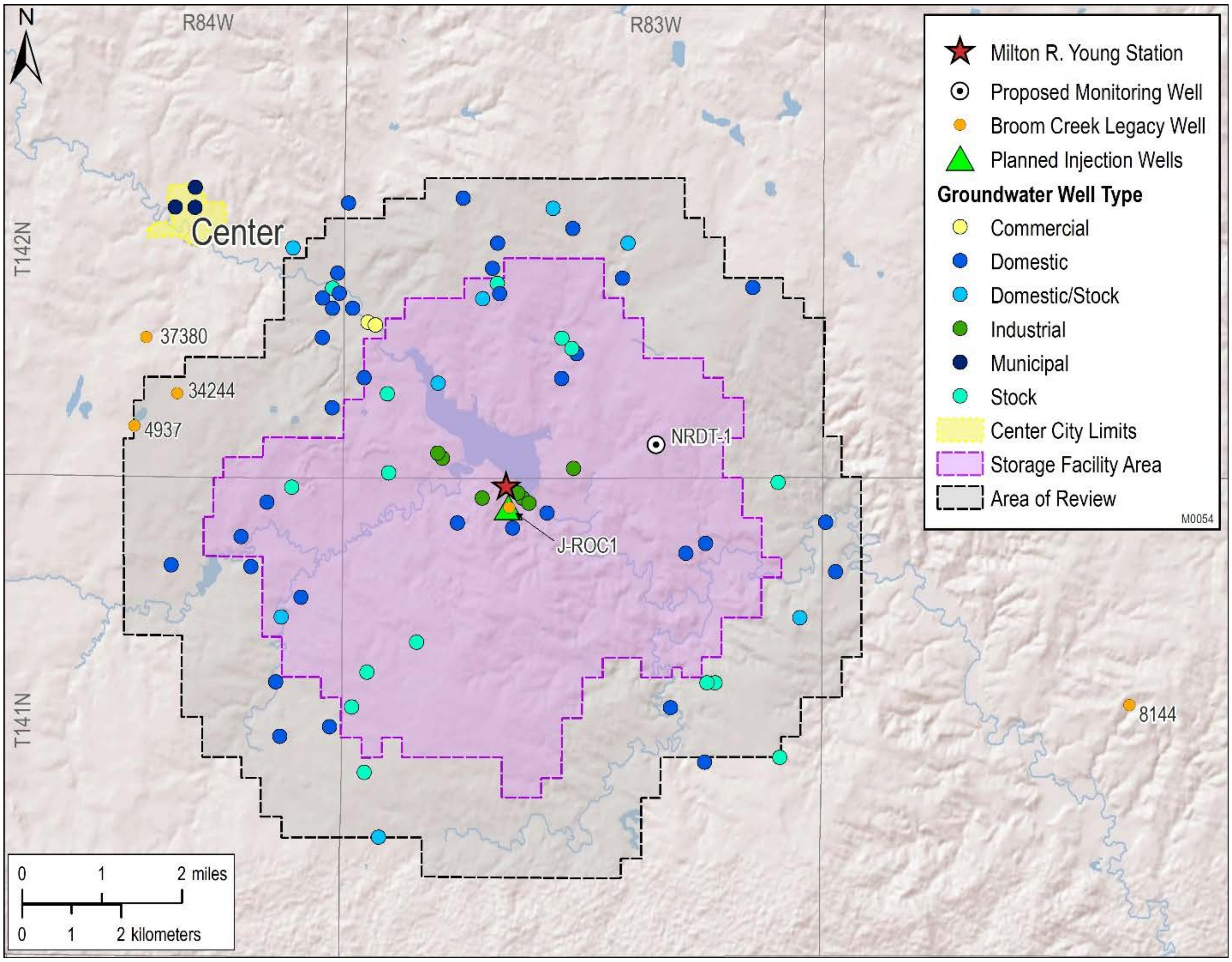


Figure 3-13. Map of water wells in the AOR in relation to the project facility, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 planned injection wells, the NRDT-1 proposed monitoring well, facility area, AOR, and legacy oil and gas wells.

The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

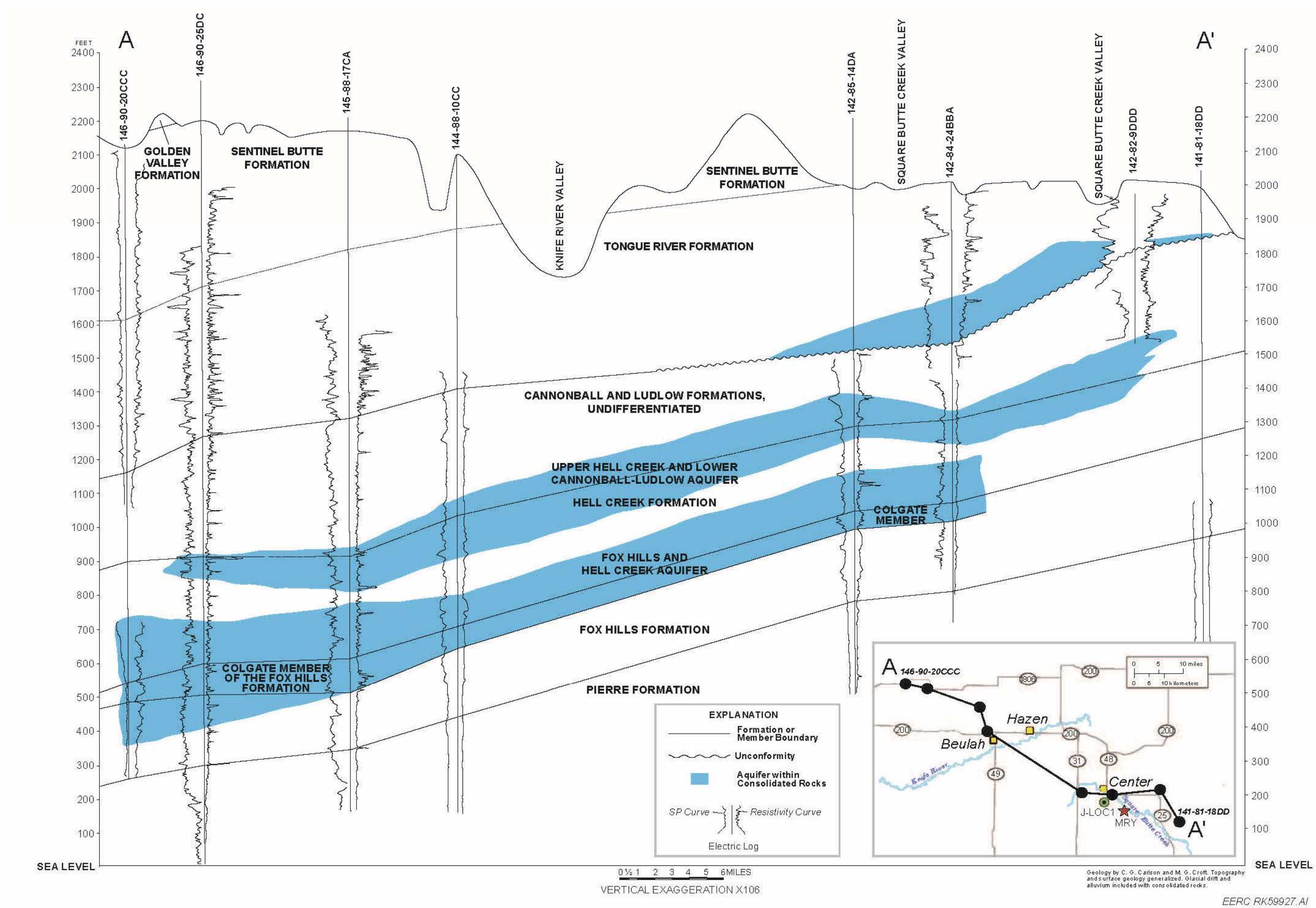


Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

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 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 3-9). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, Jurassic-aged Piper (Picard), Rierdon, 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection wells, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1, and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the AOR and primary geologic barrier between the USDWs and injection zone. The geologic strata overlying the injection zone consist 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

Croft, M.G., 1973, Ground-water resources of Mercer and Oliver Counties, North Dakota: U.S. Geological Survey, County Ground Water Studies – 15.

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

The ten supporting plans of this permit application are listed in Table 4-1 and provided in this section of the application. To aid in the review of these plans, it should be noted that 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 the single subsection entitled Testing and Monitoring Plan. The other plans are presented in their respective subsections.

Table 4-1. Supporting Plans for Permit Application

Testing and Monitoring Plan
Corrosion Monitoring and Prevention Plan*
Surface Leak Detection and Monitoring Plan*
Subsurface Leak Detection and Monitoring Plan*
Emergency and Remedial Response Plan
Financial Assurance Demonstration Plan
Worker Safety 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 4.1).

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 (Ayash, Azzolina, and Nakles, technical memorandum, February 12, 2020). The SLRA was conducted through a series of work group sessions involving subject matter experts (SMEs) that were held from May 2018 through April 2019. The technical experts were asked to review 18 individual technical project risks and four nontechnical risks and assign them a probability of occurrence and assess their potential impacts on cost, schedule, health and safety, environment, permitting/compliance, and corporate image/public relations.

The technical risks were grouped into the following six risk categories: 1) injectivity (three risks), 2) storage capacity (two risks); 3) subsurface containment – lateral migration of carbon dioxide (CO_2) or formation water brine (one risk); 4) subsurface containment – propagation of subsurface pressure plume (two risks); 5) subsurface containment – vertical migration of CO_2 or formation water brine via injection wells, plugged and abandoned wells, monitoring wells, or faults/fractures (nine risks); and 6) induced seismicity (one risk). The risk assessment results indicated that there were currently no potential risks that would prevent the storage complexes evaluated in the feasibility study from serving as commercial-scale geologic CO_2 storage sites. While the results of the SLRA indicated that there are no risks that would preclude the commercial deployment of the project, it identified 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.

Using this SLRA as a starting point, a team consisting of representatives of Oxy Permian Risk, Low Carbon Ventures (LCV) engineers, Minnkota personnel, Energy & Environmental Research Center (EERC) staff, and BNI Energy engineers met to conduct further risk assessment of Tundra SGS proposed design and operations. The purpose of this review was to identify potential hazards based on facility design and operation.

The risk assessment process used for Project Tundra was developed specifically for this project based on consultation and agreement of risk team members. The agreed-upon approach used a combination of evaluating impact and probability level for a variety of impact categories to determine the overall risk level. These steps are performed for each of the identified risk scenarios developed as discussed in more detail below.

A total of 38 scenarios associated with the facility operation were evaluated. Thirteen (13) scenarios were identified to have a Risk Level 4 or higher which may be equivalent to a medium level risk, the yellow range identified on the risk matrix (Section 6. Risk Matrix). However, the team did not define high, medium, or low risk based on risk score. Further discussion of costing and actions related to the monitoring approaches identified in this section are included in the financial assurance demonstration plan (FADP).

4.1 Testing and Monitoring Plan

An extensive monitoring, verification, and accounting (MVA) system will be implemented to verify that the Tundra SGS project is operating as permitted and is not endangering USDWs. The objectives of the MVA program are to proactively account for and verify the location of CO_2 injected. This MVA plan 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) corrosion-monitoring and prevention plan, 2) surface leak detection and monitoring plan, and 3) 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 protecting the USDWs. An overview of these individual monitoring efforts is provided in Table 4-2 along with the structure/project area that is being monitored.

Pursuant to North Dakota Administrative Code (NDAC) § 43-05-01-11.4 (1)(j), "Periodic reviews of the testing and monitoring plan by the storage operator to incorporate monitoring data collected, operational data collected, and the most recent area of review reevaluation performed. The storage operator shall review the testing and monitoring plan at least once every five years."

Table 4-2. Overview of Tundra SGS Monitoring Program for the Geologic Storage of CO_2

Monitoring Type	Tundra SGS Monitoring Program	Target Structure/ Project Area
Analysis of Injected CO_2	Compositional and isotopic analysis of the injected CO_2 stream	Upstream or downstream of the flowmeter
CO_2 Flowline	Distributed temperature sensing (DTS)/ distributed acoustic sensing (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 area of review (AOR), dedicated Fox Hills monitoring well, and soil gas-sampling and analyses	Near-surface environment, USDWs
Direct Reservoir Monitoring	Wireline logging, tubing-conveyed downhole pressure and temperature gauges, and casing conveyed DTS (fiber optic)	Storage reservoir and primary sealing formation
Indirect Reservoir Monitoring	Time-lapse geophysical (seismic) surveys, InSAR,[1] and passive seismic measurements	Entire storage complex
Internal and External Mechanical Integrity	Tubing-casing annulus pressure testing (internal) Casing-conveyed DTS (fiber optic), casing integrity tools (i.e., USIT[2]) (external)	Well infrastructure
Corrosion Monitoring	Flow-through corrosion coupon test system for periodic corrosion monitoring.	Well infrastructure

[1] Interferometric synthetic aperture radar.
[4] Ultrasonic imaging tool.

If needed, amendments to the testing and monitoring plan (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by the North Dakota Industrial Commission (NDIC). The 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.

4.1.1 Analysis of Injected CO_2 and Injection Well Testing

4.1.1.1 CO_2 Analysis

Prior to injection, Minnkota Power Cooperative, Inc. (Minnkota) will determine the chemical and physical characteristics of the CO_2 that has been captured for storage using appropriate analytical methods. The anticipated chemical composition is shown in Table 4-3.

Table 4-3. Proposed Composition of the Injection Stream (Minnkota)

Chemical Component	ppmv	mol%
CO_2	804,195	0.999
H_2O	632	7.85E-04
N_2	163	2.02E-04
O_2	6	7.45E-06
H_2	0	0.00E+00
Ar	4	4.97E-06

4.1.1.2 Injection Well Integrity Tests

Until the CO_2 injection well is plugged, Minnkota will continuously monitor its external mechanical integrity via a casing conveyed fiber optic sensing system (i.e., DTS). Casing integrity tools (e.g., USIT or electromagnetic [EM]) log will be run on the injection wells to establish the initial baseline external mechanical integrity. A USIT/EM log will be run at least once every 5 years to verify the external mechanical integrity of the injection wells. Internal mechanical integrity of the injection well will be demonstrated via a tubing-casing annulus pressure test prior to injection and at least once 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.

4.1.2 Corrosion Monitoring and Prevention Plan

The corrosion management program (CMP) includes identification of active and potential future damage mechanisms and their mitigation, control, and monitoring. The CMP is a major component of the mechanical integrity program and monitoring, reporting, and verification (MRV) plan.

For the purpose of the CMP document, the CCS (carbon capture and storage) hub was divided into the following systems:

- **CO_2 capture facility:** not included in the scope of this permit application.
- **CO_2 transportation flowline:** from the fence line of the CO_2-metering facility to the outlet at the well pad borders.
- **Surface piping, instrumentation, and pressure control equipment at the injection wellsite:** from the outlet of the main CO_2 flowline until the connection with the injection tree/wellhead.
- **Downhole equipment:** from the injection tree/wellhead to the reservoir. There are two categories for downhole equipment based on the service conditions: injector wells and in-zone monitoring wells.

4.1.2.1 Corrosion Threat Assessment

The corrosion threat assessment identifies which damage mechanism is currently active and likely to occur in systems or equipment along with the potential consequences of the damage.

4.1.2.2 Identification of Critical Components and Operating Conditions

This section identifies the different components included in the corrosion and monitoring plan as well as the fluid compositions, fluid state, operating pressures, temperatures, and flow rates to which the equipment will be exposed.

- For each system, the critical component or equipment are identified in Appendix F.
- A detailed description of the selected material and operating conditions is specified by each component or equipment.
- Table 4-4 shows the CO_2 specifications for the Tundra SGS project.

Table 4-4. CO_2 Specifications for Tundra SGS Project

Stream Description	Compressed CO_2 Product to Battery
Stream Number	606
Temperature, °F	120
Pressure, psia	1,688.7
Components	
Component Flows	**Limits**
H_2O	632 ppmv
CO_2	99.90%
N_2	163 ppmv
Ar	4 ppmv
O_2	6 ppmv
H_2	0%
SO_2	<1 ppmv
NO_2	<1 ppmv
NO	30 ppmv

4.1.2.3 Damage Mechanism

This section defines the corrosion mechanisms currently active and likely to occur, along with the potential consequences of the damage.

Damage mechanisms are classified in the following four categories:

- **Internal Corrosion**: results in loss of wall thickness of the equipment and piping due to the action of the contained fluid on the material of construction. The damage may be general or localized.
- **External Corrosion**: results in loss of wall thickness of the equipment and piping due to the action of the environment on the materials of construction. The damage may be general or localized.

- **Environmental-Assisted Cracking**: caused by a specific combination of the environment, material of construction, and applied or residual stress. Cracking may originate from the inside (process side) or outside (environment side).

- **Mechanical and Metallurgic Damage:** results from the interaction of the material and process or external environment, such as brittle fracture, creep, erosion, and metal fatigue.

Appendix F summarizes the damage mechanism associated with each component or element during the analysis.

4.1.2.4 Corrosion Control Program (CCP)

For each component identified in the corrosion threat assessment and damage mechanism association, a set of mitigations, corrosion-monitoring techniques, inspections, data gathering, and analysis will be implemented.

The CCP includes the following:

- Description of the system and damage mechanism
- Mitigations, if any
- Monitoring description
- Monitoring frequency
- Target limits for monitoring
- Person responsible for the analysis of the monitoring data
- Consequence of operation outside of target limits
- Remedial action outside of target limits
- Required period for remedial action

Appendix F includes the CCP matrix.

4.1.2.5 Annual Review

The operator shall prepare an annual CMP report, confirming the status of the actions and controls described in the CMP, highlighting any findings during inspections, and identifying the failure and root cause analysis. The CMP shall be reviewed more frequently if there are changes in the conditions that could lead to:

- An increase in severity of the active corrosion mechanism.
- A significant likelihood of any inactive corrosion mechanism being activated.

4.1.2.6 Data Management

The results of the corrosion threat assessment and CCP shall be recorded and available for review according to the operator data management standard and systems.

4.1.3 Surface Leak Detection and Monitoring Plan

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. The flowline from the capture facility to the wellhead will be monitored using a DTS/DAS and DSS fiber optic cable with an interrogator system to provide the ability to detect leaks along the flowline. The CO_2 detectors will be placed at the injection wellhead and key wellsite locations (e.g., flowline riser). Leak detection equipment will be integrated with automated 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, maintained for at least 10 years, and available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

4.1.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises the 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., residential drinking water wells, stock wells, etc.). The deep subsurface zone extends from the base of the deepest USDW to the bottom 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 that the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for the Tundra SGS project, near-surface monitoring will include installation of one dedicated Fox Hills Formation monitoring well to detect if the deepest USDW is being impacted by operations as well as three soil gas profile stations, each located at the CO_2 injection, NRDT-1, and Herbert Dresser deep monitoring wellsites. In addition, existing groundwater wells within the AOR have been identified, and a set of domestic wells will 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 CO_2 is being safely and permanently stored in the storage reservoir.

Operational monitoring at the injection wells Liberty-1 (J-ROC1 File No. 37672) and Unity-1 [proposed], including injection rates, pressures, and temperatures, will provide data to inform the monitoring approaches. Internal and external mechanical integrity of the injection wells 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.

4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring

Surface and near-surface environments will be monitored 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 in the postoperational monitoring time frame.

Using data from ongoing mine reclamation and power plant monitoring programs, Minnkota has achieved near-surface baseline sampling of the Tongue River aquifer near the injection site. The North Dakota State Water Commission (NDSWC) database was used to identify candidate wells within the AOR to complete an initial near-surface baseline sampling program, including seasonal sampling of existing groundwater wells (Figure 4-1). This baseline sampling program and results to date are described in detail in Section 4.1.6.

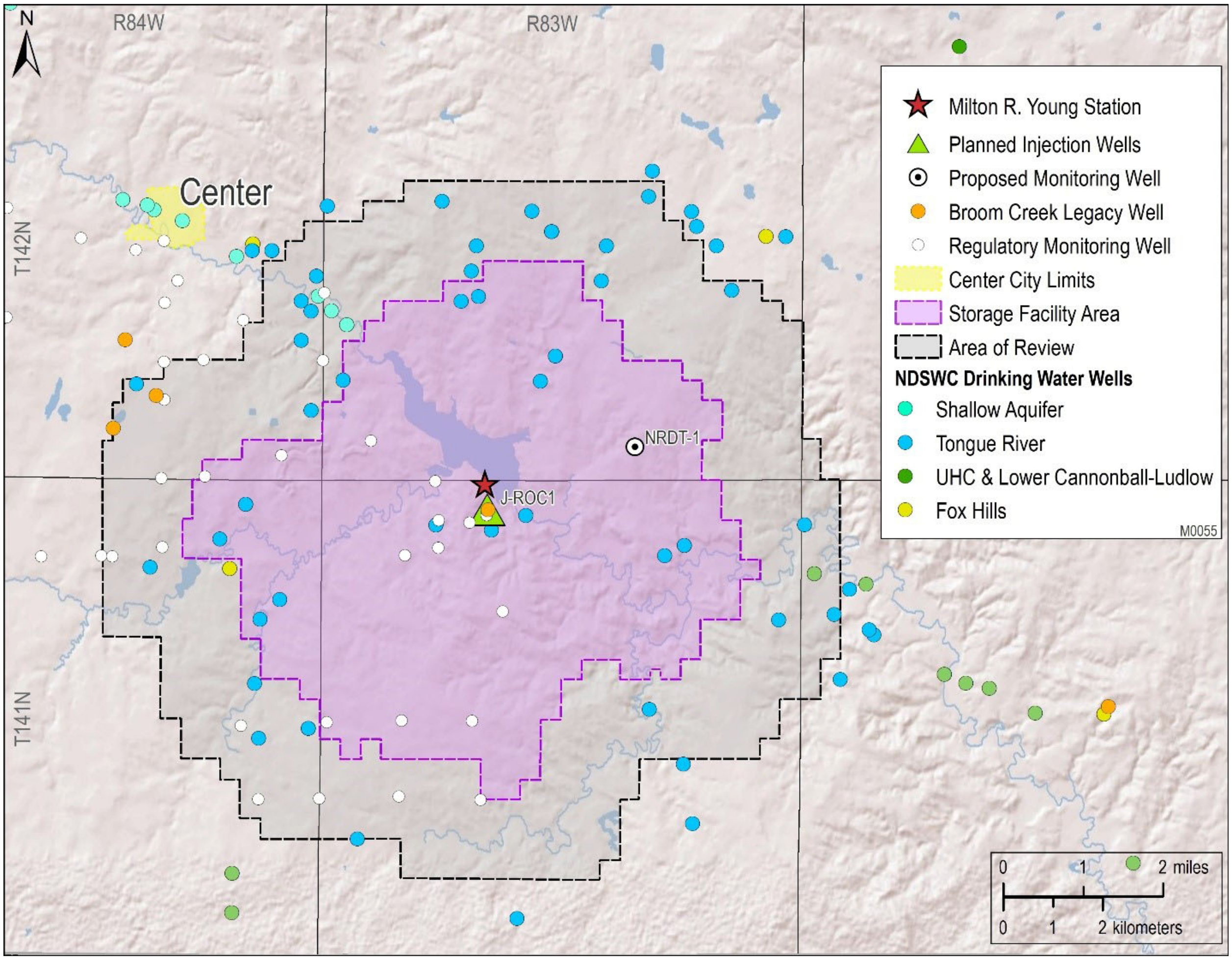


Figure 4-1. Minnkota will carry out an initial sampling program for the near-surface groundwater wells. Shown are existing monitoring wells to be used for the baseline; all wells listed for drinking water in the NDSWC database by aquifer; location of all plugged and abandoned legacy oil and gas exploratory wells; city of Center, North Dakota; Milton R. Young Station (MRYS); and Liberty-1 (J-ROC1 File No. 37672) and Unity-1 proposed injectors, and NRDT-1 (proposed monitoring well) in relation to the storage facility area and AOR. The well drilled for baseline characterization and monitoring of the Fox Hills Formation will be located at the injection wellsite.

Prior to injection operations, one dedicated Fox Hills Formation monitoring well will be installed at the CO_2 injection wellsite. The Fox Hills Formation will be sampled seasonally, and baseline state-certified laboratory analyses will be provided to NDIC prior to injection and to the state water commission. In addition, three soil gas profile stations will be installed: one near the Liberty-1 (J-ROC1 File No. 37672) injection and the other near the deep monitoring (NRDT-1) and Herbert Dresser (File No. 4937) wellsites. Baseline soil gas analyses will be provided to NDIC prior to CO_2 injection operations.

The near-surface monitoring plan will focus on the dedicated Fox Hills Formation well, a subset of the existing groundwater wells characterized to establish a baseline, and the soil gas profile stations. The plan is described in Section 4.1.7.

4.1.6 Baseline Sampling Program

4.1.6.1 Groundwater Baseline Sampling

An initial baseline characterization of the shallow groundwater near the Liberty-1 (J-ROC1 File No. 37672) injection site has been completed by acquiring data from long-term regulatory monitoring in the Tongue River aquifer by Minnkota's MRYS and BNI Coal. Additional baseline characterization of existing groundwater wells within the AOR will be completed prior to CO_2 injection by collecting and characterizing seasonal samples of up to 16 groundwater wells taken from the four aquifer systems (i.e., Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek aquifers) underlying the AOR. The locations of these candidate wells are shown in Figure 4-2. The results of the existing regulatory program to be used for baseline measurements for TDS (total dissolved solids), pH, specific conductivity, and alkalinity are provided in Table 4-5, with comprehensive laboratory analyses for each well attached in Appendix C.

Future baseline sampling will include selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek aquifers and one U.S. Geological Survey (USGS) Fox Hills observation well. Verification of the domestic well status is under way, and final selection of domestic wells will be based on viability of the well (existence, depth, access, etc.) and landowner cooperation. The locations of these candidate wells are shown in Figure 4-2. Appendix C describes the selection method and well verification results for all well permits in the NDSWC database labeled domestic, domestic/stock, and municipal. Characterization of selected domestic wells and one USGS Fox Hills observation well will include the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in Appendix C.

The results from these sampling efforts will provide a preoperational baseline of the groundwater quality in the four USDWs within the AOR of the CO_2 geologic storage project. The results will be submitted to NDIC before CO_2 injection occurs.

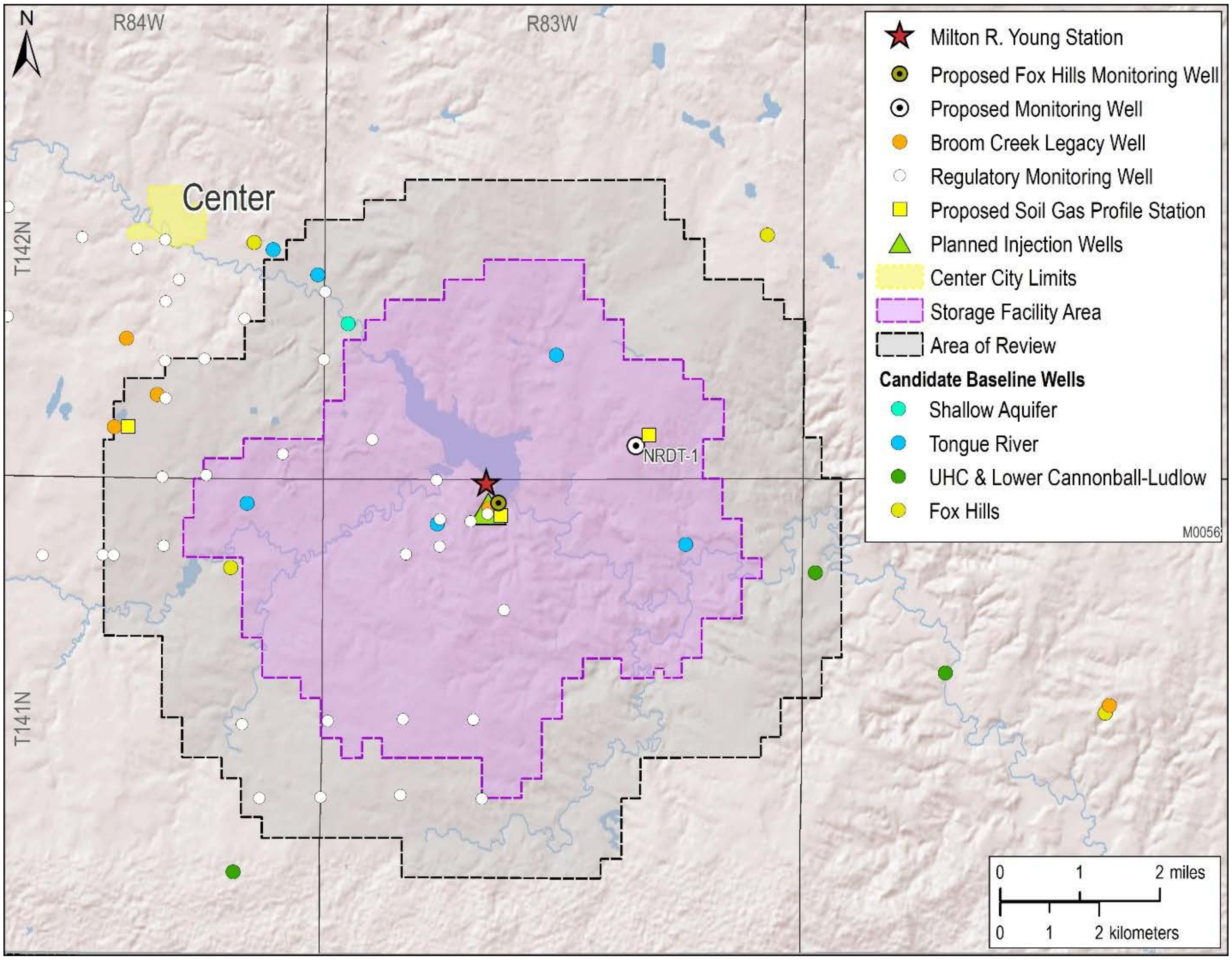


Figure 4-2. Tundra SGS project groundwater well sampling program to establish a groundwater baseline, including seasonal fluctuation, within the AOR. Shown are locations for existing regulatory monitoring well data and candidate wells for additional baseline sampling by aquifer.

Table 4-5. Baseline Groundwater Data

Parameter		Total Dissolved Solids, mg/L*			pH			Specific Conductance, mS/cm			Alkalinity as $CaCO_3$, mg/L		
BNI Well No.	**Depth, ft**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**
322A	21	525	726	532	6.19	6.6	6.6	801	980	832	118	124	165
324	88	360	817	745	7.8	7.8	7.8	649	1,193	1,182	188	345	369
363	82	1,440	1,500	1,550	8.3	8.3	8.2	2,446	2,460	2,454	1,090	1,110	1,200
C1-1	129	706	699	698	8.4	8.4	8.4	1,151	1,123	1,168	454	480	526
C7-1	184	1,410	1,480	1,490	8.5	8.4	8.2	2,105	2,098	2,096	985	1,050	1,120
C9-1	163	1,520	1,610	1,430	8.2	8.3	8.3	2,029	2,032	2,012	968	1,030	1,080
MRYS Well No.	**Depth, ft**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**
92-5A	185	800	790	780	8.75	8.9	8.94	1,131	1,184	1,129	488	520	499
92-6A	150	1,180	1,180	1,150	8.43	8.87	8.67	1,697	1,744	1,642	641	690	632
92-3	155	1,270	1,280	1,280	8.32	8.65	8.66	1,812	1,887	1,841	823	910	837
95-4	145	1,260	1,260	1,260	8.31	8.55	8.53	1,797	1,862	1,815	829	880	836
97-1	67	2,740	2,900	2,410	6.3	6.26	6.33	3,736	3,485	3,597	284	310	327
USGS Well No.	**Depth, ft**	**January 2021**			**January 2021**			**January 2021**			**January 2021**		
10	1,290	1,520			8.42			2,641			938		

* Calculation. For MRYS wells, calculated on reported field electrical conductivity.

4.1.6.2 Soil Gas Baseline Sampling

Soil gas sampling and analyses will be performed in order to establish baseline soil gas concentrations near the injection and deep monitoring wellsites, and a select legacy well in the AOR. Effective soil gas monitoring in reclaimed mine lands requires installation of soil gas profile stations, which will be located off of the well pads near the Liberty-1 (J-ROC1 File No. 37672) CO_2 injection, Herbert Dresser (File No. 4937) and deep monitoring (NRDT-1) wellsites, as shown in Figure 4-3. The analyses, which determine the concentration of CO_2, O_2, and N_2, will be performed in accordance with ASTM International (ASTM) standard procedures (D5314) for soil gas sampling and analysis (ASTM International, 2006). In addition, isotopic analysis of the baseline soil gas samples will establish the natural source partitioning of the gases.

The sampling results from these efforts will provide a preoperational baseline of the soil gas chemistry of the vadose zone in the AOR of the CO_2 geologic storage project. Results will be submitted to NDIC.

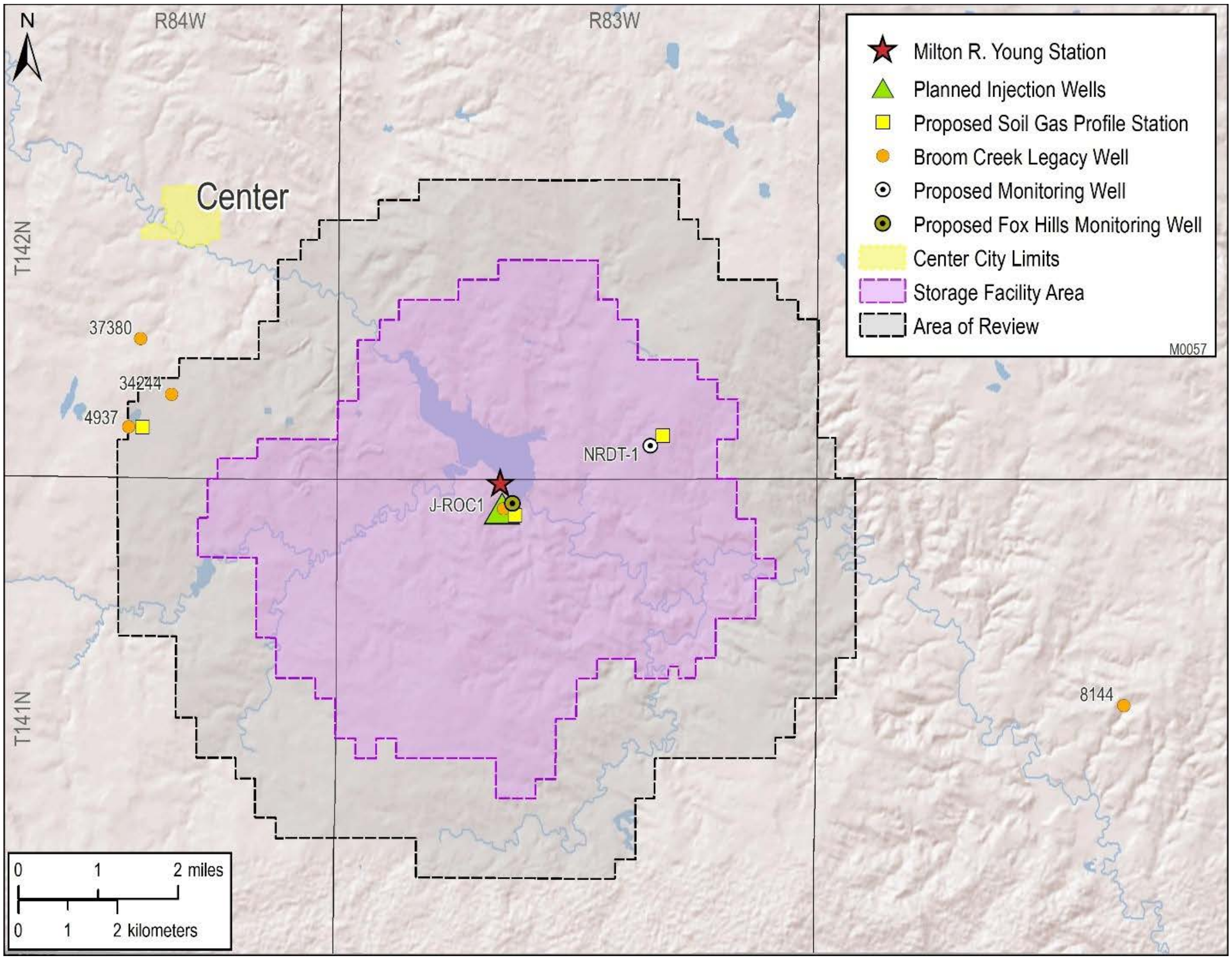


Figure 4-3. Minnkota will install soil gas profile stations and complete an initial soil gas-sampling program to establish baseline soil gas concentrations, including seasonal fluctuation. The sample locations are near the CO_2 injection and deep monitoring wellsites of the Tundra SGS project site.

4.1.7 Near-Surface (groundwater and soil gas)-Monitoring Plan

Prior to injection operations, Minnkota will drill and construct a dedicated groundwater-monitoring well in the Fox Hills Formation (i.e., deepest USDW) at the Liberty-1 (J-ROC1 File No. 37672) CO_2 injection wellsite (Figure 4-4). Baseline Fox Hills Formation water samples will be collected from this monitoring well over a 1-year period prior to CO_2 injection, with the goal of securing these samples during each of the four seasons (spring, summer, fall, and winter). Minnkota plans to monitor the vadose zone by installing three soil gas profile stations: one each near the wellsites of the Liberty-1 (J-ROC1 File No. 37672) CO_2 injection, NRDT-1 deep monitoring well pads (Figure 4-4), and the Herbert Dresser (File No. 4937) wellsite. Minnkota will select a subset of existing groundwater wells, as outlined above, within the AOR boundary for periodic monitoring during CO_2 injection operations and postinjection monitoring (see Figure 4-4).

During the first 3 years of CO_2 injection activities, the Fox Hills Formation monitoring well, soil gas profile stations (near the Liberty-1 [J-ROC1 File No. 37672] CO_2 injection, NRDT-1 deep monitoring wellsites, and Herbert Dresser [File No. 4937] wellsite), and select groundwater wells within the AOR will be sampled on an annual basis. All laboratory results will be filed with NDIC and state water commission. If the results show no significant changes to water chemistry, the well-sampling frequency will be reduced to one sample every 5 years starting at Year 5 of the injection operations for all previously monitored wells.

As the areal extent of the CO_2 plume increases, monitoring of additional groundwater wells within the AOR will be phased in over time based on monitoring of the CO_2 plume in the injection zone. Each additional well will be sampled annually for 3 years. If the results show no significant changes to the water chemistry, the sampling frequency will be reduced to one sample at a 2-year interval and then at 5-year intervals thereafter. A detailed near-surface monitoring plan is presented in Table 4-6, including the frequency and duration of the sampling during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

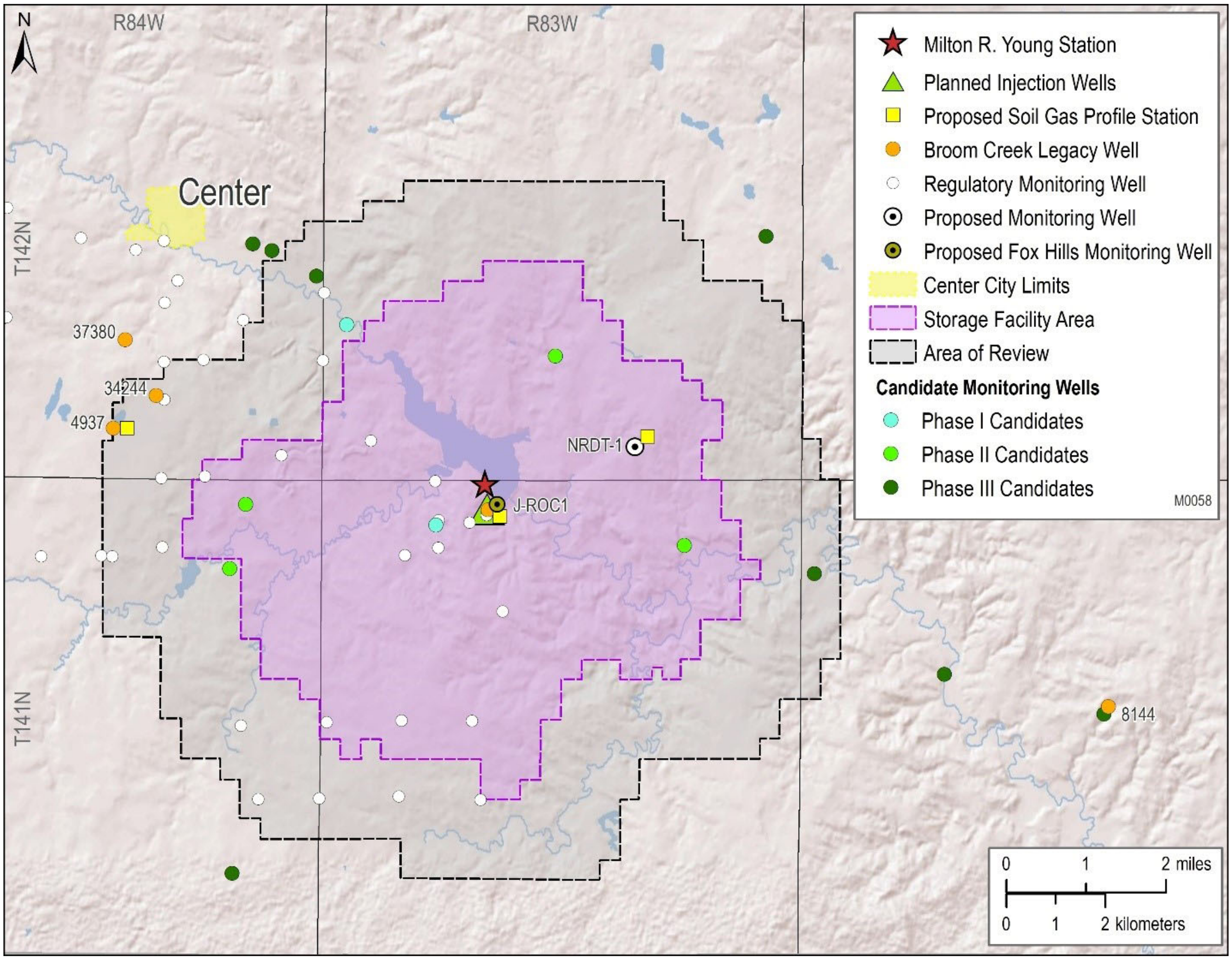


Figure 4-4. Tundra SGS project near-surface monitoring plan sample locations showing the Fox Hills Formation (deepest USDW) monitoring well, candidate groundwater wells to be sampled by monitoring phase, and two soil gas profile stations in and around the Tundra SGS project site.

Table 4-6. 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 Soil Gas Probes	Duration: minimum 1 year Frequency: Sample 3–4 events per well to establish natural seasonal baseline. Soil gas profile stations at each location (i.e., J-ROC1, NRDT-1 deep monitoring well, and Herbert Dresser wellsite) will be sampled prior to initiation of CO_2 injection operations.	Duration: 20 years Frequency: 3–4 sample events per year at soil gas profile station locations (i.e., J-ROC1, NRDT-1 deep monitoring well, and Herbert Dresser wellsite) to account for natural seasonal fluctuation. Additional soil gas probe sampling may be conducted every 5 years based on monitoring and the expansion of the subsurface CO_2 plume in the injection zone.	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas profile station locations (i.e., J-ROC1, NRDT-1 deep monitoring well, and Herbert Dresser wellsite) performed every 3 years following cessation of CO_2 injection.
Water Monitoring			
Groundwater (existing freshwater wells, e.g., domestic water wells, municipal wells, etc.)	Duration: minimum 1 year Frequency: minimum of one sample per year of select groundwater wells within the AOR. Groundwater wells are selected based on location, type, depth, aquifer, etc., to ensure a baseline of each groundwater horizon has been established prior to CO_2 injection.	Duration: 20 years Frequency: Sampling of select groundwater wells within the AOR will occur at a minimum of once per year during Years 1–3. Assuming the data are consistent during the first 3 years, monitoring frequency will decrease to one at a 2-year interval and then repeated at 5-year intervals thereafter. Additional monitoring wells will be phased in over time based on expansion of the subsurface CO_2 plume in the injection zone. Sampling frequency for added wells will follow the same structure as the original wells.	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.
Fox Hills Formation (deepest USDW)	Duration: minimum of 1 year Frequency: 3–4 sample events per well (establish seasonal fluctuation baseline). One Fox Hills Formation monitoring wells (to be installed) located at the CO_2 injection wellsite (J-ROC1).	Duration: 20 years Frequency: Sampling of Fox Hills monitoring well will occur at a minimum once per year during Years 1–3. Assuming the data are consistent during the first 3 years, monitoring frequency will decrease to one at a 2-year interval and then repeated at 5-year intervals 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 under way 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.

4.1.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

Minnkota will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume (plume) and associated pressure front (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 Table 4-7 will be used to characterize the plume and pressure within the AOR. Minnkota's testing and monitoring plan will include periodic reviews in which monitoring and operational data will be analyzed, AOR will be reevaluated and, if warranted, the testing and monitoring plan will be adapted to meet NDIC monitoring requirements.

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 plan is needed or modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and risk profile of the storage operations is addressed moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, these changes will be incorporated into the permit following approval by NDIC. During the operational period, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Early 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. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Tables 4-8a and 4-8b describe the logging programs for the Broom Creek injectors Liberty-1 (J-ROC1 File No. 37672) and Unity-1 (proposed) and monitoring (NRDT-1) wells (Figure 4-5). Included in the table is a description of logs collected. These wellbore data have been integrated with preoperational (baseline) 3D seismic and 2D seismic lines to provide a detailed reservoir and structural description for the geologic model and inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes that are based on the current geologic model and simulations are shown in Figures 4-6 and 4-7. 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.

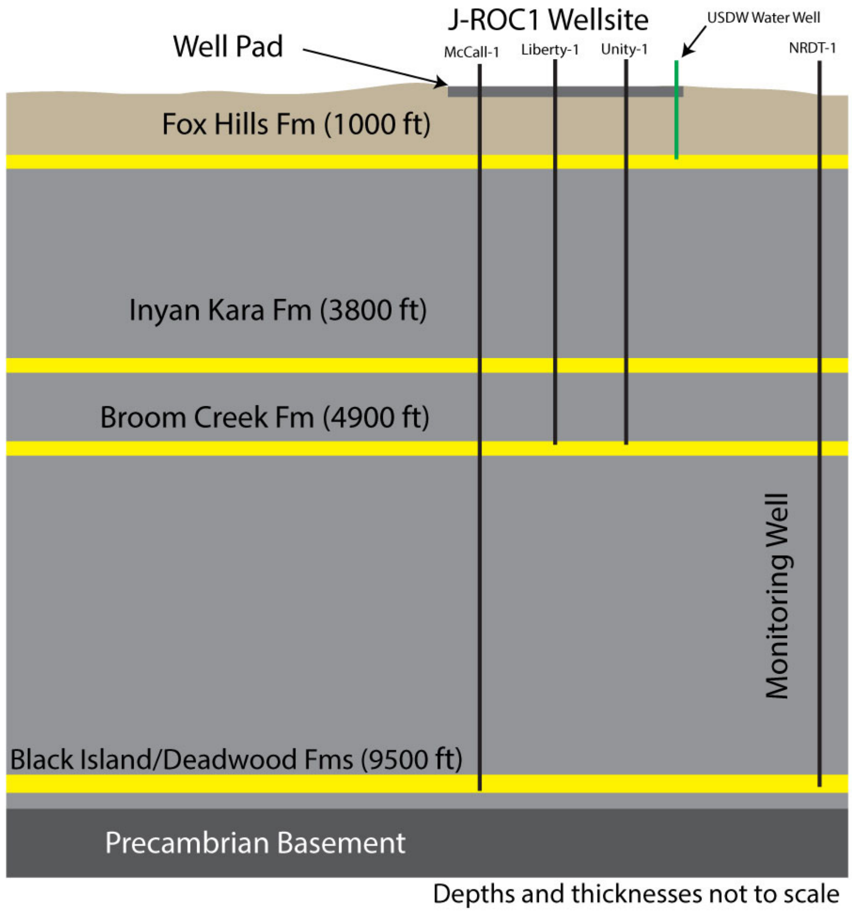


Figure 4-5. Monitoring schematic (not to scale) includes the location of the Broom Creek injectors (Liberty-1 [J-ROC1 File No. 37672] and Unity-1 [proposed]), the Deadwood injector (McCall-1 [proposed]), and the monitoring well NRDT-1 (proposed).

Table 4-7. Description of Tundra SGS Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Storage Reservoir Monitoring			
Injection Well Monitoring (Liberty-1 [J-ROC1 File No. 37672]), Unity-1 (proposed) During Operations: • Flow Rates • Volumes • Surface Injection Pressure • Surface Injectate Temperature • Annulus Pressure Between Tubing and Long-String	Frequency: initial setup The maximum allowable injection pressure and annulus pressure will be derived from preoperational injection tests.	Duration: 20 years Frequency: continuous monitoring	Plug and abandon (P&A) injection well at cessation of injection operations. Continue to monitor annulus pressure in NRDT-1 well.
• 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).	P&A injection well at cessation of injection operations. Monitor fluid levels until well is plugged.
Downhole Pressure Monitoring			
Tubing-Conveyed Pressure and Temperature Gauges in Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed)	Gauges provide baseline temperature and pressure of the injection zone (Broom Creek).	Gauges provide continuous temperature and pressure monitoring of the injection zone (Broom Creek).	Gauges in NRDT-1 (proposed) will provide continuous temperature and pressure monitoring of the injection zone (Broom Creek) until plume stabilization. Monitoring in NRDT-1 (proposed) will continue as part of postinjection site care and facility closure plan.
Wireline Logging and Retrievable Monitoring			
Pulsed-Neutron Log (PNL) Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed)	Baseline PNL logging.	PNL logging to ensure fluids are contained within storage interval and ground-truth 3D seismic monitors once every 5 years (in conjunction with timing of seismic monitor).	Log Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed) at cessation of injection and NRDT-1 once every 5 years thereafter until plume stabilization (in conjunction with timing of seismic monitor).
External Mechanical Integrity: • Casing Integrity Tools (i.e. USIT or EM casing inspection tool) Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed)	Baseline casing inspection logging 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 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 in NRDT-1 well

Continued . . .

Table 4-7. Description of Tundra SGS Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Mechanical Integrity: • Tubing-Casing Annulus Pressure Test	Mechanical integrity test –_internal pressure testing Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed).	Perform during well workovers but not more frequently than once every 5 years in Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed).	Duration: minimum 10 years postinjection Frequency: perform during well workovers but not more frequently than once every 5 years in NRDT-1.
External Mechanical Integrity: • Downhole Temperature	DTS AND baseline temperature logging through the storage interval to surface Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed).	Continuous DTS OR, if fiber fails, annual temperature logging through the storage interval to surface in Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), NRDT-1 (proposed).	Annual temperature logging in NRDT-1 (proposed) until plume stabilization.
Pressure Fall-Off Test (injection zone)	Prior to injection	Every 5 years at Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed)	Prior to P&A
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.	N/A
Geophysical Monitoring			
Time-Lapse Seismic	Existing baseline 2D and 3D seismic integrated into reservoir model for site characterization. Existing 2D and 3D seismic covers the predicted extent of the CO_2 plume in the **early** monitoring of the site.	2D and/or 3D time-lapse seismic and/or AVO (amplitude variation with offset) method implemented within first 5 years of injection sufficient to determine distribution of injected free-phase CO_2 plume relative to permitted area and every 5 years thereafter. If plumes exceed baseline data extents, additional baseline data will be acquired, or 2D or 3D AVO data can be used to monitor plume extents	2D and/or 3D time-lapse seismic and/or AVO method will continue every 5 years as part of minimum 10-year post-CO_2 injection operations monitoring plan and until stability of plume is demonstrated.
InSAR	Feasibility of surface deformation monitoring with InSAR – baseline data.	To be determined. Continuous monitoring of ground elevation based on relative surface deformation with InSAR.	To be determined. Continuous monitoring of ground elevation based on relative surface deformation with InSAR until storage facility closure.

Continued . . .

Table 4-7. Description of Tundra SGS Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Passive Seismicity	Project will plan additional seismometer stations sufficient to confidently measure baseline seismicity 5 km from injection area.	The data collected in the surface seismometers will be continuously recorded and analyzed for potential seismicity magnitudes and hypocenter locations.	N/A

Table 4-8a. Logging Program for Broom Creek Injectors: Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed). Note: Most logs were completed on J-ROC1 (Liberty-1). This logging program is planned for Unity-1 (proposed) and unless otherwise noted in the table.

Log	Justification	NDAC Section
Cased-Hole Logs: ultrasonic CBL (cement bond log), 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,* neutron,* GR, caliper) and SP** (spontaneous potential) *No density or neutron in surface section of Unity-1 (proposed) **No SP on J-ROC1.	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)*** ***No CMR on Unity-1 (proposed)	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])
Temperature Log	Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.	43-05-01-11.2(1c[2])
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 Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])

Table 4-8b. Logging Program for NRDT-1 proposed monitoring well

Log	Justification	NDAC Section
Cased-Hole Logs: Ultrasonic CBL, VDL, GR	Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo and SP *No density or neutron in surface section	Quantify 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])
Temperature Log	Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.	43-05-01-11.2(1c[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])

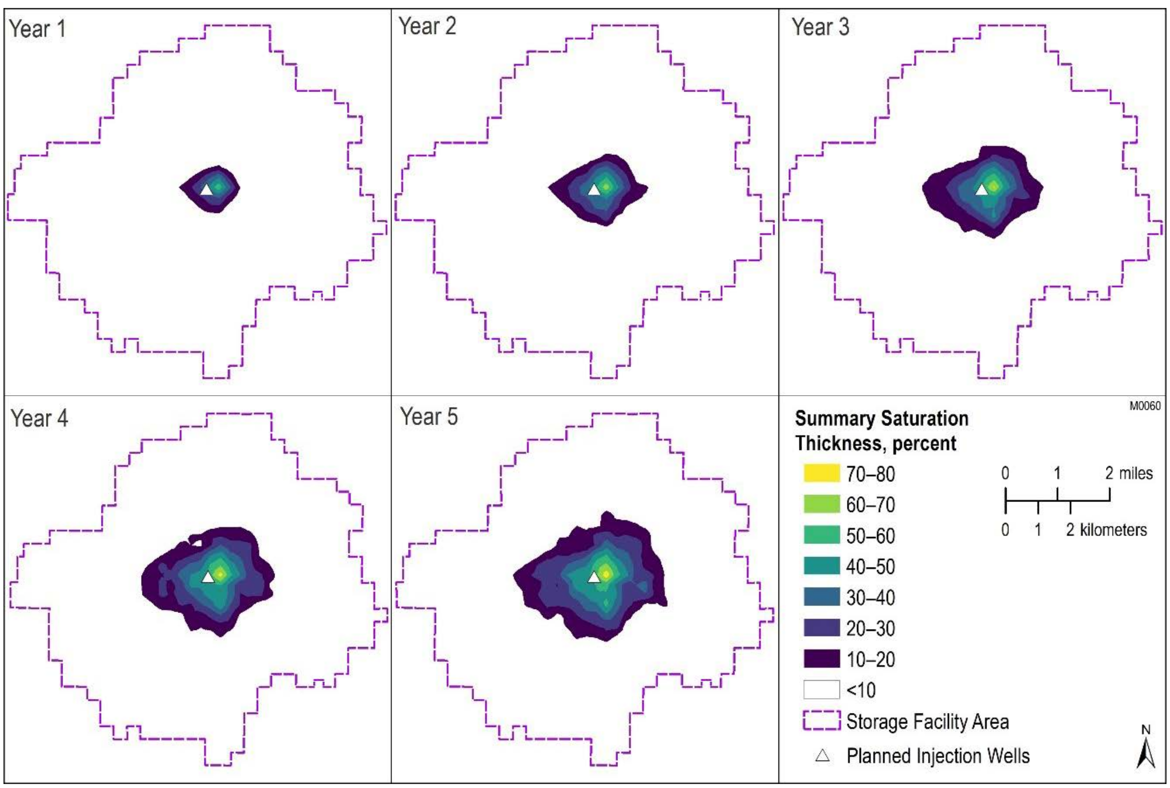


Figure 4-6. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection.

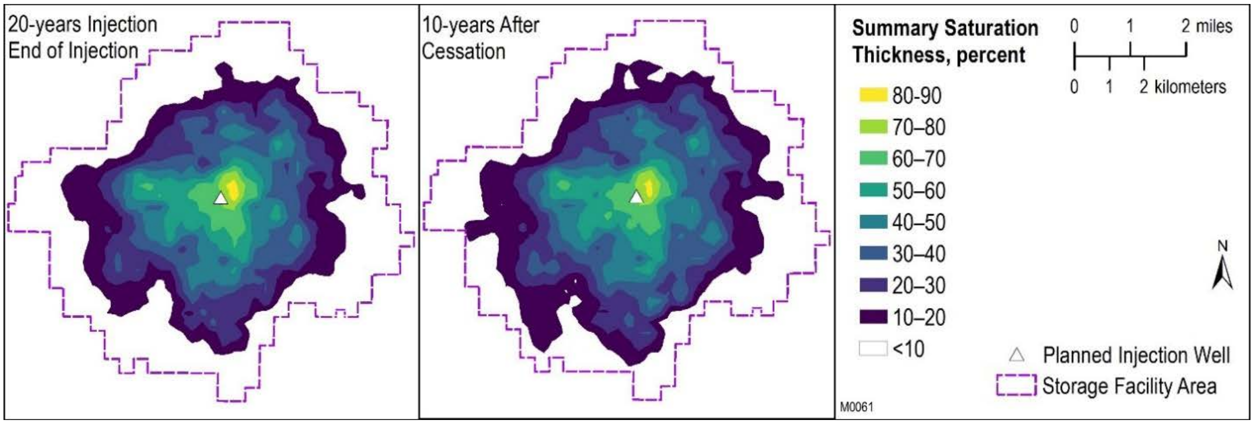


Figure 4-7. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

4.1.8.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, the injection wells (Liberty-1 [J-ROC1 File No. 37672], Unity-1 [proposed]) and monitoring well (NRDT-1) will be equipped with tubing-conveyed temperature (borehole temperature) and pressure (borehole pressure) gauges as well as distributed fiber optics systems (see Figures 4-8 and 4-9). Continuous reservoir temperature and pressure will be monitored in the Broom Creek Formation and temperature in the overlying confining zone. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, which provides sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

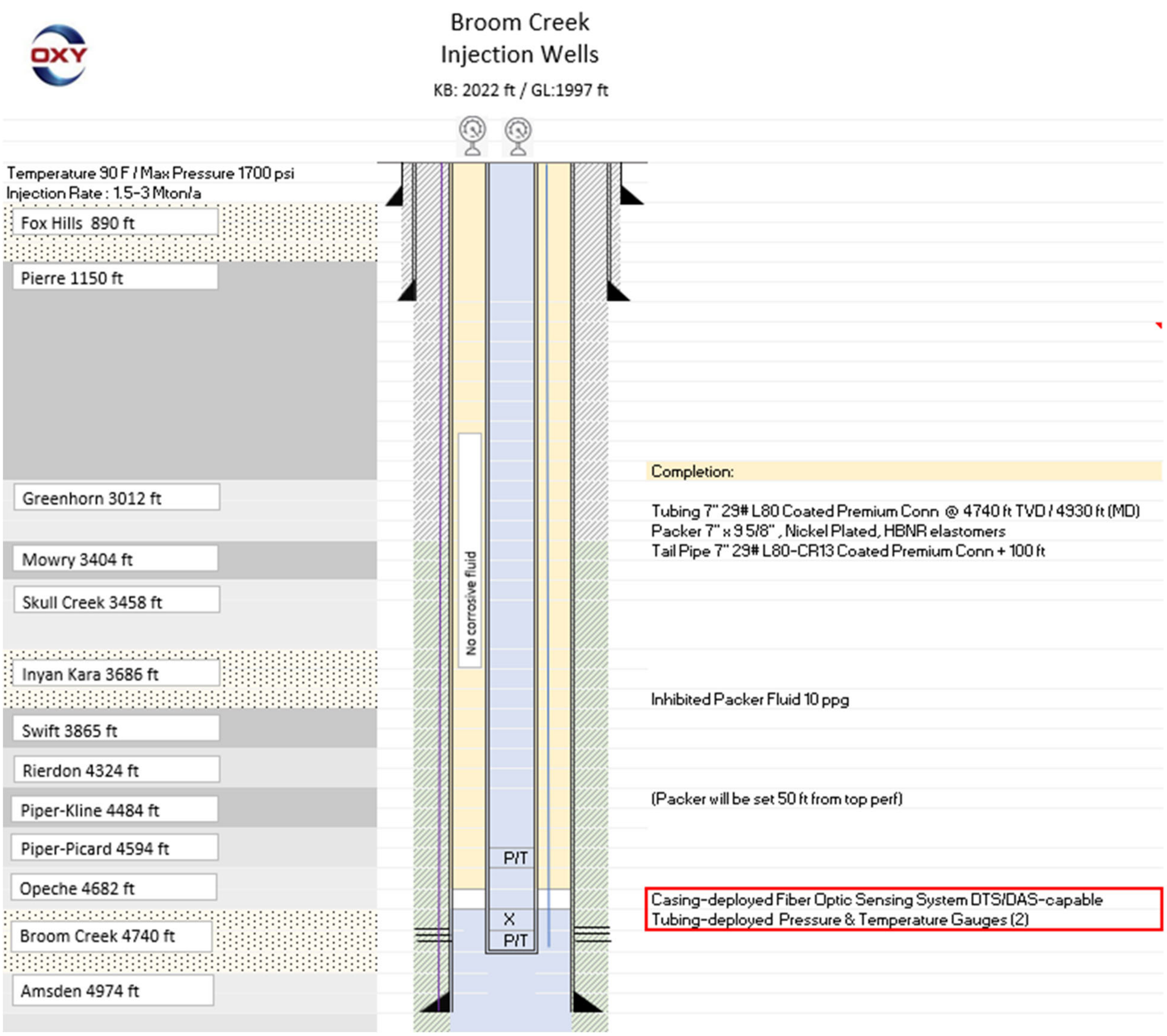


Figure 4-8. Broom Creek injection wellbore schematics showing placement of tubing-deployed pressure and temperature-monitoring gauges and casing-deployed fiber optic sensing system (DTS/DAS-capable).

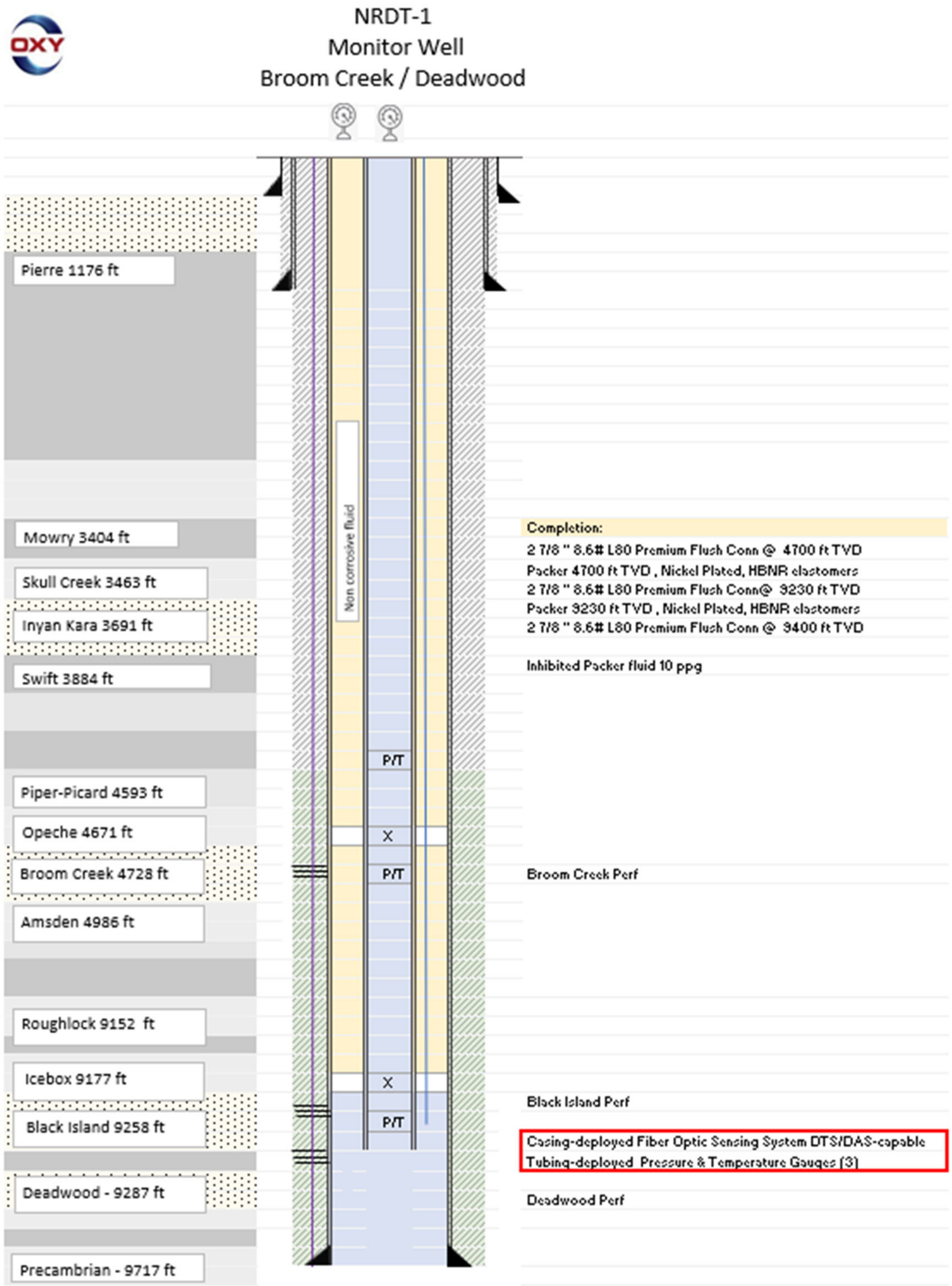


Figure 4.9. Broom Creek and Deadwood monitoring wellbore schematic showing placement of tubing-deployed pressure and temperature-monitoring gauges and casing-deployed fiber optic sensing system (DTS/DAS-capable).

The fiber optic system installed within the Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), and NRDT-1 (proposed) monitoring wells will be used to acquire continuous high-resolution temperature data. PNLs of the injection and monitoring wells will also be performed on a 5-year schedule to demonstrate that fluids are not moving beyond the sealing formations. Preoperational baseline PNL data will be collected in the injection and monitoring 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.

4.1.8.2 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 4-10 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, repeat 2D and/or 3D seismic surveys (4D seismic) will be collected to monitor the extent of the CO_2 plume within the first 5 years of CO_2 injection.

The seismic surveys will also be interpreted for an AVO response for detecting seismic response related to the CO_2 plume. In later years of the operational period (e.g., 10–20 years), if the free-phase CO_2 plume falls outside of the baseline 3D outline, AVO methods with 2D and 3D prestack seismic can be implemented as a stand-alone method for monitoring CO_2 migration. If it is found that the AVO method is not effective, the baseline 2D and/or 3D will need to be extended for sufficient time-lapse coverage. These seismic monitoring data will provide confirmation of the simulation predictions and confirm the extent 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 and or AVO methods will be utilized during the postinjection period to confirm stabilization of the plume, as defined in Appendix A. The monitoring plan will be reevaluated at least every 5 years to determine if the testing and monitoring plan is sufficiently characterizing the migrating CO_2 plume.

The time-lapse seismic response (4D seismic) and AVO methods will provide measurements of the change in fluid compressibility. Since CO_2 is a highly compressible fluid, it can be tracked with conventional seismic methods. Borehole seismic (3D vertical seismic profile [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 extent of 3D VSP coverage for the Broom Creek Formation will be limited relative to the predicted plume extents. The 3D VSP method should be implemented early in the operational period (i.e., within the first 5 years) when the simulated plume extent is predicted to be well within the possible 3D VSP coverage. The maximum radius of the 3D VSP image area, as a rule of thumb, can be estimated to be approximately the equivalent of the depth of the formation being imaged. Once the radius of the injected plume exceeds the depth to the Broom Creek Formation (~4,800 ft), the 3D VSP recorded in the injection well will not adequately monitor the plume. At this point, surface seismic (i.e., 4D seismic and/or AVO) is an appropriate method for monitoring the advancing plume.

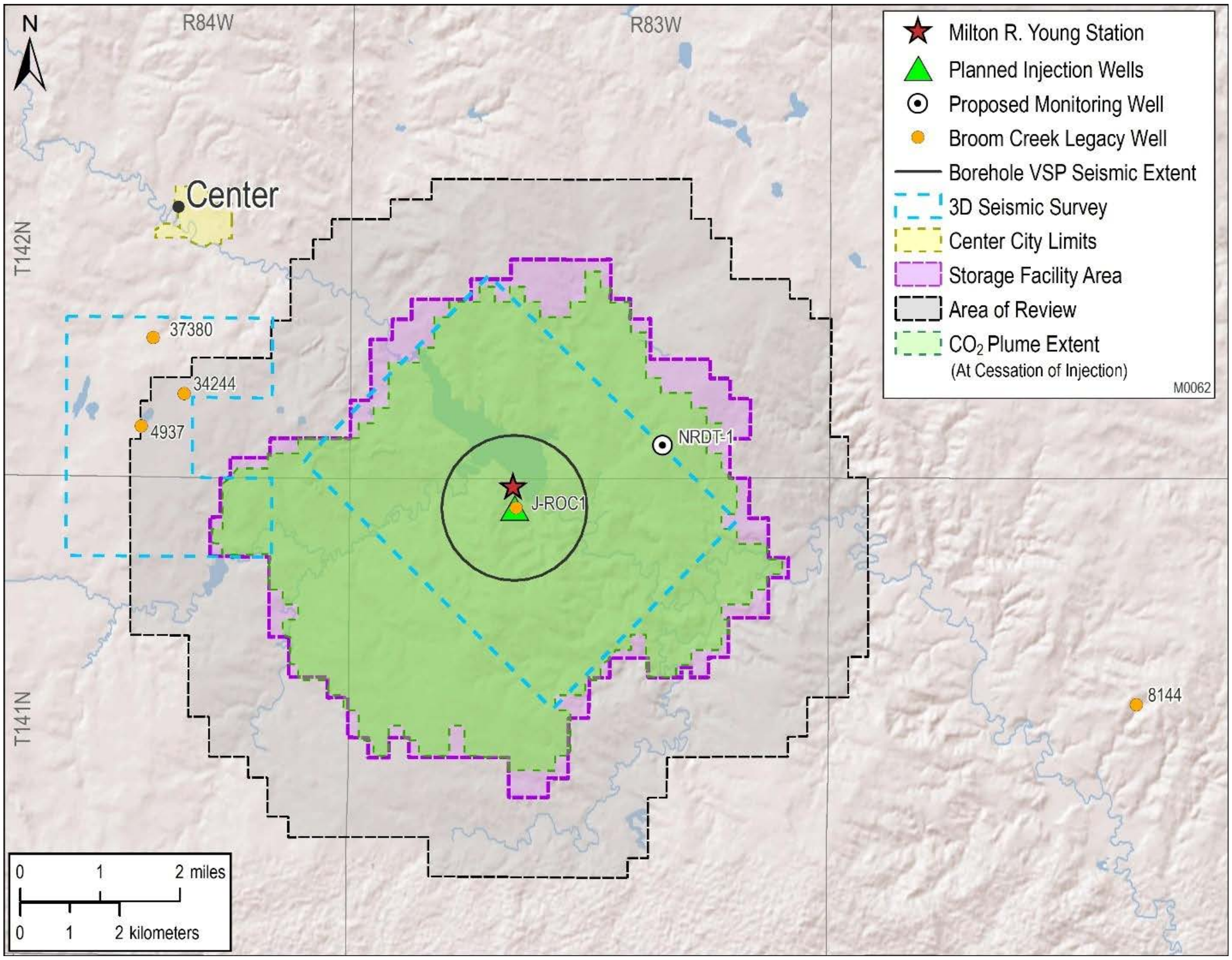


Figure 4-10. Simulated extent of the CO_2 plume at the end of injection operations in green. Surface seismic and borehole VSP seismic data outlines that are shown on the map will provide coverage for indirectly monitoring the predicted extents of the CO_2 plume over time.

Throughout the operational phase of injection operations, continuous monitoring of seismicity will be performed. Existing seismometer stations and additional stations will be installed ("array" of surface seismometers) sufficient to confidently measure baseline seismicity 5 km from injection. The data collected in the surface seismometers will be continuously recorded and analyzed for potential seismicity magnitudes and hypocenter locations. These seismometer stations with broadband sensors 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 (Vasco and others, 2020), which can detect small-scale surface ground deformation, has been shown to be one such technique for approximately mapping pressure distribution associated with subsurface fluid injection (Reed, 2021). 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 (Vasco and others, 2020). In areas where there is snowfall, agricultural changes, or erosional features, 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.

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 within 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.

4.1.9 Quality Control and Surveillance Plan

Minnkota has developed a quality control and surveillance plan (QCSP) as part of the testing and monitoring plan. The QCSP is provided in Appendix D of this permit.

4.2 Emergency and Remedial Response Plan

Minnkota developed a comprehensive emergency and remedial response plan (ERRP) for the Tundra SGS site indicating what actions would be necessary in the unlikely event of an emergency at the Tundra SGS site or within the AOR. The ERRP describes the potential affected resources and provides that site operators know which entities and individuals are to be notified and what actions need to be taken to expeditiously mitigate any emergency and protect human health and safety and the environment (HSE), including USDWs.

This ERRP describes actions the operator of Tundra SGS shall take in the event of an emergency that could endanger any USDW within the project AOR during construction, operation, or postinjection site care. Such events may include unplanned CO_2 release or detection of unexpected subsurface movement of CO_2 or associated fluids in or from the injection zone.

This ERRP incorporates the risk analysis and evaluation of Tundra SGS, including monitoring wells, monitoring system, injection well network, and CO_2 flowline from the capture facility to the storage site. The ERRP is provided in Appendix E of this permit.

4.2.1 Description of Project Area

The Tundra SGS site includes mostly land associated with the coal-mining operation of BNI Coal, the area where MRYS is located, and land primarily used for agriculture activities (Figure 4-11). The closest highly populated area is Center, North Dakota, which is approximately 3.3 mi northwest of the Tundra SGS site.

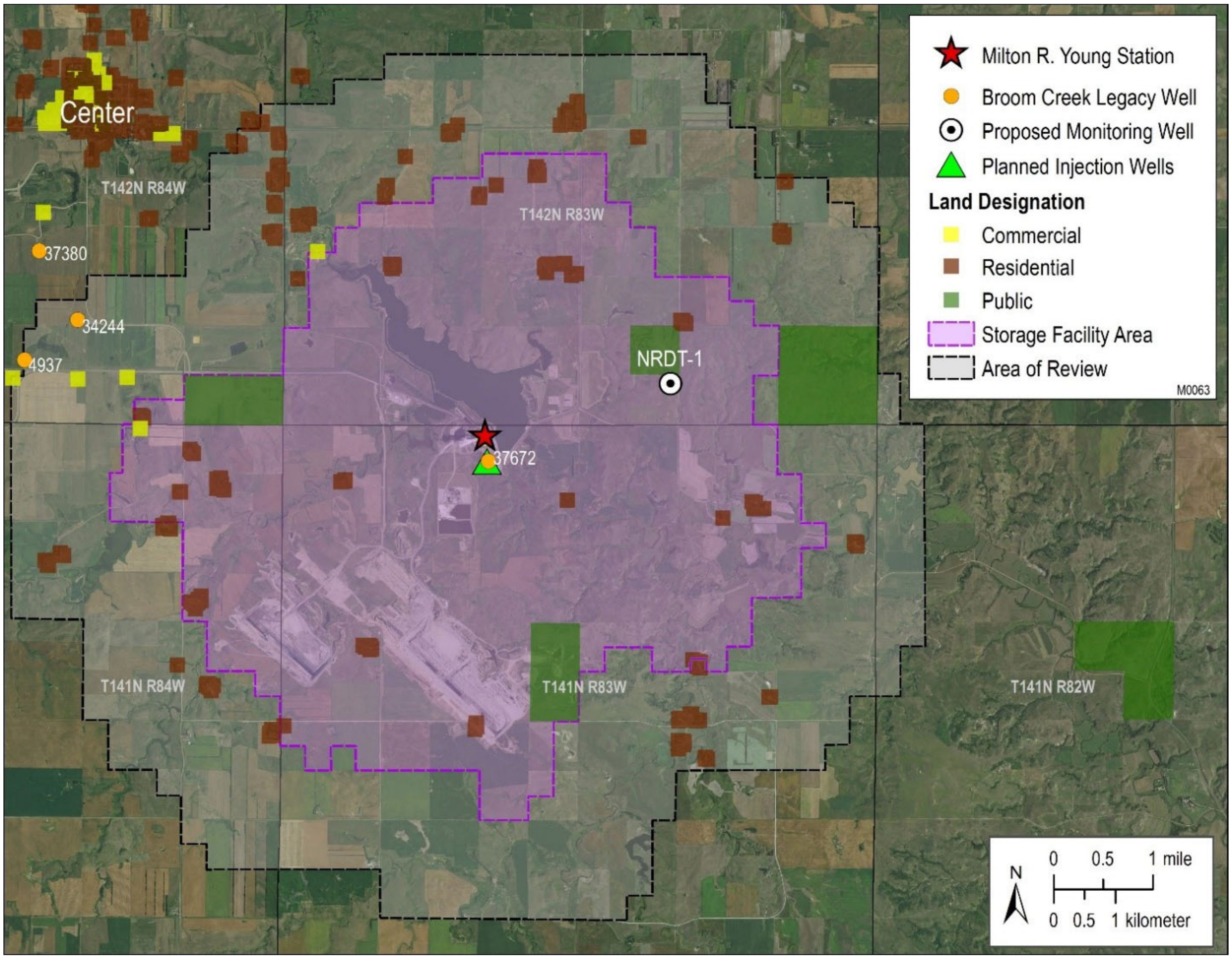


Figure 4-11. Residential, commercial, and public land use within 1 mi of the storage facility boundary.

The Tundra SGS project area consists of existing groundwater wells varying in type/use and located in shallow aquifers ranging in depth. There are two wells that penetrate the Fox Hills Formation (deepest USDW) and will be sampled (preinjection, operational, and postoperational) for periodic monitoring (ID 14108411AA, ID 14208424BBA). In addition, Minnkota will be installing a Fox Hills Formation monitoring well at the injection wellsite. Detailed information on the freshwater resources and protection of USDWs in the AOR can be found in Section 3.4, Protection of USDWs.

Section 2.6 in the Geologic Exhibits addresses any potential mineral zones within the project area.

4.2.2 Risk Identification and Severity

Several scenarios could activate an emergency response. This ERRP considers any adverse incident with the potential of causing personal injuries, USDW contamination, or property damage as an "event." The scope of response, actions, and order of activities will be proportional to the severity and impacts of the event and implemented as outlined in this ERRP. The events identified during technical reviews for the Tundra SGS are listed in Table 4-9. Appendix E contains a response protocol for each event identified in Table 4-9. The protocols may be modified and refined based on the specific circumstances and conditions of the event as well as any discussion with governmental authorities having jurisdiction.

Table 4-9. Risk Category Matrix

Construction Period • Well control event while drilling or completing the well with loss of containment • Movement of brine between formations during drilling • Presence of H_2S while drilling or completing the well
Injection Period • Loss of mechanical integrity (flowlines, injection, monitoring wells, disposal well) • Loss of containment (LOC): vertical migration of CO_2/brines via injection wells, monitor wells, Class I wells, P&A wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in flowlines, wells, and infrastructure • Monitoring equipment failure or malfunction • Induced seismicity • Seismic event • Other natural disaster
Postinjection Site Care Period • Loss of mechanical integrity (monitoring wells) • LOC: vertical migration of CO_2/brines via monitoring wells, Class I wells, P&A wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in monitoring wells • Monitoring equipment failure or malfunction • Natural seismicity • Other natural disaster

Event severity is classified as major emergency, serious emergency, and minor emergency, according to the Table 4-10 description.

Table 4-10. Severity Matrix

Consequence Degree of Severity	Definition
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. Example: well blowout while injecting
Serious Emergency	Event poses potential serious (or significant) near-term risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken. Example: malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure. Example: higher pressure reading observed in monitoring wells, with no potential to move fluid

If information from the monitoring network, alarm system, field operators, or external reports evidences a potential leak of CO_2 or formation fluids from any well or surface facility including any pressure change or monitoring data which indicate the presence of a leak or loss of containment from the storage reservoir or concern for the mechanical integrity of the system, the following actions will be taken:

1. The project will activate the emergency and remediation response protocol consistent with this ERRP and circumstances of the event.

2. The NDIC Department of Mineral Resources (DMR) Underground Injection Control Program director (UIC program director) will immediately be notified within 24 hours of the event being discovered.

The UIC program director may allow the operator to resume injection prior to remediation if the storage operator demonstrates that the injection operation will not endanger USDWs.

4.2.3 Response Protocols

Discovery of an event triggers the corresponding response plan proposed herein. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator will address an event immediately and, when required, will communicate the event to the UIC program director within 24 hours of discovery.

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

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

For each of the scenarios identified in the risk screening, a detailed description of mitigation and monitoring techniques is included in Appendix E.

4.2.4 Emergency Contacts

If an event is discovered, the Tundra SGS superintendent and HSE supervisor on duty will be notified immediately. The superintendent will be responsible for notifying off-site emergency response agencies and resources (Table 4-11). The superintendent shall also be responsible for notifying the UIC program director (Table 4-12) within 24 hours of initial discovery. Additional emergency response providers are listed in Table 4-13.

Table 4-11. Outside Emergency Response

	Agency	Location	Phone
Fire	Oliver County Rural Fire Protection District (volunteer department)	106 East Main Street, Center, ND	Phone: 911 or 701.794.3210
Ambulance	Oliver County Ambulance Service (volunteer basic life support service)	111 Main Street, Center, ND	Phone: 911 Ambulance Garage 701.794.8828 Cell 701.220.1329
Helicopter Air Care (MRY ERT trains with Sanford AirMed and can request if needed, based on emergency)	Sandford AirMed	Bismarck, ND	Phone 911 or Sandford AirMed Dispatch 1.800.437.6886 Sioux Falls, SD, Office 844.424.7633
State Police	North Dakota Highway Patrol	600 East Boulevard Avenue, Bismarck, ND	Phone: 911 or State Radio Dispatch 701.328.9921 Office 701.328.2447
Sheriff	Oliver County Sheriff Dave Hilliard	PO Box 362, Center, ND	Phone 911 or Office 701.794.3450
Emergency Response Team (ERT)	MRYS Emergency Rescue Team	3401 24th Street Southwest, Center, ND	Phone 701.794.8711 or use the Plant Gaitronics intercom system to call “U1 Control Room” and report the emergency. The operator will sound the alarm for the ERT.

Table 4-12. NDIC DMR UIC Contact

Company	Service	Location	Phone
NDIC DMR	**Class VI/CCUS Supervisor**	Bismarck, ND	**701-328-8020**

Table 4-13. Potential Contractor and Services Providers (name available)

Company	Service	Location	Phone
Baranko Brothers	Excavation & Dirt Work/Hauling	Dickinson, ND	701-690-7279
Cyclone	Drilling rig	Gillette, WY	307-660-2370
Enerstar	Housing & Rentals	Bismarck, ND	701-934-1557
GeothermEx	Site Management/Drilling Supervisor Services	Houston, TX	281-769-4517
Schlumberger	Cementing,	Denver, CO	720-272-5288
	Core Analysis	Houston, TX	801-232-5799
	Direction & Measurements	Denver, CO	484-522-8434
	Products & Services	Denver, CO	517-755-9050
	Cameron Surface	Denver, CO/Minot, ND	970-260-4260
	Bits	Denver, CO/Williston, ND	303-518-6135
	Completions	Houston, TX	440-391-2711
Reservoir Group	Coring	Denver, CO/Houston, TX	832-350-5292
Rud Oil	Diesel	Center, ND	701-794-3165
Go Wireline	Wireline Tool/Fishing Services	Dickinson/Williston, ND	406-480-1086
MI SWACO	Drilling Fluids		661-549-3645
Sunburst Mudlogging	Logging/Geologic Services	Billings, MT	406-860-1228
Innovative Solutions	Solids Control	Williston, ND	701-770-0359
WellPro Inc	Fishing Equipment	Dickinson, ND	701-227-3737
Creek Oilfield Services	Waste Disposal/Casing Runnig/Supply	Williston/Bismarck, ND	701-590-5859 715-563-7543
Environmental Solutions	Cuttings Disposal	Belfield, ND	701-300-1156
Waste Management	Trash	Bismarck, ND	701-214-9741
ASK Transportations	Bulk fresh Water	Williston, ND	701-580-5627
Darby Welding	Welding	Dickinson, ND	701-483-5896
Panther PPT	Bop testing	Watford, ND	701-227-3737
Wyoming Casing	Casing Services	Williston, ND	701-290-8522
CCS	Tank Farm	Cody, WY	701-260-7780
MVTL Lab	Formation Fluids Collection	Bismarck, ND	701-204-5478
Petroleum Services	Casing (Float, Centralizer)	Williston, ND	701-770-1763

4.2.5 Emergency Communications Plan

Prior to the commencement of CO_2 injection operations, the Tundra SGS operator will communicate in writing with landowners living adjacent to the storage site to provide a summary of the information contained within this ERRP, including but not limited to information about the nature of the operations, operator contact list, potential risks, and possible response approaches.

An emergency contact list will be maintained during the life of the project. In the occurrence of an event, the superintendent will start the contact list and make sure that responsible, essential personnel are contacted. The operator's designated personnel will handle all event communications with the public.

The Tundra SGS operators will communicate adequate information to the public about any event to allow public understanding to the extent reasonably practicable, considering the circumstances leading to the event and any known environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate based upon the circumstances and severity of the event, which may include, but is not limited to:

1. Event description and location.
2. Event investigation process and response status (e.g., actions taken).
3. Whether there is any known impact to the drinking water or other environmental resources.
4. Any known injury to person or property.

For protracted responses (e.g., passive monitoring or ongoing cleanups), the project will provide periodic updates on the progress of the response action(s).

4.2.6 ERRP Review

ERRP will be reviewed no less than:

a. Annually.
b. Following any significant changes to the Tundra SGS facility, such as AOR reevaluation or addition of injection or monitoring wells, on a schedule determined by the UIC program director.
c. When required by the UIC program director.

If the review indicates that no amendments to the ERRP are necessary, the Tundra SGS operator will provide the documentation supporting the "no amendment necessary" determination to the UIC program director.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to Tundra SGS as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

4.3 Financial Assurance Demonstration Plan

The FADP has been prepared in accordance with NDAC § 43-05-01-09.1. The FADP describes actions the operator of Tundra SGS has taken and shall take to ensure state and federal regulators that sufficient financial support is in place to:

a) Cover the cost of any corrective action that may be required at the geologic storage facility during any of its phases of operation, well plugging, postinjection site care and facility closure, ERR, and endangerment to USDWs.

b) Provide funds for routine monitoring and reporting activities by Minnkota during injection operations, closure activities, and an extended postclosure period as determined by regulatory agencies.

While there are two separate proposed storage reservoirs, these two separate reservoirs are commonly operated as dedicated Tundra SGS for a single CCS facility. The FADP was prepared to account for the entire operation of the Tundra SGS.

This FADP takes into account Tundra SGS storage facility permits and associated Class VI drilling permits in satisfying NDIC regulations contained in Title 43, Chapter 5, et seq. In preparing the FADP, U.S. Environmental Protection Agency (EPA) guidance was also considered in assessing the effectiveness of multiple qualifying financial instruments in the context of the Tundra SGS project, e.g., key aspects of long-term public confidence, optimization of stakeholder interests, and practicality of implementation.

Based on review and consideration of the available financial instruments contained in NDAC § 43-05-01-09.1, Minnkota proposes to use a combination of commercial insurance and a trust fund to fulfill the FADP requirements of the project Class VI permits. The details contained in this FADP along with supporting documentation establish the approach Minnkota proposes to use to meet the financial responsibility requirements and that each of these instruments sufficiently addresses the activities and costs associated with the corrective action plan, injection well-plugging program, postinjection site care and facility closure, ERRP, and endangerment of USDWs.

Each of these instruments is described in full in subsequent subsections of this FADP and in Appendix G. Information related to the financial instruments will be updated on an annual basis and submitted to NDIC for review and approval as required under NDAC § 43-05-01-09.1.

4.3.1 Approach to Meeting Financial Responsibility Requirements

In accordance with the requirements contained in NDAC § 43-05-01-09.1, the FADP provides financial assurance sufficient to cover the activities identified in the corrective action plan, injection well-plugging program, postinjection site care and facility closure, ERRP, and endangerment of USDWs. The following provides a summary description of the considerations and assessment approach for each component.

4.3.1.1 Corrective Action

According to § 43-05-01-05.1, corrective action involves inventorying and characterizing existing wells in the proposed AOR. The objective of corrective action assessment is planning actions to take, prior to and over the course of the project operation, on existing wells in order to proactively prevent the movement of fluid into or between USDWs. The detailed AOR can be found in Section 3.0 of this application. Minnkota has determined and asserts that there are no wells in the proposed AOR to which corrective action would be required prior to or during the course of the project operation or postclosure period. For the avoidance of doubt, if wells proposed as part of the Tundra SGS site operation require corrective action, such action and the costs relating thereto are included as part of the project operating cost.

4.3.1.2 Injection Well-Plugging Program

The plugging of injection wells as part of site program closure and as required by NDAC § 43-05-01-11.5 is included within the project cost and is covered within this FADP plan and proposed instruments. The specifics of the plugging program can be found in Section 4.6. Costs were estimated using work scopes provided by third-party industry experts and comparable actual third-party costs for performance of services and procurement of associated goods. These costs shall be disbursed through the trust as described herein, while the amount associated with well plugging shall be funded following commencement of the operation of the wells. The estimate covers the aggregated cost of P&A three injector wells, including rig mobilization, rig rentals, cementing, logging, and haulage. To ensure a conservative estimate, a 20% contingency was added, and no deductions were made for salvage value of materials.

4.3.1.3 Postinjection Site Care and Facility Closure

Postinjection site care (PISC) and facility closure cost estimates include site monitoring and periodic reassessment of the AOR, facilities maintenance and power costs, and overhead and support costs. Details of the activities and actions contained in the PISC can be found Section 4.0. The largest element of the PISC cost estimate relates to seismic studies, which are required to be carried out at 5-year intervals to validate seismicity models, which are expected to cover an area up to 25 mi^2.

4.3.1.4 Emergency and Remedial Response

The ERRP and associated detailed assessment can be found in Section 4.0. The ERRP assessment supports a determination that the likelihood of release of significant volumes of CO_2 from underground storage into the soil or the atmosphere, or significant volumes of saltwater into the environment, are considered remote. Multiple factors were considered in the development of the ERRP, including:

a) Extensive and independently verified analysis of the integrity of the storage mechanism.
b) Selection of qualified and experienced storage facility operator.
c) Selection of qualified and experienced drilling contractor.

Risk mitigation measures include:

a) Location of injection facilities away from urban population and in an industrial-zoned, brownfield property.
b) Continuous monitoring of transportation and injection systems.
c) Routine measurement and reporting of CO_2 volumes.

d) Physical security, barriers, and signage around injection facilities.
e) Primary and secondary containment for leaked fluids at injection well pads.

In the interest of providing sufficient financial assurance, Minnkota has compiled cost estimates associated with a conservative hypothetical scenario wherein a significant volume of briny water migrates to the surface during injection operations. The scenario contemplates a reactive response approach, e.g., mobilization of response personnel and equipment upon discovery of such an event. This approach is considered appropriate because of the remoteness of the residual risk. Specific postoccurrence action is not determinable until occurrence; thus actual response to such an event would be based on its severity. Because of the remote likelihood, this single conservative scenario was compiled to account for the outer-limit cost estimate to satisfy event response. The scenario used for cost estimating assumed the optimal operating conditions (10 years of operation) requiring outer-limit response and remediation costs. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP document.

Upon authorization from NDIC to begin injecting CO_2 under the Class VI well permit(s), Minnkota must be prepared to undertake any emergency or remedial response (ERR) actions, although such actions are unlikely to be needed. Minnkota proposes that the account associated with the ERR account should be funded with an initial amount sufficient to cover the costs associated with the ERR activities upon issuance of authorization to operate a Class VI injection well. Minnkota proposes an initial funding of an amount equal to the net of the cost estimate for ERR activities less the calculated 12-year commission fee based upon the projected annual average injection rate of 4 MMt, $2,120,000.00. Minnkota will fully fund the ERR activities with seven equal installments annually of $548,572.00 made in the injection period, with the first installment prior to the 1-year anniversary of NDIC's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $5,960,000.00.

4.3.1.5 Endangerment of Drinking Water Sources
As discussed in the ERRP subsection, the risk of endangerment to USDWs is considered remote. However, as part of the reactive response scenario contemplated in the ERRP cost estimate, Minnkota assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water. Because of precautions taken in the design for spill control and pollution prevention, the well pad design incorporates two liners and a berm that, in combination with the response strategy, would minimize this portion of environmental repair. Thus Minnkota assessed the second reactive scenario, which contemplates a subsurface leak scenario. This subsurface leak scenario has primary costs related to groundwater delineation and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken.

4.3.2 Approach to Financial Risk
Minnkota formed a task force (TF) to understand and quantify project risks. The TF consisted of 14 members with relevant professional qualifications and experience in subsurface analysis, facilities engineering, drilling engineering, operations, finance, environmental protection, or risk engineering. The TF identified and quantified the likelihood and impact of multiple risks using industry-standard methodology and methods. Four working sessions, each between 3 and 4 hours in duration, were conducted, and the TF reached consensus on the assessment of risks underlying

various aspects of the project. The findings of the TF support the understanding of financial risks and the approach to FADP described in this document.

4.3.3 Selected Elements of Minnkota's Analysis of Inherent Risks

The projected AOR includes mostly land associated with the coal-mining operations of BNI, the area where MRYS is located, and land primarily used for agriculture activities. Residents and man-made structures are scattered across the surface. The closest highly populated area is the town of Center, North Dakota, approximately 3.3 mi northwest of the proposed Tundra SGS facility boundary.

From the surface to the lowermost USDW—the Fox Hills Aquifer—the groundwater is considered a protected aquifer with <10,000 ppm TDS. The Fox Hills base is estimated at approximately 1,000 ft and is followed by a thick section of clays with a thickness of approximately 2,600 ft. These clays act as a seal until the next major permeable zone, the Inyan Kara. The Inyan Kara is an underpressured formation that is classified as an exempt aquifer under NDCC § 43-02-05-03 west of the 83W range line, and this formation is mostly targeted for water disposal wells in those areas. Approximately 900 ft of cap rock acts as a main seal between the Inyan Kara zone and the shallowest of the two injection reservoirs, the Broom Creek.

Inside the AOR, 64 water wells are located in shallow aquifers, providing water for the associated farms' livestock, irrigation, and localized consumption. Two wells that penetrate the Fox Hills Formation will be used as tools for monitoring the USDW (ID 14108411AA and ID 14208424BBA). The project will install one additional USDW well, as described in the monitoring plan, to sample underground water.

There are no producible mineral, oil, natural gas, or other reserves reported in the AOR for the Broom Creek Formation or overlying formations. As described in the AOR and corrective action section, for the Tundra SGS storage reservoir and drilling applications, there are three deep wells (one oil and gas [O&G] exploration, two stratigraphic) within or in proximity to the plume boundaries and the identified pressure front. These wells are identified as BNI-1 (API 33065000180000), Herbert Dresser 1-34 (API 33065000050000), and J-LOC1 (33065000190000). J-LOC1 will be converted to a pressure-monitoring well for Tundra SGS or will be permanently abandoned, and the other two wells were analyzed and included in the risk assessment as well as in the corrective action plan.

4.3.4 Cost Estimates

Tables in this section provide a detailed estimate, in current dollars, of the cost of performing corrective actions on wells in the AOR, plugging the injection well, postinjection site care and facility closure, and ERR. Table 4-14 is a summary of the cost estimates underlying the FADP document, identifying proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of Minnkota's intent and ability to fulfill its responsibilities.

Cost estimates assume that these costs would be incurred if a third party was contracted to perform these activities. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the postinjection period, e.g., the use of postinjection seismic surveys.

Table 4-14. Potential Future Costs Covered by Financial Assurance in $K

Activity	Total Cost	Covered by Special-Purpose Trust	Covered by Commercial Insurance	Details in Supporting Table
Corrective Action on Wells in AOR	$0	$0	$0	NA
Plugging Injection Wells	$2,025	$2,025	$0	Table 4-14-1
Postinjection Site Care	$10,285	$10,285	$0	Table 4-14-2
Site Closure	$1,554	$1,554	$0	Table 4-14-3
Emergency and Remedial Response	$16,560	$5,960	$10,600	Table 4-14-4
Endangerment of USDWs	$2,240	$0	$2,240	Table 4-14-5
Total	**$32,664**	**$19,824**	**$12,840**	

The values included in the FADP are based on cost estimates provided during the permit application development process and are based on the hiring of a third party to perform the services or procurement of goods associated with performance. Costs estimates are based upon historic price data from other projects managed by Oxy Low Carbon Ventures (OLCV), cost quotes from third-party companies, regulatory guidance documents, and professional judgment about the level of effort required to complete an activity. These values are subject to change during the course of the project to account for inflation of costs and any changes to the project that affect the cost of the covered activities. If the cost estimates change, Minnkota will adjust the value of the financial instruments, and any adjustment will be submitted for approval by NDIC as required under NDAC § 43-05-01-09.1(3).

Tables 4-14.1 through 4-14.6 provide detailed breakdowns of the future cost estimates provided in Table 4-14.

Table 4-14-1. Plugging Injection Wells

Activity	Cost
Mobilization and Location	$435,000
Rig Rates and Daily Cost	$467,000
Hauling and Disposal	$57,000
Balance of Plant	$
Hydrostatic Testing and Scanning	$
Pipe Rental	$
Bit and Scrapers	$
Logging	$105,000
Casing Crew and Torque	$40,000
DST Service and Manifold	$
Sensors and Fiber Optic	$60,000
Cementing	$353,000
Perforating Cost	$
Pumping Truck and Acid	$
Wellhead Service	$60,000
Tangibles	$
Subtotal	**$1,577,000**
Contingency	**20%**
Tax	**7%**
Total Cost	**$2,025,000**

Notes:
- Costs are based on estimates of current contract day rates and materials.
- Costs are based on P&A of a total of three injector wells: two in the Broom Creek Formation and one in the Deadwood Formation.

Table 4-14-2. Postinjection Site Care

Activity	Cost
Monitoring and AOR Revisions (see Table 4-14-3)	$7,197,000
Overhead and Support	$1,388,000
Facilities Maintenance and Power	$1,700,000
Total	**$10,285,000**

Notes:
- Costs are based on estimates of current contract day rates and materials.
- Postinjection seismic survey conducted at 5-year intervals.

Table 4-14-3. Monitoring and AOR Revisions (part of postinjection site care)

Activity	Cost
Gas Soil Probes	$716,000
3D Seismic Survey – Time-Lapse	$5,000,000
Water Sampling	$180,000
Saturation Log Monitoring Wells	$819,000
Annular Pressure Test	$100,000
AOR Assessment	$86,000
Casing Inspection Log Monitoring Wells	$160,000
Optical Gas Imaging	$72,000
Visual Inspection	$64,000
Total	**$7,197,000**

Table 4-14-4. Site Closure

Activity	Cost
Monitoring Well P&A	$764,000
Facilities Closure	$1,020,000
Total Site Closure	**$1,784,000**

Notes:

- Costs are based on estimates of current contract day rates and materials.
- Costs are based on P&A of two monitoring wells.
- Facilities closure estimate includes abandonment in place of buried pipelines.

Table 4-14-5. Emergency and Remedial Response

Activity/Item	Cost
Pump Trucks (twin pump)	$113,784
Frac Tanks	$48,000
Vacuum Truck	$36,000
Dozer	$18,600
Excavator	$20,400
Dump Truck	$32,400
Brine Disposal (no Class I)	$1,000
Trucking Water	$11,000
Water Transfer Pump and Personnel Package	$11,600
Light Towers, Trailers, Generator, Heaters, Communications, etc.	$7,690
Heater Packages	$36,000
Fuel Tank Storage	$3,400
Drill and P&A Relief Well in Broom Creek	$8,760,000
Special Well Control Team – (e.g., wild well/boots & coats)	$1,500,000
New Injector Well – Replacement (mob, drill and comp)	$5,060,000
Original Injector Well Abandonment	$900,000
Total	**$16,559,874**

Notes:

- These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.
- A significant portion of these costs, should they be incurred, would be covered by commercial insurance which is an industry standard control of well (COW) coverage.
- Costs are based on estimates of current contract rates.

Table 4-14-6. Endangerment of USDWs

Description	Total Estimated Amount
Subsurface Release to USDW	
General Response Actions	$6,000
Groundwater Delineation	$1,290,000
Irrigation/Domestic Well Sampling and Replacement	$131,000
Quarterly Groundwater Monitoring (10 years) and Reporting	$760,000
P&A of Groundwater-Monitoring Wells	$53,000
Total	**$2,240,000**

Notes:

- These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.
- Costs are based on estimates of current contract rates.

4.4 Worker Safety Plan

The worker safety plan (WSP) describes the minimum safety programs, permit activities, and training requirements to deploy during construction, operation, and postinjection site care periods. This document does not limit the application of additional programs and technologies that could improve the safety and performance of the operation.

This WSP incorporates the safety program for the Tundra SGS as a whole. It includes monitoring wells, monitoring system, injection well network, and CO_2 flowline from the capture facility to the storage site.

4.4.1 Definitions

a. Confined space means a space large enough and so configured that an employee can bodily enter and perform assigned work, has limited or restricted means for entry or exit (for example, tanks, vessels, silos, storage bins, hoppers, vaults, and pits or spaces that may have limited means of entry), and is not designed for continuous employee occupancy. This definition could also apply to a trench, bellhole, cellar, or excavation.

Some confined spaces are designated permit-required confined spaces, meaning entry into the space must be controlled through application of a confined space entry permit. A "yes" answer to *any one* of the following questions means the space must be designated "permit-required."

- Does the space contain, or have the potential to contain, a hazardous atmosphere?
- Does the space contain a material that has the potential for engulfing an entrant?
- Does the space have an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or a floor that slopes downward and tapers to a smaller cross section?
- Does the space contain any other recognized serious safety or health hazard?
- The confined space entry (CSE) program is provided to protect authorized employees and contractors that will enter permit-required confined spaces.

b. Contractor means a company or person performing work, providing services, or supplying equipment at the work site, including its subcontractors.
c. Hazardous energy means energy sources including electrical, mechanical, hydraulic, pneumatic, chemical, thermal, or other sources in machines and equipment where the unexpected start-up or release of stored energy can result in serious injury or death.
d. Operator means the Tundra SGS or any Tundra SGS employee.
e. Permitted work activities means activities that require the use of a permit, including but not limited to, CSE, lockout/tagout, trenching and excavation, electrical, and hotwork, which require the use of a permit.
f. Site manager/supervisor means the operator-designated representative in charge of the work site or work.
g. Work site means physical location under control of the operator where work is being performed on behalf of the operator.
h. Work means task or tasks to be executed by the operator or contractor.
i. Visitor means a person or person(s) present at the work site who are there for observational, not work, purposes.

4.4.2 Stop Work Authority

Every operator and contractor has the right, obligation, authority, and responsibility to stop any work or action that is unsafe or, if continued, may result in adverse impact to the environment. No operator employee or contractor will be subject to discipline or sanction for stopping any work or action that they believe in good faith is unsafe or may result in adverse impact to the environment. Work must be stopped in a safe manner and immediately reported to the immediate supervisor or operator representative. Appropriate actions will be taken to mitigate the hazard before work will be allowed to commence. Every contractor will have a stop work authority program that advises their employees of their rights to use stop work authority.

4.4.3 Incident Notification and Response

The operator employee or contractor shall be required to immediately notify the site manager/supervisor (or designated operator representative) of all incidents involving injury or illness to a contractor; damage to operator or contractor equipment as a result of contractor activities at the work site; and any spill, release, or leak. Prompt investigation is required of all injuries, illnesses, equipment or property damage, environmental spills/releases, and other HSE-related incidents.

Unsafe conditions must be immediately reported to the operator. "Near-miss" incidents that could have resulted in injury or damage must be reported by the operator employee or contractor to the site manager/supervisor (or designated operator representative).

4.4.4 Incident Report and Investigation

An initial preliminary written incident report for all workplace incidents shall be submitted within 24 hours of occurrence, with known facts, to the site manager/supervisor (or the designated operator representative).

An investigation will be started as soon as possible following notification into all injuries, illnesses, equipment or property damage, leak, spill or release, or other HSE-related incidents. A written interim incident investigation report for all incidents will be provided every 7 calendar days until the final incident report is submitted to the site manager/supervisor (or the designated operator representative). The operator may participate in any investigation of incidents at any work site and will be permitted to reproduce all work site audits and incident investigations for purposes of correction, training, investigation, and root cause analysis.

The final incident report shall include at a minimum: description of the incident, location, chronology, injury details, Occupational Health and Safety Administration (OSHA) classification, impact on people and the environment, protective equipment performance assessment, review of the process (design, operation, maintenance, and administrative control), identification of root cause, and recommendation for corrective actions. The operator shall provide timely notification to the site owner of all incidents involving injury or property damage and will provide weekly reports to the site owner that identify all incidents reported in the prior week.

All incident reports that result in formal notification to any government entity or authority shall be provided to the operator. Additionally, any investigations, inspections, or penalties assessed on the contractor by any government entity or authority relating to or in connection with any work performed for the operator shall promptly be provided to the operator.

4.4.5 Training

The contractor shall receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training shall be conducted by, or under the supervision of, an operator site supervisor/manager or an operator-designated representative. Trainers must be thoroughly familiar with the operations plan and ERRP.

The contractor shall conduct a training needs assessment that is representative of the contracted work site assignments. The contractor shall establish the type and frequency of training in a role and responsibility matrix by position (matrix). The contractor shall ensure that personnel have been given all core and special training identified in the matrix.

However, the following are minimum requirements regardless of position or work:

- All newly hired personnel need to attend onboarding training for the work site and fulfill the safety training according to the position before starting on the job.
- All operation employees shall participate in annual training to teach or reinforce how to perform the job, equipment functioning, and instrumentation.
- All employees shall participate in an annual refresher training for the emergency response procedures contained in the ERRP.
- Monthly briefings shall be provided to operations personnel according to their respective responsibilities and shall highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir-monitoring information.
- Documentation of all training shall be retained by the contractor and made available for operator inspection upon request.

4.4.6 Contractor Qualification and Bridging Documents

The contractor shall have a qualification program and auditing process to ensure personnel are held to the same safety standards or higher than operators' standards. A bridging document shall be created to align the safety program between operator's and contractor's policies, if required.

4.4.7 General Health, Safety, and Welfare

The work site must be maintained so as not to create or otherwise contribute to an unhealthy working or living environment. To accomplish this objective, the operator and contractor shall ensure the following:

Information/Posting/Signs. All emergency, safety, and operational information/postings/ signs shall be communicated in a format to ensure comprehension by the operator and all visitors or contractors on the work site, in accordance with OSHA 29 Code of Federal Regulations (CFR) 1910.145, country, state/province, local, or international equivalent.

Job Safety Analysis. The contractor shall complete and review, with all affected parties, a job safety analysis (JSA) prior to performing any work. Anytime the job scope or conditions change, the contractor shall review and revise (if needed) the JSA with all affected parties.

Prejob Meeting. On work sites where simultaneous operations (SIMOPS) shall be conducted, daily prejob planning meeting(s) shall be held involving representatives from all potentially affected parties.

English Language Proficiency. At least one person per crew or work group assigned to a task must be fully capable of communicating in the English language (both in a verbal and written manner) such that they can perform the work safely. If required, an interpreter shall be provided.

Short Service or New Hire. Short service personnel or new hires without experience shall be mentored and supervised by a senior professional and uniquely identified in the field (stickers and unique-colored hard hat). The employee shall fulfill core training before starting activities on the work site. Documentation of such mentoring/training must be retained and available for inspection upon request.

Medical Fitness/Personal Hygiene. Personnel shall be medically fit to safely perform the work they are expected to perform. The operator may audit to ensure that personnel maintain appropriate standards of personal hygiene during performance of the work.

Housekeeping. The contractor shall ensure good housekeeping practices are conducted at the work site by all personnel to provide for a safe and orderly working environment. Aisles, emergency exits, and controls must be kept free of obstacles at all times.

Machine Guarding. The contractor shall ensure that all equipment machine guarding (permanent, temporary, and portable) is properly installed and maintained. Before removing guards to service guarded equipment, which should be isolated, locked out, tagged out, and verified to be nonfunctioning, see lockout/tagout procedure.

Portable Hand Tools. All portable hand tools shall have proper insulation, grounding, and guarding in accordance with manufacturer requirements. All portable tools shall be properly maintained and used based on manufacturer original design and intended purpose. Tools shall be regularly inspected, and damaged or worn tools shall be taken out of service. No homemade or modified hand tools shall be used on the work site.

Management of Change (MOC). The contractor shall have a formal MOC process implemented for all equipment (except for "replacement in kind"), process, and procedural changes. The contractor shall ensure no contractor's equipment is used or modified outside of the original equipment manufacturer-design specifications.

Clothing and Other Apparel. Ragged or loose clothing and jewelry (rings, watches without breakaway nonmetallic bands, necklaces, exposed piercings, etc.) are not to be worn when on the work site. Any clothing that becomes saturated with hazardous chemicals should be promptly removed.

First Aid/CPR. The contractor shall ensure sufficient first aid/CPR and defibrillator equipment and trained personnel (National Safety Council, American Heart Association, Red Cross, etc.) are available at the work site in accordance with OSHA 29 CFR 1910.151 or equivalent country, state/province, or local regulations. First aid/CPR and defibrillator kit(s) containing an appropriate quantity of supplies shall be maintained on location at all times.

Transportation Safety. The contractor shall ensure that all modes of transportation are fit for purpose for travel to/from/within the work site. The contractor shall ensure compliance with all applicable country, state/province, and local regulations.

Industrial Hygiene

- The contractor will assess job duties to determine if hazards are present, or are likely to be present, which necessitate the use of engineering controls, administrative controls, or personal protective equipment (PPE).
- The contractor shall document this hazard assessment through a written certification that identifies the work site evaluated, person certifying that the evaluation has been performed, and date(s) of the hazard assessment. Documentation shall be retained by the contractor and made available to the operator upon request for inspection.
- Based on the results of this hazard assessment, the contractor may be required to perform an industrial hygiene assessment of the work site to determine the level of exposure to hazards (chemicals, lead, dust, noise, etc.).
- Appropriate measures shall be taken based on these assessments in order to safely manage operator, contractor, and visitor exposures.

4.4.8 Personal Protective Equipment

All contractors and visitors must wear appropriate PPE for the hazards present at the work site. Actual PPE requirements shall be determined in accordance with hazard/risk assessments, and safety data sheets (SDS) must be provided for products that personnel might be exposed to at the work site ("risk assessment").

The following PPE, at a minimum, must be used by all operators or contractors at the work site, along with the appropriate training in the proper use and care of such PPE:

- Hard hats
- Safety glasses with side shields
- Protective footwear (safety-toed boots).
- Personal monitor(s) as needed based on risk assessments for H_2S or other hazardous materials

The following is a list of PPE that, based on the hazard/risk assessment, might be required for the work site and applicable standards/certifications that apply:

- Respiratory protection meeting OSHA 29 CFR 1910.134, National Institute for Occupational Safety and Health (NIOSH)-certified.
- Head protection meeting American National Standards Institute (ANSI) Z89.1 Type 1, Classes E and G.

- Eye and face protection appropriate for the work environment and hazards meeting ANSI Z87.1.
- Foot protection meeting ASTM F 2413 or international-equivalent standard.
- Hearing protection meeting ANSI S3.19 standard.
- Hand protection (gloves) appropriate for the work environment, exposure, and hazards.
- Flame-retardant clothing certified to National Fire Protection Association (NFPA) 2112/(NFPA 70E Arc Flash PPE category for personnel performing electrical work) (as identified by regulation or local company management including but not limited to 29 CFR 1910.132, 1910.269, and 1910.335; ASTM 1506; NFPA 70E, 2112, and 2113).

Fire Protection. The contractor shall, based on a risk assessment, provide and maintain fire protection equipment for the work. Fire protection shall comply with all local regulatory or equivalent NFPA requirements and be dedicated for firefighting use only.

4.4.9 Hand Safety

The contractor shall have a hand safety awareness-training program targeting topics such as pinch points, hold points, soft grips, cutting devices, proper hand tools, hot/cold conditions, chemical handling, etc.

Selection of appropriate hand protection should be based on an evaluation of the performance characteristics of the hand protection relative to the task(s) to be performed, conditions present, duration of use, and hazards and potential hazards identified.

Contractors are required to use appropriate hand protection when they encounter the following hand hazards:

- Thermal
- Sharp materials
- Electrical current
- Chemical exposure
- Impact
- Abrasive materials

4.4.10 Permitted Work Activities

The following are considered permitted activities and require a permit to be executed.

Hot Work. Any work that may introduce any source of ignition where flammable vapors may be present or will generate sufficient heat to ignite combustible and/or flammable materials and these materials will support combustion once ignited.

CSE. Any CSE conducted on the operator property must be done under a permit-required confined space program, which shall identify methods to comply with the requirements of OSHA Standard 1910.146.

Lockout/Tagout Procedure. When any hazardous energy scenario is encountered, including but not limited to the following during performance of servicing or maintenance of equipment:

a. Removal or bypass of machine guards or other safety devices
b. Placement or positioning of any part of the body in contact with the point of operation
c. Placement or positioning of any part of the body in a danger zone associated with a machine's operating cycle
d. When the release of stored energy that could injure the operator, contractor, visitor, or a member of the public if the isolated device (e.g. valve, breaker, etc.) were to be operated by mistake

Then the following safe work practices are required:

a. Use of lockout/tagout controls to prevent the release of hazardous energy.
b. The equipment must be deenergized, and locks and tags must be applied to the energy-isolating devices.
c. All work involving isolation of hazardous energy must be done in accordance with 29 CFR 1910.147.

Excavation and Trenching. The contractor performing trenching and excavation activities on a work site must provide competent personnel capable of identifying existing and predictable hazards in the immediate surroundings. The contractor shall ensure that the competent person must be on-site during all excavation activities where the potential for injury exists. The competent person must also comply with all applicable OSHA construction regulations.

Preexcavation Notification Requirements. Injection and plant locations must have a means of receiving a written "ticket locate request" from a state one-call notification center. In addition, each location must have a 24-hour emergency telephone number, such as a plant location or answering service.

Electrical. The contractor performing electrical work activities shall provide qualified personnel. Qualified persons must be trained and knowledgeable of the construction and operations of the equipment or a specific work method and be trained to recognize and avoid the electrical hazards that might be present with respect to that equipment or work method.

Energized equipment to which a qualified or unqualified person might be exposed must be in an electrically safe work condition before an employee works within the limited approach or the arc flash protection boundaries. For cases where it is determined that the equipment cannot be placed in an electrically safe work condition, an energized electrical work permit must be completed and approved prior to commencing the work.

Energized work that is considered routine for diagnostic testing or troubleshooting is exempted from the energized electrical work permit requirements if there is an approved maintenance or operating procedure in place for the task.

Electrical Safety Program. The contractor shall have an electrical safety program which identifies the levels of all electrical and associated tasks to be performed and personnel position qualified to perform each of these tasks in accordance with OSHA/National Electrical Code (NEC), American Petroleum Institute (API) 500, NFPA 70E, or equivalent country, state/province, or local regulations.

Contractor electricians shall be qualified to perform electrical activities on contractor or operator equipment at the work site as required by local regulations or equivalent OSHA/NEC/NFPA 70E standards.

Contractors working in areas where there are electrical hazards shall be provided with and use protective equipment that is designed and constructed for the specific part of the body to be protected and work to be performed.

The contractor shall consider all overhead power lines to be energized unless proper measures have been taken for deenergizing. When work is being performed near energized overhead power lines, any part of the crane, boom, mast, gin poles, suspended loads, or machinery shall not be permitted within 10 ft (3 m) of the power lines. However, this safe working distance can be increased according to the voltage of the power lines (OSHA 29 CFR 1926.550, 1910.181, 1910.269 or equivalent country, state/province, or local regulations).

The contractor shall ensure that all personnel will use only portable ladders, scaffolding, or other elevating devices made of nonconductive material when working around energized electrical equipment.

Precautions shall be taken to ensure that all equipment used is properly grounded and accidental contact with ungrounded electrical sources is prevented.

Contractor shall ensure all contractor electrical components, tools, and PPE are maintained in a safe working condition.

Temporary electrical power setup for the operation of tools and equipment shall be protected by ground fault circuit interrupter (GFCI) circuits.

4.4.11 Chemical, Hazardous, or Flammable Materials

SDSs. The contractor shall ensure that all chemical products/materials supplied to the work site are accompanied by the respective SDS upon delivery. The contractor shall provide the site supervisor/manager with an inventory of all chemical products/materials to be used along with copies of the related SDS documents. The operator shall have authority to prohibit any chemical product/material that is deemed unacceptable at the sole discretion of the operator.

The contractor shall instruct all personnel on the safe use of the chemical products/materials in accordance with an appropriate written hazard communication program as dictated by local/state/federal regulatory requirements.

The contractor shall ensure that SDSs for chemicals are reviewed by personnel prior to exposure.

Storage, Use, and Labeling of Chemicals and Hazardous/Flammable Materials. The contractor shall ensure all hazardous and/or flammable materials/products are labeled, handled, dispensed, and stored in accordance with OSHA 29 CFR 1910.106 and 1910.1200 or equivalent country, state/province, or local regulations.

All chemicals, paints, and hazardous/flammable materials shall be kept in appropriate containers, which are clearly labeled as to the respective contents, and stored in fit-for-purpose storage containers (uniquely identified, vented, etc.). Container labeling shall be consistent with OSHA, U.S. Department of Transportation (DOT), NFPA, or equivalent country, state/province, or local regulation.

Hydrogen Sulfide. When the presence of hydrogen sulfide gas may exist at greater than 10 ppm in the wellbore, formation, facilities, or production stream, the contractor is responsible for ensuring that personnel are properly trained and qualified. Personal monitoring equipment shall be used by all personnel, and personal monitoring devices must be set to alarm at 10 ppm so that personnel are alerted to evacuate the area. The H_2S monitors shall be calibrated in accordance with the manufacturer's specifications, and at a minimum, personal H_2S monitors shall be "bump"-tested at least monthly.

Compressed Gas and Air Cylinders. Compressed gas cylinders shall be properly used, maintained, stored, handled, and transported as designated by OSHA 29 CFR 1910.101-106, 1910.252, 1910.253, and 1926.350 or equivalent country, state/province, or local regulations.

Compressed gas and air equipment shall be constructed in accordance with American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel Code, Section VIII Edition 1968 or equivalent country, state/province, local, or international laws or regulations. Equipment includes but is not limited to safety devices, flame arrestors, regulators, pressure gauges, check valves, pressure relief valves, labeling, etc.

All compressed gas cylinders shall be returned promptly to a suitable/designated storage area when not in use. Compressed gas cylinders shall be stored in the upright position and secured.

Protective caps shall be placed over the cylinder valves when not in use or being transported.

Compressed gas cylinders shall be stored away from heat, fire, molten metal, and electrical lines.

Compressed gas cylinders shall not be transported by mobile cranes unless a special carrier is used.

Oxygen and flammable gases shall be stored in areas separated by a minimum of 20 ft or fire barrier rated for 30 minutes.

Acetylene or liquid compressed gas cylinders shall never be used in a horizontal position, as the liquid may be forced out through the hose, causing a fire hazard or explosion.

Oxygen/acetylene cutting torch lines shall include flashback arrestors placed (at least) at the cylinder end. The preference is for the arrestor to be on the torch side.

Compressed air should not be used for cleaning clothing or parts of the body. If compressed air is used for cleaning, the discharge shall not exceed 30 psi (2.07 bar) and eye/face protection shall be worn.

4.4.12 Overhead/Outside Guarded Area

Lifting and Hoisting. When the contractor is working overhead, the area below shall be barricaded or other equivalent measures taken to protect workers on the work site. No one shall be permitted to pass under any suspended load.

Each lifting device shall identify the manufacturer, safe working load, service/manufactured date, and serial/identification number.

Lifting devices shall be managed in a formal maintenance program (i.e., in-service – out-of-service date, color-coding, rejection criteria, etc.).

Tail chains used on rig floor tuggers, winches, cranes, etc., must be attached to a certified lifting point and cannot be wrapped/choked around the load and/or back onto itself.

Tail chains are prohibited from use in all man-riding operations.

All other application of chains shall be consistent with original equipment manufacturer (OEM) ratings, design, and usage.

Lever-type load binders are prohibited for use on all work sites.

Homemade or modified lifting devices are prohibited for use on all work sites.

Tag lines shall be used when moving or lifting equipment.

Powered Lifting Device Safety. All contractors operating a powered lifting device (forklift, cranes, winches, gin pole trucks, etc.) shall maintain current certification/training in accordance with OSHA regulations or equivalent country, state/province, or local regulations. All powered lifting devices shall have a preuse inspection as required by local regulation or manufacturer recommendation.

Scaffolds or Platforms. All scaffolds or platforms used for installation and maintenance or removal of machinery and equipment shall be erected, maintained, and used in compliance with OSHA or a country, state/province, local, or international equivalent regulation. All scaffolds are to be inspected and tagged by a competent person prior to use and subsequently inspected by a competent person prior to each shift.

Safety Harnesses and Lifelines. When working outside of properly guarded work platforms, a full-body safety harness and lifeline, complete with shock-absorbing lanyard(s) or self-retracting lifeline, shall be provided by the contractor and worn by all workers when working above 6 ft (construction) or when walking on working surfaces higher than 4 ft (general industry) without proper guarding. The contractor shall have procedures, trained personnel, and equipment necessary to rescue workers that may be suspended from fall protection equipment following a fall.

4.4.13 Work Site Conduct

Firearms, Weapons, and Non-Work-Related Dangerous Materials. The possession of firearms, weapons, explosives, or non-work-related dangerous materials on the work site or while conducting work is strictly forbidden.

Drug, Alcohol, and Controlled Substances Requirements. The contractor shall have a written drug and alcohol program that conforms to the operator's drug, alcohol, and controlled substances requirements of which the contractor confirms receipt and understanding. The contractor shall comply with all governmental requirements, including all applicable federal, state, and local drug- and alcohol-related laws and regulations, including, without limitation, the applicable DOT regulations. The contractor shall have a drug and alcohol policy in place and a functioning drug- and alcohol-testing program, which includes provisions for preemployment, postaccident, random, reasonable suspicion, return to duty, and follow-up testing as allowable under local, state, and federal law.

At a minimum, testing requirements and procedures, including testing mechanisms, substances, and cut-off levels, must comply with current DOT guidelines under 49 CFR Part 199 and/or 49 CFR Part 40. The contractor might have a non-DOT drug program. The contractor non-DOT drug and alcohol program shall include preemployment/preaccess screening and drug testing, postincident testing, for-cause/reasonable suspicion testing, and random testing, with an annual rate of at least 25% for drug and 10% for alcohol. No alcoholic beverages are to be consumed on the work site. Any contractor determined to be under the influence of, in possession of, or distributing either drugs or alcohol will be discharged for the remainder of the work.

Smoking and Lighters/Matches. Smoking is not allowed in any facilities or vehicles owned by the operator or within at least 20 ft or more of any facility entrance or exit, windows, or air intake vents. Smoking is not allowed on any roof area. If permitted on the work site, lighters and matches should be stored in safe areas away from flammable or combustible materials. Electronic cigarettes are to be treated in the same manner and shall only be used in designated areas.

Inappropriate Behavior. Inappropriate behavior including, but not limited to, horseplay, practical jokes, offensive remarks, offensive gestures, harassment, etc., is prohibited while performing work or while on the work site. The contractors are expected to discharge any personnel engaged in fighting on the job site for the duration of the work. If any contractor is caught stealing from the operator or other contractors, those personnel are to be discharged and will be prohibited from returning to the work site.

4.5 Well Casing and Cementing Program

Minnkota plans to construct two CO_2 injection wells (Liberty-1 [J-ROC1 File No. 37672] and Unity-1 [proposed]) and a proposed monitor well (NRDT-1), as designed by OLCV in compliance with Class VI UIC injection well construction requirements. The target horizon of the injection wells is the Broom Creek Formation, while the objective of the monitoring well is to provide real-time pressure and temperature response from the injection wells during the injection operations.

4.5.1 Liberty-1 (J-ROC1 File No. 37672) – Proposed Injection Well Casing and Cementing Programs

The J-ROC1 well is a stratigraphic well that was drilled and temporarily plugged and abandoned (T&A) in 2020. The proposed completion of Liberty-1 (J-ROC1 File No. 37672) is provided below in Figure 4-12 as the Liberty-1 injection well.

Tables 4-15 through 4-18 provide the casing and cement programs for the Liberty-1 (J-ROC1 File No. 37672) well. 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.

4.5.1.1 Liberty-1 (J-ROC1 File No. 37672) Proposed Injection Well Schematic

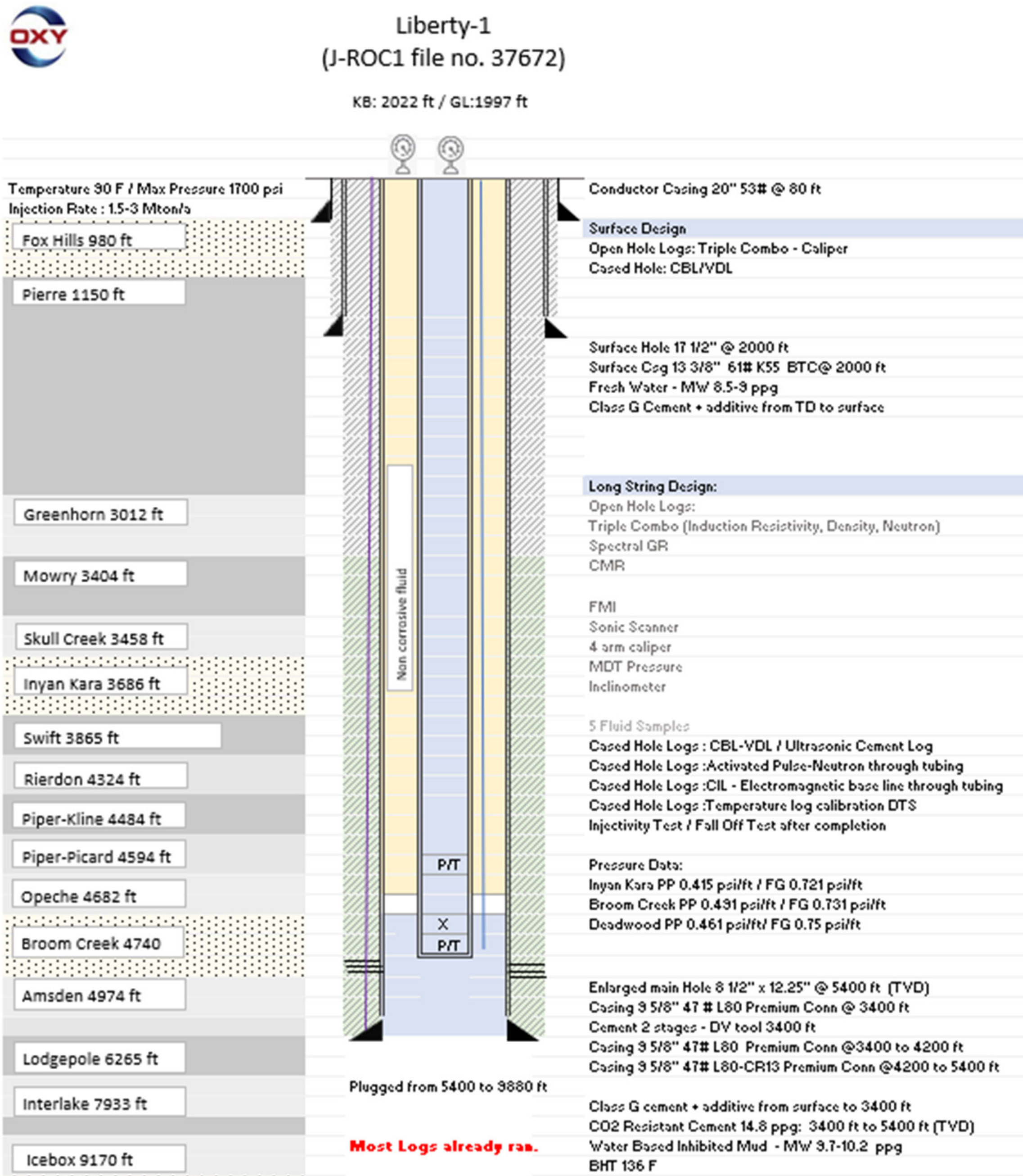


Figure 4-12. Liberty-1 (J-ROC1 File No. 37672) proposed injection wellbore schematic.

Table 4-15. Liberty-1 (J-ROC1 File No. 37672) Well Information

Well Name:	**Liberty-1 (J-ROC1 File No. 37672)**	**NDIC No.:**	37672	**API No.:**	33-065-00020-00-00
County:	Oliver	**State:**	ND	**Operator:**	Minnkota Power Cooperative, Inc.
Location:	SW/NW Sec. 04 T141N R83W	**Footages*:**	1,959.3' FNL 332.5' FWL	**Total Depth:**	9,871'

* From the north line, from the west line.

Table 4-16. Liberty-1 (J-ROC1 File No. 37672) Proposed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection*	Top Depth, ft	Bottom Depth, ft	Objective
Surface	17½	13⅜	61	K-55	BTC	0	2,000	Protect shallow freshwater aquifers
Production	12¼	9⅝	47	L-80	Premium connection	0	4,200	Protect less permeable reservoirs
Production	12¼	9⅝	47	13Cr-80	Premium connection	4,200	5,400	CO_2-resistant production casing to protect high-permeable reservoirs

* BTC: buttress-thread and coupled; pending premium connection: gastight thread and coupled.

Table 4-17. Liberty-1 (J-ROC1 File No. 37672) Surface Casing and Proposed Long-String Casing Properties

Casing Description ID	Hole, in.	Depth, ft	Casing OD, in.	Weight, lb/ft	Grade	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Tension, Klb	Thread	OD Thread
13.375 in 61 ppf K55 BTC	17.5	0–2,000	13.375	61	K55	12.515	12.359	3,090	1,540	962	BTC	14.375
9.625 in 47 ppf L80 Premium Conn.	12.25	0–4,200	9.625	47	L80	8.681	8.525	6,870	4,750	1,086	Premium Conn*	10.625
9.625 in 47 ppf L80 13Cr Premium Conn.	12.25	4,200–5,400	9.625	47	L80 13Cr	8.681	8.525	6,870	4,750	1,086	Premium Conn*	10.625

* Pending premium connection selection.

Table 4-18. Liberty-1 (J-ROC1 File No. 37672) Surface Cement and Proposed Long-String Cement Program

Section	Type	Depth, ft	Density	Sx	Excess	Cap	Vol	Yield
17½ in. Hole	Class G cement with additives	0–1,500	12.5	822	50%	0.1237219	278	1.90
	Class G cement with additives	1,500–2,000	15.8	449	50%	0.1237219	93	1.16
12¼ in. Hole	Class G cement with additives	0–2,900	11.8–12.5	615	20%	0.0557819	194	1.77
	Class G cement with additives	2,900–3,400	14.8	164	20%	0.0557819	33	1.15
	CO_2-resistant cement	3,400–5,400	14.8	677	20%	0.0557819	134	1.11

4.5.2 Unity-1 – Proposed Injection Well Casing and Cementing Programs

The Unity-1 well will be drilled as a second Broom Creek injection well, with a target trajectory depth of approximately 1,000 ft from the surface location. The well trajectory of Unity-1 is provided in Figure 4-13 while the proposed completion wellbore schematic is provided in Figure 4-14.

Tables 4-19 through 4-22 provide the casing and cement programs for Unity-1. The well construction materials will comply with NDAC § 43-05-01-11 (Injection Well Construction and Completion Standards).

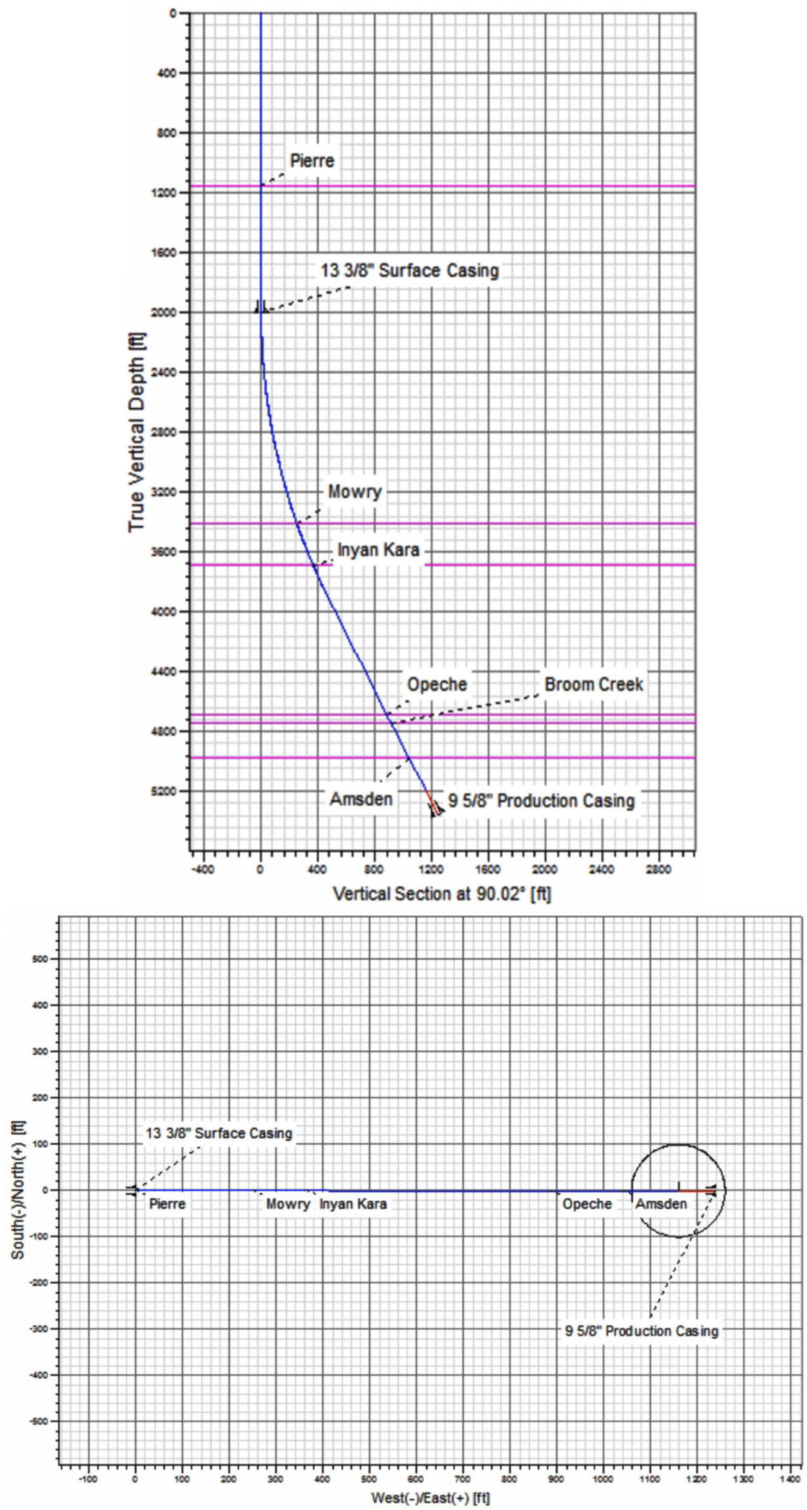


Figure 4-13. Unity-1 proposed well trajectory.

4.5.2.1 Unity-1 Proposed Injection Well Schematic

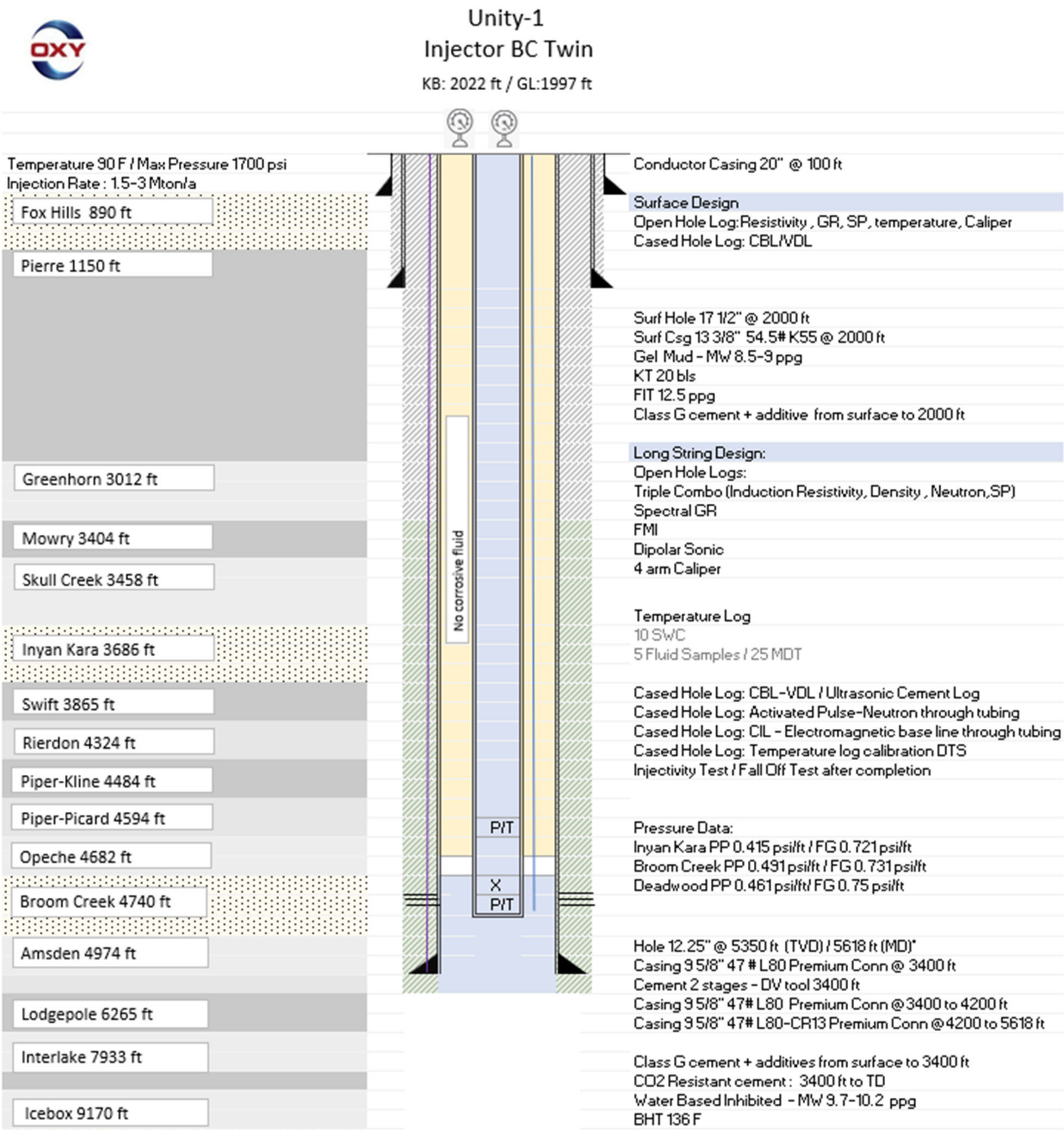


Figure 4-14. Unity-1 proposed injection wellbore schematic

Table 4-19. Unity-1 Well Information

Well Name:	Unity-1	**NDIC No.:**		**API No.:**	
County:	Oliver	**State:**	ND	**Operator:**	Minnkota Power Cooperative, Inc.
Location:		**Footages*:**		**Total Depth:**	5,618' MD

* From the north line, from the west line.

Table 4-20. Unity-1 Proposed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection*	Top Depth, ft	Bottom Depth, MD ft	Objective
Surface	17½	13⅜	54.5	K-55	BTC	0	2,000	Protect shallow freshwater aquifers
Production	12¼	9⅝	47	L-80	Premium connection	0	4,200	Protect less permeable reservoirs
Production	12¼	9⅝	47	13Cr-80	Premium connection	4,200	5,618	CO_2-resistant production casing to protect high-permeable reservoirs

* Pending Premium connection selection: gas-tight thread and coupled.

Table 4-21. Unity-1 Proposed Casing Properties

Casing Description ID	Hole, in.	Depth, ft	Casing OD, in.	Weight, lb/ft	Grade	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Tension, Klb	Thread	OD Thread
13.375 in 54.5 ppf K55 BTC	17.5	0–2,000	13.375	54.5	K55	12.615	12.459	2,730	1,130	766	BTC	14.375
9.625 in 47 ppf L80 Premium Conn.	12.25	0–4,200	9.625	47	L80	8.681	8.525	6,870	4,750	1,086	Premium Conn.*	10.625
9.625 in 47 ppf L80 13Cr Premium Conn.	12.25	4,200–5,618	9.625	47	L80 13Cr	8.681	8.525	6,870	4,750	1,086	Premium Conn.*	10.625

* Pending premium connection selection.

Table 4-22. Unity-1 Proposed Cement Program

Section	Type	Depth, ft	Density	Sx	Excess	Cap	Vol	Yield
17½ in. Hole	Class G cement with additives	0–1,500	12.5	822	50%	0.1237219	278	1.90
	Class G cement with additives	1,500–2,000	15.8	449	50%	0.1237219	93	1.16
12¼ in. Hole	Class G cement with additives	0–2,900	11.8–12.5	615	20%	0.0557819	194	1.77
	Class G cement with additives	2,900–3,400	14.8	164	20%	0.0557819	33	1.15
	CO_2-resistant cement	3,400–5,618	14.8	751	20%	0.0557819	149	1.11

4.5.3 NRDT-1 – Proposed Broom Creek CO_2-Monitoring Well Casing and Cementing Programs

The NRDT-1 well will be drilled as a monitoring well. The proposed completion is provided in Figure 4-15.

Tables 4-23 through 4-26 provide the casing and cement programs for the proposed CO_2-monitoring well (NRDT-1). The well construction materials will comply with NDAC § 43-05-01-11 (Injection Well Construction and Completion Standards).

4.5.3.1 NRDT-1 Proposed Monitoring Well Schematic

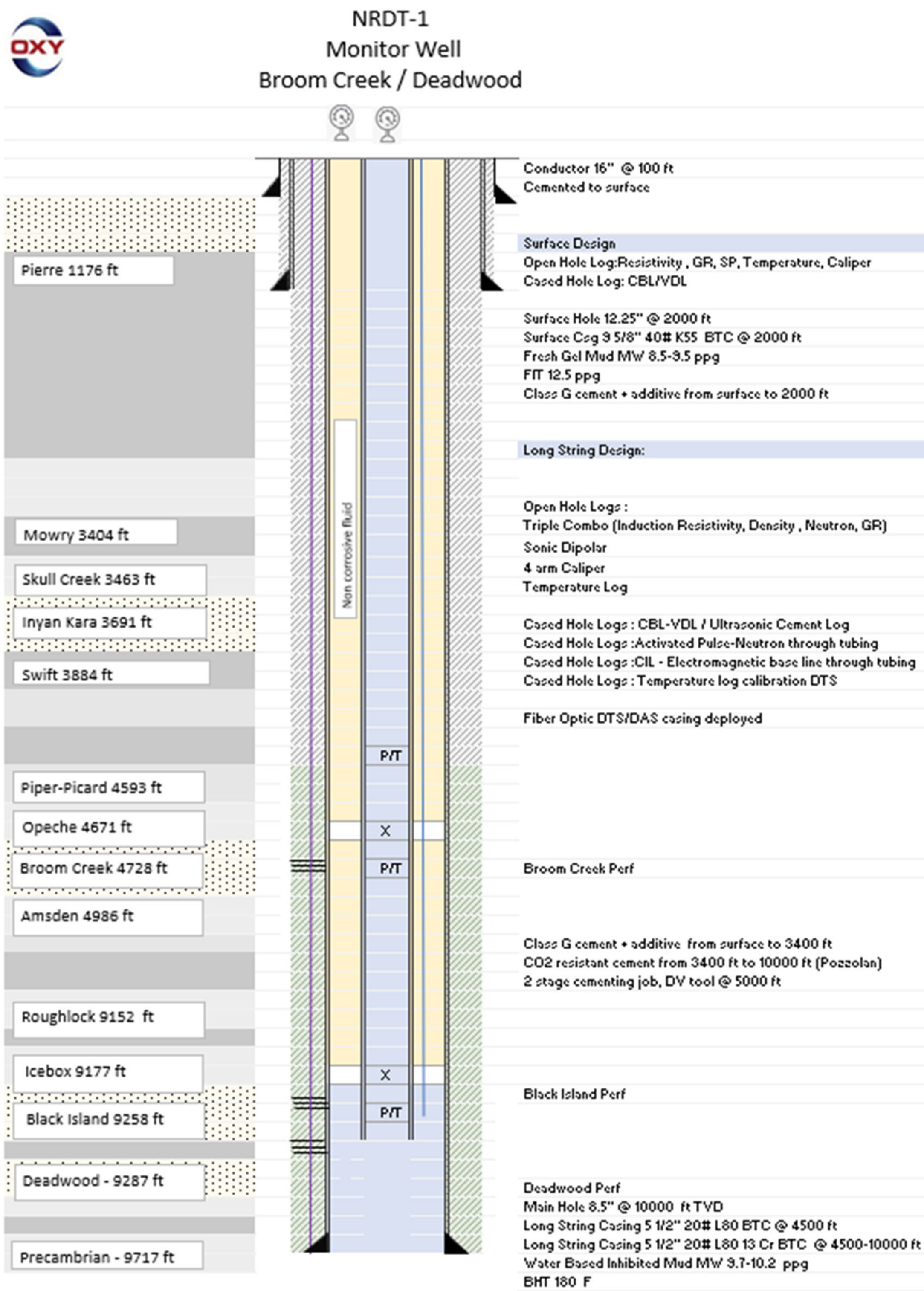


Figure 4-15. NRDT-1 Proposed design of the CO_2-monitoring wellbore schematic.

Table 4-23. NRDT-1 Proposed CO_2-Monitoring Well Information

Well Name:	NRDT-1	**NDIC No.:**		**API No.:**	
County:	Oliver	**State:**	ND	**Operator:**	Minnkota Power Cooperative, Inc.
Location:		**Footages*:**		**Total Depth:**	10,000'

* From the north line, from the west line.

Table 4-24. NRDT-1 CO_2-Monitoring Well Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	12¼	9⅝	40.0	K-55	BTC	0	2,000	Protect shallow freshwater aquifers
Long-String	8½	5½	20.0	L-80	BTC	0	4,500	Protect low permeable formations
Long-String	8½	5½	20.0	13CR-80	BTC	4,500	10,000	Protect high permeable formations

Table 4-25. NRDT-1 Proposed CO_2-Monitoring Well Casing Properties

Casing Description ID	Hole, in.	Depths, ft	Casing OD, in.	Weight, lb/ft	Grade	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Tension, Klb	Thread	OD Thread
9.625 in. 40 ppf K55 BTC	12.25	0–2,000	9.625	40	K55	8.835	8.679	3,950	2,570	630	BTC	10.625
5.5 in. 20 ppf L80 BTC	8.5	0–4,500	5.5	20	L80	4.778	4.653	9,190	8,830	466	BTC	6.05
5.5 in. 20 ppf L80 13Cr BTC	8.5	4,500–10,000	5.5	20	L80 13Cr	4.778	4.653	9,190	8,830	466	BTC	6.05

Table 4-26. NRDT-1 Proposed CO_2-Monitoring Well Cement Program

Section	Hole Size, in.	Type	Depths, ft	Density, ppg	Sacks of Cement	Excess	Vol, bbl	Yield, ft^3/sk
Surface	12.25	Class G cement with additives	0–1,500	12.5	370	50%	126	1.90
		Class G cement with additives	1,500–2,000	15.8	202	50%	42	1.16
Long-String	8.5	Class G cement with additives	0–3,400	11.8–12	528	20%	166	1.77
		CO_2-resistant Cement	3,400–5,000	14.8	357	20%	78	1.23
		Class G cement with additives	5,000–8,500	11.8–12	543	20%	171	1.77
		CO_2-resistant Cement	8,500–10,000	14.8	335	20%	73	1.23

4.6 Well P&A Program

Upon end of life for the Liberty-1 (J-ROC1 File No. 37672) and Unity-1 (proposed) Broom Creek CO_2 injection wells or completion of the project, Minnkota plans to P&A these two CO_2 injection wells in the Broom Creek Formation (Liberty-1 [J-ROC1 File No. 37672], Figure 4-16 and Unity-1 [proposed], Figure 4-17) and one monitoring well (NRDT-1) through the Deadwood Formation, as designed by OLCV according to NDAC § 43-05-01-11.5. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO_2 with water mixtures, and protect any USDWs. Tables 4-27 and 4-28 provide the cement program for plugging the proposed Broom Creek CO_2 injection wells, Liberty-1 (J-ROC1 File No. 37672) and Unity-1 (proposed).

The injection zone, the Broom Creek Formation, and overlying seal will be isolated from upper zones and USDWs with CO_2-resistant cement. An external mechanical integrity log will be performed before plugging. In addition, the well will be flushed with brine to force CO_2 into the formation.

Table 4-27. Liberty-1 (J-ROC1 File No. 37672) Proposed Broom Creek CO_2 Injection Well P&A Cement Plug Program

Description/Plug No.	1	2	3	4
Placement Method	Squeeze	Balanced plug	Balanced plug	Balanced plug
Slurry Density	15.8	15.8	15.8	15.8
Type of Slurry	CO_2-resistant		Class G + additive	
ID, in.	8.681	8.681	8.681	8.681
Slurry Volume, bbl	77	48	40	6
Sacks of Cement by Plug	388	244	195	31
Plug Top, feet	4,500	3,300	1,700	0
Plug Bottom, feet	5,200	3,900	2,200	80

Table 4-28. Unity-1 Proposed CO_2 Injection Well Cement Plug Program

Description/Plug No.	1	2	3	4
Placement Method	Squeeze	Balanced plug	Balanced plug	Balanced plug
Slurry Density	15.8	15.8	15.8	15.8
Type of Slurry	CO_2-resistant		Class G + additive	
ID, in.	8.681	8.681	8.681	8.681
Slurry Volume, bbl	77	56	40	6
Sacks of Cement by Plug	388	285	195	31
Plug Top, feet	4,650	3,300	1,700	0
Plug Bottom, feet	5,350	4,000	2,200	80

4.6.1 Liberty-1 (J-ROC1 File No. 37672) Broom Creek CO_2 Injection Well P&A

1. After injection has ceased, the well will be flushed with a kill fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure.

2. Bottomhole pressure measurements will be taken using the installed downhole gauges. In case the gauges are not functional, the operator will run pressure gauges during the P&A process of the well.

3. An active pulsed-neutron log will be run, and the well will be pressure-tested to ensure integrity both inside and outside of the casing prior to plugging. Production logging tools (PLTs), tracers, noise, or temperature logs could be run in substitution.

4. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding further with the plugging operations.

5. All casing in this well will have been cemented to surface at the time of construction and will not be retrievable at abandonment.

6. After injection is terminated permanently, the injection tubing and packer will be removed.

7. Then the balanced-plug placement method will be used to plug the well. A cement retainer will be used to isolate the perforation section to avoid flowback of formation fluids that could contaminate the plug.

Contingency: If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer, which will be left in the well. The cement retainer method will be used for plugging the injection formation below the abandoned packer.

8. All casing strings will be cut off at least 5 ft below the surface and plow line.

9. A blanking plate with the required permit information will be welded on top of the cutoff casing.

4.6.1.1 Liberty-1 (J-ROC1 File No. 37672) Injection Well-Plugging Schematic

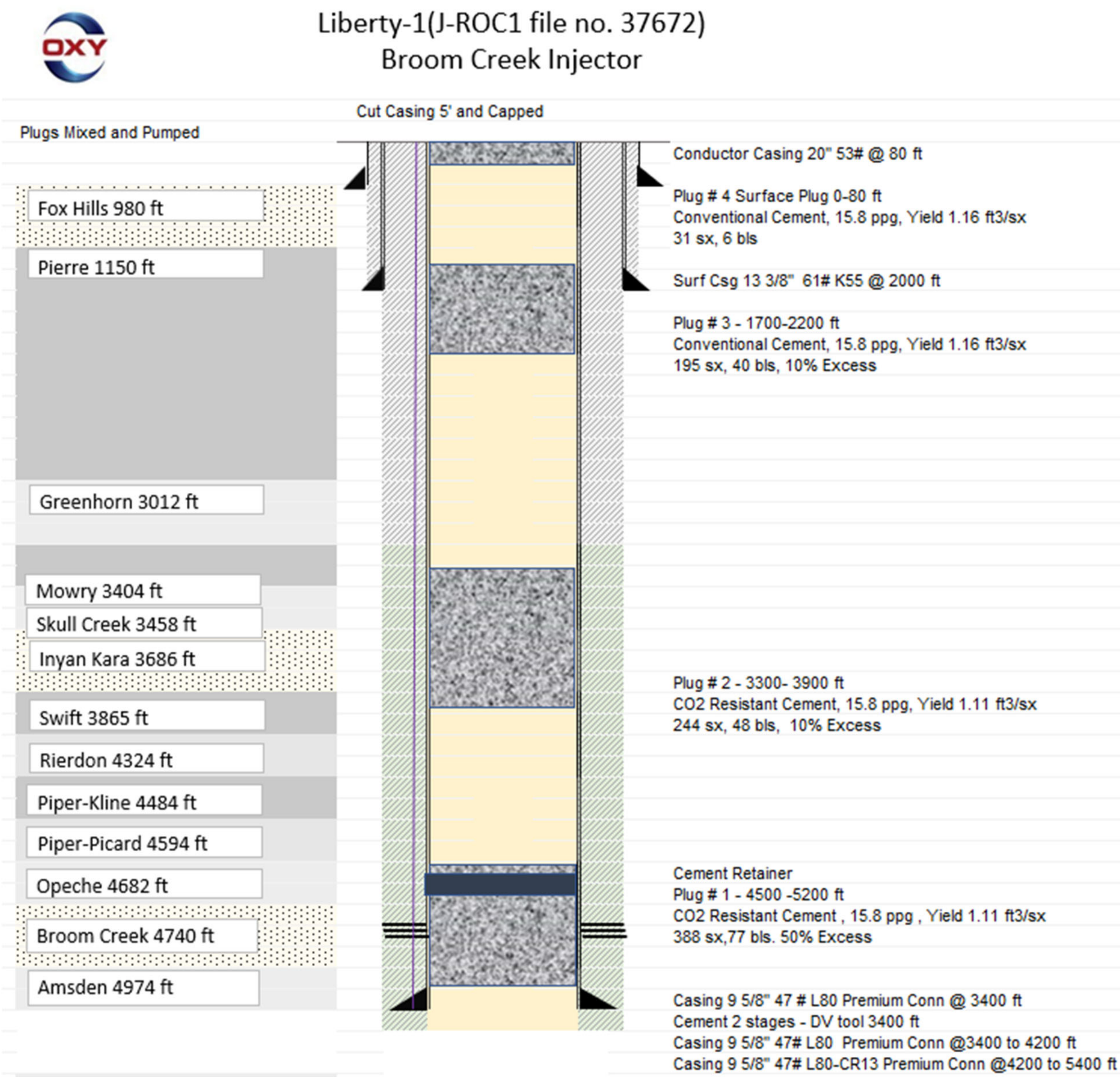


Figure 4-16. Proposed design of the Broom Creek CO_2 injection well, Liberty-1 (J-ROC1 File No. 37672), P&A wellbore schematic.

4.6.1.2 Tentative Plugging Procedures

1. Move in (MI) rig onto Liberty-1 (J-ROC1 File No. 37672) and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Record bottomhole pressure from downhole gauge and calculate the kill fluid density.

4. Test the pump and line to 5,000 psi. Fill tubing with kill fluid (determined by bottomhole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing pressure.

5. Test casing annulus to 1,500 psi, or NDIC-approved test pressure, and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.
   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior the P&A.

6. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).
   Contingency: If the well is not dead or pressure cannot be bled off the tubing, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

7. Pull out of hole and lay down tubing, packer, cable, and sensors.
   Contingency: If unable to release tubing and retrieve packer, RU electric line, and make cut on the tubing string just above packer. Make a cut above the packer at least 5 to 10 ft MD, pull the work string out of hole, and proceed to next step. If problems are noted, update cement remediation plan. The cement retainer might be used to force cement in case the packer cannot be removed.

8. Pick up work string, and trip in hole (TIH) with bit to condition wellbore.

9. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.

   a. Activate neutron log
   b. Noise log
   c. PLT
   d. Tracers
   e. Temperature log

10. TIH work string with cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

11. Mix and pump CO_2-resistant slurry to cover the Broom Creek Formation and isolate it from the Dakota Group in accordance with program. Disconnect from retainer and check flow. Circulate.

12. Set balanced plug with CO_2-resistant cement, 15.8 ppg to cover the Dakota Group and isolate it from the Fox Hills USDW. Pull out above the plug and circulate. Wait on setting time, and tag top of the plug.

13. Set balanced plug with Class G cement + additive, 15.8 ppg to cover the shoe of the surface casing. Pull out above the plug and circulate. Wait on setting time, and tag top of the plug.

14. Set surface plug with Class G cement + additive, 15.8 ppg to isolate the top of surface casing.

15. Lay down all the work string. Rig down all equipment and move out. Cut the casing at 3' below the ground. Clean cellar to where a plate can be welded with well information.

16. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4.6.2 Unity-1 (proposed) Broom Creek CO_2 Injection Well P&A

1. After injection has ceased, the well will be flushed with a kill fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure.

2. Bottomhole pressure measurements will be taken using the installed downhole gauges. In case the gauges are not functional, the operator will run pressure gauges during the P&A process of the well.

3. An active pulsed-neutron log will be run, and the well will be pressure-tested to ensure integrity both inside and outside the casing prior to plugging. PLT, tracers, noise, or temperature logs could be run in substitution.

4. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding further with the plugging operations.

5. All casing in this well will have been cemented to surface at the time of construction and will not be retrievable at abandonment.

6. After injection is terminated permanently, the injection tubing and packer will be removed.

7. Then the balanced-plug placement method will be used to plug the well. A cement retainer will be used to isolate the perforation section to avoid flowback of formation fluids that could contaminate the plug.

   Contingency: If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer, which will be left in the well. The cement retainer method will be used for plugging the injection formation below the abandoned packer.

8. All casing strings will be cut off at least 5 ft below the surface and plow line.

9. A blanking plate with the required permit information will be welded on top of the cutoff casing.

4.6.2.1 Unity-1 (proposed) Injection Well-Plugging Schematic

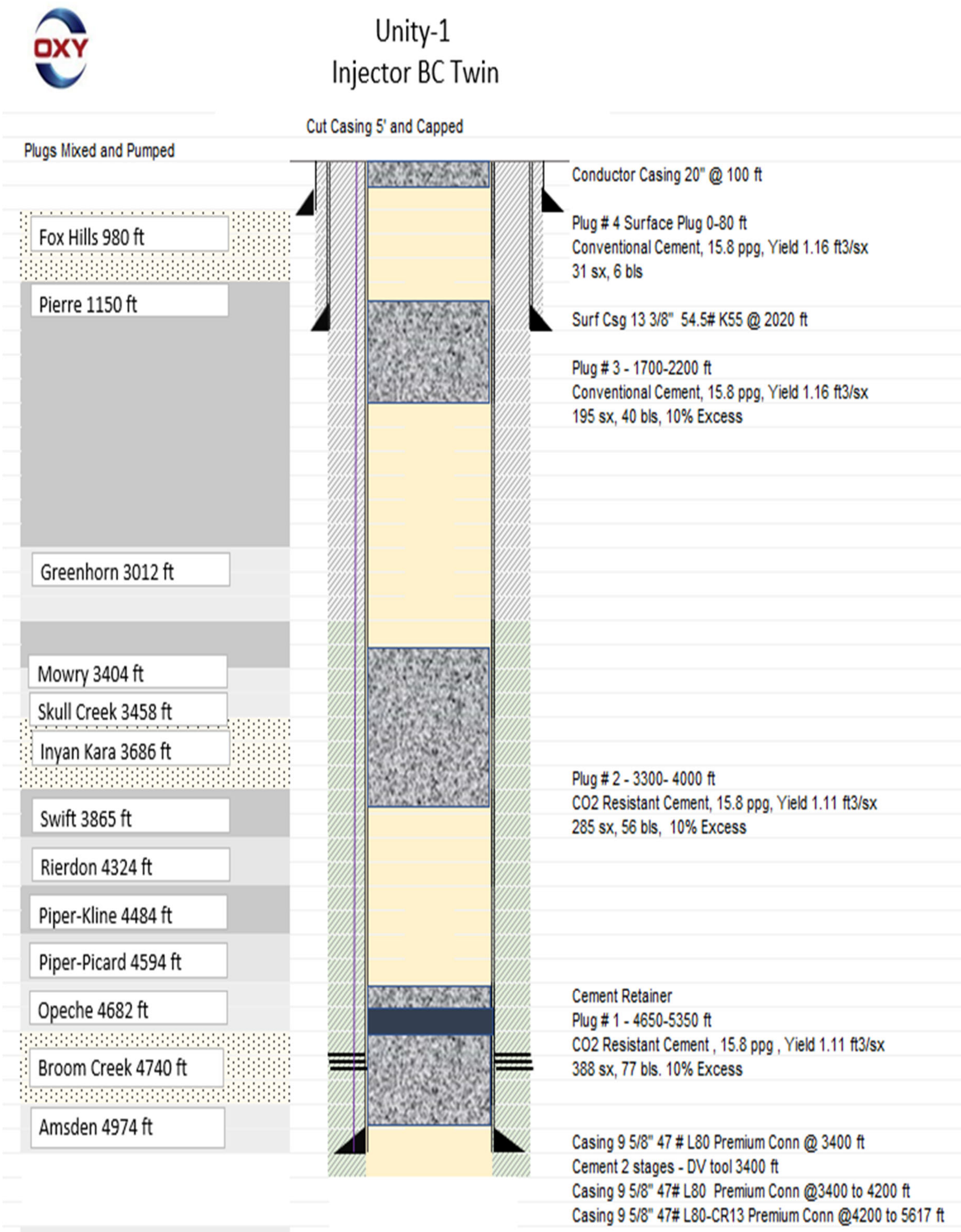


Figure 4-17. Unity-1 proposed design of the Broom Creek CO_2 injection well P&A wellbore schematic.

4.6.2.2 Tentative Plugging Procedures

1. MI rig onto Unity-1 (proposed) and RU. All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Record bottomhole pressure from downhole gauge and calculate kill fluid density.

4. Test the pump and line to 5,000 psi. Fill tubing with kill fluid (determined by bottomhole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing pressure.

5. Test casing annulus to 1,500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in the long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

6. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or pressure cannot be bled off the tubing, RU slickline, and set plug in the lower profile nipple below the packer. Circulate tubing and annulus with kill weight fluid until the well is dead. Then nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with a work string.

7. Pull out of hole, and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release the tubing and retrieve packer, RU electric line and make a cut on tubing string just above the packer. Make a cut above the packer at least 5 to 10 ft MD, pull work string out of the hole, and proceed to the next step. If problems are noted, update cement remediation plan. A cement retainer might be used to force cement out in case the packer cannot be removed.

8. Pick up the work string and TIH with bit to condition wellbore.

9. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.

   a. Activate neutron log
   b. Noise log
   c. PLT
   d. Tracers
   e. Temperature log

10. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

11. Mix and pump CO_2-resistant slurry to cover Broom Creek Formation and isolate it from the Dakota Group as per program. Disconnect from the retainer, and check flow. Circulate.

12. Set a balanced plug with CO_2-resistant cement 15.8 ppg to cover the Dakota Group, and isolate it from the Fox Hills USDW. Pull up above the plug and circulate. Wait on setting time, and tag top of the plug.

13. Set balanced plug with Class G cement + additive, 15.8 ppg to cover the shoe of the surface casing. Pull up above the plug and circulate.

14. Set surface plug with Class G cement + additive, 15.8 ppg to isolate the top of the surface casing.

15. Lay down the work string. Rig down all equipment and move out. Cut the casing at 3 ft below the ground. Clean cellar to where a plate can be welded on with well information.

16. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4.6.3 NRDT-1 Monitor Well P&A

Upon completion of the project, as part of the closure plan of the facilities, the NRDT-1 monitor well will be plugged and abandoned according to NDAC § 43-05-01-11.5. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO_2 with water mixtures, and protect any USDWs.

NRDT-1 is located at the border of the projected CO_2 plume, which minimizes the probability that the CO_2 mixed with formation fluids will cause damage to the cement or proposed tubulars. The plugs are designed to isolate the Black Island/Deadwood perforations from the Broom Creek section and overlaying seal until the USDW. An external mechanical integrity log will be performed before plugging. In addition, the well will be flushed with brine to force any formation fluid back into the reservoir. Table 4-29 provides the plugging cement program for the proposed NRDT-1 CO_2-monitoring well. Figure 4-18 shows the wellbore schematic.

Table 4-29. NRDT-1 Proposed CO_2 Monitor Well P&A Cement Plug Program

Description/Plug No.	1	2	3	4	5
Placement Method	Squeeze	Squeeze	Balanced plug	Balanced plug	Balanced plug
Slurry Density	15.8	15.8	15.8	15.8	15.8
Type of Slurry		CO_2-resistant		Class G + additive	
ID, in.	4.653	4.653	4.653	4.653	4.653
Slurry Volume, bbl	19	13	14	12	4
Sacks of Cement by Plug	96	64	70	56	18
Plug Top, feet	9,100	4,600	3,300	1,700	0
Plug Bottom, feet	9,700	5,000	3,900	2,200	160

4.6.3.1 NRDT-1 Monitor Well-Plugging Schematic

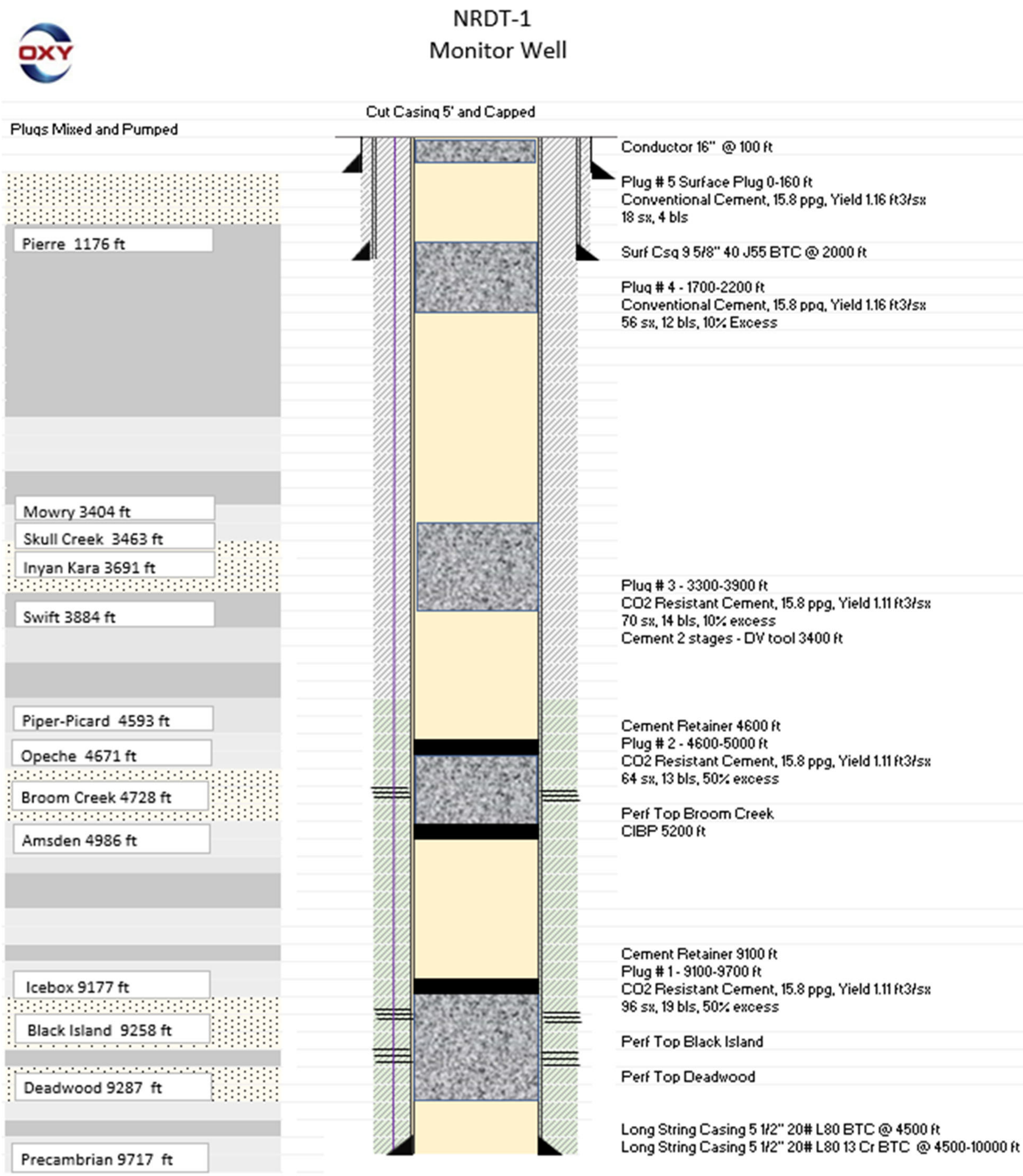


Figure 4-18. NRDT-1 proposed design of the CO_2 monitor well P&A wellbore schematic.

4.6.3.2 Tentative Plugging Procedures

1. MI rig onto NRDT 01 and RU.

2. Conduct and document a safety meeting.

3. Test the pump and line to 5,000 psi. Fill tubing with kill fluid. Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing pressure.

4. Test casing annulus to 1,500 psi and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long string casing is identify, the operator will prepare a plan to repair the well prior to P&A.

5. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or the pressure cannot be bled off tubing, RU slickline and set plug in lower-profile nipple below first packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down tree, NU blowout preventers and perform a function test. Prepare to recover packer with work string.

6. Pull out of hole, and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packers due to:

   a) Top Packer Stuck: Prepare plan to cut tubing above the top packer, 5 to 10 ft of MD. Mill/wash over the seals and OD of the top packer to release the string, until the bottom packer. Run fishing equipment and work fish out.

   b) Bottom Packer Stuck: If bottom packer is stuck, proceed to RU electric line and make cut on tubing string just above bottom packer pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan.

7. Pick up work string and TIH with bit to condition wellbore.

8. Pull out of the hole and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.

   a. Activate neutron log
   b. Noise log
   c. PLT
   d. Tracers
   e. Temperature log

9. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

10. Mix and pump CO_2-resistant slurry to cover the Black Island/Deadwood Formations and isolate it from the upper formations. Disconnect from the retainer and check flow. Circulate.

11. Pull work string out of the hole.

12. Run CIBP 50 ft below the perf in Broom Creek ~ 5,000 ft.

13. TIH work string with work string and cement retainer to the top of Plug 2. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

14. Mix and pump CO_2 resistant slurry 15.8 ppg to isolated Broom Creek Formation from Dakota Group. Disconnect from retainer and check flow. Circulate.

15. Pull work string to 3,900 ft. Circulate. Set balanced plug, CO_2 resistant slurry 15.8 ppg to cover Dakota Group and isolate it from USDW Fox Hills. Pull 300 ft above the plug. Wait on cement. Run in the hole and tag plug.

16. Set balanced plug with Class G cement + additive 15.8 ppg to cover the shoe of the surface casing. Pull out above the plug and circulate.

17. Set surface plug with Class G cement + additive, 15.8 ppg to isolate the top of surface casing.

18. Lay down all work string. Rig down all equipment and move out. Cut the casing at 5 ft below surface. Clean cellar to where a plate can be welded with well information.

19. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4.7 Postinjection Site and Facility Closure Plan

The PISC and facility closure plan describes the activities that Minnkota 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. The monitoring locations, methods, and schedule are designed to show the position of the CO_2 plume and demonstrate that the CO_2 injected is within the storage reservoir and there is no endangerment to USDWs.

Based on the 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), ensuring the safety of USDWs within the AOR. 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 and safety of USDWs. The nature and duration of that extension will be determined based upon 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 surface land of the site will be reclaimed to as close as 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 be submitted to NDIC 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 in both formations at a rate of 2 MMt per year, followed by a postinjection period of 10 years.

Figure 4-19 shows the predicted pressure differentials in the Broom Creek Formation at the conclusion of 20 years of CO_2 injection. As shown, at the time that CO_2 injection is stopped in both formations, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 336 to 434 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 these pressure evaluations are provided as part of the AOR delineation of this permit application (see Appendix A).

A description of the predicted decrease in the pressure profile of the Broom Creek Formation over the 10-year postinjection period is provided in Figure 4-20. 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 186 to 284 psi as compared to the pressure at the time CO_2 injection was terminated. This trend of decreasing pressure in the storage reservoirs 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.

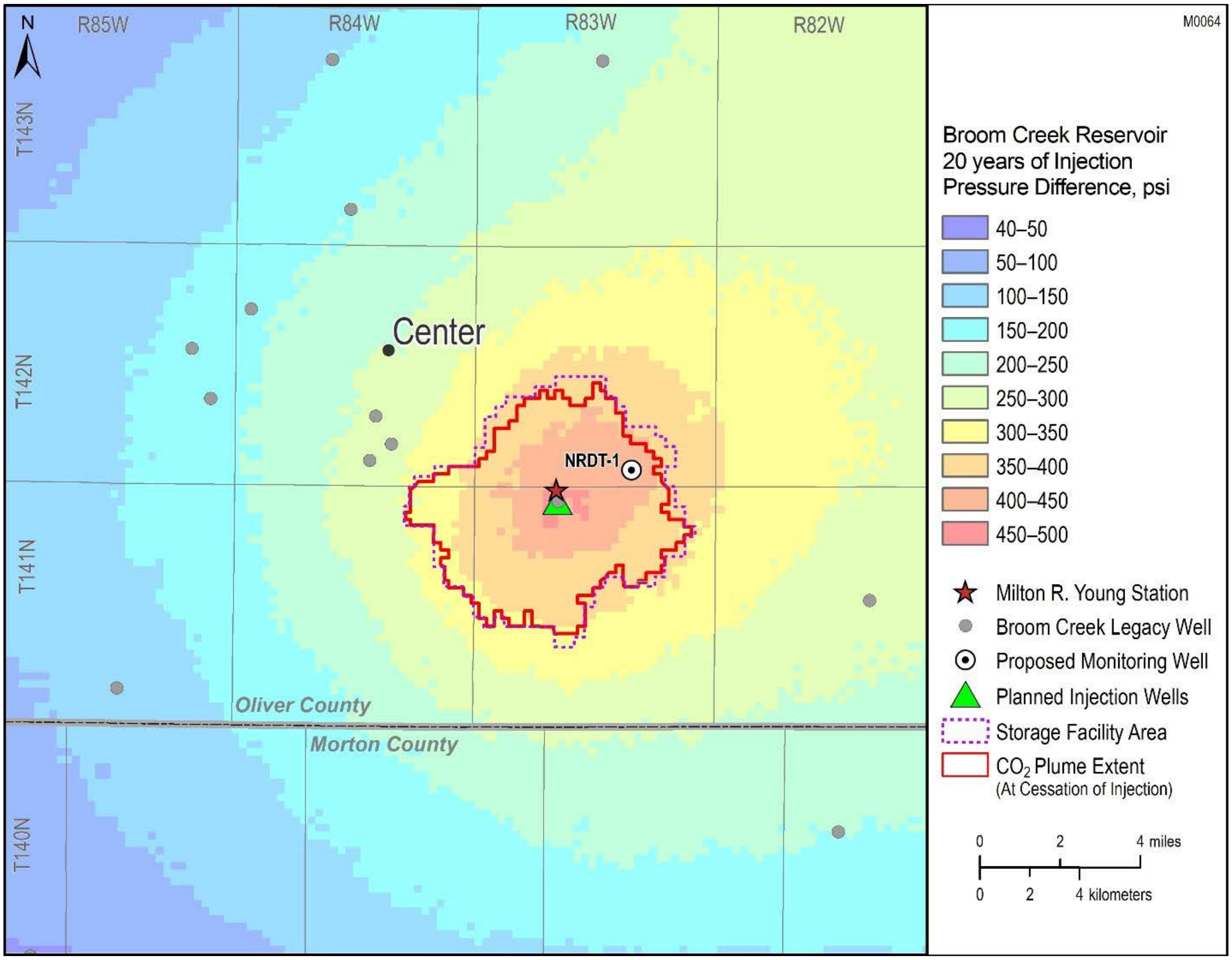


Figure 4-19. Predicted pressure increase in storage reservoir following 20 years of injection of 2 MMt per year of CO_2.

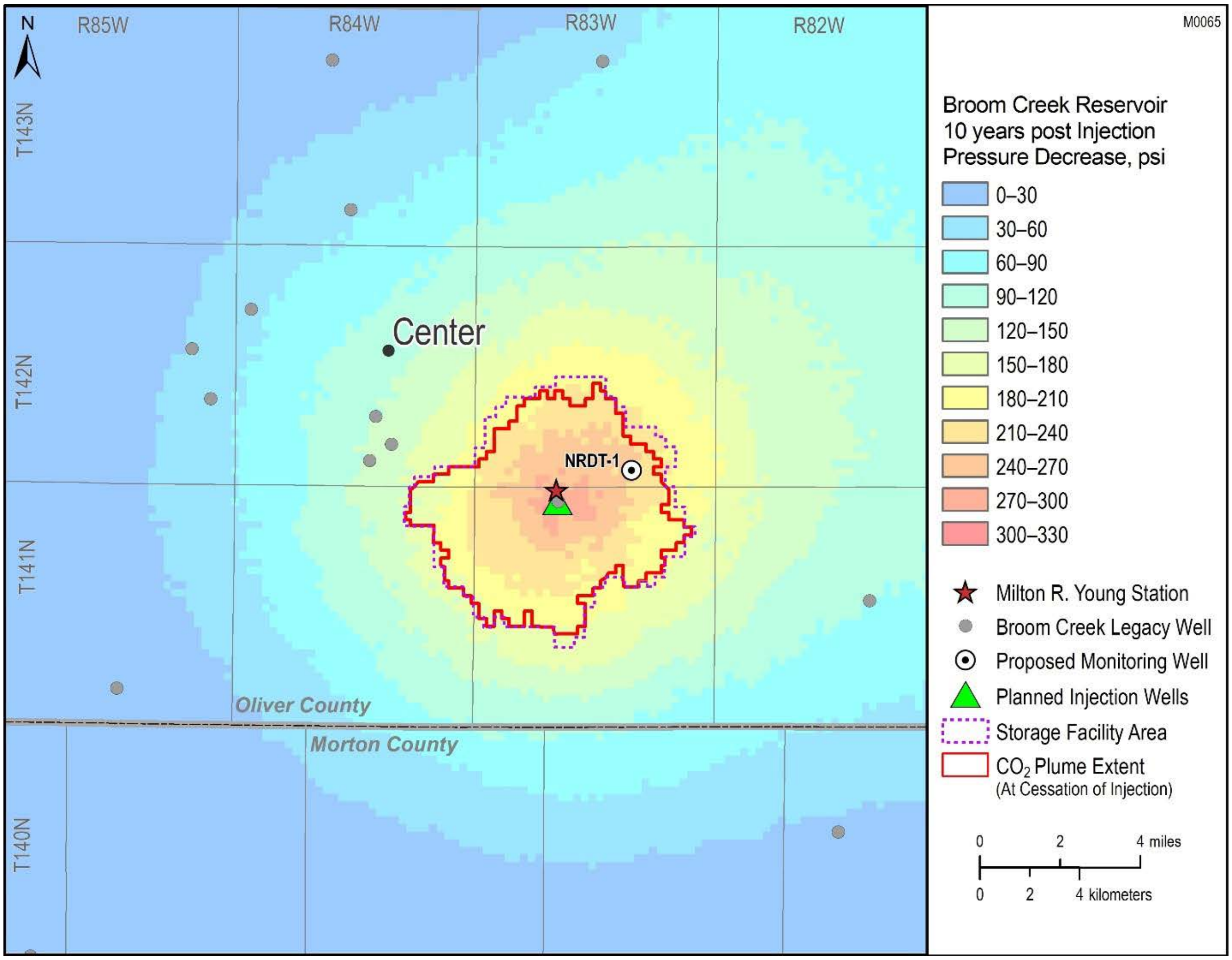


Figure 4-20. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

4.7.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 4-19 and 4-20 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 will be contained within an area of 24 mi^2 at the end of CO_2 injection (see Figure 4-19). As shown in Figure 4-20, 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 predicted that at no time will the boundary of the stabilized plume at the site extend beyond the boundary of the storage facility area, which is shown on both Figures 4-19 and 4-20. 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.

4.7.2 Postinjection Monitoring Plan

A summary of the postinjection monitoring plan that will be implemented during the 10-year postinjection period is provided in Table 4-35. 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 4-35.

Table 4-35. Summary of 10-year Postinjection Site Care – Monitoring Program

Type of Monitoring	Frequency	Comments
	Near-Surface Monitoring	
Soil Monitoring		
Soil Gas Profile Stations (Soil Gas Location – see Figure 4-21)	Duration: minimum 10 years. Frequency:3–4 seasonal sample events at soil gas profile station locations performed every 3 years following cessation of CO_2 injection.	Located at Liberty-1 (J-ROC1 File No. 37672), NRDT-1, and Herbert Dresser wells (see Figure 4-21.
Water Monitoring		
Groundwater Wells 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. Duration: minimum 10 years. Frequency: 3–4 sample events per year per well at cessation of CO_2 injection and at the last year as part of the final site closure assessment.	Sampling will be performed on all active and accessible freshwater groundwater wells within the AOR (see Figure 4-21) deepest USDW.

Continued . . .

Table 4-35. Summary of 10-year Postinjection Site Care – Monitoring Program (continued)

Type of Monitoring	Frequency	Comments
Storage Reservoir Monitoring		
Injection Well (Liberty-1 [J-ROC1 File No. 37672] and Unity-1 [proposed])	Monitor fluid levels until well is plugged.	Minnkota plans to P&A injection wells (Liberty-1 [J-ROC1 File No. 37672], Unity-1 [proposed]) at cessation of injection operations.
Downhole Pressure and Temperature Monitoring (NRDT-1)		
Distributed Fiber Optic Temperature (DTS)	Continuous.	DTS fiber will give continuous temperature profile for monitoring well NRDT-1 from the base of fiber to the surface until plume stabilization.
Pressure and Temperature Gauges in NRDT-1 (proposed)	Bimonthly.	Gauges provide continuous temperature and pressure monitoring of the injection zone (Broom Creek) until plume stabilization. Monitoring will continue as part of postinjection site care and facility closure plan.
Wireline Logging and Retrievable Monitoring (NRDT-1)		
PNL (NRDT-1 [proposed])	NRDT-1 at cessation of injection and once every 5 years thereafter until plume stabilization is demonstrated.	Log Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed), and NRDT-1 wells at cessation of injection.
Well Integrity Test		
External Mechanical Integrity: USIT or Electromagnetic Casing Inspection Tool	Duration: minimum. 10 years postinjection Frequency: perform during well workovers but not more frequently than once every 5 years in NRDT-1.	N/A P&A Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed) wells.
External Mechanical Integrity: Downhole Temperature	Annual temperature logging in NRDT-1 (proposed) (if fiber fails) until plume stabilization	
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 in NRDT-1.	

Continued . . .

Table 4-35. Summary of 10-year Postinjection Site Care – Monitoring Program (continued)

Type of Monitoring	Frequency	Comments
Geophysical Monitoring		
Time-Lapse Seismic	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	To be determined.	To be determined – continuous monitoring of ground elevation based on relative storage deformation with InSAR until storage facility achieves stabilization.

4.7.3 Groundwater and Soil Gas Monitoring

Three soil gas profile stations, two Fox Hills Formation (i.e., deepest USDW) monitoring wells, and various 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 4-21 identifies the location of these soil gas profile stations, Fox Hills Formation (USDW) 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.

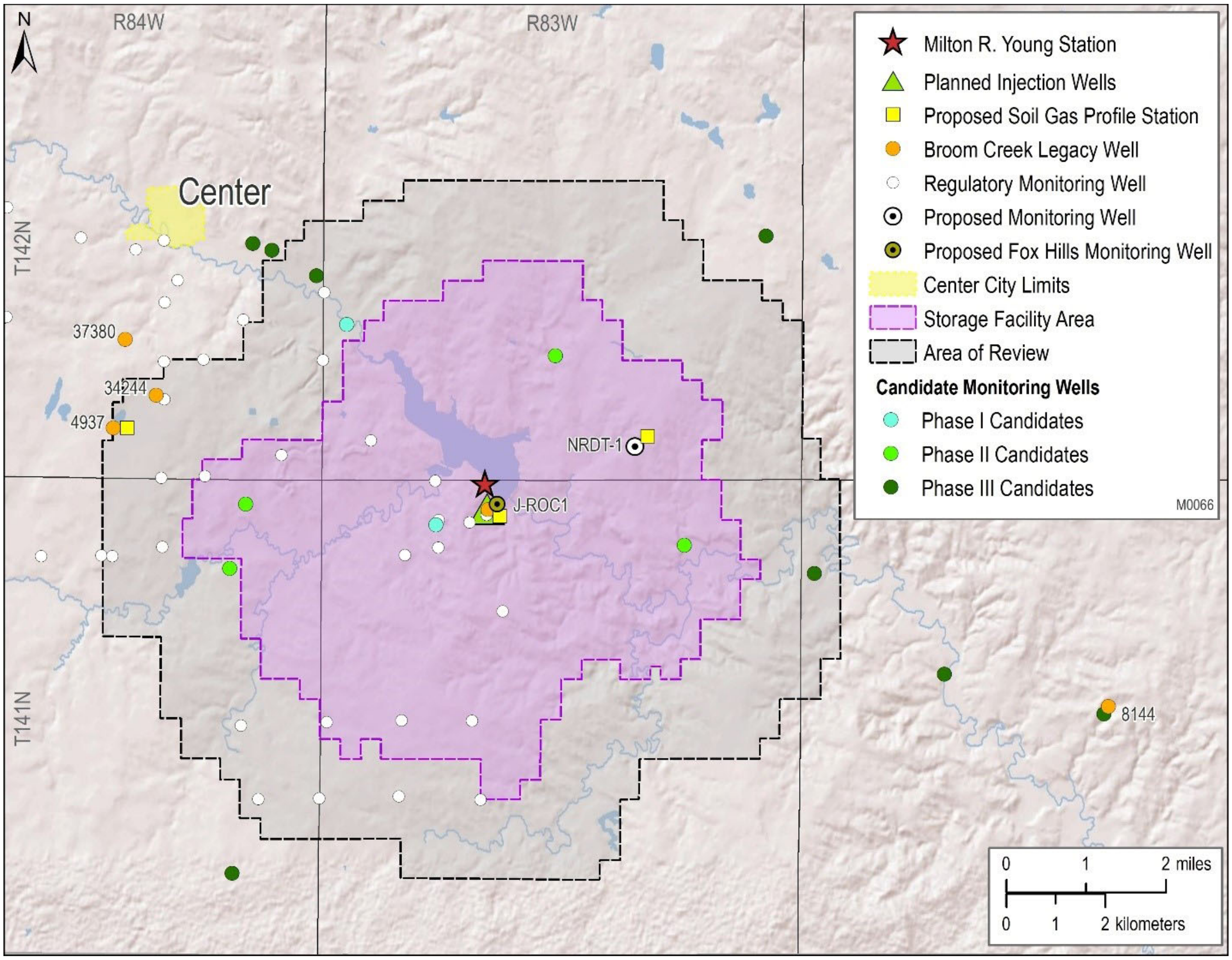


Figure 4-21. Location of soil gas and USDW/groundwater well sampling locations included in the PISC monitoring program.

4.7.4 Monitoring of CO_2 Plume and Pressure Front

Monitoring of the CO_2 plume location and storage reservoir pressure will be conducted during the PISC period using the methods summarized in Table 4-34, 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 3D seismic monitor [4D seismic]) that monitor CO_2 saturation. Figure 4-22 provides an aerial view of the extents of both the existing 3D seismic surveys and potential borehole seismic (or VSP) surveys as compared to the predicted areal extents of the CO_2 plume at cessation of injection and stabilized plume.

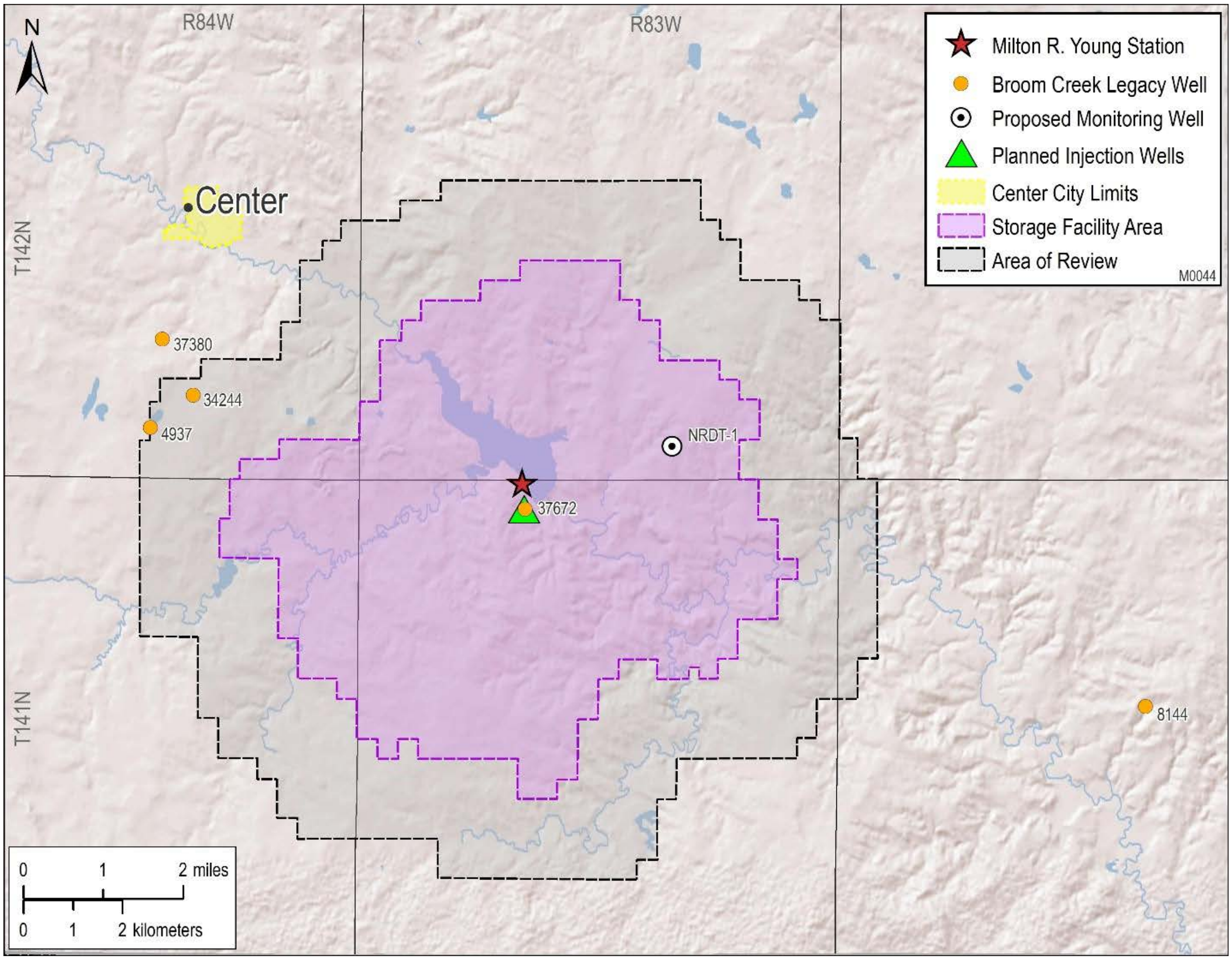


Figure 4-22. Simulated extent of the CO_2 plume at the end of injection operations in green Surface seismic and borehole VSP seismic data outlines that are shown on the map will provide coverage for indirectly monitoring the predicted extents of the CO_2 plume over time.

4.7.4.1 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. Water analysis reports will be submitted to the state water commission annually.

4.7.4.2 Site Closure Plan

Minnkota 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; decommissioning of storage facility equipment, appurtenances, and structures (e.g., structures/buildings, gravel pads, access roads, etc.) not associated with monitoring; and reclaiming of the surface land of the site to as close as practical to its original condition.

4.7.4.3 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 the 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 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, Minnkota 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, Minnkota 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

ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.atsm.org (accessed December 2020).

Reed, S., Ge, J., Burnison, S.A., Bosshart, N.W., Hamling, J.A., and Gorecki, C.D., 2018, Viability of InSAR as a monitoring tool in challenging terrain–Bell Creek, Montana: Paper presented at the 14th International Conference on Greenhouse Gas Control Technologies (GHGT-14), Melbourne, Australia, October 21–25, 2018.

Vasco, D.W., Dixon, T.H., Ferretti, A., and Samsonov, S.V., 2020, Monitoring the fate of injected CO_2 using geodetic techniques: The Leading Edge, v. 39, no. 1, p. 29–37.

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, Tables 5-1 and 5-2) and NDAC § 43-05-01-11.3.

Table 5-1. Proposed Broom Creek Injection Well Operating Parameters (with total data between the two wells)

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume	76.64 million tonnes	Based on 4.0MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years for a total injection period of 20 years at an average daily injection rate of 10,577 tonnes/day (using 360 operating days per year).
Injection Rates		
Proposed Average Injection Rate	10,577 tonnes/day	Based on 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years for a total injection period of 20 years (using 360 operating days per year).
Calculated Maximum Daily Injection Rate	10,948 tonnes/day	Based on the 20 years of injection with a group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years.

Table 5-2. Proposed Broom Creek Injection Well Operating Parameters

	Liberty-1	Unity-1	Description/Comments
Injection Volume			
Total Injected Volume, million tonne	36.42	41.04	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum bottomhole pressures (BHPs) of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Injection Rate			
Predicted Average Injection Rate, tonne/day	4988.2	5615.8	Based on total injected volumes for 20 years and using 360 operating days per year.
Maximum Predicted Daily Injection Rate, tonne/day	5162.6	5829	Based on the 20 years of injection with • A constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years with wells injecting independently. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
	8744.9	9260.6	Based on the 20 years of injection with: • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Pressure			
Formation Fracture Pressure at Top Perforation, psi	3371.3	3352.6	The injectivity test results fracture propagation formation fracture gradient of 0.712 psi/ft.
Average Predicted Operating Surface Injection Pressure, psi	1399	1431	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Maximum Wellhead Injection Pressure, psi	1700	1700	Maximum wellhead injection pressure is limited based on surface facility constraints and 90% of formation fracture pressure.
Average Predicted Operating BHP, psi	3008	2993	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Maximum BHP, psi	3035.1	3018.3	Calculated maximum BHP using 90% of the propagation pressure from the injectivity test at the top of the perforation.

5.1 Proposed Completion Procedure to Conduct Injection Operations in the Broom Creek Injection Wells Liberty-1 (J-ROC1 File No. 37672) and Unity-1

Minnkota Power Cooperative (Minnkota) plans to construct two Broom Creek carbon dioxide (CO_2) injection wells: 1) Liberty-1 (J-ROC1 File No. 37672) well reentry and 2) proposed Unity-1 well, with all wells designed by Oxy Low Carbon Ventures in compliance with Class VI UIC (underground injection control) injection well construction requirements. Plans to construct the second Broom Creek injection well, Unity-1, follow completion procedures similar to the Liberty-1 (J-ROC1 File No. 37672) well. The drilling of the cement plugs and casing of the wellbore for the Liberty-1 (J-ROC1 File No. 37672) well is included in the drilling program. The following proposed completion procedure outlines the steps necessary to complete both the Broom Creek wells for injection purposes (Tables 5-3 and 5-4, Figure 5-1, Figure 5-2, and Figure 5-3).

Table 5-3. Liberty-1 (J-ROC1 File No. 37672) Wellbore Surface and Proposed Longstring Casing Properties

Casing Description ID	Hole, in.	Depth, ft	ID, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Conn, in.
13.375" 61# K55 BTC	17.5	0–2,000	12.515	3,090	1,540	962	14.375
9.625" 47# L80 Premium Conn	12.25	0–4,200	8.681	6,870	4,750	1,086	10.625
9.625" 47# L80 13Cr Premium Conn	12.25	4,200–5,400	8.681	6,870	4,750	1,086	10.625

Table 5-4. Unity-1 Proposed Casing Properties

Casing Description ID	Hole, in.	Depth, ft	ID, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Conn, in.
13.375" 54.5# K55 BTC	17.5	0–2,000	12.615	2,730	1130	766	14.375
9.625" 47# L80 Premium Conn	12.25	0–4,200	8.681	6,870	4750	1,086	10.625
9.625" 47# L80 13Cr Premium Conn	12.25	4,200–5,618	8.681	6,870	4750	1,086	10.625

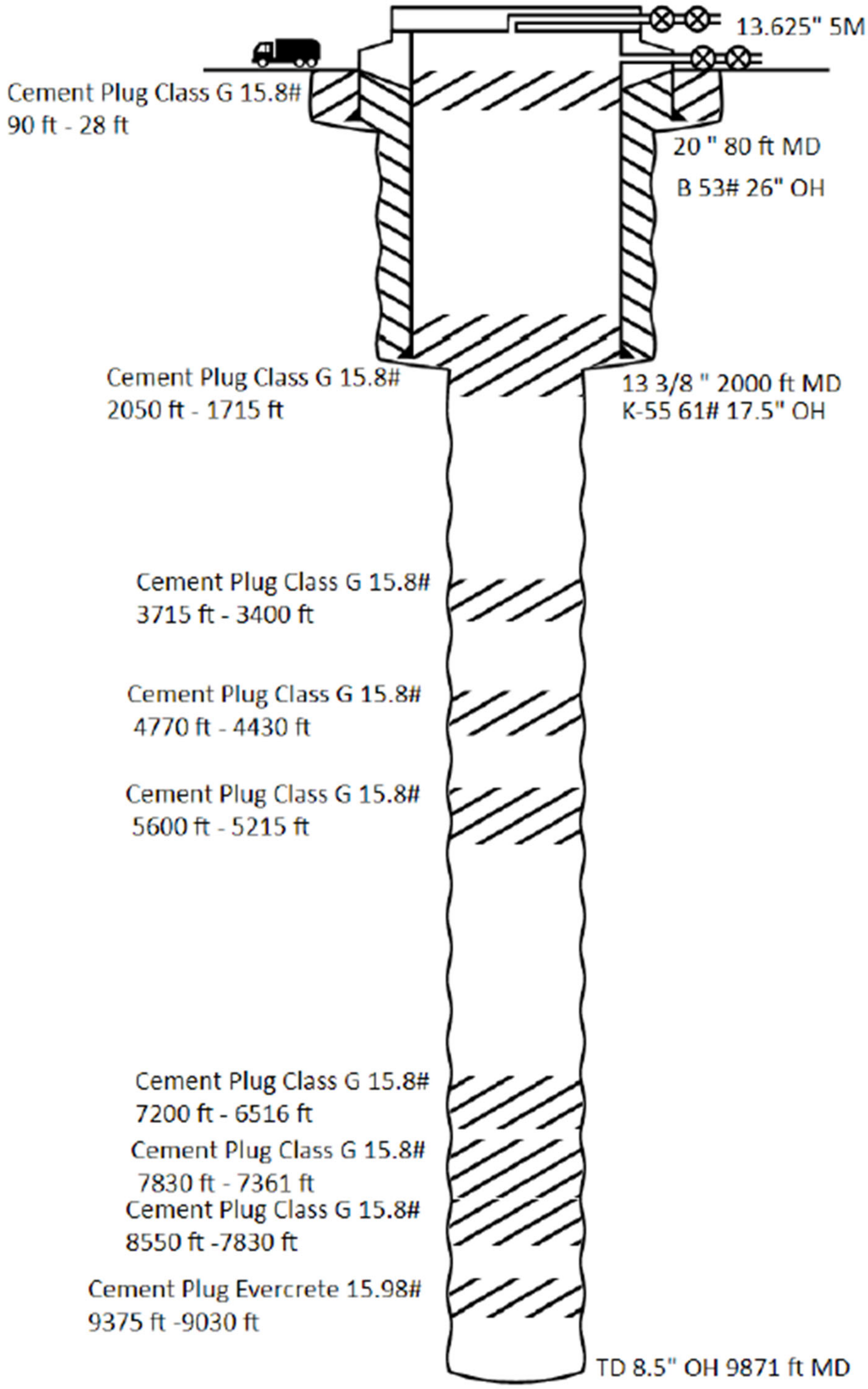


Figure 5-1. Liberty-1 (J-ROC1 File No. 37672) as-constructed wellbore schematic.

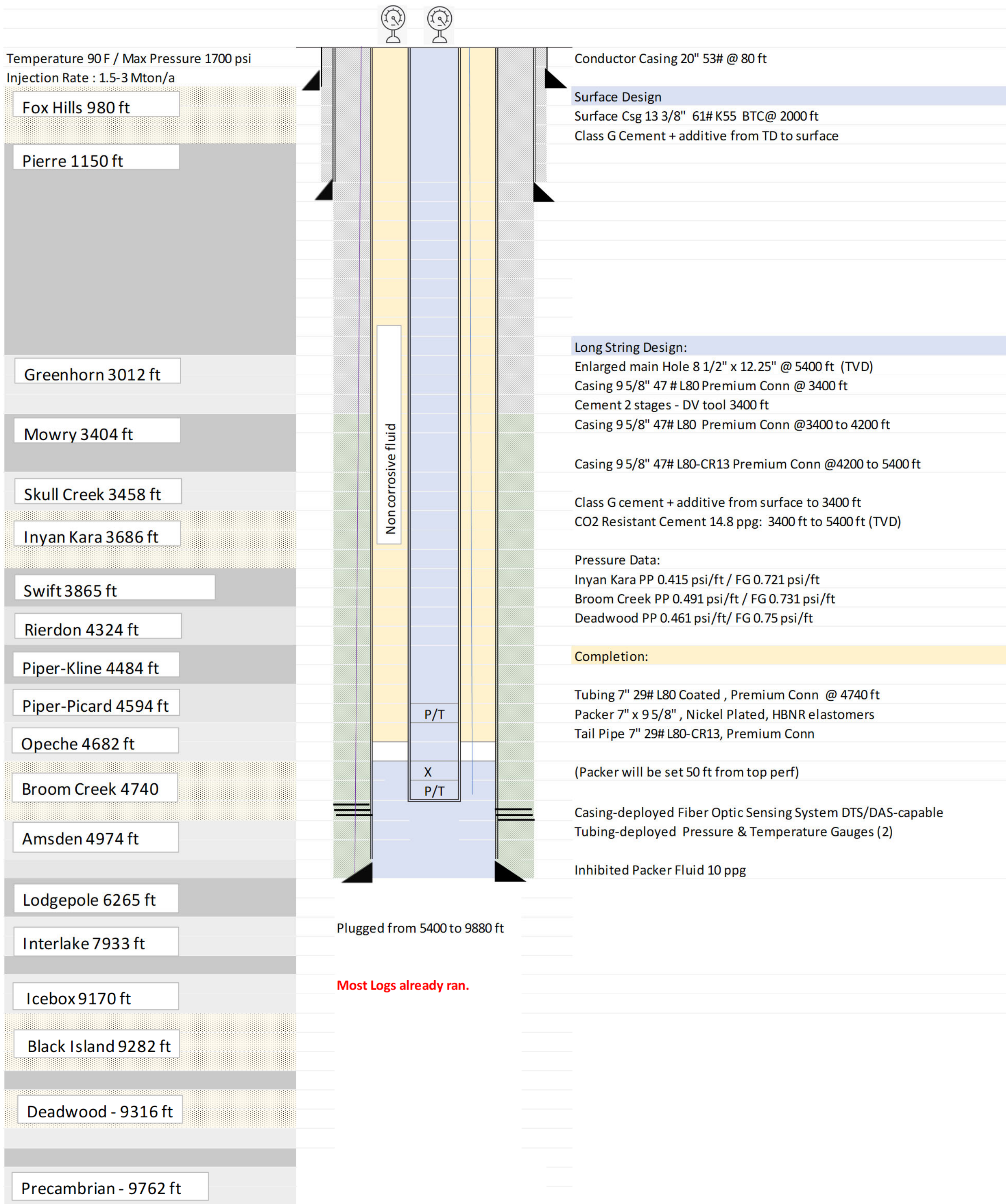


Figure 5-2. Liberty-1 (J-ROC1 File No. 37672) Broom Creek injection proposed well completion wellbore schematic.

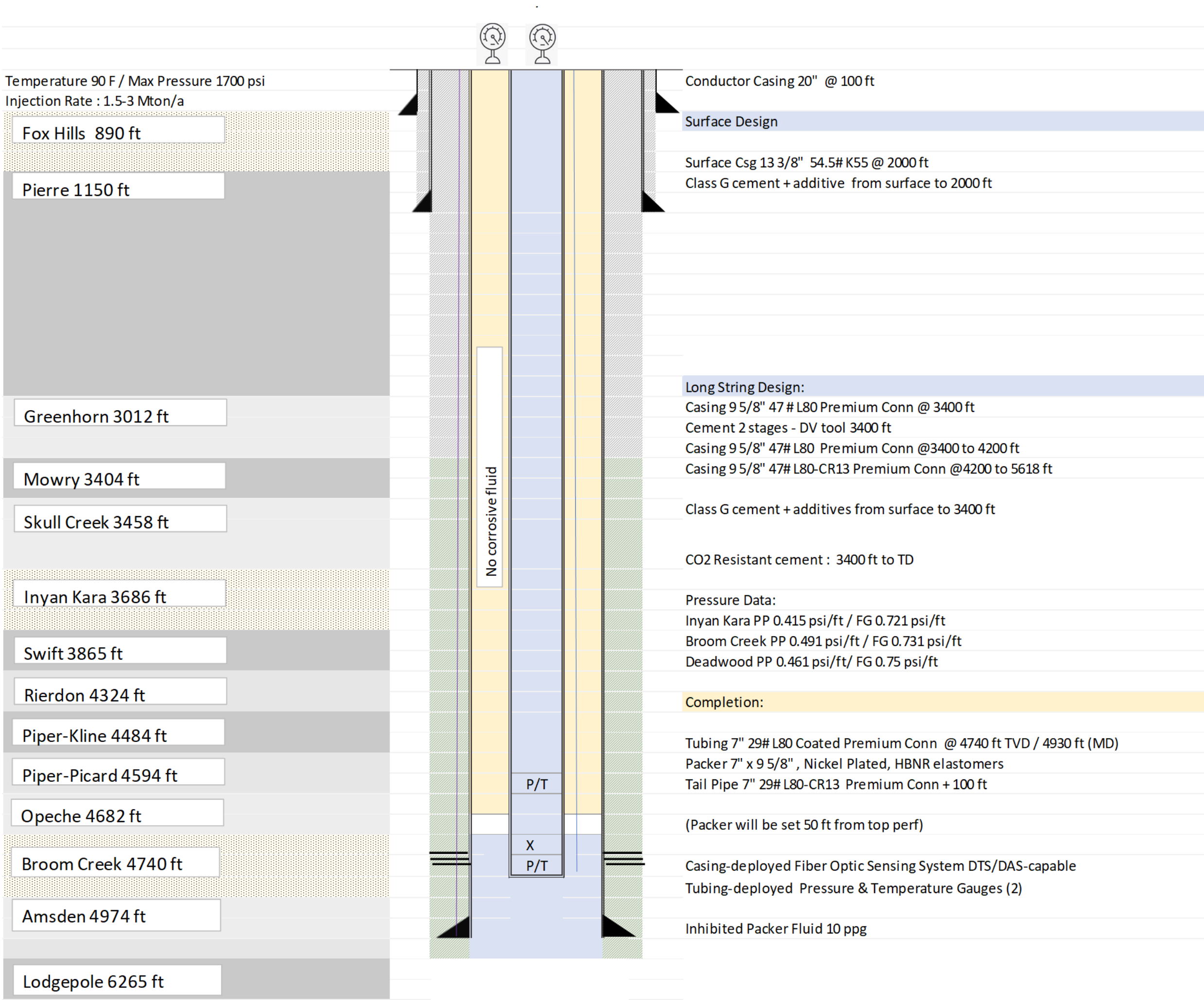


Figure 5-3. Unity-1 Broom Creek injection well proposed completion wellbore schematic.

5.2 Proposed Completion Procedure for Broom Creek CO_2 Injectate Well

1. Nipple up BOP (blowout preventer).
2. Test BOP.
3. Pick up work string and bit to clean out cement.
4. Run in the hole and tag the stage tool.
5. Circulate with brine, 10 ppg.
6. Drill out the stage tool and clean the casing until the top of the float collar.
7. Circulate with brine, 10 ppg.
8. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the Operator may require assessing the root cause and correcting it.
9. Pull BHA (bottomhole assembly) out of the hole.
10. Perform safety meeting to discuss logging and perforating operations.
11. Rig up logging truck.
12. Run cased-hole logs by program. Note: run CBL/VDL (cement bond log/variable density log) and USIT (ultrasonic imaging tool) logs without pressure as a first pass and run them with 1000 psi pressure as a second pass.

    Note: In case cementing logs show poor bonding in the cementing job, the results will be communicated to the North Dakota Industrial Commission (NDIC), and an action plan will be prepared.

13. Run oriented perforating guns to the injection target. An oriented gun should be used to avoid any damage to the external fiber optic.
14. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). The depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation.
15. Pull guns out of the hole.
16. Rig down logging truck.
17. Pick up straddle packer and run in the hole with work string.
18. Circulate with brine, 10 ppg.
19. Set packer to isolate the perforations.
20. Rig up acid trucks and equipment.
21. Perform cleaning of the perforations with acid. Adjust acid formulation and volumes with water samples and compatibility test.
22. Rig down acid trucks and equipment.
23. Perform an injectivity test/step rate test.
24. Unset packer and circulate hole.
25. Pull packer and work string out of the hole.
26. Rig up spooler and prepare rig floor to run upper completion.
27. Run completion assembly per program.
28. Circulate well with inhibited packer fluid.
29. Set packer 50 ft above the top perforations.
30. Install tubing sections, cable connector, and tubing hanger.
31. Rig up logging truck.

32. Run cased-hole logs through tubing by program.
33. Rig down logging truck.
34. Nipple down BOP.
35. Install injection tree.
    Note: Figure 5-4 illustrates the proposed wellhead schematic.
36. Rig down equipment.

Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber optic will be run along the exterior of the long string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations.

The proposed tubing design for the two wells is presented in Tables 5-5 and 5-6.

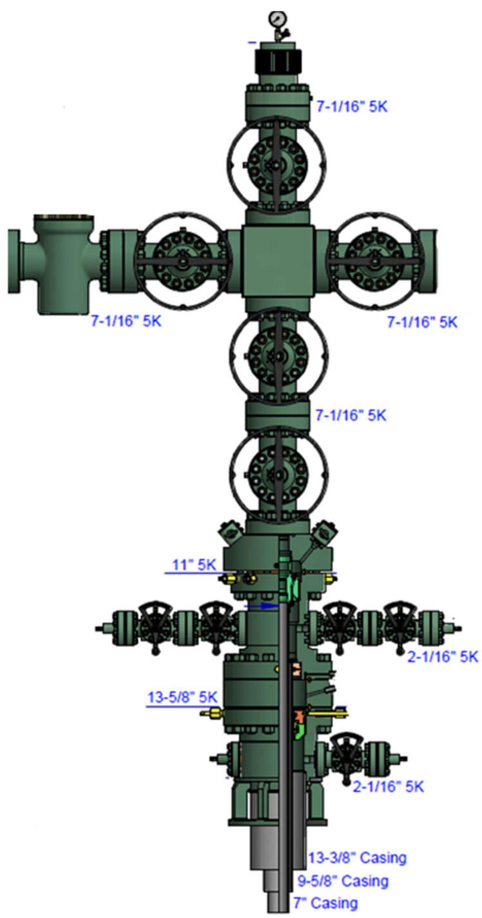


Figure 5-4. Proposed Broom Creek injection well CO_2-resistant wellhead schematic.

Table 5-5. Liberty-1 (J-ROC1 File No. 37672) Broom Creek CO_2 Injection Well Proposed Tubing Design

Description	Type, in.	Depth, ft	ID, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Thread, in.

* Hydrogenated nitrile butadiene rubber.

Table 5-6. Unity-1 Broom Creek CO_2 Injection Well Proposed Tubing Design

Description	Type, in.	Depth, ft	ID, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Thread, in.
7" 29# L80 Coated Premium Conn	Tubing	0–4,930	6.184	8,160	7,030	676	
		5,030					

1. The packer depth will be adjusted with the final perforation depth interval.
2. The packer will be set 50 ft above the top perforations.
3. Packers are required to be nickel-plated with HNBR elastomers.
   Inconel cable and quartz pressure and temperature gauges will be run in upper completion.

5.3 Logging and Testing Program

Tables 5-7 and 5-8 detail the proposed cased-hole logging program.

Table 5-7. Liberty-1 (J-ROC1 File No. 37672) Broom Creek CO_2 Injection Well Proposed Logging Program

Section	Type	Depth, ft
17½" Hole	**N/A**	
	Cased Hole: CBL/VDL	0–2,000
12¼" Hole	**Open Hole:**	
	GR	0–5,400
	5 Fluid Samples	By log
	Cased Hole:	
	Casing Inspection Log – Through Tubing	0–5,400
	Temperature – Calibration DTS	0–5,400

Table 5-8. Unity-1 Broom Creek CO_2 Injection Well Proposed Logging Program

Section	Type	Depth, ft
17½" Hole	**Open Hole:** Resistivity, GR (gamma ray), SP (spontaneous potential), Temperature	0–2,000
	Cased Hole: CBL/VDL	0–2,000
12¼" Hole	**Open Hole:**	
	Induction Resistivity	2,000–TD
	Density	2,000–TD
	Neutron	2,000–TD
	Sonic Dipolar	2,000–TD
	GR	2,000–TD
	Caliper	2,000–TD
	Temperature Log	2,000–TD
	SP	2,000–TD
	Spectral GR	2,000–TD
	Full-Bore Formation Microimager	3,400–TD
	10 SWC (seals, injection zones)	Depth by log
	5 Fluid Samples (injection zones)	Depth by log
	25 MDT (injection zones)	Depth by log
	Cased Hole:	
	CBL–VDL–Ultrasonic	0–TD
	Casing Inspection Log – Through Tubing	0–TD
	Active Pulse Neutron – Through Tubing	3,400–TD
	Temperature – Calibration DTS	0–TD

5.4 BOP Equipment (BOPE)

1. BOPE must be API-monogramed, adhere to API Standard 53 and Specifications 16A and 16C, at a minimum, and meet or exceed all applicable regulatory specifications (Figure 5-5).
2. BOPE other than annular preventers must have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
3. All BOPE stacks must incorporate a set of blind or blind/shear rams.
4. Blind rams must be located in the lower ram cavity of a two-ram stack or middle-ram cavity of a three-ram stack.
5. Choke and kill line outlets must be located below the blind rams on either a three- or two-ram stack.
6. All rigs must have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace from the hole during all tripping operations, including casing or completion string running. Trip sheets must include number of joints or stands ran into or pulled from the hole versus the calculated and actual displacements per step and running total, as a minimum.

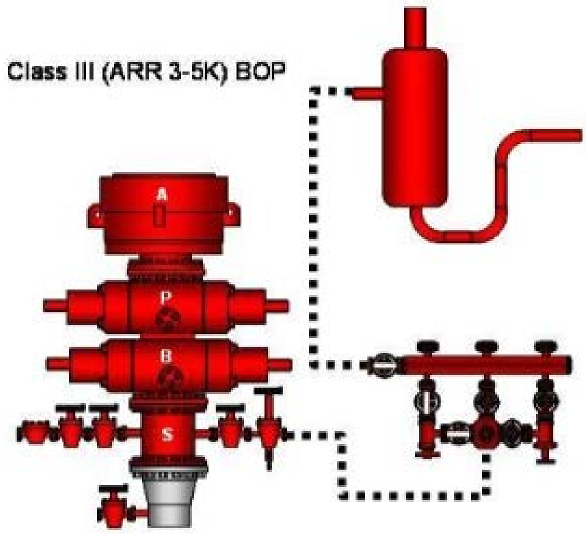


Figure 5-5. Proposed Broom Creek injection well blowout preventer schematic.

7. A full opening safety valve (FOSV) and inside BOP safety valve (IBOPSV) must be always available on the rig floor for each drill pipe, drill collar size, and connection type in use. The FOSV is used to stab into the string and shut off flow through the drill string. The IBOPSV is used **above** the FOSV to prevent backflow through the drill string. This equipment must remain in the full open position until installed.

Note: This requirement is in addition to any integral safety valve in the top drive system inclusive of casing running operations. In the event of a power failure on a VFD (variable-frequency drive) rig, it is impossible to slack off and make up the top drive to the string; therefore, an additional independent stabbing valve(s) is always required on the floor.

8. If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline must be available if a lubricator is not in use.
9. Pressure-energized metal ring gaskets must be used on flanged well control equipment. These gaskets must not be reused on equipment that will be nippled up on the wellbore.

5.4.1 Choke Manifolds and Kill Line

1. The choke manifold must be API-monogrammed, meet API Spec. 16C, at a minimum, and meet or exceed all applicable regulatory specifications.
2. All BOPE must include a choke manifold with at least one remotely operated choke and one manual choke installed. The control panel must contain calibrated drill pipe and casing pressure gauges that must be both accurate and maintained. The choke manifold casing pressure should have the capability of being recorded on the rig drilling recorder. If necessary, for clear dialogue, an electronic means of direct communication with the driller should be in place. This equipment must be tested and calibration-checked at each casing shoe, as well as at every BOPE test, and will be logged on every BOPE test report.

3. Flare/vent lines must be as long as practical, a minimum of 150' from well center, straight as possible, without sumps, collection areas or uphill flow areas (to prevent fluids buildup and resulting backpressure), and securely anchored.

5.4.2 Closing Units

1. BOPE closing units must adhere to API Spec. 16D and API STD 53, at a minimum, and meet or exceed all applicable regulatory specifications.
2. BOPE control systems must include full controls on the closing unit and at least one remote control station, which must be located within 10' of the drillers console.
3. The BOPE closing unit must have two separate charging pumps with two independent power sources, as specified in API Spec. 16D, or have N_2 bottle backup.
4. Closing units must have sufficient usable hydraulic fluid volume with pumps inoperative to close one annular preventer, close all ram preventers, and open one HCR (high closing ratio) valve against zero wellbore pressure with 200 psi remaining pressure above the precharge pressure.

5.4.3 Pressure Testing

1. BOPE (Figure 5-5) components (including the BOP stack, choke manifold, and choke lines) must be pressure-tested at the following frequency:
   a. When installed. If the BOPE is stump-tested, only the new connections are required to be tested at installation.
   b. Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due in the near future, consider testing the BOPE prior to drilling H_2S, abnormal pressure, or any lost return zones in order to avoid testing while drilling these intervals.
   c. Anytime a BOPE connection seal is broken, the break must be pressure-tested.
   d. When utilizing tapered strings, the variable bore-type rams and annular preventer must be pressure-tested with all tubing or drill pipe sizes anticipated to be used.
2. BOPE should be tested using a test plug or other means to isolate the casing and open hole from the test pressures. The casing head valve should be opened and monitored to avoid exerting BOPE test pressure on the casing or open hole.
3. BOPE components must first be low-pressure-tested to between 250 and 350 psi. If during the test, the pressure exceeds 350 psi, the pressure must be bled off to 0 psi and the test restarted. Pressuring up beyond 350 psi can induce a seal and give a false test result.
4. BOPE components, excluding the annular preventer, must be tested to the lesser of rated working pressure (RWP) or wellhead RWP if less than the BOPE RWP. The annular preventer must be tested to 70% of its RWP. In all cases, the test pressure must not exceed the RWP of any components being tested.
5. Use of a cup tester should be avoided. If a cup tester is utilized for BOPE testing, consideration must be given to the casing burst pressure and possible pressure applied to the casing string or open hole below the cup tester in the event of a leaking cup tester.
6. An accumulator closing test must be performed after the initial nipple up of the BOPE, after any repairs that required isolation or partial isolation of the system, or at initial nipple up on each well.
7. During drilling, the pipe rams must be functionally operated at least once every 24-hour period. The blind rams must also be functionally operated each trip out of the wellbore.

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

Minnkota Power Cooperative's (Minnkota) Tundra SGS site located proximate to the Milton R. Young Station (MRYS) has been a focus of investigation of future potential commercial-scale carbon dioxide (CO_2) injection within the sandstones of the Permian Broom Creek Formation. The Tundra SGS site is located near Center, North Dakota, in the south-central portion of the Williston Basin.

Multiple sets of 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 surface seismic surveys, were also used in the model construction. Two 3D seismic surveys were collected over the Tundra SGS site, and three stratigraphic test wells were drilled to augment data available from the 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 response resulting from injection and disposition of injected CO_2 within the Broom Creek Formation. Reservoir conditions observed from the stratigraphic test wells were used to characterize and establish 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.

The well logs acquired in the J-LOC1, BNI-1, and J-ROC1 wells (NDIC file numbers 37380, 34244 and 37672, respectively) (Figure A-1) 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 74-mile × 74-mile area around the proposed storage site were added to these existing site-specific data to understand the geologic extent, depth, and thickness of the 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.

Core samples obtained from the J-LOC1 and BNI-1 wellbores were analyzed and added to existing data sets for the Opeche–Picard, Broom Creek, and Amsden data sets, which were obtained from the NDIC database. These analyses included x-ray fluorescence (XRF), x-ray diffraction (XRD), thin sections, porosity, and flow measurements. The knowledge gained from these site-specific core data analyses and well logs collected from the J-LOC1, BNI-1, and J-ROC1 wellbores 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 lithofacies properties of the Broom Creek Formation. Fifteen offset wells with porosity logs were used to inform petrophysical property distributions in addition to the core data from J-LOC1 and BNI-1. The various data sets derived from J-LOC1, BNI-1, and J-ROC1 showed good agreement with the offset well data available near the J-LOC1 site.

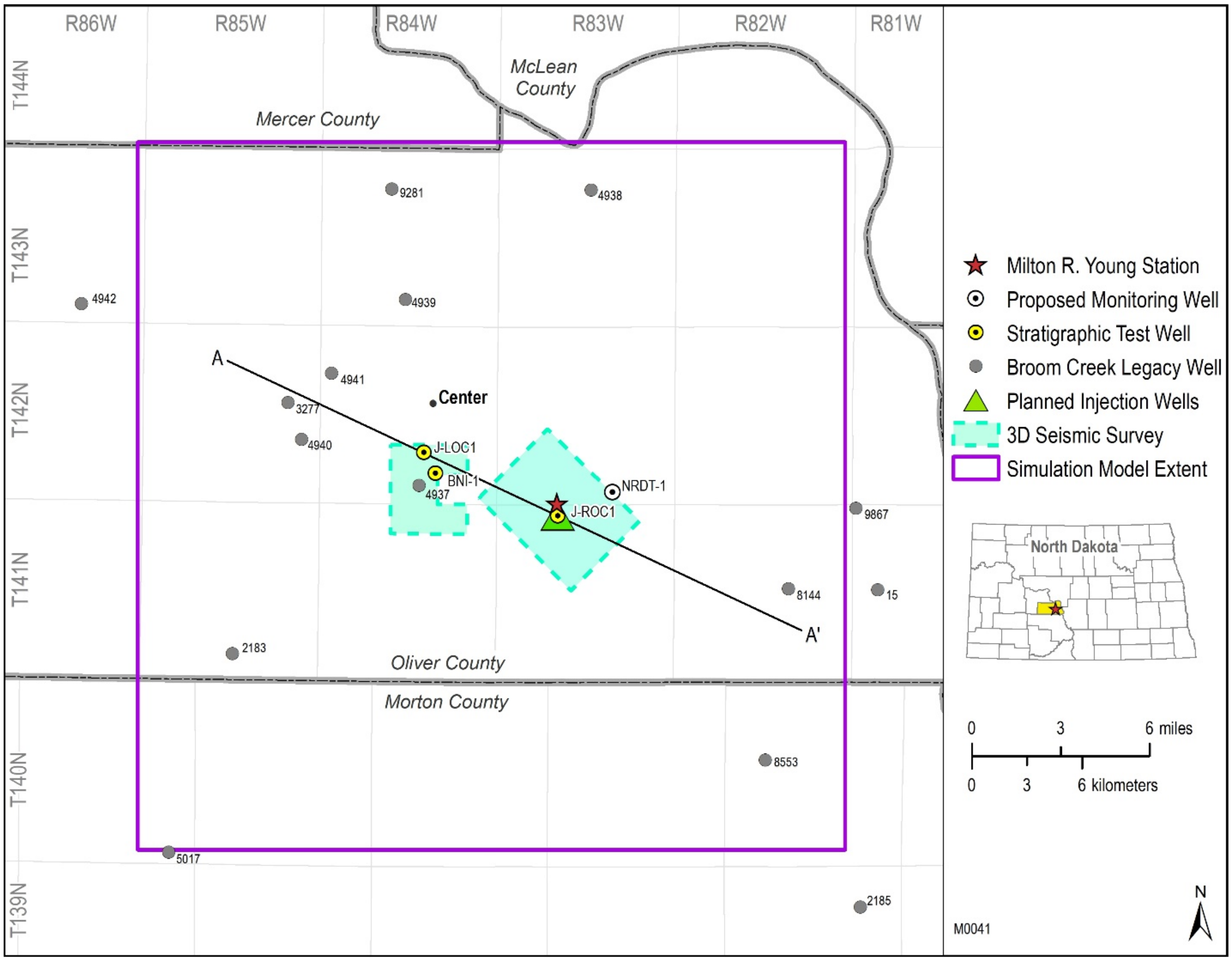


Figure A-1. Map of the geologic model boundary (purple polygon), east and west 3D seismic surveys (green polygons), model cross section, and nearby Broom Creek wells.

A geologic model was constructed using Schlumberger's Petrel software suite (Schlumberger, 2020). 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 is a digital representation of the subsurface geology, including the proposed CO_2 storage reservoir and its primary confining zones. The upper confining zone includes (in descending order) the Picard Member of the Piper Formation, Spearfish, and Opeche Formations (hereafter "Opeche–Picard interval"). The lower confining zone includes the Amsden Formation (Figure A-2). Geologic properties were distributed within the 3D model 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 (bodies of rock with similar geologic characteristics) which were used to assign relative permeability curves 2) porosity, and 3) permeability.

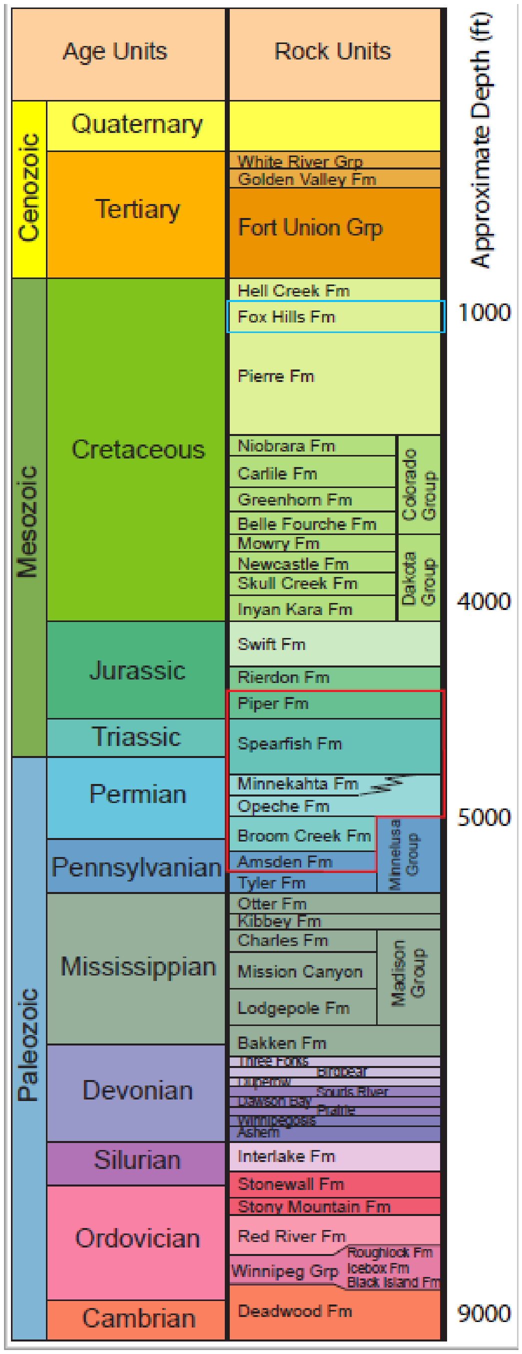


Figure A-2. Stratigraphic column identifying the storage reservoir and confining zones (red polygon) and lowest underground source of drinking water (USDW) (blue polygon) for the geology underlying the Tundra SGS storage facility area.

The geologic model provided the basis for inputs of fluid flow simulations using Computer Modelling Group's (CMG's) GEM software (Computer Modelling Group, 2019). Fluid flow properties, such as the relative permeability and capillary pressures associated with each lithofacies, were determined by mercury injection capillary pressure (MICP) measurements of representative core samples from their respective formations, and then adjusted for the geomodel-inferred average porosity of each lithofacies in the model. Finally, the fluid flow simulation permeability was tuned using a permeability multiplier based on measured permeability during brine injectivity tests conducted within the injection zone. This tuned simulation to site-specific injectivity testing and core sample data was utilized to simulate expected CO_2 injection capacity and the resulting CO_2 plume and pressure plume throughout the project life and post-injection period.

GEOLOGIC MODEL DEVELOPMENT

Geologic modeling activities to characterize the injection zone, overlying formation, and underlying sealing formations included data aggregation, structural modeling, data analysis, and property distribution (along with lithofacies and petrophysical properties). Major inputs for the geologic model, which acted as control points during the distribution of the geologic properties throughout the modeled area, included seismic survey data, geophysical logs from nearby wells, and core sample measurements.

Structural Framework Construction

Schlumberger Petrel software was used to interpolate structural surfaces for the Piper-Picard, Opeche, Broom Creek, and Amsden Formations. Input data included formation top depths from the online NDIC database; data collected from the J-LOC1, BNI-1, and J-ROC1 wells; and two 3D seismic surveys 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–Picard Interval and Amsden Formations)

The Opeche–Picard interval was assigned a siltstone lithofacies designation, and the Amsden Formation was assigned a dolostone designation; both classifications were determined as primary lithologic constituents through well log analysis. Porosity and permeability logs, after comparison with core data sets, were upscaled to a geologic model to serve as control points for respective property distributions. The control points were used in combination with variograms and Gaussian random function simulation algorithms to distribute the properties. 3,000-ft major and minor axis length variogram structures in the lateral direction and a 6-ft vertical variogram length were used within the Picard Member; 4,000-ft major and minor axis length variogram structures in the lateral direction and a 6-ft vertical variogram length for were used for the Opeche Formation. A major axis length of 6,000 ft and minor axis length of 3,000 ft were used for the Amsden Formation along an azimuth of 155° with a vertical variogram of 5 ft.

Injection Zone (Broom Creek Formation)

Seismic data were resampled to the geologic model grid and used to determine lateral heterogeneity within through a variogram assessment. 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 5,000 ft, minor axis range of 4,500 ft, and an azimuth of 155°. Well logs recorded from the J-LOC1, BNI-1, and J-ROC1 wellbores served as the basis for deriving a vertical variogram length of 7 ft.

Available sonic (ΔT) and bulk density (RHOB) well logs in the area were transformed to acoustic impedance (AI) logs (AI = RHOB*1,000,000/ΔT) to aid in discovering trends between well log data and seismic AI data. The AI from 3D seismic surveys (east and west) was edited to remove edge effects. The east 3D AI range was rescaled into alignment of the west 3D prior to combining the volumes to account for the differences in acquisition methods.

The AI logs were smoothed to resolve vertical resolution differences between the seismic and well log resolutions. By using an arithmetic smoothing window centered on each depth point, the smoothed well log AI with a 40-ft sampling window provided the best correlation of the well log acoustic impedance and the seismic acoustic impedance. Using a 40-ft sampling window, a correlation coefficient of 0.687 was observed between the AI logs and AI seismic (Figure A-3). This correlation allows for a high level of control when using seismic results to apply trends during property distributions.

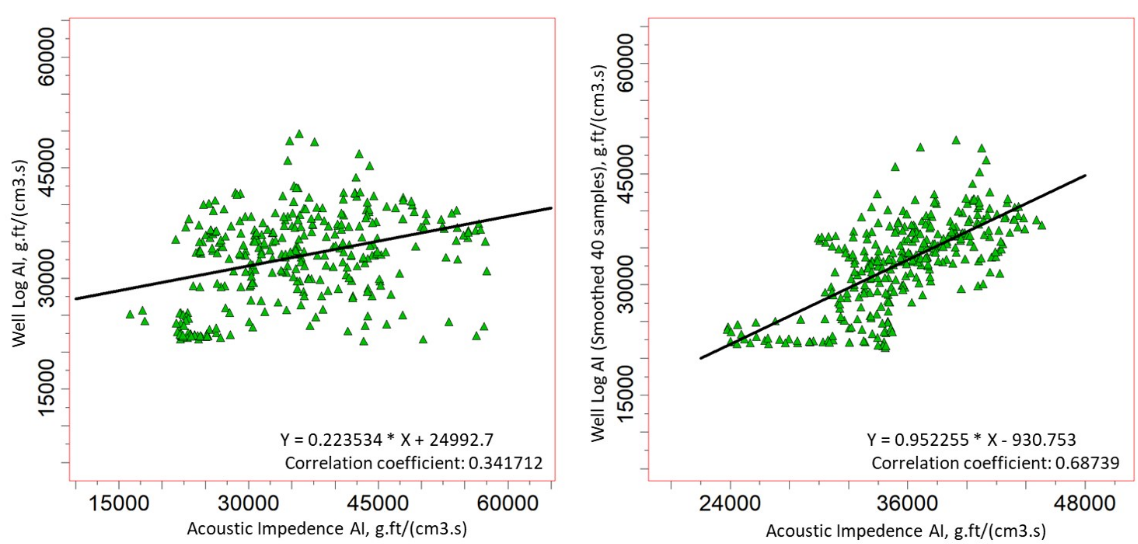


Figure A-3. Correlation coefficient between well log-derived AI and seismic AI data: 1) correlation coefficient of 0.341 was determined based on the initial data (left panel) and 2) correlation coefficient of 0.687 was determined after performing smoothing every 40 samples to resolve vertical resolution differences (right panel).

The smoothed AI logs were distributed over the seismic area using Gaussian random function simulation, the upscaled point set, and the variogram structures described previously for each zone. The AI logs were then distributed throughout the model using the same variogram parameters and cokriged with the distributed smoothed AI logs for each zone with a colocated cokriging coefficient of 0.69 (Figure A-3). The distributed AI property (Figure A-4) was used to distribute lithofacies and petrophysical properties to link these properties to the seismic data.

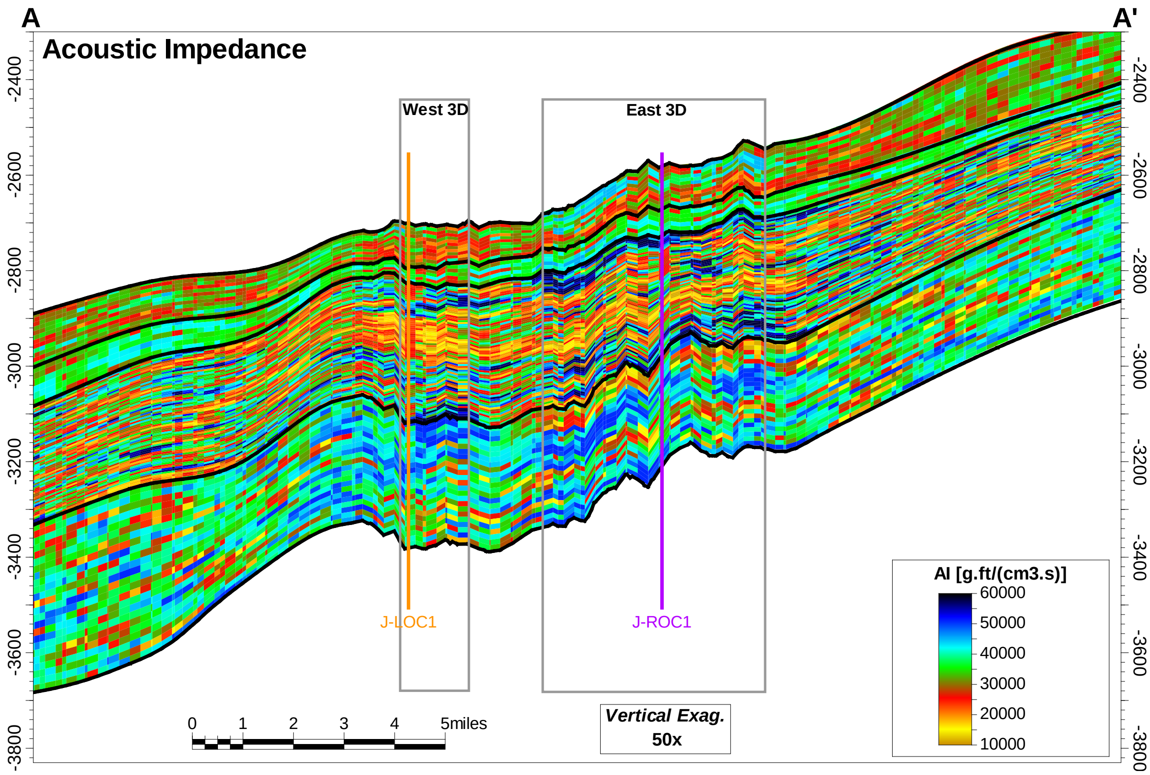


Figure A-4. Distributed AI property along a NW-SE cross section. The distributed AI property was used to distribute lithofacies and petrophysical properties to seismic data. Vertical units on the y-axis are displayed as feet below mean sea level (50x vertical exaggeration shown).

Lithofacies classifications were determined from well log data and correlated with descriptions of core taken from the J-LOC1, Flemmer-1 (NDIC No. 34243), and BNI-1 wells. Four predominant lithofacies were identified within the Broom Creek Formation: 1) sandstone, 2) dolomitic sandstone, 3) dolostone, and 4) anhydrite. Lithofacies logs were manually interpreted from these observations and upscaled to serve as control points for geostatistical distribution using sequential indicator simulation with trends determined from the distributed AI property (Figures A-5 and A-6).

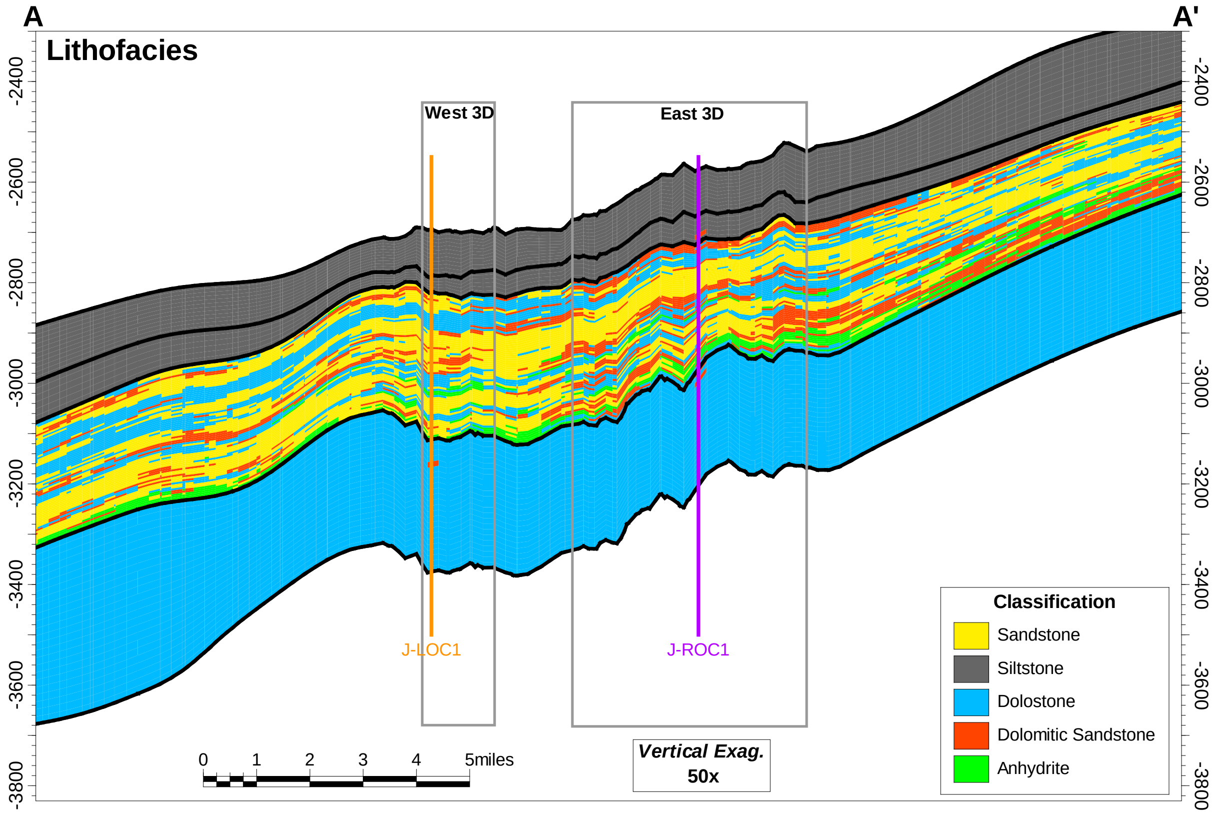


Figure A-5. Cross section view of lithofacies property. Sandstone and dolostone heterogeneity within the Broom Creek was captured within the geologic model and correlated with the AI property based on seismic data. Vertical units on the y-axis are displayed as feet below sea level (50x vertical exaggeration shown).

Prior to distributing the porosity and permeability properties, core porosity and permeability measurements from the J-LOC1 and BNI-1 wells were compared with effective porosity well logs and permeabilities estimated from the Wyllie–Rose model (Wyllie and Rose, 1950) to ensure good agreement between the two data sets (Figure A-6).

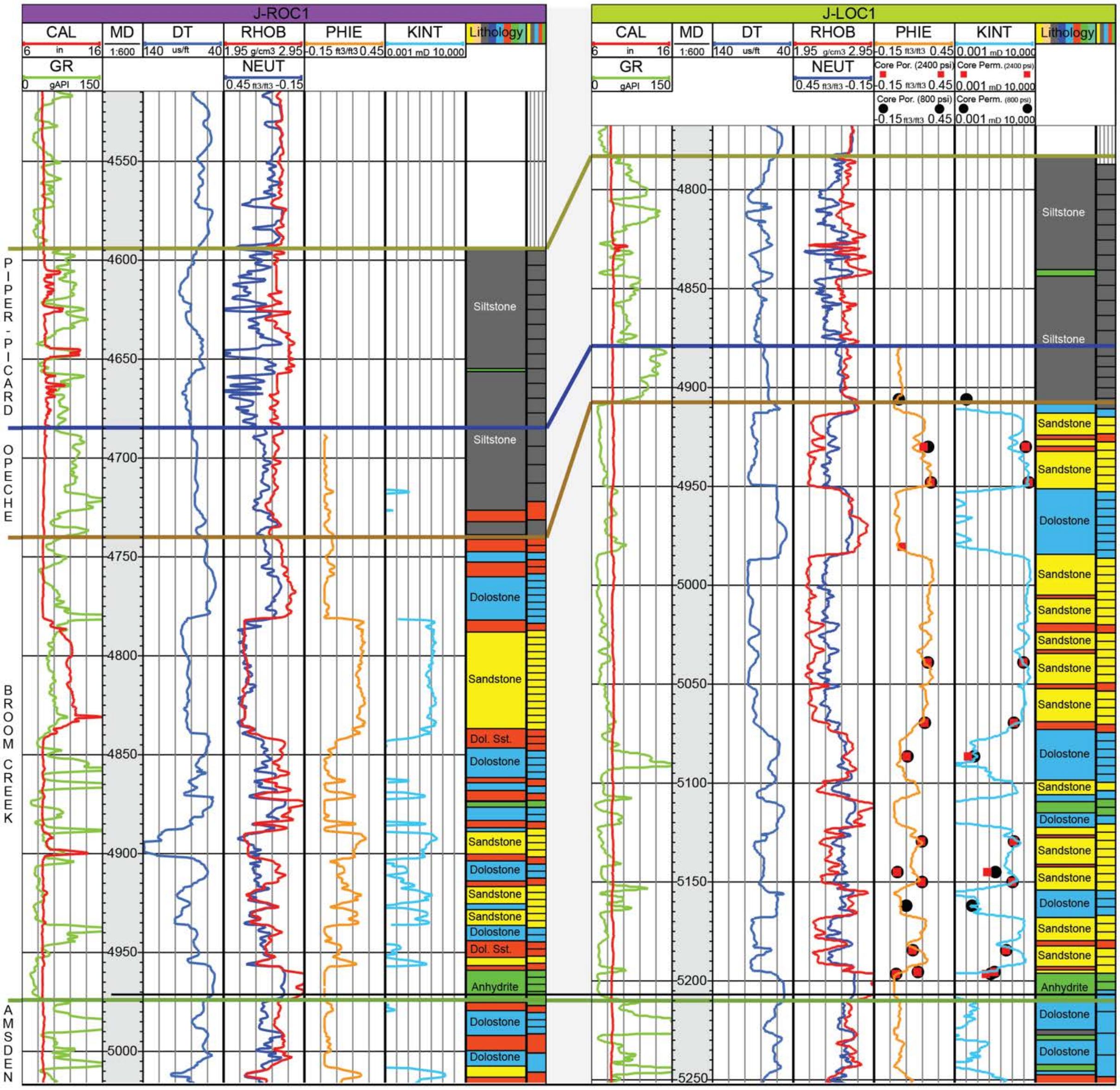


Figure A-6. Lithofacies classification in wells J-ROC1 and J-LOC1. Well logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red); 2) delta time (blue); 3) neutron porosity (dark blue), density (red); 4) porosity (orange) core porosity (orange and blue dots); 4) permeability (light blue) and core permeability (black and red dots); 6) interpreted lithology log; and 7) upscaled lithology.

Total porosity (PHIT; total pore space) and effective porosity (PHIE; total porosity less occupied or isolated pore space) logs were estimated and used as control points for petrophysical distributions. A PHIT property was distributed using PHIT well logs upscaled to the resolution of the 3D model (approximately 6 ft on average) as control points, variogram structures described previously with Gaussian random function simulation, and the distributed AI property as a secondary cokriging variable.

A PHIE property was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points; variogram structures described previously with Gaussian random function simulation; and the distributed AI property as a secondary cokriging variable. A permeability property was distributed using the same variables and algorithm, but cokriged to the PHIE volume (Figures A-7 and A-8).

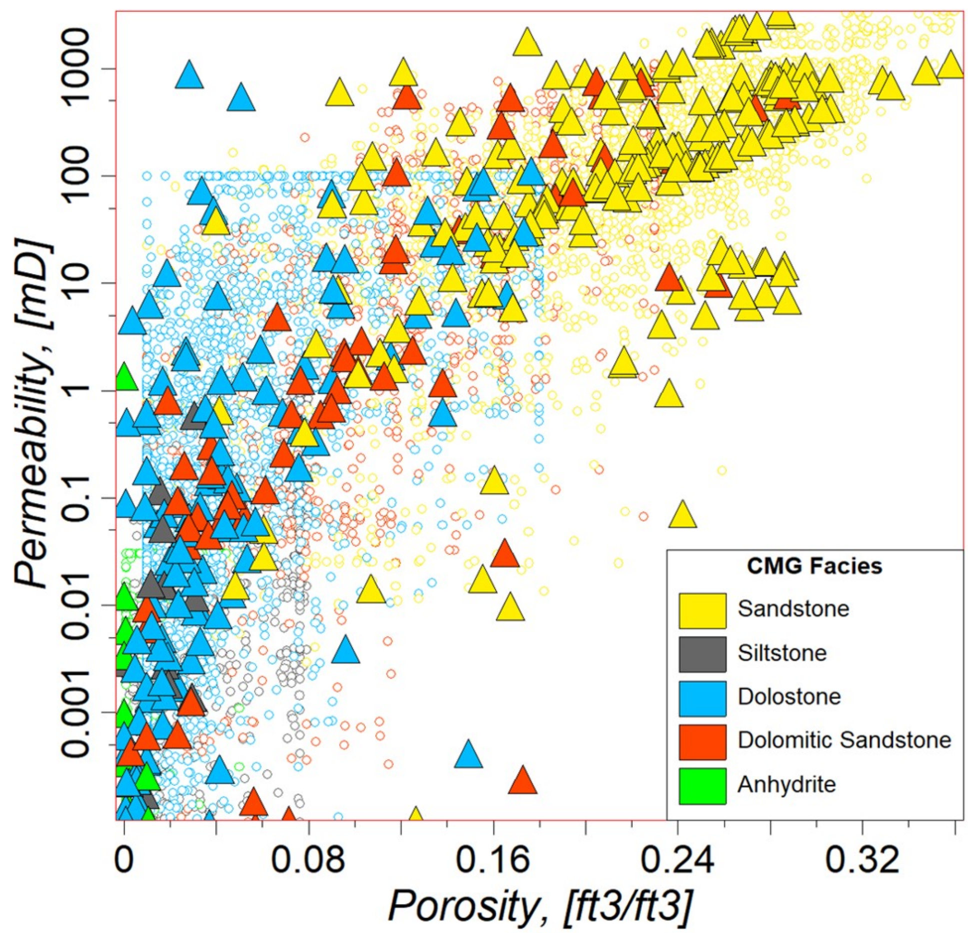


Figure A-7. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to lithofacies classification, as seen in Figure A-6.

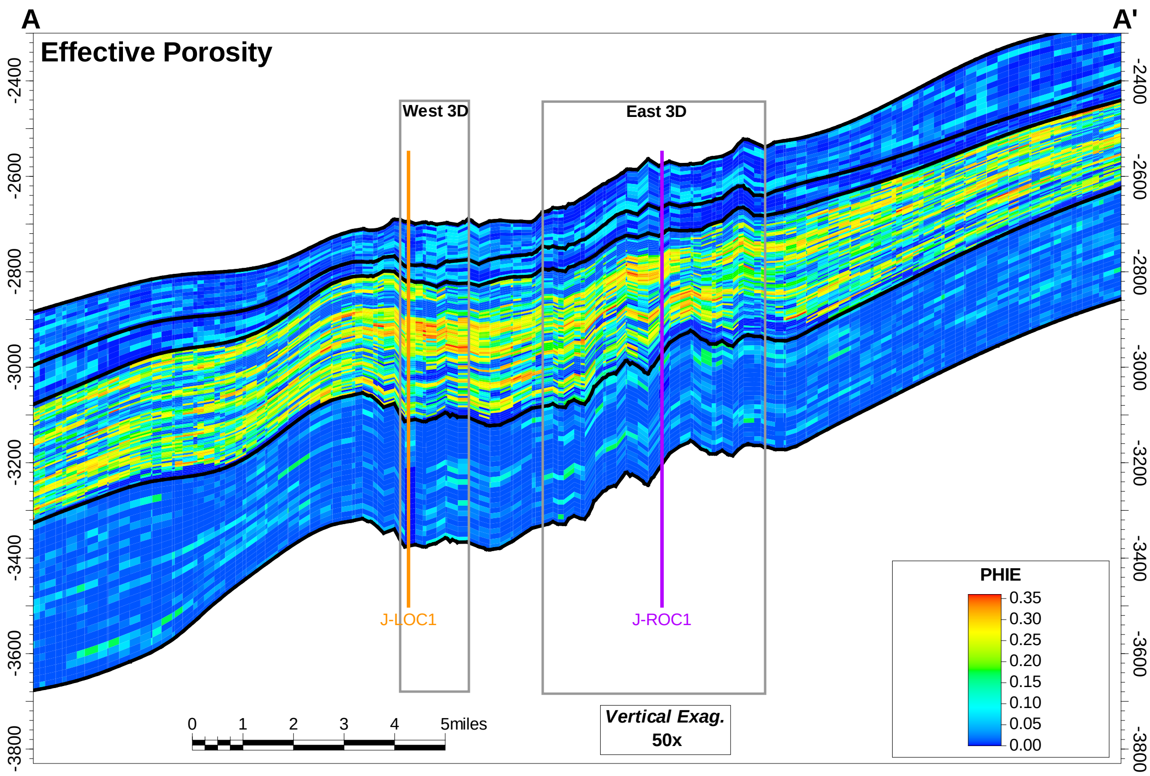


Figure A-8. Distributed PHIE property along a NW-SE cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the Y-axis represent feet below mean sea level (50x vertical exaggeration shown).

NUMERICAL SIMULATION OF CO_2 INJECTION

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above (Figure A-9). Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. A compositional simulator is one of the most mechanistically accurate methods to solve compositional multiphase fluid flow processes. Compositional simulators utilize cubic equations of state, such as Peng–Robinson's, 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.

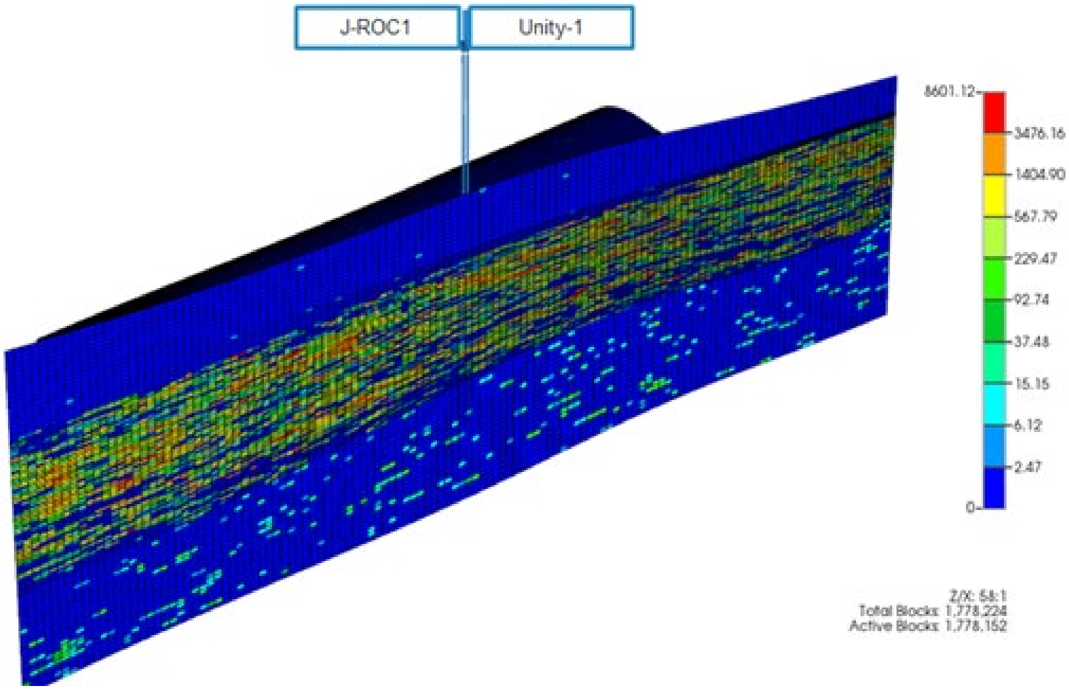


Figure A-9. The 3D view of the simulation model with the permeability property and injection wells displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Piper-Picard and Opeche/Spearfish Formations (upper) and the Amsden Formation (lower). The varied permeability of the Broom Creek is observed in between these layers.

The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area. Distances to the pinch-out are assumed to be 57,500 feet (~10.9 miles) to the east and 36,400 feet (~6.9 miles) to the northeast from the edge of the simulation domain. The reservoir was assumed to be 100% brine saturated with an initial formation salinity of 49,000 ppm total dissolved solids (TDS).

Simulations performed allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for the Broom Creek Formation were analyzed and generated for five representative rock types in the simulation (sandstone, siltstone, anhydrite, dolostone, and dolomitic sandstone) through Core Laboratory's MICP evaluation and Energy & Environmental Research Center (EERC) laboratory analysis (Figures A-10–A-13). Within the cap rock layers, the relative permeability curve estimated for anhydrite lithofacies was assigned because no siltstone lithology samples were available from the MICP calculations. Capillary pressure curves calculated from the MICP data were adapted to the permeability and porosity values from the numerical model by project partner Oxy Low Carbon Ventures (OLCV). These adapted capillary pressure curves are also shown in Figures A-10–A-13.

Capillary entry pressure data derived from core testing was used in the dynamic reservoir simulations. Capillary entry pressures were assigned based on lithologies. The sandstone lithofacies were assigned the value derived from a core sample representative of the Broom Creek sand, 0.20 psi. Dolostone lithofacies, including those in the Amsden layers of the simulation model, were assigned a value derived from a core sample from the Broom Creek which was determined to be representative of the dolostone lithofacies, 18.08 psi. Shales and anhydrite lithofacies including those in the Opeche\Spearfish Formation were assigned a capillary entry pressure of 168.10 psi as derived from Broom Creek shale and anhydrite samples.

Because of poor wellbore conditions, measurement of temperature and pressure within the J-ROC1 well was not possible. Temperature data recorded from logging the J-LOC1 wellbore were used to derive a temperature gradient of 0.02°F/ft for the proposed injection site. In combination with depth, this temperature gradient was used to calculate subsurface temperatures throughout the study area. Pressure testing within the J-LOC1 well was performed with a modular formation dynamics testing (MDT) tool. Multiple pressure readings recorded from the Broom Creek Formation were used to derive a pore pressure gradient of 0.49 psi/ft (Table A-1).

Table A-1. MDT Pressure Measurements Recorded from the J-LOC1 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
4,920.05	2,415.86	0.49
5,044.80	2,470.91	0.49
5,045.09	2,471.43	0.49
5,129.16	2,509.60	0.49

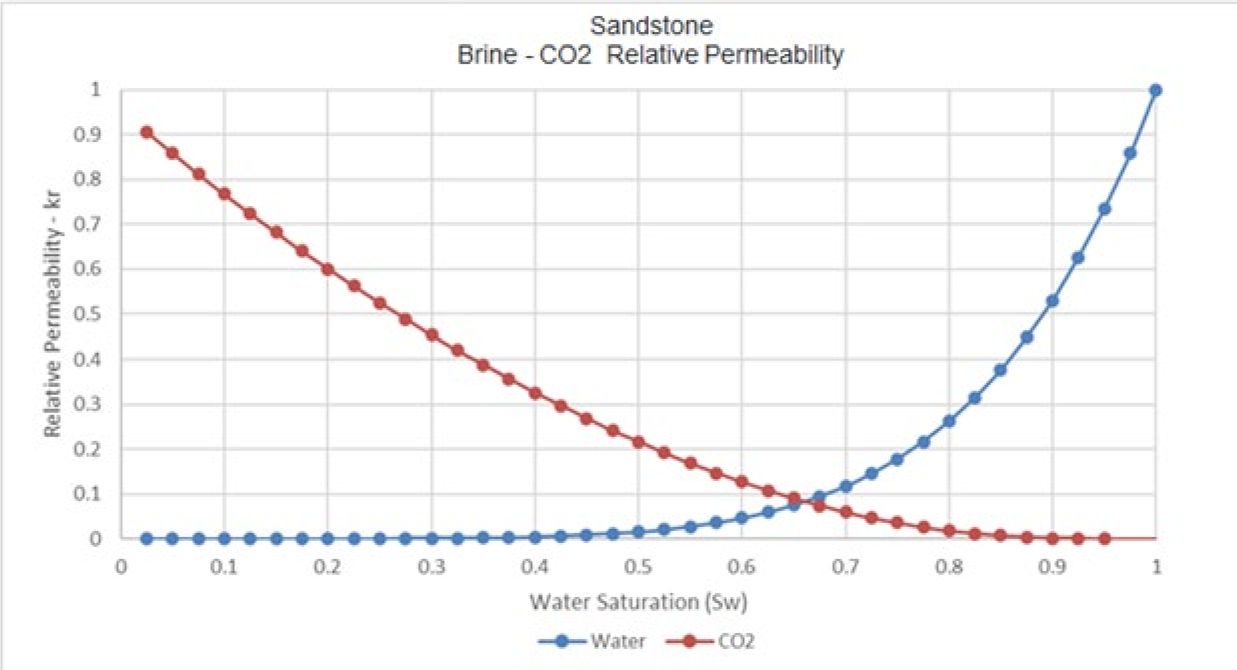
* Measured depth.

The simulation model permeability was tuned globally by applying a multiplier to match reservoir properties estimated from Broom Creek Formation step rate test. The permeability multiplier was calculated based on the area of study during the injectivity test and the permeability and thickness (transmissibility) values from the numerical transient analysis. The value obtained from this calculation resulted in a permeability multiplier of 5. Ultimately, a global multiplier of 2.5 was applied before numerical simulations to provide a more conservative input for simulation.

Table A-2 shows the general properties used for numerical simulation analysis in this study. Two injection wells, J-ROC1 and proposed well Unity-1 (Figure A-9), were simulated as perforated across the Broom Creek Formation interval. The J-ROC1 and Unity-1 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 for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis suggested at the given injection volume, the wellhead temperature played a prominent role in determining wellhead pressure response. Thus a wellhead temperature value was chosen that most closely represents an expected temperature from the final project design of the simulation study.



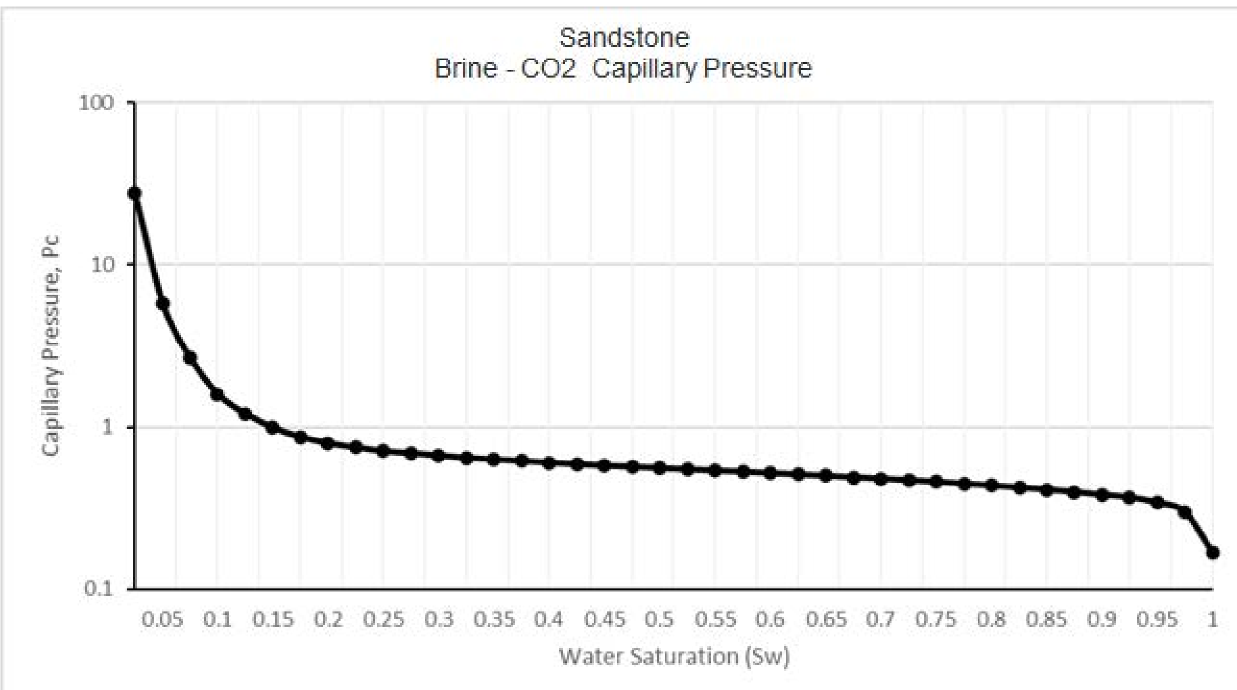
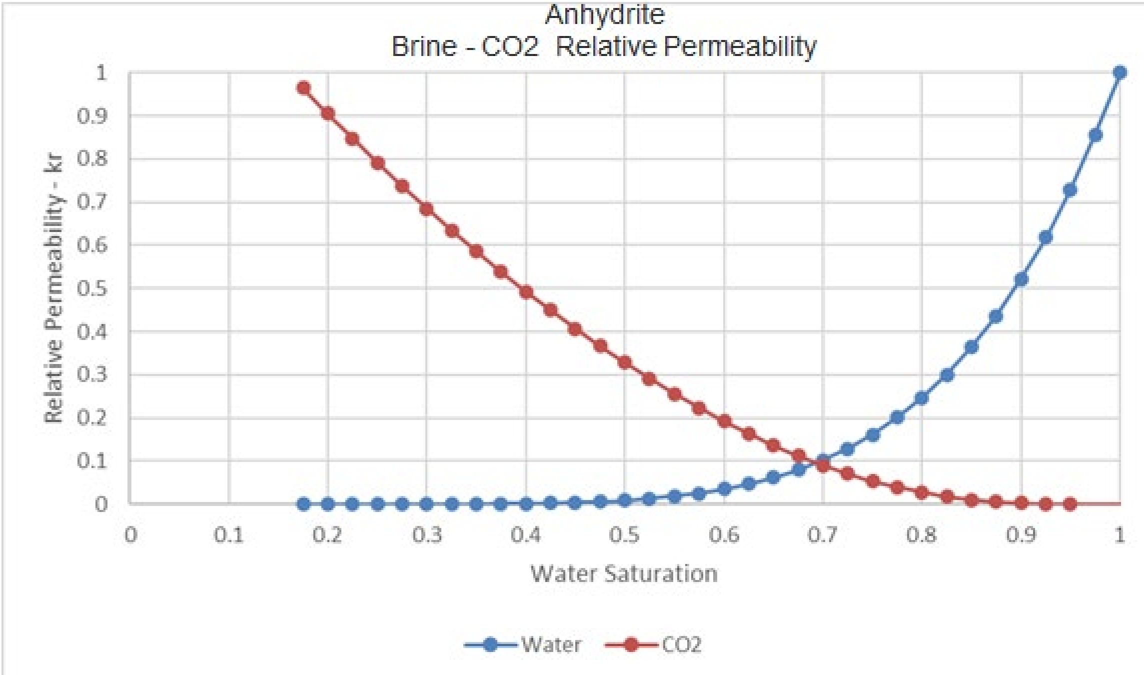


Figure A-10. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



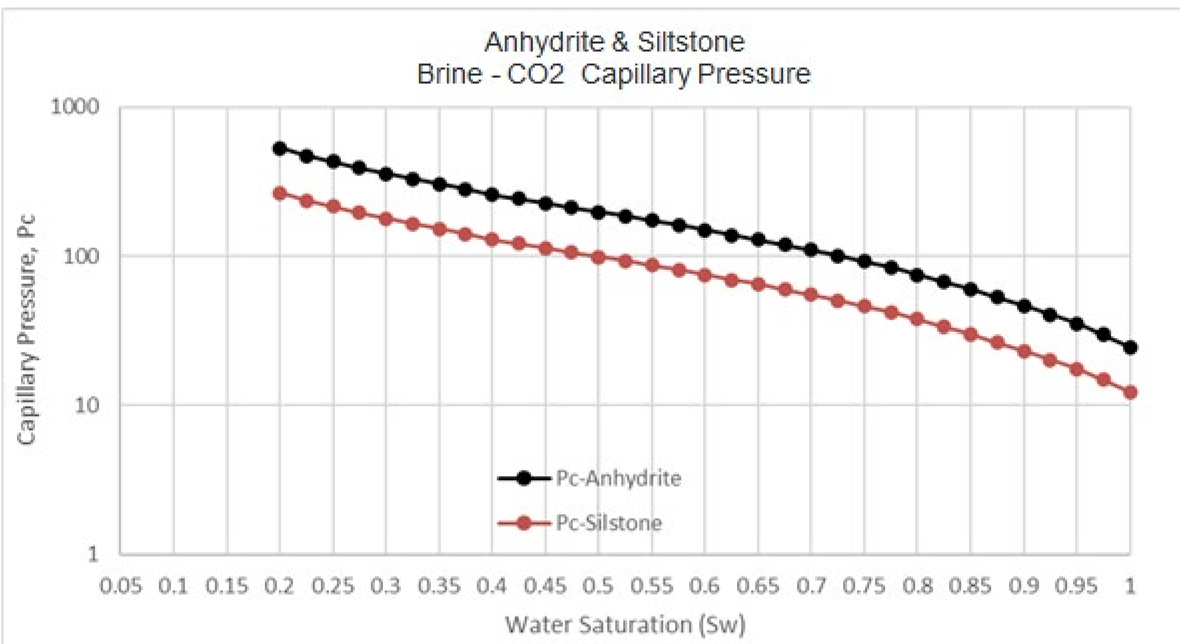


Figure A-11. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone rock type in the Opeche–Picard interval and Opeche Formations and anhydrite rock type within in the Broom Creek Formation.

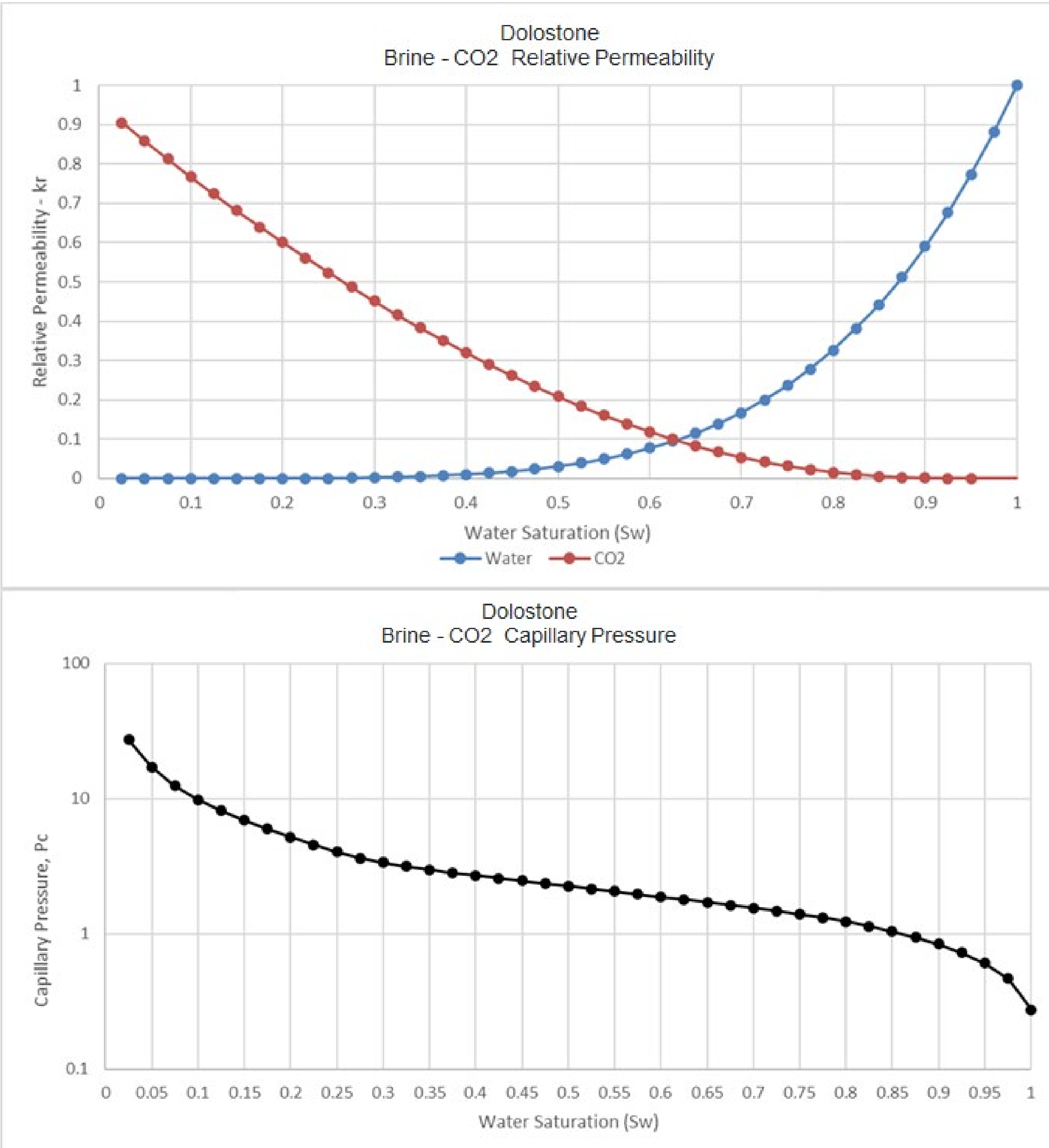
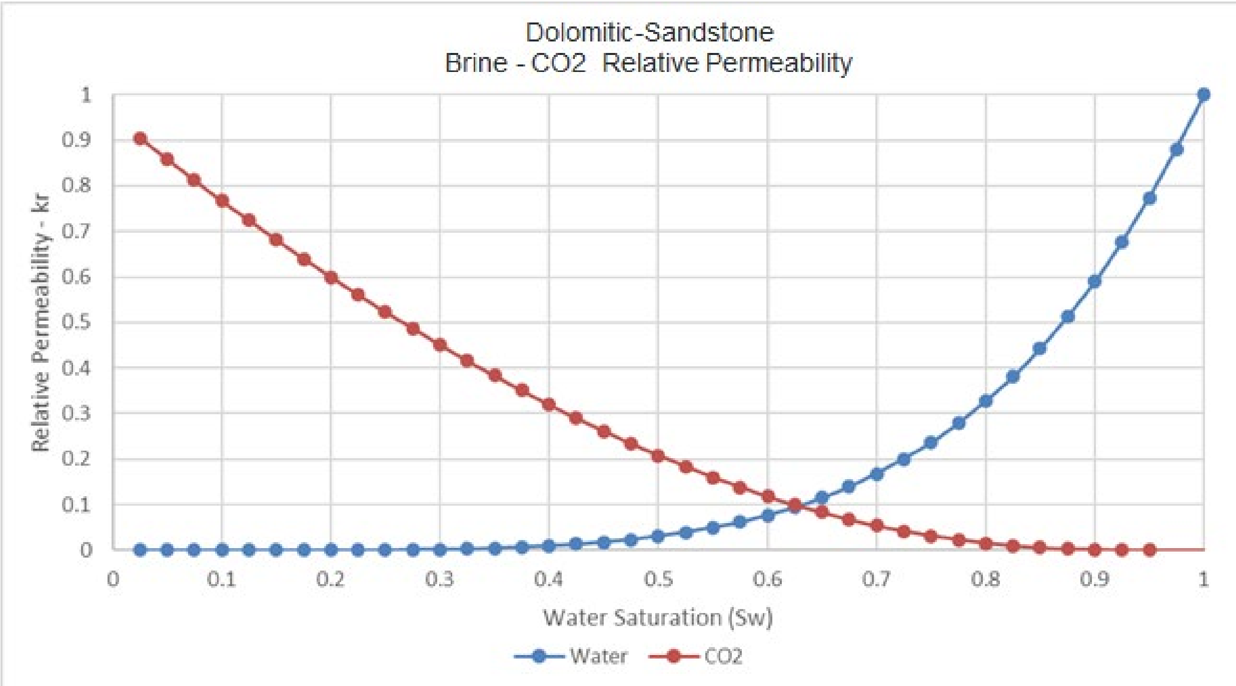


Figure A-12. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone rock types in the Broom Creek and Amsden Formations.



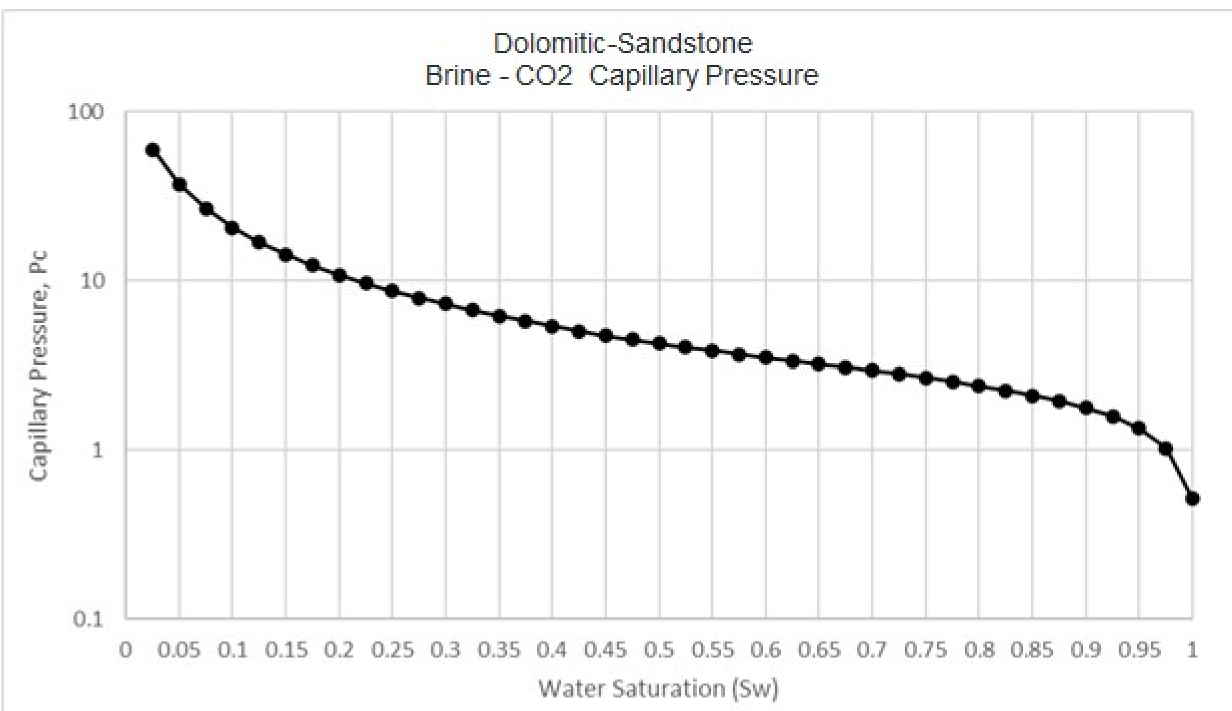


Figure A-13. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone rock type in the Broom Creek Formation.

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/Spearfish: ~0.11 Broom Creek: ~439 Amsden/Tyler: ~2.94	Opeche/Spearfish: ~20 Broom Creek: ~13 Amsden/Tyler: ~2.20	~2,415.8 (at 2,827.05 ft)	49,000	Partially closed

Table A-3. Well Constraints and Wellbore Model in the Simulation Model

Primary Group Constraint, injection rate	Primary Well Constraint, maximum bottomhole pressure	Secondary Well Constraint, wellhead pressure	Tubing Size	Wellhead Temperature	Downhole Temperature
4.0 MM tonnes/year for the first 15 years & 3.5 MM tonne/year for the last 5 years	3035.1 psi for J-ROC1; 3,018.3 psi for Unity-1	1,700 psi	7 in.	90°F	136°F

Simulation Results

Simulations of CO_2 injection with the given well and group constraints, listed in Table A-3, predicted the wellhead injection pressure (WHP) of both wells would not exceed 1,700 psi during injection. The bottomhole pressures (BHP) are not reaching the maximum values of 3,035.1 and 3,018.3 psi for J-ROC1 and Unity-1, respectively (Figure A-14). The target injection rate of 4.0 million tonnes (MMt) for the first 15 years and 3.5 MMt per year for the last 5 years were consistently achievable over the 20 years of injection. A total of 77.5 MMt of CO_2 was injected into the Broom Creek Formation with two wells at the end of 20 years of simulated injection (Figure A-15). The injected volume was 41.1 and 36.4 MMt for the Unity-1 and J-ROC1 wells, respectively.

During and after injection, the free-phase CO_2 accounts for the majority of CO_2 observed in the model 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 pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), 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-16).

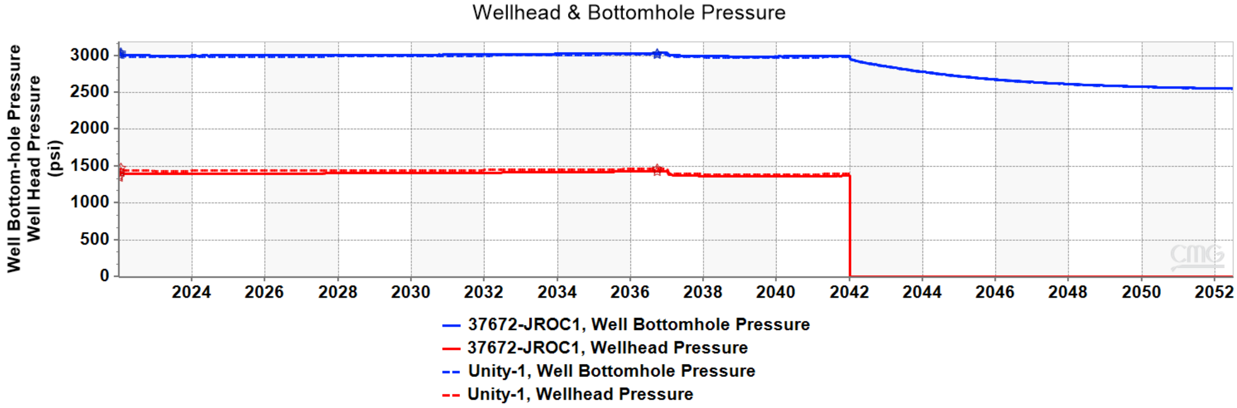


Figure A-14. WHP and BHP response with the expected injection rate.

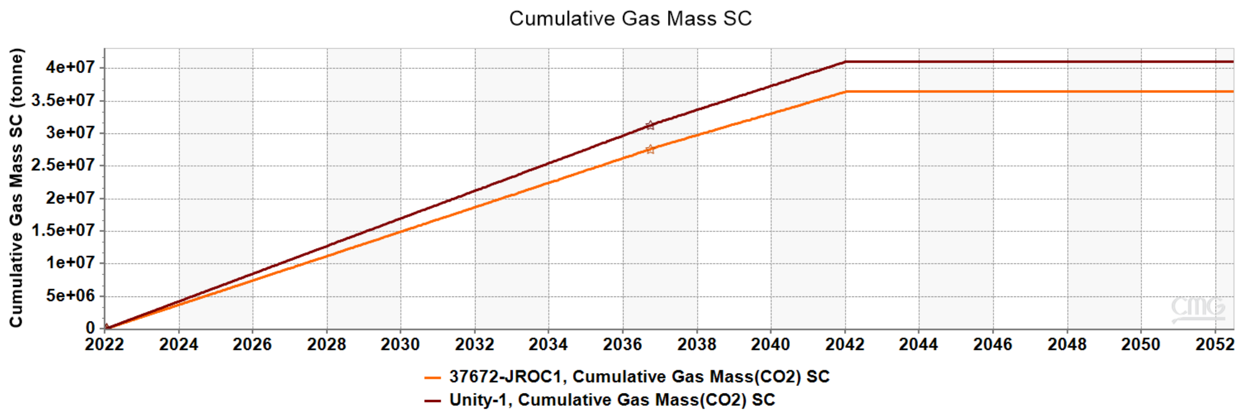


Figure A-15. Cumulative injected gas mass over 20 years of injection.

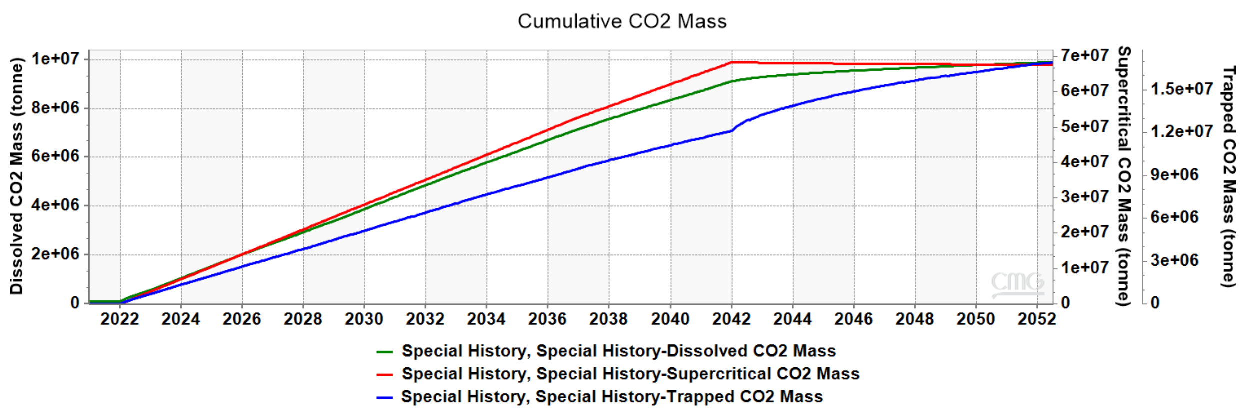


Figure A-16. Simulated total supercritical-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

The pressure front (Figure A-17) shows the distribution of pressure increase throughout the Broom Creek Formation during the 20-year injection period. A maximum increase of 488 psi is estimated in the near wellbore area.

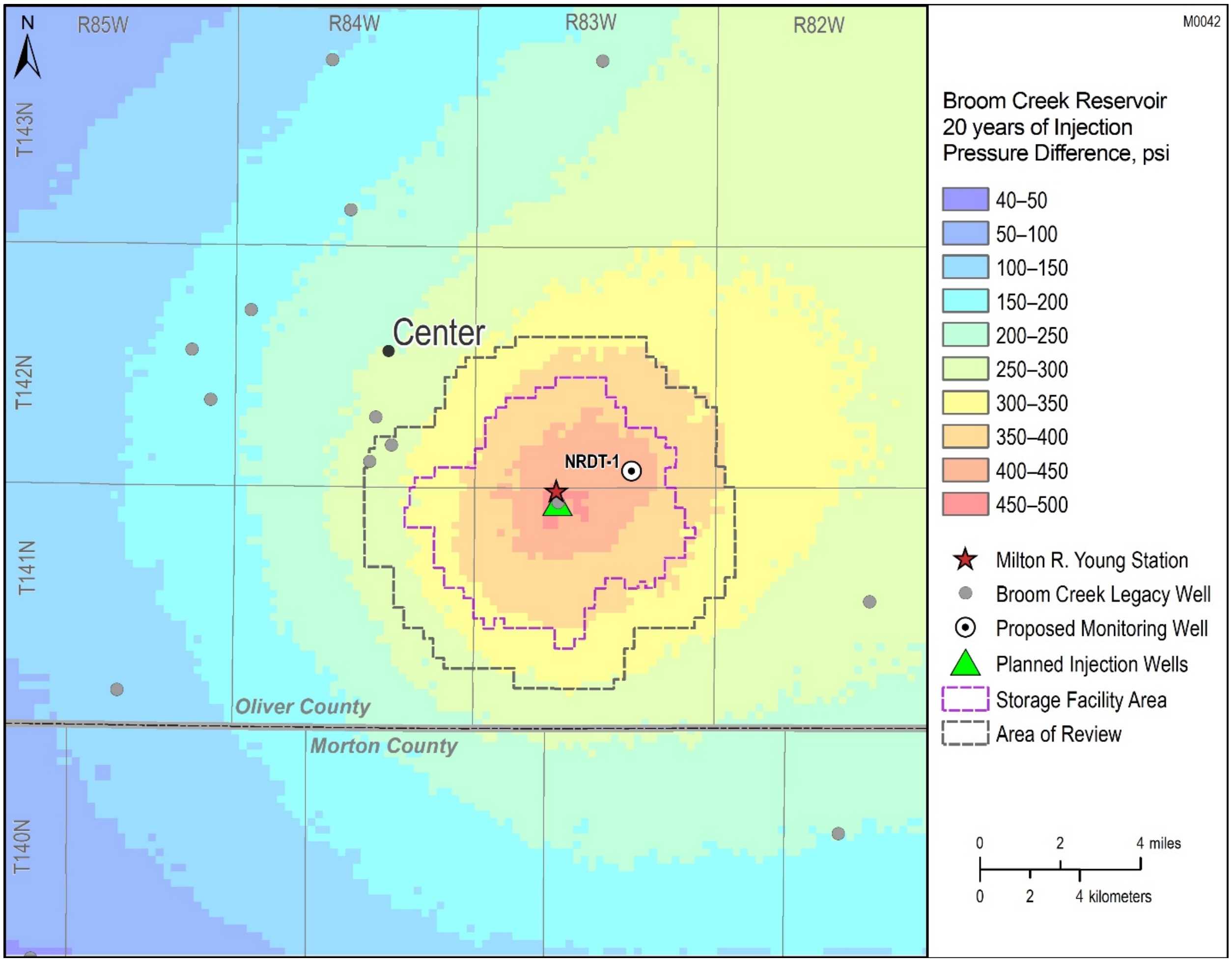


Figure A-17. Average pressure increase within the Broom Creek Formation at the end of a simulated 20-year CO_2 injection operation.

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 Formation 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. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures A-18 and A-19 show the gas saturation at the end of injection in north-to-south and east-to-west cross-sectional views, respectively.

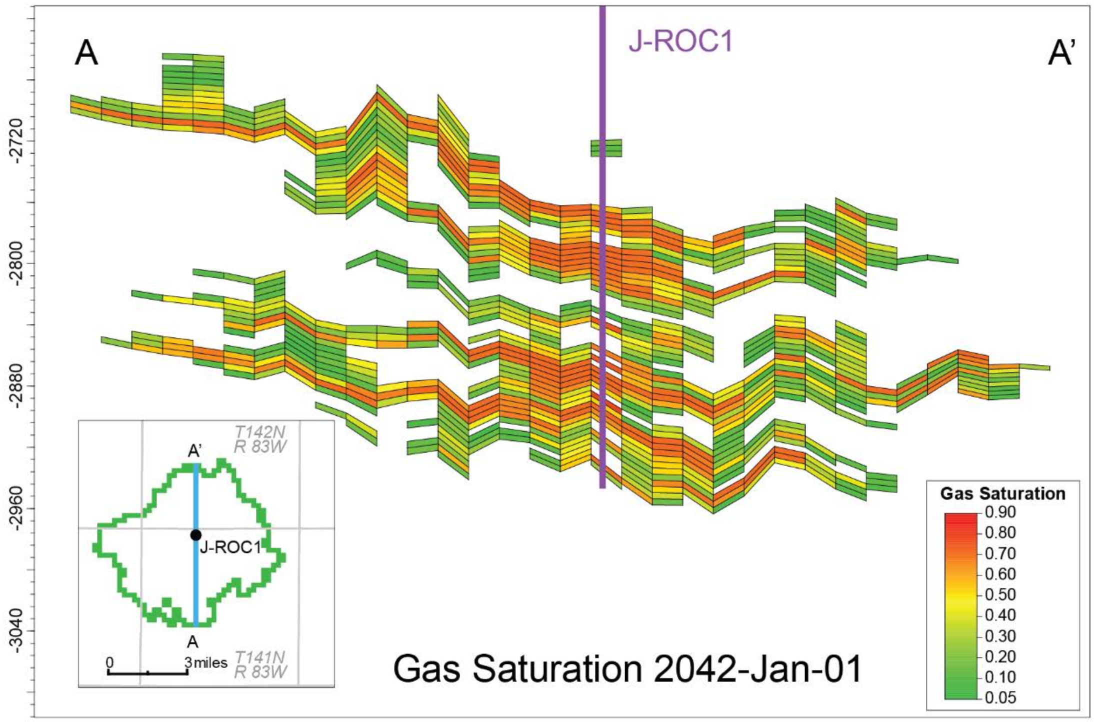


Figure A-18. CO_2 plume boundary and cross-section at the end of injection displayed south to north through the J-ROC1 well.

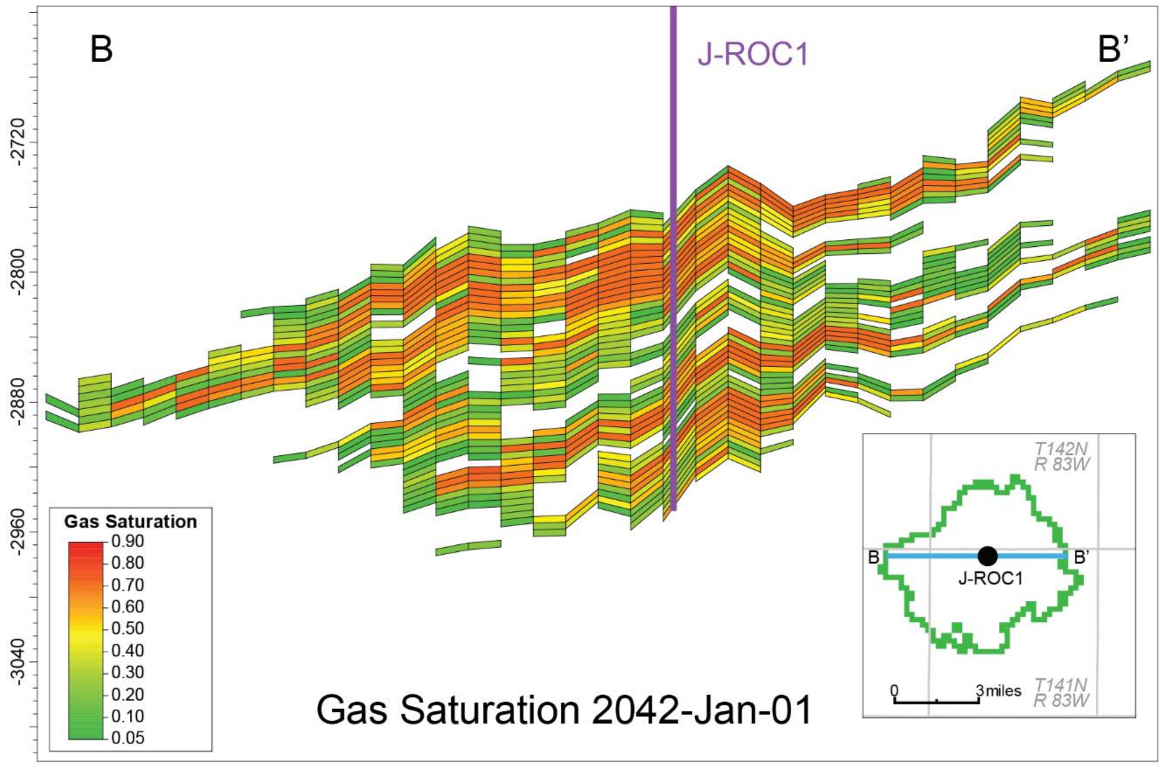
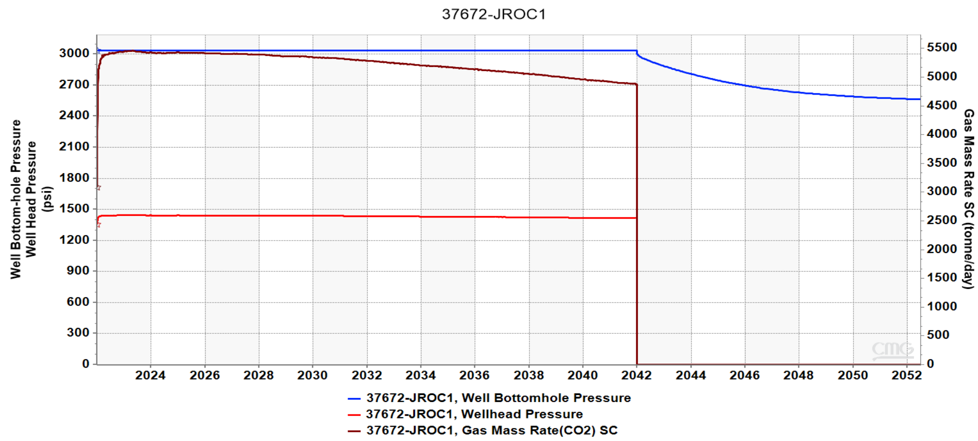


Figure A-19. CO_2 plume boundary and cross section at the end of injection displayed east to west through the J-ROC1 well.

Maximum Injection Pressures and Rates

An additional case was run to determine if the wells would ultimately be limited by the maximum WHP of 1,700 psi or maximum calculated downhole pressures of 3,035.1 and 3,018.3 psi for the J-ROC1 and Unity-1 wells, respectively. Results of a step rate test performed within the Broom Creek Formation, over an interval from 4,912 to 4,922 ft, indicated a fracture propagation pressure of 3,593 psi, resulting in an estimated fracture propagation pressure gradient of 0.71 psi/ft. The propagation pressure gradient was used to calculate maximum BHP constraints, based upon 90% of the fracture propagation pressure. In this scenario, the group injection limit of 4.0 MMt per year for the first 15 years and 3.5 MMt per year for the last 5 years was removed. Other parameters were kept the same for the additional tests.

The maximum BHPs were reached in the simulation before the maximum WHPs were encountered. At the maximum BHP of 3,035.1 and 3,018.3 psi, the corresponding predicted maximum wellhead injection pressure responses were 1,443 and 1,487 psi, respectively, for the J-ROC1 and Unity-1 wells, respectively. In addition, the average surface injection pressures were 1,432 and 1,467 psi, respectively (Figure A-20). In this scenario, the J-ROC and Unity-1 wells were able to inject at daily average rates of 5,225 and 5,873 tonnes/day of CO_2, respectively, with the planned 7-in.-diameter tubing, thereby achieving a total injection volume of 81.3 MMt of CO_2.



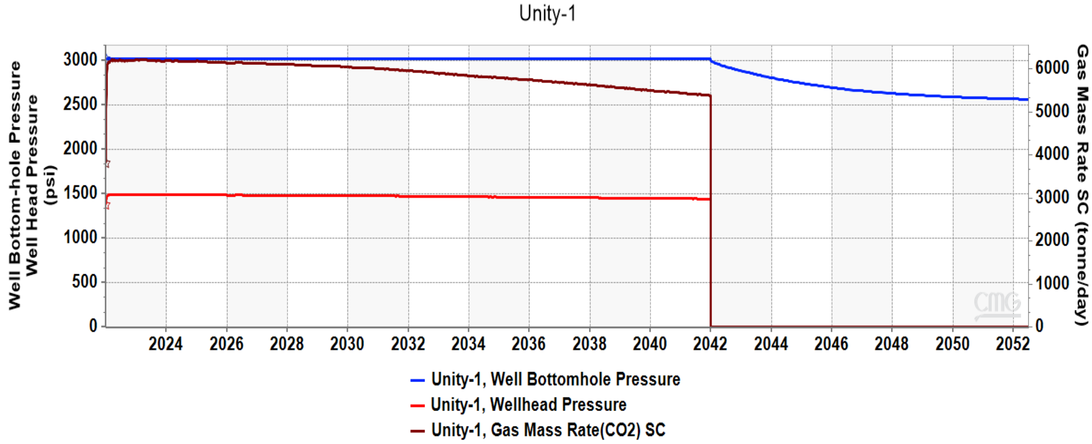


Figure A-20. Maximum pressure and rate response when the wells were operated without any injection rate limits, J-ROC1 well (top) and Unity-1 well (bottom).

DELINEATION OF THE AREA OF REVIEW

The North Dakota Administrative Code (NDAC) defines the AOR 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 the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir.

However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure."

Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. 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 resulting critical threshold pressure.

In this document, “storage reservoir” refers to the Broom Creek Formation (the injection zone), and the “lowest USDW” refers to the Fox Hills Formation.

EPA Methods 1 and 2 AOR Delineation for Class VI Wells

EPA (2013) guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a “critical threshold pressure” that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW. The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the J-LOC1 stratigraphic well) using site-specific data, or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA (2013) Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW. Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_i is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical pressure threshold (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f} = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming

1) hydrostatic conditions, 2) initially linearly 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:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
ρ_i is the fluid density in the injection zone (kg/m^3).
ρ_u is the fluid density in the USDW (kg/m^3).

Risk-Based AOR Delineation

The methods described by EPA (2013) for estimating the AOR under the Class VI Rule were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geological situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit applicants. As an alternative, Burton-Kelly and others (2021, in review) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others. (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name, ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described in Cihan and others. (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, the NRAP-IAM-CS and subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Schlumberger Petrel) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's compositional simulator, GEM), provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that is unwarranted given the amount of uncertainty that may be present if only few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably well described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure A-21).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either ΔP_{if} for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021, in review). Inputs, assumptions, and results are discussed in the current document.

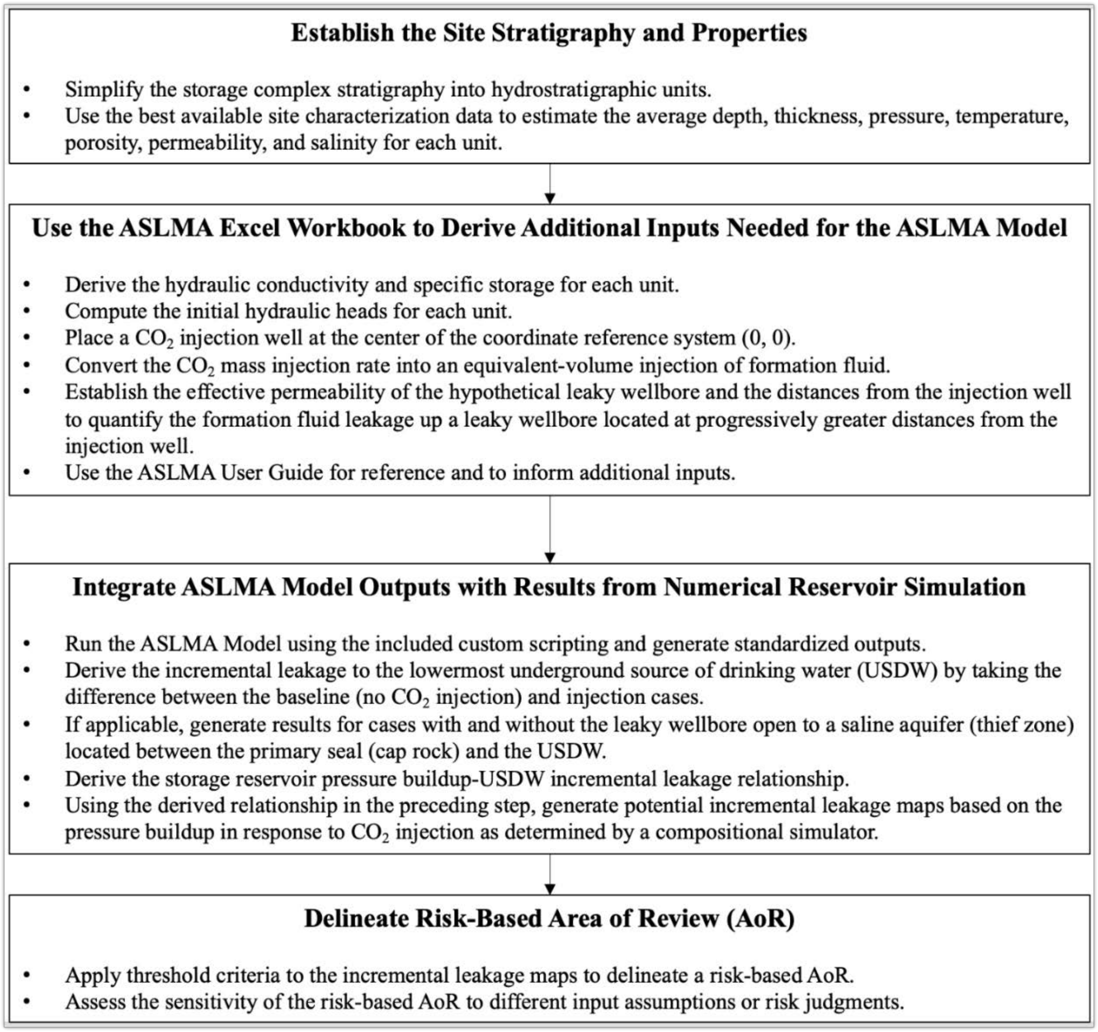


Figure A-21. Workflow for delineating a risk-based AOR for a storage facility permit (modified from Burton-Kelly and others, 2021).

EPA Methods 1 and 2 at J-ROC1

For the purposes of delineating AOR for the Tundra SGS study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. A density of 1001 kg/m^3 was used to represent the USDW fluids (ρ_u), and a density of 1023 kg/m^3 was used to represent the injection zone fluids (ρ_i), which is estimated based on the in situ brine salinity, temperature, and pressure as measured with an MDT tool from the nearby J-LOC1 stratigraphic test well.

Application of EPA Method 1 (Equation 1) using site-specific data from the J-LOC1 and J-ROC1 wells shows that the injection zone in the Tundra SGS area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table A-4, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table A-4. EPA Method 1 Critical Threshold Pressure Increase Calculated at the J-ROC1 Wellbore Location

Depth*		P_i Injection Zone Pressure	P_u USDW Pressure	ρ_i Injection Zone Density	Z_u USDW Base Elevation	Z_i Reservoir Elevation	$\Delta P_{i,f}$ Threshold Pressure Increase	
ft	m	MPa	MPa	kg/m^3	m amsl	m amsl	MPa	psi
4,740	1,445	15.919	3.535	1,024	266	−828	−1.391	−201
4,857	1,480	16.312	3.535	1,024	266	−864	−1.430	−207
4,974	1,516	16.705	3.535	1,023	266	−900	−1.470	−213

* Chosen depths represent the top, middle, and base of the Broom Creek Formation at J-ROC1. Ground surface elevation is 609 m above mean sea level.

In accordance with EPA (2013) guidance, the combination of a) Method 1 negative $\Delta P_{i,f}$ value across the Tundra SGS area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021, in review). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed used in the method (hereafter "ASLMA Workbook").

Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming an equivalent freshwater head based on the unit-specific elevations and pressures. The equivalent freshwater heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case equivalent freshwater heads for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are 802, 557, and 619 m, respectively, which illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021, in review).

CO_2 Injection Parameters

Tundra SGS has a Broom Creek CO_2 injection rate target of 3.5 million metric tons per year (MMtpa) for 20 years. A single injector is placed at the center of the ASLMA model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel VBA functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density of 677 kg/m^3. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate of approximately 14,163 m^3 per day.

Hypothetical Leaky Wellbore

In the Tundra SGS area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, what-if scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 20-year injection period, provide the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 to values more representative of leakage through a wellbore annulus of 10^{-10} to 10^{-12} m^2 (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-10} to 10^{-20} m^2. For the Tundra SGS Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m^2, which is a relatively conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites.

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir and, therefore, a greater leakage of formation fluid up the leaky wellbore.

Saline Aquifer Thief Zone

As shown in Table A-5, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduces the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an "elevator model," by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term "thief zone" is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

Aquifer- and Aquitard-Derived Properties
The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table A-5). For each unit shown in Table A-5, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived from well log data within the Tundra SGS study area. Porosity is represented as an arithmetic mean and permeability as a geometric mean of well log values within each hydrostratigraphic unit, including both reservoir and nonreservoir rock types.

The compositional reservoir simulation used a 2.5× multiplier on permeability from the geologic model, and the same multiplier was applied to the storage reservoir permeability to be consistent between models. Visual Basic for Applications (VBA) functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate the HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are 3.5E-02, 5.31E-02, and 2.03E-01 m/d, respectively, while the estimated SS for these units is 1.21E-06, 1.08E-06, and 2.67E-06 (1/m), respectively. Details about the HCON and SS derivations are provided in Supporting Information for Burton-Kelly and others (2021, in review).

Table A-5. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top*	Thickness	Pressure	Temperature	Salinity	Porosity	Permeability		HCON	Specific Storage	Equivalent Freshwater Head
	m	m	MPa	°C	ppm	%	mD	m^2	m/d	m^{-1}	m
Overlying Units to Ground Surface (not directly modeled)	0	224									
Aquifer 3 (USDW–Fox Hills Fm)	224	126	2.9	14.5	1,800	34.4	280	2.76E-13	2.03E-01	2.67E-06	619
Aquitard 2 (Pierre Fm-Inyan Kara Fm)	351	773	7.3	27.6	5,800	10	0.1	9.87E-17	9.9E-05	1.23E-06	620
Aquifer 2 (Thief Zone–Inyan Kara Fm)	1123	55	10.8	48.1	3,365	13.3	36.4	3.59E-14	5.31E-02	1.08E-06	557
Aquitard 1 (Swift—Broom Creek Fm) (primary upper seal)	1178	267	12.9	44.4	40,000	10	0.1	9.87E-17	1.31E-04	1.27E-06	612
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1445	71	16.4	57.4	49,350	14.5	22**	2.17E-14**	3.5E-02	1.21E-06	802

* Ground surface elevation 609 m amsl.

** Average (geometric mean) permeability from well logs was multiplied by the 2.5, the same permeability multiplier used in dynamic simulations.

Risk-Based AOR Results

Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

Figure A-22 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for the case without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure A-22) is used to predict incremental leakage using a linear interpolation between the points making up the curve.

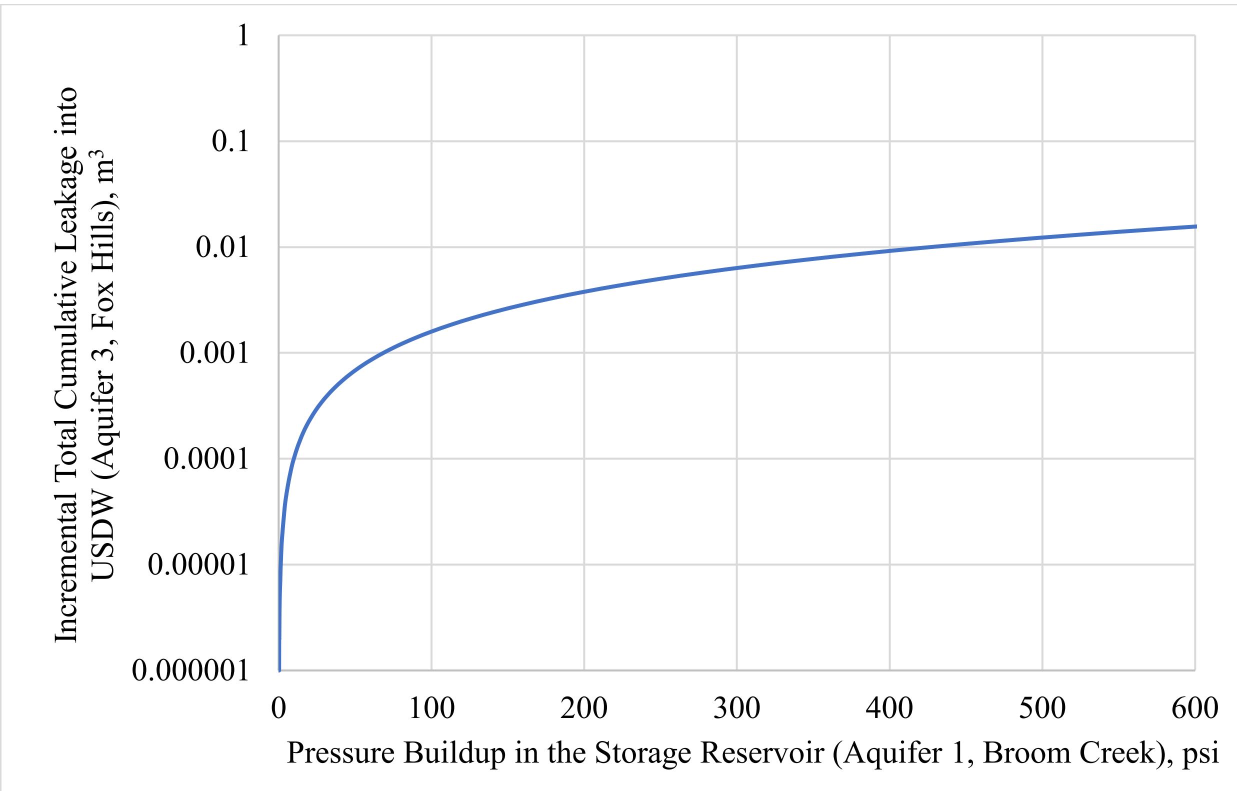


Figure A-22. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) for Aquifer 3 (USDW, Fox Hills). In this scenario, the leaky wellbore is closed to Aquifer 2 (Inyan Kara).

Incremental Leakage Maps and AOR Delineation

The pressure buildup-incremental leakage relationship, shown in Figure A-22, results in the incremental leakage maps shown in Figure A-23, which show the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire 20-year period.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the Tundra SGS site, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the 20-year injection period is established. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure A-22. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 569 psi in the raster cell intersected by the injection well, which corresponds to less than 0.015 m^3 of flow over 20 years. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

The assumptions and calculations used to determine the risk-based AOR at Tundra SGS site incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—A more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—A real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the Tundra SGS area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressurized nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 50-year) timescales, overpressurized aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

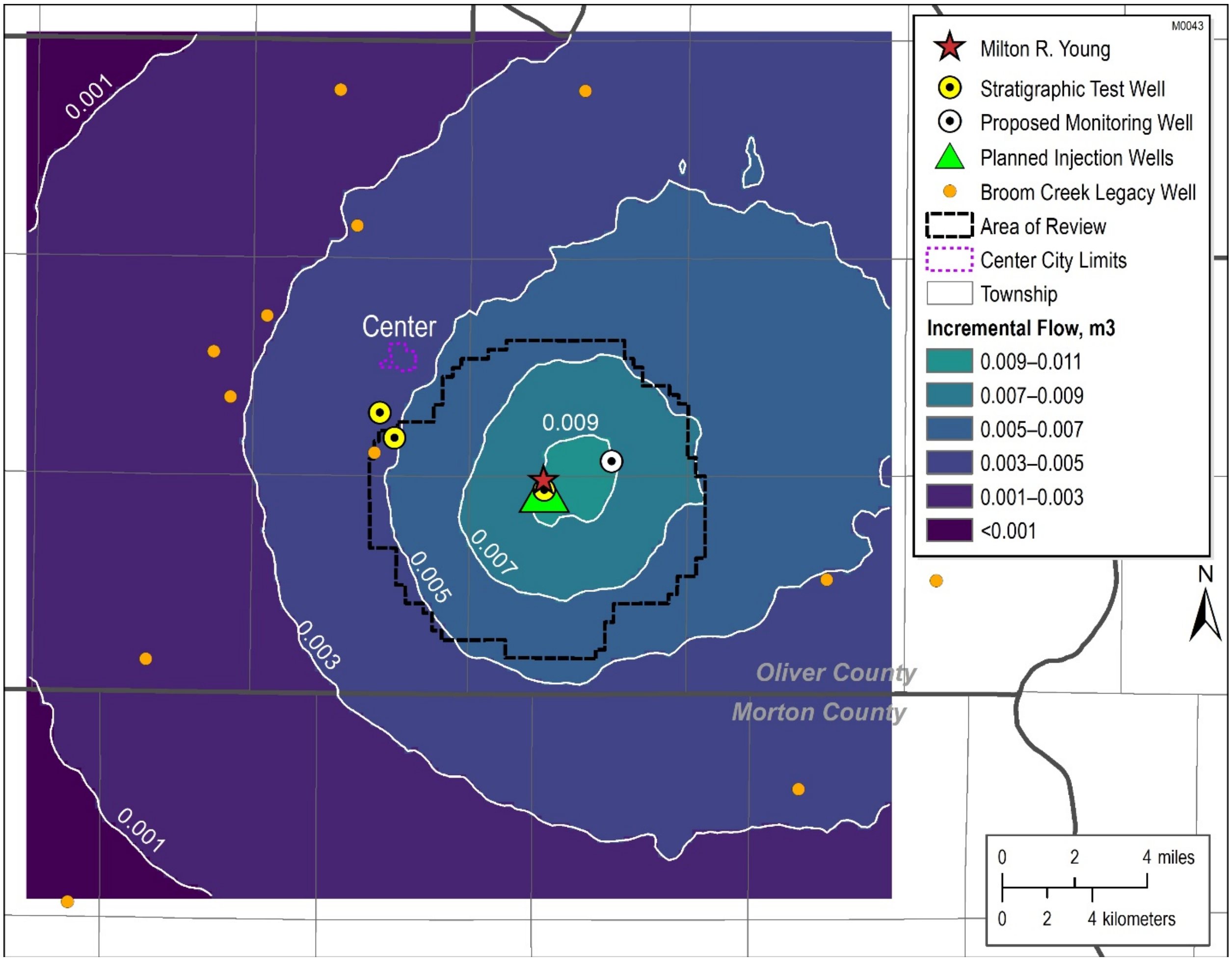


Figure A-23. Incremental leakage maps at the end of 20 years of CO_2 injection for the scenario where the leaky wellbore is closed to Aquifer 2 (thief zone). The dotted black polygon denotes the areal extent of the CO_2 plume in the storage reservoir plus 1-mile buffer at the end of 20 years of CO_2 injection as determined using a compositional simulator and the site-specific geologic model.

Results of the risk-based method detailed above generate a minimum AOR extent which is equivalent to the storage facility area plus a 1-mile buffer. Within the AOR, the pressure increase is not expected to be large enough to cause incremental flow of more than 1 m^3 into the USDW over the injection period (Figure A-24). As shown, the AOR is depicted by the gray shaded area, which includes the storage facility area. Figure A-25 illustrates the land use within the AOR.

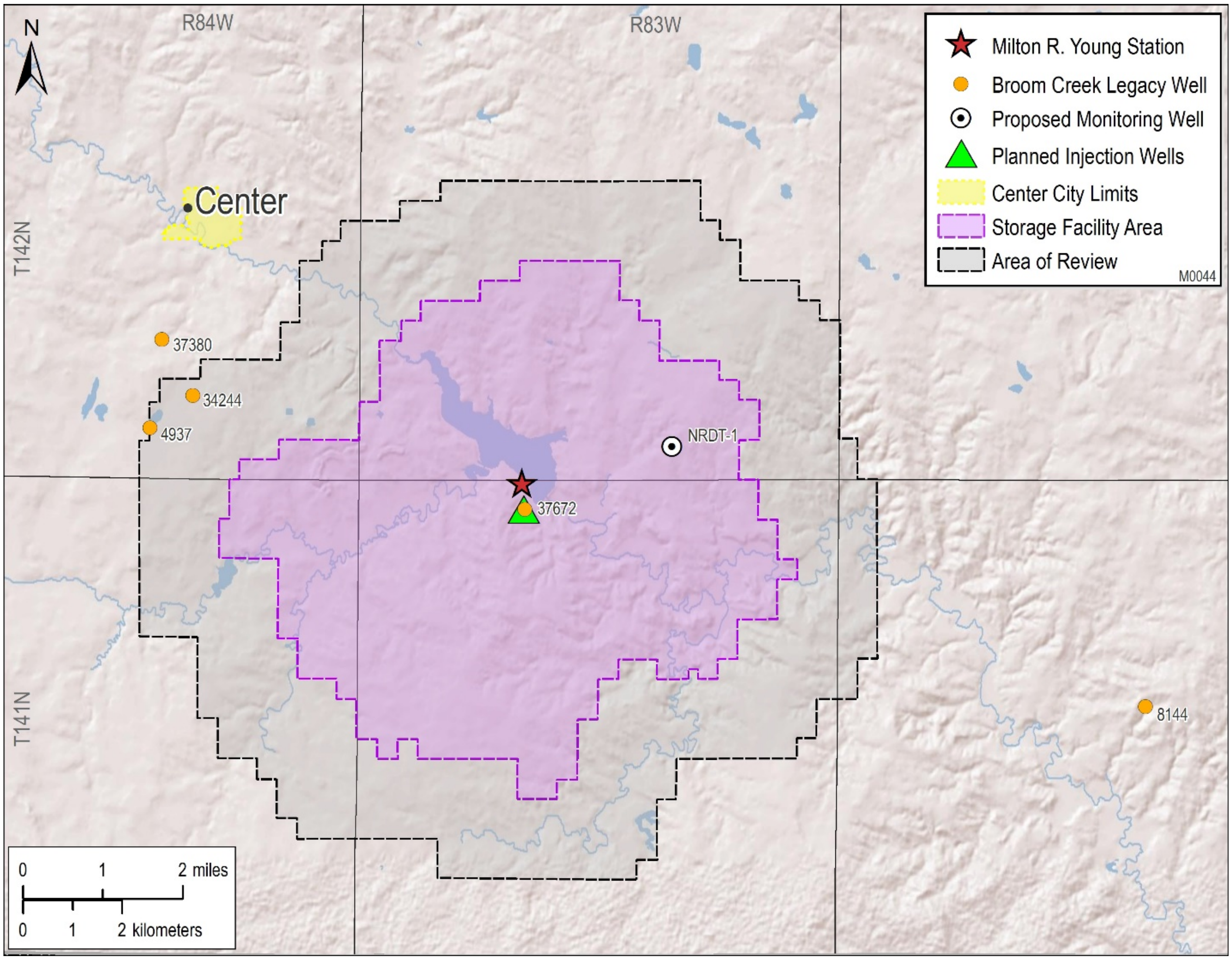


Figure A-24. Final AOR estimations of the Tundra SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), area of review (gray boundary and shaded area), and Center city limits (dotted yellow boundary). Orange circles represent nearby legacy wells near the storage facility area.

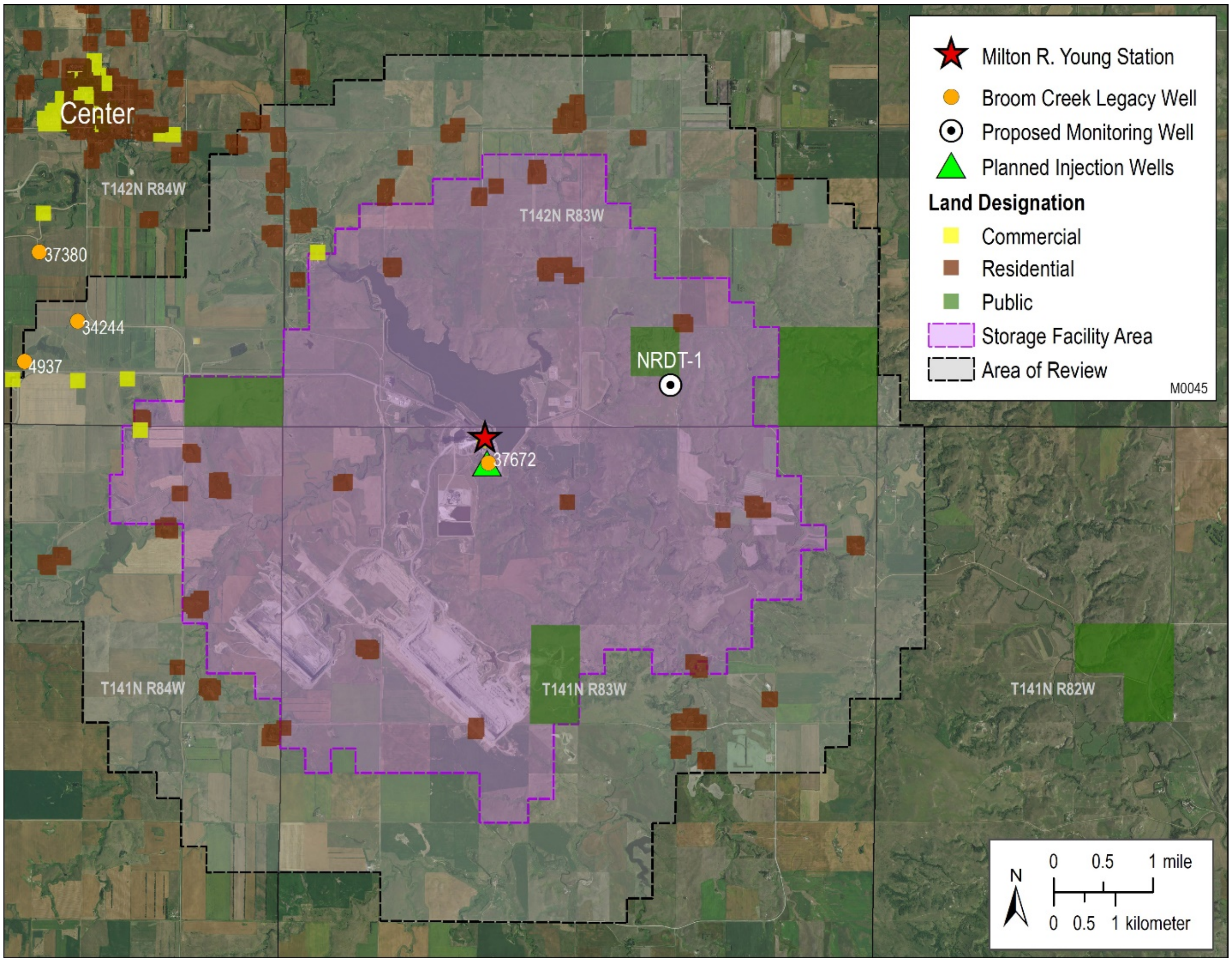


Figure A-25. Land use in and around the AOR of the Tundra SGS storage facility.

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APPENDIX B

WELL AND WELL FORMATION FLUID-SAMPLING LABORATORY ANALYSIS

EERC
Energy & Environmental Research Center®
UNIVERSITY OF NORTH DAKOTA
15 North 23rd Street -- Stop 9018 / Grand Forks, ND 58202-9018 / Phone: (701) 777-5000 Fax: 777-5181

ANALYTICAL RESEARCH LAB - Final Results

Set Number: 54654
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020

July 24, 2020

Sample	Parameter	Result	
54654-03	**Broom Creek 6/13/20**		
	Alkalinity, as Bicarbonate (HCO3-)	83.4	mg/L
	Alkalinity, as Carbonate (CO3=)	0	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	68.4	mg/L
	Aluminum	263	µg/L
	Antimony	< 5	µg/L
	Arsenic	< 5	µg/L
	Barium	187	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 5	µg/L
	Boron	11.7	mg/L
	Bromide	< 20	mg/L
	Cadmium	< 2	µg/L
	Calcium	2030	mg/L
	Chloride	26400	mg/L
	Chromium	< 40	µg/L
	Cobalt	109	µg/L
	Conductivity at 25°C	68800	µS/cm
	Copper	< 200	µg/L
	Dissolved Inorganic Carbon	15.5	mg/L
	Dissolved Organic Carbon	1130	mg/L
	Fluoride	< 1	mg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	8.2	mg/L
	Magnesium	404	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	936	µg/L
	Nickel	213	µg/L
	Phosphorus	< 1	mg/L

Distribution ________________________ Date ___________

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Sample	Parameter	Result
54654-03	**Broom Creek 6/13/20**	
	Potassium	202 mg/L
	Selenium	88.0 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	16900 mg/L
	Strontium	49.0 mg/L
	Sulfate	3060 mg/L
	Thallium	< 5 µg/L
	Thorium	< 3 µg/L
	Total Dissolved Solids	49000 mg/L
	Total Inorganic Carbon	17.0 mg/L
	Total Organic Carbon	1160 mg/L
	Uranium	23 µg/L
	Vanadium	95.4 µg/L
	Zinc	< 0.1 mg/L
54654-04	**Broom Creek 6/13/20 duplicate**	
	Alkalinity, as Bicarbonate (HCO3-)	84.0 mg/L
	Alkalinity, as Carbonate (CO3=)	0 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	68.9 mg/L
	Aluminum	248 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	188 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	11.2 mg/L
	Bromide	< 20 mg/L
	Cadmium	< 2 µg/L
	Calcium	2000 mg/L
	Chloride	27000 mg/L
	Chromium	< 40 µg/L

Distribution ________________________ Date ____________

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Due Date: Thursday, July 2, 2020
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Sample	Parameter	Result	
54654-04	**Broom Creek 6/13/20 duplicate**		
	Cobalt	108	µg/L
	Conductivity at 25°C	69900	µS/cm
	Copper	< 200	µg/L
	Dissolved Inorganic Carbon	15.5	mg/L
	Dissolved Organic Carbon	1120	mg/L
	Fluoride	< 1	mg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	9.4	mg/L
	Magnesium	399	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	946	µg/L
	Nickel	219	µg/L
	Phosphorus	< 1	mg/L
	Potassium	202	mg/L
	Selenium	87.6	µg/L
	Silicon	< 1	mg/L
	Silver	< 5	µg/L
	Sodium	16900	mg/L
	Strontium	48.1	mg/L
	Sulfate	3070	mg/L
	Thallium	< 5	µg/L
	Thorium	< 3	µg/L
	Total Dissolved Solids	49700	mg/L
	Total Inorganic Carbon	16.8	mg/L
	Total Organic Carbon	1190	mg/L
	Uranium	24	µg/L
	Vanadium	103	µg/L
	Zinc	< 0.1	mg/L

Distribution ______________________ Date __________

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ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result	
54655-03	**Broom Creek 6/13/20 (Total Metals)**		
	Aluminum	311	µg/L
	Antimony	< 5	µg/L
	Arsenic	< 5	µg/L
	Barium	259	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 5	µg/L
	Boron	11.0	mg/L
	Cadmium	< 2	µg/L
	Calcium	2000	mg/L
	Chromium	< 40	µg/L
	Cobalt	109	µg/L
	Copper	< 200	µg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	8.2	mg/L
	Magnesium	381	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	973	µg/L
	Nickel	224	µg/L
	Phosphorus	< 1	mg/L
	Potassium	194	mg/L
	Selenium	92.4	µg/L
	Silicon	< 1	mg/L
	Silver	< 5	µg/L
	Sodium	16200	mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result
54655-03	**Broom Creek 6/13/20 (Total Metals)**	
	Strontium	46.5 mg/L
	Thallium	< 5 µg/L
	Thorium	< 3 µg/L
	Uranium	25 µg/L
	Vanadium	107 µg/L
	Zinc	< 0.1 mg/L
54655-04	**Broom Creek 6/13/20 duplicate (Total Metals)**	
	Aluminum	289 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	246 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	11.3 mg/L
	Cadmium	< 2 µg/L
	Calcium	1940 mg/L
	Chromium	< 40 µg/L
	Cobalt	112 µg/L
	Copper	< 200 µg/L
	Iron	< 1 mg/L
	Lead	< 5 µg/L
	Lithium	7.9 mg/L
	Magnesium	398 mg/L
	Manganese	26 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	980 µg/L
	Nickel	220 µg/L
	Phosphorus	< 1 mg/L
	Potassium	197 mg/L
	Selenium	90.8 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result	
54655-04	**Broom Creek 6/13/20 duplicate (Total Metals)**		
	Sodium	16300	mg/L
	Strontium	46.9	mg/L
	Thallium	< 5	µg/L
	Thorium	< 3	µg/L
	Uranium	25	µg/L
	Vanadium	110	µg/L
	Zinc	< 0.1	mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ______________________ Date __________

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1768
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:10
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Broom Creek

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	15 Jun 20	JD
pH	* 7.3	units	N/A	SM4500 H+ B	15 Jun 20 17:00	HT
Conductivity (EC)	66249	umhos/cm	N/A	SM2510-B	15 Jun 20 17:00	HT
pH - Field	7.21	units	NA	SM 4500 H+ B	13 Jun 20 10:10	JSM
Temperature - Field	20.9	Degrees C	NA	SM 2550B	13 Jun 20 10:10	JSM
Total Alkalinity	67	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Bicarbonate	67	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Conductivity - Field	65006	umhos/cm	1	EPA 120.1	13 Jun 20 10:10	JSM
Total Organic Carbon	1360	mg/l	0.5	SM5310-C	26 Jun 20 12:37	NAS
Sulfate	2620	mg/l	5.00	ASTM D516-11	17 Jun 20 11:38	EV
Chloride	29900	mg/l	1.0	SM4500-Cl-E	17 Jun 20 9:50	EV
Nitrate-Nitrite as N	25.1	mg/l	0.10	EPA 353.2	18 Jun 20 8:37	EV
Ammonia-Nitrogen as N	0.36	mg/l	0.20	EPA 350.1	16 Jun 20 11:40	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Jun 20 12:37	MDE
Total Dissolved Solids	49000	mg/l	10	I1750-85	17 Jun 20 15:53	HT
Calcium - Total	1990	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Magnesium - Total	376	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Sodium - Total	16300	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Potassium - Total	226	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Iron - Total	< 2 @	mg/l	0.10	6010D	24 Jun 20 11:07	MDE
Manganese - Total	< 1 @	mg/l	0.05	6010D	24 Jun 20 11:07	MDE
Barium - Dissolved	< 2 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ

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

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MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1768
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:10
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Broom Creek

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 1 @	mg/l	0.05	6010D	23 Jun 20 12:02	SZ
Molybdenum - Dissolved	< 2 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Strontium - Dissolved	45.2	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Cadmium - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Lead - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE
Selenium - Dissolved	0.1204	mg/l	0.0050	6020B	15 Jun 20 16:05	MDE
Silver - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE

* 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:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX C

NEAR-SURFACE MONITORING PARAMETERS AND BASELINE DATA

C1. Near-Surface Monitoring: Groundwater and Soil Gas

Near-surface sampling discussed herein comprises 1) sampling of shallow groundwater aquifers (underground sources of drinking water [USDW]) 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.

C1-1. Groundwater Analysis Protocol

Baseline Groundwater Wells

Two laboratories will be used to analyze the water samples: 1) Minnesota Valley Testing Laboratories, Inc. (MVTL) for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-1 and C-2) and 2) Isotech Laboratories, Inc., for isotopic signatures (Table C-3).

Table C-1. 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 C-2 for entire sampling list of total and dissolved metals.

Table C-2. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Major Cations	Minor and Trace Metals		
Calcium	Aluminum	Copper	Selenium
Magnesium	Antimony	Iron	Silicon
Potassium	Arsenic	Lead	Silver
Sodium	Barium	Lithium	Strontium
	Beryllium	Manganese	Thallium
	Bismuth	Mercury	Thorium
	Boron	Molybdenum	Uranium
	Cadmium	Nickel	Vanadium
	Chromium	Phosphorus	Zinc
	Cobalt		

Table C-3. Isotope Measurements for Groundwater Samples

Isotope	Units
$\delta^{2}H$ H_2O	‰[a]
$\delta^{18}O$ H_2O	‰
Tritium	TU[b]
$\delta^{13}C$ DIC	‰
^{14}C DIC	pMC[c]

[a] One tenth of a percent (0.1%).
[b] Tritium unit.
[c] Percent modern carbon.

C1-2. Soil Gas-Sampling and Analysis Protocol

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.

Soil Gas Profile Station Locations

Fixed soil gas profile stations will be installed for the sampling of soil gas adjacent to the well pads at the injection and monitoring wellsites J-ROC1 and MLR-1 prior to the initiation of CO_2 injection. A schematic of these soil gas profile stations is shown in Figure C-1. Each soil gas profile station contains three isolated gas-sampling screens 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 are as follows: sampling will not proceed until the screens have been purged and the composition of the soil gas has been determined to be stable. Following industry standards for landfill gas analysis, an on-site analysis of the soil gas will be conducted (RAE handheld meter) and a laboratory sample collected for the parameters identified in Table C-4. In addition, a sample will be collected and sent to Isotech Laboratories, Inc. (Champaign, Illinois) for isotopic analyses (see Table C-5).

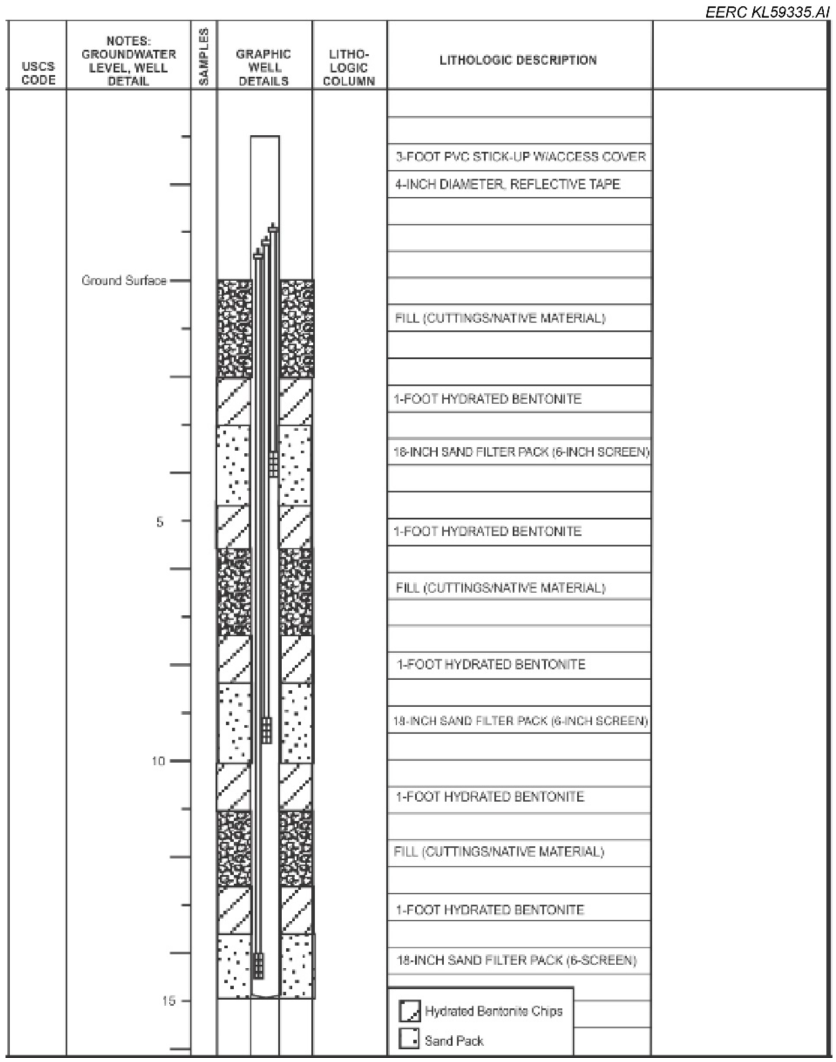

Figure C-1. Schematic of soil gas profile stations near the well pads for J-ROC1 and MLR-1.

Table C-4. 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 C-5. 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

C2. Near-Surface Water Well Verification

The North Dakota State Water Commission (NDSWC) drilling records provided the starting point for selecting baseline characterization and monitoring wells. Nearly 600 drilling records were included in the project area. Key well characteristics for further investigations were 1) potential as a drinking water source (i.e., labeled domestic, domestic/stock, and municipal) and 2) aquifer. Based on the database drilling records, most of the wells in the area draw from the Tongue River aquifer. As a result, wells labeled for purposes other than drinking water (e.g., stock, industrial, unknown) were included in the initial selection for the Fox Hills and Upper Hell Creek and Cannonball and Ludlow aquifers. The 42 well records fitting these criteria underwent review to verify their status (e.g., do they still exist? can they be sampled?). The verification process is ongoing. It is anticipated that up to 19 viable wells may be selected to characterize the baseline groundwater quality of the USDWs in the project area.

C3. Laboratory Analyses of Baseline Data

Existing monitoring well data have been compiled as one element of the baseline characterization effort. These data represent long-term regulatory monitoring associated with the BNI coal mine and MRYS power plant operations. Additionally, baseline sampling has begun in an existing observation well in the deepest USDW for in the USGS-managed Fox Hills observation well (NDSWC Well No. 3558) east of Center, North Dakota. The first of four anticipated baseline sampling events occurred on January 12, 2021.

Attached to this appendix are laboratory results from these three sources. They include the following:

1. 3 years of analyses from annual sampling of six mine land wells monitored by BNI

2. 3 years of analyses from five ash disposal pond wells monitored by MRYS.

3. Laboratory results from one sample of Fox Hills observation well 2558.

APPENDIX C-1

BNI COAL MONITORING WELL ANALYSES FOR BASELINE DATA

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 8 Aug 18
Lab Number: 18-W2083
Work Order #: 82-1752
Account #: 003022
Date Sampled: 17 Jul 18 12:47
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 322A
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 3.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 6.4	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	801	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	6.19	units	NA	SM 4500 H+ B	17 Jul 18 12:47	DJN
Temperature - Field	11.2	Degrees C	NA	SM 2550B	17 Jul 18 12:47	DJN
Total Alkalinity	118	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Bicarbonate	118	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Conductivity - Field	870	umhos/cm	1	EPA 120.1	17 Jul 18 12:47	DJN
Tot Dis Solids(Summation)	525	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	144	mg/l HCO3	NA	SM2320-B	19 Jul 18 17:00	Calculated
Total Hardness as CaCO3	415	mg/l	NA	SM2340-B	30 Jul 18 12:35	Calculated
Cation Summation	9.84	meq/L	NA	SM1030-F	30 Jul 18 12:35	Calculated
Anion Summation	8.25	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	8.79	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	0.70		NA	USDA 20b	30 Jul 18 12:35	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	277	mg/l	5.00	ASTM D516-07	20 Jul 18 14:32	EMS
Chloride	3.6	mg/l	1.0	SM4500-Cl-E	26 Jul 18 12:11	EV
Nitrate-Nitrite as N	0.25	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	96.2	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Magnesium - Total	42.4	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Sodium - Total	32.8	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Potassium - Total	2.1	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Iron - Dissolved	1.55	mg/l	0.10	6010D	27 Jul 18 11:25	BT
Manganese - Dissolved	0.28	mg/l	0.05	6010D	27 Jul 18 11:25	BT

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

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

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Report Date: 27 Aug 19
Lab Number: 19-W2683
Work Order #: 82-1966
Account #: 003022
Date Sampled: 29 Jul 19 14:40
Date Received: 30 Jul 19 15:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 322A

Temp at Receipt: 0.7C

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 6.6	units	N/A	SM4500 H+ B	31 Jul 19 18:00	SVS
Conductivity (EC)	980	umhos/cm	N/A	SM2510-B	31 Jul 19 18:00	SVS
pH - Field	6.21	units	NA	SM 4500 H+ B	29 Jul 19 14:40	JSM
Temperature - Field	14.4	Degrees C	NA	SM 2550B	29 Jul 19 14:40	JSM
Total Alkalinity	124	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Bicarbonate	124	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Conductivity - Field	1193	umhos/cm	1	EPA 120.1	29 Jul 19 14:40	JSM
Tot Dis Solids(Summation)	726	mg/l	12.5	SM1030-F	22 Aug 19 8:28	Calculated
Bicarb as HCO3	151	mg/l HCO3	NA	SM2320-B	31 Jul 19 18:00	Calculated
Total Hardness as CaCO3	561	mg/l	NA	SM2340-B	14 Aug 19 10:17	Calculated
Cation Summation	13.0	meq/L	NA	SM1030-F	16 Aug 19 18:14	Calculated
Anion Summation	11.3	meq/L	NA	SM1030-F	22 Aug 19 8:28	Calculated
Percent Error	6.94	%	NA	SM1030-F	22 Aug 19 8:28	Calculated
Sodium Adsorption Ratio	0.72		NA	USDA 20b	14 Aug 19 10:17	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	31 Jul 19 18:00	SVS
Sulfate	419	mg/l	5.00	ASTM D516-07	22 Aug 19 8:28	EV
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	31 Jul 19 10:28	EV
Nitrate-Nitrite as N	0.17	mg/l	0.10	EPA 353.2	31 Jul 19 14:48	EMS
Calcium - Total	130	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Magnesium - Total	57.4	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Sodium - Total	39.2	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Potassium - Total	2.0	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Iron - Dissolved	1.16	mg/l	0.10	6010D	16 Aug 19 18:14	SZ
Manganese - Dissolved	0.23	mg/l	0.05	6010D	16 Aug 19 18:14	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll 28 Aug 19 CC

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2663
Work Order #: 82-2008
Account #: 003022
Date Sampled: 27 Jul 20 12:50
Date Received: 27 Jul 20 16:49
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: 322A
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 4.3C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 6.6	units	N/A	SM4500 H+ B	28 Jul 20 17:00	HT
Conductivity (EC)	832	umhos/cm	N/A	SM2510-B	28 Jul 20 17:00	HT
pH - Field	6.14	units	NA	SM 4500 H+ B	27 Jul 20 12:50	DJN
Temperature - Field	10.0	Degrees C	NA	SM 2550B	27 Jul 20 12:50	DJN
Total Alkalinity	165	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Bicarbonate	165	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Conductivity - Field	863	umhos/cm	1	EPA 120.1	27 Jul 20 12:50	DJN
Tot Dis Solids(Summation)	532	mg/l	12.5	SM1030-F	30 Jul 20 11:00	Calculated
Bicarb as HCO3	201	mg/l HCO3	NA	SM2320-B	28 Jul 20 17:00	Calculated
Total Hardness as CaCO3	423	mg/l	NA	SM2340-B	29 Jul 20 11:25	Calculated
Cation Summation	9.96	meq/L	NA	SM1030-F	3 Aug 20 13:38	Calculated
Anion Summation	8.68	meq/L	NA	SM1030-F	30 Jul 20 11:00	Calculated
Percent Error	6.87	%	NA	SM1030-F	3 Aug 20 13:38	Calculated
Sodium Adsorption Ratio	0.69		NA	USDA 20b	29 Jul 20 11:25	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	28 Jul 20 17:00	HT
Sulfate	253	mg/l	5.00	ASTM D516-11	29 Jul 20 12:30	EV
Chloride	3.5	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	0.13	mg/l	0.10	EPA 353.2	30 Jul 20 11:00	EV
Calcium - Total	99.3	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Magnesium - Total	42.6	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Sodium - Total	32.4	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Potassium - Total	1.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Iron - Dissolved	0.88	mg/l	0.10	6010D	3 Aug 20 13:38	MDE
Manganese - Dissolved	0.14	mg/l	0.05	6010D	3 Aug 20 13:38	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 4 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 8 Aug 18
Lab Number: 18-W2170
Work Order #: 82-1784
Account #: 003022
Date Sampled: 19 Jul 18 9:16
Date Received: 19 Jul 18 15:08
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 324

Temp at Receipt: 7.2C ROI

Event and Year: 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 7.8	units	N/A	SM4500 H+ B	23 Jul 18 17:00	SVS
Conductivity (EC)	649	umhos/cm	N/A	SM2510-B	23 Jul 18 17:00	SVS
pH - Field	7.47	units	NA	SM 4500 H+ B	19 Jul 18 9:16	DJN
Temperature - Field	9.28	Degrees C	NA	SM 2550B	19 Jul 18 9:16	DJN
Total Alkalinity	188	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Bicarbonate	188	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Conductivity - Field	632	umhos/cm	1	EPA 120.1	19 Jul 18 9:16	DJN
Tot Dis Solids(Summation)	360	mg/l	12.5	SM1030-F	7 Aug 18 16:30	Calculated
Bicarb as HCO3	229	mg/l HCO3	NA	SM2320-B	23 Jul 18 17:00	Calculated
Total Hardness as CaCO3	92.1	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	6.53	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	6.09	meq/L	NA	SM1030-F	7 Aug 18 16:30	Calculated
Percent Error	3.47	%	NA	SM1030-F	7 Aug 18 16:30	Calculated
Sodium Adsorption Ratio	4.81		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	0.20	mg/l	0.10	SM4500-F-C	23 Jul 18 17:00	SVS
Sulfate	103	mg/l	5.00	ASTM D516-07	20 Jul 18 16:05	EMS
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	1.06	mg/l	0.10	EPA 353.2	7 Aug 18 16:30	EMS
Calcium - Total	20.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	10.0	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	106	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	3.1	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Jul 18 11:55	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Jul 18 11:55	SZ

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 19 Aug 19
Lab Number: 19-W2667
Work Order #: 82-1950
Account #: 003022
Date Sampled: 29 Jul 19 16:35
Date Received: 30 Jul 19 8:00
Sampled By: MVTL Field Services

Temp at Receipt: 6.8C ROI

Sample Description: 324

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 7.8	units	N/A	SM4500 H+ B	30 Jul 19 17:00	SVS
Conductivity (EC)	1193	umhos/cm	N/A	SM2510-B	30 Jul 19 17:00	SVS
pH - Field	7.31	units	NA	SM 4500 H+ B	29 Jul 19 16:35	DJN
Temperature - Field	9.36	Degrees C	NA	SM 2550B	29 Jul 19 16:35	DJN
Total Alkalinity	345	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Bicarbonate	345	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Conductivity - Field	1224	umhos/cm	1	EPA 120.1	29 Jul 19 16:35	DJN
Tot Dis Solids(Summation)	817	mg/l	12.5	SM1030-F	8 Aug 19 15:19	Calculated
Bicarb as HCO3	421	mg/l HCO3	NA	SM2320-B	30 Jul 19 17:00	Calculated
Total Hardness as CaCO3	212	mg/l	NA	SM2340-B	8 Aug 19 15:19	Calculated
Cation Summation	14.0	meq/L	NA	SM1030-F	16 Aug 19 17:14	Calculated
Anion Summation	13.4	meq/L	NA	SM1030-F	2 Aug 19 14:11	Calculated
Percent Error	2.12	%	NA	SM1030-F	16 Aug 19 17:14	Calculated
Sodium Adsorption Ratio	6.63		NA	USDA 20b	8 Aug 19 15:19	Calculated
Fluoride	0.29	mg/l	0.10	SM4500-F-C	31 Jul 19 17:00	SVS
Sulfate	309	mg/l	5.00	ASTM D516-07	2 Aug 19 14:11	EMS
Chloride	3.8	mg/l	1.0	SM4500-Cl-E	31 Jul 19 9:52	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 Jul 19 14:03	EMS
Calcium - Total	47.0	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Magnesium - Total	23.0	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Sodium - Total	222	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Potassium - Total	4.8	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Iron - Dissolved	0.17	mg/l	0.10	6010D	16 Aug 19 17:14	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	16 Aug 19 17:14	SZ

* Holding time exceeded

CC

Approved by: Claudette K Carroll 20 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 7 Aug 20
Lab Number: 20-W2552
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 11:51
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 324

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 7.8	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	1182	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	7.54	units	NA	SM 4500 H+ B	21 Jul 20 11:51	DJN
Temperature - Field	9.58	Degrees C	NA	SM 2550B	21 Jul 20 11:51	DJN
Total Alkalinity	369	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	369	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	1174	umhos/cm	1	EPA 120.1	21 Jul 20 11:51	DJN
Tot Dis Solids(Summation)	745	mg/l	12.5	SM1030-F	5 Aug 20 8:19	Calculated
Bicarb as HCO3	450	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	173	mg/l	NA	SM2340-B	31 Jul 20 9:21	Calculated
Cation Summation	12.4	meq/L	NA	SM1030-F	31 Jul 20 9:21	Calculated
Anion Summation	12.8	meq/L	NA	SM1030-F	5 Aug 20 8:19	Calculated
Percent Error	-1.82	%	NA	SM1030-F	5 Aug 20 8:19	Calculated
Sodium Adsorption Ratio	6.68		NA	USDA 20b	31 Jul 20 9:21	Calculated
Fluoride	0.29	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	256	mg/l	5.00	ASTM D516-11	5 Aug 20 8:19	EV
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	28 Jul 20 15:16	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:53	EMS
Calcium - Total	37.7	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Magnesium - Total	19.2	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Sodium - Total	202	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Potassium - Total	4.3	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Iron - Dissolved	0.16	mg/l	0.10	6010D	27 Jul 20 11:42	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	27 Jul 20 11:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 8 Aug 18
Lab Number: 18-W2086
Work Order #: 82-1752
Account #: 003022
Date Sampled: 17 Jul 18 12:22
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 363
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 3.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 8.3	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	2446	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	7.94	units	NA	SM 4500 H+ B	17 Jul 18 12:22	DJN
Temperature - Field	14.8	Degrees C	NA	SM 2550B	17 Jul 18 12:22	DJN
Total Alkalinity	1090	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Bicarbonate	1090	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Conductivity - Field	2395	umhos/cm	1	EPA 120.1	17 Jul 18 12:22	DJN
Tot Dis Solids(Summation)	1440	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	1330	mg/l HCO3	NA	SM2320-B	18 Jul 18 17:00	Calculated
Total Hardness as CaCO3	37.6	mg/l	NA	SM2340-B	30 Jul 18 12:35	Calculated
Cation Summation	26.7	meq/L	NA	SM1030-F	30 Jul 18 12:35	Calculated
Anion Summation	25.4	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	2.56	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	42.1		NA	USDA 20b	30 Jul 18 12:35	Calculated
Fluoride	0.84	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	164	mg/l	5.00	ASTM D516-07	20 Jul 18 14:32	EMS
Chloride	5.5	mg/l	1.0	SM4500-Cl-E	26 Jul 18 12:11	EV
Nitrate-Nitrite as N	0.26	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	7.8	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Magnesium - Total	4.4	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Sodium - Total	593	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Potassium - Total	6.9	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	27 Jul 18 11:25	BT
Manganese - Dissolved	0.07	mg/l	0.05	6010D	27 Jul 18 11:25	BT

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2687
Work Order #: 82-1966
Account #: 003022
Date Sampled: 29 Jul 19 13:45
Date Received: 30 Jul 19 15:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 363

Temp at Receipt: 0.7C

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 8.3	units	N/A	SM4500 H+ B	31 Jul 19 18:00	SVS
Conductivity (EC)	2460	umhos/cm	N/A	SM2510-B	31 Jul 19 18:00	SVS
pH - Field	7.97	units	NA	SM 4500 H+ B	29 Jul 19 13:45	JSM
Temperature - Field	13.4	Degrees C	NA	SM 2550B	29 Jul 19 13:45	JSM
Total Alkalinity	1110	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Bicarbonate	1093	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Conductivity - Field	2426	umhos/cm	1	EPA 120.1	29 Jul 19 13:45	JSM
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	14 Aug 19 10:17	Calculated
Bicarb as HCO3	1330	mg/l HCO3	NA	SM2320-B	31 Jul 19 18:00	Calculated
Total Hardness as CaCO3	36.8	mg/l	NA	SM2340-B	14 Aug 19 10:17	Calculated
Cation Summation	28.5	meq/L	NA	SM1030-F	16 Aug 19 18:14	Calculated
Anion Summation	26.1	meq/L	NA	SM1030-F	2 Aug 19 14:31	Calculated
Percent Error	4.37	%	NA	SM1030-F	16 Aug 19 18:14	Calculated
Sodium Adsorption Ratio	45.5		NA	USDA 20b	14 Aug 19 10:17	Calculated
Fluoride	0.99	mg/l	0.10	SM4500-F-C	31 Jul 19 18:00	SVS
Sulfate	176	mg/l	5.00	ASTM D516-07	2 Aug 19 14:31	EMS
Chloride	5.9	mg/l	1.0	SM4500-Cl-E	31 Jul 19 10:28	EV
Nitrate-Nitrite as N	0.54	mg/l	0.10	EPA 353.2	31 Jul 19 14:48	EMS
Calcium - Total	7.8	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Magnesium - Total	4.2	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Sodium - Total	634	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Potassium - Total	5.0	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Iron - Dissolved	0.30	mg/l	0.10	6010D	16 Aug 19 18:14	SZ
Manganese - Dissolved	0.07	mg/l	0.05	6010D	16 Aug 19 18:14	SZ

* Holding time exceeded

CC

Approved by: Claudette K Carroll 28 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2657
Work Order #: 82-2008
Account #: 003022
Date Sampled: 27 Jul 20 13:43
Date Received: 27 Jul 20 16:49
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: 363
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 4.3C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 8.2	units	N/A	SM4500 H+ B	28 Jul 20 17:00	HT
Conductivity (EC)	2454	umhos/cm	N/A	SM2510-B	28 Jul 20 17:00	HT
pH - Field	7.94	units	NA	SM 4500 H+ B	27 Jul 20 13:43	DJN
Temperature - Field	11.0	Degrees C	NA	SM 2550B	27 Jul 20 13:43	DJN
Total Alkalinity	1200	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Bicarbonate	1200	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Conductivity - Field	2508	umhos/cm	1	EPA 120.1	27 Jul 20 13:43	DJN
Tot Dis Solids(Summation)	1550	mg/l	12.5	SM1030-F	30 Jul 20 10:43	Calculated
Bicarb as HCO3	1460	mg/l HCO3	NA	SM2320-B	28 Jul 20 17:00	Calculated
Total Hardness as CaCO3	53.6	mg/l	NA	SM2340-B	29 Jul 20 10:25	Calculated
Cation Summation	27.2	meq/L	NA	SM1030-F	3 Aug 20 12:38	Calculated
Anion Summation	28.4	meq/L	NA	SM1030-F	30 Jul 20 10:43	Calculated
Percent Error	-2.16	%	NA	SM1030-F	3 Aug 20 12:38	Calculated
Sodium Adsorption Ratio	35.4		NA	USDA 20b	29 Jul 20 10:25	Calculated
Fluoride	0.90	mg/l	0.10	SM4500-F-C	28 Jul 20 17:00	HT
Sulfate	195	mg/l	5.00	ASTM D516-11	29 Jul 20 12:30	EV
Chloride	12.1	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Jul 20 10:43	EV
Calcium - Total	10.6	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Magnesium - Total	6.6	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Sodium - Total	596	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Potassium - Total	6.8	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Iron - Dissolved	0.82	mg/l	0.10	6010D	3 Aug 20 12:38	MDE
Manganese - Dissolved	0.08	mg/l	0.05	6010D	3 Aug 20 12:38	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 4 Aug 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

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MEMBER ACIL

Report Date: 2 Aug 18
Lab Number: 18-W2077
Work Order #: 82-1751
Account #: 003022
Date Sampled: 17 Jul 18 10:58
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: C1-1
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 1.7C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 8.4	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	1151	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	8.36	units	NA	SM 4500 H+ B	17 Jul 18 10:58	DJN
Temperature - Field	11.3	Degrees C	NA	SM 2550B	17 Jul 18 10:58	DJN
Total Alkalinity	454	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Bicarbonate	441	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Conductivity - Field	1164	umhos/cm	1	EPA 120.1	17 Jul 18 10:58	DJN
Tot Dis Solids(Summation)	706	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	538	mg/l HCO3	NA	SM2320-B	19 Jul 18 17:00	Calculated
Total Hardness as CaCO3	25.3	mg/l	NA	SM2340-B	30 Jul 18 11:35	Calculated
Cation Summation	13.0	meq/L	NA	SM1030-F	30 Jul 18 11:35	Calculated
Anion Summation	11.9	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	4.13	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	24.6		NA	USDA 20b	30 Jul 18 11:35	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	132	mg/l	5.00	ASTM D516-07	20 Jul 18 14:12	EMS
Chloride	4.3	mg/l	1.0	SM4500-Cl-E	18 Jul 18 12:12	EMS
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	5.5	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Magnesium - Total	2.8	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Sodium - Total	284	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Potassium - Total	4.7	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	27 Jul 18 10:25	BT
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	27 Jul 18 10:25	BT

* Holding time exceeded

Approved by: Claudette K. Carroll cc 7 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 19 Aug 19
Lab Number: 19-W2664
Work Order #: 82-1950
Account #: 003022
Date Sampled: 29 Jul 19 9:40
Date Received: 30 Jul 19 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: C1-1

Temp at Receipt: 6.8C ROI

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 8.4	units	N/A	SM4500 H+ B	30 Jul 19 17:00	SVS
Conductivity (EC)	1123	umhos/cm	N/A	SM2510-B	30 Jul 19 17:00	SVS
pH - Field	8.52	units	NA	SM 4500 H+ B	29 Jul 19 9:40	DJN
Temperature - Field	10.4	Degrees C	NA	SM 2550B	29 Jul 19 9:40	DJN
Total Alkalinity	480	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Bicarbonate	463	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Conductivity - Field	1152	umhos/cm	1	EPA 120.1	29 Jul 19 9:40	DJN
Tot Dis Solids(Summation)	699	mg/l	12.5	SM1030-F	8 Aug 19 15:19	Calculated
Bicarb as HCO3	565	mg/l HCO3	NA	SM2320-B	30 Jul 19 17:00	Calculated
Total Hardness as CaCO3	21.3	mg/l	NA	SM2340-B	8 Aug 19 15:19	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	16 Aug 19 15:14	Calculated
Anion Summation	12.2	meq/L	NA	SM1030-F	2 Aug 19 13:49	Calculated
Percent Error	1.04	%	NA	SM1030-F	16 Aug 19 15:14	Calculated
Sodium Adsorption Ratio	25.9		NA	USDA 20b	8 Aug 19 15:19	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	31 Jul 19 17:00	SVS
Sulfate	124	mg/l	5.00	ASTM D516-07	2 Aug 19 13:49	EMS
Chloride	1.7	mg/l	1.0	SM4500-Cl-E	31 Jul 19 9:52	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 Jul 19 14:03	EMS
Calcium - Total	4.9	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Magnesium - Total	2.2	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Sodium - Total	275	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Potassium - Total	3.6	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Iron - Dissolved	0.18	mg/l	0.10	6010D	16 Aug 19 15:14	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	16 Aug 19 15:14	SZ

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 20 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2669
Work Order #: 82-2018
Account #: 003022
Date Sampled: 28 Jul 20 10:08
Date Received: 28 Jul 20 14:25
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: C1-1
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 2.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 8.4	units	N/A	SM4500 H+ B	28 Jul 20 18:00	HT
Conductivity (EC)	1168	umhos/cm	N/A	SM2510-B	28 Jul 20 18:00	HT
pH - Field	8.31	units	NA	SM 4500 H+ B	28 Jul 20 10:08	DJN
Temperature - Field	11.6	Degrees F	1	SM 2550B	28 Jul 20 10:08	DJN
Total Alkalinity	526	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Bicarbonate	522	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Conductivity - Field	1143	umhos/cm	1	EPA 120.1	28 Jul 20 10:08	DJN
Tot Dis Solids(Summation)	698	mg/l	12.5	SM1030-F	30 Jul 20 11:00	Calculated
Bicarb as HCO3	637	mg/l HCO3	NA	SM2320-B	28 Jul 20 18:00	Calculated
Total Hardness as CaCO3	26.7	mg/l	NA	SM2340-B	29 Jul 20 11:25	Calculated
Cation Summation	12.3	meq/L	NA	SM1030-F	3 Aug 20 13:38	Calculated
Anion Summation	12.7	meq/L	NA	SM1030-F	30 Jul 20 11:00	Calculated
Percent Error	-1.45	%	NA	SM1030-F	3 Aug 20 13:38	Calculated
Sodium Adsorption Ratio	22.5		NA	USDA 20b	29 Jul 20 11:25	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	28 Jul 20 18:00	HT
Sulfate	99.7	mg/l	5.00	ASTM D516-11	29 Jul 20 13:56	EV
Chloride	2.6	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Jul 20 11:00	EV
Calcium - Total	5.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Magnesium - Total	2.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Sodium - Total	267	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Potassium - Total	3.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Iron - Dissolved	1.71	mg/l	0.10	6010D	3 Aug 20 13:38	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	3 Aug 20 13:38	MDE

* Holding time exceeded

CC
4 Aug 2020

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 10 Aug 18
Lab Number: 18-W2160
Work Order #: 82-1776
Account #: 003022
Date Sampled: 18 Jul 18 10:00
Date Received: 19 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: C7-1

Temp at Receipt: 4.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 8.5	units	N/A	SM4500 H+ B	19 Jul 18 18:00	SVS
Conductivity (EC)	2105	umhos/cm	N/A	SM2510-B	19 Jul 18 18:00	SVS
pH - Field	8.02	units	NA	SM 4500 H+ B	18 Jul 18 10:00	DJN
Temperature - Field	11.5	Degrees C	NA	SM 2550B	18 Jul 18 10:00	DJN
Total Alkalinity	985	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Bicarbonate	957	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Carbonate	28	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Conductivity - Field	2091	umhos/cm	1	EPA 120.1	18 Jul 18 10:00	DJN
Tot Dis Solids(Summation)	1410	mg/l	12.5	SM1030-F	7 Aug 18 16:11	Calculated
Bicarb as HCO3	1170	mg/l HCO3	NA	SM2320-B	19 Jul 18 18:00	Calculated
Total Hardness as CaCO3	58.5	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	25.0	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	25.1	meq/L	NA	SM1030-F	7 Aug 18 16:11	Calculated
Percent Error	-0.31	%	NA	SM1030-F	7 Aug 18 16:11	Calculated
Sodium Adsorption Ratio	30.7		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	1.07	mg/l	0.10	SM4500-F-C	19 Jul 18 18:00	SVS
Sulfate	234	mg/l	5.00	ASTM D516-07	20 Jul 18 15:44	EMS
Chloride	20.2	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	7 Aug 18 16:11	EMS
Calcium - Total	10.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	7.9	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	540	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	7.1	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	4.02	mg/l	0.10	6010D	30 Jul 18 10:55	SZ
Manganese - Dissolved	0.09	mg/l	0.05	6010D	30 Jul 18 10:55	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll CC 10 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2712
Work Order #: 82-1976
Account #: 003022
Date Sampled: 30 Jul 19 9:07
Date Received: 31 Jul 19 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Temp at Receipt: 7.3C ROI

Sample Description: C7-1

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	31 Jul 19	MDE
pH	* 8.4	units	N/A	SM4500 H+ B	1 Aug 19 17:00	SVS
Conductivity (EC)	2098	umhos/cm	N/A	SM2510-B	1 Aug 19 17:00	SVS
pH - Field	7.97	units	NA	SM 4500 H+ B	30 Jul 19 9:07	DJN
Temperature - Field	9.19	Degrees C	NA	SM 2550B	30 Jul 19 9:07	DJN
Total Alkalinity	1050	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Bicarbonate	1030	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Carbonate	20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Conductivity - Field	2084	umhos/cm	1	EPA 120.1	30 Jul 19 9:07	DJN
Tot Dis Solids(Summation)	1480	mg/l	12.5	SM1030-F	14 Aug 19 13:17	Calculated
Bicarb as HCO3	1260	mg/l HCO3	NA	SM2320-B	1 Aug 19 17:00	Calculated
Total Hardness as CaCO3	55.5	mg/l	NA	SM2340-B	14 Aug 19 13:17	Calculated
Cation Summation	25.3	meq/L	NA	SM1030-F	26 Aug 19 10:38	Calculated
Anion Summation	27.1	meq/L	NA	SM1030-F	2 Aug 19 15:11	Calculated
Percent Error	-3.33	%	NA	SM1030-F	26 Aug 19 10:38	Calculated
Sodium Adsorption Ratio	31.9		NA	USDA 20b	14 Aug 19 13:17	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	1 Aug 19 17:00	SVS
Sulfate	252	mg/l	5.00	ASTM D516-07	2 Aug 19 15:11	EMS
Chloride	28.8	mg/l	1.0	SM4500-Cl-E	31 Jul 19 11:15	EV
Nitrate-Nitrite as N	< 2 @	mg/l	0.10	EPA 353.2	31 Jul 19 15:56	EMS
Calcium - Total	9.7	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Magnesium - Total	7.6	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Sodium - Total	547	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Potassium - Total	5.3	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Iron - Dissolved	7.52	mg/l	0.10	6010D	26 Aug 19 10:38	SZ
Manganese - Dissolved	0.17	mg/l	0.05	6010D	26 Aug 19 10:38	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll CC 28 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 7 Aug 20
Lab Number: 20-W2541
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 8:23
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Sample Description: C7-1

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 8.2	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	2096	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	8.20	units	NA	SM 4500 H+ B	21 Jul 20 8:23	DJN
Temperature - Field	10.9	Degrees C	NA	SM 2550B	21 Jul 20 8:23	DJN
Total Alkalinity	1120	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	1120	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	2239	umhos/cm	1	EPA 120.1	21 Jul 20 8:23	DJN
Tot Dis Solids(Summation)	1490	mg/l	12.5	SM1030-F	27 Jul 20 11:17	Calculated
Bicarb as HCO3	1370	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	54.5	mg/l	NA	SM2340-B	24 Jul 20 13:45	Calculated
Cation Summation	24.3	meq/L	NA	SM1030-F	27 Jul 20 10:42	Calculated
Anion Summation	28.3	meq/L	NA	SM1030-F	27 Jul 20 11:17	Calculated
Percent Error	-7.64	%	NA	SM1030-F	27 Jul 20 11:17	Calculated
Sodium Adsorption Ratio	30.6		NA	USDA 20b	24 Jul 20 13:45	Calculated
Fluoride	1.06	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	258	mg/l	5.00	ASTM D516-11	22 Jul 20 15:38	EMS
Chloride	19.0	mg/l	1.0	SM4500-Cl-E	27 Jul 20 11:17	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:33	EMS
Calcium - Total	9.8	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Magnesium - Total	7.3	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Sodium - Total	519	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Iron - Dissolved	13.5	mg/l	0.10	6010D	27 Jul 20 10:42	MDE
Manganese - Dissolved	0.35	mg/l	0.05	6010D	27 Jul 20 10:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 10 Aug 18
Lab Number: 18-W2163
Work Order #: 82-1776
Account #: 003022
Date Sampled: 18 Jul 18 11:13
Date Received: 19 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: C9-1

Temp at Receipt: 4.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 8.2	units	N/A	SM4500 H+ B	19 Jul 18 18:00	SVS
Conductivity (EC)	2029	umhos/cm	N/A	SM2510-B	19 Jul 18 18:00	SVS
pH - Field	8.06	units	NA	SM 4500 H+ B	18 Jul 18 11:13	DJN
Temperature - Field	14.1	Degrees C	NA	SM 2550B	18 Jul 18 11:13	DJN
Total Alkalinity	968	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Bicarbonate	968	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Conductivity - Field	2028	umhos/cm	1	EPA 120.1	18 Jul 18 11:13	DJN
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	7 Aug 18 16:30	Calculated
Bicarb as HCO3	1180	mg/l HCO3	NA	SM2320-B	19 Jul 18 18:00	Calculated
Total Hardness as CaCO3	111	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	24.3	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	27.7	meq/L	NA	SM1030-F	7 Aug 18 16:30	Calculated
Percent Error	-6.42	%	NA	SM1030-F	7 Aug 18 16:30	Calculated
Sodium Adsorption Ratio	20.7		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	1.11	mg/l	0.10	SM4500-F-C	19 Jul 18 18:00	SVS
Sulfate	364	mg/l	5.00	ASTM D516-07	20 Jul 18 15:44	EMS
Chloride	25.5	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	0.42	mg/l	0.10	EPA 353.2	7 Aug 18 16:30	EMS
Calcium - Total	21.0	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	14.3	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	503	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	8.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	0.79	mg/l	0.10	6010D	30 Jul 18 10:55	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Jul 18 10:55	SZ

* Holding time exceeded

CC
Approved by: Claudette K Carroll 10 Aug 18

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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www.mvtl.com

MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2715
Work Order #: 82-1976
Account #: 003022
Date Sampled: 30 Jul 19 9:55
Date Received: 31 Jul 19 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: C9-1

Temp at Receipt: 7.3C ROI

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	31 Jul 19	MDE
pH	* 8.3	units	N/A	SM4500 H+ B	1 Aug 19 17:00	SVS
Conductivity (EC)	2032	umhos/cm	N/A	SM2510-B	1 Aug 19 17:00	SVS
pH - Field	7.75	units	NA	SM 4500 H+ B	30 Jul 19 9:55	DJN
Temperature - Field	11.3	Degrees C	NA	SM 2550B	30 Jul 19 9:55	DJN
Total Alkalinity	1030	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Bicarbonate	1014	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Conductivity - Field	1991	umhos/cm	1	EPA 120.1	30 Jul 19 9:55	DJN
Tot Dis Solids(Summation)	1610	mg/l	12.5	SM1030-F	14 Aug 19 13:17	Calculated
Bicarb as HCO3	1240	mg/l HCO3	NA	SM2320-B	1 Aug 19 17:00	Calculated
Total Hardness as CaCO3	148	mg/l	NA	SM2340-B	14 Aug 19 13:17	Calculated
Cation Summation	27.3	meq/L	NA	SM1030-F	26 Aug 19 11:38	Calculated
Anion Summation	29.6	meq/L	NA	SM1030-F	2 Aug 19 15:38	Calculated
Percent Error	-4.11	%	NA	SM1030-F	26 Aug 19 11:38	Calculated
Sodium Adsorption Ratio	18.7		NA	USDA 20b	14 Aug 19 13:17	Calculated
Fluoride	1.19	mg/l	0.10	SM4500-F-C	1 Aug 19 17:00	SVS
Sulfate	350	mg/l	5.00	ASTM D516-07	2 Aug 19 15:38	EMS
Chloride	61.6	mg/l	1.0	SM4500-Cl-E	31 Jul 19 11:15	EV
Nitrate-Nitrite as N	< 10 @	mg/l	0.10	EPA 353.2	31 Jul 19 15:56	EMS
Calcium - Total	28.3	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Magnesium - Total	18.8	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Sodium - Total	523	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Potassium - Total	8.4	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Iron - Dissolved	37.3	mg/l	0.10	6010D	26 Aug 19 11:38	SZ
Manganese - Dissolved	0.77	mg/l	0.05	6010D	26 Aug 19 11:38	SZ

* Holding time exceeded

CC
28 Aug 19

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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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 7 Aug 20
Lab Number: 20-W2543
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 8:59
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Sample Description: C9-1

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 8.3	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	2012	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	8.20	units	NA	SM 4500 H+ B	21 Jul 20 8:59	DJN
Temperature - Field	9.91	Degrees C	NA	SM 2550B	21 Jul 20 8:59	DJN
Total Alkalinity	1080	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	1080	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	2012	umhos/cm	1	EPA 120.1	21 Jul 20 8:59	DJN
Tot Dis Solids(Summation)	1430	mg/l	12.5	SM1030-F	5 Aug 20 8:19	Calculated
Bicarb as HCO3	1320	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	92.4	mg/l	NA	SM2340-B	24 Jul 20 13:45	Calculated
Cation Summation	24.2	meq/L	NA	SM1030-F	27 Jul 20 10:42	Calculated
Anion Summation	26.9	meq/L	NA	SM1030-F	5 Aug 20 8:19	Calculated
Percent Error	-5.27	%	NA	SM1030-F	5 Aug 20 8:19	Calculated
Sodium Adsorption Ratio	23.0		NA	USDA 20b	24 Jul 20 13:45	Calculated
Fluoride	1.14	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	210	mg/l	5.00	ASTM D516-11	5 Aug 20 8:19	EV
Chloride	32.4	mg/l	1.0	SM4500-Cl-E	27 Jul 20 11:17	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:53	EMS
Calcium - Total	17.2	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Magnesium - Total	12.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Sodium - Total	508	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Potassium - Total	7.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Iron - Dissolved	1.96	mg/l	0.10	6010D	27 Jul 20 10:42	MDE
Manganese - Dissolved	0.06	mg/l	0.05	6010D	27 Jul 20 10:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

APPENDIX C-2

MILTON R. YOUNG POWER STATION MONITORING WELL ANALYSES FOR BASELINE DATA

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 21 Sep 20
Lab Number: 20-W3411
Work Order #: 82-2509
Account #: 007048
Date Sampled: 9 Sep 20 13:33
Date Received: 10 Sep 20 8:10
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-5A

Temp at Receipt: 0.5C ROI

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Sep 20	HT
Total Suspended Solids	183	mg/l	2	USGS I3765-85	10 Sep 20 16:00	HT
Conductivity (EC)	1099	umhos/cm	1	SM2510B-11	10 Sep 20 17:00	HT
pH - Field	9.06	units	NA	SM 4500 H+ B	9 Sep 20 13:33	JSM
pH	* 8.9	units	0.1	SM4500-H+-B-11	10 Sep 20 17:00	HT
Temperature - Field	8.66	Degrees C	NA	SM 2550B	9 Sep 20 13:33	JSM
Total Alkalinity	510	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Phenolphthalein Alk	29	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Bicarbonate	451	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Carbonate	59	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Conductivity - Field	1071	umhos/cm	1	EPA 120.1	9 Sep 20 13:33	JSM
Tot Dis Solids(Summation)	686	mg/l	12.5	SM1030-F	17 Sep 20 8:50	Calculatec
Total Hardness as CaCO3	34.8	mg/l	NA	SM2340B-11	14 Sep 20 13:15	Calculatec
Cation Summation	12.9	meq/L	NA	SM1030-F	15 Sep 20 9:55	Calculatec
Anion Summation	12.0	meq/L	NA	SM1030-F	17 Sep 20 8:50	Calculatec
Percent Error	3.42	%	NA	SM1030-F	17 Sep 20 8:50	Calculatec
Fluoride	0.50	mg/l	0.10	SM4500-F-C	11 Sep 20 17:00	HT
Sulfate	85.5	mg/l	5.00	ASTM D516-11	16 Sep 20 9:14	EV
Chloride	2.3	mg/l	1.0	SM4500-Cl-E-11	14 Sep 20 9:54	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	17 Sep 20 8:50	EV
Phosphorus as P - Total	0.23	mg/l	0.10	EPA 365.1	11 Sep 20 8:25	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Sep 20 15:01	MDE
Calcium - Total	5.2	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Magnesium - Total	5.3	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Sodium - Total	279	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Potassium - Total	2.2	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Iron - Dissolved	0.30	mg/l	0.10	6010D	15 Sep 20 9:55	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	15 Sep 20 9:55	MDE
Boron - Dissolved	0.34	mg/l	0.10	6010D	11 Sep 20 9:57	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Barium - Dissolved	0.0586	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 21 Sep 20
Lab Number: 20-W3411
Work Order #: 82-2509
Account #: 007048
Date Sampled: 9 Sep 20 13:33
Date Received: 10 Sep 20 8:10
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-5A

Temp at Receipt: 0.5C ROI

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	14 Sep 20 16:12	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 24 Sep 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2873
Work Order #: 82-2147
Account #: 007048
Date Sampled: 6 Aug 20 15:55
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 97-1

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 7.1	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	3440	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	32	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	6.41	units	NA	SM 4500 H+ B	6 Aug 20 15:55	DJN
Temperature - Field	15.3	Degrees C	NA	SM 2550B	6 Aug 20 15:55	DJN
Total Alkalinity	376	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	376	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	3337	umhos/cm	1	EPA 120.1	6 Aug 20 15:55	DJN
Tot Dis Solids(Summation)	3000	mg/l	12.5	SM1030-F	13 Aug 20 9:30	Calculated
Total Hardness as CaCO3	2180	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculated
Cation Summation	52.2	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculated
Anion Summation	46.9	meq/L	NA	SM1030-F	13 Aug 20 9:30	Calculated
Percent Error	5.37	%	NA	SM1030-F	13 Aug 20 9:30	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	1810	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	59.0	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:30	SD
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	14 Aug 20 9:12	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	471	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	245	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	181	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	5.1	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	13.2	mg/l	0.10	6010D	10 Aug 20 16:07	SZ
Manganese - Dissolved	1.25	mg/l	0.05	6010D	10 Aug 20 16:07	SZ
Boron - Dissolved	0.36	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Barium - Dissolved	0.0423	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Beryllium - Dissolved	< 0.002 ^	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE
Cadmium - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 20 11:31	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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2873
Work Order #: 82-2147
Account #: 007048
Date Sampled: 6 Aug 20 15:55
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 97-1

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 20 11:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC

Approved by: Claudette K Carroll 25 Aug 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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2869
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 16:40
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 95-4

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.7	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1792	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	< 2	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.55	units	NA	SM 4500 H+ B	5 Aug 20 16:40	DJN
Temperature - Field	8.77	Degrees C	NA	SM 2550B	5 Aug 20 16:40	DJN
Total Alkalinity	889	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	826	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	63	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1763	umhos/cm	1	EPA 120.1	5 Aug 20 16:40	DJN
Tot Dis Solids(Summation)	1100	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculatec
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculatec
Cation Summation	19.5	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculatec
Anion Summation	20.2	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Percent Error	-1.83	%	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Fluoride	1.13	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	109	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	6.2	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.15	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	442	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	2.4	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.46	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.0982	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2869
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 16:40
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 95-4

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 25Aug2020

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 concentration of other analytes
\+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2868
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 14:57
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-3

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.8	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1822	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	< 2	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.66	units	NA	SM 4500 H+ B	5 Aug 20 14:57	DJN
Temperature - Field	9.14	Degrees C	NA	SM 2550B	5 Aug 20 14:57	DJN
Total Alkalinity	901	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	34	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	832	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	69	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1797	umhos/cm	1	EPA 120.1	5 Aug 20 14:57	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculated
Cation Summation	19.7	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculated
Anion Summation	20.6	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculated
Percent Error	-2.24	%	NA	SM1030-F	13 Aug 20 9:14	Calculated
Fluoride	1.63	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	117	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	6.2	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.26	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.4	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	447	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.1072	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2868
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 14:57
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 25 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2867
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 11:01
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-6A

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.5	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1646	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	7	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.84	units	NA	SM 4500 H+ B	5 Aug 20 11:01	DJN
Temperature - Field	8.22	Degrees C	NA	SM 2550B	5 Aug 20 11:01	DJN
Total Alkalinity	799	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	783	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1618	umhos/cm	1	EPA 120.1	5 Aug 20 11:01	DJN
Tot Dis Solids(Summation)	1090	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculated
Total Hardness as CaCO3	11.2	mg/l	NA	SM2340B-11	11 Aug 20 14:10	Calculated
Cation Summation	17.3	meq/L	NA	SM1030-F	11 Aug 20 14:10	Calculated
Anion Summation	20.4	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculated
Percent Error	-8.21	%	NA	SM1030-F	13 Aug 20 9:14	Calculated
Fluoride	0.97	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	211	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	2.3	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.13	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Sodium - Total	392	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.39	mg/l	0.10	6010D	12 Aug 20 12:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.0146	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	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 sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2867
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 11:01
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-6A

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 25 Aug 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

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W774
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:17
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 92-5A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.8	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1129	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	371	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.94	units	NA	SM 4500 H+ B	23 Apr 20 13:17	DJN
Temperature - Field	8.45	Degrees C	NA	SM 2550B	23 Apr 20 13:17	DJN
Total Alkalinity	499	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	24	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	452	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	47	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1120	umhos/cm	1	EPA 120.1	23 Apr 20 13:17	DJN
Tot Dis Solids(Summation)	672	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	43.7	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	12.0	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	2.11	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.49	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	91.2	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	1.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	0.32	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.15	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	6.3	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	6.8	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	264	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	1.62	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.36	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Barium - Dissolved	0.0806	mg/l	0.0020	6020B	27 Apr 20 16:34	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 17:15	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 17:15	CC
Chromium - Dissolved	0.0040	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Lead - Dissolved	0.0016	mg/l	0.0005	6020B	27 Apr 20 13:50	CC

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W774
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:17
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-5A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 17:15	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:50	CC

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 8 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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@ = Due to sample matrix
# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W775
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 10:12
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-6A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1642	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	12	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.67	units	NA	SM 4500 H+ B	23 Apr 20 10:12	DJN
Temperature - Field	7.93	Degrees C	NA	SM 2550B	23 Apr 20 10:12	DJN
Total Alkalinity	632	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	598	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	34	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1639	umhos/cm	1	EPA 120.1	23 Apr 20 10:12	DJN
Tot Dis Solids(Summation)	987	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	12.4	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	17.3	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	17.0	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	0.69	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.97	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	209	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	1.8	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.16	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	3.0	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	390	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.6	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.39	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Barium - Dissolved	0.0132	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Cadmium - Dissolved	< 0.0005	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	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

RL = Method Reporting Limit

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# = Due to concentration of other analytes
! = Due to sample quantity
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 May 20
Lab Number: 20-W775
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 10:12
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-6A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 10:20	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

* Holding time exceeded

Approved by: Claudette K. Carroll CC 8 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W776
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 16:51
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-3

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1841	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	3	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.66	units	NA	SM 4500 H+ B	23 Apr 20 16:51	DJN
Temperature - Field	8.34	Degrees C	NA	SM 2550B	23 Apr 20 16:51	DJN
Total Alkalinity	837	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	26	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	785	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	52	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1822	umhos/cm	1	EPA 120.1	23 Apr 20 16:51	DJN
Tot Dis Solids(Summation)	1110	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	20.7	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	19.5	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	3.16	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	1.64	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	124	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	5.0	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.26	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	2.4	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	470	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.47	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.1085	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W776
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 16:51
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

PO #: 200004

Temp at Receipt: 3.8C ROI

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

Approved by: Claudette K. Carroll CC 8 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W777
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 15:09
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Temp at Receipt: 3.8C ROI

Project Name: Minnkota - CCWDF

Sample Description: 95-4

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.6	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1815	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	3	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.53	units	NA	SM 4500 H+ B	23 Apr 20 15:09	DJN
Temperature - Field	8.32	Degrees C	NA	SM 2550B	23 Apr 20 15:09	DJN
Total Alkalinity	836	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	798	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	38	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1802	umhos/cm	1	EPA 120.1	23 Apr 20 15:09	DJN
Tot Dis Solids(Summation)	1090	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	9.77	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	19.9	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	19.4	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	1.33	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	122	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	4.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.21	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	2.1	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.1	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	452	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.47	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.0992	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

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

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W777
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 15:09
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 95-4

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

Approved by: Claudette K. Carroll 8 May 2020 cc

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W781
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:28
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 97-1

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 6.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	3597	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	64	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	6.33	units	NA	SM 4500 H+ B	23 Apr 20 13:28	JSM
Temperature - Field	10.3	Degrees C	NA	SM 2550B	23 Apr 20 13:28	JSM
Total Alkalinity	327	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	327	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	3447	umhos/cm	1	EPA 120.1	23 Apr 20 13:28	JSM
Tot Dis Solids(Summation)	3130	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	2200	mg/l	NA	SM2340-B	27 Apr 20 11:26	Calculated
Cation Summation	53.1	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	48.8	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	4.20	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	1960	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	51.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	0.11	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	1 May 20 8:34	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	475	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Magnesium - Total	246	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Sodium - Total	196	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Potassium - Total	5.3	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Iron - Dissolved	12.3	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	1.33	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.34	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.0440	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

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

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www.mvtl.com

MEMBER ACIL

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 May 20
Lab Number: 20-W781
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:28
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

PO #: 200004

Temp at Receipt: 3.8C ROI

Project Name: Minnkota - CCWDF

Sample Description: 97-1

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 8 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

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 3 Oct 19
Lab Number: 19-W3428
Work Order #: 82-2442
Account #: 007048
Date Sampled: 5 Sep 19 14:18
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF - Hagel

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	27	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	3485	umhos/cm	1	SM2510-B	20 Sep 19 17:00	CC
pH - Field	6.26	units	NA	SM 4500 H+ B	5 Sep 19 14:18	DJN
pH	* 7.1	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	14.1	Degrees C	NA	SM 2550B	5 Sep 19 14:18	DJN
Total Alkalinity	310	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	310	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	4146	umhos/cm	1	EPA 120.1	5 Sep 19 14:18	DJN
Tot Dis Solids (Summation)	3180	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	2320	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	55.1	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	49.1	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	5.76	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	0.11	mg/l	0.10	SM4500-F-C	20 Sep 19 17:00	CC
Sulfate	1990	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	52.8	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.10	mg/l	0.10	EPA 365.1	13 Sep 19 9:13	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	510	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	254	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	186	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	5.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	14.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	1.32	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.34	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Barium - Dissolved	0.0360	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Chromium - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	2 Oct 19 13:37	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 sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Amended 5 Oct 19 (Pb result) - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 3 Oct 19
Lab Number: 19-W3428
Work Order #: 82-2442
Account #: 007048
Date Sampled: 5 Sep 19 14:18
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF - Hagel

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	2 Oct 19 13:37	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

cc 50CT19

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

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3421
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 14:05
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-5A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	20	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1184	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.90	units	NA	SM 4500 H+ B	5 Sep 19 14:05	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	9.19	Degrees C	NA	SM 2550B	5 Sep 19 14:05	DJN
Total Alkalinity	520	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	440	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	80	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1131	umhos/cm	1	EPA 120.1	5 Sep 19 14:05	DJN
Tot Dis Solids(Summation)	695	mg/l	12.5	SM1030-F	19 Sep 19 11:36	Calculated
Total Hardness as CaCO3	19.5	mg/l	NA	SM2340-B	19 Sep 19 11:36	Calculated
Cation Summation	12.9	meq/L	NA	SM1030-F	19 Sep 19 11:36	Calculated
Anion Summation	12.2	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	2.70	%	NA	SM1030-F	19 Sep 19 11:36	Calculated
Fluoride	0.48	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	86.8	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	1.2	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 14:42	EV
Phosphorus as P - Total	0.14	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	3.7	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Magnesium - Total	2.5	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Sodium - Total	287	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Potassium - Total	1.8	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.34	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0350	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	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

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3421
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 14:05
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-5A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed		Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19	9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19	9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE

* Holding time exceeded

CL

Approved by: Claudette K. Carroll 1 OCT 19

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

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3422
Work Order #: 82-2441
Account #: 007048
Date Sampled: 4 Sep 19 16:01
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-6A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	3	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1744	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.87	units	NA	SM 4500 H+ B	4 Sep 19 16:01	DJN
pH	* 8.9	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.07	Degrees C	NA	SM 2550B	4 Sep 19 16:01	DJN
Total Alkalinity	690	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	610	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	80	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1685	umhos/cm	1	EPA 120.1	4 Sep 19 16:01	DJN
Tot Dis Solids(Summation)	1050	mg/l	12.5	SM1030-F	19 Sep 19 11:36	Calculated
Total Hardness as CaCO3	13.1	mg/l	NA	SM2340-B	19 Sep 19 11:36	Calculated
Cation Summation	18.0	meq/L	NA	SM1030-F	19 Sep 19 11:36	Calculated
Anion Summation	18.3	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	-0.85	%	NA	SM1030-F	19 Sep 19 11:36	Calculated
Fluoride	0.99	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	216	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	1.5	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	3.1	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Sodium - Total	407	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Potassium - Total	2.6	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.40	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0121	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	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 sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3422
Work Order #: 82-2441
Account #: 007048
Date Sampled: 4 Sep 19 16:01
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-6A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed		Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19	9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19	9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE

* Holding time exceeded

Approved by: Claudette K Carroll CC 1OCT19

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
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CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3423
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 16:15
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	< 2	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1887	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.65	units	NA	SM 4500 H+ B	5 Sep 19 16:15	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.78	Degrees C	NA	SM 2550B	5 Sep 19 16:15	DJN
Total Alkalinity	910	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	850	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	60	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1823	umhos/cm	1	EPA 120.1	5 Sep 19 16:15	DJN
Tot Dis Solids(Summation)	1140	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	20.2	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	20.9	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	-1.69	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	1.64	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	124	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	4.5	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	2.4	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	458	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	0.17	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0978	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	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

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3423
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 16:15
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19 9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 1OCT19

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3424
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 17:59
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	< 2	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1862	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.55	units	NA	SM 4500 H+ B	5 Sep 19 17:59	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.62	Degrees C	NA	SM 2550B	5 Sep 19 17:59	DJN
Total Alkalinity	880	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	840	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1800	umhos/cm	1	EPA 120.1	5 Sep 19 17:59	DJN
Tot Dis Solids(Summation)	1200	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	24.0	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	20.1	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	8.87	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	113	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	4.4	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	2.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	545	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Barium - Dissolved	0.1012	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3424
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 17:59
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	30 Sep 19 15:16	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 1OCT19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1534
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 14:41
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1812	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	< 2	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.32	units	NA	SM 4500 H+ B	28 May 19 14:41	DJN
Temperature - Field	8.38	Degrees C	NA	SM 2550B	28 May 19 14:41	DJN
Total Alkalinity	823	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	25	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	772	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	51	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1813	umhos/cm	1	EPA 120.1	28 May 19 14:41	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	10.3	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	22.1	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	19.0	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	7.59	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.63	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	116	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	5.3	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.30	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	2.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	503	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.5	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.47	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.1104	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1534
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 14:41
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

PO #: 190093

Temp at Receipt: 3.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

Sample Description: 92-3

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

lc

Approved by: Claudette K. Carroll 28 Jun 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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www.mvtl.com

MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1535
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 16:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1797	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	< 2	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.31	units	NA	SM 4500 H+ B	28 May 19 16:23	DJN
Temperature - Field	8.33	Degrees C	NA	SM 2550B	28 May 19 16:23	DJN
Total Alkalinity	829	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	25	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	779	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	50	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1796	umhos/cm	1	EPA 120.1	28 May 19 16:23	DJN
Tot Dis Solids(Summation)	1110	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	9.19	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	21.7	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	18.9	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	6.99	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.15	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	104	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	5.2	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	1.7	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	494	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.47	mg/l	0.10	6010D	4 Jun 19 12:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0984	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1535
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 16:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 28 Jun 19

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
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1533
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 12:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-6A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.8	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1697	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	3	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	28 May 19 12:23	DJN
Temperature - Field	7.85	Degrees C	NA	SM 2550B	28 May 19 12:23	DJN
Total Alkalinity	641	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	580	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	61	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1692	umhos/cm	1	EPA 120.1	28 May 19 12:23	DJN
Tot Dis Solids(Summation)	1080	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	10.3	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	19.6	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	17.9	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	4.60	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.01	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	241	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	2.2	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	2.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	445	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.5	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 12:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 12:03	SZ
Boron - Dissolved	0.41	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0130	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	0.0011	mg/l	0.0005	6020B	11 Jun 19 15:27	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

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1533
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 12:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-6A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 28 Jun 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1532
Work Order #: 82-1235
Account #: 007048
Date Sampled: 29 May 19 12:10
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-5A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 9.0	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1131	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	44	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.75	units	NA	SM 4500 H+ B	29 May 19 12:10	DJN
Temperature - Field	9.13	Degrees C	NA	SM 2550B	29 May 19 12:10	DJN
Total Alkalinity	488	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	35	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	417	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	71	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1137	umhos/cm	1	EPA 120.1	29 May 19 12:10	DJN
Tot Dis Solids(Summation)	693	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	2.50	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	13.6	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	11.6	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	7.88	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	0.53	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	85.4	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	2.0	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.16	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	1.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	< 1	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	310	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	1.7	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 12:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 12:03	SZ
Boron - Dissolved	0.37	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0325	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1532
Work Order #: 82-1235
Account #: 007048
Date Sampled: 29 May 19 12:10
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-5A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

CC
28 Jun 19

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

Report Date: 19 Jun 19
Lab Number: 19-W1539
Work Order #: 82-1251
Account #: 007048
Date Sampled: 29 May 19 8:54
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 6.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	3736	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	108	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	6.30	units	NA	SM 4500 H+ B	29 May 19 8:54	DJN
Temperature - Field	10.6	Degrees C	NA	SM 2550B	29 May 19 8:54	DJN
Total Alkalinity	284	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	284	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	3920	umhos/cm	1	EPA 120.1	29 May 19 8:54	DJN
Tot Dis Solids(Summation)	3140	mg/l	12.5	SM1030-F	13 Jun 19 14:56	Calculated
Total Hardness as CaCO3	2200	mg/l	NA	SM2340-B	13 Jun 19 14:56	Calculated
Cation Summation	54.6	meq/L	NA	SM1030-F	13 Jun 19 14:56	Calculated
Anion Summation	48.4	meq/L	NA	SM1030-F	5 Jun 19 10:24	Calculated
Percent Error	6.00	%	NA	SM1030-F	13 Jun 19 14:56	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	1960	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	67.5	mg/l	1.0	SM4500-Cl-E	5 Jun 19 10:24	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:26	EMS
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	453	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Magnesium - Total	259	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Sodium - Total	228	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Potassium - Total	5.9	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Iron - Dissolved	14.7	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	1.38	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.41	mg/l	0.10	6010D	4 Jun 19 12:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Barium - Dissolved	0.0425	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Beryllium - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	18 Jun 19 11:57	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 19 Jun 19
Lab Number: 19-W1539
Work Order #: 82-1251
Account #: 007048
Date Sampled: 29 May 19 8:54
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Jun 19 23:06	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC

Approved by: Claudette K. Carroll 28 Jun 19

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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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3108
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 11:04
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	62	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	3574	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	6.28	units	NA	SM 4500 H+ B	25 Sep 18 11:04	DJN
pH	* 6.5	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	9.46	Degrees C	NA	SM 2550B	25 Sep 18 11:04	DJN
Total Alkalinity	296	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	296	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	3600	umhos/cm	1	EPA 120.1	25 Sep 18 11:04	DJN
Tot Dis Solids(Summation)	2960	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	2240	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	54.3	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	44.6	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	9.77	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	1780	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	58.0	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.10	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	485	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	251	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	201	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	5.5	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	13.5	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	1.43	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.35	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0496	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

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! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3108
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 11:04
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 10 OCT 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3109
Work Order #: 82-2513
Account #: 007048
Date Sampled: 24 Sep 18 18:02
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	18	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1198	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.80	units	NA	SM 4500 H+ B	24 Sep 18 18:02	DJN
pH	* 8.9	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.57	Degrees C	NA	SM 2550B	24 Sep 18 18:02	DJN
Total Alkalinity	513	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	449	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	64	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1118	umhos/cm	1	EPA 120.1	24 Sep 18 18:02	DJN
Tot Dis Solids(Summation)	690	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	3.25	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	13.4	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	11.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	6.23	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.50	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	72.1	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	1.4	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	0.11	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.12	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	1.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	< 1	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	305	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	1.8	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.36	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0357	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3109
Work Order #: 82-2513
Account #: 007048
Date Sampled: 24 Sep 18 18:02
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

CC
10 OCT 18

Approved by: Claudette K Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3110
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 10:41
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	9	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1717	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.75	units	NA	SM 4500 H+ B	25 Sep 18 10:41	DJN
pH	* 8.8	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	7.77	Degrees C	NA	SM 2550B	25 Sep 18 10:41	DJN
Total Alkalinity	654	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	36	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	581	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	73	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1681	umhos/cm	1	EPA 120.1	25 Sep 18 10:41	DJN
Tot Dis Solids(Summation)	1010	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	13.3	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	18.2	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	17.3	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	2.40	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.95	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	200	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	2.3	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.17	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	3.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	410	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.4	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.38	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0142	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

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CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3110
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 10:41
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

Approved by: Claudette K Carroll CC 10 OCT 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3111
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 13:07
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	2	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1864	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	25 Sep 18 13:07	DJN
pH	* 8.6	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.42	Degrees C	NA	SM 2550B	25 Sep 18 13:07	DJN
Total Alkalinity	862	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	798	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	64	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1847	umhos/cm	1	EPA 120.1	25 Sep 18 13:07	DJN
Tot Dis Solids(Summation)	1130	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	21.2	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	19.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	3.20	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	1.61	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	117	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	5.9	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	2.4	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	480	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.46	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.1182	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3111
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 13:07
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

Approved by: Claudette K. Carroll CC 10 OCT 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3112
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 14:50
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	6	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1852	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	25 Sep 18 14:50	DJN
pH	+ 8.6	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.33	Degrees C	NA	SM 2550B	25 Sep 18 14:50	DJN
Total Alkalinity	866	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	33	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	800	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	66	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1831	umhos/cm	1	EPA 120.1	25 Sep 18 14:50	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	10.0	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	20.9	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	19.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	2.69	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	110	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	6.0	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.20	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	2.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.1	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	474	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.1108	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

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@ = Due to sample matrix
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3112
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 14:50
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

CC
10 OCT 18

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

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1293
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 13:07
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	91	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	4017	umhos/cm	1	SM2510-B	24 May 18 17:00	SVS
pH - Field	6.10	units	NA	SM 4500 H+ B	22 May 18 13:07	DJN
pH	* 6.5	units	0.1	SM4500 H+ B	24 May 18 17:00	SVS
Temperature - Field	12.3	Degrees C	NA	SM 2550B	22 May 18 13:07	DJN
Total Alkalinity	247	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Bicarbonate	247	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Conductivity - Field	3890	umhos/cm	1	EPA 120.1	22 May 18 13:07	DJN
Tot Dis Solids(Summation)	3890	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	2110	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	54.0	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	64.1	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-8.55	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	24 May 18 17:00	SVS
Sulfate	2740	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	73.9	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	384	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	280	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	258	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	6.2	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	9.59	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	1.34	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.35	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0518	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1293
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 13:07
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

Approved by: Claudette K Carroll cc 16 Jun 18

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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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1294
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 12:40
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	8	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1193	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.99	units	NA	SM 4500 H+ B	23 May 18 12:40	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	9.21	Degrees C	NA	SM 2550B	23 May 18 12:40	DJN
Total Alkalinity	522	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	459	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	63	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1123	umhos/cm	1	EPA 120.1	23 May 18 12:40	DJN
Tot Dis Solids(Summation)	731	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	13.1	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-2.40	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	0.48	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	128	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	1.2	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.13	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	287	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	1.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.39	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0328	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1294
Work Order #: 82-1116
Account #: 00704B
Date Sampled: 23 May 18 12:40
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

CC
Approved by: Claudette K. Carroll 16 Jun 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1295
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 15:11
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	17	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1718	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.98	units	NA	SM 4500 H+ B	22 May 18 15:11	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	8.04	Degrees C	NA	SM 2550B	22 May 18 15:11	DJN
Total Alkalinity	669	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	43	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	582	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	87	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1593	umhos/cm	1	EPA 120.1	22 May 18 15:11	DJN
Tot Dis Solids(Summation)	1080	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	18.3	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	18.8	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-1.43	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	0.93	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	259	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	1.8	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	419	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.6	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.43	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0124	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1295
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 15:11
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

Approved by: Claudette K. Carroll cc 16 Jun 18

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

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1296
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 16:24
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	3	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1869	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.58	units	NA	SM 4500 H+ B	23 May 18 16:24	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	9.21	Degrees C	NA	SM 2550B	23 May 18 16:24	DJN
Total Alkalinity	868	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	29	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	809	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	59	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1796	umhos/cm	1	EPA 120.1	23 May 18 16:24	DJN
Tot Dis Solids(Summation)	1150	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	11.6	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	20.6	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	20.6	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-0.02	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	1.55	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	148	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	4.7	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 13:12	EV
Calcium - Total	2.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	1.3	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	466	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.51	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.1043	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1296
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 16:24
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 16 Jun 18

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 concentration of other analytes
+ = Due to internal standard response

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1297
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 14:26
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	8	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1851	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.60	units	NA	SM 4500 H+ B	23 May 18 14:26	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	8.97	Degrees C	NA	SM 2550B	23 May 18 14:26	DJN
Total Alkalinity	873	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	812	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	61	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1767	umhos/cm	1	EPA 120.1	23 May 18 14:26	DJN
Tot Dis Solids(Summation)	1130	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	20.5	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	20.3	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	0.49	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	1.07	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	132	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	4.9	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 13:12	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	471	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.4	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.50	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0970	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1297
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 14:26
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

CC

Approved by: Claudette K Carroll 16 Jun 18

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

APPENDIX C-3

FOX HILLS OBSERVATION WELL 3558
ANALYSES
FOR BASELINE DATA

MVTL

MINNESOTA VALLEY TESTING LABORATORIES, INC.

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
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MEMBER
ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Jan 21	HT
pH - Field	8.42	units	NA	SM 4500 H+ B	12 Jan 21 12:45	JSM
Temperature - Field	11.8	Degrees C	NA	SM 2550B	12 Jan 21 12:45	JSM
Total Alkalinity	938	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Bicarbonate	912	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Carbonate	26	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Conductivity - Field	2641	umhos/cm	1	EPA 120.1	12 Jan 21 12:45	JSM
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	15 Jan 21 11:45	Calculated
Nitrate as N	< 0.2	mg/l	NA	EPA 353.2	14 Jan 21 9:17	Calculated
Bromide	2.83	mg/l	0.100	EPA 300.0	14 Jan 21 22:24	RMV
Total Organic Carbon	1.7	mg/l	0.5	SM5310C-11	22 Jan 21 17:28	NAS
Dissolved Organic Carbon	1.7	mg/l	0.5	SM5310C-96	22 Jan 21 17:28	NAS
Fluoride	3.54	mg/l	0.10	SM4500-F-C	12 Jan 21 17:00	HT
Sulfate	< 5	mg/l	10.0	ASTM D516-11	15 Jan 21 8:50	EV
Chloride	323	mg/l	2.0	SM4500-Cl-E-11	13 Jan 21 11:25	EV
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 9:17	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 7:59	EV
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	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

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Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	4.0	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Sodium - Total	630	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Lithium - Total	0.186	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Iron - Total	0.40	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Silicon - Total	5.04	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Total	0.16	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	20 Jan 21 10:36	MDE
Boron - Total	2.87	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Calcium - Dissolved	3.7	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Sodium - Dissolved	670	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Potassium - Dissolved	3.2	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Lithium - Dissolved	0.102	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Iron - Dissolved	0.25	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Silicon - Dissolved	5.12	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Dissolved	0.15	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	20 Jan 21 9:36	MDE
Boron - Dissolved	2.85	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	14 Jan 21 19:47	MDE

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

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MEMBER ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Barium - Total	0.0966	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Lead - Total	0.0006	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Manganese - Total	0.0088	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Molybdenum - Total	0.0058	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	14 Jan 21 19:47	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	15 Jan 21 14:56	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Barium - Dissolved	0.0954	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	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

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MEMBER
ACIL

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

Sample Description: USGS Well

PO #: B. Botnen

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Manganese - Dissolved	0.0081	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Molybdenum - Dissolved	0.0058	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	15 Jan 21 14:56	MDE
Silver - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

^ 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 concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX D

TESTING AND MONITORING – QUALITY CONTROL AND SURVEILLANCE PLAN

TESTING AND MONITORING – QUALITY CONTROL AND SURVEILLANCE PLAN
Tundra SGS (Secure Geological Storage)

1. PROJECT MANAGEMENT AND SURVEILLANCE PROCESS

From conception to closure, Tundra SGS operation will include the participation of multidisciplinary teams of government representatives, researchers , operator staff, consultants, and subcontractors. Each of these teams are highly specialized and recognized in their specific areas of expertise, providing technical and economic inputs to the project in order to ensure a safe, successful, and efficient operation.

Characterization of the reservoirs, seals, and subsurface features has been done by experienced professionals in geosciences from the Energy & Environmental Research Center (EERC), Oxy Low Carbon Ventures (OLCV), Schlumberger, etc., led by Minnkota Power Cooperative, Inc., applying the latest technology in logging and testing equipment as well as industry recognized software and techniques for modeling and simulations.

The main flowline, surface equipment, and well designs comply with industry standards for carbon dioxide (CO_2) material selection and operating conditions to guaranty mechanical integrity of the system during the life of the project and have been prepared by specialized companies such as Burns & McDonnell and OLCV.

Monitoring programs for leak detection, corrosion, and surveillance have been tailored for the site to ensure protection of underground sources of drinking water (USDWs), the environment, and communities; ensure the mechanical integrity of storage; maximize operating time; and extend the life of the assets. These plans incorporate best practices and recommendation for carbon capture and storage projects worldwide as well as the experience of years of development in enhanced oil recovery (EOR) fields.

As part of the quality control (QC) process, during testing and surveillance, most of the samples collected and data gathered will be analyzed, processed, validated, or witnessed by third parties independent and outside of the operator staff.

For specialized data such as seismicity and distributed temperature sensing (DTS), the project will have additional support from the provider of the selected technologies to perform QC and verification of the data as well as calibration of the systems as needed.

Sensors, transducers and controllers will be connected in a central platform (supervisory control and data acquisition [SCADA] system) to monitor the operating conditions, set alarms for malfunction, and establish safety protocols in case of abnormal conditions in the system. Data interfaces will be created for equipment that is not linked directly to the SCADA system, to be integrated in a unique surveillance platform.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the project will be stored in a central database to provide support for area of review (AOR) reviews, quality assurance (QA) programs, and reporting.

The project established a key staffing position that will ensure reliable operation with the highest standard of quality and surveillance procedures as well as accurate storage evaluation and reporting. Some of the staff will be dedicated full time to the operation, and others will be as required by AOR reviews, maintenance activities, or specific activities of the project.

Once the project is in operation, the Tundra SGS operator will maintain a contact list with the specific names of the individuals in each position and will keep that list updated.

1.1 Operator Organizational Chart

Figure D-1 shows the operator organizational chart for Tundra SGS.

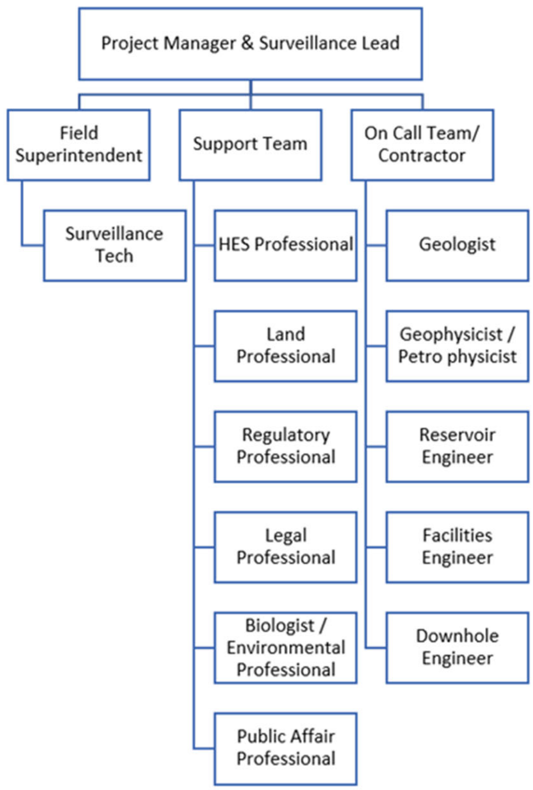


Figure D-1. Operator organizational chart.

A brief description of full-time positions is as follows:

- Project Manager: The project manager (PM) plays a central role in the implementation of all data gathering and analysis for the Tundra SGS project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans. The PM is responsible to enforce the data validation process and perform surveillance on the site.

- Field Superintendent: The field superintendent (FS) is responsible to ensure operating procedures are followed and any deviation from set parameters is corrected. The FS is responsible to verify surveillance is being performed and data are being communicated and reported properly. The FS is responsible to ensure all personnel comply with the safety worker plan and policies of the operator. The FS is the focal point for activation of the emergency response and remedial plan. The FS is responsible to coordinate personnel and contractors on the site.

- Surveillance Technician: The surveillance technician (ST) is responsible for the surveillance of the system on the field. The position is 24/7 and requires an experience SCADA operator to monitor the sequestration complex, clear alarms, and troubleshoot deviation from normal operation.

Additional to the key staffing positions and specialized consultants identified in the above sections, the project will have the support of additional subcontractors based on the scope of the work to be performed.

1.2 Data Verification and Validation

The project will establish a standardized program to validate the data and acquisition methods. The program will verify that collected data are reasonable, were processed and analyzed correctly, and are free of errors. Peer reviews or third-party consultant will be used as a QC mechanism to verify the information. If issues are identified during a peer review, they will be addressed and corrected by the data owner. If an error is identified in data under validation, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

1.3 Management of Change (MOC)

The project will implement a MOC procedure to communicate and document any deviation from facilities designs, policies, operational parameters, standard operating procedures, etc. The MOC procedure aims to control major deviations in cost.

1.4 Contractor Requirements

Each contractor will follow a qualification process defined by the operator, before being authorized to execute work in the site. Each contractor providing service to Tundra SGS must provide a copy of its QA/QC and safety management program before it is qualified to perform the work and might be audited by the operator's subject matter experts. All contractors are required to comply with the

Worker Safety Program described in this permit as well as the operator's policies at the working site. The operator reserves the right to inspect and audit contractors' operation and quality program to guaranty safety and quality programs are being followed.

1.5 Special Training/Certifications

Wireline logging, indirect geophysical methods, and some nonroutine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements.

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. Some special training will be required for project personnel, particularly in the areas of pulsed-neutron capture (PNC) logging interpretation, certain geophysical methods, certain data acquisition/transmission systems, and certain sampling technologies.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

1.6 Documentation, Records and Reporting

All data and project records will be stored electronically on secure servers and routinely backed up. Reporting will comply with North Dakota Administrative Code (NDAC) § 43-05-01-18.

2. TESTING AND MONITORING TECHNIQUES QA/QC

2.1 Logging Program

The logging program is described in detailed in the testing and monitoring section of the permit. These activities are executed by specialized contractors with proven technology in the oil and gas industry. Calibration and QC of the tools will follow specific protocols and procedures based on the provider. Example of data sheets for the different formation evaluation tools are included in the Appendix D-1 of this document as reference only.

2.1.1 Ultrasonic Casing Inspection Tool, Isolation Scanner, and Electromagnetic Pipe Examiner

For mechanical integrity evaluation, the Tundra SGS monitoring program proposed ultrasonic and electromagnetic tools that evaluate the conditions of the tubulars in the well and provide information about thickness, ovality, ruptures, potential corrosion, etc. Table D-1 provides basic data for each tool.

2.1.2 Pulsed-Neutron Logging

Pulsed-neutron logging is considered a proven technique to detect gas saturation in reservoirs. Advances in the technology have improved the accuracy of the tool to track the movement of the CO_2 plumes in the reservoir and evaluate flow conformance. Table D-2 shows basic specifications of the tools based on the provider.

Table D-1. Types of Data Provided by Individual Tools

Logging Type	Isolation Scanner	USIT	EM Pipe Xaminer	EM Pipe Scanner	CAST-XR
Acquisition	Real time	Real time	Real time	Real time	Real time
Logging Speed	2,700 ft/h	1800 ft/h	900 ft/h	1,800–3,600 ft/h	3,600 ft/h
Thickness Measurement Accuracy				EM thickness 15%	± 0.05 in.
Range of Measurement	0 to 10 Mrayl	0 to 10 Mrayl		1.5 in.	0–10 Mrayl
Mud Type Limitations	None	None	None	None	None
Temperature Rating	350°F	350°F	350°F	302°F	350°F
Pressure Rating	20,000 psi	20,000 psi	15,000 psi	15,000 psi	20,000 psi
Casing Size Min.	4 ½ in.	4½ in.	2.38 in.	2⅞ in.	4.67 in.
Casing Size Max.	9⅝ in.	13⅜ in.	24 in.	13⅜ in.	20 in.
Outside Diameter	3.37 in.	3.375 in.	1.69 in.	2.125 in.	3.625 in.
Length	19.73 ft	19.75 in.	17.34 ft	19.7 ft	17.9 ft
Weight	333 lb	333 lb	87 lb	110 lb	316 lb
1st Pipe Defect Detection Accuracy			1%	± 0.05 in	
1st Pipe (2Cs) Accuracy			2% or 0.015 in		
Total Metal Thickness 1.2 In (3Cs) Overall Average			7%		
Total Metal Thickness 1.8 In (4Cs) Overall Average			10%		

Table D-2. Data Specifications for the Pulsed-Neutron Logging Tool

Logging Type	Pulsar[1] – Neutron	TMD3D[2] Pulse Neutron
Acquisition	Real time	Real time
Logging Speed	200–3,600 ft/h	60–1,800 ft/h
Depth of Investigation		10–14 in.
Vertical Resolution		24 in.
Range of Measurement	0 to 60 pu	5 to 60 pu
Mud Type Limitations	None	None
Temperature Rating	350°F	300°F
Pressure Rating	15,000 psi	15,000 psi
Casing Size Min.	2⅜ in.	2 in.
Casing Size Max.	9⅝ in.	16 in.
Outside Diameter	1.72 in.	1.69 in.
Length	18.3 ft	14.25 ft
Weight	88 lb	35 lb

[1] Pulsar – Schlumberger technology.
[2] TMD3D – Halliburton technology.

2.2 Mud-Logging Sampling

Mud-logging samples must be collected from surface to final total depth (TD), every 30 ft maximum. The samples must be washed, dried, and placed in standard envelopes, and packed in the correct order into standard sample boxes. The sample boxes must be identified with a label indicating operator, well name, well file number, API number, and location and depth of samples and forwarded to the state core and sample library within 30 days of the completion of drilling operations.

2.3 Coring or Sidewall Coring (SWC) Sampling

The coring program is described in detailed in the specific drilling and completion program of the wells. The coring provider must provide tools in good condition and according to the program discussed with the technical team. Operators reserve the right to inspect the tools and request a replacement if substandard conditions are detected. The coring provider must provide the tools to cut, retrieve, and stabilize the core to get the maximum possible recovery factor. All cores or SWCs taken shall be preserved, placed in a standard core box, and the entire core forwarded to the state core and sample library, free of cost, within 180 days after completion of drilling operations.

2.4 MDT In Situ Stress Testing

The Schlumberger MDT (modular dynamics testing) tool delivers real-time formation temperature and pressure measurements and fluid sampling. The tools for formation pressure measurements incorporate a wireline-conveyed tester with a dual packer module, with two probes for pressure measurements, pumps, a flow control module, and sample chambers (Appendix D-2). Reservoir pressure measurements require inserting a probe into the reservoir and withdrawing a small amount of fluid. The pressure gauge is exposed to many temperature and pressure changes and has high resolution to accurately measure the dynamic conditions. Precise flowline control during testing and sampling ensures monophasic flow, delivering accurate permeability. In situ reservoir stress testing measurements provide formation breakdown, propagation, and closure pressures.

The dual-packer module (MRPA) is used to isolate formation intervals to provide enhanced data because the cross-sectional area of the isolated interval is greater than the standard MDT probe. This small interval lowers the wellbore storage effects. The MRPA is used to take pressure measurements and fluid samples in unconsolidated formations.

The MDT tool allows the measurements of the in situ reservoir stresses without breaking into confining zones. The tool creates a controlled fracture in the isolated zone and measures the related pressure response. The created fracture plane is perpendicular to the direction of the minimum in situ stress. The fracture is reopened and closed for measurement repeatability, with several constant rate injection cycles. The repeated cycles assist the fracture to grow beyond hoop stresses to sense far-field stresses accurately.

MDT interpretation software provides real-time plotting of pressure, resistivity, and optical properties versus time. This capability is essential for real-time QC and ongoing optimization of the job. Using the InterACT* wellsite-monitoring and control system provides real-time data transfer to remote sites.

2.4.1 Tool Limitations

Schlumberger's dual-packer mechanical specifications were set with a maximum differential pressure between the upper packer and the hydrostatic pressure of 5500 psi (Appendix D-3). This limited the maximum injection pressure during the microfracture stress tests in the formations, which caused certain tests to be unsuccessful.

2.5 Formation Pressure and Fluid Sampling

The self-sealing Saturn * 3D radial probe delivers circumferential flow in the formation around the wellbore to obtain representative formation fluid samples and provides downhole fluid analysis and complete pressure surveys (Appendix D-4). In the water-based mud environment, the MDT flowline resistivity measurement helps discriminate between fluid contaminated by mud filtrate and formation oil or freshwater. Formation pressure testing similarly requires fluid withdrawal.

2.6 Analysis of Injected CO_2

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow as part of the instrumentation and control systems of the site. Quarterly samples will be collected and analyzed to track CO_2 composition and purity. Based on the anticipated composition of the CO_2 stream, a list of parameters has been identified for analysis.

Additional to the parameters listed in Table D-3, isotopic signatures of the CO_2 stream will be analyzed as baseline for potential use in monitoring techniques.

Table D-3. CO_2 Stream Analysis

Parameter	Frequency
Pressure, psi	Continuous
Temperature, °F	Continuous
CO_2, %	Quarterly
Water, ppm	Quarterly
Nitrogen, ppm	Quarterly
Oxygen, ppm	Quarterly
Argon, ppm	Quarterly
Hydrogen, %	Quarterly
Sulfur Dioxide SO_2, ppm	Quarterly
Nitrogen Dioxide NO_2, ppm	Quarterly
Nitric Oxide NO, ppm	Quarterly
	Quarterly

2.6.1 Sampling and Custody

CO_2 sampling will be performed upstream or downstream of the flowmeter. Sampling procedures will follow contractor protocols to ensure the sample is representative of the injectant, and samples will be processed, packaged, and shipped to the contracted laboratory following standard sample handling and chain-of-custody guidance (U.S. Environmental Protection Agency [EPA] 540-R-09-03 or equivalent). Sampling tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers.

Once the samples are analyzed, the laboratory will be responsible of properly disposed containers and residues.

2.6.2 Equipment and Calibration

For sampling, field equipment will be maintained, serviced, and calibrated in accordance with manufacturer recommendations. Spare parts that may be needed during sampling will be included in supplies on hand during field sampling. For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory in accordance with method-specific protocols and the laboratory's QA program. The Tundra SGS operator reserve the right to audit the protocols and methods of the selected laboratory prior to awarding the work.

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory in accordance with method-specific protocols and the laboratory's QA program, which will be reviewed by the alliance prior to contract award.

2.6.3 Personnel and Training

Sampling will be performed by trained personnel from the laboratory at the beginning of the operation, and the field staff will be trained in the procedures and protocols to take the samples.

2.6.4 Analytical Method

Table D-4 shows analytical parameters and methods.

Table D-4. Example Analytical Parameters and Methods

Analytical Parameter	Analytical Method	Detection Limit	Typical Precision/Accuracy
CO_2	GC/TCD[1]	1 ppm to 100%	± 1% of full scale
Water	GC/HID[2]	1 ppm to 100%	± 10%
Nitrogen	GC/TCD	1 ppm to 100%	± 1% of full scale
Oxygen	GC/TCD	1 ppm to 100%	± 1% of full scale
Argon	GC/TCD	1 ppm to 100%	± 1% of full scale
Hydrogen	GC/TCD	1 ppm to 100%	± 1% of full scale
Sulfur Dioxide	GC/FPD[3]	0 to 500 (ppmv)	± 2% of full scale
Nitrogen Dioxide	Colorimetric	0.2 to 5 µL/L (ppmv)	± 20%
Nitric Oxide	Colorimetric	0.2 to 5 µL/L (ppmv)	± 20%
Hydrogen Sulfide	GC/FPD	0 to 500 ppm	± 2% of full scale

[1] GC/TCD – gas chromatography with a thermal conductivity detector.
[2] GC/HID – gas chromatography with helium ionization detector.
[3] GC/FDP – gas chromatography with flame photometric detector.

Additional to compositional gas, the samples will be analyzed during the baseline period to identify the isotopes in Table D-5.

Table D-5. Isotopes to Be Identified During Baseline Sampling

Hydrocarbons	Method
$\delta^{13}C$ and ^{14}C of CO_2	GC–IRMS, AMS for ^{14}C

GC–IRMS, AMS = gas chromatography–isotope-ratio mass spectrometry/accelerator mass spectrometry.

2.6.4 Quality Control

If CO_2 composition shows abnormal values during the testing period, the project will perform a validation of the sampling process. A new sample will be collected by the laboratory technician and sent to the testing facilities for verification.

2.7 Corrosion Coupons

Samples of injection well materials (coupons) will be monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Coupons shall be collected and sent quarterly to a third-party company for analysis conducted in accordance with NACE (National Institute of Corrosion Engineers) Standard SP-0775-2018-SG to determine and document corrosion wear rates based on mass loss.

2.7.1 Sampling and Custody

Prior to installation of the corrosion-monitoring flow-through corrosion coupon test system, the following information should be recorded: coupon serial number, installation date, identification (ID) of the location in the system, and orientation of the coupon and holder. The coupon should be handled carefully to avoid contamination.

The field operator will collect the coupons and identify them by serial number, date, company name, ID of the location, ID of where the coupon was removed from, and the field operator name. The field operator will visually inspect the coupon for signs of erosion, pitting, scale, or other damage and take a photograph before packing the sample. The coupon will be protected from contamination by oxidation and handling, placing the coupon in a moisture-proof or special envelope impregnated with volatile corrosion inhibitor, and shipped immediately to the laboratory for analysis.

There is no special training required to collect the coupons; however, the field operator will be trained in best practices to keep the coupon for contamination, and process refreshers will be provided as part of the continuous training process.

2.7.2 Equipment and Calibration

The preparation, cleaning, and evaluation of the corrosion specimens will be handled by a certified third-party contractor and will follow NACE RP0775-2005 or equivalent. The contractor is responsible for the calibration and maintenance of the measurement equipment as well as the disposal of the samples when the analysis is finished.

2.7.3 Analytical Method

Table D-6 shows the analytical methods to be used for sampling.

Table D-6. Analytical Method to Be Used for Sampling

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

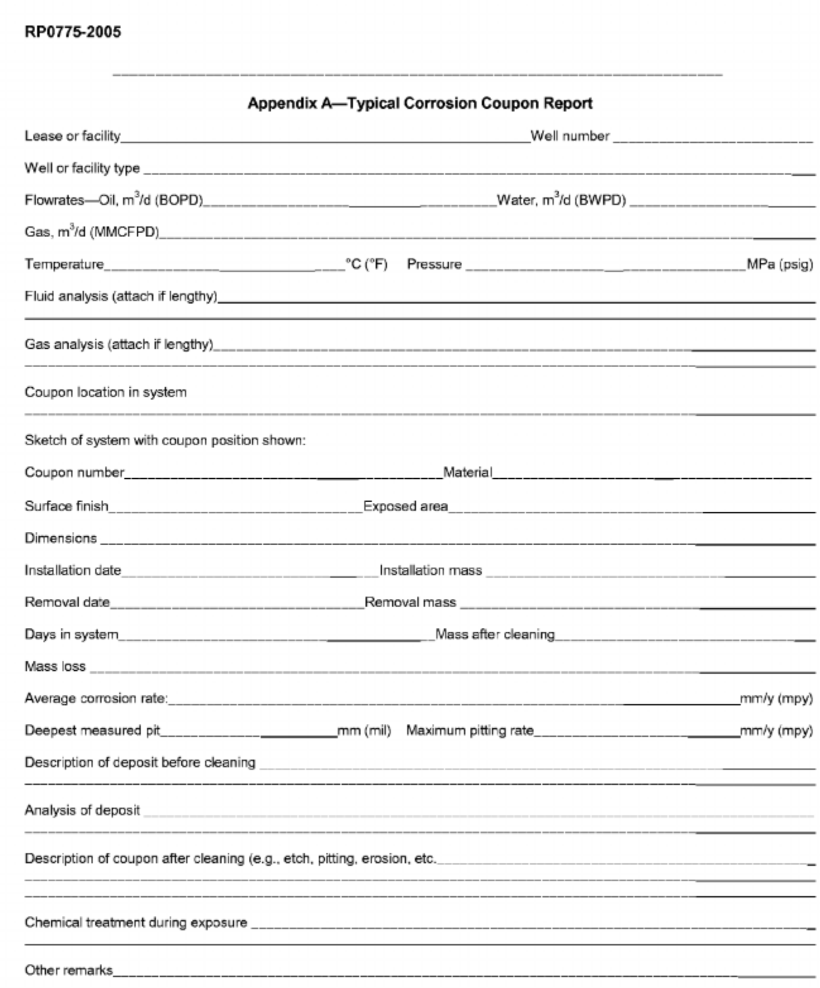
NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations.

2.7.4 Quality Control

The operators reserve the right to audit the QA/QC procedures prior to awarding the work to a contractor and during the execution of the service to ensure the quality and safety program are being followed.

2.7.5 Typical Corrosion Coupon Report

Figure D-2 provides an example typical corrosion coupon report.



RP0775-2005

Appendix A—Typical Corrosion Coupon Report

Lease or facility__________ Well number __________

Well or facility type __________

Flowrates—Oil, m^3/d (BOPD)__________ Water, m^3/d (BWPD) __________

Gas, m^3/d (MMCFPD)__________

Temperature__________ °C (°F) Pressure __________ MPa (psig)

Fluid analysis (attach if lengthy)__________

Gas analysis (attach if lengthy)__________

Coupon location in system

Sketch of system with coupon position shown:

Coupon number__________ Material__________

Surface finish__________ Exposed area__________

Dimensions __________

Installation date__________ Installation mass __________

Removal date__________ Removal mass __________

Days in system__________ Mass after cleaning__________

Mass loss __________

Average corrosion rate:__________ mm/y (mpy)

Deepest measured pit__________ mm (mil) Maximum pitting rate__________ mm/y (mpy)

Description of deposit before cleaning __________

Analysis of deposit __________

Description of coupon after cleaning (e.g., etch, pitting, erosion, etc.__________

Chemical treatment during exposure __________

Other remarks__________

Figure D-2. Example typical corrosion coupon report.

2.8 Soil Gas Sampling

The method for soil gas sampling is described in Appendix C of the permit. The samples will be sent to a specialized laboratory to determine gas composition and perform isotopic analysis to characterize the fluid and get a fingerprint for appropriation. In between sampling events, a handheld device should be enough for routine monitoring purposes, which could be done monthly.

2.8.1 Analytical Method

Compositional analysis of the gases includes chromatographic determination of the concentrations of fixed gases and hydrocarbons listed in Table D-7.

Table D-7. Fixed Gas and Hydrocarbons for Compositional Analysis

Fixed Gases		**Method**
Nitrogen	N_2	GC
Oxygen	O_2	GC
Argon	Ar	GC
Carbon Dioxide	CO_2	GC
Carbon Monoxide	CO	GC
Hydrogen	H_2	GC
Helium	He	GC
Hydrocarbons		**Method**
Methane	CH_4	GC
Ethane	C_2H_6	GC
Ethylene	C_2H_4	GC
Propane	C_3H_8	GC
Propylene	C_3H_6	GC
Isobutane	iC_4H_{10}	GC
Normal Butane	nC_4H_{10}	GC
Isopentane	iC_5H_{12}	GC
Normal Pentane	nC_5H_{12}	GC
Hexanes Plus	C_6+	GC

In addition to compositional gas analysis, the samples will be analyzed during the baseline period to identify the isotopes in Table D-8.

Table D-8. Isotopes to Be Identified During Baseline Sampling

Hydrocarbons	**Method**
$\delta^{13}C$ and ^{14}C of CO_2 and CH_4	GC–IRMS, AMS for ^{14}C
δD of CH_4.	GC–IRMS

Isotopes are different forms of the same element, differing only in the number of neutrons in the nucleus of the atom. Although some isotopes are unstable and decay radioactively, most are stable. Isotopes are valuable tools to distinguish the source of the element and create a fingerprint of the gas.

2.8.2 Equipment and Calibration

Calibration will be performed in accordance with manufacturer protocol. Sampling will be performed by trained or specialize personnel from the lab at the beginning of the operation, and the field operator will be trained in the process to be able to take samples and monitor gas composition with handheld devices as routine operation.

2.9 Water Sampling

2.9.1 Sampling and Custody

2.9.1.1 Sampling Flowing Surface Waters (rivers, streams, drainage ditches)

- Surface water samples at both flowing water and still water sites will be collected using the nonisokenetic (bottles or bailers) sampling method. Field measurement instruments will be calibrated in accordance with manufacturer instructions.

- Before samples are collected, the sample-wetted portions of most of the collection and processing equipment require a field rinse with native water. Field rinsing helps to condition sampling equipment to the sample environment. Rinsing also serves to ensure that all cleaning solution residues have been removed. An area of low-flow turbidity should be located at the sampling site to partially fill and rinse the bottle sampler, trying to avoid getting sand or sediment in the sampler.

- Location and site conditions will be recorded on the field data sheets (i.e., GPS [global positioning system] coordinates, air temperature, wind speed, precipitation, and barometric pressure). An area will be identified in the flowing water body where the water is well mixed laterally and vertically. In general, downstream samples should be collected first followed by upstream samples to minimize disturbance of bottom sediments. Extreme caution should be taken wading in fast-flowing water, and every attempt should be made to utilize a sampling device that does not require wading. In general, personnel shall not wade into flowing water when the product of depth (in feet) and velocity (in feet per second) equals 10 or greater. If flow data are not available, personnel shall not exceed a water depth of knee height. For sample locations that are considerable distance from the shoreline, a boat, dock, or bridge may be employed for sampling.

- Using a bottle, the sample should be collected by standing downstream of the bottle. Care must be taken to avoid collecting particulates that might be resuspended as the result of wading.

- Following the manufacturer instructions for the YSI multiparameter meter and the HANNA chemistry kits, the following measurements should be taken on the first sample collected: temperature, pH, conductivity, dissolved oxygen (DO), total dissolved solids (TDS), oxidation reduction potential (ORP), CO_2, alkalinity calcium carbonate ($CaCO_3$), and chloride (Cl). Measurements should be recorded on the field data sheet.

- Sample containers should be filled and samples filtered and/or preserved according to instructions in Section 7.0. Date and time of sampling should be recorded on the field data sheet.

- Samples should be labeled with the name of the person sampling, sample description, date, and time. The chain-of-custody form should also be completed.

- Any unusual conditions or deviations from the sampling procedure should be documented on the field data sheet.

2.9.1.2 Sampling Still Waters (lakes, reservoirs, ponds, marshes)

- Since still waters have a greater tendency to stratify than rivers or streams, it is important to collect a vertical sample near the bottom of the body of water without disturbing the sediment.

- If the body of water is so large that the sampling locations cannot be reached from the bank, it may be necessary to use a small boat to reach the sampling area.

- If using a bailer or bottle, the sampler should be slowly lowered to the desired depth while minimizing disturbance of the water column, the sample collected, and the sampler slowly raised to the surface. Sampling should be repeated until enough water is collected for the sample bottles.

- If using a peristaltic pump, the pump sample tubing (attached to a weighted line) should be lowered to the desired sampling depth. The pump should be turned on, and about three sample tubing volumes should be pumped to rinse and condition the pump, tubing, and other sample collection or processing equipment. The rinse should be discarded.

- Following the manufacturer instructions for the multiparameter meter and the chemistry kits, the following measurements should be taken on the first sample collected: temperature, pH, conductivity, DO, TDS, ORP, CO_2, alkalinity ($CaCO_3$), and Cl. Measurements should be recorded on the field data sheet.

- Flow should be direct sampled into collection container(s) until sufficient sample volume has been collected to fill sample bottles.

- Sample containers should be filled and samples filtered and/or preserved. Date and time of sampling should be recorded on the field data sheets.

- Samples should be labeled with the name of person sampling, sample description, date, and time. A chain-of-custody form should be completed.

- Any unusual conditions or deviations from the sampling procedure should be documented on the field data sheet.

2.9.1.3 Ground Water Sampling

Purging the well removes standing and/or stagnant water from the well casing. The purpose of purging is to reduce chemical and biochemical artifacts caused by the materials used for well installation and well construction and by reactions occurring within an open borehole or annular space between a well casing and borehole wall. The rule of thumb is to remove a minimum of three well casing volumes while monitoring field parameters until they stabilize before actual samples can be collected. The well diameter, water level, well bottom depth, and purge volume should be recorded on the field data sheet. At a minimum, three well volumes should be purged while monitoring the temperature, pH, and conductivity until the readings have stabilized. If the readings have stabilized after three well volume purges and meet the criteria in Table D-9, sample collection can proceed. If readings are not stable after three volumes, purge should continue until they are stable, but ten purge volumes should not be exceeded before collecting samples. Those instances when readings are not stable prior to sample collection should be documented. The following stability criteria for the measurements are the allowable variation among five or more field measurements.

Table D-9. Field Measurement Stability Criteria

Field Measurement	Stability Criteria
pH	± 0.1 standards units
Temperature, °C	± 0.5°C
Conductivity, mS/cm	± 5%

2.9.2 Equipment and Calibration

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on hand during field sampling. For all laboratory equipment, testing, inspection, maintenance, and calibration will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program.

2.9.3 Personnel and Training

Water testing will be performed by personnel of a certified laboratory following the specific methods approved by EPA or other standard. The operator might audit the procedures and results of the selected laboratory with a third party to improve QC.

2.9.4 Analytical Method

Where possible, methods are based on standard protocols from EPA or Standard Methods for the Examination of Water and Wastewater. Laboratories shall have standard operating procedures for the analytical methods performed (Table D-10).

Table D-10. Analytic Method and Parameters that May Be Used During Testing

Parameter	Analytical Method
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si, Zn, Sr	ICP–AES, EPA Method 200.7 or similar
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP–MS, EPA Method 200.8 or similar
Cyanide (CN-)	EPA 335.4, olorimetry
Mercury	EPA 245.1, CVAA
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-	Ion chromatography, EPA Method 300.1, 4110B or similar
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B
Hardness—Total, as $CaCO_3$, mg/L	Automated colorimetric, EPA 130.1
Gravimetric TDS	Gravimetric method Standard Methods 2540C
Water Density	ASTM International D5057 or equivalent
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent
Total Organic Carbon (TOC)	SW846 9060A or equivalent
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent
Methane	RSK-175 Mod headspace GC/FID or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline prep and dual inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, modified ASTM 1945D
pH	pH electrode, EPA 150.2, D1293
Temperature	2550B
Conductivity	2510B
Specific Conductance	EPA 120.1

ICP–AES = inductively coupled plasma atomic emission spectrometry; ICP–MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: cold-vapor atomic absorption; CF–IRMS: continuous flow isotope ratio mass spectrometry.

2.9.5 Quality Control

QC of the sampling and results will follow the protocols established in the analytical method for testing. The Tundra SGS operator reserves the right to audit the lab procedures and protocols to validate the methods are being follow and the results are accurate.

2.10 CO_2 Flowline Monitoring with Fiber Optics

2.10.1 Equipment and Calibration

Fiber optic cables are installed on the flowline for continuous conditioning monitoring. This method is accurate, continuous, and can detect leaks, movement of the flowline due to seismic activities, ground erosion, etc. The main characteristics are as follows:

- Distributed acoustic sensing (DAS): Various DAS technologies are used in the market; the most common is based on coherent optical time domain reflectometry (C-OTDR). C-OTDR utilizes Rayleigh back-scattering, allowing acoustic frequency signals to be detected over long distances. The interrogator sends a coherent laser pulse along an optical fiber (sensor cable). Scattering sites within the fiber causes the fiber to act as a distributed interferometer with a gauge length like the pulse length. Acoustic disturbance on a fiber generates microscopic elongation or compression of the fiber (microstrain), which causes a change in the phase relation and/or amplitude. Before the next laser pulse can be transmitted, the previous pulse must have had time to travel the full length of the fiber and for its reflections to return. Hence, the maximum pulse rate is determined by the length of the fiber. Therefore, acoustic signals can be measured that vary at frequencies up to the Nyquist frequency, which is typically half of the pulse rate. As higher frequencies are attenuated very quickly, most of the relevant ones to detect and classify events are in the lower of the 2-kHz range.

- Distributed temperature sensing (DTS): DTS uses fiber optic sensor cables, typically over lengths of several kilometers, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS utilizes the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in some scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The anti-Stokes Raman signal changes its amplitude significantly with changing temperature; the Stokes Raman signal is relatively stable. The *position* of the temperature reading is determined by measuring the arrival timing of the returning light pulse similar to a radar echo.

- Distributed stain sensing (DSS): DSS detects change in strain along the flowline due to shifting soil, erosion, frost, and seismic activities.

2.10.2 Resolution and Accuracy

Multiple strands of optical fibers in a sheath are installed to take care of the monitoring requirements listed above. A single standard-range temperature sensor can measure up to 9 mi (15 km) of fiber with 3-ft (1-m) resolution, update data in just a few seconds, and resolve temperatures to 0.018°F (0.01°C). The DAS/strain sensor can measure 25 mi in intervals of 6.5 ft to give multiple data alongside the pipe.

Table D-11. Technical Specifications for DTS Sensor

Parameter	
Number of Channels	12 SE or 6 DE
Total Fiber Length (SE)	9 mi
Spatial Resolution	3 or 6 ft
Sample Spacing	15. or 3 ft
Temperature Repeatability	±1.8°F in 12 s
Operating Temperature	32° to 104°F
Non-Operating Temperature	−4° to 149°F
Humidity	5% to 85% relative

Table D-12. Technical Specifications for Intelligence Vibration Sensor/Strain

Parameter	
Number of Channels	1 SE
Total Fiber Length (SE)	25 mi
Lost Budget	18.5 dB
Output	Full aperture seismic waveform or vibration logs
Measurement Parameter	Strain
Operating Wavelength	1550 nm
Range	25 mi
Output Spatial Interval	6.6, 16.4 and 32.8 ft
Output Time Interval	0.1, 0.25, 0.5, 1 and 2 ms
Low-Frequency Limit	5 Hz
Operating Temperature	32° to 113°F
Storing Temperature	−4° to 158°F

2.10.3 Quality Control

The fiber optic cable is governed by American National Standards Institute (ANSI)/Insulated Cable Engineers Association (ICEA) S-87-640 and ANSI/ICEA S104-696 standards. The size and construction details of the cable and installation details will be decided during detailed design of the flowline in consultation with the vendor specialized in the engineering and installation of fiber optic cables.

2.11 Continuous Recording of Injection Pressures, Rate, Temperature, and Volume

Injection pressure and temperature will be continuously measured at the surface via real-time pressure/temperature (P/T) instruments installed in the CO_2 flowline near the interface with the wellhead. The pressure will be measured by electronic pressure transmitter, with analog output mounted on the CO_2 line associated with each injection well (example technical specifications shown in Table D-13). The temperature will be measured by an electronic temperature transmitter mounted in the CO_2 line at a location near the pressure transmitter, and both transmitters will be located near the wellhead (Table D-14).

Table D-13. Technical Specifications for Surface Pressure Gauges

Parameter	
Calibrated Working Pressure Range	0 to 3,000 psi
Pressure Resolution	0.001 psi
Type of Sensor	4–20-mA output transmitter; static measurement; 4-wire

Table D-14. Technical Specifications for Surface Temperature Gauges

Parameter	
Calibrated Working Temperature Range	0 to 150°F
Temperature Accuracy	±0.0055%
Temperature Resolution	0.01°F
Type of Sensor	4–20-mA output; RTD

RTD = resistance temperature detector.

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements (example technical specifications found in Table D-15). Trend analysis will also help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

Table D-15. Technical Specifications for Multivariable Pressure Transmitter

Parameter	
Mass Flow Rate Accuracy	±0.075%
Differential Pressure	−1000 to 1000 in H_2O (−2.5 to 2.5 bar)
Static Pressure Type	Gauge
Static Pressure Range Url	3,626 psi
Temperature Range	−328° to 1562°F
Type of Equipment	Orifice meter with multivariable transmitters and direct process variable outputs for static pressure, differential pressure, and temperature

The flow rate of CO_2 injected into the well field will be measured by flowmeter skids with senior orifice meters (Table D-16). A total of three meters will be supplied. Each well will have a dedicated meter. Piping and valving will be configured to permit the calibration of each flowmeter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flowmeter skid.

Table D-16. Technical Specifications for Senior Orifice

Senior Orifice	
Sizing	8-in., 16-in. ranges, flow rate by manufacturer
Temperature Range	−50° to 200°F
Tolerance	Based on manufacturer manual

The flowmeters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into each well. The flow rate into each well will be controlled using a flow control valve located in the CO_2 pipeline associated with each well.

Pressure and temperature gauges will be deployed on tubing above and below the injection packer to monitor in real-time bottomhole conditions. The gauges and cables will be selected to comply with CO_2 service conditions, and the data will be integrated in the SCADA system and the surveillance platform. Table D-17 shows an example of technical specifications for downhole gauges.

Table D-17. Technical Specifications for Downhole Sensors P/T

Parameter	
Pressure of Sensor	Quartz/Inconel® Carriers
Pressure Accuracy	± 0.02%
Pressure Repeatability	≤0.01% of full scale
Temperature Sensor	Quartz/Inconel carriers
Temperature Accuracy	±0.5°C
Temperature Resolution	0.005°C
Operating Temperature Ranges	−20° to 200°C
Sample Rate	1 s
Inconel Cable	Required

2.12 Annular Pressure Testing

Annular pressure testing is used to validate mechanical integrity in the system. Tests will be performed at least once every 5 years in injectors and monitoring wells, when tubing and packer are pulled for workover, or when the monitoring systems indicate a potential mechanical integrity issue.

To start the test, the well is shut in to stabilize the pressures (injectors). The testing equipment is connected to the annular valves, and surface lines are tested to 1500 psi above the testing pressure. The operator must ensure there are no surface leaks from the pumping unit to the wellhead valve. Any air in the system is bled. If needed, the annular I completed with packer fluid and corrosion inhibitor (it should require minimum amount if so). Initial tubing and casing pressure are recorded. The well will be tested to 1000 psi in the annular, and the pressure should not decrease more than 10% in 30 minutes. Tubing and casing pressure is monitored continuously. Final tubing and casing pressure are recorded and pressure and volume bled.

If the pressure decreases more than 10%, the pressure is bled, the surface connection tested, and the test repeated. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the director.

Surface gauges should be calibrated according to manufacturer recommendations and should have a pressure range which will allow the test pressure to be near the midrange of the gauge. Additionally, the gauge must be of sufficient accuracy and scale to allow an accurate reading of a 10% change. The test results will be documented and store in the centralized database of the project for reporting and documentation.

2.13 Fall-Off Test in Injector Wells

Pressure fall-off testing will be conducted upon completion of the injection wells to characterize reservoir hydrogeologic properties and aquifer response model characteristics as well as changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Pressure fall-off testing will also be conducted at least once 5 years after injection for AOR review. Specifically, the objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect well/reservoir performance.

2.13.1 Testing Method

Controlled pressure fall-off tests are conducted by terminating injection for a designed period/duration of time. The pressure fall-off test is then started with shutting in the well by closing the surface wellhead valve(s) and maintaining continuous monitoring of the surface and downhole pressure recovery within the well/test interval system during the fall-off/recovery period. The designed duration of the pressure fall-off recovery test is a function of a number of factors, including the exhibited preoperational injection reservoir test response characteristics, injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir. Because of the potential impact of injection rate variability on early-time pressure fall-off recovery behavior, its recommended that injection rates and pressures be uniform and held constant prior to initiating a pressure fall-off test.

Upon shutting-in the well, pressure measurements are monitored continuously in real time, both downhole (within or in the proximity to the injection reservoir) and at the surface wellhead location. Temperature measurements taken during the test may assist in data interpretation. Bottomhole reservoir pressure measurements may be less subject to data scatter, and because of the compressible nature of supercritical and liquid CO_2, bottomhole gauges should be the least affected by wellbore effects. Wellhead (surface) pressure measurements may be sufficient if a positive pressure is maintained at the surface throughout the test.

The duration of the shut-in period used in conducting the pressure fall-off test should be extended sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of infinite-acting radial flow (IARF) conditions. The establishment of IARF conditions is best determined by using pressure derivative diagnostic analysis plots (Boudet and others, 1989; Spane, 1993; Spane and Wurstner, 1993) and is indicated when the log–log pressure derivative/recovery time plot forms a horizontal line. When IARF pressure fall-off conditions are indicated, the pressure response versus log of fall-off/recovery time becomes a straight line on a standard semi-log plot.

EPA (2012) recommends a general rule-of-thumb of extending pressure fall-off tests a factor of three to five beyond the time required to reach radial flow conditions, while Earlougher (1977) suggests extending recovery periods between 1 and 1.5 log cycles beyond when the pressure response starts to deviate from purely wellbore storage response characteristics (i.e., a unit slope, 1:1 on a standard log–log pressure fall-off recovery plot).

For projects like the Tundra SGS Broom Creek Formation that will use more than one injection well completed in the same reservoir, special considerations need to be taken to execute the pressure fall-off testing to minimize the pressure response impacts from neighboring injection wells in the well recovery response. For the neighboring injection wells (i.e., those not being tested), EPA (2012) recommends that injection at these wells either be terminated prior to initiating the pressure fall-off test for a duration exceeding the planned shut-in period or injection rates at the neighboring wells be held constant and continuously recorded prior to and during the fall-off recovery test. Following the fall-off test, owners or operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well. These pulses will demonstrate communication between the wells, and if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

No specialized sample/data-handling procedures are required. Electronic sensor data (e.g., pressure data) will be recorded on data loggers. All electronic data and field records will be transferred and stored on secure servers at the conclusion of each test.

2.13.2 Analytical Methods

Quantitative analysis of the pressure fall-off test response recorded following termination of injection for the test well provides the basis for assessing near well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots established prior to the operational injection of CO_2 and periodic fall-off tests conducted during the operational injection phases can be used to determine whether significant changes in well or injection reservoir conditions have occurred. Diagnostic derivative plot analysis (Boudet and others, 1989; Spane, 1993; Spane and Wurstner, 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

The plotting of downhole temperature concurrent with the observed fall-off test pressure is also useful diagnostically for assessing any observed anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures responding differently than registered within the probe sensor), erroneous fall-off pressure response results maybe be derived. As previously discussed, concurrent plotting of downhole temperature and pressure fall-off responses is commonly useful for assessing when temperature anomalies may be affecting pressure fall-off/recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log–log and semi-log plots of observed pressure change and/or pressure derivative plots versus recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity, etc.) based on characteristic diagnostic fall-off pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard and others (2009).

Early pressure fall-off recovery response corresponds to flow conditions within and in the proximity of the wellbore, while later fall-off recovery response is reflective of progressively more distant reservoir conditions from the injection well location. Significant divergence in pressure fall-off response patterns from previous pressure fall-off tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure fall-off tests for discerning possible changes to well and reservoir conditions is presented by EPA (2002).

Quantitative analysis of the pressure fall-off test data can be used to determine formation hydraulic property characteristics (e.g., permeability, transmissivity) and well skin factor (additional pressure change effects due to altering the permeability/storativity conditions of the reservoir/well injection interval boundary). Determination of well skin is a standard result for pressure fall-off test analysis and described in the standard well test analysis texts such as that by Earlougher (1977). Software programs are also commercially available for analyzing pressure fall-off tests. Significant changes in well and reservoir property characteristics (as determined from pressure fall-off analysis), compared to those used in site computational modeling and AOR delineation, may signify a reevaluation of the AOR.

2.13.3 Instrument/Equipment Calibration and Frequency

All field equipment will be visually inspected and tested prior to use. Spare instruments, batteries, etc., will be stored in the field support trailer.

Pressure gauges that are used to conduct fall-off tests will be calibrated in accordance with manufacturer recommendations. In lieu of removing the injection tubing to regularly recalibrate the downhole pressure gauges, their accuracy might be demonstrated by comparison to a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data.

2.14 CO_2 Leak Detector

An infrared gas detector will be installed closed to the wellheads of the injector wells and the monitoring well. This sensor will be the interface with the surveillance system to set alarms and provide information on potential leaks at the surface. An example of sensor technical specifications is described in the following data sheet as a reference only (Figure D-3). Final selection of the technology will consider the integration of all the sensors and transducers in a unique surveillance system. Calibration and maintenance protocols will be based on manufacturer specifications and will be performed by specialized professionals. Table D-18 shows referential technical specifications for the CO_2 leak detector.

2.15 DTS Fiber Optic Array Downhole

DTS for downhole application follows the same physical principle discussed for flowline monitoring in the previous sections. The fiber optic is run alongside the casing as an umbilical, and it is protected with clamps and a centralizer to avoid any damage while deploying in the well. The fiber is connected on surface to an interrogator to convert the signal to temperature values, and data are transmitted to the monitoring platform in real time to perform surveillance.

The maintenance and calibration of the equipment will be performed in accordance with manufacturer manuals and will be the responsibility of the provider of the technology. Tables D-19 and D-20 show referential technical specification for DTS systems and fiber optic cable.

2.16 Time-Lapsed 3D Seismic Survey

3D surface seismic is a proven deep reflection technique utilizing seismic sources and receivers to produce full volumetric images of subsurface structure including reservoir and overburden. Under favorable circumstances, 3D surface seismic can offer spatial resolution down to a few meters or less. It offers an effective means of imaging compressible fluids (i.e., CO_2) in the subsurface. A key application of surface seismic methods for monitoring purposes is the time-lapse 3D (4D) seismic method, in which a number of repeat surveys are acquired, enabling changes in fluid distribution to be mapped through time. This has been used successfully in the oil industry to image fluid changes in hydrocarbon reservoirs for a number of years. The technique produces reflections that correspond to P-wave acoustic impedance boundaries in the subsurface. These are commonly associated with boundaries between different rock units, so reflectivity is an effective proxy for subsurface structure. Because of its physical properties, CO_2 in the free (gaseous or fluid) state is highly compressible, which enhances reflectivity over a range of underground storage situations and is particularly well-suited to seismic imaging methods.

2.16.1 Equipment and Calibration

Seismic acquisition and processing are performed by highly specialized companies and crews that provide the equipment, procedures, and QC protocols based on the technology selected for acquisition and parameters for processing the data. As such, these parameters are verified by the client with a parameter sheet, as shown in Figure D-4.

S5000 **Gas Monitor**

Specifications

General Monitors by MSA

Product Specifications	
COMBUSTIBLE GAS SENSOR TYPE	Catalytic bead (Passive comb., XCell comb.) Infrared (IR400)
TOXIC GAS & OXYGEN SENSOR TYPE	**XCell Toxic** Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Chlorine (Cl_2), Sulfur Dioxide (SO_2) **Passive MOS, Echem, XCell Toxic** Hydrogen Sulfide (H_2S) **XCell O_2** Oxygen (O_2) **Infrared** Carbon Dioxide (CO_2) **Electrochem** Ammonia (NH_3), Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Nitric Oxide (NO), Nitrogen Dioxide (NO_2)
SENSOR MEASURING RANGES	**Combustible** 0-100% LEL (CB, IR) **Cl_2** 0-5, 0-10, 0-20 ppm **CO** 0-100, 0-500, 0-1000 ppm **CO, H_2-resistant** 0-100 ppm **CO_2** 0-2000, 0-5000, 0-10000, 0-30000, 0-50000 ppm **H_2** 0-1000 ppm **HCl** 0-50 ppm **HCN** 0-50 ppm **H_2S** 0-10, 0-20, 0-50, 0-100, 0-500 ppm **NH_3** 0-100 ppm, 0-1000 ppm **NO** 0–100 ppm **NO_2** 0-10 ppm **O_2** 0-25% **SO_2** 0-25, 0–100 ppm
APPROVALS CLASSIFICATION	*See manual for complete CSA listings.*
DIVISIONS (US/CAN)	Class I, Div/Zone 1&2, Groups A, B, C & D T5/T4; Class II, Div/Zone 1&2, Groups E, F & G, T6; Class III Type 4X, IP66
US ZONES	Class I, Zone 1 AEx db IIC T5 Gb Class I, Zone 2 AEx nA nC IIC T4 Gc Zone 21 AEx tb IIIC T85°C Db
CANADIAN ZONES/ ATEX/ IECEx	Ex db IIC T5 Gb Ex nA nC IIC T4 Gc Ex tb IIIC T85°C Db
CE MARKING DIRECTIVES	Complies with EMC, RED, ATEX
WARRANTY	**S5000 transmitter** 2 years **XCell Sensors** 3 years **Passive comb., MOS, IR400, IR700** 2 years **Echem Sensors** Varies by gas
APPROVALS	CSA, FM**, ATEX, IECEx, INMETRO, ABS, DNV-GL Marine, CE Marking. Complies with C22.2 No. 152, FM 6320, ANSI/ISA/CSA/IEC/EN 60079-29-1, ANSI/ISA 12.13.01. Suitable for SIL 2.

Dimensions	
HOUSING (W x H x D)	6.37" x 5.38" x 4.25" (162 x 137 x 108 mm)
W/PASSIVE SENSOR	6.37" x 7.62" x 4.25" (162 x 193 x 108 mm)
W/DIGITAL SENSOR	6.37" x 10.4" x 4.25" (162 x 265 x 108 mm)
W/IR400 IR SENSOR	14.8" x 6.0" x 4.25" (375 x 152 x 108 mm)
WEIGHT	8 lb. (3.6 kg), 316 SS

Environmental Specifications		
OPERATING TEMPERATURE RANGE	**Transmitter**	-55°C to +75°C
	CB (sintered, Zones)	-40°C to +70°C
	CB (screened, Div)	-40°C to +75°C
	MOS (sintered, Zones)	-40°C to +70°C
	MOS (screened, Div)	-40°C to +75°C
	IR (CSA)	-40°C to +75°C
	IR (ATEX/IECEx)	-60°C to +75°C
	XCell (Comb)	-55°C to +60°C
	XCell (Toxic/O_2)	-40°C to +60°C
STORAGE TEMPERATURE RANGE	**Housing, IR400, IR700, passive sensors**	-50°C to +85°C
	XCell sensors	-40°C to +60°C
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell sensors, IR400, IR700**	10-95%
	Passive combustible	0-95%
	Passive H_2S	15-95%

Mechanical Specifications			
INPUT POWER	24 VDC nominal, 12 to 30 VDC		
SIGNAL OUTPUT	Dual 4-20 mA current source or sink, HART, Modbus, Bluetooth. *Optional: w/o Bluetooth*		
RELAY RATINGS	5A @ 30VDC; 5A @220 VAC (3X) SPDT – fault, warn, alarm		
RELAY MODES	Common, discrete, horn		
NORMAL MAX POWER		**Without Relays**	**With Relays**
	Passive comb.	5.0 W	6.0 W
	Passive MOS	9.8 W	10.8 W
	IR400/IR700	7.9 W	8.9 W
	XCell comb.	5.0 W	6.0 W
	XCell toxic & O_2	2.6 W	3.6 W
	IR400/IR700 + XCell comb.	10.8 W	11.8 W
	IR400/IR700 + XCell toxic or O_2	8.6 W	9.6 W
	Dual XCell toxic or O_2	3.3 W	4.3 W
	Dual XCell comb.	7.4 W	8.4 W
	XCell comb. + XCell toxic or O_2	5.7 W	6.7 W
STATUS INDICATORS	4-digit scrolling LED, icons depicting fault, warn, alarm, Bluetooth, 1 and 2 to indicate sensor reading displayed		
RS-485 OUTPUT	Modbus RTU, suitable for linking up to 128 units or up to 247 units with repeaters		
BAUD RATE	2400, 4800, 9600, 19200, 38400, 115200		
HART	HART 7, Device Description (DD) and Device Type Manager (DTM) available		
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, calibration faults, analog output mismatch fault		
CABLE REQUIREMENTS	3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*		

*** See manual for FM-approved sensors*

Specifications subject to change without notice.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

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MSA**safety**.com/detection

Figure D-3. Example data sheet of sensor technical specifications.

Table D-18. Technical Specifications for CO_2 Leak Detector

Type of Sensor	Infrared
Measurement Ranges	
Combustible	0–100% lower explosive limit (LEL)
CO_2	0–2,000, 0–5,000, 0–10,000, 0–30,000 ppm
Resolution	1% LEL
Response Time	T50 <4 s, T90 < 9 s
Approval Classification	Class I, Div/Zone 1&2, Groups A,B,C,D T5/T4
Operating Ranges	−40°to 50°C
Relative Humidity	10%–95%

Table D-19. Technical Specification for DTS

Parameter	
Spatial Resolution	1 m (3.2 ft) across entire measurement range
Sampling Resolution	Down to 0.5 m (1.6 ft) across entire measurement range
Temperature Resolution	0.1°C (0.18°F)
Accuracy	±0.5°C (± 0.9°F)
Measurement Range	Up to 12 km
Measurement Temperature Range	−250° to 400°C
Measurement Times	10 s to 24 h
Dynamic Range	30 dB
Operating Environment	−10° to 60°C, humidity 0–95% noncondensing

Table D-20. Technical Specifications for Fiber Optic Cable

Parameter	
Tensile Strength	2,372 lb
Yield Strength	2,018 lb
Strain @ Yield	0.31%
Hydrostatic Pressure	23,872 psi
Burts Pressure	28,050 psi
Working Pressure	20,526 psi
Static Bend Radius	3.2 in.

SAExploration

ZLand Gen2 Transcriber Parameter Sheet

Project Name:	**Carbonsafe Phase III 2D/3D**	Test Line: ☐ Yes ☒ No
Project Co-ordinate system:	NAD_1927_StatePlane_North_Dakota_South_FIPS_3302	
Transcriber Script Projection:		
Acquisition Schedule:	☒ Continuous	☐ Scheduled: Start: Finish:
Acquisition Parameters:	Sample Rate	☐0.5ms ☐1ms ☒2ms ☐4ms
	Pre-Amp Gain	☐0dB ☐6dB ☐12dB ☐18dB ☐24dB ☐30dB ☒36dB
	Anti-Alias Filter	☒ Linear ☐Minimum
*Note no low cut filter is not recommended by Fairfield Nodal.	Low Cut Filter	☒ 1-60Hz (1Hz) ☐None (Not recommended)
Pre-Start Instrument Tests:	☐ All gains and sample rates ☒Production Parameters Only	
Source Type:	☒ Vibroseis ☐ Dynamite ☐ OnSeis © ☐ Other:Passive	
	Vibroseis Sweep Length:	3 x 20 seconds
Record Length:	5 seconds total	
Wireline Regularity: N/A	☐ Weekly ☐ Monthly ☐ Other (Post Startup wirelines can be requested after project completion)	
Aux Channels Required:	☒ Timebreak ☐ Pilot ☐ Spare Pilot	
*Note: 2 Pilots is SAE Standard for Vib	☒ Others: TBD, reference marks, uphole	
Sensor to be used:	☒ Internal 10hz DTCC SOLO ☐ External: SM24 6x1	
Deliverable Data:	☒ Shot Gather RAW ☒ Shot Gather Correlated ☐Stacked	
*Note: Correlation will be done with 3rd party software.	☐ Receiver Gather (Combed)	
	☒ Continuous Receiver Gather (Record length: ☒30 Sec ☐60Sec)	
Supporting Documents:	☒ Data Output Logs ☒ Deployment File ☒ Receiver File	☐ Other:
Data Delivery Address:	One copy: Earth Signal Processing Ltd., Attn: Brendan Smith, 1600, 715 – 5th Avenue SW Calgary, Alberta, Canada T2P 2X6 One copy: Minnkota Power Cooperative, Attn: Dan Laudal, 5301 32nd Ave. S., Grand Forks, ND 58201	

Figure D-4. Example parameter sheet.

2.17 Geophone Array for Seismicity

Based on the information provided by the U.S. Geological Survey (USGS), the North Dakota area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex or nearby infrastructure. Seismicity history was discussed in Section 2.0 of the permit.

Change of in situ stresses on existing faults caused by human activities (e.g., mining, dam impoundment, geothermal reservoir stimulation, wastewater injection, hydraulic fracturing, and CO_2 sequestration) may induce earthquakes on critically stressed fault segments. To monitor potential induced seismicity due to the injection of CO_2 in the area. The project will plan to continuously monitor seismicity magnitudes and hypocenter locations through sufficiently supplementing existing available stations. The existing 3D seismic and velocity data in the AOR provide additional confidence for locating the hypocenter of measurable seismicity. Other sources of impulsive seismic noise (i.e., large commercial vehicles, mine blasts, etc.), recorded with the proposed seismometer array, can be easily discriminated from potential seismicity related to injection operations.

2.17.1 Personnel and Equipment

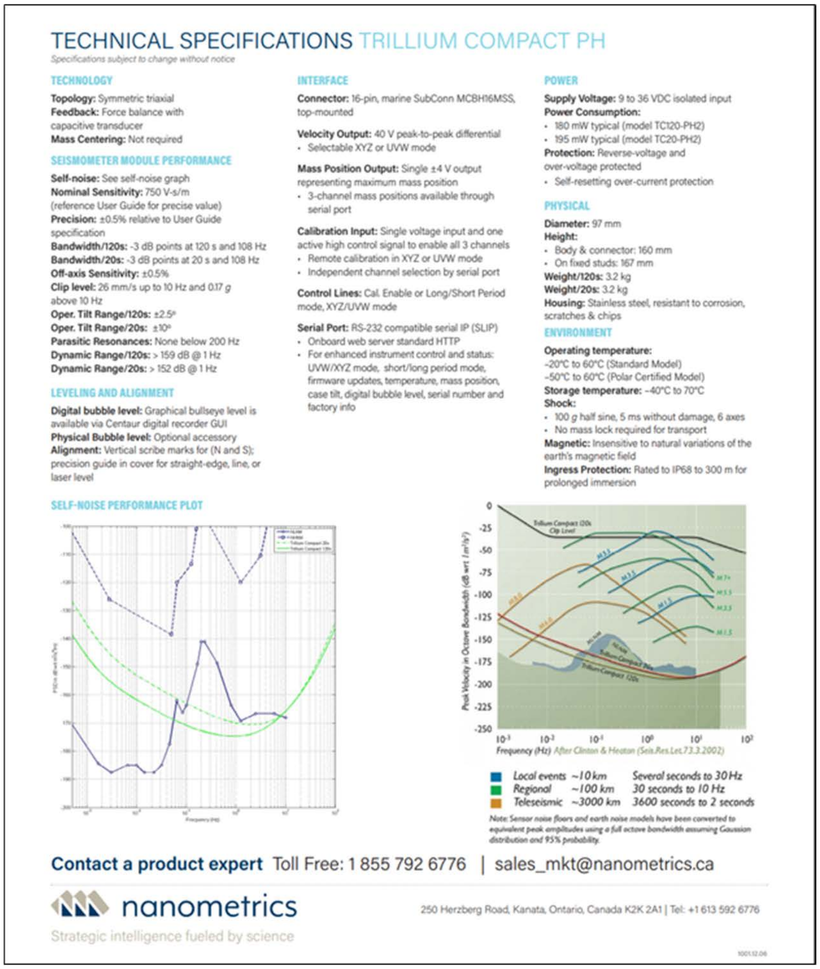
The design and installation of the seismometer station array is performed by specialized contractors including the following activities:

- Project management support to design seismometer array, model network performance, coordinate permitting and equipment installation, testing and maintenance, and ensuring optimum execution of project.
- Field operation to deploy surface seismic station instrumentation, power and communication systems, data quality, and commissioning.
- Data acquisition, system configuration, and processing setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst review and alert notifications for events at or above predetermined magnitude thresholds over the seismic area.

The equipment proposed for seismic station includes the following:

- Broadband sensors
- Data logger
- Solar power system and back-up battery
- Communication system
- Cabling
- Mounting equipment

Figure D-5 shows technical specifications for the broadband seismometer as a reference. Figure D-6 shows an example of setup for data acquisition, transfer, storage, and analysis.



TECHNICAL SPECIFICATIONS TRILLIUM COMPACT PH

Specifications subject to change without notice

TECHNOLOGY

Topology: Symmetric triaxial
Feedback: Force balance with capacitive transducer
Mass Centering: Not required

SEISMOMETER MODULE PERFORMANCE

Self-noise: See self-noise graph
Nominal Sensitivity: 750 V-s/m (reference User Guide for precise value)
Precision: ±0.5% relative to User Guide specification
Bandwidth/120s: -3 dB points at 120 s and 108 Hz
Bandwidth/20s: -3 dB points at 20 s and 108 Hz
Off-axis Sensitivity: ±0.5%
Clip level: 26 mm/s up to 10 Hz and 0.17 *g* above 10 Hz
Oper. Tilt Range/120s: ±2.5°
Oper. Tilt Range/20s: ±10°
Parasitic Resonances: None below 200 Hz
Dynamic Range/120s: > 159 dB @ 1 Hz
Dynamic Range/20s: > 152 dB @ 1 Hz

LEVELING AND ALIGNMENT

Digital bubble level: Graphical bullseye level is available via Centaur digital recorder GUI
Physical Bubble level: Optional accessory
Alignment: Vertical scribe marks for (N and S); precision guide in cover for straight-edge, line, or laser level

INTERFACE

Connector: 16-pin, marine SubConn MCBH16MSS, top-mounted

Velocity Output: 40 V peak-to-peak differential
- Selectable XYZ or UVW mode

Mass Position Output: Single ±4 V output representing maximum mass position
- 3-channel mass positions available through serial port

Calibration Input: Single voltage input and one active high control signal to enable all 3 channels
- Remote calibration in XYZ or UVW mode
- Independent channel selection by serial port

Control Lines: Cal. Enable or Long/Short Period mode, XYZ/UVW mode

Serial Port: RS-232 compatible serial IP (SLIP)
- Onboard web server standard HTTP
- For enhanced instrument control and status: UVW/XYZ mode, short/long period mode, firmware updates, temperature, mass position, case tilt, digital bubble level, serial number and factory info

POWER

Supply Voltage: 9 to 36 VDC isolated input
Power Consumption:
- 180 mW typical (model TC120-PH2)
- 195 mW typical (model TC20-PH2)

Protection: Reverse-voltage and over-voltage protected
- Self-resetting over-current protection

PHYSICAL

Diameter: 97 mm
Height:
- Body & connector: 160 mm
- On fixed studs: 167 mm

Weight/120s: 3.2 kg
Weight/20s: 3.2 kg
Housing: Stainless steel, resistant to corrosion, scratches & chips

ENVIRONMENT

Operating temperature:
-20°C to 60°C (Standard Model)
-50°C to 60°C (Polar Certified Model)
Storage temperature: −40°C to 70°C
Shock:
- 100 *g* half sine, 5 ms without damage, 6 axes
- No mass lock required for transport

Magnetic: Insensitive to natural variations of the earth's magnetic field
Ingress Protection: Rated to IP68 to 300 m for prolonged immersion

SELF-NOISE PERFORMANCE PLOT

Contact a product expert Toll Free: 1 855 792 6776 | sales_mkt@nanometrics.ca

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1001.12.06

Figure D-5. Reference technical specifications for broadband seismometer.

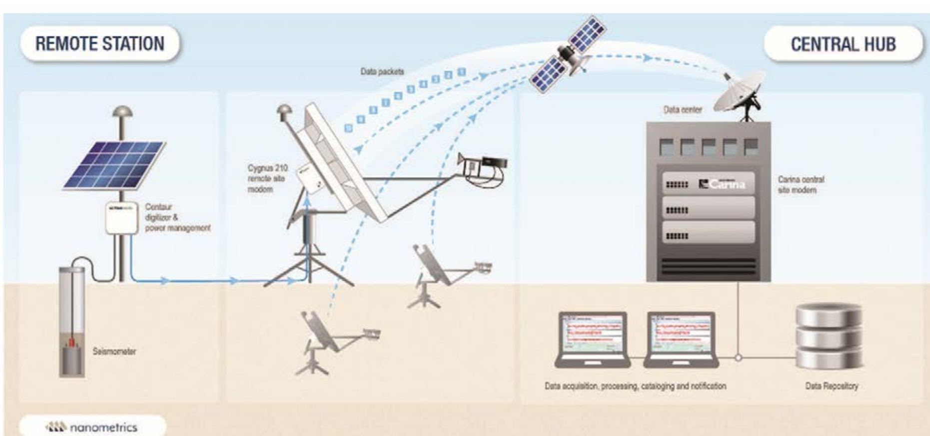

Figure D-6. Example setup for data acquisition, transfer, storage, and analysis.

2.17.2 Traffic Light System

While the historical seismicity of the project area indicates few earthquakes in the area, the operator intends to maintain a surface array for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. This seismic monitoring will be conducted with a surface array deployed to ensure detection of events above ML 2.0, with epicentral locations within 5 km of the injection well.

If an event is recorded by either the local private array or the public national array to have occurred within 5 km of the injection well, the operator would implement its response plan subject to detected earthquake magnitude limits defined below so as to eliminate or reduce the magnitude and/or frequency of seismic events.

- For events above ML 2.0 within 5 km of the injection well, the operator will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity.

- For events above ML 4.0 within 5 km of the injection well, the operator will stop injection and perform an inspection in surface facilities and wells. If there is no damage, the operator will reduce the injection rate by not less than 50% and perform a detailed analysis to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

If the event is not related to the storage facility operation, the operator will resume normal injection rates.

- For events above ML 4.5 within 5 km of the injection well, the operator will stop injection. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. The operator will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis is conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

If the event is not related to the storage facility operation, and previously approved by the regulators, the operator will resume normal injection rates in steps, increasing the surveillance.

2.18 InSAR Method for Surface Deformation

Geodetic methods, like interferometric synthetic aperture radar (InSAR) (Vasco and others, 2020), can detect small-scale surface deformation and has been shown to approximately map pressure distribution associated with subsurface fluid injection (Reed and others, 2018). InSAR is widely available and allows for multiple nonunique interpretations requiring integration with other monitoring methods (e.g., time-lapse seismic). InSAR requires continuous satellite coverage with consistent surface reflectivity (Klemm and others, 2010). 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.

3. REFERENCES

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APPENDIX D-1

DATA SHEET FOR FORMATION EVALUATION TOOLS

S5000 **Gas Monitor**

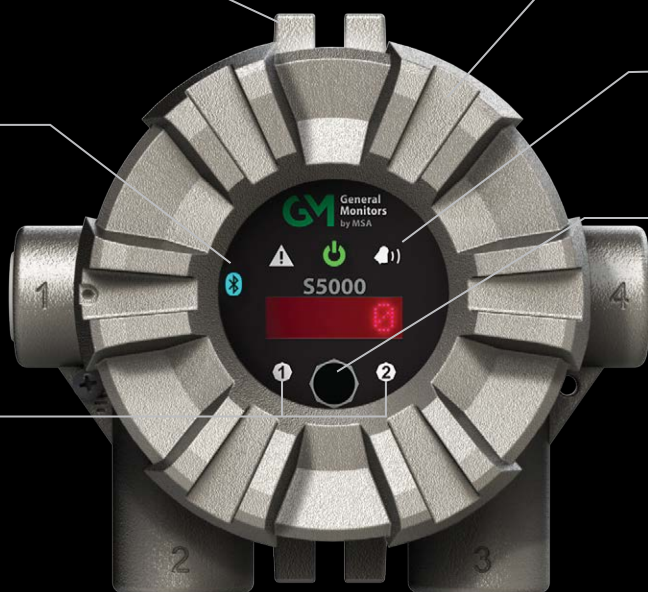
Extreme Durability. Anytime. Anywhere.

General Monitors

Simple retrofits have identical footprint and wiring to S4000 Gas Monitor series.

Bluetooth® wireless technology allows mobile device to act as HMI screen and controller via the X/S Connect App.

Dual sensor capability increases detection coverage without increasing CAPEX expense. Remote mount gas sensors up to 100 m away.



Wide operating temperature for extreme environments (-55°C to +75°C).

Instrument status indicators illuminate power, fault, and alarm conditions.

Intuitive user experience with industry-first touch-button interface or familiar magnetic interface.

X/S Connect App

Reduce setup time by at least 50% with the X/S Connect App.

Advanced Sensor Technology

POWERED BY XCell® SENSORS WITH TruCal® TECHNOLOGY

- Patented XCell H_2S and CO Sensors with TruCal technology extend calibration cycles for as long as 2 years, actively monitor sensor integrity, and compensate for environmental factors and electrochemical sensor drift.
  - **Diffusion Supervision** sends acoustic signal every 6 hours to check that sensor inlet isn't obstructed so gas can reach the sensor.
  - Worry-free operation; automatically self-checks four times per day.
- Three-year warranty and five-year expected life for XCell Sensors.
- **SafeSwap** enables safe and quick XCell Sensor replacement without powering off gas detector.

Applications

- Compressor stations
- CNG maintenance facilities
- Drilling and production platforms
- Fuel loading facilities
- LNG/LPG processing and storage
- Oil well logging
- Petrochemical
- Refineries

MSA *The Safety Company*

WE KNOW WHAT'S AT STAKE.

S5000 **Gas Monitor**

Sensor Specifications

General Monitors by MSA

Electrochemical Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
Ammonia - 100	0 - 100 ppm	25 - 100 ppm	0.1 ppm	< 20 Sec	< 60 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Ammonia - 1000	0 - 1000 ppm	190 - 1000 ppm	10 ppm	< 20 Sec	< 300 Sec	< +/- 15%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Carbon Monoxide - 100	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 500	0 - 500 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 1000	0 - 1000 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - H2 Resistant	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Chlorine - 5	0 - 5 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 10	0 - 10 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 20	0 - 20 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Hydrogen	0 - 1000 ppm	250 - 1000 ppm	10 ppm	< 40 Sec	< 185 Sec	< +/- 10%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Chloride	0 - 50 ppm	25 - 50 ppm	1 ppm	< 30 Sec	< 120 Sec	< +/- 35%	<1% FS / Month	-30 C (-22 F)	40 C (104 F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Cyanide	0 - 50 ppm	25 - 50 ppm	1 ppm	< 8 Sec	< 30 Sec	< +/- 15%	<1% FS / Month	-20 C (-4 F)	40 C (40 F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Sulfide - 10	0 - 10 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 50	0 - 50 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 100	0 - 100 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 500	0 - 500 ppm	20 - 500 ppm	1 ppm	< 20 Sec	< 60 Sec	< +/- 10%	<1% FS / Month	-40 C (-40 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Nitric Oxide	0 - 100 ppm	2.5 - 100 ppm	0.5 ppm	< 5 Sec	< 20 Sec	<+/-15%	<1% FS / Month	-30 C (-22 F)	50C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Nitrogen Dioxide	0 - 10 ppm	1.5 - 10 ppm	0.1 ppm	< 30 Sec	< 60 Sec	< +/- 10%	<1% FS / Month	-40 C (-40 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Oxygen/Oxygen (FM)	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< +/- 1% Vol	<0.2 % Vol / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen (Low)	0 - 25%	2 - 25%	0.10%	< 10 Sec	< 30 Sec	< +/- 10%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Sulfur Dioxide - 100	0 - 100 ppm	25 - 100 ppm	1 ppm	< 10 Sec	< 30 Sec	< +/- 15%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Sulfur Dioxide - 25	0 - 25 ppm	5 - 25 ppm	0.1 ppm	< 3 Sec	< 6 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2

XCell Catalytic Bead Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
Methane (5.0 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Propane (2.1 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Heptane (1.05 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Nonane (0.8 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Hydrogen (4.0 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Methane (4.4 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Propane (1.7 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Heptane (0.85 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Nonane (0.7 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1

** At ambient conditions*

S5000 **Gas Monitor**

Sensor Specifications

General Monitors by MSA

Infrared Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
IR400 0-100 % LEL Propane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Hexane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Pentane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Ethylene	0 - 100% LEL	N/A	1% LEL	< 2 Sec	< 4 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	60 C (140 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Butane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Ethane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% by Volume Methane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Methane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Propane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Hexane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Ethylene EN	0 - 100% LEL	N/A	1% LEL	< 2 Sec	< 4 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	60 C (140 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Butane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Ethane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR700 0-2000 ppm Carbon Dioxide	0-2000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-5000 ppm Carbon Dioxide	0-5000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-10000 ppm Carbon Dioxide	0-10000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-30000 ppm Carbon Dioxide	0-30000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-50000 ppm Carbon Dioxide	0-50000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1

Passive Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
10058-1	0 - 100% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	75 C (167 F)	Cat Bead Screened	3-5 Years	2 Years	Div/Zone 1
11159-8	0-20% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	70 C (158 F)	Cat Bead Sintered	3-5 Years	2 Years	Div/Zone 1
11159-1	0 - 100% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	70 C (158 F)	Cat Bead Sintered	3-5 Years	2 Years	Div/Zone 1
50448-9	0-20 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
50448-5	0-50 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
50448-1	0-100 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
51457-9	0-20 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1
51457-5	0-50 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1
51457-1	0-100 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1

** At ambient conditions*

S5000 **Gas Monitor**

Specifications

General Monitors by MSA

Product Specifications		
COMBUSTIBLE GAS SENSOR TYPE	Catalytic bead (Passive comb., XCell comb.) Infrared (IR400)	
TOXIC GAS & OXYGEN SENSOR TYPE	**XCell Toxic**	Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Chlorine (Cl_2), Sulfur Dioxide (SO_2)
	Passive MOS, Echem, XCell Toxic	Hydrogen Sulfide (H_2S)
	XCell O_2	Oxygen (O_2)
	Infrared	Carbon Dioxide (CO_2)
	Electrochem	Ammonia (NH_3), Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Nitric Oxide (NO), Nitrogen Dioxide (NO_2)
SENSOR MEASURING RANGES	**Combustible**	0-100% LEL (CB, IR)
	Cl_2	0-5, 0-10, 0-20 ppm
	CO	0-100, 0-500, 0-1000 ppm
	CO, H_2-resistant	0-100 ppm
	CO_2	0-2000, 0-5000, 0-10000, 0-30000, 0-50000 ppm
	H_2	0-1000 ppm
	HCl	0-50 ppm
	HCN	0-50 ppm
	H_2S	0-10, 0-20, 0-50, 0-100, 0-500 ppm
	NH_3	0-100 ppm, 0-1000 ppm
	NO	0–100 ppm
	NO_2	0-10 ppm
	O_2	0-25%
	SO_2	0-25, 0–100 ppm
APPROVALS CLASSIFICATION	*See manual for complete CSA listings.*	
DIVISIONS (US/CAN)	Class I, Div/Zone 1&2, Groups A, B, C & D T5/T4; Class II, Div/Zone 1&2, Groups E, F & G, T6; Class III Type 4X, IP66	
US ZONES	Class I, Zone 1 AEx db IIC T5 Gb Class I, Zone 2 AEx nA nC IIC T4 Gc Zone 21 AEx tb IIIC T85°C Db	
CANADIAN ZONES/ ATEX/ IECEx	Ex db IIC T5 Gb Ex nA nC IIC T4 Gc Ex tb IIIC T85°C Db	
CE MARKING DIRECTIVES	Complies with EMC, RED, ATEX	
WARRANTY	**S5000 transmitter**	2 years
	XCell Sensors	3 years
	Passive comb., MOS, IR400, IR700	2 years
	Echem Sensors	Varies by gas
APPROVALS	CSA, FM**, ATEX, IECEx,INMETRO, ABS, DNV-GL Marine, CE Marking. Complies with C22.2 No. 152, FM 6320, ANSI/ISA/CSA/IEC/EN 60079-29-1, ANSI/ ISA 12.13.01. Suitable for SIL 2.	

Dimensions	
HOUSING (W x H x D)	6.37" x 5.38" x 4.25" (162 x 137 x 108 mm)
W/PASSIVE SENSOR	6.37" x 7.62" x 4.25" (162 x 193 x 108 mm)
W/DIGITAL SENSOR	6.37" x 10.4" x 4.25" (162 x 265 x 108 mm)
W/IR400 IR SENSOR	14.8" x 6.0" x 4.25" (375 x 152 x 108 mm)
WEIGHT	8 lb. (3.6 kg), 316 SS

Environmental Specifications		
OPERATING TEMPERATURE RANGE	**Transmitter**	-55°C to +75°C
	CB (sintered, Zones)	-40°C to +70°C
	CB (screened, Div)	-40°C to +75°C
	MOS (sintered, Zones)	-40°C to +70°C
	MOS (screened, Div)	-40°C to +75°C
	IR (CSA)	-40°C to +75°C
	IR (ATEX/IECEx)	-60°C to +75°C
	XCell (Comb)	-55°C to +60°C
	XCell (Toxic/O_2)	-40°C to +60°C
STORAGE TEMPERATURE RANGE	**Housing, IR400, IR700, passive sensors**	-50°C to +85°C
	XCell sensors	-40°C to +60°C
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell sensors, IR400, IR700**	10-95%
	Passive combustible	0-95%
	Passive H_2S	15-95%

Mechanical Specifications			
INPUT POWER	24 VDC nominal, 12 to 30 VDC		
SIGNAL OUTPUT	Dual 4-20 mA current source or sink, HART, Modbus, Bluetooth. *Optional: w/o Bluetooth*		
RELAY RATINGS	5A @ 30VDC; 5A @220 VAC (3X) SPDT – fault, warn, alarm		
RELAY MODES	Common, discrete, horn		
NORMAL MAX POWER		**Without Relays**	**With Relays**
	Passive comb.	5.0 W	6.0 W
	Passive MOS	9.8 W	10.8 W
	IR400/IR700	7.9 W	8.9 W
	XCell comb.	5.0 W	6.0 W
	XCell toxic & O_2	2.6 W	3.6 W
	IR400/IR700 + XCell comb.	10.8 W	11.8 W
	IR400/IR700 + XCell toxic or O_2	8.6 W	9.6 W
	Dual XCell toxic or O_2	3.3 W	4.3 W
	Dual XCell comb.	7.4 W	8.4 W
	XCell comb. + XCell toxic or O_2	5.7 W	6.7 W
STATUS INDICATORS	4-digit scrolling LED, icons depicting fault, warn, alarm, Bluetooth, 1 and 2 to indicate sensor reading displayed		
RS-485 OUTPUT	Modbus RTU, suitable for linking up to 128 units or up to 247 units with repeaters		
BAUD RATE	2400, 4800, 9600, 19200, 38400, 115200		
HART	HART 7, Device Description (DD) and Device Type Manager (DTM) available		
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, calibration faults, analog output mismatch fault		
CABLE REQUIREMENTS	3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*		

*** See manual for FM-approved sensors*

Specifications subject to change without notice.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

APPENDIX D-2

SCHLUMBERGER MDT BROCHURE

MDT Modular Formation Dynamics Tester

Quality fluid samples and highly accurate reservoir pressures

Applications

- Formation pressure measurement and fluid contact identification
- Formation fluid sampling
- Permeability measurement
- Permeability anisotropy measurement
- Mini-drillstem test (DST) and productivity assessment
- In-situ stress and minifrac testing

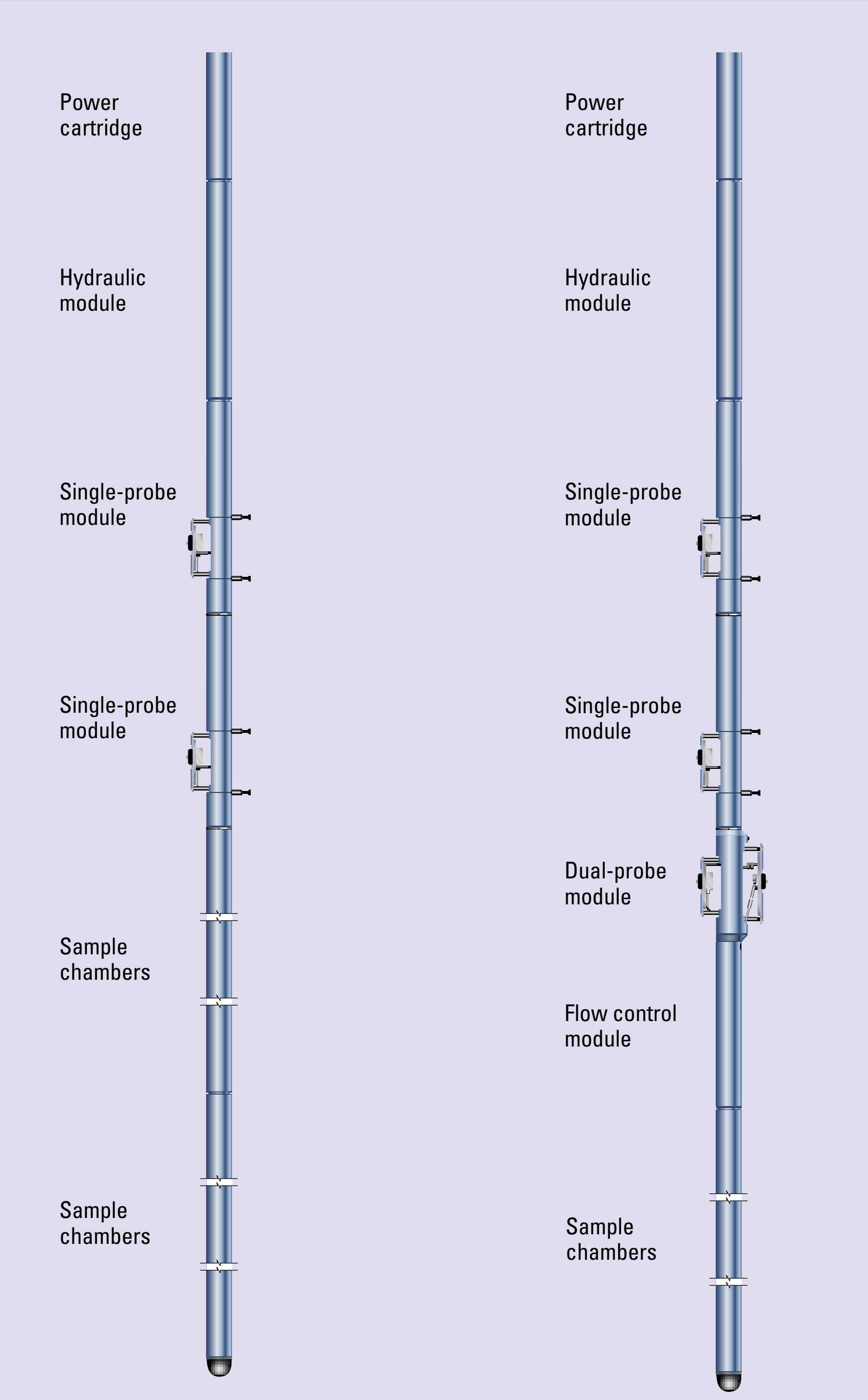
Benefits

- Testing and sampling in low permeability, laminated, fractured, unconsolidated and heterogeneous formations
- Fast, repeatable pressure measurements
- Faster tests in low permeability—reduced seal losses and probe plugging
- Pressure, volume and temperature (PVT) formation fluid samples
- Downhole fluid differentiation
- Real-time fluid gradients, permeability and contamination assessment

Features

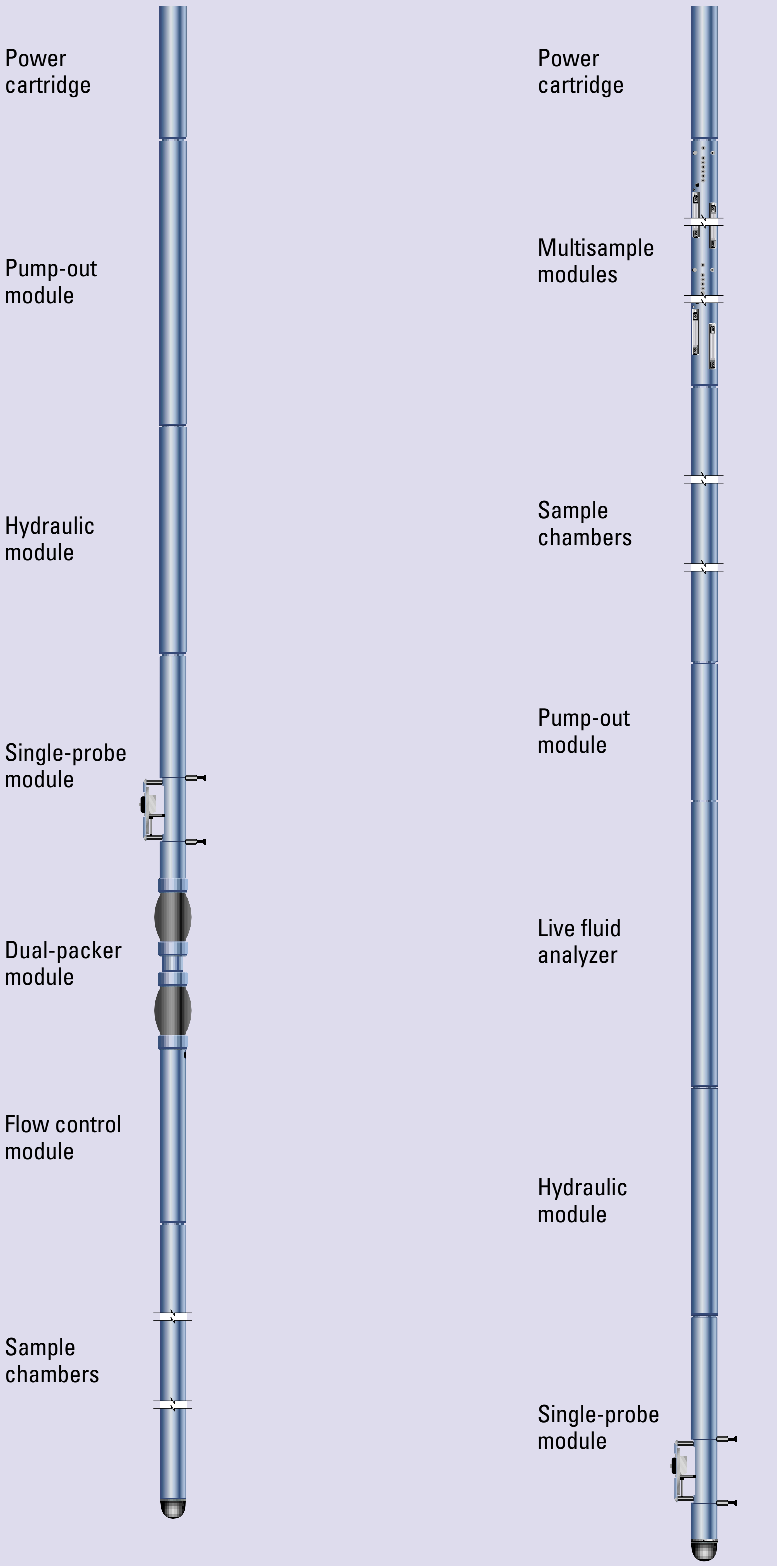
- Modular, custom-design capability
- Multiple samples in one trip
- Multiprobe and inflatable dual packer module options
- Efficient integration with other tools
- Accurate pressure measurements using a CQG* Crystal Quartz Gauge
- Programmable pretest pressure, rate and volume
- Filtrate pumpout prior to sampling
- Fluid resistivity and temperature measurements at the probe
- Quantatative sample contamination measurement with optical spectroscopy techniques
- Low-shock and single-phase sampling
- Field-proven database for accurate pumpout time

The MDT tool can be customized and efficiently assembled on-site to meet exact requirements depending on the needs of a particular well evaluation.



Basic MDT configuration for pressure, permeability and sampling

Multi-probe vertical interference testing



Vertical interference test with probe-packer

Low shock PVT-quality sampling

Real-time measurements

The Schlumberger MDT* Modular Formation Dynamics Tester tool provides fast and accurate pressure measurements and high-quality fluid sampling. It can also measure permeability anisotropy. In a single trip, the MDT tool is able to acquire most of the data requirements needed for accurate and timely decision making.

Flexibility

The key to this remarkable tool is an innovative, modular design that lets you customize the tool for the required applications. MDT modules combine to meet the exact needs and goals of the data acquisition program. This designed flexibility makes the tool compatible with almost all Schlumberger measurement technologies and allows the MDT tool to evolve as new measurement techniques, technologies and options evolve.

Quick, accurate pressure and permeability measurements

Reservoir pressure measurements using a wireline tester require inserting the probe into the reservoir and withdrawing a small amount of fluid. Since the pressure gauge is exposed to many temperature and pressure changes, these measurements require accurate gauges with high resolution that can dependably react to the dynamic conditions.

The MDT tool uses highly accurate gauges with best-in-class resolution, repeatability and dynamic response for pressure measurements. These pressure gauges exhibit excellent response with no compromise in accuracy or resolution. Precise flowline control during testing and sampling ensures monophasic flow. These innovative features provide the most efficient and accurate permeability determination available.

MDT modules

Electronic power module

The power cartridge (MRPC) converts AC power from the surface to provide DC power for all modules in the tool. It is an essential part of any MDT configuration.

Hydraulic power module

The hydraulic power module (MRHY) contains an electric motor and hydraulic pump to provide hydraulic power for setting and retracting the single- and dual-probe modules. The MRHY module features an accumulator that allows the test probes to autoretract and prevent a stuck-tool situation in the event of a power failure.

Single-probe module

The single-probe module (MRPS) contains the probe assembly, (with packer and telescoping backup pistons), the pressure gauges, fluid resistivity and temperature sensors, and a 20-cc pretest chamber. The MRPS also contains a strain gauge and an accurate, high-resolution, quick-response CQG gauge. The volume, rate and drawdown of this chamber can be controlled from the surface to adjust to any test situation, especially in tight formations.

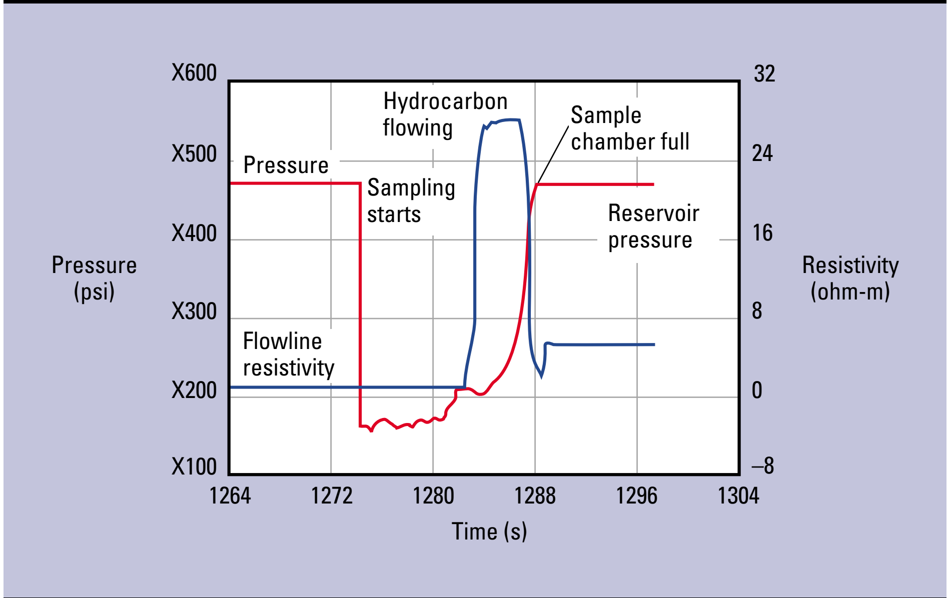
Dual-probe module

The dual-probe module (MRPD) contains two probes mounted back-to-back, 180° apart on the same block. When combined with an MRPS module, it forms a multi-probe system capable of determining horizontal and vertical permeability.

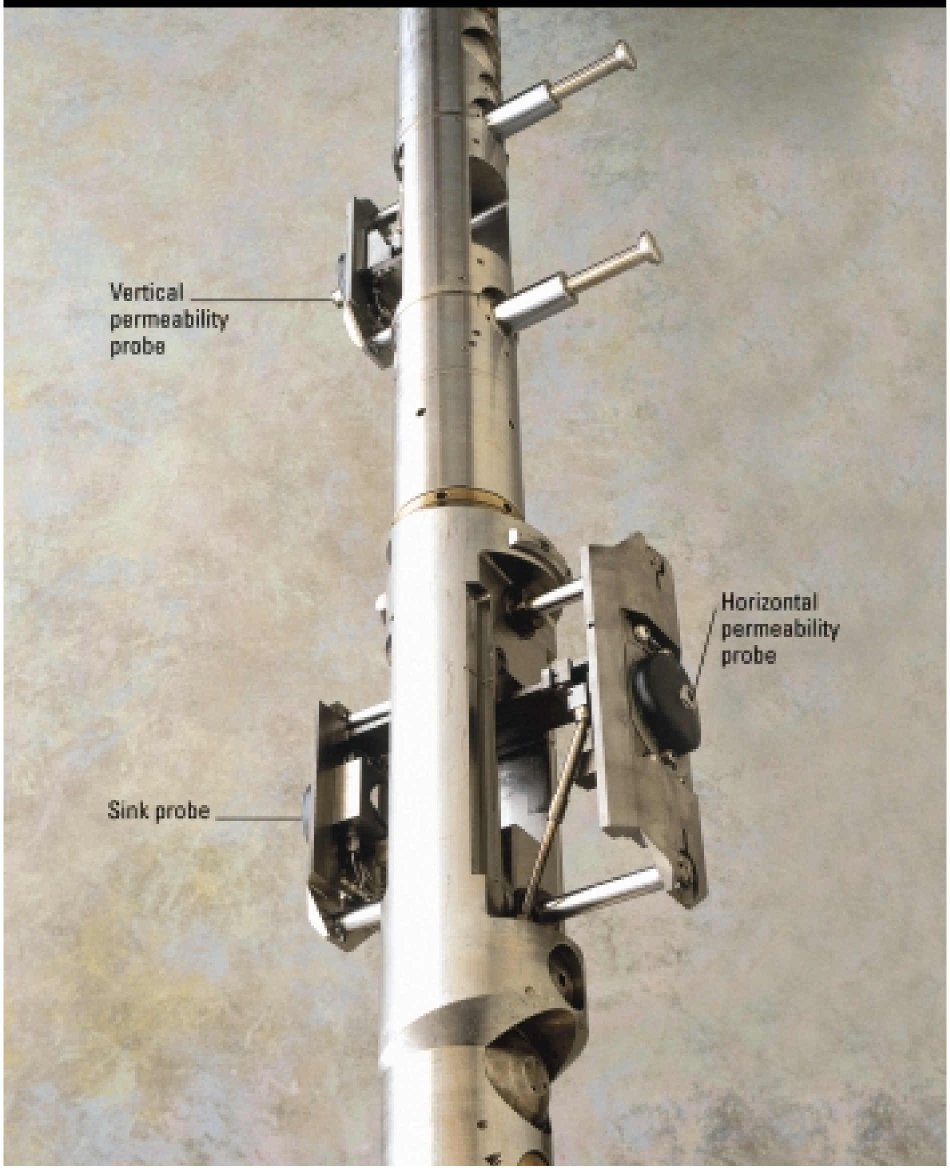
During a typical test with the MRPD module, formation fluid is diverted through the sink probe to a one-liter pretest chamber in the flow control module. The MRPD module, in conjunction with the pressure measured at the vertical probe from the MRPS module, measures the pressure at both probes. These measurements are used to determine near-wellbore permeability anisotropy.

Flexible probe configurations are a unique feature of the MDT tool. By running multiple probe modules, pressure communication between adjacent formations can be monitored during an interference test. The MDT multi-probe configuration also allows in-situ verification of gauge quality and utilization of two different probe assemblies for redundancy in difficult conditions.

In a water-based mud environment, the MDT flowline resistivity measurement helps discriminate between fluid contaminated by mud filtrate and formation oil or fresh water.



The multiprobe configuration of the MDT tool measures the pressure response at two or more locations in addition to the single probe data. Data from the MDT multiprobe configuration provide an evaluation of horizontal and vertical permeabilities and formation heterogeneity.



The MRPA module employs two inflatable packers to isolate a borehole interval for testing. Tests in low-permeability formations are greatly enhanced, because the cross-sectional area of the isolated interval is many times greater than that of the standard MDT probe.

Dual-packer module

The dual-packer module (MRPA) uses two inflatable packers, set against the borehole wall, to isolate a 3 to 11 ft. section of the formation and provide access to the formation over a wall area that is thousands of times larger than the standard probe area. This allows fluids to be withdrawn at a higher rate without dropping below the bubble point, and it provides a permeability estimate with a radius of investigation in the range of tens of feet. The MRPA is useful for making pressure measurements and taking fluid samples in difficult conditions (tight, vuggy, fractured and unconsolidated formations) and has also been used in cased holes after a perforation operation. In addition, the MRPA module can be used for in-situ stress testing and mini-frac testing.

Modular sample chamber

The Modular Sample Chamber (MRSC) is available in three sizes: 1 gal, 2.75 gal and 6 gal. The upper block of each chamber contains a throttle valve that can be operated fully open, fully closed or in throttle mode. The 1-and 2.75-gal chambers exist in both H_2S and non-H_2S versions. The 6-gal chamber can be expanded in 6-gal increments to act as dump chambers by adding more 6-gal cylinders.

Multisample module

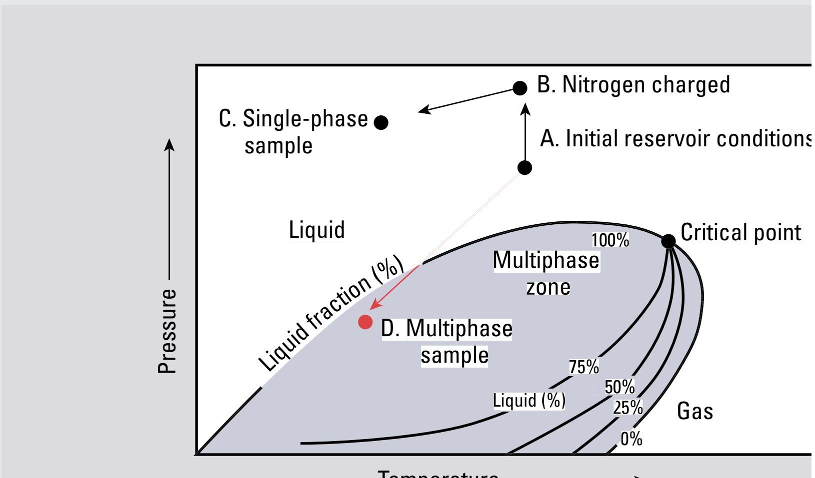
The Multisample Module (MRMS) allows the collection of high-quality samples for PVT analysis. The module is designed to retrieve six formation fluid samples, 450-cc each, during a single trip into the well. Sample bottles detach easily from the tool for transport to a PVT laboratory. The bottles meet transportation regulations for shipping pressurized vessels, so no wellsite transfer is necessary.

Since multiple MRSC and MRMS modules can be combined, the total number of sample modules is limited only by cable strength and well conditions. For longer tool strings, as well as highly deviated and horizontal wells, the MDT tool can be combined with the TLC* Tough Logging Conditions system for efficient sampling operations.

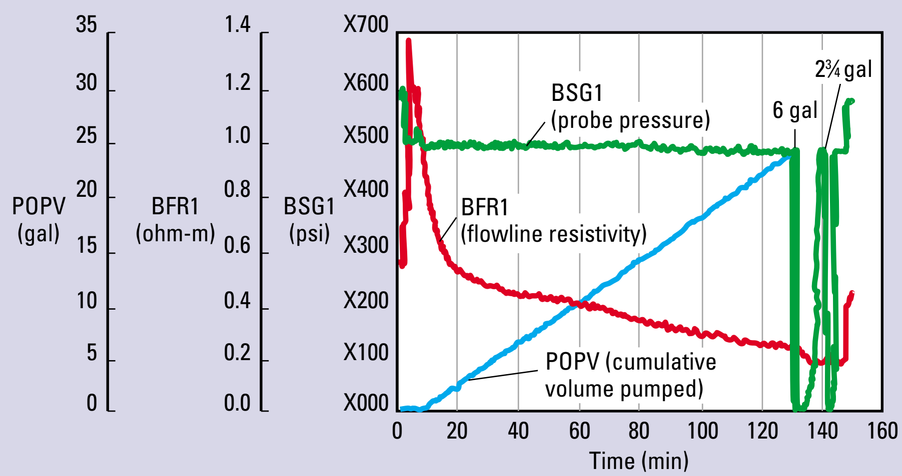
Multiple MRMS modules—each capable of collecting six high-quality PVT samples—can be combined in one run to meet sampling requirements.

Chemical analysis of MDT-acquired samples helps to characterize the reservoir fluid and facilitates optimal completion and surface facilities design.

As they are brought to the surface, samples taken at reservoir temperature and pressure (A) can change phase at lower temperatures and pressures (D). Overpressuring the sample downhole (B) will maintain its initial phase as it is brought to the surface (C) at a lower temperature.



In oil-based mud environments, flowline resistivity may also aid in formation water sampling.



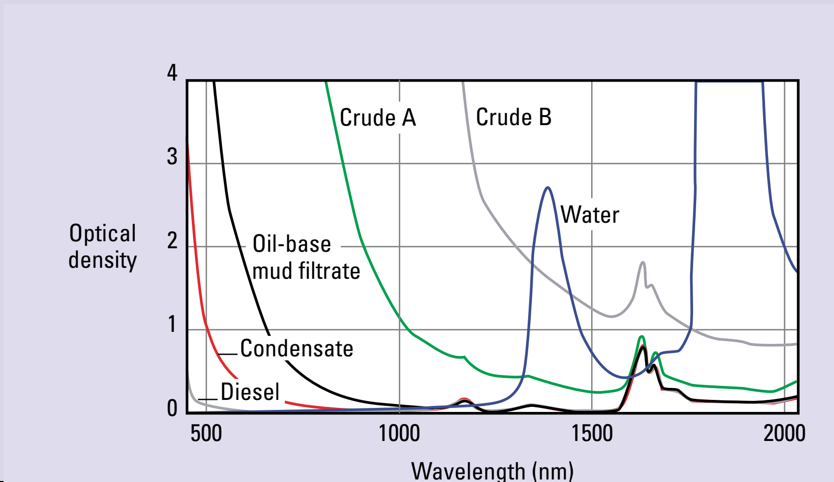
Single-phase multisample chamber

The single-phase multisample chamber ensures collection of monophasic fluid samples by overpressuring samples after they are taken at reservoir conditions. Sample chambers are pressurized with a nitrogen gas chamber across two pistons. This compensates for the temperature-induced pressure drop as the samples are returned to the surface.

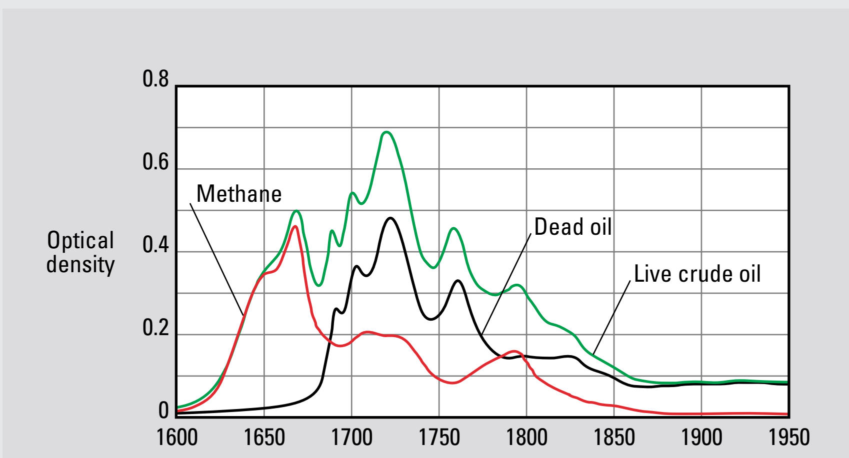
Pump-out module

The Pump-Out Module (MRPO) is used to pump unwanted fluid (mud filtrate) from the formation to the borehole, so representative samples can be taken. It is also used to pump fluid from the borehole into the flowline for inflating the packers of the MRPA module. In addition, the module can pump within the tool, for example, from a sample chamber to the inflatable packers.

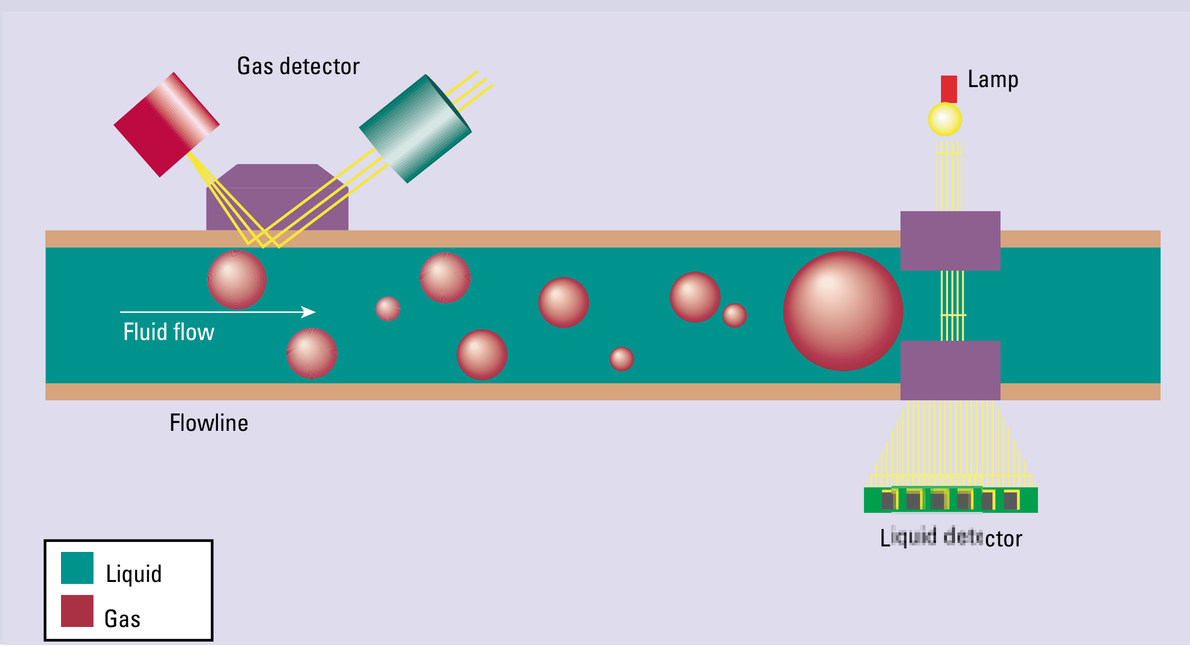
Optical density spectra can be used to uniquely identify different fluids.



The graph below illustrates the optical density (OD) of methane, dead oil and live crude oil. An OD of zero means there is full transmission (no absorption) of light. An OD of 1 means that 10% of the light is transmitted, and 90% is absorbed. Methane and dead oil peaks are prominently shown in the live crude oil spectrum.



The LFA module provides real-time downhole fluid analysis by measuring multiple optical properties of the fluid to quantify the amount of reservoir and drilling fluids in the flowline.



Live fluid analyzer module

Downhole fluid analysis in real time, as provided by the LFA* Live Fluid Analyzer module, enhances the usefulness of new techniques like pumpout and dual inflatable packers. The LFA module measures optical properties of the fluid in the flowline.

The LFA module employs an absorption spectrometer that utilizes visible and near infrared light to quantify the amount of reservoir and drilling fluids in the flowline. Light is transmitted through the fluid as it flows past the LFA spectrometer. The amount of light absorbed by the fluid depends on the composition of the fluid. Water and oil are reliably detected by their unique absorption spectra. A second sensor in the LFA module is the gas refractometer, which can be used to differentiate between gas and liquid.

Optical absorption in the visible and near infrared region is used for fluid discrimination and quantification; the change in index of refraction is used for free gas detection; and methane presence is used for both contamination monitoring and gas detection.

Flow control module

The Flow Control Module (MRCF) is a 1-liter pretest chamber where the flow rate can be accurately measured and controlled. The MRCF can also be used during sampling that requires a controlled flow rate. The volume is limited to 1 liter. The module creates a pressure pulse in the formation large enough for multi-probe measurements.

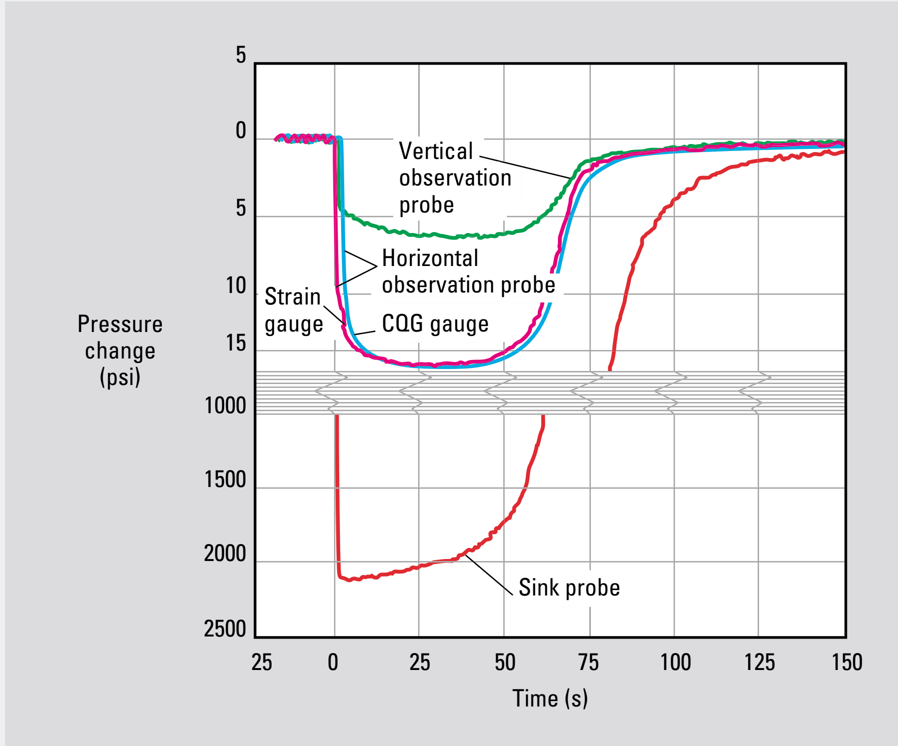
Prejob modeling and real-time answers

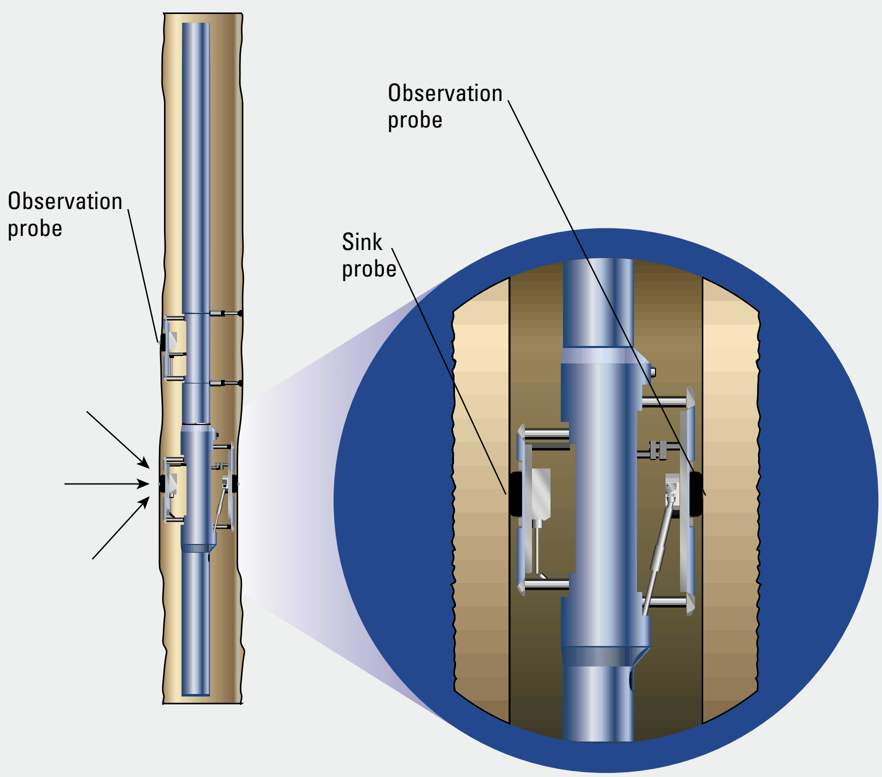
The software capabilities of the MDT tool enhance its hardware capabilities. Drawing on experience based on the vast number of MDT projects that have been completed over the past decade, programs are available to accurately plan and execute new MDT jobs. Highly sophisticated interpretation programs generate accurate pressure gradient, permeability and fluid sampling answers when they are needed.

Planning programs are also available to predict the response of the different gauges under any given environment and for any tool configuration. These programs also predict the duration of required pumping time and the likelihood of sticking in any given situation. These expert systems, based on the huge MDT job database, help optimize the running of the job. In the unlikely event that sticking does occur, the LWF* logging while fishing technique can be used to simultaneously complete the survey on drillpipe and safely retrieve the stuck string.

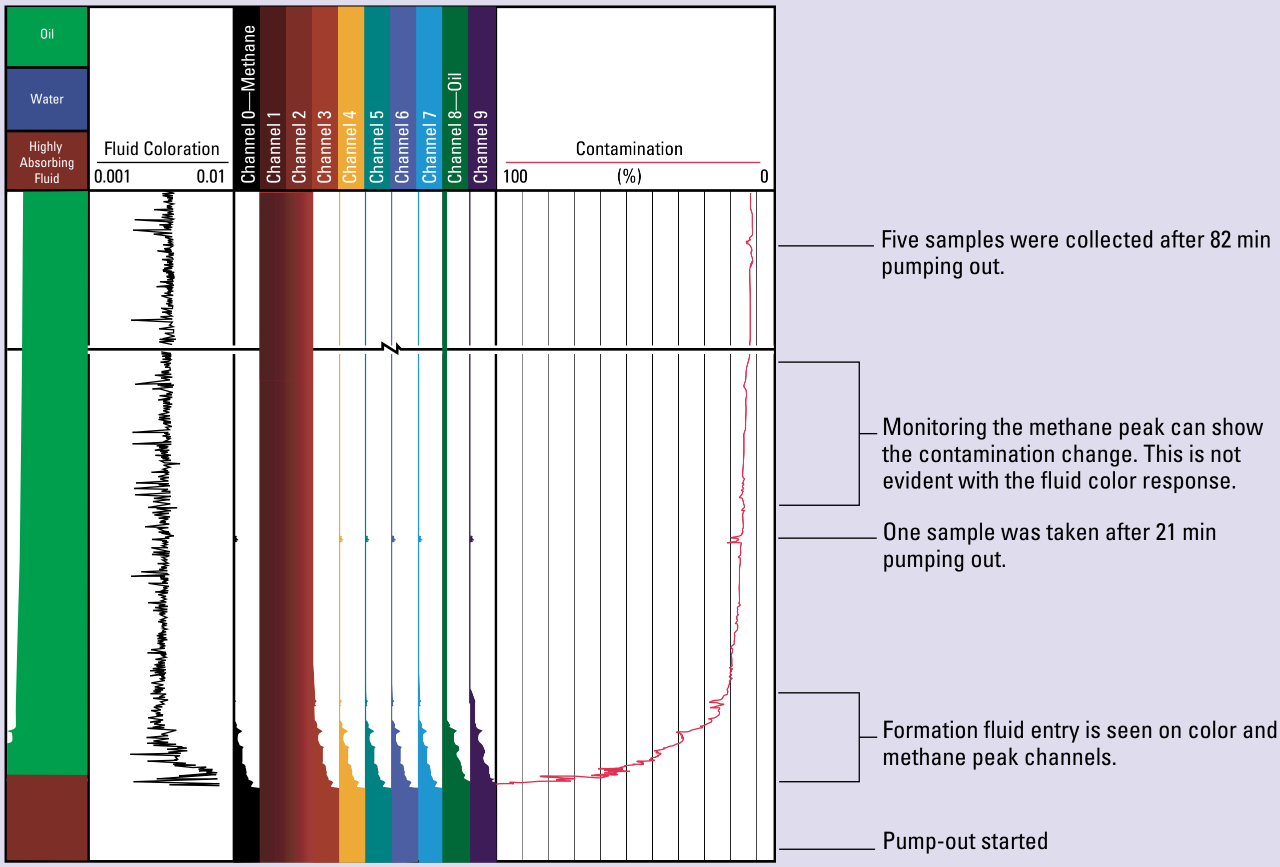
MDT interpretation software provides real-time plotting of pressure, resistivity and optical properties versus time. These plots generate derivatives and perform interpretation at the wellsite. This capability is essential for real-time quality control and ongoing optimization of the job. Using the InterACT* wellsite monitoring and control system for real-time data transfer to remote sites, Schlumberger and customer experts can simultaneously apply more sophisticated and elaborate modeling and interpretation software offsite.

The Flow Control Module contains a one-liter pretest chamber and metering valves capable of producing finely tuned drawdowns.





The LFA module monitors oil-based mud contamination by analyzing fluid color and methane content to ensure quality fluid sampling. Color and methane curves indicate the percentage of fluid contamination.



Fluid identification example

The purpose of fluid sampling is to obtain a representative sample of the virgin reservoir fluid. To obtain the sample, the unwanted fluid must be discarded prior to collecting the formation fluid sample. There also must be a method to analyze and determine the nature of the fluid in real time. The MDT tool with the pump-out module, LFA module and the flow-line resistivity measurement identifies and collects high-quality reservoir fluid samples suitable for further laboratory analysis.

Flowline resistivity measurements taken by the probe module help discriminate between formation fluids and filtrate from water- and oil-base muds. Equipping the MDT tool with a pump-out module makes it possible to sample fluid, while monitoring the flowline resistivity, by pumping filtrate-contaminated fluid into the mud column. Fluid removed from the formation is excluded from the sample chamber until an uncontaminated sample can be recovered.

MDT Specifications	
Single-probe configuration	
OD	4.75 in. [120.6 mm]
Min hole size	5⅞ in. [149. 2 mm]†
Max without kits	14.25 in. [361.5 mm]
Max with kits	24 in. [610 mm]
Pressure rating	25,000 psi [17,235 kPa]‡
Max temperature rating	400°F [205°C]§
Multiprobe tool configuration	
OD	6.00 in. [152.4 mm]
Min hole size	7.62 in. [193.6 mm]
Max without kit	13.75 in. [336.5 mm]
Max with kit	15.00 in. [381.00 mm]
Max pressure rating	25,000 psi [17,235 kPa]
Max temperature rating	400°F [205°C]
Dual-packer configuration	
OD	5.00 to 10.00 in. [127.0 to 254 mm]††
Min hole size	5⅞ in. [149.2 mm]††
Max hole size	14.75 in. [374.6 mm]††
Pressure rating	25,000 psi [17,235 kPa]
Max temperature rating	325°F [163°C]††
LFA module	
OD	4.75 in. [120.6 mm]
Length	5.83 ft [1.7 m]
Weight	161 lbm [73 kg]
Range	0 to 5 optical density
Accuracy	0.01 optical density
Pressure rating	25,000 psi [17,236 kPa]
Temperature rating	350°F [176°C]

Pressure gauge specifications	
Strain gauge	
Range	0 to 25,000 psi [0 to 17,236 kPa]‡‡
Accuracy	0.10% full scale
Repeatability	0.06% full scale
Resolution	0.1 psi [0.689 kPa]
Temperature rating	400°F [205°C]‡‡
CQG gauge	
Range	0 to 25,000 psi‡‡
Accuracy	2.0 psi [13.8 kPa]+ 0.01% of reading
Repeatability	< 1.0 psi
Resolution	0.01 psi
Temperature rating	400°F [205°C]‡‡

† If wellbore conditions are favorable, the tool can be run on TLC in holes with an ID as small as 5½ in. [14 cm].

‡ 25,000 psi [172.5 mPa] for the high pressure MDT and 20,000 psi [138 mPa] for the normal MDT tool

§ 350°F [175°C] with some CQG types

†† Functional rating based on the actual packer installed and type of mud used.

‡‡ Actual pressure/temperature combination will depend on specific type of gauge. For the CQG, HCQG-A is rated 175°C/25,000 psi, HCQG-B/D 200°C/18,000 psi or 180°C/20,000 psi and CQG-C/G 175°C/15,000 psi.

Schlumberger

APPENDIX D-3

SCHLUMBERGER DUAL PACKER MODULE SPECIFICATIONS GUIDELINES

Schlumberger

Dual-Packer Module

Inflatable packers that seal against the borehole wall to isolate the interval for MDT tester operations

APPLICATIONS

Used with the MDT* modular formation dynamics tester for

- Downhole fluid analysis (DFA)
- Formation fluid sampling
- Formation pressure measurement and fluid gradient estimation
- Determination of pretest drawdown mobility (permeability/viscosity)
- Permeability and anisotropy determination away from the well
- In situ stress determination

High-performance packers

The Dual-Packer Module (MRPA) of the MDT modular formation dynamics tester consists of two inflatable packer elements that seal against the borehole wall to isolate an interval, improving the effectiveness of pressure measurement and fluid sampling in low-permeability, laminated, or fractured formations.

High-performance packers are run with the MRPA to expand the MDT tester's operating envelope, with a temperature rating to 410 degF [210 degC] and compatibility with both water- and oil-base mud systems. The superior elasticity and improved durability of the high-performance packers enable performing more stations per run and lessen packer replacement. The asymmetrical packer design reduces sticking and bulging potential.

Operational reliability is further enhanced by the autoretract mechanism (ARM), which applies a longitudinal tensile force to assist in retracting the packers after deflation, in turn minimizing drag. At temperatures below 225 degF [107 degC], the elements retain enough elasticity for operation without the ARM.

The MDT Pumpout Module (MRPO) is used to inflate the packers with fluid.

Reliability in high-H_2S environments

For operations in H_2S environments, the Dual-Packer Module is available in a NACE-compliant version for sampling up to 50% H_2S in hole sizes from 5⅞ to 9⅝ in.

Effective isolation of large areas

The length of the test interval between the packers is 3.2 ft [0.98 m] and can be extended to 5.2, 8.2, or 11.2 ft [1.58, 2.5, or 3.41 m] by using 2- and 3-ft [0.61- and 0.91-m] spacers with large-diameter mandrels. For the 3.2-ft interval, the area of the isolated interval of the borehole is about 3,000 times larger than the area of the borehole wall isolated by the MDT tester's Single-Probe Module (MRPS). For fluid sampling, the large area results in flowing pressures that are only slightly below the reservoir pressure, which avoids phase separation even for pressure-sensitive fluids such as gas condensates or volatile oils. In low-permeability formations, high drawdown usually occurs with the probe, whereas fluid can be withdrawn from the formation using the MRPA with minimum pressure drop through the larger flowing area. In finely laminated formations, the MRPA can be used to straddle permeable streaks that would be difficult to locate with a probe. In fractured formations, the MRPA can usually seal the interval whereas a probe could not.

Dual-Packer Module.

Dual-Packer Module

For pressure transient testing, following a large-volume flow from the formation, the resulting pressure buildup has a radius of investigation of 50 to 80 ft [15 to 24 m]. Depending on the application, an interval pressure transient test (IPTT) provides advantages over a conventional drillstem test (DST). It is environmentally friendly because no fluids flow to the surface, and it is cost effective because many zones can be tested in a short time.

The MRPA can be used to create a micro-hydraulic fracture that can be pressure tested to determine the minimum in situ stress magnitude. The fracture is created by pumping wellbore fluid into the interval between the inflatable packer elements.

Measurement Specifications	
	MRPA
Range of measurement	CQG* crystal quartz gauge: 750 to 15,000 psi [5 to 103 MPa]
	Quartzdyne® gauge: 0 to 25,000 psi [0 to 172 MPa]
	Axton* dynamically compensated single quartz gauge: 0 to 30,000 psi [207 MPa] to 374 degF [190 degC] and 0 to 20,000 psi [138 MPa] to 392 degF [200 degC]†
	Temperature: –67 to 400 degF [–55 to 204 degC]
Resolution	CQG gauge: 0.008 psi [55 Pa] at 1.3-s gate time
	Quartzdyne gauge: 0.01 psi/s [69 Pa/s]
	Axton gauge: 0.008-psi [55-Pa] rms at 1-s gate time
	Temperature: 0.01 degF [0.05 degC]
Accuracy	CQG gauge: ±(2 psi [13,789 Pa] + 0.01% of reading)‡
	Quartzdyne gauge: ±(0.02% of full scale + 0.01% of reading)
	Axton gauge: ±2.0 psi [±13,689 Pa] for typical HPHT operational range (>212 degF [>100 degC] and >15,000 psi [>103 MPa]) and ±6.0 psi [±41,368 Pa] for full range‡
	Temperature: ±1.0 degF [±0.5 degC]

† Operating range up to 400 degF and default calibration to 392 degF with calibration to higher temperature on requries.
‡ Includes fitting error, hysteresis, repeatability, and allowance for sensor aging; the corresponding percentages of the pressure reading account for the incertitude of the calibration equipment.

Dual-Packer Module Packers Mechanical Specifications

Packer	Outside Diameter, in [cm]	Hole Size—Min., in	Hole Size—Max., in	Temperature Rating, degF [degC]	Pressure Rating, psi [MPa]	Differential Pressure Rating, psi [MPa]	Type	Recommended Number of Settings†
SIP-A3-5in	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	4,500 [31]	Symmetrical	10 settings at 3,000 psi in 6-in hole
SIP-A3A-5in	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	4,500 [31]	Asymmetrical	10 settings at 3,000 psi in 6-in hole
IPCF-H2S-500	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	TBQ‡	Asymmetrical	TBQ‡
SIP-A3-6.75in	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Symmetrical	10 settings at 3,000 psi in 8.75-in hole
SIP-A3A-6.75in	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.75-in hole
IPCF-PAS-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Symmetrical	10 settings at 3,000 psi in 8.5-in hole
IPCF-PA-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.5-in hole
IPCF-PC-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	4,500 [31]	Asymmetrical	5 settings at 4,500 psi in 8.5-in hole
IPCF-BA-700	7 [17.78]	7.875	9.625	410 [210]	20,000 [138]	3,000 [21]	Asymmetrical	3 settings at 3,000 psi in 8.5-in hole
IPCF-H2S-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.5-in hole
SIP-A3A-8.5in	8.5 [21.59]	9.875	14	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 12.25-in hole
SIP-A3A-10in	10 [25.40]	11	17.5	350 [177]	20,000 [138]	2,100 [14]	Asymmetrical	7 settings at 2,100 psi in 14.4-in hole

† At the specified pressure and hole size
‡ To be qualified

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APPENDIX D-4

SCHLUMBERGER SATURN 3D RADIAL PROBE

Schlumberger

Saturn

3D radial probe

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.

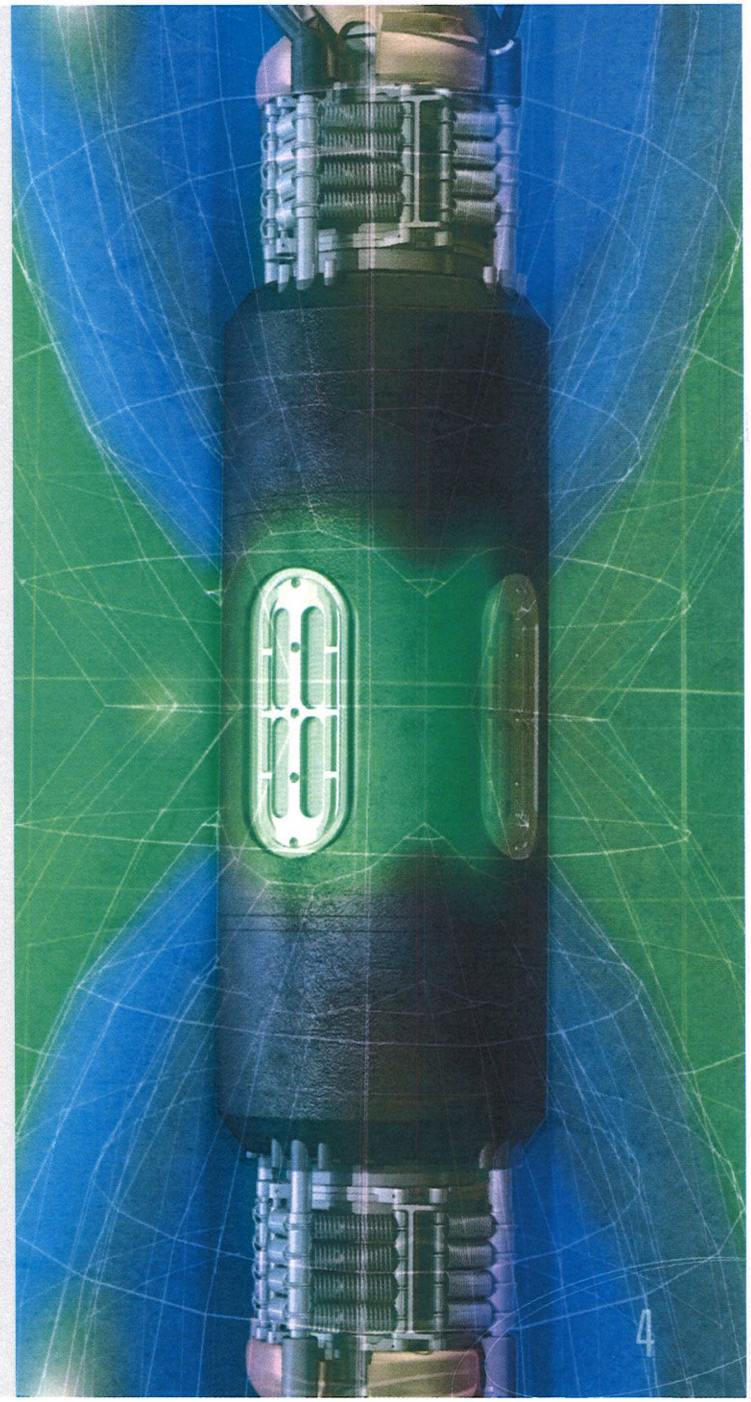
$$q = \frac{k A dP}{\mu L}$$

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.

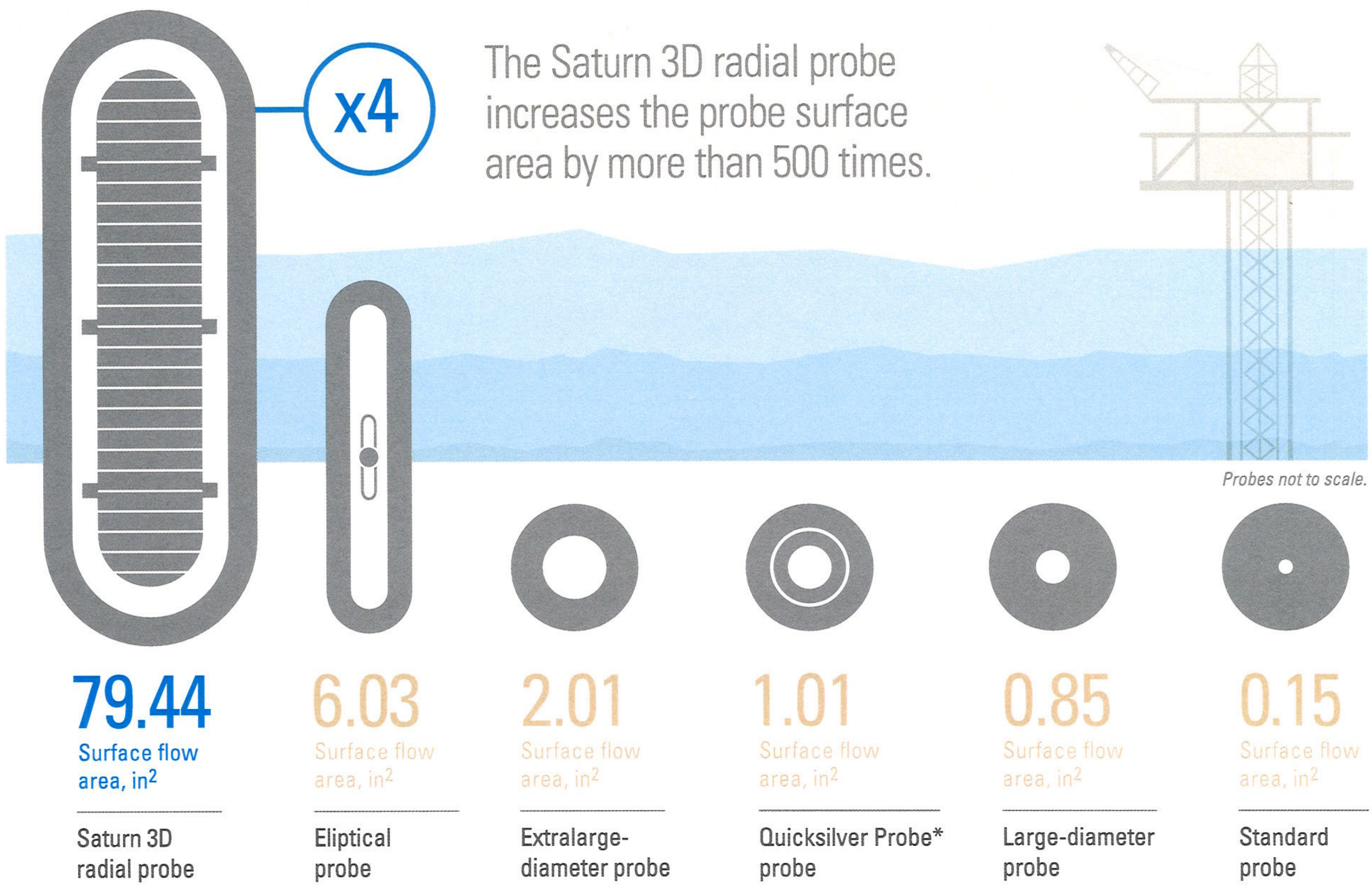
Different probe surface flow areas and the maximum pressure drawdowns that the formation tester can manage are used depending on the formation permeability and fluid viscosity. Typically, the larger the surface area and the higher the maximum drawdown pressure, the higher the flow rate of fluid from 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.

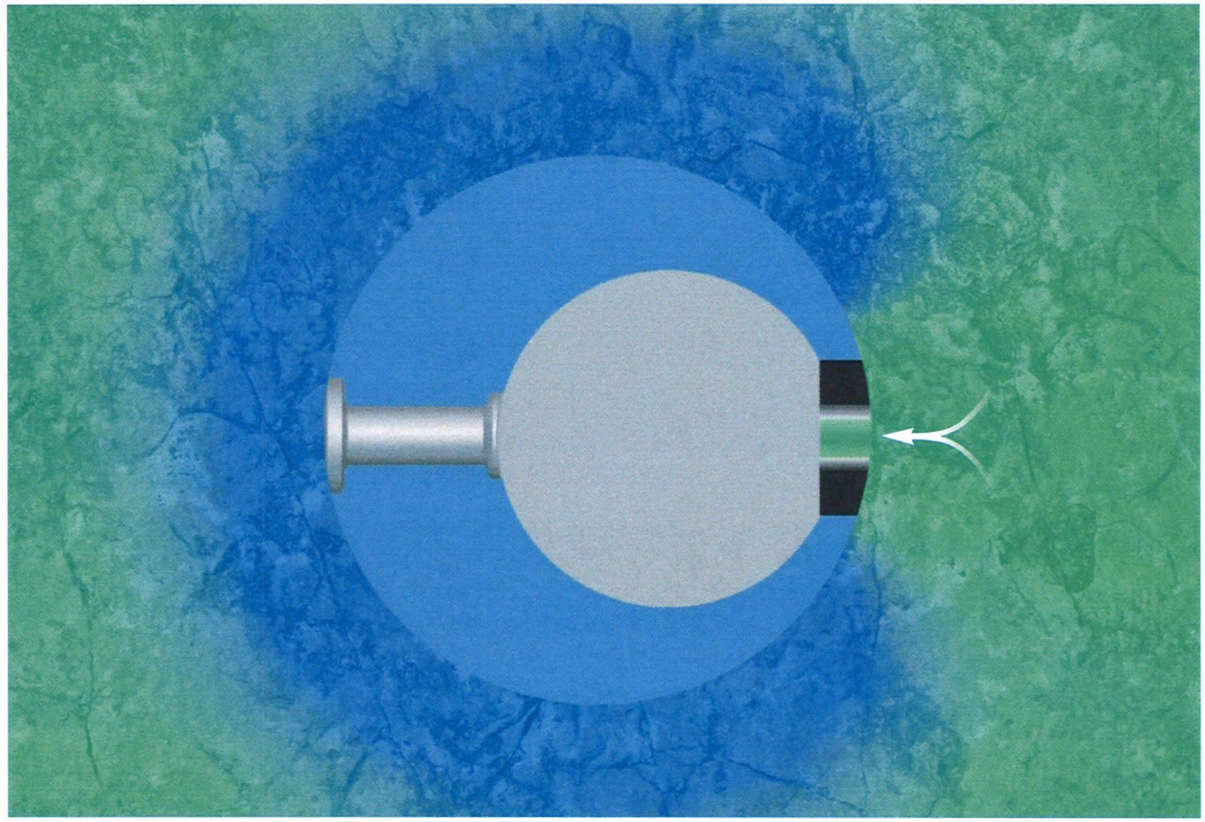
Reliably out of the hole, every time

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.

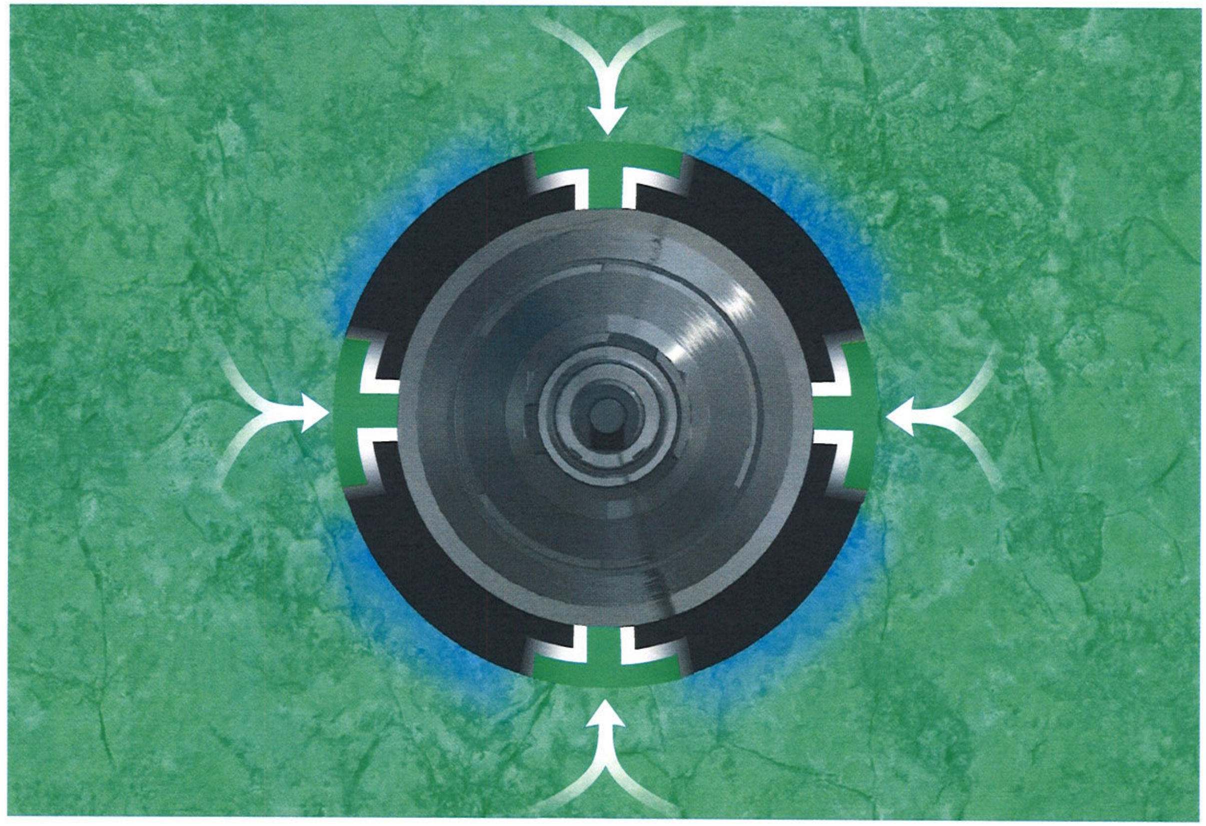
Flow fluid in three dimensions

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.



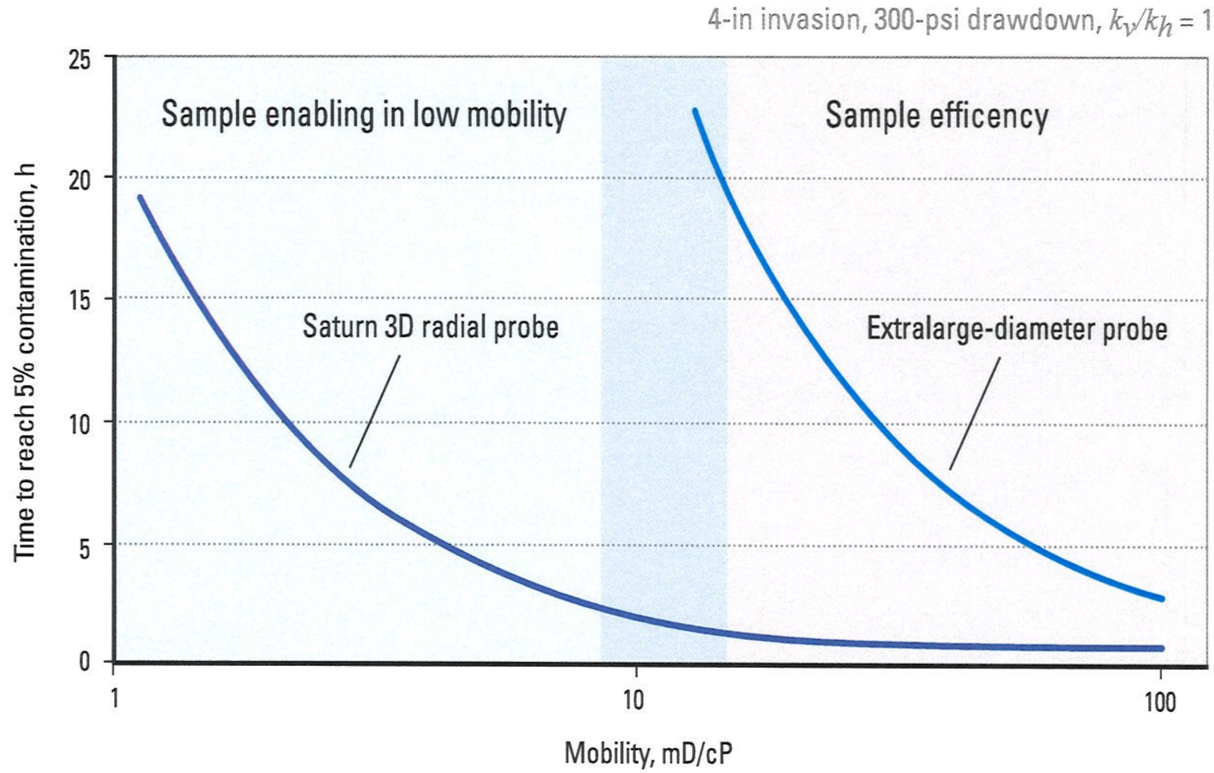
The four Saturn probes efficiently establish circumferential flow from the formation to quickly remove filtrate-contaminated fluid and flow uncontaminated, representative fluid for DFA, sampling, and pressure measurements.

Sealing with confidence

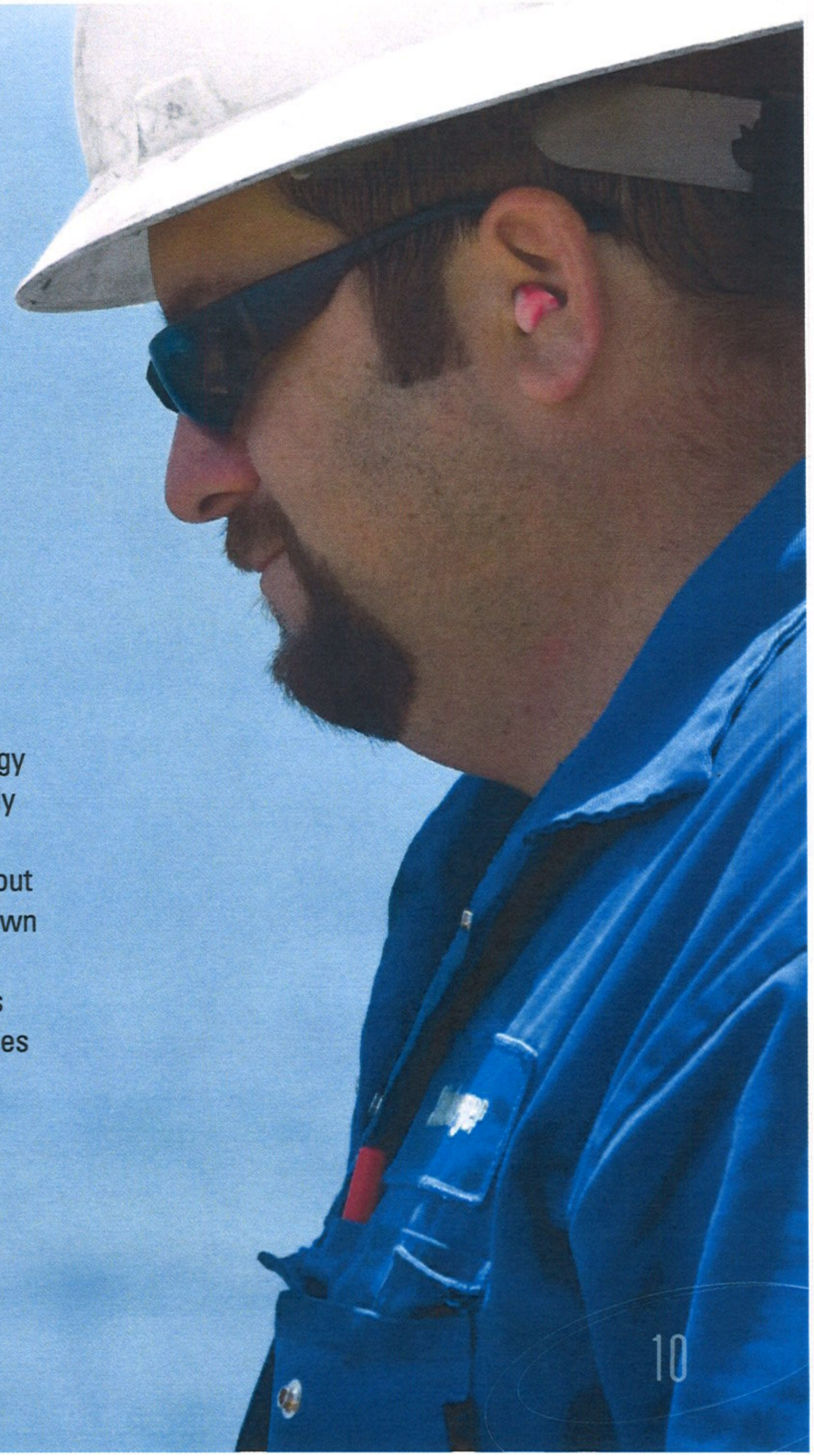
Unlike the packer incorporated in a conventional probe assembly or operations using a dual straddle packer in the testing string, the Saturn probes self-seal with suction to the borehole wall to receive direct flow from the formation with faster cleanup.

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.



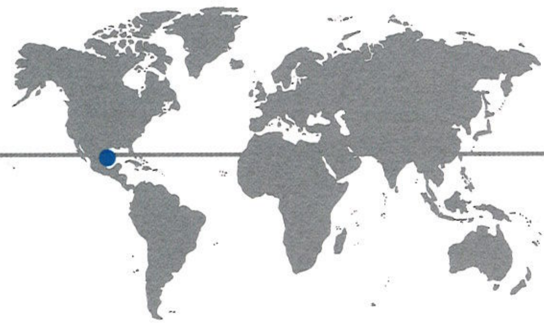
Complete pressure surveys in low-mobility formations

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.

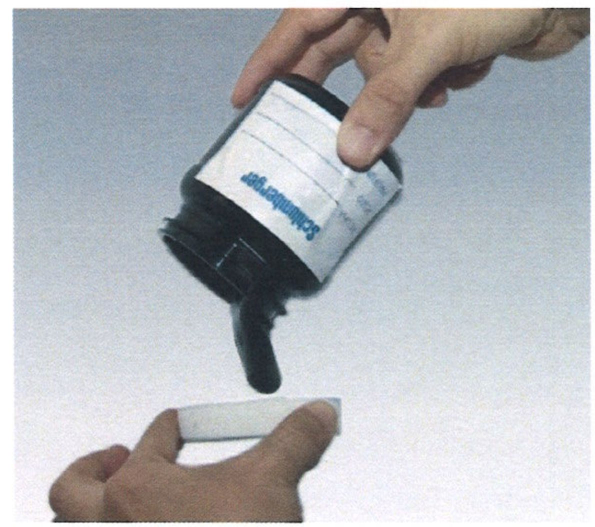
Each self-sealing Saturn probe incorporates a filter to capture any dislodged matrix and prevent plugging.

If sand grains were drawn in with the flowing fluid, the Saturn drain assembly incorporates individual probe filters to prevent flowline plugging.

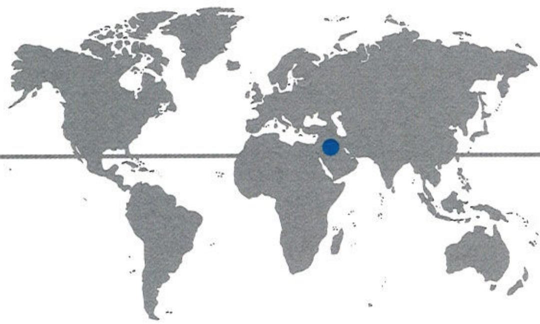
The Saturn 3D radial probe was deployed in the field to test and sample at multiple stations in several wells, which have up to 12% ovalization. Whereas conventional probes commonly experienced lost seals in the rugose holes, the Saturn self-sealing probes maintained seal integrity to support the borehole 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.



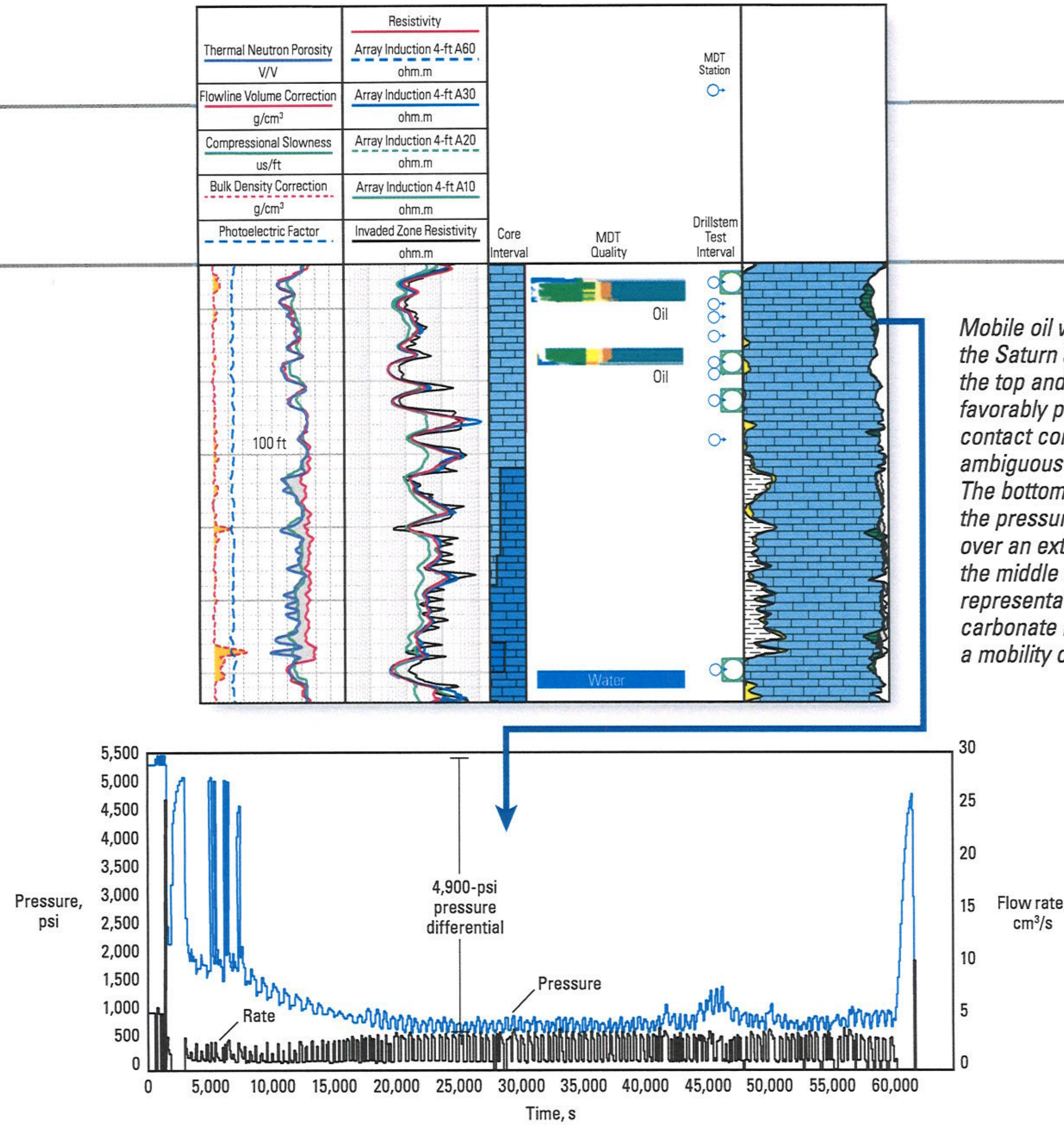
Saturn probe delineates low-mobility oil zone in carbonate reservoir

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.

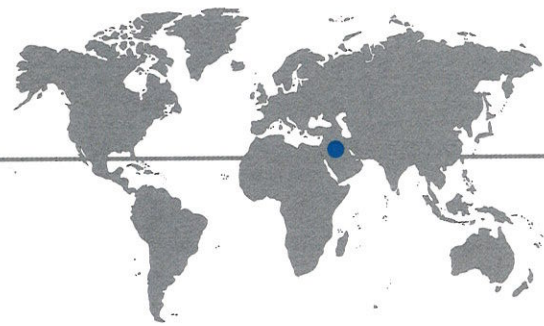
Extensive pumpout by the Saturn probe confirmed light oil in the top zone through DFA. A radial flow regime was established with an estimated horizontal permeability of approximately 1 mD. The station in the bottom zone yielded water and had a similar permeability.

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

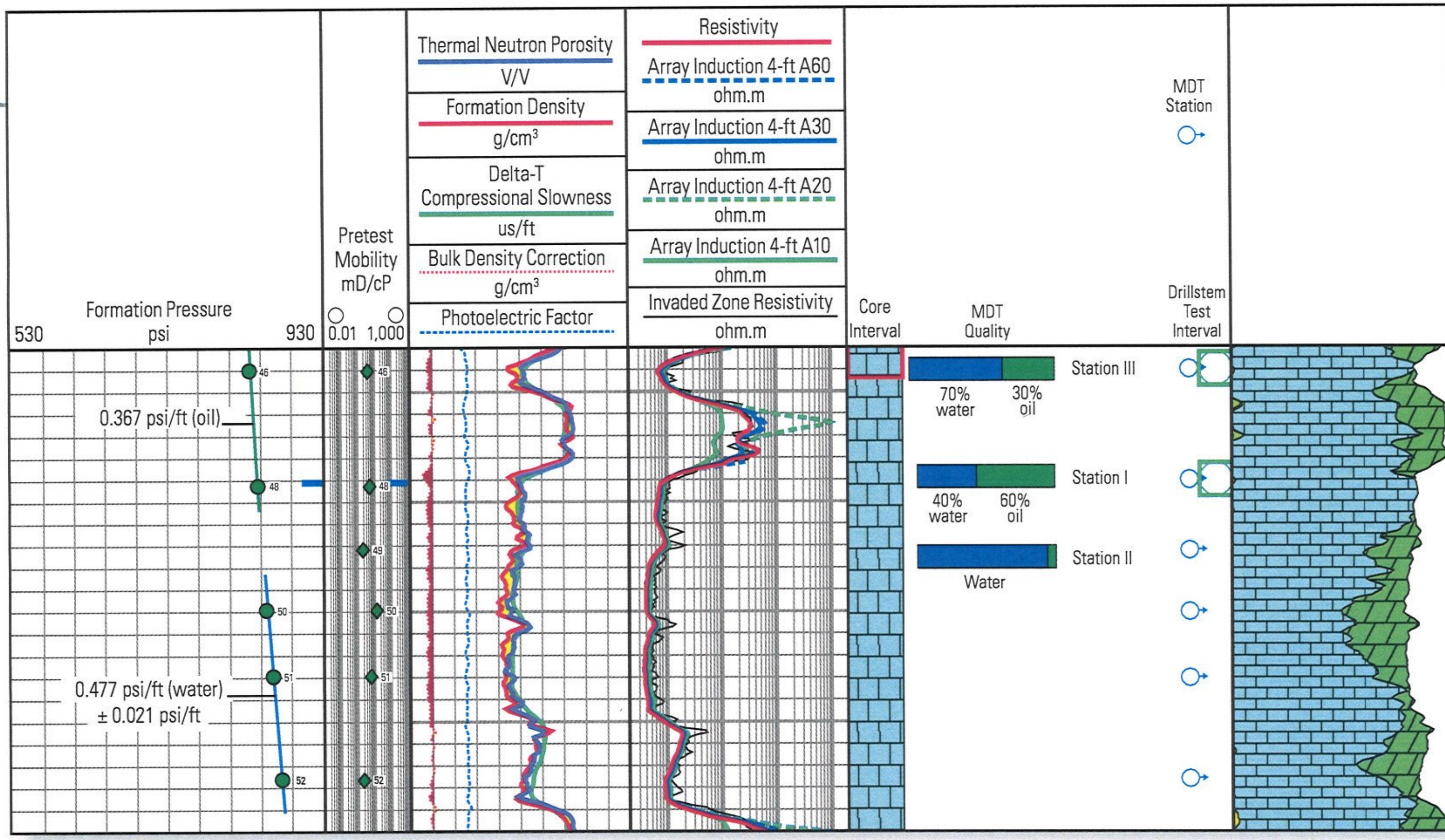


650% faster flow rate efficiently acquires fluids from dolomite

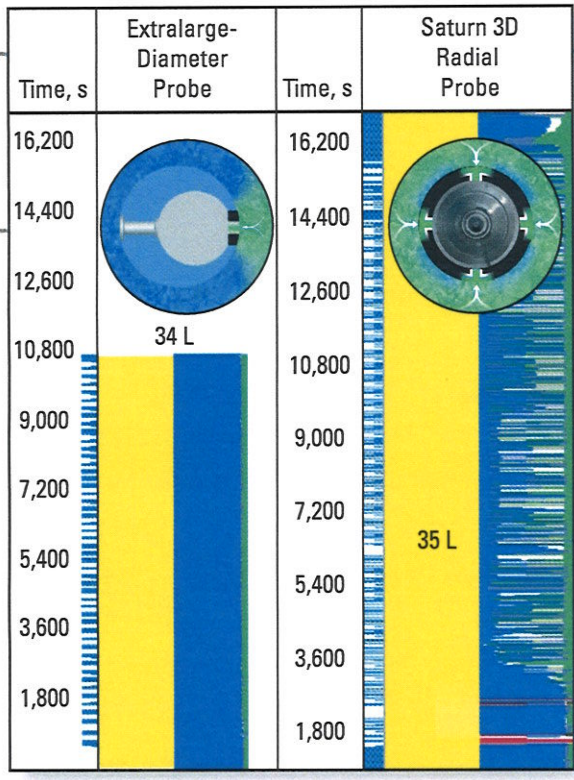
The openhole logs from a dolomitic limestone interval drilled with saline water-base mud in the Middle East did not indicate the presence of hydrocarbon, but the analysis was ambiguous because some zones had resistivity values as low as 0.7 ohm.m. The operator wanted to conduct DFA and collect samples 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.

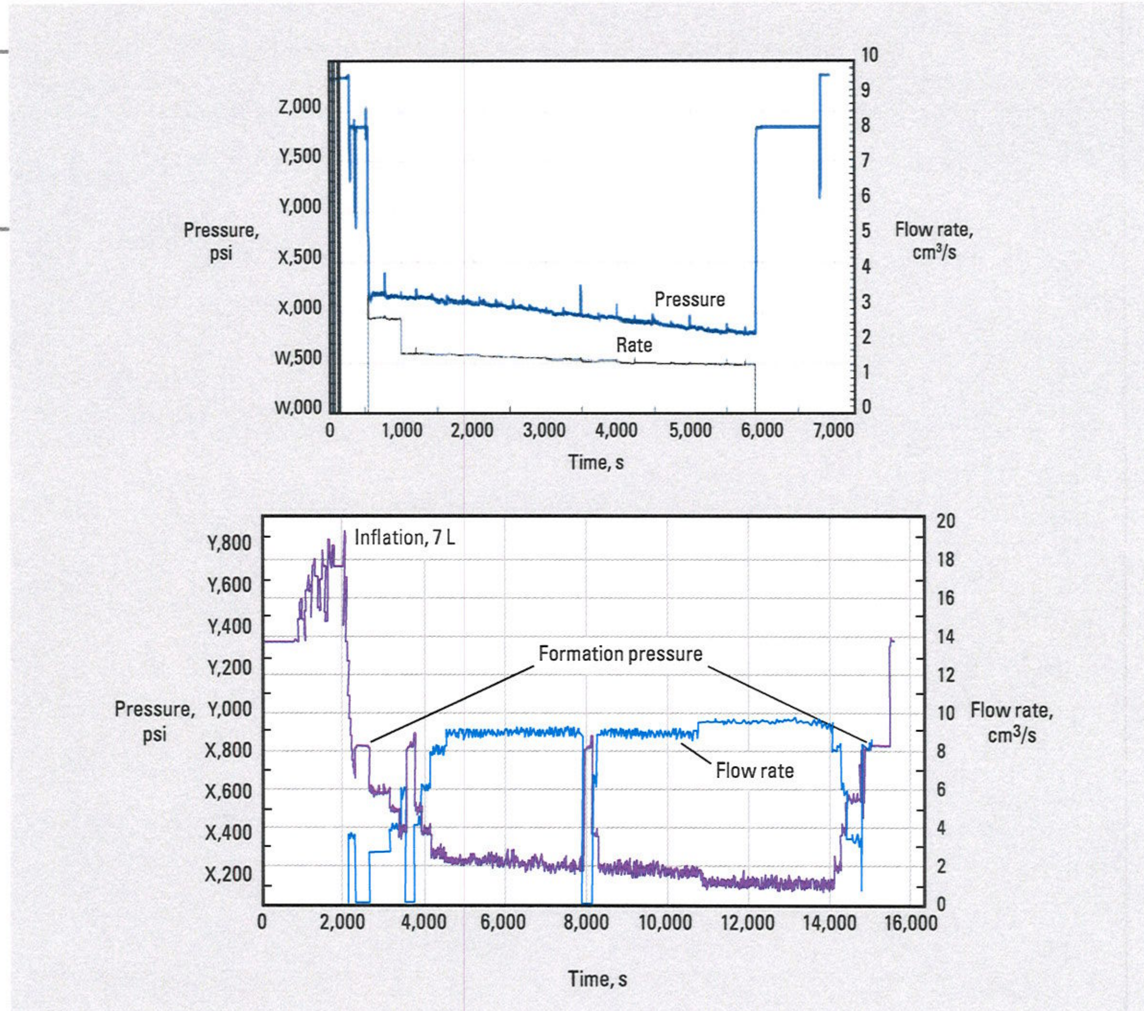
After DFA at Station I clearly identified 60%–70% oil, Station II was selected for determining the lowest mobile oil. The initial sampling attempt with the extralarge-diameter probe experienced a significant pressure drop, with 2,000-psi drawdown and a low flow rate of 5.2 L/h. The resulting pretest 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]

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APPENDIX E

RISK ASSESSMENT EMERGENCY REMEDIAL AND RESPONSE

Stage	Risk	Description	Severity	Likelihood	Monitoring	Control in Place	Potential Response Actions	Response Personnel
Construction Period	Well control event while drilling or completing the well with loss of containment.	This event could occur during drilling and completion operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well suddenly.	Serious	Unlikely	* Flow sensor. * Pressure sensor. * Tank level indicator. * Tripping displacement practices. * Mud weight control.	* Blowout prevention (BOP) equipment. * Kill fluid. * Well control training. * BOP testing protocol. * Kick drill. * Lubricators for wireline operations.	Drilling: * Stop operation. * Close BOP. * Clear floor and secure area. * Execute well control procedure. * Evaluate drilling parameters to identify root cause. * Continue operations. Completion: * Stop operations. * Close BOP. * Clear floor and secure area. * Execute well control procedure. * Continue operations.	* Rig crew * Rig manager * Field superintendent * Project manager
Construction Period	Movement of brine between formations during drilling.	This event could occur if, while drilling the injection target, there is cross flow, with losses into the USDW.	Minor	Unlikely	* Tank level sensor. * Mud lab test. * Pressure sensors. * Flow sensors. * Tripping sheets.	* USDW will be covered with the surface casing and set in Pierre Formation. * Casing test after cementing surface casing to check integrity. * FIT test to verify shoe integrity. * Mud used in surface casing are based on fresh water and clays. * CBL to check cement bonding.	* Stop drilling. * Check well level to detect a lost circulation or influx. * In case of losses, treat the well with lost circulation material, and evaluate mud weight and drilling parameters. * In case of influx, control the well, without compromising the shoe integrity. * In case shoe is identified as leaking, squeeze to regain integrity. * In case surface casing shows a leak, squeeze or install a casing patch.	* Rig crew * Rig manager * Field superintendent
Injection Period	Loss of mechanical integrity injection wells – tubing/packer leak	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause communication of formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario.	Serious	Likely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * Annular pressure test * CO_2 leak sensors on the wellhead	* Coated tubing. * Inhibited packer fluid in annular. * Corrosion monitoring plan. * Dry CO_2 injected. * Nickel-plated packers. * FF trim tubing hanger and tree. * CR tubing tailpipes below packers. * CR or Inconel carrier for the sensors. * New tubing.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * If tubing leak is detected, discuss with regulator the action plan based on the finding. * Schedule well service to repair tubing.	* Operation engineer * Field superintendent * Project manager
Injection Period Postinjection	Loss of mechanical integrity monitoring wells – tubing/packer leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause a communication of the formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario. Monitoring wells are designed to be outside of the projected plume for the majority of the project which reduces the risk of contact with CO_2.	Minor	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * Annular pressure test. * CO_2 leak sensors on the wellhead.	* Coated tubing. * Inhibited packer fluid in annular. * Corrosion monitoring plan. * Nickel-plated packers * CR tubing below/between packers. * CR or Inconel carrier for the sensors. * New tubing.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * If tubing leak is detected, discuss with regulator the action plan for well service. * Schedule well service to repair tubing or abandon the well.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors

Injection Period	Loss of mechanical integrity injection wells – casing leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, or others. This event could cause a migration of CO2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	Serious	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * CO_2 leak sensors on the wellhead. * DTS fiber real time alongside the casing. * Flow rate monitoring. * Soil gas probes. * Neutron activated logs. * USDW water monitoring.	* CO_2-resistant cement and metallurgic across injection zone. * Injection through tubing and packer. * Nickel-plated packers. * CR or Inconel carrier sensors. * Inhibited packer fluid in the annular. * Cement to surface. * Corrosion monitoring plan. * CBL/USIT after installation. * New casing and tubing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * If casing leak is detected, discuss with regulator the action plan based on the finding and location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	Loss of mechanical integrity monitoring wells – casing leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others. This event could cause a migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW. Monitoring wells are designed to be outside of the projected plume for the majority of the project which minimizes the risk of contact with CO_2.	Serious	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * CO_2 leak sensors on the wellhead. * Soil gas probes. * Neutron activated logs. * USDW water monitoring.	* CO_2-resistant cement across injection zone. * Nickel-plated packers. * CR or Inconel carrier sensors. * Inhibited packer fluid in the annular. * Cement to surface. * Corrosion monitoring plan. * CBL/USIT after installation. * New casing and tubing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * If casing leak is detected, discuss with regulator the action plan based on the findings and the location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period	LOC: vertical migration via injection wells.	During the life of the injector wells, there are induced stresses and chemical reactions on the tubulars and cement exposed to the CO_2 pressure and plume. Changes in temperature and injection pressure create stresses in the tubulars trying to expand or contract, and it can lead to microannulus effects. The combination of the dry CO_2 injected and the formation brines creates carbonic acid that reacts with the components of the cement to degrade properties such as permeability, strength, porosity, etc., weakening the matrix. These mechanics could lead to cracks, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * DTS fiber real time alongside the casing. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI. * Pressure gauges at surface. * Flow rate monitoring.	* CO_2-resistant cement and metallurgic across injection zone. * Injection through tubing and packer. * Cement to surface. * CBL/USIT after installation. * USDW covered as second barrier with surface casing and surface cement sheet. * New casing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator the action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors

Injection Period Postinjection	LOC: vertical migration via monitoring wells.	During the life of the monitoring wells, there are induced stresses and chemical reactions on the tubulars and cement-exposed brines, pressure plume and, eventually, CO_2. These mechanics could lead to cracks, cement deterioration, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2. Monitoring wells are designed to be outside of the plume for the majority of the injection period.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI. * Pressure gauges at surface.	* CO_2-resistant cement across injection zone. * Cement to surface. * CBL/USIT after installation. * USDW covered as second barrier with surface casing and surface cement sheet. * New casing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	LOC: vertical migration via water disposal well in Inyan Kara.	This scenario could occur if there is a LOC in the CO_2 injector well through poor cement or cracks that could allow movement of carbonic acid into the Inyan Kara Formation. Inyan Kara is the main target for water disposal in the area. If carbonic acid gets in contact with the cement and casing for the water disposal well, corrosion and cement degradation could happen, with a potential path to USDW.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI or tracers. * Pressure gauges at surface.	* Evaluate CO_2-resistant cement through Inyan Kara in the water disposal well. * Validate Class I well will cover USDW to Pierre as well. * Recommended to include water disposal well in corrosion monitoring plan.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop injection. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW and the source of the leak. * If the injector is the source of the leak, follow protocol for LOC in injectors. * In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	LOC: vertical migration via legacy wells and P&A wells.	Brines and CO_2 could migrate through poor cement bonding, cement degradation, or cracking in the cement in P&A wells.	Serious	Unlikely	* Soil gas probes. * CO_2 leak sensors. * 4D seismic survey (AOR review periods).	* Legacy wells are properly abandoned for brine movement because of pressurization of injection zone. * Injectors will be abandoned as soon as CO_2 injection in the HUB ends, except if they are left as monitoring wells.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Evaluate if it's a positive CO_2 release because of a leak in the legacy/P&A well. * Discuss plan with regulator to repair the well, delineate the area, and identify potential resources affected. * Discuss specific remediation actions and monitoring plans. * Execute program, monitor, and evaluate efficacy.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period	LOC: vertical migration due to failure of confining rock, faults, or fractures.	This event can occur if, during injection, the pressurization of the injection zone exceeds the sealing capacity of the cap rock/seal above or if there are features such as fault or fractures that are reactivated. CO_2 and brine could find a leak path to a shallower formation, including USDW.	Serious	Unlikely	* USDW water sampling. * 4D seismic survey. * Neutron activated log in injector and monitoring wells. * Gas soil monitoring.	* Seismic survey in the area shows no faults crossing the storage formation or the seal. * Injection is limited to 90% of frac gradient. * Extensive characterization of the rocks show good sealing capacity. * In case cap rock above Broom Creek fails, Inyan Karan underpressure zone will act as a buffer formation before CO_2 or brines reaching USDW.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop injection. * Assess root cause by reviewing monitoring data. * If required, conduct geophysical survey to delineate potential leak path. * Evaluate if there is a movement of CO_2 or brines to USDW. In the event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with regulator.	* Monitoring staff * Geologist * Reservoir engineer * Project manager * Remediation contractors

Injection Period Postinjection	LOC: lateral migration of CO_2 outside defined AoR.	This event could occur if the CO_2 plume moves faster or in an unexpected pattern and expands beyond the secured pore space for the project and the AoR.	Serious	Unlikely	* 4D seismic. * Neutron activated logs in monitoring wells. * Pressure and temperature gauges real time in monitoring wells.	* Detailed geologic model with stratigraphic wells as calibration. * Seismic survey integrated in the model. * Extensive characterization of the rocks and formation. * AoR review and calibration at least every 5 years. * Monitor the plume until stabilization (min 10 years).	Injection period: * Trigger alarm by monitoring staff. * Review monitoring data and trends, and compare with the simulation. * Discuss with regulatory agency the findings, and request to keep injection process while AoR is reviewed, if the data show that CO_2 will stay in the secured pore space. * Perform logging in monitoring wells. * Conduct geophysical survey as required to evaluate AoR. * Recalibrate model, and simulate new AoR. * Assess if additional corrective actions are needed and if it's required to secure additional pore space. * Assess if any remediation is needed, and discuss action plan with regulatory agency. * Present AoR review to regulatory agency for approval and adjust monitoring plan. Postinjection period: * Trigger alarm by monitoring staff. * Review monitoring data and trends, compare with the simulation. * Discuss findings with regulatory agency. * Conduct geophysical survey as required to evaluate AoR. * Recalibrate model, and simulate new AoR. * Assess if additional corrective actions are needed and if it's required to secure additional pore space. * Assess if any remediation is needed, and discuss action plan with regulatory agency.	* Monitoring staff * Geologist * Reservoir engineers * Project manager
Injection Period	External impact – injector well.	This event could occur if, during injection, the wellhead is hit by a massive object that causes major damages to the equipment. The well gets disconnected from the pipeline and from the shutoff system and leads to a loss of containment of CO_2 and brine.	Major	Unlikely	* Pressure, temperature, and flow sensors in real time. * Field inspections. * OGI cameras.	* Fence location and block direct access to the wellhead. * No populated area. * Doubled lined pads. * Location is able to contain 70.000 bbl, and additional transfer pump and lines are designed to move fluid to the settling ponds southwest of the location.	* Trigger alarm by the system or operations staff. * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional. * If there is injured personnel, call emergency team, and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include but is not limited to capping the well, secure location, drill relief well to kill injector, properly repair or abandon injection well. This plan would be discussed with the regulatory agency. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist

Injection Period Postinjection	External impact – monitoring well.	This event could occur if the wellhead of the deep monitoring well is hit by a massive object that causes major damages leading to a LOC. Since the well is open to the formation pressure at the injection zone, formation fluids have the potential to flow and spill on the location.	Major	Unlikely	* Pressure, temperature, and flow sensors in real time. * Field inspections. * OGI cameras.	* Fence location, and block direct access to the wellhead. * No populated area. * Lined pads. * Reduced pressure in the monitoring well compared with the injector well on bottom.	* Trigger alarm by the system or operations staff. * If there is injured personnel, call emergency team and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include, but is not limited to, capping the well, securing the location, drilling relief well to kill the injector, properly repairing, or abandoning the injection well. This plan would be discussed with the regulatory agency. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist
Injection Period	External impact – pipeline.	This event could occur if, during injection, the CO_2 pipeline is hit, causing major damages and LOC of the CO_2.	Major	Unlikely	* Pressure, temperature, and flowmeter sensors in real time. * Field inspections. * OGI cameras?	* Buried pipe. * Bollards and/or concrete barriers installed to protect aboveground piping at valve stations. * Painting for visibility in varied weather conditions. * Signage along right of way as needed. * One-call 811 program.	* Trigger alarm by the system or operations staff. * If there is injured personnel, call emergency team, and execute evacuation protocol. * Verify CO_2 flow was shut off by the system, or start protocol to stop flow. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Remediation contractors * Emergency teams * Plant manager/contact
Injection Period	Monitoring equipment failure or malfunction.	If there is a failure on the monitoring system/ alarm devices, it could lead to overpressurization of the system or reservoir beyond the design limits, causing potential fracturing of the reservoir, leaks or failure on equipment and tubulars, and damage of the facilities.	Serious	Unlikely	* Real-time monitoring system and redundancy. * Field inspections.	* Preventive maintenance. * Periodic inspections.	* Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Assess mechanical integrity of the system, and propose repair actions if needed. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * If the assessment allows resuming injection safely, discuss plan with the Commission, and get approval. * Repair or replace instrumentation. Calibrate equipment. * Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

Injection Period	Induced seismicity.	This event could occur if pressurization of the reservoir, during injection of CO_2, activates preexisting fault planes and creates a displacement that causes a seismic event. If it's a major event (>2.7 Richter), it could compromise the integrity of the wells, facilities, or pipeline.	Major	Unlikely	* Geophones array in surface to monitor induced seismicity. * Geophones/DAS fiber.	* Seismic survey of the storage complex shows no faults that could be reactivated. * A detailed geomechanical model was created to evaluate the storage complex. * The region is seismically stable.	Event < 2.7 Richter: * Trigger alarm by monitoring personnel. * Review monitoring parameters to validate normal operations. If parameters indicate a potential mechanical integrity failure, follow procedure for Event > 2.7 Richter. * Compare storage behavior with the model, and if needed, propose adjustment in operating conditions. Event > 2.7 Richter *Trigger alarm by the system or operations staff. * If there is injured personnel or property damages, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection. * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * Review regional information as well as monitoring records to determine the origin of the event (natural or induced). * If it's an induced event, reevaluate model, define new injection parameters, and get approval from the Commission. * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff
Injection Period Postinjection	Major seismic event.	Major natural seismic event.	Major	Unlikely	* Geophones array in surface to monitor induced seismicity. * Geophones/DAS fiber.	* The region is seismically stable.	Event < 2.7 Richter: * Trigger alarm by monitoring personnel. * Review monitoring parameters to validate normal operations. If parameters indicate a potential mechanical integrity failure, follow procedure for Event > 2.7 Richter. Event > 2.7 Richter *Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection (injection period). * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * Review regional information as well as monitoring records to determine the origin of the event (natural or induced). * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period).	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

Injection Period Postinjection	Other major natural disaster.	This scenario could occur in the event of a natural disaster that limits or endangers the normal operation of the Hub.			n/a	n/a	*Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection. * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

APPENDIX F

CORROSION CONTROL MATRIX

System	Category	Component	Material	Additional Specs	Temperature		Pressure		Flow Rate (MMscfd)		Fluid Composition	
					Surface	Downhole	Surface	Downhole	Min	Max	External	Internal
Downhole Equipment	Injection well Broom Creek.	Tubing, nipples, XO.	* L80, coated TK-805 or equiv. * 13CR any tail pipe or tubular potentially exposed to carbonic acid.	Internal connection flush, "corrosion barrier-type."	Ambient 6° to 120°F	Max: 140°F	Max: 1,700 psi.	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Broom Creek.	Casing.	* L80 from surface to min 200 ft above first injection zone. * CR13 across all injection zones.	Premium connection gas sealed.	Ambient 6° to 120°F	Max: 140°F	Max: 1,700 psi.	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* CO_2-resistant cement across injection zone and min 200 ft above the seal formation. * Conventional cement above seal formation to surface.	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * CO_2 Tundra spec. from injection packer to perforations. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Broom Creek.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event
Downhole Equipment	Injection well Broom Creek.	Electric cable for the gauges.	* Inconel.	n/a	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut in event in tail pipes during shut in event	n/a
Downhole Equipment	Injection well Broom Creek.	Packers.	* Nickel-plated. * Hydrogenated nitrile rubber (HNBR), rapid gas decompression (RGD) with 90 D hardness.	Validate with provider.	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* Packer fluid (corrosion inhibitor additive), above packer. * CO_2 Tundra spec. below packer. * Potential CO_2 mixed with formation brine below packer.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine when shut in.
Downhole Equipment	Injection well Broom Creek.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	1,700 psi.	n/a	50	150	Ambient air.	n/a
Downhole Equipment	Injection well Broom Creek.	Tree and tubing hanger.	* CC or FF trim.	n/a	Min: 6°F Max: 120°F	n/a	1,700 psi.	n/a	50	150	Ambient air.	* CO_2 Tundra spec.
Downhole Equipment	Injection well Deadwood.	Tubing, nipples, XO.	* L80, coated TK-805 or equiv.	Internal connection flush, corrosion barrier-type.	Min: 6°F Max: 120°F	Max: 190°F	Max: 2,800 psi.	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	Casing.	* L80 from surface min to 200 ft above first injection zone. * CR13 across all injection zones. * L80 between injection zones.	Premium connection gas sealed.	Min: 6°F Max: 120°F	Max: 190°F	Max: 2,800 psi.	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* CO_2-resistant cement across all injection zone and min 200 ft above the seal. * Conventional cement above seal formation to surface.	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * CO_2 Tundra spec. from injection packer to perforations. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	Electric cable.	* Inconel.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in tail pipes during shut-in event.	n/a
Downhole Equipment	Injection well Deadwood.	Packers.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* Packer fluid (corrosion inhibitor additive), above packer. * CO_2 Tundra spec. below packer. * Potential CO_2 mixed with formation brine below packer.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine when shut in.
Downhole Equipment	Injection well Deadwood.	Tapered long string hanger.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	Validate with provider.	n/a	Max: 190°F	n/a	Max: 5800 psi. Assuming 0.3 psi/ft fluid and 2800 psi max on surface.	n/a	n/a	* CO_2-resistant cement	* Packer fluid (corrosion inhibitor additive).
Downhole Equipment	Injection well Deadwood.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	2800 psi	n/a	50	100	Ambient air.	n/a
Downhole Equipment	Injection well Deadwood.	Tree and tubing hanger.	* CC or FF trim.	n/a	Min: 6°F Max: 120°F	n/a	2800 psi	n/a	50	100	Ambient air.	* CO_2 Tundra spec.
Downhole Equipment	In-zone monitoring well.	Tubing.	* L80. * 13CR between packers in open zones.	Premium connection gas-sealed.	Min: 6°F Max: 120°F	Max: 190°F	n/a	Max: 5800 psi. Assuming 0.3 psi/ft fluid and 2800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Formation brine between packers in monitoring zone. Once CO_2 breakthrough, CO_2 + formation brines.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Casing.	* L80 from surface to 200 ft from injection zones. * CR injection zones.	Premium connection gas-sealed.	Min: 6°F Max: 120°F	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* CO_2-resistant cement across all injection zone and min 200 ft above the seal. * Conventional cement above seal formation to surface.	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.
Downhole Equipment	In-zone monitoring well.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Electric cable.	* Inconel.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	n/a
Downhole Equipment	In-zone monitoring well.	Packers.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	Validate with provider.	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	2,800 psi.	n/a	n/a	n/a	Ambient air.	n/a
Downhole Equipment	In-zone monitoring well.	Tree and tubing hanger.	* Carbon or low-alloy steel	n/a	Min: 6°F Max: 120°F	n/a	2,800 psi.	n/a	n/a	n/a	Ambient air.	n/a

System	Category	Component	Material	Additional Specs	Temperature		Pressure		Flow Rate (MMscfd)		Fluid Composition	
CO_2 Pipeline – Minimum Burial Depth 48"	Pipeline.	Pipeline.	API 5L	14–16 mil fusion. Bond epoxy external coating.	Min: 0°F; Max: 120°F		1,800 psig.		224		Ground.	*CO_2 Tundra spec.
CO_2 Pipeline – Surface	Pipeline.	Pipeline.	API 5L	Painted.	Min: −50°F; Max: 120°F		1,800 psig.		224		Ambient air.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Surface piping.	API 5L	Painted.	Min: −50°F; Max: 120°F		1,800 psig.		224		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Valves.	Carbon steel body x stainless steel or ENP carbon steel internals.	Soft seats; CO_2-compatible materials.	Min: −50°F; Max: 120°F		1,800 psig.		156 (each well total flow)		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Instrumentation.	Stainless steel x stainless steel 2" isolating valving (WOG3000); in-line instrumentation per piping specification.		Varied.	Varied.	1,800 psig.		Varied		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection pressure gauge.			Min: 6°F; Max: 120°F		Design pressure: 1,800 psig. Analog gauge operating range: 1,500–3,000 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection rate meter.	Carbon steel body x stainless steel internals.	Senior orifice meter.	Min: 6°F; Max: 120°F		1,800 psig.		50–160 (each well flow range)		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection temperature gauge.			Operating range: −40°–200°F.				n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra Spec
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Emergency shutdown valve.	Carbon steel body x stainless steel internals.	Soft seats; CO_2-compatible materials.	Min: 6°F; Max: 120°F		1,800 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Surface piping.	API 5L	Painted.	Min: −50°F; Max: 120°F		3,500 psig.		68		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Valves.	Carbon steel body x stainless steel or ENP carbon steel internals.	Soft seats; CO_2-compatible materials.	Min: −50°F; Max: 120°F		3,500 psig.		68		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Instrumentation.	Stainless steel x stainless steel 2" isolating valving (WOG3000); in-line instrumentation per piping specification.		Varied.	Varied.	3,500 psig.		Varied.		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection pressure gauge.			Min: 6°F; Max: 120°F		Design pressure: 3,500 psig. Analog gauge operating range: 2,000–4,000 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection rate meter.	Carbon steel body x stainless steel internals.	Senior orifice meter.	Min: 6°F; Max: 120°F		3,500 psig.		30–70		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection temperature gauge.			Operating Range: −40°–200°F				n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Emergency shutdown valve.	Carbon steel body x stainless steel internals.	Soft seats; CO_2-compatible materials.	Min: 6°F Max: 120°F		3,500 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.

Corrosion Threat Assessment – Damage Mechanism

Corrosion Damage Mechanism Category

		Internal Corrosion Mechanism				External Corrosion				Enviromental Induced Cracking		Mechanical and Metallurgical		
System	Component/ Equipment	CO_2 Corrosion	Deadleg Corrosion	Wet H_2S Corrosion	Microbiological Corrosion	Atmospheric Corrosion	Corrosion under Insulation (CUI)	Soil Corrosion	CO_2 Corrosion	Chloride SCC	Wet H_2S Damage	Erosion	Fatigue	Brittle Fracture
Downhole Equipment	Tubing, nipples, X/O	x							x					
Downhole Equipment	Casing	x							x					
Downhole Equipment	P/T gauges and carriers	x												
Downhole Equipment	Electric cable	x												
Downhole Equipment	Packers	x							x					
Downhole Equipment	Injection well wellhead	x				x								
Downhole Equipment	Injection well tree	x				x								
Downhole Equipment	Injection well tubing hanger	x												
Downhole Equipment	Monitoring well wellhead	x				x								
Downhole Equipment	Monitoring well tree	x				x								
Downhole Equipment	Monitoring well tubing hanger	x												
Downhole Equipment	Tapered long string hanger	x							x					
Surface Piping, Instrumentation, and Pressure Control	Surface piping	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Valves	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Instrumentation	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection pressure gauge	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection rate meter	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection temperature gauge	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Emergency shutdown valve	x					x							x
CO_2 Pipeline – Buried	API-5L line pipe	x						x						
CO_2 Pipeline – Surface	API-5L line Pipe	x				x								

Corrosion Control Program – Corrosion Control Matrix

System	Category	Equipment or Component	Damage Mechanism	Mitigation	Monitoring Activity	Location	Frequency	Limits	Consequences	Remedial Action	Remedial Action Responsible Person	Remedial Action Time Limit
Downhole Equipment	Injection Wells	Tubing , Nipples, X/O	CO_2 Corrosion	* Dehydrated CO_2 to 630 ppm of H_2O Injected. * Internal coating applied to the tubing. * CR13 specification for tail pipe below packers. * Inhibited packer fluid.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Surface.	1. Every 5 years. 2. Quarterly. 3. Real time. 4. Every 5 years.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr and discuss with action plan. 5. Pull tubing and packer scanning . 6. Run casing inspection log. 7. If well has casing integrity , run back completion hydrostesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Casing	CO_2 Corrosion	* CR13 material selected across CO_2 injection zones. * CO_2-resistant cement covering injection zone interval. * Injection though packer and tubing. * Casing cemented to surface. * Continous injection.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. DTS fiber technology. 5. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Casing exterior. 5. Surface.	1. Every 5 years. 2. Quarterly. 3. Real time. 4. Real time. 5. Every 5 years.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If required, propose casing repair program or P&A and discuss with Commission, based on the findings. 8. Once the casing is repaired, run back completion hydrotesting. 9. Perform annular pressure test. 10. Run CIL log through tubing. 11. Perform falloff test. 12. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	P/T Gauges & Carriers	CO_2 Corrosion	* Inconel carriers and quartz gauges. * Packer inhibited fluid in the annular in contact with the tools.	1. Real-time data transfer. 2. Electromagnetic logging. 3. Annular pressure test.	1. n/a 2. Log run through tubing. 3. Surface test.	1. Real time. 2. Annually. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Replace or repair tool.	1. Stop injection. 2. Perform annular pressure test to identify any loss of mechanical integrity in tubing or casing above injection zone. 3. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or aquire the date. 4. If the Commission approves, continue injection while the remedial action is taken. 5. During well service to repair or replace the gauges and carriers, run casing integrity log and pressure test well, inspect tubing, and change any defective equipment on the completion. 6. Identify root cause of failure to take remedial actions, and record the findings in the corrosion management database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.

Downhole Equipment	Injection Wells	Electric Cable	CO_2 Corrosion	* Inconel material * Packer inhibited fluid in the annular in contact with the tools.	* Real-time data transfer.	n/a	* Real time.	* Failure detected.	Replace or repair tool.	1. Troubleshoot the system. 2. Review monitoring data. 3. If the well has integrity , inform Commission within 24 hr, and discuss WO or alternative to replace cable or acquire data. 4. Prepare plan for replacement or repair of the equipment. 5. Upon Commission approval, continue injection and monitor pressure with surface gauges.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.
Downhole Equipment	Injection Wells	Packers	CO_2 Corrosion	* Nickel-plated packers. * Elastomers HNBR (RGD).	1. Pressure and temperature gauges surface and downhole. 2. DST fiber alongside the casing. 3. Annular pressure test.	1. Wellhead and downhole. 2. Casing. 3. Surface test.	1. Real time. 2. Real time. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrostesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Wellhead	CO_2 Corrosion Atmospheric Corrosion	* Wellhead sections are not in contact with CO_2 or formation fluids.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	1. Surface. 2. Surface.	1. Quarterly. 2. Weekly.	* Damage detected.	Replace or repair equipment (potentially the valves).	1. Perfom inspection with wellhead provider. 2. Define replacement or repair procedure.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	n/a
Downhole Equipment	Injection Wells	Tree	CO_2 Corrosion Atmospheric Corrosion	* FF trim selected in the wellhead. * Dry CO_2 injected , no H_2S in the system.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	Surface.	1. Quarterly. 2. Weekly. 3. By manufacturer recommendation.	* Damage or malfunction detected.	Stop injection to replace equipment.	1. Stop injection. 2. Perform inpection by wellhead specialist. 3. Define action plan based on findings.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	To be defined by the procedure and findings.
Downhole Equipment	Injection Wells	Tubing Hanger	CO_2 Corrosion	* FF trim selected in the wellhead. * Dry CO_2 injected, no H_2S in the system.	1. Surface pressure gauges.	1. Surface. 2. Surface.	1. Real time.	* Damage or malfunction detected.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. Actions will depend on the assessment and troubleshooting. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Execute repair. 6. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Tapered Long String Hanger	CO_2 Corrosion	* CO_2-resistant cement. * Inhibited packer fluids above tapered long string. * Top packer seal. * Continuous injection. * Elastomers HNBR (RGD).	1. Corrosion coupons. 2. Pressure and temperature gauges. 3. DTS fiber technology.	1.Installed upstream injection wellhead. 2. Wellhead and on top of the packer. 3. Casing exterior.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If needed, pressure-test the casing with straddle packers. 8. If damage in the tapered long string hanger is detected, prepare workover proposal, and discuss it with the Commission. 9. Once the tapered long string hanger is repaired, run back upper completion hydrotesting. 10. Perform annular pressure test. 11. Run CIL log through tubing. 12. Perform falloff test. 13. Perform root cause analysis, and report	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.

Downhole Equipment	Monitoring Wells	Tubing , Nipples, X/O	CO_2 Corrosion	* CR13 metallurgic for tail pipe below/between packers. * Inhibited packer fluid.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Surface.	1. Annually . 2. Quarterly. 3. Real time. 4. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Trigger alarm from monitoring system/operator. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrotesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back within a year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	Casing	CO_2 Corrosion	* CR13 metallurgic across injection zones. * Inhibited packer fluid in annular above injection zones. * Casing cemented to surface. * Isolated monitoring zone with packer across injection targets.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Run through tubing. 2. Installed upstream injection wellhead. 3. Surface and downhole. 4. Surface.	1. Annually . 2. Quarterly. 3. Real time. 4. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Trigger alarm from monitoring system/ operator. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If required, propose casing repair program or P&A, and discuss with director, based on the findings. 8. Once the casing is repaired, run back completion hydrotesting. 9. Perform annular pressure test. 10. Run CIL log through tubing. 11. Perform root cause analysis and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back within a year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	P/T Gauges & Carriers	CO_2 Corrosion	* Inconel carriers and quartz gauges.	1. Real-time data transfer. 2. Electromagnetic logging. 3. Annular pressure test.	1.n/a 2. Log run through tubing. 3. Surface test.	1. Real time. 2. Annually. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Replace or repair tool.	1. Trigger alarm from monitoring system/ operator. 2. Troubleshoot the well. 3. Perform annular pressure test to identify any loss of mechanical integrity in tubing or casing above packers. 4. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or acquire the date. 6. During well service to repair or replace the gauges and carriers, run electromagnetic integrity log to verify condition of the casing, replace any packer or equipment damaged, and hydrotest tubing. 7. Identify root cause of failure to take preventive actions, and record findings in the corrosion management database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the remediation with the Commission.
Downhole Equipment	Monitoring Wells	Electric Cable	CO_2 Corrosion	* Inconel material. * Packer inhibited fluid in the annular in contact with the tools.	* Real-time data transfer.	n/a	* Real time.	* Failure detected.	Replace or repair tool.	1. Troubleshoot the system. 2. Review monitoring data. 3. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace cable or acquire data. 4. Prepare plan for replacement or repair of the equipment. 5. Upon Commission approval, continue injection and monitor pressure with surface gauges.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.

Downhole Equipment	Monitoring Wells	Packers	CO_2 Corrosion	* Nickel-plated packers. * Elastomers HNBR (RGD).	1. Pressure and temperature gauges surface and downhole. 2. DST fiber alongside the casing. 3. Annular pressure test.	1. Wellhead and downhole. 2. Casing. 3. Surface test.	1. Real time. 2. Real time. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or acquire the data. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrotesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 1 year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	Wellhead / Tree	CO_2 Corrosion Atmospheric Corrosion	* Wellhead and tree section are not in contact with CO_2 or formation fluids.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	1. Surface. 2. Surface. 3. Surface.	1. Quarterly. 2. Weekly. 3. By manufacturer recommendatio.n	* Damage detected.	Replace or repair equipment (potentially the valves).	1. Preform inspection with wellhead provider. 2. Define replacement or repair procedure based on the findings.	1. Field Superintendent. 2. Project Manager. 3. Surface maintenance team.	n/a
CO_2 Pipeline	CO_2 Pipeline	API-5L Line Pipe	CO_2 in the Presence of H_2O	Dehydrate the CO_2 to 630 ppm of H_2O (30 #/MMscf).	1. ILI smart pig the pipeline every 5 years. 2. Annual cathodic protection potential survey. 3. Monitor cathodic protection rectifier monthly. 4.DCVG survey every 5 years (DOT pipeline). 5. Analyze product for H_2O levels above 30 lb/MMscf with shut-off capabilities prior to entering pipelines. 6. Coupon test station near pipeline inlet.	n/a	1. Every 5 years. 2. Annually. 3. Monthly 4. Every 5 years. 5. Continuously. 6. Monthly.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination.	TBD by the severity of the finding on the examination.	Mechanical Integrity (MI) personnel in charge of the pipeline.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility.	1. Surface. 2. Capture facility.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of piping segment, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility.	1. Surface. 2. Capture facility.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of valve, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of the instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2. composition from capture facility. 3. Visual inspection of orifice plate using senior fittings.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Quarterly.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.

Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Testing of valve integrity.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. By manufacturer recommendation.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of valve, depending on severity of examination.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	Corrosion under Insulation (CUI)	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	CUI	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	CUI	*Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	CUI	*Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	CUI	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	CUI	* Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	CUI	* External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of piping depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of valve(s) depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.

Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.		1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of valve depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.

Fluid Specifications

1. CO_2 Spec

Stream Description	Compressed CO_2 Product to Battery Limits
Stream Number	606
Temperature, °F	120
Pressure, psia	1688.7
Components	
Component Flows	Limits
H_2O	632 ppmv
CO_2	99.90%
N_2	163 ppmv
Ar	4 ppmv
O_2	6 ppmv
H_2	0%
SO_2	<1 ppmv
NO_2	< 1ppmv
NO	30 ppmv

APPENDIX G

FINANCIAL ASSURANCE DEMONSTRATION PLAN

Tundra Secure Geologic Storage Site
Financial Assurance Plan
Details of Financial Instruments Provided in Conjunction with Application

SPECIAL-PURPOSE TRUST

This section describes the selection of a trustee for the Tundra SGS Trust Fund, the Trust Agreement, and the financial strength of the trustee. The trust fund will be established prior to first injection and will be designed to meet the requirements of NDAC § 43-05-01-09.1.

The trust fund will be available for emergency and remedial response upon approval of the Class VI permits and, after injection ceases, for injection well plugging, postinjection site care, and site closure. The trust funds will be available to the Applicant or to a third party if the Applicant were no longer involved with Tundra SGS site operation.

Applicant sent request to three local, regional, and national banks seeking a statement of qualifications for the management of an irrevocable trust to meet Tundra SGS obligations for injection well plugging and postinjection site care and site closure. The Applicant provided the trustee requirements and specifications that prospective trustees must meet and provided the draft Trust Agreement attached hereto as Appendix G-1. Expressions of interest were due to Applicant February 15, 2021.

On March 8, 2021, the Applicant sent a formal Request for Proposal to two banks that had expressed interest in serving as the trustee for the Tundra SGS Trust Fund. Applicant selected Bank of North Dakota (BND) based upon its experience, expertise, and overall approach and responsiveness.

BND provides corporate trust services for the state of North Dakota and its political subdivisions. Services include trustee, escrow agent, paying agent, bond registrar, and transfer agent. BND monitors compliance with financing documents, oversees reporting requirements, invests fund balance, receives and disburses funds, reconciles accounts, and maintains proper records. BND will provide monthly transaction and balance sheet reports, and annual valuations of the account will be completed.

BND has a Compliance Officer who monitors regulations and assists with implementation of new requirements. In addition, Internal Audit staff provide periodic reviews of the Trust Services to ensure adherence to policies and procedures.

Strength of the Trustee

BND maintains a Standard & Poor's long-term A+ and short-term A-1 credit rating. The Trust department currently has over $2 billion under management.

Trust Agreement

The trust fund will be funded in a phased approach to account for the fact that certain covered activities will not be incurred until shortly before authorization of operation is received. For example, resources to cover the cost of activities like emergency remedial response and postinjection site care will not need to be covered until closer to when injection begins. The Applicant is providing financial responsibility for the cost of plugging injection wells, postinjection site care, site closure, and emergency and remedial response via a trust fund valued at $19,824,000.00 and established through the attached Trust Agreement which BND has expressed willingness to accept all recommended terms.

Payment Schedule

The payment schedule for Trust funds commences upon approval of the Class VI permit to operate. Commercial insurance will be bound upon approval of drilling contractor for injection wellbores and is not included in this section.

Initial funding for Trust, in the amount of $2.12 million, representing potential exposure for emergency and remedial response actions, shall be placed into the Trust upon approval of the Class VI permit to operate.

Subsequent funding of the Trust, in the amount of $17.704 million, representing obligations for injection well plugging and postinjection site care and site closure, shall be placed into the Trust in equal installments over a period of seven (7) years commencing on the anniversary of the date of first injection.

Pay-In Periods

The following table provides the pay-in periods for the funding of the Trust. Amounts after initial pay-in are subject to annual review and reporting for continuing validation of estimated costs and underlying assumptions.

Funding	Activities	Costs ($000)	Amount to Be Added Before End of Phase ($000)
Preinjection (within 7 days of operating permit issuance)	Emergency and Remedial Response	$5,960	$2,120
	AOR and Corrective Action	$0	
Injection (seven (7) equal installments at least 7 days prior to successive anniversaries of operating permit issuance)	Plugging Injection and Monitoring Wells	$2,025	$17,704
	Emergency and Remedial Response	$3,840	
	Postinjection Site Care (includes monitoring)	$10,285	
	Closure	$1,554	
		Total Fund	**$19,824**

COMMERCIAL INSURANCE

This section describes the manner in which the Applicant will select a third-party insurer, develop an insurance estimate, obtain proof of insurance, and confirm the financial strength of the insurer.

The Applicant has procured the services of Marsh McLennan Companies.

The Applicant intends to secure third-party insurance to cover the potential need to undertake emergency and remedial response actions to protect USDWs in the AOR. Although the Applicant has been able to obtain information about the possible terms, conditions, and cost of such a policy, the Applicant has not yet applied for such a policy. This section and accompanying market assessment describe the type of coverage that the Applicant expects to obtain from a third-party insurer, including protective conditions of coverage (cancellation, renewal, and continuation provisions). Additional information about deductions, exceptions, and the premium to be paid is also provided in the attached Appendix G-2 Market Assessment.

Coverage Limits

The greatest exposure would be an acute upward migration through the CO_2 injection well, which would have an estimated cost of $16,560,000.00 for emergency and remedial response actions, and such coverage would be an amount sufficient to cover the amounts identified in the endangerment of USDWs. The coverage limit will not be lower than the estimated amount to be covered by Commercial Insurance, $10,600,000.00, as found in Section 4.0, Table 4-14, and may be acquired at a higher limit based upon assessment of available insurance products and market capacity.

Premium

These are only estimates; the premium will be determined based on information provided to the underwriter prior to a cost quotation.

Proof of Insurance

Proof of insurance will be provided when the insurance policy is obtained, prior to first injection.

Financial Strength of Insurer

The financial strength of the insurer will be an important component of the Applicant's selection of an insurer. Information regarding the insurer's financial strength will be provided to the Commission when the insurer is selected.

APPENDIX G-1

STANDBY TRUST AGREEMENT

APPENDIX G-1
STANDBY TRUST AGREEMENT

THIS TRUST AGREEMENT (the "Agreement") is entered into as of _______________ by and between Minnkota Power Cooperative, Inc. (MPC), owner or operator, a corporation (the "Grantor"), and Bank of North Dakota (the "Trustee"), a bank duly organized and existing under the laws of the State of North Dakota.

WHEREAS, the North Dakota Industrial Commission (Commission), an agency of the State of North Dakota, has established authority to administer certain regulations pursuant to the US Environmental Protection Agency's Class VI Underground Injection Control Program (UIC). The Commission's regulations, applicable to the Grantor, require that an owner or operator of an injection well shall provide assurance that funds will be available when needed for corrective actions, injection well plugging, post-injection site care and site closure, and emergency and remedial response during the operation of carbon dioxide (CO_2) geologic sequestration injection wells;

WHEREAS, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facility or facilities identified herein, and;

WHEREAS, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this Agreement, and the Trustee is willing to act as trustee.

NOW THEREFORE, the Grantor and the Trustee agree as follows:

Section 1. Definitions. As used in this Agreement:

A. The term "Grantor" means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor.
B. The term "Trustee" means the Trustee who enters into this Agreement and any successor Trustee.
C. Facility or activity means any "underground injection well" or any other facility or activity that is subject to regulation under the Underground Injection Control Program.
D. "Commission" means the North Dakota Industrial Commission or an authorized representative.
E. "ERR" means emergency and remedial response plan, associated cost estimate and the funded trust property and income apportioned to cover these costs.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a CO_2 Storage Trust Fund (the "Fund") to satisfy the financial responsibility demonstration and storage facility fees under the Class VI Underground Injection Control ("UIC") regulations (N.D.A.C. § 43-05-01-09.1 and N.D.A.C. § 43-05-01-17). This Fund shall remain dormant until funded with the proceeds listed on Schedule C. The Trustee shall have no duties or responsibilities beyond safekeeping this Agreement. Upon funding, this Fund shall become active and be administered pursuant to the terms of this instrument. The Grantor and the Trustee acknowledge that the purpose of the Fund is to fulfill the Grantor's corrective action, injection well plugging, post-injection site care, site closure, emergency and remedial response, and storage facility fee obligations described at N.D.A.C. § 43-05-01-05.1 (Area of review and corrective action), N.D.A.C. § 43-05-01-11.5 (Injection well plugging), N.D.A.C. § 43-05-01-19 (Post-injection site care and site closure), N.D.A.C. § 43-05-01-13 (Emergency and remedial response), and N.D.A.C. § 43-05-01-17 (Storage Facility Fees) respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission or any other state agency. The Grantor and the Trustee intend that no third party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN TRUST, as hereinafter provided. The Trustee shall not be responsible, nor shall it undertake any responsibility, for the amount or adequacy of any additional payments necessary to discharge any liabilities of the Grantor established by the Commission.

Section 4. Payment for Corrective Action, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response. The Trustee shall make payments from the Fund only as the Commission shall direct, in writing, to provide for the payment of the costs of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response of the injection wells covered by this Agreement. The Trustee shall use the Fund to direct-pay or reimburse the Grantor, other persons selected by the Grantor to perform work, or as otherwise directed by the Commission when the Commission advises in writing that the work will be or was necessary for the fulfillment of the Grantor's corrective action, injection well plugging, post-injection site care and site closure, or emergency and remedial response obligations described in N.D.A.C. §§ 43-05-01-05.1, 43-05-01-11.5, 43-05-01-19 and 43-05-01-13, respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission, as the Commission is not a beneficiary of the Trust. The Commission may advise the Trustee that amounts in the Fund are no longer necessary to fulfill the Grantor's obligations under N.D.A.C. § 43-05-01-09.1 and that the Trustee may refund all or a portion of the remaining funds to the Grantor. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

Section 5. Payments Comprising the Fund. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee. Schedule C provides the amounts and timing of the seven (7) payments (i.e., the pay-in schedule).

Section 6. Trustee Management and Investment. Trustee shall manage, invest, and reinvest all of the Trust assets, made up of the principal and income of the Fund, in accordance with the North Dakota Prudent Investor Standards, Chapter 59-17, *et seq.* of the North Dakota Century Code, as amended ("Act"). The Trustee shall invest and reinvest the principal and income, without distinction, according to the investment instructions included within the attached Exhibit B (referred to as "Permitted Investments"), *provided* the Permitted Investments may be revised at any time upon notice from the Grantor. To the extent not inconsistent with the Act and Permitted

Investments, Trustee shall hold the Fund assets thereon subject to the terms and conditions of this Agreement and is empowered and directed to invest and reinvest the Fund assets and any accumulated income in such certificates of deposit, obligations to the United States of America, demand deposits, commercial paper or other securities or accounts as the Grantor shall direct. In the absence of instructions from the Grantor, Trustee shall invest and reinvest the Fund assets in money market funds available upon demand or short notice. All interest earned on the Fund principal shall become part of the Fund assets. Notwithstanding the foregoing, none of the Fund assets may be held in any investment that cannot be sold, redeemed or otherwise liquidated at the holders' option in ninety (90) days or less without loss of interest or discount. All amounts and investments (other than bearer instruments) comprising the Fund assets shall be registered and held in the name of the Trustee.

Section 7. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

A. To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;
B. To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;
C. To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund;
D. To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the Federal or State government; and,
E. To compromise or otherwise adjust all claims in favor of or against the Fund, including claims in favor of the Trust as a loss payee under applicable insurance policies.

Section 8. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other charges and disbursements of the Trustee permitted under this Agreement shall be paid from the Fund.

Section 9. Annual Valuation. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the Commission a statement confirming the value of the Fund. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund.

Section 10. Advice of Counsel. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement or any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

Section 11. Trustee Compensation. Trustee shall be entitled to reasonable compensation for its services provided hereunder in accordance with the Trustee's fee schedule as in effect during the course of this Agreement, *provided* that any change or revision to the fee schedule shall be effective only upon Trustee providing Grantor with thirty (30) days written notice, or another mutually agreed to period of time, which notice shall include effective date(s) of any change or revision. Trustee's current fee schedule is attached as Exhibit C, with such fees identified therein being each and together "Trustee Fees." Additionally, Trustee shall be reimbursed for all expenses reasonably incurred by Trustee in connection with the performance of its duties and enforcement of its rights hereunder and otherwise in connection with the preparation, operation, administration and enforcement of this Agreement, including, without limitation, attorneys' fees, brokerage costs and related expenses incurred by Trustee ("Trustee Expenses"). Grantor shall pay the Trustee Fees and Trust Expenses within thirty (30) days following receipt of an invoice from Trustee.

Section 12. Successor Trustee. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment, and the Commission consents to the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance and receipt of Commission consent of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the Commission, and the present Trustee by certified mail ten (10) days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

Section 13. Instructions to the Trustee. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the Commission to the Trustee shall be in writing, signed by the Commission or its duly constituted delegate(s), and the Trustee may rely on these instructions to the extent permissible by law. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or Commission hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or the Commission, except as provided for herein.

Section 14. Notice of Nonpayment. The Trustee shall notify the Grantor and the Commission, by certified mail within ten (10) days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period.

Section 15. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Provided, however, that the Commission may not be named as a beneficiary of the Trust, receive funds from the Trust, or direct that Trust funds be paid to a particular entity selected by the Commission.

Section 16. Cancellation, Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Upon termination of the Trust, all remaining Fund property, less final trust administration expenses, and excluding the principal and income contained in the ERR fund account, shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission. At termination of the Trust or upon early written direction by the Grantor, with concurrence of the Commission, Trustee must distribute ERR principal in an amount calculated in accordance with N.D.A.C. § 43-05-01-17 plus a pro rata portion of the income accrued. Following the distribution of the ERR principal and income in accordance with the foregoing clause, any remaining Fund property shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission.

Section 17. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense. The Commission does not indemnify either the Grantor or the Trustee. Rather, any claims against the Commission are subject to Chapter 32-12.2, *et seq*.

Section 18. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of North Dakota with regard to claims by the Grantor or Trustee. Claims involving the Commission are subject to North Dakota State law.

Section 19. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

{*Signature Page to Follow*}

IN WITNESS WHEREOF the parties below have caused this Agreement to be executed by their respective representatives duly authorized and their seals to be hereunto affixed and attested as of the date first above written.

Signature of Grantor's Authorized Representative: ______________________________
Name of Grantor's Authorized Representative: ______________________
Title: ___________________

Attest:

Signature: ________________________________
Name of Attester: _____________________
Title of Attester: ______________________

Certification of Acknowledgement of Notary:

Signature of Trustee's Authorized Representative: ______________________________
Name of Trustee's Authorized Representative: ______________________
Title: ___________________

Attest:

Signature: ________________________________
Name of Attester: _____________________
Title of Attester: ______________________

Certification of Acknowledgement of Notary:

Schedule A: Facilities and Cost Estimates to which the Trust Agreement Applies

Because the three injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the three wells will form one co-mingled and overlapping, stacked CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to all three injection wells as one integrated facility.

<table>
<tr><th>Facility</th><th>Corrective Action ($)</th><th>Injection Well Plugging ($)</th><th>Post-injection Site Care ($)</th><th>Site Closure ($)</th><th>Emergency and Remedial Response ($)</th></tr>
<tr><td>Unity-2 (BC-2)</td><td rowspan="4">$0.00</td><td rowspan="4">$2,025,000.00</td><td rowspan="4">$10,285,000.00</td><td rowspan="4">$1,554,000.00</td><td rowspan="4">$5,960,000.00</td></tr>
<tr><td>Liberty-1 (BC-1)</td></tr>
<tr><td>McCall-3 (DW-1)</td></tr>
<tr><td>NRDT(Monitoring Well)</td></tr>
</table>

Schedule B: Trust Fund Property

Because the three injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the three wells will form one co-mingled and overlapping, stacked CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to all three injection wells as one integrated facility.

Facility	Funding Value for Activities
Unity-2 (BC-2)	$19,824,000.00
Liberty-1 (BC-1)	
McCall-3 (DW-1)	
NRDT(Monitoring Well)	

Schedule C: Pay-in Periods/Schedule

The Fund will be funded according to when the financial risks are incurred in three (3) distinct Periods of activity.

- **Pre-Injection**: Upon authorization from the Commission to begin injecting CO_2 under the Class VI well permit(s), Grantor must be prepared to undertake any emergency or remedial response (ERR) actions, although such actions are unlikely to be needed. Further, in accordance with N.D.C.C. § 43-05-01-17 Grantor must account for a one cent fee on each metric ton of carbon dioxide for administration of a storage facility fund and a fee of seven cents on each ton of carbon dioxide injected for a storage facility fund which can be utilized for post closure period activities (together referred to as "Commission Fee"). The average projected amount of carbon dioxide injected will be 4MM metric tons annually. The Grantor estimates a minimum of 12 years of operation and is permitting operation of the storage facility for 20 years of injection. Grantor's estimated total cost of ERR activities is $16,560,000.00 assuming conditions allowing a conservative outer-limit cost estimate (at least 10 years of operation) with $5,960,000.00 of the estimate funded by the trust. Grantor shall initially fund an amount equal to the net of the cost estimate for ERR activities less the calculated 12 year Commission Fee based upon the projected annual average injection rate of 4MM metric tons, $2,120,000.00. The initial funding payment in the amount of $2,120,000.00 will fund the Fund account in the Pre-Injection Period with the remaining equal installments made in the Injection Period, as further discussed below.

- **Injection**:

    - Once an injection or monitoring well is drilled, plugging costs will need to be incurred prior to cessation of injection operations. Therefore, the trust account will need to account for the cost of plugging injection and monitoring wells prior to the Post-Injection period. Grantor's estimated cost of this plugging activity is $2,025,000.00. The total plugging cost will be paid across the seven (7) equal annual funding installments made in the Injection Period, each installment consisting of $289,285.71 for plugging expenses with the first installment prior to the one-year anniversary of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $2,025,000.00.

    - Also, Grantor will fully fund the ERR Fund account making seven (7) equal annual installments of $548,572.00 made in the Injection Period, with the first installment prior to the one-year anniversary Commission's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $5,960,000.00. However, if at any time the Commission determines the actual amount of the Commission Fee as calculated under N.D.C.C. 43-05-01-17 exceeds the principal amount then contained in the ERR account, then upon written direction from the Commission, Grantor shall fund amounts to bring the principal and income to an amount sufficient cover the Commission Fee.

    - Grantor will fund the Fund account for post-injection site care, monitoring and site closure making seven (7) equal annual installments of $1,691,286.00. Grantor's estimated cost of post-injection site care and monitoring is $10,285,00.00 and site closure activities is $1,554,000.00. The first installment to be made in the Injection period prior to the one-year anniversary of the Commission's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $11,839,000.00.

    - The seven (7) installments are to be made individually prior to the successive anniversary of the Commission's issuance of authorization to operate a Class VI injection well until fully funding the principal amount of $19,824,000.00.

- **Post-Injection and Closure**: All costs associated with post-injection and closure activities must be funded before or at the start of the post-injection phase. However, the Fund may phase out these costs as associated Pre-Injection and Injection Period activities are completed (with approval from the Commission). For example, once wells have been plugged, their corresponding plugging costs may be subtracted from the total value of the Fund account.

Pay-in Schedule
Within seven (7) calendar days after the issuance of final Class VI authorization to operate for the three injection wells, Grantor will ensure that $2,120,000.00 is in the Fund to cover the cost of Injection Period activities (Emergency and Remedial Response Plan). The total value of the trust at the beginning of the Injection Period will be $2,120,000.00.

On or before the seven-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells, Grantor will ensure that an additional $17,704,000.00 is in the Fund to cover the remaining costs of the Pre-Injection, Injection, Post-Injection, and Closure Periods. An additional $2,529,143.00 will be added on or before the one-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the two-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the three-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the four-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the five-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the six-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. A final installment of $2,529,142.00 will be added on or before the seven-year anniversary for the permit to operate for the three injection wells, completing the phase-in of financial responsibility payments for the Pre-Injection, Post-Injection, and Closure Periods. Grantor may also elect to substitute another mechanism to demonstrate financial responsibility for emergency and remedial response for the injection and post-injection phases. If Commission approves such a substitution, this Agreement will be amended accordingly.

These amounts are based on the third-party cost estimate submitted by Grantor in its *Supporting Documentation: Underground Injection Control Class VI Injection Well Permit Applications for Tundra SGS _______________ Wells _,_,_ and _*, dated ____________ (Appendix _) and on the

Commission's independent evaluation of the cost estimates. These costs are subject to review and approval by the Commission and may be adjusted for inflation or any change to the cost estimate in accordance with N.D.C.C. § 43-05-01-09.1.

Table 1 shows the activities and estimated costs according to when the payments would be required (i.e., at the start of the "Pre-Injection") phase or at the start of the "Injection and Post-Injection Phase").

Table 1: Trust Funding Schedule

<table>
<tr><th>Funding Phase</th><th>Activities</th><th>Total Activities' Costs Prior to Funding Phase ($000)</th><th>Amount to be Added Before End of Phase ($000)</th></tr>
<tr><td rowspan="2">Pre-Injection (within 7 days of operating permit issuance)</td><td>Emergency and Remedial Response</td><td>$5,960</td><td rowspan="2">$2,120</td></tr>
<tr><td>AoR and Corrective Action</td><td>$0</td></tr>
<tr><td rowspan="4">Injection (seven (7) equal installments prior to successive anniversaries of operating permit issuance)</td><td>Plugging Injection and Monitoring Wells</td><td>$2,025</td><td rowspan="4">$17,704</td></tr>
<tr><td>Emergency and Remedial Response</td><td>$3,840</td></tr>
<tr><td>Post-Injection Site Care (Includes Monitoring)</td><td>$10,285</td></tr>
<tr><td>Closure</td><td>$1,554</td></tr>
<tr><td colspan="3">Total Fund</td><td>$19,824</td></tr>
</table>

Exhibit A: [Grantor] Designee Authorized to Instruct Trustee

[Name]
[Title]
[Grantor name or company if different]
[Address 1]
[Address 2]
[Phone]

[Grantor], as Grantor, may designate other designees by amendment to this Exhibit.

<u>Exhibit B</u>

Permitted Investments

(i) Direct obligations of the United States of America or any agency or instrumentality thereof or obligations backed by the full faith and credit of the United States of America maturing in twelve (12) months or less from the date of acquisition:

(ii) Commercial paper maturing in 180 days of less rated not lower than A-1, by Standard & Poor's or P-1 by Moody's Investors Service, Inc. on the date of acquisition.

(iii) Demand deposits, time deposits or certificates of deposit maturing within one year in commercial banks whose obligations are rated A-1, A or the equivalent or better by Standard & Poor's on the date of acquisition;

(iv) Money market or mutual funds whose investments are limited to those types of investments described in clauses (i) and (iii) above; and

(v) Deposits of the Bank of North Dakota, to the extent guaranteed by the State of North Dakota under North Dakota Century Code Section 6-09-10, or a successor statute.

Exhibit C

Compensation and Reimbursement of Expenses
Trustees Fee Schedule

Outlined below are the initial and ongoing fees for the Bank of North Dakota to provide Trustee services:

One Time Initial Fee:	$1,250.00
Annual fee for Administration:	$1,250.00
Legal Review of Documents:	$400 - $600 estimated
Contact:	Carrie Willits (701) 328-5612 cwillits@nd.gov

The Annual Fee for Administration is subject to change upon a 30 day notification.

APPENDIX G-2

MARKET ASSESSMENT

Marsh

Project Tundra

Use of Insurance in the FADP

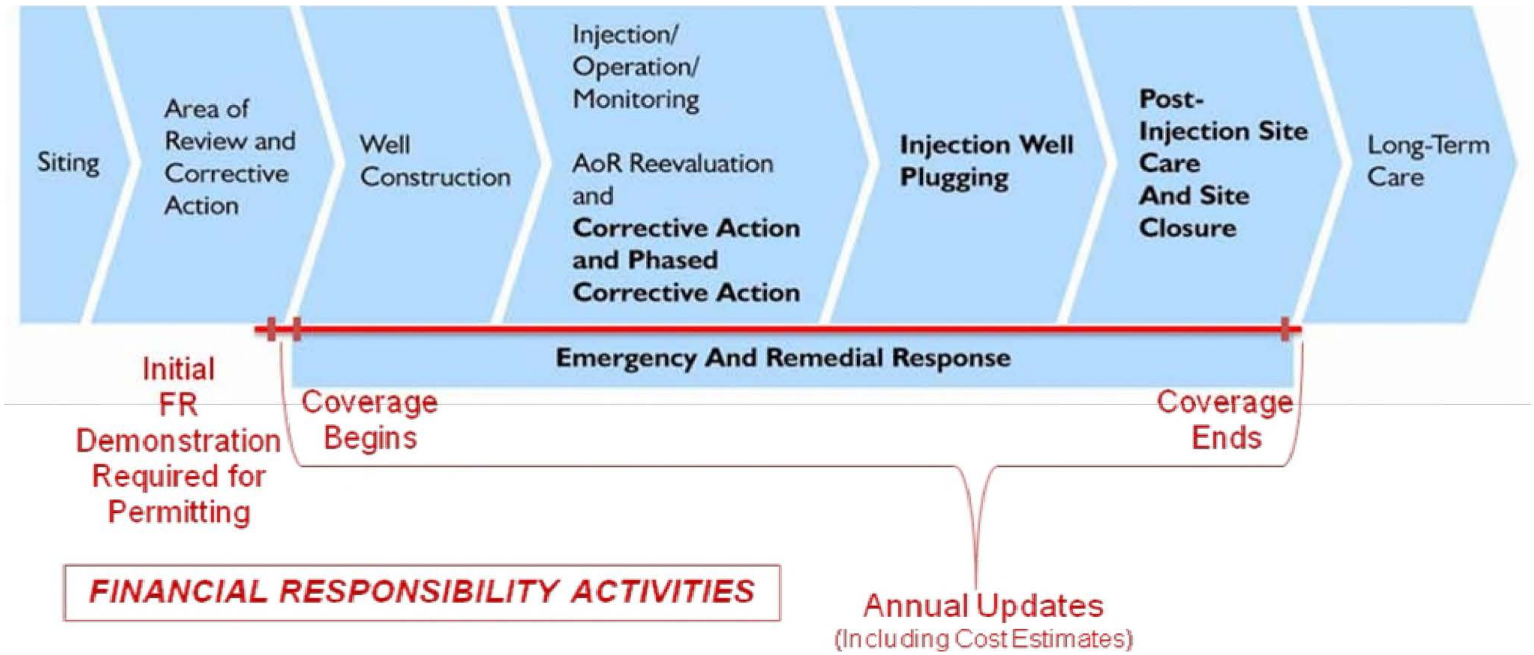
May 26, 2021

Contents

Section One

Executive Summary

This document will examine pollution liability insurance options over the course of the operating lifetime of the CO_2 sequestration company, “Tundra SGS”, including the 10 year, post-injection site care period prior to transfer of liability to the State of North Dakota. The following graphic is a helpful summary.



The market review was requested to outline the applicable environmental insurance products, expected policy terms and conditions, exclusions, costs and deductibles to support applicant to the North Dakota Industrial Commission for necessary UIC Class VI well injection permit financial responsibility requirements. The examination extends only to Contractors Pollution Liability, Pollution Liability and Operators Extra Expense/Control of Well insurances based on the Emergency and Remedial Response activities for the Tundra SGS geologic sequestration project, which could respond following a liability claim arising from contamination of an Underground Source of Drinking Water (USDW). First party/property insurances as well as the extended family of 3rd party liability insurance such as (but not limited to): general liability, auto liability, employer’s liability, cyber liability, professional liability and all measure of executive liability coverages, while generally critical to the greater project and highly recommended, are not under consideration in this analysis. All coverage descriptions, options and estimates provided herein are non-binding estimates based on whatever project data has been provided at this point. Over the 20+ year of life of the project (not to mention the next few months) these estimates will change, as such no guarantee is possible as to the future fitness of the program details provided in this report.

Marsh & McLennan Companies Introduction

Marsh & McLennan Companies (MMC) is the leading global professional services firm in the areas of risk, strategy and people. With annual revenue approaching USD17 billion and 76,000 colleagues worldwide, MMC helps clients navigate an increasingly dynamic and complex environment through four market-leading businesses: Marsh, Guy Carpenter, Mercer, and Oliver Wyman.

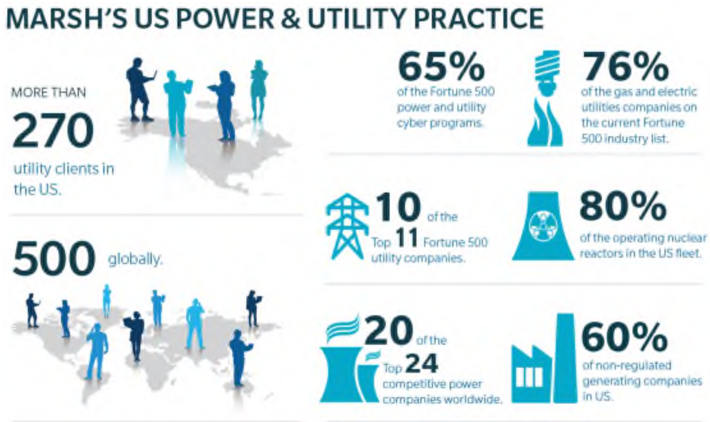
We are four companies, with one purpose: helping our clients to meet the challenges of our time.

About Marsh

Marsh is the world's leading insurance broker and risk adviser. With over 35,000 colleagues operating in more than 130 countries, Marsh serves commercial and individual clients with data driven risk solutions and advisory services.

Power Industry Expertise

With more than 270 utility clients in the United States, the Marsh Power and Utilities team remains at the forefront of helping utilities manage the many risks they face. We placed over $1 billion of insurance premium on behalf of our utility clients into the global insurance market. We are recognized as the leading broker in the power and utility industry sector, and have deep relationships with all the major insurers actively underwriting power and utilities business, including AEGIS, EIM, AIG, ANI, Everest, Liberty International, and FM Global. We have extensive knowledge and deliver results for clients owning all forms of power generation, including natural gas, coal, nuclear, hydro, biomass, geothermal, wind, solar, and energy storage.



Contact

Gavin Hurd, Managing Director, Energy & Power

Marsh Specialty, a business of Marsh McLennan

T +1 713-346-1090; M +1 832-454-8136

Gavin.hurd@marsh.com

Section Two

Coverage Assessment by Project Phase

This section outlines the certain types of insurance which may respond to a pollution event during certain phases of the project life.

Project Phase	General Risks Associated	Types of Insurance	Assumptions/Questions
Construction phase pollution event	1. Pollution event during construction 2. Well control event during drilling or completion	1. Contractors Pollution Liability (CPL) for Contractor. Separate CPL policy for Owner interest. 2. Operators Extra Expense (OEE) for either owner or contractor as assigned in the drilling contract	1. CPL required by contract with contractor. Owners CPL operates as a difference in limits/difference in conditions to contractors policy 2. Party responsible to provide OEE is established by contract
Operations phase pollution event	1. Pollution during operations 2. Well control event during operations	1. Pollution Liability (PL) Coverage for owner 2. Operators Extra Expense (OEE) for owner or operator	1. Multi-year policy could be desirable. Combined GL/PL may also be available 2. Responsibility to carry OEE can be transferred to the contract operator and can include operator of record via Contract Operator Endorsement.
Injection Well Plugging phase pollution event	Well control event during plugging	OEE for either owner or contractor as per contract	Party responsible to provide OEE is established by contract. Owner's operating pollution liability coverage remains in force until Tundra SGS operations are discontinued
Post Injection Site Care pollution event	Gradual migration of CO_2 into USDWs	Pollution Liability	Following injection well plugging, pollution policies adjusted to maximum terms and renewed as necessary until liabilities assumed by State of North Dakota

Section Three

Contractors Pollution Liability Coverage Details

Summary

Contractors Pollution Liability (CPL) covers third party damages for bodily, injury property damage or cleanup related to pollution events which occur during construction operations. Unlike other pollution coverage, CPL does not have reporting windows for discovery or reporting of an occurrence. The following coverage sections can be included in a CPL policy:

Coverage A: Contractors Pollution Liability
Coverage B: Pollution Liability during Transportation
Coverage C: Non-Owned Site Pollution Liability
Coverage D: Time-Element Pollution Liability
Coverage E: Image Restoration Expenses
Coverage F: Disinfection Event Expenses
Coverage G: Pre-Claim Event Expenses

Refer to Specimen Policy Form in Appendix A

Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate and are elected at time of binding.

Pollution Liability (PL) policies (discussed in the following section) prefer not to extend coverage to construction operations, including those events occurring during the operations period but arising directly from construction. Accordingly, in order to keep PL market selection as broad as possible, we recommend a separate CPL to cover construction operations.

Status of Market

The market for CPL is stable and very competitive. Viable markets include Ironshore, Aspen, Ascot, Enviant, Hamilton, and Markel.

Review of Coverage

Coverage Limits

Benchmarking reveals an average Contractors Pollution Liability purchase of $20M for multi-year policies. Drilling contractors often carry lower than average CPL limits due to the historical experience of pollution events at contractor risk which occur during drilling operations, the rural location of their work and general reliance on the pollution coverage grants within other policies which can cover sudden and accidental pollution events. Selection of CPL limits is often driven by broader contract negotiations as well as the aggregate nature of the limit provided over the term of the construction period and completed operations period.

CPL coverage can be structured in many ways, as owner or contractor controlled for the project, owner's or contractor's interest separately or in a combination. The owner's basic objective should be to cover a target limit for pollution events arising from construction activities both during the actual construction and completed operations coverage for 10-years following construction. The simplest approach would be to require the contractor via the construction contact to carry the entire desired limit. While most contractors already carry CPL, the limit may not be large enough and is usually shared across the contractor's entire portfolio of projects. Given smaller usual limits and the shared aggregate, requiring the contractor to cover the entire desired limit can restrict contractor selection and distort available bids.

For this project we recommend that part of the desired CPL limit be stipulated by contract as a Contractor required insurance, along with others such as General Liability, Auto Liability, Excess, etc. All contractors and subcontractors engaged to perform work at the site should carry the required CPL. We further recommend the owner carry the balance of the desired limit in a CPL Owner's Interest policy to protect against contractor CPL policy deficiencies and termination of coverage or exhaustion of limit over the completed operations period. The owner's CPL policy would operate as Difference in Conditions/Difference in Limit to the Contractors so would only be accessed in the event the limit was exhausted or not maintained in accordance with the contract requirements. We recommend that both CPL and CPL Owner's interest policies be purchased during the construction period. For the contractor's CPL, a project specific policy is recommended, but not required in this case as the Owner's CPL can supplement. If contractor needs more flexible terms (such as lower limit and not project specific), the owner's CPL can be adjusted to make up the balance of the target pollution policy limit.

Market capacity for CPL is estimated at $500M.

Deductible

Standard deductibles vary from $25,000 to $100,000 for Owner's Interest CPL policies

Exclusions

Exclusions – Refer to Specimen Policy Form in Appendix A

Some of the basic exclusions in a pollution legal liability policy are outlined below, however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in agreement
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Identified Underground Storage Tank (unless scheduled)
- Closure/Post Closure and Reclamation Costs
- Drilling and Specialty Equipment
- Divested Property
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds

Renewal

The policies would not renew. The recommended Contractor's CPL and owner's interest CPL would both run the course of construction and carry a 10 year completed operations extension.

Cancellation

Policy cancellation as per Section IV. Conditions clause 3. Cancellation on page 11 of the sample wording in Appendix A

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

CPL Limit: Contractor premiums are difficult to estimate without detailed knowledge of contractor revenues, operations and loss history.

CPL Owner's interest Limit Option: Construction Period plus 10 Years Completed Operations, Limit of $10M – at $50,000 Deductible = $25,000 to $35,000 annually ($250,000 to $350,000 for a 10-year term), not including applicable taxes and fees.

Pollution Liability Coverage Details

Summary

Pollution Liability is an insurance policy which protects business organizations against liability claims for bodily injury (BI), property damage (PD) and Cleanup (CU) arising out of premises and operations at scheduled locations. Coverage may include various extensions, including first party discovery, non-owned disposal sites, contingent transportation, emergency response, image restoration, and Natural Resource Damages. Additionally, as this coverage does not have reporting windows for events, it can be coordinated with other liability policies that may offer sudden & accidental pollution coverage, such as General Liability and Excess and Operators Extra Expense.

Pollution Liability (PL) coverage can be provided on an annual or multi-year policy term covering property, assets. Coverage is offered on a claims-made policy form for specifically scheduled assets. Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate. *Most often those limits are the same; however, some Insured's choose a split aggregate limit. A split aggregate makes it challenging to build a significant tower of* limits.

Coverage A: Third party claims for Bodily Injury, Property Damage or Remediation expenses
Coverage B: First party Remediation Expenses
Coverage C: Emergency Response Expenses
Coverage D: Evacuation Expenses
Coverage E: Image Restoration Expenses

Status of Market

The pollution market is hardening, fueled by claims and the exit of a major carrier. This has led to increased retentions, increased premiums, and lower limits. This has primarily applied to operators and facility owners. On the other hand, CO_2 sequestration has caught the attention of many insurers who want to be involved in the next trend, especially a green initiative. However, since CO_2 sequestration unrelated to enhanced oil recovery projects are rare, there is limited appetite at this moment. We anticipate that as more projects are developed and come to market, the coverage will be easier to obtain.

Many insurers offer coverage on an annual basis. However, some can offer on a multi-year basis. Therefore, it is important to remember the limits do not reinstate annually. However, this type of structure is advantageous as discounts are built into multi-year options. Pollution Liability is driven by severity, not frequency. Viable markets include Ironshore, Aspen, Ascot, Enviant, Hamilton, and Markel.

Review of Coverage

Coverage Limits

Benchmarking reveals an average Pollution Liability (PL) purchase of $10M for annual and 2-3 year policies. Longer-term policies (such as 10 years) have larger limits to accommodate the possibility of erosion of the aggregate limit. At first glance, the average PL limit purchase of $10M would appear lower than necessary to respond to recent pollution events. Pollution Liability is often purchased as an excess and difference in conditions coverage to sudden and accidental pollution coverage grants within the main liability program. Operational liability programs normally have much larger limits and serve as a natural downward influence on PL limits purchased. It is almost impossible to say how insurance programs covering CO_2 sequestration compare to the benchmark as there are so few working examples with pollution policies. Considering the nature of sequestration operations, contamination of an underground source of drinking water is likely to occur gradually and not be discovered until well after the event which caused it. Typical sudden & accidental pollution liability with discovery and reporting windows generally around 21 and 45-days respectively (and shorter) may not reasonably be expected to provide much coverage. Due to the novel nature of CO_2 sequestration operations and lack of an ability to rely on the sudden and accidental pollution grants within the operational liability, it is likely that selection of Pollution Liability limits by CO_2 sequestration operations will trend well above benchmarked limits.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the PL policy such as Coverages A, C and E and potentially D. Generally, the policy would respond to efforts to measure the extent of the contamination and compensate any users of the drinking water for property damage and/or bodily injury arising from the contamination. Costs to control the breach and restore the well to production would be covered under the OEE policy discussed in the following section.

Market capacity for PL for this risk is estimated at $150M. A combined General Liability and Pollution Liability product is often preferred by other waste disposal operations as it tends to be more cost efficient than standalone liability and pollution towers. Given the novel nature of standalone CO_2 sequestration, this is certainly the desired option but may not be available until the market gains more comfort with sequestration operations.

Deductible

The minimum deductible for this risk will likely be $250,000. Small credits are available for incremental increases in deductible but are generally not efficient. Deductible is usually established by market preference and premium for the overall account and limit. The preferred maximum deductible would be $1,000,000, as very small discounts are provided above that amount. The deductible will be a self-insured retention versus a true deductible. Environmental markets do not typically analyze individual financial performance or require collateral for support.

Exclusions

Refer to Specimen Policy Form in Appendix B

Some of the basic exclusions in a PL policy are outlined below, however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in JOAs
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Identified Underground Storage Tank (unless scheduled)
- Closure/Post Closure and Reclamation Costs
- Drilling and Specialty Equipment
- Divested Property
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds

Renewal

Operations: If PL is purchased on a standalone basis, then we recommend a multi-year period for premium efficiency. The longest available multi-year period for operating assets is usually three years. A combined GL/PL form may be available in the near future as Insurers become more comfortable with risk, technology and appetite. A combined form renews annually.
Post Injection Site Closure: After plugging of the injection well, it would be desirable (if possible) to purchase a 10-year policy to match the post injection site closure period.

Cancellation

Policy cancellation as per Section VII. Conditions clause E. on page 9 of the sample wording in Appendix B

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

Pollution Legal Limit Options

PL Limit Option 1: Annual Limit of $15M = $125,000

PL Limit Option 2: Three-year Limit of $25M = $400,000

PL Limit Option 3: Three-year Limit of $50M = $700,000

All premiums are non-adjustable

Section Four

Operators Extra Expense Coverage Details

Operators Extra Expense (OEE), also known as Control of Well (COW), indemnifies owners against costs associated with a well out of control. The base coverage is divided into 3 coverage grants:

A. Cost to control,
B. Cost of re-drill or restoration of the well, and
C. Cost of pollution clean-up

Coverage C. grant is of interest to this analysis but can only be triggered by a well out of control event per policy definition. Limits are also supplemented by various extensions (see below).

Review of Coverage

Coverage Limits

OEE policy limits are combined single limits of liability across all coverage sections and extensions for any one occurrence (including defense costs). Therefore, it is prudent to be conservative with limit selection. Conventional wisdom for OEE limit selection for exploration and production accounts holds that the OEE limit should be 3-5 times the dry hole cost of the well insured. While this approach tends to breakdown for uncommon well types and operations, it is considered the general benchmark in selecting limits. A comparison of five times the projected dry hole cost ($5.8MM * 5 = $29MM) and the sum of estimated Emergency and Remedial Response expenses from the FADP report ($16.6MM) reveals that a limit of either $25,000,000(100%) or $30,000,000(100%) any one occurrence appears reasonable for both drilling and producing wells.

OEE and PL limits can be coordinated by the insured but the OEE limit is generally not viewed as substitute for PL coverage for the following reasons:

- The priority of payments clause on the OEE policy allows the Insured to direct the limit to whichever sections he chooses
- Operators prefer to reserve OEE limits for Cost to Control or Re-drill. These activities have been known to be very expensive in large or difficult claims and could leave little for pollution clean-up.
- Given the broader nature of PL coverage, insureds prefer to reserve PL limits for claims arising from an occurrence which would not be covered by either the OEE or Operational Liability program.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the OEE policy such as Coverages A, B and C. We recommend that Tundra SGS direct costs to control and restore the well to production first to the OEE policy and deploy any remaining limit to clean-up pollution. The PL policy referenced above should be used to respond to all other remaining clean-up costs that are covered by the policy.

Coverage form should be as broad as possible and include such coverage extensions as: Making Wells Safe, Underground Control of Well, Care Custody and Control, Unlimited Re-Drill, Extended Re-Drill, Extended Pollution, and Removal of Wreck.

The load or credit associated with increased or diminished limits is discussed in the premium section.

Deductible

Often referred to as a retention or excess, the OEE policy carries a single deductible over all coverage sections. The Project should expect a deductible of between $250,000(100%) and $500,000(100%) any one occurrence for drilling and producing wells. Due to the small schedule and Minnkota's minimal well operating record, Insurers may be reluctant to offer lower deductibles.

The credit associated with increased deductibles is discussed in the premium section

Exclusions

A sample copy of the wording is provided in the Appendix C. Exclusions of note are:

- Fines or Penalties
- Breach of Warranties Clause and breach of Due Diligence Clause
- Delay or loss of use (adding Loss of Production Insurance would serve to add back coverage)
- Costs arising out of a well which flow can be promptly controlled by use of onsite equipment or by increasing the weight of drilling fluid
- Exclusion for claim recoverable under the policy solely by reason of the addition or attachment to Section A of the Underground Control of Well Endorsement. This exclusion should be amended or removed to better fit CO_2 Sequestration operations.

Renewal

Most OEE policies renew annually.

Cancellation

As per clause 13. Cancellation on page 9 of the sample policy wording in Appendix C

Premium

All premiums are annual minimum and deposit premiums which are adjustable for drilling wells and flat at inception for producing wells. Based on current market feedback, the $100,000 minimum premium drives the premium during the operating phase due to the small schedule of wells and Minnkota's minimal well operating record. A contract operator could possibly leverage their experience and existing premium base to provide lower OEE premiums. Additionally, we may be able to negotiate lower premiums for the operating period once injection operations are established and the market is more comfortable with the risk.

Type of Well	Combined Single Limit	Est. Annual Premium
2 Broom Creek Wells (drilling phase)	$25,000,000	Rate of 1.5% times Completed Well Cost (CWC), minimum annual premium $100,000. Eg. CWC est. $5.8M for each then Est. Annual Premium for 2 wells is $174,000
	$30,000,000 (option)	Rate of 1.7% on CWC, minimum annual premium of $100,000. Eg. CWC est. $5.8M for each then Est. Annual Premium for 2 wells is $197,200
2 Broom Creek Wells (operating phase)	$25,000,000	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000
	$30,000,000 (option)	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000

Type of Well	Combined Single Limit	Est. Annual Premium
2 Broom Creek wells & 1 Deadwood Well (drilling phase)	$25,000,000	Rate of 1.5% times Completed Well Cost (CWC), minimum annual premium $100,000. Eg. CWC est. $5.8M for each Broom Creek well and $8.2M for the Deadwood well then Est. Annual Premium for 3 wells is $297,000
	$30,000,000 (option)	Rate of 1.7% on CWC, minimum annual premium of $100,000. Eg. CWC est. $5.8M for each Broom Creek well and $8.2M for the Deadwood well then Est. Annual Premium for 3 wells is $336,600
2 Broom Creek wells & 1 Deadwood well (operating phase)	$25,000,000	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000
	$30,000,000 (option)	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000

Appendix A

Contractors Pollution Wording

Ironshore sample
CPL wording.pdf

Appendix B

Pollution Liability Policy Wording

IE.COV.SPILLS.OG.001
_1212_ Oil and Gas Cc

Appendix C

OEE Draft Policy Wording

EED FORM.pdf

APPENDIX H

SURFACE USE AND PORE SPACE LEASE

STORAGE AGREEMENT
TUNDRA BROOM CREEK – SECURE GEOLOGIC STORAGE
OLIVER COUNTY, NORTH DAKOTA

THIS AGREEMENT ("Agreement") is entered into as of the 1st day of November 1, 2021, 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.

RECITALS:

A. 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 coal and power industries, to the economic benefit of North Dakota and its citizens;

B. 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

C. 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.

AGREEMENT:

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 18903.211 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 Opeche-Picard (Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at two stratigraphic wells, the J-LOC1 well (File No. 37380) and the J-ROC1 1 well (File No. 37672). The log suites included caliper, gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, spectral GR, a combinable magnetic resonance (CMR), and fracture finder log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from two 3D seismic surveys covering an area totaling 18.5 miles in and around the J-ROC1 1 (located in Section 4, Township 141 North, Range 83 West) and the J-LOC 1 (located in Section 27, Township 142 North, Range 84 West) stratigraphic wells located in Oliver County, North Dakota. Formation top depths were picked from the top of the Pierre Formation to the top of the Precambrian. These logs and data which encompass the stratigraphic interval from an average depth of 4,650 feet to an average depth of 5,450 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, fluids, and minerals.

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 Tundra Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Tundra Broom Creek 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 a 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 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 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.** Minnkota Power Cooperative, Inc. 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.** As permitted by the Commission 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 April 1, 2022 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 § 38-22-17 of the North Dakota Century Code.

15.2 **<u>Termination by Storage Operator</u>.** This Agreement may be terminated at any time by the Storage Operator with the approval of the Commission.

15.3 **<u>Effect of Termination</u>.** 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 **<u>Salvaging Equipment Upon Termination</u>.** 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 **<u>Certificate of Termination</u>.** 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 **<u>Original, Counterpart or Other Instrument</u>.** 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 **<u>Joinder in Dual Capacity</u>.** 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 **<u>Approval by the North Dakota Industrial Commission</u>.**
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 **<u>Amendments Affecting Pore Space Owners</u>.** Amendments hereto relating wholly to Pore Space Owners may be made with approval by the Commission.

17.4 **<u>Construction</u>.** 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: ___________, 2021

STORAGE OPERATOR

MINNKOTA POWER COOPERATIVE, INC.

By:________________________________

Its:________________________________

73023763.1

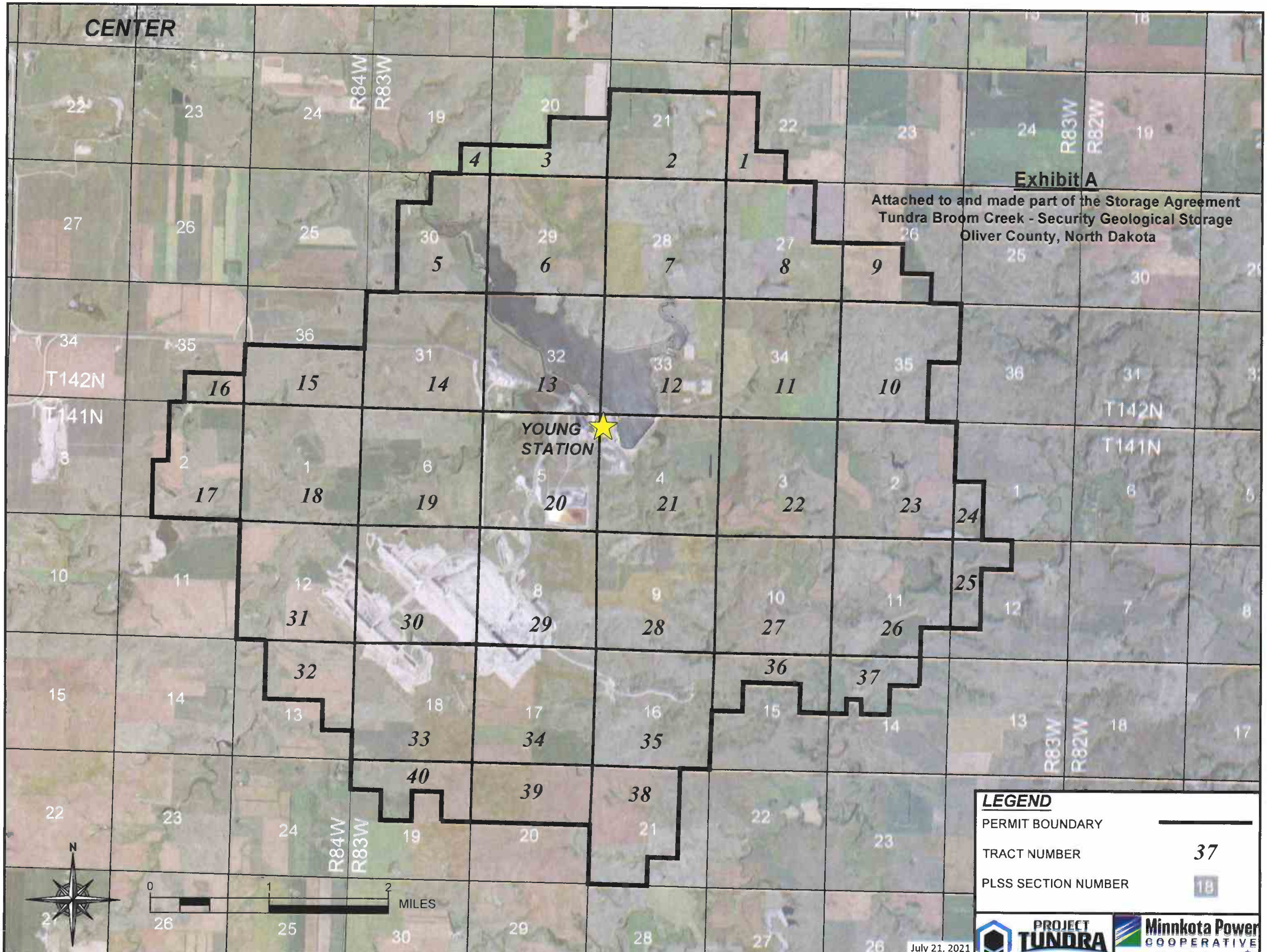


Exhibit A
Attached to and made part of the Storage Agreement
Tundra Broom Creek - Security Geological Storage
Oliver County, North Dakota
CENTER
YOUNG STATION
T142N
T141N
R84W
R83W
R82W
LEGEND
PERMIT BOUNDARY
TRACT NUMBER 37
PLSS SECTION NUMBER 18
0 1 2 MILES
N
July 21, 2021
PROJECT TUNDRA
Minnkota Power COOPERATIVE

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Tundra Broom Creek - Secure Geological Storage
Oliver County, North Dakota

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 22-T142N-R83W	Melvin Schoepp	20.000	12.50000000%	0.10580213%
		Caroline K. Schoepp	20.000	12.50000000%	0.10580213%
		Marie Mosbrucker	30.000	18.75000000%	0.15870320%
		Raymond Friedig	30.000	18.75000000%	0.15870320%
		Duane Friedig	30.000	18.75000000%	0.15870320%
		Shirley Hilzendeger	30.000	18.75000000%	0.15870320%
		Tract Total:	**160.000**	**100.00000000%**	
2	Section 21-T142N-R83W	Jeff Erhardt and Mary Erhardt	120.000	25.00000000%	0.63481278%
		Keith Erhardt	35.000	7.29166667%	0.18515373%
		Keith Erhardt and Kelly Jo Erhardt	5.000	1.04166667%	0.02645053%
		Melvin Schoepp and Caroline Schoepp	320.000	66.66666667%	1.69283409%
		Tract Total:	**480.000**	**100.00000000%**	
3	Section 20-T142N-R83W	Jeff Erhardt and Mary Erhardt	160.000	66.66666667%	0.84641705%
		Matthias A. Erhardt, as trustee of the Matthias A. Erhardt Trust dated December 27, 1994	40.000	16.66666667%	0.21160426%
		Josephine Erhardt, as trustee of the Josephine Erhardt Trust dated December 27, 1994	40.000	16.66666667%	0.21160426%
		Tract Total:	**240.000**	**100.00000000%**	
4	Section 19-T142N-R83W	Matthias A. Erhardt, trustee, or successor trustee(s), of the Matthias A. Erhardt Trust dated December 27, 1994	20.000	50.00000000%	0.10580213%
		Josephine Erhardt, trustee, or successor trustee(s), of the Josephine Erhardt Trust dated December 27, 1994	20.000	50.00000000%	0.10580213%
		Tract Total:	**40.000**	**100.00000000%**	
5	Section 30-T142N-R83W	Minnkota Power Cooperative, Inc.	322.170	73.22045455%	1.70431362%
		Ryan J. Weber	40.000	9.09090909%	0.21160426%

		Darlene Voegele	77.830	17.68863636%	0.41172899%
		Tract Total:	**440.000**	**100.00000000%**	
6	Section 29-T142N-R83W	Minnkota Power Cooperative, Inc.	92.360	14.43125000%	0.48859424%
		Darlene Voegele	227.640	35.56875000%	1.20423985%
		Charles Kuether	150.000	23.43750000%	0.79351598%
		Doris Kuether	150.000	23.43750000%	0.79351598%
		Terrie Nehring	20.000	3.12500000%	0.10580213%
		Tract Total:	**640.000**	**100.00000000%**	
7	Section 28-T142N-R83W	Minnkota Power Cooperative, Inc.	160.000	25.00000000%	0.84641705%
		Dale Barth	476.320	74.42500000%	2.51978354%
		Dusty Backer	3.680	0.57500000%	0.01946759%
		Tract Total:	**640.000**	**100.00000000%**	
8	Section 27-T142N-R83W	Dale Barth	560.000	100.00000000%	2.96245966%
		Tract Total:	**560.000**	**100.00000000%**	
9	Section 26-T142N-R83W	Raymond Friedig, as personal representative of the Estate of Magdalen F. Friedig, deceased	154.460	77.23000000%	0.81710986%
		Carl Schwalbe	13.333	6.66666667%	0.07053475%
		Heirs or Devisees of the Estate of Loren Schwalbe, deceased	13.333	6.66666667%	0.07053475%
		Rolland Schwalbe	13.333	6.66666667%	0.07053475%
		Randolph Middleton and Mary Middleton	5.540	2.77000000%	0.02930719%
		Tract Total:	**200.000**	**100.00000000%**	
10	Section 35-T142N-R83W	Brennan Price	560.000	100.00000000%	2.96245966%
		Tract Total:	**560.000**	**100.00000000%**	
11	Section 34-T142N-R83W	Minnkota Power Cooperative, Inc.	477.990	74.68593750%	2.52861802%
		State of North Dakota	160.000	25.00000000%	0.84641705%
		County of Oliver	2.010	0.31406250%	0.01063311%
		Tract Total:	**640.000**	**100.00000000%**	
12	Section 33-T142N-R83W	Square Butte Electric Cooperative	3.900	0.60937500%	0.02063142%
		Minnkota Power Cooperative, Inc.	625.040	97.66250000%	3.30652819%
		ALLETE, INC.	11.060	1.72812500%	0.05850858%
		Tract Total:	**640.000**	**100.00000000%**	
13	Section 32-T142N-R83W	Minnkota Power Cooperative, Inc.	465.830	72.78593750%	2.46429033%
		Heirs or Devisees of Alex Sorge, deceased	80.000	12.50000000%	0.42320852%

		Darlene Voegele	37.470	5.85468750%	0.19822029%
		BNI Coal, Ltd.	56.700	8.85937500%	0.29994904%
		Tract Total:	**640.000**	**100.00000000%**	
14	Section 31-T142N-R83W	Robert Reinke	456.910	70.56743065%	2.41710258%
		Darlene Voegele	149.640	23.11113857%	0.79161154%
		BNI Coal, Ltd.	40.930	6.32143078%	0.21652406%
		Tract Total:	**647.480**	**100.00000000%**	
15	Section 36-T142N-R84W	State of North Dakota Board of University and School Lands	320.000	100.00000000%	1.69283409%
		Tract Total:	**320.000**	**100.00000000%**	
16	Section 35-T142N-R84W	Michael P. Dresser	80.000	100.00000000%	0.42320852%
		Tract Total:	**80.000**	**100.00000000%**	
17	Section 2-T141N-R84W	City of Center Park District	46.050	10.68544645%	0.24360941%
		Barry A. Berger and Carrie Berger	286.460	66.47020605%	1.51540392%
		Dwight Wrangham and Linda Wrangham	3.000	0.69612029%	0.01587032%
		BNI Coal, Ltd.	95.450	22.14822721%	0.50494067%
		Tract Total:	**430.960**	**100.00000000%**	
18	Section 1-T141N-R84W	Jolene Berger	627.320	97.93917442%	3.31858963%
		Travis Klatt and Jessica Klatt	8.310	1.29738338%	0.04396079%
		Gary Leinius	4.890	0.76344220%	0.02586862%
		Tract Total:	**640.520**	**100.00000000%**	
19	Section 6-T141N-R83W	Brian Reinke	19.577	3.02274377%	0.10356336%
		Benjamin Reinke	30.997	4.78601096%	0.16397532%
		Elizabeth Wagendorf	30.997	4.78601096%	0.16397532%
		Jolene Berger	245.840	37.95877403%	1.30051979%
		Gary Leinius	320.240	49.44646028%	1.69410372%
		Tract Total:	**647.650**	**100.00000000%**	
20	Section 5-T141N-R83W	Minnkota Power Cooperative, Inc.	641.12000000	99.92518703%	3.39159310%
		Square Butte Electric Cooperative	0.48000000	0.07481297%	0.00253925%
		Tract Total:	**641.600**	**100.00000000%**	
21	Section 4-T141N-R83W	Square Butte Electric Cooperative	3.820	0.59499704%	0.02020821%
		Minnkota Power Cooperative, Inc.	638.200	99.40500296%	3.37614599%
		Tract Total:	**642.020**	**100.00000000%**	

22	Section 3-T141N-R83W	Minnkota Power Cooperative, Inc.	7.720	1.20256714%	0.04083962%
		Alan Schwalbe	634.240	98.79743286%	3.35519717%
		Tract Total:	**641.960**	**100.00000000%**	
23	Section 2-T141N-R83W	Carl Schwalbe	214.347	33.33333333%	1.13391846%
		Rolland Schwalbe	214.347	33.33333333%	1.13391846%
		Loren Schwalbe	214.347	33.33333333%	1.13391846%
		Tract Total:	**643.041**	**100.00000000%**	
24	Section 1-T141N-R83W	Carl Schwalbe	26.667	33.33333333%	0.14106951%
		Rolland Schwalbe	26.667	33.33333333%	0.14106951%
		Loren Schwalbe	26.667	33.33333334%	0.14106951%
		Tract Total:	**80.000**	**100.00000000%**	
25	Section 12-T141N-R83W	Richard A. Schwalbe and Lila M. Schwalbe	160.000	100.00000000%	0.84641705%
		Tract Total:	**160.000**	**100.00000000%**	
26	Section 11-T141N-R83W	Alan Schwalbe	480.000	80.00000000%	2.53925114%
		Julie Hatzenbihler	15.000	2.50000000%	0.07935160%
		Rodney J. Hatzenbihler	15.000	2.50000000%	0.07935160%
		Nancy Henke	15.000	2.50000000%	0.07935160%
		Bonnie Schwab	15.000	2.50000000%	0.07935160%
		Peggy Gobar	15.000	2.50000000%	0.07935160%
		Annette Hatzenbihler	15.000	2.50000000%	0.07935160%
		Brent Hatzenbihler	15.000	2.50000000%	0.07935160%
		Randy Hatzenbihler	15.000	2.50000000%	0.07935160%
		Tract Total:	**600.000**	**100.00000000%**	
27	Section 10-T141N-R83W	Alan Schwalbe	237.840	37.16250000%	1.25819894%
		Minnkota Power Cooperative, Inc.	2.160	0.33750000%	0.01142663%
		Delmar Hagerott	400.000	62.50000000%	2.11604261%
		Tract Total:	**640.000**	**100.00000000%**	
28	Section 9-T141N-R83W	Minnkota Power Cooperative, Inc.	640.000	100.00000000%	3.38566818%
		Tract Total:	**640.000**	**100.00000000%**	
29	Section 8-T141N-R83W	BNI Coal, Ltd.	161.000	25.15625000%	0.85170715%
		Minnkota Power Cooperative, Inc.	160.000	25.00000000%	0.84641705%
		Five D's, LLP	319.000	49.84375000%	1.68754398%
		Tract Total:	**640.000**	**100.00000000%**	

30	Section 7-T141N-R83W	Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	328.460	50.65231471%	1.73758839%
		Gary Leinius	320.000	49.34768529%	1.69283409%
		Tract Total:	**648.460**	**100.00000000%**	
31	Section 12-T141N-R84W	Jolene Berger	160.00000000	25.00000000%	0.84641705%
		Brian Dresser	320.00000000	50.00000000%	1.69283409%
		Frances Fuchs	160.00000000	25.00000000%	0.84641705%
		Tract Total:	**640.000**	**100.00000000%**	
32	Section 13-T141N-R84W	Mark Leischner and Susan Leischner	280.000	100.00000000%	1.48122983%
		Tract Total:	**280.000**	**100.00000000%**	
33	Section 18-T141N-R83W	Janet K. Dohrmann and L.J. Dohrmann, as Trustees of The Janet and L.J. Fast Revocable Trust	123.820	19.12100809%	0.65502099%
		Wayne Reuther	33.957	5.24378693%	0.17963438%
		Kent Reuther	33.957	5.24378693%	0.17963438%
		Keith Reuther	33.957	5.24378693%	0.17963438%
		Karen Shulz	33.957	5.24378693%	0.17963438%
		Jerald Reuther	33.957	5.24378693%	0.17963438%
		Martha Reuther	33.957	5.24378693%	0.17963438%
		Larry F. Schmidt and Virginia Schmidt	320.000	49.41627031%	1.69283409%
		Tract Total:	**647.560**	**100.00000000%**	
34	Section 17-T141N-R83W	Five D's LLP	320.000	50.00000000%	1.69283409%
		Jerald O. Reuther	79.698	12.45286458%	0.42161267%
		Wayne A. Reuther	53.333	8.33333333%	0.28213902%
		Karen L. Reuther	26.667	4.16666667%	0.14106951%
		Jeanette M. Reuther	0.302	0.04713542%	0.00159585%
		Larry F. Schmidt and Virginia Schmidt	160.000	25.00000000%	0.84641705%
		Tract Total:	**640.000**	**100.00000000%**	
35	Section 16-T141N-R83W	Larry F. Schmidt and Virginia Schmidt	160.000	25.00000000%	0.84641705%
		BNI Coal, Ltd.	160.000	25.00000000%	0.84641705%
		Oliver County	2.510	0.39218750%	0.01327817%
		State of North Dakota - Dept. of Trust Lands Attn: Commissioner of University and School Lands	317.490	49.60781250%	1.67955592%
		Tract Total:	**640.000**	**100.00000000%**	
36	Section 15-T141N-R83W	Delmar Hagerott	240.000	100.00000000%	1.26962557%
		Tract Total:	**240.000**	**100.00000000%**	

37	Section 14-T141N-R83W	Alan Schwalbe	190.000	100.00000000%	1.00512024%
		Tract Total:	**190.000**	**100.00000000%**	
38	Section 21-T141N-R83W	Douglas D. Doll and Deberra K. Doll	100.000	22.72727273%	0.52901065%
		James D. Pazdernik and Bonita Pazdernik	100.000	22.72727273%	0.52901065%
		Anton Pfleger and Helen Pfleger	160.000	36.36363636%	0.84641705%
		Delmar Hagerott	80.000	18.18181818%	0.42320852%
		Tract Total:	**440.000**	**100.00000000%**	
39	Section 20-T141N-R83W	Douglas D. Doll and Deberra K. Doll	80.000	25.00000000%	0.42320852%
		James D. Pazdernik and Bonita Pazdernik	80.000	25.00000000%	0.42320852%
		Dale P. Pfliger and Judy Pfliger	80.000	25.00000000%	0.42320852%
		Thomas Pfliger	80.000	25.00000000%	0.42320852%
		Tract Total:	**320.000**	**100.00000000%**	
40	Section 19-T141N-R83W	Winfrid Keller	120.000	49.59497438%	0.63481278%
		Jerald Reuther	23.684	9.78839478%	0.12529088%
		Wayne Reuther	23.684	9.78839478%	0.12529088%
		Kent Reuther	23.684	9.78839478%	0.12529088%
		Keith Reuther	27.224	11.25144552%	0.14401786%
		Karen Shulz	23.684	9.78839478%	0.12529088%
		Tract Total:	**241.960**	**100.00000000%**	
		Total Acres:	**18903.211**	**Total Participation:**	**100.00000000%**

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Storage Agreement
Tundra Broom Creek - Secure Geological Storage
Oliver County, North Dakota

Tract No.	**Acres**	**Tract Participation Factor**
1	160.000	0.84641705%
2	480.000	2.53925114%
3	240.000	1.26962557%
4	40.000	0.21160426%
5	440.000	2.32764687%
6	640.000	3.38566818%
7	640.000	3.38566818%
8	560.000	2.96245966%
9	200.000	1.05802131%
10	560.000	2.96245966%
11	640.000	3.38566818%
12	640.000	3.38566818%
13	640.000	3.38566818%
14	647.480	3.42523818%
15	320.000	1.69283409%
16	80.000	0.42320852%
17	430.960	2.27982431%
18	640.520	3.38841904%
19	647.650	3.42613750%
20	641.600	3.39413235%
21	642.020	3.39635420%
22	641.960	3.39603679%
23	643.041	3.40175539%
24	80.000	0.42320852%
25	160.000	0.84641705%
26	600.000	3.17406392%
27	640.000	3.38566818%
28	640.000	3.38566818%
29	640.000	3.38566818%
30	648.460	3.43042248%
31	640.000	3.38566818%
32	280.000	1.48122983%
33	647.560	3.42566139%
34	640.000	3.38566818%
35	640.000	3.38566818%
36	240.000	1.26962557%
37	190.000	1.00512024%
38	440.000	2.32764687%
39	320.000	1.69283409%
40	241.960	1.27999418%
Total:	**18903.211**	**100.00000000%**

EXHIBIT D

Surface Use And Pore Space Lease
Attached to and made part of the Storage Agreement
Tundra Broom Creek
Oliver County, North Dakota

SURFACE USE AND PORE SPACE LEASE

THIS SURFACE USE AND PORE SPACE LEASE (**"Lease"**) is made, entered into, and effective as of the _______day of ___________________, 2020 (**"Effective Date"**) by and between _______________, whose address is ______________________ (whether one or more, **"Lessor"**), and Minnkota Power Cooperative, Inc., a Minnesota cooperative association, whose address is _________________________ (whether one or more, **"Lessee"**). Lessor and Lessee are sometimes referred to in this Lease individually as a "**Party**" and collectively as the **"Parties."**

1. **DEFINITIONS.** The following terms shall have the following meanings in this Lease:

"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.

"Commencement of Operations" means the date on which Carbon Dioxide is first injected into a Reservoir for commercial operations under this Lease, provided that the performance of test injections and related activities shall not be deemed Commencement of Operations.

"Commission" means the North Dakota Industrial Commission.

"Completion Notice" means a certificate of project completion issued to Lessee by the Commission pursuant to Chapter 38-22 of the North Dakota Century Code.

"Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the Operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits.

"Environmental Incentives" means any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into the Operations, environmental benefits of Operations, or other similar programs available from any regulated entity or any Governmental Authority.

"Facilities" means all facilities, structures, improvements, fixtures, equipment, and any other personal property at any time acquired or constructed by or for Lessee that are necessary or desirable in connection with any use of Reservoirs and their Formations or Operations, including without limitation wells, pipelines, roads, utilities, metering or monitoring equipment, and buildings.

"Financing Parties" means person or persons providing construction or permanent financing to Lessee in connection with construction, ownership, operation and maintenance of Facilities or Operations, including financial institutions, leasing companies, institutions, tax equity partners, joint venture partners and/or private lenders.

"Formation" means the geological formation of which any Reservoir is a part.

"Hazardous Substance" means any chemical, waste or other substances, expressly excluding Carbon Dioxide and Non-Native Carbon Dioxide, (a) which now or hereafter becomes defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollutions," "pollutants," "regulated substances," or words of similar import under any law pertaining to environment, health, safety or welfare, (b) which is declared to be hazardous, toxic or polluting by any Governmental Authority, (c) exposure to which now or hereafter prohibited, limited or regulated by any Governmental Authority, (d) the storage, use, handling, disposal or release of which is restricted or regulated by any Governmental Authority, or (e) for which remediation or cleanup is required by any Governmental Authority.

"Leased Premises" means the surface and subsurface of the land, excluding mineral rights, described in **Exhibit A** of this Lease.

"Native Oil and Gas" means all oil, natural gas, and other hydrocarbons present in and under the Leased Premises and not injected by Lessor, Lessee or any third party.

"Non-Native Carbon Dioxide" means Carbon Dioxide that is not naturally occurring in the Reservoir together with incidental associated substances, fluids, minerals, oil, and gas, excluding that which, independent of Operations, originates from an accumulation meeting the definition of a Pool. All Non-Native Carbon Dioxide will be considered personal property of the Lessee and its successor and assigns under this Agreement.

"Operating Year" means the calendar year or portion of the calendar year following Commencement of Operations during which Operations occur.

"Operations" means the transportation and injection of Carbon Dioxide into a Reservoir after Commencement of Operations, and any withdrawal of this Carbon Dioxide, as well as the withdrawal of Non-Native Carbon Dioxide, for sale or disposal in accordance with applicable law.

"Option Money" means 20 percent of the Initial Term Payment (as such term is defined in that certain Option to Lease between Lessor and Lessee with respect to the Leased Premises).

"Pool" means an underground Reservoir containing a common accumulation of Native Oil and Gas that is economically recoverable. A zone of a structure that is completely separated from any other zone in the same structure is a Pool.

"Pore Space" means a cavity or void, whether natural or artificially created, in a Reservoir.

"Related Person" means any member, partner, principal, officer, director, shareholder, predecessor-in-interest, successor-in-interest, employee, agent, heir, representative, contractor, lessee, sublessee, licensee, invitee, permittee of a Party, Financing Parties or any other person or entity that has obtained or in future obtains rights or interests from, under or through a Party (excluding the other Party itself).

"Reservoir" means any subsurface stratum, sand, formation, aquifer, cavity or void, whether natural or artificially created, wholly or partially within the Leased Premises, suitable for the storage or sequestration of carbon dioxide or other gaseous substances.

"Storage Fee" means Lessor's proportionate share of sixteen cents ($0.16) per metric ton of Carbon Dioxide ("Storage Rate") as determined by the Lessee's last meter before injection as part of Operations. For injection periods after 2026, the Storage Rate shall be adjusted to an amount equal to the product of sixteen cents ($0.16) and the inflation adjustment factor for such calendar year. The inflation adjustment factor shall be determined in the same manner as provided in 26 U.S.C. §45Q(f)(7)(B), substituting "2026" for "2008". The Storage Fee shall be: (i) calculated separately for each amalgamated area as created and established by the Commission that includes any portion of the Leased Premises; (ii) limited to the Carbon Dioxide injected in said amalgamated area in the immediately preceding Operating Year; and (iii) based on the Lessor's proportionate per net acre share of said unit. For avoidance of doubt, the Lessor shall receive a separate Storage Fee for each amalgamated area created and established by the Commission that includes any portion of the Leased Premises on a net acre basis within the Lessor's interest being the numerator and the acres in the amalgamated area being the denominator.

"Tax Credits" means any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. §45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to construction, ownership or Operations

2. LEASE RIGHTS. In consideration of the compensation, covenants, agreements, and conditions set forth in this Lease, Lessor grants, demises, leases and lets to Lessee the exclusive right to use all Pore Space, Reservoirs and their Formations in the Leased Premises for any purpose not previously granted or reserved by an instrument of record related to the capture, injection, storage, sequestration, sale, withdrawal or disposal of Carbon Dioxide, Non-Native Carbon Dioxide and incidental associated substances, fluids, and minerals, provided that Lessee shall have no right to use potable water from within the Leased Premises in Operations; together with the following exclusive rights:

(a) to use the Leased Premises for developing, constructing, installing, improving, maintaining, replacing, repowering, relocating, removing, abandoning in place, expanding, and operating Facilities;

(b) to lay, maintain, replace, repair, and remove roads on the Leased Premises to allow Lessee, in its sole discretion, to exercise its rights under this Lease; and

(c) to enter upon and use the Leased Premises for the purposes of conducting:

(i) any investigations, studies, surveys, and tests, including without limitation drilling and installing test wells and monitoring wells, seismic testing, and other activities as Lessee deems necessary or desirable to determine the suitability of the Leased Premises for Operations,

(ii) any inspections and monitoring of Reservoirs and Carbon Dioxide as Lessee or any governmental authority deems necessary or desirable during the term of this Lease, and

(iii) any maintenance to the Facilities that Lessee or any governmental authority deems necessary or as required by applicable law.

Lessor also hereby grants and conveys unto Lessee all other and further easements across, over, under and above the Leased Premises as reasonably necessary to provide access to and services reasonably required for Lessee's performance under the Lease. The easements granted hereunder shall run with and burden the Leased Premises for the term of this Lease. Notwithstanding the surface easements granted herein, Lessee shall provide notice to Lessor prior to accessing the surface of the Property, and if such activity requires permit then prior notice shall be in form and not be less than that required by law or rule.

Lessee may exercise its rights under this Lease in conjunction with related operations on other properties near the Leased Premises. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or to 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.

3. INITIAL TERM. This Lease shall commence on the Effective Date and shall continue for an initial term of twenty (20) years ("Initial Term") unless sooner terminated in accordance with the terms of this Lease. Lessee may, but is not obligated to, extend the Initial Term for up to four successive five-year periods by paying Lessor $25.00 per net acre in the Leased Premises per five-year extension on or prior to the last day of the Initial Term or expiring five-year extension period. The Initial Term together with any extensions are referred to as the "Primary Term."

4. OPERATIONAL TERM. Upon Commencement of Operations at any time during the Primary Term, this Lease shall continue for so long as any portion of the Leased Premises or

Lessee's Facilities are subject to a permit issued by the Commission or under the ownership or control of the State of North Dakota ("Operational Term"); *provided, however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a Completion Notice, except for payment of the Final Royalty Payment (as applicable), and Final Occupancy Fee (as applicable). If Commencement of Operations does not occur during the Primary Term, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county in which the Leased Premises is located.

5. COMPENSATION.

(a) **Initial Term Payment.** Lessee shall pay to Lessor the greater of $50.00 per net acre in the Leased Premises ("Initial Term Payment") or a one-time flat $500.00 payment, the receipt and sufficiency of which are hereby acknowledged.

(b) **Royalty.** During the Operational Term, Lessee shall annually on or before May 31st pay to Lessor a royalty equal to the greater of a flat $100.00 payment or the Storage Fee(s) for the immediately preceding Operating Year. For the Operating Year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay a pro rata share of the Storage Fee(s) ("Final Royalty Payment"), as applicable, and said payment shall be made within sixty days after the date the Completion Notice was issued.

(c) **Occupancy Fee.** Within sixty days of the anniversary of the Effective Date after which any Facilities are installed or used, Lessee shall pay Lessor, as applicable, a one-time fee of (i) $3,000.00 per net surface acre of the Leased Premises occupied by Facilities (excluding pipelines), and (ii) $1.50 for each linear foot of pipeline in place on the Leased Premises. For the year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay any fees owed pursuant to this provision ("Final Occupancy Fee") within sixty days after the date the Completion Notice was issued.

Lessor and Lessee agree that the Lease shall continue as specified herein even in the absence of Operations and the payment of royalties.

6. AMALGAMATION. (a) Lessee, in its sole discretion, shall have the right and power, at any time (including both before and after Commencement of Operations), to pool, unitize, or amalgamate any Reservoir or portion of a Reservoir with any other lands or interests into which that Reservoir extends and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county in which the amalgamated unit. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit agreements and operating agreements with respect to the operation of any amalgamated areas formed under this Lease.
(b) The injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide into a Reservoir from any property within a amalgamated area that includes the Leased Premises shall be treated as if Operations were occurring on the Leased Premises, except that the royalty payable to Lessor under Section 5(b) of this Lease shall be Lessor's per net acre proportionate share of the total Storage Fee for the preceding Operating year's injection of Carbon Dioxide into the amalgamated area.

7. ENVIRONMENTAL INCENTIVES. Unless otherwise specified, Lessee is the owner of all

Environmental Attributes and Environmental Incentives and is entitled to the benefit of all Tax Credits or any other attributes of ownership of the Facilities and Operations. Lessor shall cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

8. SURRENDER OF LEASED PREMISES. Lessee shall have the unilateral right at any time and from time to time to execute and deliver to Lessor a written notice of surrender and/or release covering all or any part of the Leased Premises for which the subsurface pore space 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.

9. FACILITIES.

(a) Lessee shall in good faith consult with Lessor regarding the location of the Facilities, selection of the Facilities location shall be within the discretion of the Lessee with consent of the Lessor, not to be unreasonably withheld. The withholding of such consent by the Lessor regarding the location of the Facilities shall be deemed "unreasonable" if the proposed location of the Facility is located more than 500 feet from any occupied dwellings or currently used buildings existing on the Leased Premises as of the Effective Date. Notwithstanding the foregoing, in no event shall Facilities be located within 500 feet of any currently occupied dwelling or currently used building existing on the Leased Premises as of the Effective Date without Lessor's express consent. Lessee may erect fences around all or part of any aboveground Facilities (excluding roads) to separate Facilities from adjacent Lessor-controlled lands, and shall do so if Lessor so requests. Lessee shall maintain and repair at its expense any roads it constructs on the Leased Premises in reasonably safe and usable condition.

(b) Lessor and Lessee agree that all Facilities and property of whatever kind and nature constructed, placed or affixed on the rights-of-way, easements, patented or leased lands as part of Lessee's Operations, as against all parties and persons whomsoever (including without limitation any party acquiring interest in the rights-of-way, easements, patented or leased lands or any interest in or lien, claim or encumbrance against any of such Facilities), shall be deemed to be and remain the property of the Lessee, and shall not be considered to be fixtures or a part of the Leased Premises. Lessor waives, to the fullest extent permitted by applicable law, any and all rights it may have under the laws of the State of North Dakota, arising under this Lease, by statute or otherwise to any lien upon, or any right to distress or attachment upon, or any other interest in, any item constituting the Facilities or any other equipment or improvements constructed or acquired by or for Lessee and located on the leased Premises or within any easement area. Each Lessor and Lessee agree that the Lessee (or the designated assignee of Lessee or Financing Parties) is the tax owner of any such Facilities, structures, improvements, equipment and property of whatever kind and nature and all tax filings and reports will be filed in a manner consistent with this Lease. Facilities shall at all times retain the legal status of personal property as defined under Article 9 of the Uniform Commercial Code. If there is any mortgage or fixture filing against the Premises which could reasonably be construed as prospectively attaching to the Facilities as a fixture of the Premises, Lessor shall provide a disclaimer or release from such lienholder. Lessor, as fee owner, consents to the filing of a disclaimer of the Facilities as a fixture of the Premises in the Oliver County Recorder's Office, or where real estate records of Oliver County are customarily filed.

10. SURFACE DAMAGE COMPENSATION ACT. The 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 (to the extent applicable).

11. MINERALS, OIL AND GAS. This Lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for Lessee to explore for or produce minerals, including Native Oil and Gas, that may exist on the Leased Premises. Lessee shall not engage in any activity or permit its Related Persons to engage in any activity that unreasonably interferes with the Lessor's or third party's (or parties') rights to the granted, leased, or reserved mineral interests. If Lessor owns hydrocarbon mineral interests in the Leased Premises and Lessee should inadvertently discover a Pool in conjunction with its efforts to explore for and develop a Reservoir for Operations, Lessee shall inform Lessor within 60 days of discovery. If Lessee determines that it will not use in conjunction with Operations a well that has encountered a Pool within the Leased Premises, Lessor shall have the option but not the obligation to buy such well at cost, provided Lessor has the ability and assumes all permits and risks and liabilities which are associated with the ownership and operation of an oil, gas or mineral well.

12. FORCE MAJEURE. Should Lessee be prevented from complying with any express or implied covenant of this Lease, from utilizing the Leased Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material failure or breakdown of equipment, or by operation of force majeure (including, but not limited to, riot, insurrection, war (declared or not), mobilization, explosion, labor dispute, fire, flood, earthquake, storm, lightning, tsunami, backwater caused by flood, vandalism, act of the public enemy, terrorism, epidemic, pandemic (including COVID-19), civil disturbances, strike, labor disturbances, work slowdown or stoppage, blockades, sabotage, labor or material shortage, national emergency, and the amendment, adoption or repeal of or other change in, or the interpretation or application of, any applicable laws, orders, rules or regulations 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.

13. DEFAULT/TERMINATION. Lessor may not terminate the Lease for any reason whatsoever unless a Default Event has occurred and is continuing consistent with the terms of this Section 13. Any Party that fails to perform its responsibilities as listed below shall be deemed to be the "Defaulting Party," the other Party shall be deemed to be the "Non-Defaulting Party," and each event of default shall be a "Default Event." A Default Event is: (a) failure of a Party to pay any amount due and payable under this Lease, other than an amount that is subject to a good faith dispute, within thirty (30) days following receipt of written notice from Non-Defaulting Party of such failure to pay; or (b) a material violation or default of any terms of this Lease by a Party, provided the Non-Defaulting Party provides written notice of violation or default and Defaulting Party fails to substantially cure the violation or default within sixty (60) days after receipt of said notice to cure such violations or defaults. Parties acknowledge that in connection with any construction or long-term financing or other credit support provided to Lessee or its affiliates by Financing Parties, that such Financing Parties may act to cure a continuing Default Event and Lessor agrees to accept performance from any such Financing Parties so long as such Financing Parties perform in accordance with the terms of this Lease. If Lessee, its affiliates or Financing Parties, fail to substantially cure such Default Event within the applicable 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, plug, and/or abandon in place all Facilities of Lessee located on the Leased Premises in accordance with applicable permit requirements or other applicable statutes, rules or regulations.

14. ASSIGNMENT. (a) Lessor shall not sell, transfer, assign or encumber the Facilities or any part of Operations, Lessee's title or Lessee's rights under this Lease. (b) Lessee has the right to sell, assign, mortgage, pledge, transfer, use as collateral, or otherwise collaterally assign or convey all or any of its rights under this Lease, including, without limitation, an assignment by Lessee to Financing Parties. (c) In the event Lessee assigns its rights under this Lease, Lessee shall be relieved of all obligations with respect to the assigned portion arising after the date of assignment so long as notice of such assignment is provided to Lessor, and provided that Lessee shall not be relieved from any obligation in respect of any payment or other obligations that have not been satisfied or performed prior to such date of assignment. (d) This Lease shall be binding on and inure to the benefit of the successors and assignees. 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. Further, no change or division in Lessor's ownership of or interest in the Leased Premises or royalties shall enlarge the obligations or diminish the rights of Lessee or be binding on Lessee until after Lessee has been furnished with a written assignment or a true copy of the assignment with evidence that same has been recorded with the Oliver County Recorder's Office.

15. FINANCING. (a) Lessor acknowledges that Lessee may obtain tax equity, construction, long-term financing and other credit support from one or more Financing Parties and that Lessee intends to enter into various agreements and execute various documents relating to such financing, which documents may, among other things, assign this Lease and any related easements to a Financing Party, grant a sublease in the Leased Premises and a lease of the Facilities from such Financing Party to Lessee, grant the Financing Parties a sublease or other real property interest in Lessee's interests in and to the Leased Premises, grant a first priority security interest in Lessee's interest in the Facilities and/or this Lease and Lessee's other interests in and to the Leased Premises, including, but not limited to, any easements, rights of way or similar interests (such documents, "Financing Documents"). Lessor acknowledges notice of the foregoing and consents to the foregoing actions and Financing Documents described above.

(b) Lessor agrees, to execute, and agrees to cause any and all of Lessor's lenders to execute, such commercially reasonable subordination agreements, non-disturbance agreements, forbearance agreements, consents, estoppels, modifications of this Lease and other acknowledgements of the foregoing as Lessee or the Financing Parties may reasonably request (collectively, "Lessor Financing Consent Instruments"). Lessor acknowledges and agrees that (i) Lessee's ability to obtain financing for the construction and operation of the Facilities is dependent upon the prompt cooperation of Lessor and its lenders as contemplated by this Section 15; (ii) if Lessee is unable to close on the financing for the Facilities, the construction of the Facilities and the Commencement of Operations will not likely occur; and (iii) it is in the best interest of both Lessee and Lessor for Lessee to obtain financing from the Financing Parties as contemplated by this Section 15. Therefore, Lessor agrees to act promptly, reasonably and in good faith in connection with any request for approval and execution of all Lessor Financing Consent Instruments. The Lessor shall also reasonably cooperate with the Lessee or the Financing Party in the making of any filings required by such requesting party for regulatory compliance or in accordance with applicable laws and in the operation and maintenance of the Facilities, all solely at the expense of the Lessee.

(c) As a precondition to exercising any rights or remedies as a result of any default or alleged default by Lessee under this Lease, Lessor shall deliver a duplicate copy of the applicable notice of default to each Financing Parties concurrently with delivery of such notice to Lessee, specifying in detail the alleged default and the required remedy, provided Lessor was given notice of such Financing Parties and if no such notice of default is required to be delivered to Lessee under this Lease, Lessor may not terminate this Lease unless Lessor has delivered a notice of default to each Financing Party specifying in detail the alleged default or breach and permitting each Financing Party the opportunity to cure as provided in this Section 15(c). Each Financing Party shall have the same period after receipt of a notice of default to remedy default, or cause the same to be remedied, as is given to Lessee after Lessee's receipt of a notice of default under this Lease, plus, in each instance, the following additional time periods: (i) ten (10) Business Days in the event of any monetary default; and (ii) sixty (60) days in the event of any non-monetary default; provided, however, that (A) such sixty (60)-day period shall be extended for an additional sixty 60 days to enable such Financing Party to complete such cure, including the time required for such Financing Party to obtain possession of the Facilities (including possession by a receiver), institute foreclosure proceedings or otherwise perfect its right to effect such cure and (B) such Financing Party shall not be required to cure those defaults which are not reasonably susceptible of being cured or performed. Lessor shall accept such performance by or at the instance of a Financing Party as if the performance had been made by Lessee.

(d) If any Lessee Default Event cannot be cured without obtaining possession of all or part of the Facilities and/or the leasehold interest created by the Lease (the "Leasehold Estate"), then any such Lessee Default Event shall nonetheless be deemed remedied if: (i) within sixty (60) days after receiving the notice of default, a Financing Party acquires possession thereof, or commences appropriate judicial or non-judicial proceedings to obtain the same; (ii) such Financing Party is prosecuting any such proceedings to completion with commercially reasonable diligence; and (iii) after gaining possession thereof, such Financing Party performs all other obligations as and when the same are due in accordance with the terms of the Lease. If a Financing Party is prohibited by any process or injunction issued by any court or by reason of any action of any court having jurisdiction over any bankruptcy or insolvency proceeding involving Lessee from commencing or prosecuting the proceedings described above, then the sixty (60)-day period specified above for commencing such proceedings shall be extended for the period of such prohibition.

(e) Financing Parties shall have no obligation or liability to the Lessor for performance of the Lessee's obligations under the Lease prior to the time the Financing Party acquires title to the Leasehold Estate. A Financing Party shall be required to perform the obligations of the Lessee under this Lease only for and during the period the Financing Party directly holds such Leasehold Estate. Any assignment pursuant to this Section 15 shall release the assignor from obligations accruing under this Lease after the date the liability is assumed by the assignee.

(f) Each Financing Party shall have the absolute right to do one, some or all of the following things: (i) assign the rights, mortgage or pledge held by Financing Party (the "Financing Party's Lien"); (ii) enforce the Financing Party's Lien; (iii) acquire title (whether by foreclosure, assignment in lieu of foreclosure or other means) to the Leasehold Estate; (iv) take possession of and operate the Facilities or any portion thereof and perform any obligations to be performed by Lessee under the Lease, or cause a receiver to be appointed to do so; (v) assign or transfer the Leasehold Estate to a third party; or (vi) exercise any rights of Lessee under this Lease. Lessor's consent shall not be required for any of the foregoing; and, upon acquisition of the Leasehold Estate by a Financing Party or any other third party who acquires the same from or on behalf of the Financing Party or any purchaser who purchases at a foreclosure sale, Lessor shall recognize the Financing Party or such other party (as the case may be) as Lessee's proper successor, and this Lease shall remain in full force and effect.

(g) If this Lease is terminated for any reason whatsoever, including a termination by Lessor on account of a Lessee Default Event, or if this Lease is rejected by a trustee of Lessee in a bankruptcy or reorganization proceeding or by Lessee as a debtor-in-possession (whether or not such rejection shall be deemed to terminate this Lease), if requested by Financing Party, Lessor shall execute a new lease (the "New Lease") for the Leased Premises with the Financing Parties (or their designee(s), if applicable) as Lessee, within thirty (30) days following the date of such request. The New Lease shall be on substantially the same terms and conditions as are in this Lease (except for any requirements or conditions satisfied by Lessee prior to the termination or rejection). Upon execution of the New Lease by Lessor, Financing Parties (or their designee, if applicable) shall pay to Lessor any and all sums owing by Lessee under this Lease that are unpaid and that would, at the time of the execution of the New Lease, be due and payable under this Lease if this Lease had not been terminated or rejected. The provisions of this Section 15(g) shall survive any termination of this Lease prior to the expiration of the Term, and any rejection of this Lease in any bankruptcy or reorganization proceeding.

(h) Lessor consents to each Financing Party's security interest, if any, in the Facilities and waives all right of levy for rent and all claims and demands of every kind against the Facilities, such waiver to continue so long as any sum remains owing from Lessee to any Financing Parties. Lessor agrees that the Facilities shall not be subject to distraint or execution by, or to any claim of, Lessor.

16. INDEMNIFICATION; WAIVER. (a) Each Party shall indemnify, defend, and hold harmless the other Party and its Related Persons from and against any and all third-party suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of physical damage to property and physical injuries to any person, including death, caused by the indemnifying Party or its Related Persons except to the extent such claims arise out of the negligence or willful misconduct of the indemnified Party or its Related Persons. (b) Each Party shall indemnify, defend and hold harmless the other Party and its Related Persons from and against all suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of or relating to the existence at, on, above, below or near the Leased Premises of any Hazardous Substance, except to the extent deposited, spilled or otherwise caused by the indemnified Party or any of its contractors or agents, provided that Lessee shall not be obligated to indemnify Lessor with respect to any Hazardous Substance on the Leased Premises prior to the Effective Date.

17. INSURANCE. Lessee shall, at its sole cost and expense, keep and maintain in force commercial general liability insurance including broad form property damage liability, personal injury liability, and contractual liability coverage, on an "occurrence" basis, with a combined single limit, which may be effected by primary and excess coverage, of not less than Five Million Dollars ($5,000,000.00) during the primary term, except that such limit in the Primary Term shall be instead not less than One Million Dollars ($1,000,000.00) until such time as Lessee commences physical testing of any injection wells or other similar commercial activities, with such commercially reasonable deductibles as Lessee, in its discretion, may deem appropriate. Lessor shall be named as an additional insured in such policy but only to the extent of the liabilities specifically assumed by the Lessee under this Lease. The policy shall contain provisions by which the insurer waives any right of subrogation it may have against Lessor and shall be endorsed to provide that the insurer shall give Lessor thirty days written notice before any material modification or termination of coverage. Upon Lessor's request, Lessee shall promptly deliver certificates of such insurance to Lessor.

18. MISCELLANEOUS.

(a) **Confidentiality.** Lessor shall maintain in the strictest confidence, and shall require each of Lessor's Related Persons to hold and maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business, operations on the Leased Premises or on any other lands, the capacity and suitability of the Reservoir, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

(b) **Liens.** (i) Lessee shall protect the Leased Premises from liens of every character arising from its activities on the Leased Premises, provided that Lessee may, at any time and without the consent of Lessor, encumber, hypothecate, mortgage, pledge, or collaterally assign (including by mortgage, deed of trust or personal property security instrument) all or any portion of Lessee's right, title or interest under this Lease (but not Lessor's right, title or interest in the Leased Premises), as security for the repayment of any indebtedness and/or the performance of any obligation. (ii) Lessor shall not directly or indirectly cause, create, incur, assume or allow to exist any mortgage, pledge, lien, charge, security interest, encumbrance or other claim of any nature on or with respect to the Facilities, Operations or any interest therein. Lessor shall immediately notify Lessee in writing of the existence of any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim, shall promptly cause the same to be discharged and released of record without cost to Lessee, and shall indemnify the Lessee against all costs and expenses (including reasonable attorneys' fees) incurred in discharging and releasing any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim.

(c) **Warranty of Title.** Lessor represents and warrants to Lessee that Lessor is the owner in fee of the surface and subsurface pore space 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. At any time on or after the Effective Date, Lessee may obtain for itself and/or any Financing Party, at Lessee's expense, a policy of title insurance in a form and with exceptions acceptable to Lessee and/or such Financing Party in its sole discretion (the "Title Policies"). Lessor agrees to cooperate fully and promptly with Lessee in its efforts to obtain the Title Policies, and Lessor shall take such actions as Lessee or any Financing Party may reasonably request in connection therewith.

(d) **Conduct of Operations.** Each Party shall, at its expense, use best efforts to comply (and cause its Related Persons to comply) in all material respects with all laws applicable to its (or their) activities on the Leased Premises, provided that each Party shall have the right, in its sole discretion, to contest, by appropriate legal proceedings, the validity or applicability of any law, and the other Party shall cooperate in every reasonable way in such contest, at no out-of-pocket expense to the cooperating Party. During the Primary Term, Lessee, its agents, affiliates, servants, employees, nominees and licensees shall be entitled to: (i) apply for and obtain any necessary permits, approvals and other governmental authorizations (collectively called "Governmental Authorizations") required for the development, construction, operation and maintenance of the Project and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to the Governmental Authorizations upon Lessee's written request and at Lessee's direction, cost and expense; and (ii) apply for any approvals and permits and any zoning amendment of any area of the Leased Premises required in connection with the Project, and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to such approvals, permits and zoning amendments upon Lessee's written request and at Lessee's direction, cost and expense.

(e) **Title to Carbon Dioxide.** As between Lessor and Lessee, all right, title, interest and ownership to all Carbon Dioxide injected into any Reservoir shall belong to Lessee, as measured by corresponding Storage Fee payment to Lessor.

(f) **Hazardous Substances.** Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or within the Leased Premises by Lessor or any of its Related Persons on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances.

(g) **Interference.** Lessee shall peaceably and quietly have, hold and enjoy the Leased Premises against any person claiming by, through or under the Lessor and without disturbance by the Lessor, unless Lessee is found in default of the terms of this Lease and such default is continuing. Lessor shall not unreasonably interfere with Lessee's access to or maintenance of the Facilities or associated use of Leased Premises under this Lease; endanger the safety of Lessor, Lessee, the general public, private or personal property, or the Facilities; or install or maintain or permit to be installed or maintained vegetation, undergrowth, trees (including overhanging limbs and foliage and any trees standing which are substantially likely to fall), buildings, structures, installations, and any other obstructions which unreasonably interfere to Lessee access or use of the Facilities, Formations or Lessee's use of the Leased Premises under this Lease. Lessor shall not engage in any activity or permit its Related Persons to engage in any activity that might damage or undermine the physical integrity of any Formation or interfere with Lessee's use of the Leased Premises under this Lease, provided however that it is understood by Lessee that Lessor has no right to permit or to prohibit the exercise of any mineral rights not owned by Lessor at the time of entering into the Option to Lease between Lessor and Lessee with respect to the Leased Premises. Neither Lessee nor its agents will engage in any activity that damages existing oil, gas and other mineral exploration and development activities occurring on the Leased Premises without first obtaining permission from the relevant mineral rights holder.

(h) **Reservations.** Lessor reserves the right to sell, lease, or otherwise dispose of any interest in the Leased Premises subject to the rights granted in this Lease and agrees that sales, leases, or other dispositions of any interest or estate in the Leased Premises shall be expressly made subject to the terms of this Lease and shall not unreasonably interfere with Lessee's rights under this Lease.

(i) **Taxes.** Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall pay any taxes, assessments, fines, fees, and other charges levied by any governmental authority against its Facilities on the Leased Premises. The Parties agree to cooperate fully to obtain any available tax refunds or abatements with respect to 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.

(j) **Amendments.** Lessee reserves the right to revise this Lease to remedy any mistakes, including correcting the names of the Parties, the legal description of the Leased Premises, or otherwise. In the event that any amendment alters the bonus and royalty payable under Section 5(a)-(b) of this Lease, the Lessee shall pay the Lessor the amount owed under the Lease as amended. Any amendments must be in writing and signed by both parties.

(k) **Remedies.** Notwithstanding anything to the contrary in this Lease, neither Party shall be liable to the other for any indirect, special, punitive, incidental or exemplary damages, whether foreseeable or not and whether arising out of or in connection with this Lease, by statute, in contract, tort, including negligence, strict liability or otherwise, and all such damages are expressly disclaimed.. This provision does not limit Lessee's obligation to indemnify Lessor for third-party suits, claims, or damages under Section 16 of this Lease.

(l) **Financial Responsibility.** Lessee will comply with all applicable law regarding financial responsibility for Carbon Dioxide storage, and will post bonds or other financial guarantees as required by the government entities.

(m) **Attorneys' Fees.** If any suit or action is filed or arbitration commenced by either Party against the other Party to enforce this Lease or otherwise with respect to the subject matter of this Lease, the prevailing party shall be entitled to recover reasonable costs and attorneys' fees incurred in investigation of related matters and in preparation for and prosecution of such suit, action, or arbitration as fixed by the arbitrator or court, and if any appeal or other form of review is taken from the decision of the arbitrator or any court, reasonable costs and attorneys' fees as fixed by the court.

(n) **Representations and Warranties.** Lessor represents and warrants to Lessee the following as of the Effective Date and covenants that throughout the Term: (i) Lessor has the full right, power and authority to grant rights, interests and license as contained in this Lease. Such grant of the right, interests and license does not violate any law, ordinance, rule or other governmental restriction applicable to the Lessor or the Leased Premises and is not inconsistent with and will not result in a breach or default under any agreement by which the Lessor is bound or that affects the Leased Premises. (ii) Neither the execution and delivery of this Lease by Lessor nor the performance by Lessor of any of its obligations under this Lease conflicts with or will result in a breach or default under any agreement or obligation to which Lessor is a party or by which Lessor or the Leased Premises is bound. (iii) All information provided by Lessor to Lessee, as it pertains to the Leased Premises' physical condition, along with Lessor's rights, interests and use of the Leased Premises, is accurate in all material respects. (iv) Lessor has no actual or constructive notice or knowledge of Hazardous Substances at, on, above, below or near the Leased Premises. (v) Each of the undersigned represents and warrants that they have the authority to execute this Lease on behalf of the Party for which they are signing.

(o) **Severability.** Should any provision of this Lease be held, in a final and unappealable decision by a court of competent jurisdiction, to be either invalid, void or unenforceable, the remaining provisions of this Lease shall remain in full force and effect, unimpaired by the holding. If the easements or other rights under this Lease are found to be in excess of the longest duration permitted by applicable law, the term of such easements or other rights shall instead expire on the latest date permitted by applicable law.

(p) **Memorandum 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 is situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

(q) **Notices.** All notices required to be given under this Lease shall be in writing, and shall be deemed to have been given upon (a) personal delivery, (b) one (1) Business Day after being deposited with FedEx or another reliable overnight courier service, with receipt acknowledgment requested, or (c) upon receipt or refused delivery deposited in the United States mail, registered or certified mail, postage prepaid, return receipt required, and addressed to the respective Party at the addresses set forth at the beginning of this Lease, or to such other address as either Party shall from time to time designate in writing to the other Party.

(r) **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.

(s) **Estoppels.** Either party hereto (the "Receiving Party"), without charge, at any time and from time to time, within ten (10) Business Days after receipt of a written request by the other party hereto (the "Requesting Party"), shall deliver a written statement, duly executed, certifying to such Requesting Party, or any other person, firm or entity specified by such Requesting Party: (i) that this Lease is unmodified and in full force and effect, or if there has been any modification, that the same is in full force and effect as so modified and identifying the particulars of such modification; (ii) whether or not, to the knowledge of the Receiving Party, there are then existing any offsets or defenses in favor of such Receiving Party against enforcement of any of the terms, covenants and conditions of this Lease and, if so, specifying the particulars of same and also whether or not, to the knowledge of such Receiving Party, the Requesting Party has observed and performed all of the terms, covenants and conditions on its part to be observed and performed, and if not, specifying the particulars of same; and (iii) such other information as may be reasonably requested by the Requesting Party. Any written instrument given hereunder may be relied upon by the recipient.

(t) **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.

(u) **Governing Law.** This Lease shall be governed, interpreted, and enforced in accordance with the laws of the state of North Dakota.

(v) **Further Action.** Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of easement and all documents required to obtain any necessary government approvals.

(w) **Entire Agreement.** This Lease, into which the attached **Exhibit A** is incorporated by reference, contains the entire agreement of the Parties. There are no other conditions, agreements, representations, warranties, or understandings, express or implied.

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

IN WITNESS OF THE ABOVE, Lessor and Lessee have caused this Lease to be executed and delivered by their duly authorized representatives as of the Effective Date.

LESSOR:

By:_______________________________

Print:_____________________________

By:_______________________________

Print:_____________________________

LESSEE:

MINNKOTA POWER COOPERATIVE, INC.

By:_______________________________

Print:_____________________________

Its:_______________________________

Exhibit A

LEGAL DESCRIPTION OF THE PROPERTY

The Leased Premises consists of the lands located in Oliver County, North Dakota that are owned by the Lessor and generally described as follows:

For purposes of calculating the royalty payable under Section 5(b) of this Lease, the Parties stipulate that the Leased Premises consists of ____________ acres.

73932984.1

APPENDIX I

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE – BROOM CREEK

Permit Item	NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit (section and page number; 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 [0.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [0.80 kilometer] of its outside 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;	Minnkota Power Cooperative, Inc. (Minnkota) 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. Minnkota 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 required by North Dakota statute for geologic storage of carbon dioxide (CO2) to make a good faith attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith attempt, it was able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of the pore space. 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, Minnkota submits the form of storage agreement attached hereto as Appendix H 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. **1.1 Storage Reservoir Pore Space** Minnkota Power Cooperative, Inc. (Minnkota) defines the proposed storage reservoir boundaries as the projected vertical and horizontal migration of the CO2 plume from the start until the end of injection. The storage reservoir vertical and horizontal boundaries are identified based on the computational model output of the areal extent of the CO2 plume volume at the end of the injection period (20 years), in which a CO2 saturation is predicted to be greater than or equal to 5%. The model utilizes applicable geologic and reservoir engineering information and analysis as detailed in Section 2.0 and Appendix A. The operation inputs for the simulation scenarios assumes storage at the average designed injection rates, approximately 4.0 MMt/year injected into the Broom Creek storage reservoir for the first 15 years of operation and 3.5 MMt/year for year 15 through year 20 of operation. These maximum rates were based on Minnkota's consideration of the planned maintenance, outage, and operating capacity of the Milton R. Young Station (MRYS) and carbon capture equipment along with the planned maintenance requirements and testing requirements of the Tundra SGS (secure geologic storage) site equipment. ***1.1.1 Horizontal Boundaries*** The proposed horizontal boundaries of the storage reservoirs, including an adequate buffer area, are defined by the simulated migration of the CO2 plume, using the actual rate of injection from the start until the end of injection. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Deadwood storage facilities if needed. The horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off the maximum design life of the carbon capture equipment. The reservoir models will be updated regularly with operating data, and the operator will provide evidence of the CO2 plume migration as part of the reevaluations required under NDAC §§ 43-05-01-05.1 and 43-05-01-11.4. These reevaluations are to occur no later than every 5 years, thus the simulation output at 5 years of operation is indicated in Figure 1-1 to exemplify the buffer existing within the proposed storage facility area, allowing safe operation as proposed and contemplated. The stacked storage operations scenario option allows for coordination of the capacity of the Black–Island Deadwood with the Broom Creek capacity and provides further assurance of the contemplated operation within the defined storage reservoir boundary.	Figure 1-1. Broom Creek storage facility area map.
			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. Broom Creek storage facility area map.
			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;		Figure 1-1. Broom Creek storage facility area map.
			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;		Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification
			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 1-2. Mineral Owners, Mineral Lessees and Operators Requiring Hearing Notification

		c. Each owner of record of the surface within the facility area and one-half mile [0.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [0.80 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 [0.80 kilometer] of the reservoir's boundary; and 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.		The simulated horizontal storage reservoir boundary results proposed for the Broom Creek Formation are depicted in Figure 1-1. ***1.1.2 Vertical Boundaries*** The Tundra SGS site was designed using a stacked storage concept, where two storage reservoirs identified with varying vertical depths could be accessed by a common wellsite. A key benefit of this development approach is to minimize the surface land use impact by reducing the amount of surface facilities required for operation. Despite the significant overlap of pore space area between the Broom Creek and Deadwood reservoirs, two distinct SFPs are being requested, with the distinct vertical boundaries based upon geologic analysis and simulations, which are further detailed and described in Section 2.0 of the respective SFP application supporting information. The applicant requests amalgamation of the injection zone pore space within the Broom Creek interval, as identified in Section 2.0, Figure 2-3. In addition to the injection zone, the applicant requests the permitted storage facility consist of the Opeche–Picard interval as the upper confining zone and Amsden Formation as the lower confining zone (Section 2.0, Figure 2-3). **1.2 Persons Notified** Minnkota will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 mi of its outside boundary. Minnkota will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to 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 in accordance with North Dakota law (NDCC Chapter 47-31): • A map showing the extent of the pore space that will be occupied by the CO2 plume over the injection period, including the storage reservoir boundary and 0.5 mi (0.8 km) outside of the storage reservoir boundary, with a description of the pore space ownership, surface owner, and pore space lessees of record (Figure 1-1). • A table identifying all pore space (surface) owners, and lessees of pore space of record, their mailing addresses, and legal descriptions of their pore space landownership (Table 1-1). • A table identifying each owner of record of minerals, mineral lessees and operators of record (Table 1-2).	
Geologic Exhibits	NDAC 43-05-01-05 §1b(1) and §1b(2)(k)	**NDAC 43-05-01-05 §1b(1) and §1b(2)(k)** (1) The name, description, and	a. Geologic description of the storage reservoir: Name Lithology	**2.3 Storage Reservoir (injection zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) and comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone and anhydrite layers (impermeable layers). The Broom Creek	Figure 2-8. Left: cross section of the inverted acoustic impedance volume for the western seismic 3D survey that transects the J-LOC1 well. The acoustic impedance log calculated

<table>
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<td>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>Average depth
Average thickness</td>
<td>Formation unconformably overlies the Amsden Formation and is unconformably overlain by mudstone, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3).

At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft.

The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14).

Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone.

Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15).

<u>For additional information, go to Section 2.3 of the Tundra SGS SFP.</u>

Table 2-1. Formations Making up the Tundra SGS CO_2 Storage Complex (average values calculated from the simulation model and well log data)
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Average Thickness, ft</th><th>Average Depth, ft</th><th>Lithology</th></tr>
<tr><td rowspan="3">Storage Complex</td><td>Opeche–Picard</td><td>Upper confining zone</td><td>154</td><td>4,712</td><td>Siltstone, mudstone evaporites</td></tr>
<tr><td>Broom Creek</td><td>Storage reservoir (i.e., injection zone)</td><td>249</td><td>4,915</td><td>Sandstone, dolostone, dolomitic sandstone, anhydrite</td></tr>
<tr><td>Amsden</td><td>Lower confining zone</td><td>270</td><td>5,175</td><td>Dolostone, limestone, anhydrite</td></tr>
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<td>from the J-LOC1 sonic and density logs is shown on the inset panel. Right: cross section of the inverted acoustic impedance volume for the eastern 3D survey. Figure 2-7 shows the location of these two cross sections.

Figure 2-9. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh, 1990).
Figure 2-10. Isopach map of the Broom Creek Formation in the Tundra SGS area.

Figure 2-11. Well log display of the interpreted lithologies of the Opeche–Picard, Broom Creek, and upper Amsden Formations in J-ROC1.

Figure 2-12a. Regional well log stratigraphic cross sections of the Opeche–Picard and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 2-12b. Regional well log cross sections showing the structure of the Opeche–Picard, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 2-13. Structure map of the Broom Creek Formation across the Tundra SGS area.

Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

Table 2-9. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex.

Table 2-10. Broom Creek Microfracture Results from J-LOC1 and BNI-1</td>
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	NDAC 43-05-01-05 §1b(2)(k)	**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;	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 Facies changes	**2.3 Storage Reservoir (injection zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. 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Table 2-9. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Broom Creek
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite
Formation Top Depth, ft	4,906
Thickness, ft	Sandstone 168 Dolostone 103 Dolomitic Sandstone 26 Anhydrite 19

Capillary Entry Pressure (CO_2/brine), psi	0.20

Geologic Properties

Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Broom Creek (sandstone)	Porosity, %*	19.51 (2.46–27.38)	21.4 (1.0–36.0)
	Permeability, mD**	69.29 (0.06–2,690)	168.8 (0.0–8,601.1)
Broom Creek (dolostone)	Porosity, %	8.11 (5.48–8.97)	5.8 (0.0–18.0)
	Permeability, mD	0.03 (0.02–0.05)	0.13 (0.0–2,259.6)

2.3.1 J-LOC1 Injectivity Tests

The J-LOC1 formation well testing was performed specifically to characterize the injectivity and obtain the breakdown pressure of the Broom Creek Formation in December 2020. The well testing consisted of a step rate test, extended injection test, and pressure falloff test. The well was perforated from 4,912 to 4,922 ft with 4 shots per foot (spf) and 90° phasing. To record the bottomhole pressure, a tandem downhole memory gauge was installed at a depth of 4,862 and 4,868 ft. The well test data were interpreted by GeothermEx, a Schlumberger Company.

The step rate test was performed with a total of ten injection rates. The initial injection rate was 1.27 barrels per minute (bpm), and final injection rate was 16 bpm. From the step rate test evaluation, the fracture opening pressure was observed at 3,424 psi, as shown in Figure 2-17.

A 12-hour extended injection rate was performed at a constant rate of 5 bpm followed by a 24-hour pressure falloff test. The interpretation of the pressure falloff data interpretation shows a permeability of 4,485 mD with reservoir pressure of 2,410 psi. No lateral boundary was observed from the pressure falloff test within the radius of investigation of 24,804 ft, as shown in Figures 2-18 and 2-19. Broom Creek Formation well testing is summarized in Table 2-11.

2.3.2 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 carbonate and anhydrite. Seventeen 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. Thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals shows that quartz (~85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (~4%), dolomite (~5%), and anhydrite as cement (~6%). 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 from 15% to 25%.

Two distinct carbonate intervals are notable. The first is the presence of a very fine- to fine-grained dolostone (75%), with quartz (16%) and feldspar (9%) present. The porosity is intercrystalline and not well-developed, averaging 5.5%. Diagenesis is expressed by dolomitization of the original calcite grains. The second carbonate interval comprises fine-grained dolomite (78%), quartz (10%), feldspar (8%), and clay (4%). Diagenesis is expressed by the dissolution of dolomite, resulting in vuggy porosity. The porosity averages 9%. The anhydrite intervals are expressed as thin beds that separate different sand bodies and cement. The porosity ranges from 1.5% to 2.5%.

Table 2-10. Broom Creek Microfracture Results from J-LOC1 and BNI-1

Figure 2-16. J-LOC1 Broom Creek Formation MDT microfracture in situ stress pump cycle graph at 5,045.4 ft.

Figure 2-17. Step rate test data of the Broom Creek Formation with fracture opening pressure observed at 3,424 psi (courtesy of GeothermEx, a Schlumberger Company). The x-axis is injection rate in barrels per minute while the y-axis is bottomhole injection pressure in psi.

Figure 2-18. GeothermEx interpretation of the Broom Creek pressure formation falloff test using Saphir – Kappa (courtesy of GeothermEx, a Schlumberger Company).

Figure 2-19. Broom Creek well test summary of J-LOC1 well (modified from Schlumberger presentation).

Table 2-11. J-LOC1 Broom Creek Formation Test Summary

Figure 2-20. Laboratory-derived mineralogic characteristics of the Broom Creek Formation.

Figure 2-21. XRF data from the Broom Creek from J-LOC1.

Table 2-12. XRD Results for JLOC-1 Broom Creek Core Samples

Table 2-13. Broom Creek Water Ionic Composition, expressed as molality

Figure 2-22. Upper graph shows cumulative injection vs. time. There is no observable difference in injection due to geochemical reactions. Lower graph shows wellhead injection pressure for the two cases is the same, 1,700 psi.

Figure 2-23. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality with a log scale. Upper image is a north-south cross section. Lower image is a planar view of Simulation Layer 11.

				XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, dolomite, anhydrite, feldspar, clay, and iron oxides (Figure 2-20). XRD data show illite is the most prominent type of clay within the formation. XRF data are shown in Figure 2-21 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%–80%), CaO (0%–30%), and MgO (0%–20%). The high percentage of CaO and SO_3 at 5,196 and 5,111 ft indicate a presence of a thin layer of anhydrite. The formation shows very little clay, with a range of 0% to 6% being the highest detected. ***2.3.3 Mechanism of Geologic Confinement*** For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche–Picard interval), 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), which confines the CO_2 within the proposed storage reservoir as identified in (Figure 2-3). 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. However, adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams. ***2.3.4 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 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. For this geochemical modeling study, the injection scenario consisted of a 20-year injection period with BHP (bottomhole pressure) and WHP (wellhead pressure) constraints of 3,005.4 and 1,700 psi, resulting in an annual injection rate of 3.35–3.67 MM tonnes/year. This scenario was run with and without the geochemical analysis option included, 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 meaningful change to storage reservoir performance or mechanical properties (porosity) of the storage formation. The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (87% of bulk reservoir volume) and average formation brine composition (13% of bulk reservoir volume). XRD data from the JLOC-1 well core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table 2-12). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the formation water is listed in Table 2-13. The injection stream is expected to be 99.9% CO_2. Other constituents represent 0.1% of the stream and are expected to include nitrogen (N_2) and water vapor (H_2O). However, 100% CO_2 was assumed for computational efficiency in the geochemical simulation to investigate rock and fluid interaction in the saline storage formation. N2 is known to be an inert gas, and water is already in the saline storage formation and will have little to no impact on the geochemical reactions. In the injection stream, argon (Ar) and oxygen vapor (O_2) may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation. The geochemistry case was run for the 20-year injection period followed by 22 years of postinjection monitoring. <u>For additional information, go to Section 2.3.4 of the Tundra SGS SFP.</u>	Figure 2-24. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine. Figure 2-25. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of illite, anhydrite, and K-feldspar with precipitation of calcite, quartz, and dolomite was observed. Figure 2-26. Change in molar distribution of illite, the most prominent dissolved mineral at the end of the injection period, shown in orange/yellow color. Compare to the molar CO_2 distribution in Figure 2-23. Figure 2-27. Change in molar distribution of quartz, a prominent precipitated mineral at the end of the injection period, shown in orange/yellow color. Compare to the molar CO_2 distribution in Figure 2-23. Figure 2-28. Change in porosity due to net geochemical dissolution after the 20-year injection period. Maximum porosity change is less than 0.4%. Compare to the molar CO_2 distribution in Figure 2-23.

Table 2-12. XRD Results for JLOC-1 Broom Creek Core Samples

Mineral Data	%
Dolomite	14.98
Quartz	53.78
Illite	2.20
K-Feldspar	5.52
Anhydrite	23.48
Albite	0.04

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 Opeche–Picard interval and underlying Amsden Formation (Figure 2-3, Table 2-14). Both the Amsden and Opeche–Picard intervals consist of impermeable rock layers.

Table 2-14. Properties of Upper and Lower Confining Zones in Simulation Area

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche–Picard	Amsden
Lithology	Siltstone	Dolostone
Formation Top Depth, ft	4,636	5,040
Thickness, ft	154	270
Porosity, % (core data)*	6.55	7.04
Permeability, mD (core data)**	0.112	0.017
Capillary Entry Pressure (CO_2/brine), psi	20.59	69.03
Depth below Lowest Identified USDW, ft	3,409	3,813

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35).

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool.

For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish.

Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite.

2.4.1.1 Mineralogy

Table 2-14. Properties of Upper and Lower Confining Zones in Simulation Area

Figure 2-29. Areal extent of the Piper Picard in western North Dakota (modified from Carlson, 1993).

Figure 2-30. Thickness of the Opeche–Picard interval in Oliver County derived from well log data.

Figure 2-31. Structure map of the Opeche/Spearfish interval of the upper confining zone across the greater Tundra SGS area.

Figure 2-32. Structure map of the lower Piper interval of the upper confining zone across the greater Tundra SGS area.

Figure 2-33. Isopach map of the Opeche/Spearfish interval of the upper confining zone in the Tundra SGS area.

Figure 2-34. Isopach map of the lower Piper interval of the upper confining zone in the Tundra SGS area.

Figure 2-35. Well log display of the upper confining zone at the J-ROC1 well.

Figure 2-36. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,887.7 ft.

Figure 2-37. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,888.8 ft.

Thin-section investigation shows that the Opeche/Spearfish Formation comprises alternating intervals of silty mudstone, argillaceous siltstone, mudstone, and anhydrite. Thin sections were created from the base of the Opeche/Spearfish and the transition zone present at the top of the Broom Creek which comprises clay-rich siltstone. The transition zone has similar characteristics as the Opeche/Spearfish Formation and will also act as a seal. The mineral components present in these samples are anhydrite, quartz, feldspar, dolomite, clay, and iron oxides. The grains are typically surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. The porosity equals 3.5%. Log interpretations and visual inspection of the collected core validate consistent mineral assemblage within the Opeche/Spearfish Formation.

XRD data from samples in the J-LOC1 well core supported facies interpretations from core descriptions and thin-section analysis. The Opeche/Spearfish Formation mainly comprises anhydrite, quartz, clay, and dolomite.

XRF analysis of the Opeche/Spearfish Formation identifies the major chemical constituents to be dominated by SiO_2 (47%), SO_3 (18%), CaO (16%), Al_2O_3 (4%), and MgO (2%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by the XRD (Table 2-15). Thus these results correlate with XRD, core description, and thin-section analysis.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 on the Opeche/Spearfish Formation, the primary confining zone. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche/Spearfish Formation was honored (Table 2-16). Formation brine composition was assumed as the same as the known composition from the Broom Creek injection zone below (Table 2-17). The CO_2 stream composition was as described by Minnkota (Table 2-18). The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/yr. This overestimate 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 of postinjection. The simulations were performed at reservoir pressure and temperature conditions.

Results showed geochemical processes at work. Figures 2-40, 2-41, and 2-42 show results from geochemical modeling. Figure 2-40 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, C1, the pH starts declining from an initial pH of 7.25 and stabilizes at a level of 5.3 after 14 years of injection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 25. Lastly, the pH is unaffected in Cell C3, indicating CO_2 does not penetrate this cell within the first 45 years. Figure 2-41 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock. The dashed lines are for Cell C1, solid lines that are only faintly seen in the figure are for Cell C2, 1.0 to 2.0 meters into the cap rock. The net change due to precipitation or dissolution in Cell C2 is less than 500 grams per cubic meter per year during active injection, with little to no precipitation or dissolution taking place after injection ceases in Year 2044. Any effects in cell C3 are too small to represent at this scale. Figure 2-42 shows change in porosity of the cap rock. Cell 1 experiences an initial increase in porosity as it is first exposed to CO_2 because of dissolution. The porosity decreases to nearly its initial condition after Year 14 because of precipitation. As dissolution occurs in Cell 1, reaction products move into Cell 2, where they precipitate, causing the porosity to slightly decrease. No significant change in porosity is seen in Cell 3 during the 45-year duration of the simulation. Note the scale of percent porosity change, E-05 to E-04. The net porosity changes from dissolution and precipitation are miniscule and unchanging in later years of the simulation. These results suggest that geochemical change from exposure to CO_2 is minor and will not cause substantive deterioration of the Opeche/Spearfish cap rock.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Piper–Picard interval. Impermeable rocks above the primary seal include the Upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-19). Together with the Opeche–Picard interval, these formations are 154 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-43). Including the Opeche–Picard there is over 850 ft of impermeable rocks that separate the Broom Creek from the Inyan Kara. Above the Inyan Kara Formation, 2,545 ft of impermeable rocks acts as an additional seal between the Inyan Kara Formation

Figure 2-38. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,873 ft.

Figure 2-39. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,897 ft.

Table 2-15. XRF Data for the Opeche/Spearfish Formation from J-LOC1

Table 2-16. Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of JLOC-1 Core Samples

Table 2-17. Formation Water Chemistry from Broom Creek Fluid Samples from JLOC-1

Table 2-18. Proposed Composition of the Injection Stream (Minnkota)

Figure 2-40. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1, 0.5 meters above the Opeche/Spearfish cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. pH for Cell C2 does not begin to change until after Year 25.

Figure 2-41. Dissolution and precipitation of minerals in the Opeche/Spearfish cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2, 1.5 meters above the cap rock base; these changes are barely visible. Results from Cell C3, 2.5 meters above the cap rock base, are not shown as they are too small to be seen at this scale.

Figure 2-42. Change in percent porosity of the Opeche/Spearfish cap rock. Red line shows porosity change calculated for Cell C1 at 0.5 meters above the cap rock base. Yellow line shows Cell C2, 1.5 meters above the cap rock base. Green line shows Cell C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to precipitation of minerals and negative change is due to mineral dissolution.

Figure 2-43. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift and lowermost USDW, the Fox Hills Formation (see Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-19).

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 (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensing (DTS) data for the Inyan Kara Formation using the downhole fiber optic cable provides an additional opportunity for mitigation and remediation (Section 4). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation in the Tundra SGS area is 3,714 ft, and the formation itself is 294 ft thick.

Table 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1,862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334

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 can be correlated across the Tundra SGS area (Figures 2-45 and 2-46). The Amsden Formation is 5,040 ft below land surface and 270 ft thick at the Tundra SGS site (Table 2-14).

The contact between the overlying Broom Creek and Amsden Formations 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 the J-LOC1 well. The lithology of the cored section of the Amsden Formation from the J-LOC1well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the two core plug samples taken from the Amsden Formation show porosity values ranging from 5.4% to 7.3% and permeability values from 0.0053 to 0.0062 mD (Table 2-20).

2.4.3.1 Mineralogy

The well logs and thin-section analyses show that the Amsden Formation comprises dolomite, sandy dolomite, shaly sandstone, and anhydrite. The dolomite is expressed by very fine- to fine-grained dolostone (35%), with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. Quartz overgrowth and the absence of intercrystalline porosity were observed in thin sections (Figure 2-47). The existing porosity (secondary porosity) is mainly due to the dissolution of feldspar and quartz and averages 5% (Figure 2-47, Table 2-21).

Anhydrite is present as beds that separate the dolomite intervals and cement and mineral components. It comprises anhydrite minerals with minor inclusions of iron oxides. The porosity is almost null.

The sandy dolomite mainly comprises 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 quartz and averages 5%.

Formation. This interval represents the primary and secondary confinement zones.

Figure 2-44. 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 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Figure 2-45. Structure map of the Amsden Formation across the greater Tundra SGS area.

Figure 2-46. Isopach map of the Amsden Formation across the Tundra SGS area.

Table 2-20. Amsden Core Sample Porosity and Permeability from J-LOC1

Figure 2-47. Plane-polarized light thin-section images from the J-LOC1 well Amsden Formation. This image shows the dolomite-quartz-rich nature of this interval of the Amsden Formation. The example shows dolomite, corroded quartz grains, and iron oxides. Porosity is due to the dissolution.

Table 2-21. XRF Data for the Amsden Formation from the J-LOC1 Well

Table 2-22. Mineral Composition of the Amsden Derived from XRD Analysis of JLOC1 Core Samples at a Depth of 5,211 ft and 5,218 ft MD

Figure 2-48. Change in fluid pH in the Amsden underlying confining layer for Cells C1–C19.

Figure 2-49. CO_2 concentration (molality) in the Amsden underlying confining layer for Cells C1–C19.

Figure 2-50. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for Cell C1, 0 to 1 meter below the Amsden top. Solid lines show results for Cell C2, 1 to 2 meters below the Amsden top.

				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 frequently separated by clay cement. The porosity is very low, averaging 7%, and is mainly due to the dissolution of feldspar and quartz. XRD was performed, and the results confirm the observations made during core description, thin-section description, and well log analysis. XRF data show the Amsden Formation has the same major chemical constituents as the Opeche/Spearfish Formation (Table 2-21). However, the interval at the contact with the Broom Creek Formation is underlain by 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. *2.4.3.2 Geochemical Interaction* The Broom Creek's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of nineteen cells, each cell 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation, and CO_2 was allowed to enter the system by advection and dispersion processes. Results were calculated at the center of each cell below the confining layer– CO_2 exposure boundary. The mineralogical composition of the Amsden was honored (Table 2-22). Formation brine composition was assumed to be the same as the known composition from the Broom Creek injection zone above (Table 2-17). The CO_2 stream composition was as described by Minnkota (Table 2-18). The Amsden Formation temperature and pressure were extrapolated from regional temperature and pressure gradients. Two different pressure levels, 2,360 and 3,675 psi, were applied to the CO_2 saturated brine at the base of the Broom Creek Formation. These values represent the initial and potential maximum pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. These simulations were run for 45 years to represent 20 years of injection plus 25 years of postinjection. Results show geochemical processes at work. Figures 2-48, 2-49, 2-50, and 2-51 show results from the geochemical modeling. Figure 2-48 shows change in fluid pH over 45 years of simulation time as CO_2 enters the system. Initial change in pH in all the cells from 7.3 to 7 is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines to a level of 5.4 after 20 years of injection and slowly declines further to 5.2 after an additional 25 years of postinjection. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2 interface. The pH for Cells 15–19 did not decline over the 45 years of simulation time. Figure 49 shows that CO_2 does not penetrate more than 14 meters (represented by Cell C14) within the 45 years simulated. Figure 2-50 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cells C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation period while quartz begins to precipitate. Montmorillonite (smectite) and illite clays largely follow mirror image paths of dissolution and precipitation during the time of the simulation. Figure 2-51. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to precipitation of minerals, and negative change is due to mineral dissolution. Change in porosity (% units) of the Amsden underlying confining layer is displayed in Figure 2-51 for Cells C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. Cell C1 shows an initial porosity increase, of 0.17%, but this change is temporary, and the cell quickly returns to its near initial porosity value of 7.5%. At later times, no significant porosity changes were observed. Cells C4–C19 showed similar results with net porosity change being less than 0.1%.	Figure 2-51. Change in percent porosity in the Amsden underlying confining layer red line shows porosity change for Cell C1, 0 to 1 meter below the Amsden top. Yellow line shows Cell C2, 1 to 2 meters below the Amsden top. Green line shows Cell C3, 2 to 3 meters below the Amsden top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to precipitation of minerals, and negative change is due to mineral dissolution.
	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	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	***2.3.3 Mechanism of Geologic Confinement*** For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche–Picard interval), 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), which confines the CO_2 within the proposed storage reservoir as identified in (Figure 2-3). 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	

		existing information on all geologic strata overlying the storage reservoir, including caprock containment monitoring. The include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault comprehensive description of local and regional stratigraphic features. describe the storage geologic confinement, including rock properties, regional pressure gradients, and adsorption regard to the ability of prevent migration of beyond the proposed storage reservoir. The 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 one mile [1.61 kilometers] of its outside boundary. The evaluation must		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. However, adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.	

		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 Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche–Picard interval), 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), which confines the CO_2 within the proposed storage reservoir as identified in (Figure 2-3). 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. However, 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 5-mi-long seismic source test and 6.5-mi2 3D seismic survey were acquired in 2019, and a 12-mi2 3D seismic survey and 21 mi of 2D seismic lines were acquired in 2020 (Figure 2-7). The 3D seismic data allowed for visualization of deep geologic formations at lateral spatial intervals as short as tens of feet. The 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the Tundra SGS area. The seismic data were used for assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement. Data products generated from the interpretation and inversion of the 3D seismic data were used as inputs into the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 4). The 3D seismic data and J-LOC1 and J-ROC1 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 J-LOC1 and J-ROC1 sonic logs. 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 Tundra SGS area. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the seismic data. The 3D seismic data were also used to gain a better understanding of interwell heterogeneity across the Tundra SGS area for petrophysical property distributions. Acoustic impedance volumes were created using the 3D seismic and petrophysical data from the J-LOC1 and J-ROC1 wells (e.g., dipole sonic and density logs), as shown in Figure 2-8. The acoustic impedance volumes were 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 2-7. Map showing the 2D and 3D seismic surveys in the Tundra SGS area. Cross section A-A' and B-B' are shown in Figure 2-8.
	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** ***2.5.1 Faults and Fractures*** In the Tundra SGS 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. The following section discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment.	
	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	g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review: Location Orientation	**2.5 Faults, Fractures, and Seismic Activity** ***2.5.1 Faults and Fractures*** In the Tundra SGS 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	

		and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;	Determination of the probability that they would interfere with containment	studies, or oil and gas exploration activities. The following section discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment.	
	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 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	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** ***2.5.1 Faults and Fractures*** In the Tundra SGS 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. The following section discusses the seismic history of North Dakota and low probability that seismic activity will interfere with containment. ***2.5.2 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 seismic events have been detected within the North Dakota portion of the Williston Basin (Table 2-26) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-64). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 mi from the J-ROC1 well near Huff, North Dakota (Table 2-26). The magnitude of this seismic event is estimated to have been 4.4. 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 damaging seismic events predicted to occur over a 10,000-year time period (Figure 2-65) (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 seismic events in North Dakota that could be associated with nearby oil and gas activities. These results indicate relatively stable geologic conditions in the region surrounding the potential injection site. Based upon the review and assessment of 1) the USGS studies, 2) the characteristics of the Broom Creek injection zone and upper and lower confining zones, 3) the low risk of induced seismicity due to the basin stress regime, and 4) history of recorded seismic events, seismic activity will not interfere with containment of the maximum volume of CO_2 proposed to be injected annually over the life of this project.	Table 2-26. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016) Figure 2-66. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations listed in Table 2-26. Figure 2-67. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging seismic events occurring in North Dakota.

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<td>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 one 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)(m)
(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;</td>
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<td>NDAC 43-05-01-05 §1b(2) ¶ NDAC 43-05-01-05 §1b(2)(n)</td>
<td>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,</td>
<td>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:
Geologic maps
Topographic maps
Cross sections</td>
<td>Table 2-1. Formations Making up the Tundra SGS CO_2 Storage Complex (average values calculated from the simulation model and well log data)
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Average Thickness, ft</th><th>Average Depth, ft</th><th>Lithology</th></tr>
<tr><td rowspan="3">Storage Complex</td><td>Opeche–Picard</td><td>Upper confining zone</td><td>154</td><td>4,712</td><td>Siltstone, mudstone evaporites</td></tr>
<tr><td>Broom Creek</td><td>Storage reservoir (i.e., injection zone)</td><td>249</td><td>4,915</td><td>Sandstone, dolostone, dolomitic sandstone, anhydrite</td></tr>
<tr><td>Amsden</td><td>Lower confining zone</td><td>270</td><td>5,175</td><td>Dolostone, limestone, anhydrite</td></tr>
</table>

2.3 Storage Reservoir (Injection Zone)
Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3).</td>
<td>Figure 2-8. Left: cross section of the inverted acoustic impedance volume for the western seismic 3D survey that transects the J-LOC1 well. The acoustic impedance log calculated from the J-LOC1 sonic and density logs is shown on the inset panel. Right: cross section of the inverted acoustic impedance volume for the eastern 3D survey. Figure 2-7 shows the location of these two cross sections.

Figure 2-9. Areal extent of the Broom Creek Formation in North Dakota (modified from Rygh, 1990).

Figure 2-10. Isopach map of the Broom Creek Formation in the Tundra SGS area.

Figure 2-11. Well log display of the interpreted lithologies of the Opeche–Picard, Broom Creek, and upper Amsden Formations in J-ROC1.</td>
</tr>
</table>

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 one 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; and

At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft.

The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14).

Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone.

Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15).

For additional information, go to Section 2.3 of the Tundra SGS SFP.

Table 2-9. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth, ft	4,906		
Thickness, ft	Sandstone 168 Dolostone 103 Dolomitic Sandstone 26 Anhydrite 19		
Capillary Entry Pressure (CO_2/brine), psi	0.20		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %*	19.51 (2.46–27.38)	21.4 (1.0–36.0)
	Permeability, mD**	69.29 (0.06–2,690)	168.8 (0.0–8,601.1)
Broom Creek (dolostone)	Porosity, %	8.11 (5.48–8.97)	5.8 (0.0–18.0)
	Permeability, mD	0.03 (0.02–0.05)	0.13 (0.0–2,259.6)

Figure 2-12a. Regional well log stratigraphic cross sections of the Opeche–Picard and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 2-12b. Regional well log cross sections showing the structure of the Opeche–Picard, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 2-13. Structure map of the Broom Creek Formation across the Tundra SGS area.

Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

Table 2-9. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex.

Table 2-10. Broom Creek Microfracture Results from J-LOC1 and BNI-1

Table 2-14. Properties of Upper and Lower Confining Zones in Simulation Area

Figure 2-29. Areal extent of the Piper Picard in western North Dakota (modified from Carlson, 1993).

Figure 2-30. Thickness of the Opeche–Picard interval in Oliver County derived from well log data.

Figure 2-31. Structure map of the Opeche/Spearfish interval of the upper confining zone across the greater Tundra SGS area.

Figure 2-32. Structure map of the lower Piper interval of the upper confining zone across the greater Tundra SGS area.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche–Picard interval and underlying Amsden Formation (Figure 2-3, Table 2-14). Both the Amsden and Opeche–Picard intervals consist of impermeable rock layers.

Table 2-14. Properties of Upper and Lower Confining Zones in Simulation Area

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Opeche–Picard	Amsden
Lithology	Siltstone	Dolostone
Formation Top Depth, ft	4,636	5,040
Thickness, ft	154	270
Porosity, % (core data)*	6.55	7.04
Permeability, mD (core data)**	0.112	0.017
Capillary Entry Pressure (CO_2/brine), psi	20.59	69.03
Depth below Lowest Identified USDW, ft	3,409	3,813

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35).

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool.

For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish.

Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Piper–Picard interval. Impermeable rocks above the primary seal include the Upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-19). Together with the Opeche–Picard interval, these formations are 154 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-43). Including the Opeche–Picard there is over 850 ft of impermeable rocks that separate the Broom Creek from the Inyan Kara. Above the Inyan Kara Formation, 2,545 ft of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (see Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-19).

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 (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an

Figure 2-33. Isopach map of the Opeche/Spearfish interval of the upper confining zone in the Tundra SGS area.

Figure 2-34. Isopach map of the lower Piper interval of the upper confining zone in the Tundra SGS area.

Figure 2-35. Well log display of the upper confining zone at the J-ROC1 well.

Figure 2-36. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,887.7 ft.

Figure 2-37. J-LOC1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,888.8 ft.

Figure 2-38. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,873 ft.

Figure 2-39. BNI-1 Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 4,897 ft.

Figure 2-43. 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 2-44. 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 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Figure 2-45. Structure map of the Amsden Formation across the greater Tundra SGS area.

Figure 2-46. Isopach map of the Amsden Formation across the Tundra SGS area.

Table 2-20. Amsden Core Sample Porosity and Permeability from J-LOC1

Table 3-6. Description of Zones of Confinement above the Immediate Upper overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber optic cable provides an additional opportunity for mitigation and remediation (Section 4). 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 Formation. The depth to the Inyan Kara Formation in the Tundra SGS area is 3,714 ft, and the formation itself is 294 ft thick.

Table 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1,862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334

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 can be correlated across the Tundra SGS area (Figures 2-45 and 2-46). The Amsden Formation is 5,040 ft below land surface and 270 ft thick at the Tundra SGS site (Table 2-14).

The contact between the overlying Broom Creek and Amsden Formations 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 the J-LOC1 well. The lithology of the cored section of the Amsden Formation from the J-LOC1well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the two core plug samples taken from the Amsden Formation show porosity values ranging from 5.4% to 7.3% and permeability values from 0.0053 to 0.0062 mD (Table 2-20).

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 deepest USDW in the AOR. The Opeche Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6).

3.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises 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 3-9). 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; overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and Tertiary Golden Valley Formation (Figure 3-10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973).

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 700 to 900 ft deep and 200 to 350 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 3-11).

Confining Zone (data based on the J-ROC1 well)

Figure 3-9. Major aquifer systems of the Williston Basin.

Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

Figure 3-12. 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 Oliver County (modified from Fischer, 2013).

Figure 3-13. Map of water wells in the AOR in relation to the project facility, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 planned injection wells, the NRDT-1 proposed monitoring well, facility area, AOR, and legacy oil and gas wells.

Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

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 1,000 ft thick in the AOR (Thamke and others, 2014).

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, which isolates 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 east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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.

Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown.

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

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 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 3-9). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, Jurassic-aged Piper (Picard), Rierdon, 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection wells, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1, and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the AOR and primary geologic barrier between the USDWs and injection zone. The geologic strata overlying the injection zone consist 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.

	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 2-10** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14). Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone. Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15). For additional information, go to Section 2.3 of the Tundra SGS SFP.	Figure 2-10. Isopach map of the Broom Creek Formation in the Tundra SGS 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 2-33 and Figure 2-46** **2.4 Confining Zones** The confining zones for the Broom Creek Formation are the Opeche–Picard interval and underlying Amsden Formation (Figure 2-3, Table 2-14). Both the Amsden and Opeche–Picard intervals consist of impermeable rock layers. ***2.4.1 Upper Confining Zone*** In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35).	Figure 2-33. Isopach map of the Opeche/Spearfish interval of the upper confining zone in the Tundra SGS area. Figure 2-46. Isopach map of the Amsden Formation across the Tundra SGS area.

				Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool. For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish. Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite. *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 can be correlated across the Tundra SGS area (Figures 2-45 and 2-46). The Amsden Formation is 5,040 ft below land surface and 270 ft thick at the Tundra SGS site (Table 2-14). The contact between the overlying Broom Creek and Amsden Formations 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 the J-LOC1 well. The lithology of the cored section of the Amsden Formation from the J-LOC1well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the two core plug samples taken from the Amsden Formation show porosity values ranging from 5.4% to 7.3% and permeability values from 0.0053 to 0.0062 mD (Table 2-20).	
			l. An isopach map of the secondary containment barrier for the storage reservoir;	**Figure 2-34, Figure 2-43, and Figure 2-44** ***2.4.1 Upper Confining Zone*** In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35). Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool. For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish. Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite. ***2.4.2 Additional Overlying Confining Zones*** Several other formations provide additional confinement above the Piper–Picard interval. Impermeable rocks above the primary seal include the Upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-19). Together with the Opeche–Picard interval, these formations are 154 ft thick and will impede Broom	Figure 2-34. Isopach map of the lower Piper interval of the upper confining zone in the Tundra SGS area. Figure 2-43. 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 2-44. 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.

				Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-43). Including the Opeche–Picard there is over 850 ft of impermeable rocks that separate the Broom Creek from the Inyan Kara. Above the Inyan Kara Formation, 2,545 ft of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (see Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-19). 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 (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber optic cable provides an additional opportunity for mitigation and remediation (Section 4). 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 Formation. The depth to the Inyan Kara Formation in the Tundra SGS area is 3,714 ft, and the formation itself is 294 ft thick.	
	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 2-13 and Figure 2-31** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14). Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone. Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15).	Figure 2-13. Structure map of the Broom Creek Formation across the Tundra SGS area. Figure 2-31. Structure map of the Opeche/Spearfish interval of the upper confining zone across the greater Tundra SGS area.

				For additional information, go to Section 2.3 of the Tundra SGS SFP. ***2.4.1 Upper Confining Zone*** In the Tundra SGS area, the Piper–Picard interval consists of siltstone, and the Opeche/Spearfish Formation consists of silty mudstone. The upper confining zone (Opeche–Picard) is laterally extensive across the Tundra SGS area (Figures 2-29 and 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4,636 ft below the land surface and 154 ft thick at the Tundra SGS Site (Table 2-14 and Figures 2-31–2-34). The contact between the upper confining zone and 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 2-35). Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 and BNI-1 wellbores. For the J-LOC1 well, in the Opeche/Spearfish Formation, at 4,887.7 and 4,888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8,162.49 and 8,150.95 psi, respectively, Figures 2-36 and 2-37. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool. For the BNI-1 well, in the Opeche/Spearfish Formation, at 4,873 ft, the MDT tool was unable to cause breakdown in the formation with an applied maximum injection pressure of 7,561 psi, Figure 2-38. The maximum injection pressures were limited by the maximum differential pressure for the MDT tool. An additional test was performed at 4,897 ft with a breakdown pressure of 5,897 psi, Figure 2-39, for the Opeche/Spearfish. Laboratory measurements from the Opeche/Spearfish Formation core sample taken from the J-LOC1 well indicate a porosity value of 3.53% and a permeability value of 0.0104 mD. The lithology of the cored sections of the Opeche/Spearfish is primarily silty mudstone with interbedded fine sandstone and anhydrite.	
			n. A structure map of the base of the storage formation;	**Figure 2-13 and Figure 2-45** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14). Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). The wide range in porosity and permeability reflects the differences between the sandstone and	Figure 2-13. Structure map of the Broom Creek Formation across the Tundra SGS area. Figure 2-45. Structure map of the Amsden Formation across the greater Tundra SGS area.

				dolostone lithofacies in the Broom Creek Formation. Portions of the Broom Creek Formation core revealed unconsolidated or poorly consolidated sandstone. Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15). For additional information, go to Section 2.3 of the Tundra SGS 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 can be correlated across the Tundra SGS area (Figures 2-45 and 2-46). The Amsden Formation is 5,040 ft below land surface and 270 ft thick at the Tundra SGS site (Table 2-14). The contact between the overlying Broom Creek and Amsden Formations 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 the J-LOC1 well. The lithology of the cored section of the Amsden Formation from the J-LOC1well is dolostone, anhydrite, and mudstone with laminated, fine-grained sandstone and siltstone. Data acquired from the two core plug samples taken from the Amsden Formation show porosity values ranging from 5.4% to 7.3% and permeability values from 0.0053 to 0.0062 mD (Table 2-20).	
	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 2-12a and 2-12b; and 2-14** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14). Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone.	Figure 2-12a. Regional well log stratigraphic cross sections of the Opeche–Picard and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Opeche–Picard, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level.

				Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15). For additional information, go to Section 2.3 of the Tundra SGS SFP.	
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	**Figures 2-12a and 2-12b; and 2-14** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Broom Creek Formation is laterally extensive (Figure 2-9) 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, siltstones, and evaporites of the Opeche/Spearfish Formation (Figure 2-3). At J-ROC1, the Broom Creek Formation is made up of 81 ft of sandstone, 77 ft of dolostone, and 58 ft of dolomitic sandstone and is located at a depth of 4,740 ft. Across the simulation model area, the Broom Creek Formation varies in thickness from 60 to 375 ft (Figure 2-10), with an average thickness of 249 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model area ranges from 15 to 195 ft, with an average of 107 ft. The top of the Broom Creek Formation was picked across the Tundra SGS area based on the transition from a relatively high GR signature representing the mudstones and siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-11). 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 entirety of the Tundra SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) 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 the J-LOC1 and J-ROC1 wells (Figures 2-12a and 2-12b). The Broom Creek Formation is estimated to pinch out ~24 mi to the east of the J-ROC1 site. A structural map of the Broom Creek Formation shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the Tundra SGS area (Figures 2-13 and 2-14). Seventeen 1-in.-diameter core plug samples were taken from the sandstone and dolostone lithofacies of the Broom Creek Formation core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation. Porosity and permeability measurements from the J-LOC1 Broom Creek Formation core samples have porosity values ranging from 1.2% to 27.01% and permeability ranging from <0.02 to 2,690 mD (Table 2-9). 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 Formation core revealed unconsolidated or poorly consolidated sandstone. Analysis of ten core samples from the sandstone portion of the Broom Creek Formation core from the J-LOC1 well showed porosity values ranging from 2.46% to 27.38%, with an average of 19.51%. Permeability of the sandstone samples ranged from 0.06 to 2,690 mD, with a geometric average of 69.28 mD. Porosity values of dolostone samples from the Broom Creek Formation core ranged from 5.48% to 8.97%, with an average of 8.11%. Dolostone permeability values ranged from 0.02 to 0.05 mD, with a geometric average of 0.03 mD (Table 2-9 and Figure 2-15). For additional information, go to Section 2.3 of the Tundra SGS SFP.	Figure 2-12a. Regional well log stratigraphic cross sections of the Opeche–Picard and Broom Creek Formations flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Opeche–Picard, Broom Creek, and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Broom Creek Formation. Elevations 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	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 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	

		underground sources of drinking water, if any;		water (USDWs) may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[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 resultant pressure as the "critical threshold pressure." Application of risk-based methods using site-specific data from the J-LOC1 and J-ROC1 wells shows that the storage reservoir in the project area is overpressurized with respect to the deepest USDW (i.e., the critical threshold pressure increase is less than zero [Appendix A, Table A-4]). Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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. This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 3-1. **Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS** **DELINEATION OF THE AREA OF REVIEW** The North Dakota Administrative Code (NDAC) defines the AOR 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 the potential for vertical migration of CO_2 and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO_2 plume within the storage reservoir. However, the CO_2 plume has an associated pressure front where CO_2 injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO_2 plume. Therefore, the AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g.,	

legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO_2 plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. 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 resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), and the "lowest USDW" refers to the Fox Hills Formation.

EPA Methods 1 and 2 AOR Delineation for Class VI Wells

EPA (2013) guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW. The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the J-LOC1 stratigraphic well) using site-specific data, or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA (2013) Method 1 (pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW. Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by:

$$\Delta Pi,f = Pu + \rho ig \cdot (zu - zi) - P\mathrm{i} \qquad \text{[Eq. 1]}$$

Where:

Pu is the initial fluid pressure in the USDW (Pa).
ρi is the storage reservoir fluid density (mg/m^3).
g is the acceleration due to gravity (m/s^2).
zu is the representative elevation of the USDW (m amsl).
zi is the representative elevation of the injection zone (m amsl).
Pi is the initial pressure in the injection zone (Pa).
ΔPi,f is the critical pressure threshold (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta Pi,f$ = 0, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta Pi,f$ > 0, then the reservoir is underpressurized relative to the USDW; and if $\Delta Pi,f$ < 0, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium (ΔPi,f = 0), EPA Method 2 (pressure front based on displacing fluid initially present in the borehole) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔPc), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔPc is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linearly 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 critical threshold pressure increase (Pa). g is the acceleration of gravity (m/s^2). zu is the elevation of the base of the lowermost USDW (m amsl). zi is the elevation of the top of the injections zone (m amsl). ρi is the fluid density in the injection zone (kg/m^3). $\rho\ u$ is the fluid density in the USDW (kg/m^3).	
	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/Spearfish Formation, the overlying confining zone, and Amsden Formation, the underlying confining zone, have been assessed during the description of the J-LOC1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stress were assessed through the interpretation of the QuantaGeo log acquired during the drilling of the J-LOC1 well. *2.4.4.2 Fracture Analysis Core Description* Fractures within the Opeche/Spearfish Formation are primarily resistive and mixed. They are commonly filled with anhydrite. However, some conductive fractures are highlighted. 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, resistive fractures are commonly coincident with the horizontal compaction features (stylolite) observed. On the other hand, few mixed fractures are highlighted. 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 J-LOC1 well. *2.4.4.3 Borehole Image Fracture Analysis (FMI)* Schlumberger's QuantaGeo 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 2-52a and 2-52b show two sections of the interpreted borehole imagery and primary features observed. The far-right track on Figure 2-52a notes the presence of electrically resistive features. These are interpreted as minor anhydrite-filled fractures. Figure 2-52b demonstrates that the tool provides information on surface boundaries and bedding features. Some isolated fractures are identified in Figure 2-51b and are likely clay-filled because of their electrically conductive signal. Figures 2-53a and 2-53b show two thin-section images and give an indication of different minerals within the reservoir with observed change in the electrical response shown on the QuantaGeo log. Figure 2-54 shows the logged interval for the entire Opeche/Spearfish Formation at the J-LOC1 well. As shown, the section closest to the Broom Creek Formation (4,900 ft) is dominated by anhydrite layers and compaction features (stylolites) and has corresponding tensional features, as noted in the core description analysis. The observed stylolites are parallel to bedding and 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. The rose diagrams shown in Figures 2-55, 2-56, and 2-57 provide the orientation of the conductive, resistive, and mixed features in the Opeche/Spearfish Formation. The logged interval of the Amsden Formation shows that the main features present are stylolite–tension pairs, which are an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. One zone between 5,220 and 5,222.5 ft shows some evidence of resistive fractures (Figure 2-58). 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 2-59 and 2-60 provide the orientation of the mixed and resistive features in the Amsden Formation. As shown in Figure 2-61, only one electrically mixed feature was picked in the Amsden interval with an azimuth-oriented NW. Some electrically resistive features are present with an azimuth-oriented NE–SW and E–W. Drilling-induced fractures were not identified in the Amsden Formation. *2.4.4.4 Stress*	Figure 2-52a. Examples of the interpreted QuantaGeo log for the J-LOC1 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/Spearfish QuantaGeo borehole image analysis. Figure 2-52b. Examples of the interpreted QuantaGeo log for the J-LOC1 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/Spearfish QuantaGeo borehole image analysis. Figure 2-53a. Plane-polarized light thin-section images from the J-LOC1 well Opeche/Spearfish Formation. This image shows the silt-rich nature of this interval of the Opeche/Spearfish Formation. On the example shown, the quartz grains (white) are rimmed by anhydrite and iron. Figure 2-53b. Plane-polarized light thin-section images from the J-LOC1 well Opeche/Spearfish Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the QuantaGeo log. Figure 2-54. Interpreted QuantaGeo log through the lower Opeche/Spearfish Formation. Figure 2-55. Conductive fracture dip orientation in the Opeche/Spearfish Formation. Figure 2-56. Resistive fracture dip orientation in the Opeche/Spearfish Formation. Figure 2-57. Mixed fracture dip orientation in the Opeche/Spearfish Formation.

During drilling of the J-LOC1 well, an openhole MDT microfracture in situ stress test was completed to determine a formation breakdown pressure and minimum horizontal stress. The microfracture in situ stress test operation was performed using the MDT dual-packer module to obtain the formation breakdown pressure followed by multiple injection–falloff cycles to determine formation geomechanics properties. Within the Opeche/Spearfish Formation confining zone, two attempts were made at a depth of 4,888.78 and 4,887.66 ft to determine the formation breakdown pressure and closure pressure, which corresponds to the minimum horizontal stress. Unfortunately, the two attempts were unsuccessful to achieve the formation breakdown pressure with an applied maximum injection pressure of 8,150.95 and 8,162.95 psi (Figure 2-62 and Figure 2-63). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module."

J-LOC1 openhole logging data were used to construct a 1D mechanical earth model (1D MEM) for different formations, including the Spearfish/Opeche Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties, such as Young's modulus, Poisson's ratio, shear modulus, and bulk modulus, were calculated based on the available well logs. The formation strength properties, like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion, were also estimated from the available data (Figure 2-64). Table 2-23 provides the summary of stresses in the Spearfish/Opeche Formation generated using 1D MEM.

Table 2-23. Summary of Stresses in Spearfish/Opeche Formation

Depth, ft	Hydrostatic Pressure, psi	Vertical Stress, psi	Minimum Stress, psi
4,800	2,064	4,957	2,922
4,904	2,108	5,073	2,623

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/Spearfish Formation core in the J-LOC1 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 2-24 shows the sample parameters, and Table 2-25 shows the elastic parameters obtained.

Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-63, the sample failed at a maximum stress of 113.8 MPa (16,505.295 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 2-1. Description of J-LOC1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Opeche/Spearfish	4,889.2	143.90
Broom Creek	4,920.0	136.26
	5,045.1	136.60
	5,129.1	137.26
Mean Broom Creek Temp., °F	136.71	
Broom Creek Temperature Gradient, °F/ft	0.02*	

Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

Figure 2-58. Interpreted QuantaGeo log through the upper Amsden Formation.

Figure 2-59. Mixed fracture dip orientation in the Amsden Formation.

Figure 2-60. Resistive fracture dip orientation in the Amsden Formation.

Figure 2-61. Interpreted QuantaGeo log through the Amsden Formation.

Figure 2-62. J-LOC1 Spearfish/Opeche MDT microfracture in situ stress test (first attempt) at 4,888.78 ft.

Figure 2-63. J-LOC1 Spearfish/Opeche MDT microfracture in situ stress test (second attempt) at 4,887.66 ft.

Figure 2-64. 1D MEM of the Spearfish/Opeche Formation.

Table 2-23. Summary of Stresses in Spearfish/Opeche Formation

Table 2-24. Sample Parameters

Table 2-25. Elastic Properties Obtained Through Experimentation: E = Young's Modulus, n = Poisson's Ratio, K = Bulk Modulus, G = Shear Modulus, P = Uniaxial Strain Modulus

Figure 2-65. 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 113.8 MPa.

Table A-2. MDT Pressure Measurements Recorded from the J-LOC1 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
9,800	4,507	0.46
9,885	4,548	0.46
9,885	4,548	0.46
10,087	4,651	0.46
10,254	4,734	0.46

Table A-3. Summary of Reservoir Properties in the Simulation Model

Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Icebox: 7.25×10^{-7} Black Island: 9.81 Deadwood: 31.65 Precambrian: 7.88×10^{-7}	Icebox: ~0.12 Black Island: ~5.48 Deadwood: ~3.81 Precambrian: ~0.74	~4,548.42	256,000	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 other formations provide additional confinement above the Piper–Picard interval. Impermeable rocks above the primary seal include the Upper Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-19). Together with the Opeche–Picard interval, these formations are 154 ft thick and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (see Figure 2-43). Including the Opeche–Picard there is over 850 ft of impermeable rocks that separate the Broom Creek from the Inyan Kara. Above the Inyan Kara Formation, 2,545 ft of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (see Figure 2-44). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-19).

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 (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring digital temperature sensor (DTS) data for the Inyan Kara Formation using the downhole fiber optic cable provides an additional opportunity for mitigation and remediation (Section 4). 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 Formation. The depth to the Inyan Kara Formation in the Tundra SGS area is 3,714 ft, and the formation itself is 294 ft thick.

Table 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1,862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334

Figure 2-43. 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 2-44. 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 2-19. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

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

The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front

3.0 AREA OF REVIEW

3.1 AOR Delineation

3.1.1 Written Description

		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 one 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:	caused by injection activities. The area of review delineation must include the following:	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[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 resultant pressure as the "critical threshold pressure." Application of risk-based methods using site-specific data from the J-LOC1 and J-ROC1 wells shows that the storage reservoir in the project area is overpressurized with respect to the deepest USDW (i.e., the critical threshold pressure increase is less than zero [Appendix A, Table A-4]). Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., storage facility area, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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. This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were 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	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	**3.1.2 Supporting Maps**	Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings.

		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. 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;	iv. Any existing or proposed above ground facilities;		
	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 other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	**3.1.2 Supporting Maps**	Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings. Figure 3-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the storage facility area and AOR boundaries.
	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**	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**	

		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;			
	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; (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; and (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	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 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;	**3.3 Reevaluation of AOR and Corrective Action Plan** Minnkota will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified. • The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	

		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.			
	NDAC 43-05-01-05 §1b(2)(b)	**NDAC 43-05-01-05 §1b(2)(b)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	**3.1.2 Supporting Maps**	Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings.
	NDAC 43-05-01-05 §1b(2) ¶	**§1b(2)** (2) A geologic and hydrogeologic facility area, including existing information on all geologic strata overlying the storage reservoir, including the immediate caprock used for monitoring. include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional and a comprehensive description of local and regional structural or stratigraphic describe the storage reservoir's mechanisms of geologic confinement,	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage outside of its boundary;	The North Dakota Geological Survey recognizes the Spearfish Formation 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 2-68). There has been no exploration for, nor development of, hydrocarbon resource from the Formation in the storage facility area. The only hydrocarbon exploration well near the storage facility area, the Herbert Dresser 1-34 (NDIC File No. 4937) was drilled in 1970 to explore potential hydrocarbons in the Charles Formation. The well seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced." Lignite coal currently is mined in the area of the Center Coal Mine, operated by BNI Coal. The Center Mine currently mines the Hagel coal seam for use as fuel at Minnkota Power Cooperative's MRYS. The Hagel coal seam is the lowermost Thickness of the Hagel coal seam averages 7.8 ft in the area permitted to be mined but varies, with some areas exceeding below the Hagel seam, but currently the Hagel is the only economically minable seam with its thickness and overburden of 100 ft or less (Figures 2-69 and 2-70). The Hagel and other coal seams in the Fort Union Group thicken and deepen to the west. The overlying Beulah-Zap coal seam has pinched out farther to the west but is economically minable in the central part of Mercer County at North American Coal's Coteau Mine. The Hagel seam pinches out to the east, and no other coal seams	Figure 2-68. Drillstem test results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020). Figure 2-69. Hagel net coal isopach map (modified from Ellis and others, 1999). Figure 2-70. Hagel overburden isopach map (modified from Ellis and others, 1999).

		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 one 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 one 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	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	**3.1.2 Supporting Maps**	Figure 3-4. The AOR map in relation to nearby legacy wells. Shown are the storage facility area (purple boundary), Center city limits (yellow dotted boundary), and AOR (gray boundary). Orange circles represent nearby legacy wells near the project area, including within the AOR.

		commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone. 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; and			
	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)	**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	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	**3.2 Corrective Action Evaluation** **Table 3-2. Wells in AOR Evaluated for Corrective Action** **Table 3-3. J-ROC1 (NDIC File No. 37672) Well Evaluation** **Table 3-4. BNI-1 (NDIC File No. 34244) Well Evaluation** **Table 3-5. Herbert Dresser 1-34 (NDIC File No. 4937) Well Evaluation** **Table 3-1. Investigated and Identified Surface and Subsurface Features (Figures 3-1 through 3-5)**	Figure 3-6. J-ROC1 (NDIC File No. 37672) well schematic showing the location and thickness of cement plugs. Figure 3-7. BNI-1 (NDIC File No. 34244) well schematic showing the location and thickness of cement plugs. Figure 3-8. Herbert Dresser 1-34 (NDIC File No. 4937) well schematic showing the location and thickness of cement plugs.

	NDAC 43-05-01-05 §1b(3)(b)(f)	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 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	e. Springs (5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: 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 (7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		

		country boundary lines, and roads; **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;			
	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; and	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	**Appendix C – NEAR-SURFACE MONITORING PARAMETERS AND BASELINE DATA** **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 deepest USDW in the AOR. The Opeche Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6). ***3.4.2 Geology of USDW Formations*** The hydrogeology of western North Dakota comprises 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 3-9). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014). The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and Tertiary Golden Valley Formation (Figure 3-10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973). 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 700 to 900 ft deep and 200 to 350 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 3-11). 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 1000 ft thick in the AOR (Thamke and others, 2014). ***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, which isolates 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 east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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.	Table 3-6. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well) Figure 3-9. Major aquifer systems of the Williston Basin. Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973). Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). Figure 3-12. 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 Oliver County (modified from Fischer, 2013). Figure 3-13. Map of water wells in the AOR in relation to the project facility, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 planned injection wells, the NRDT-1 proposed monitoring well, facility area, AOR, and legacy oil and gas wells. Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

				Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown. Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973). The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973). ***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 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 3-9). The primary seal of the injection zone is the Permian-aged Opeche Formation with the shales of the Permian-aged Spearfish, Jurassic-aged Piper (Picard), Rierdon, 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection wells, Liberty-1 (J-ROC1 NDIC File No. 37672) and Unity-1, and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, Niobrara, and Pierre. The Pierre Formation is the thickest shale formation in the AOR and primary geologic barrier between the USDWs and injection zone. The geologic strata overlying the injection zone consist 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.	
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 pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**4.3 Financial Assurance Demonstration Plan;** See Appendix G ***4.3.1 Approach to Meeting Financial Responsibility Requirements*** *4.3.1.1 Corrective Action* *4.3.1.2 Injection Well-Plugging Program* *4.3.1.3 Postinjection Site Care and Facility Closure* *4.3.1.4 Emergency and Remedial Response* *4.3.1.5 Endangerment of Drinking Water Sources* ***4.3.2 Approach to Financial Risk*** ***4.3.3 Selected Elements of Applicant's Analysis of Inherent Risks***	

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4.3.4 Costs Estimates

Table 4-14. Potential Future Costs Covered by Financial Assurance in $K

Activity	Total Cost	Covered by Special-Purpose Trust	Covered by Commercial Insurance	Details in Supporting Table
Corrective Action on Wells in AOR	$0	$0	$0	NA
Plugging Injection Wells	$2,025	$2,025	$0	Table 4-14-1
Postinjection Site Care	$10,285	$10,285	$0	Table 4-14-2
Site Closure	$1,554	$1,554	$0	Table 4-14-3
Emergency and Remedial Response	$16,560	$5,960	$10,600	Table 4-14-4
Endangerment of USDWs	$2,240	$0	$2,240	Table 4-14-5
Total	**$32,664**	**$19,824**	**$12,840**	

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<tr><td></td><td>NDAC 43-05-01-05 §1d</td><td>NDAC 43-05-01-05 §1d
d. An emergency and remedial response plan pursuant to section 43-05-01-13;</td><td>b. An emergency and remedial response plan;</td><td>4.2 Emergency and Remedial Response Plan; See Appendix E

4.2.1 Description of Project Area

4.2.2 Risk Identification and Severity

4.2.3 Response Protocols

4.2.4 Emergency Contacts

4.2.5 Emergency Communications Plan

4.2.6 ERRP Review</td><td></td></tr>
<tr><td></td><td>NDAC 43-05-01-05 §1e</td><td>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;</td><td>c. A detailed worker safety plan that addresses the following:
i. Carbon dioxide safety training
ii. Safe working procedures at the storage facility;</td><td>4.4 Worker Safety Plan (NDAC 43-05-01-05 §1e; NDAC 43-05-01-13)

4.4.1 Definitions

4.4.2 Stop Work Authority

4.4.3 Incident Notification and Response

4.4.4 Incident Report and Investigation

4.4.5 Training

4.4.6 Contractor Qualification and Bridging Documents

4.4.7 General Health, Safety, and Welfare

4.4.8 Personal Protective Equipment

4.4.9 Hand Safety

4.4.10 Permitted Work Activities</td><td></td></tr>
</table>

				4.4.11 Chemical, Hazardous, or Flammable Materials ***4.4.12 Overhead/Outside Guarded Area*** ***4.4.13 Work Site Conduct***	
	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;	***4.1.2 Corrosion Monitoring and Prevention Plan*** *4.1.2.1 Corrosion Threat Assessment* *4.1.2.2 Identification of Critical Components and Operating Conditions;* See Appendix F *4.1.2.3 Damage Mechanism* *4.1.2.4 Corrosion Control Program (CCP)* *4.1.2.5 Annual Review* *4.1.2.6 Data Management*	
	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 sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	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;	***4.1.3 Surface Leak Detection and Monitoring Plan***	
	NDAC 43-05-01-05 §1h	**NDAC 43-05-01-05 §1h**	f. A subsurface leak detection and monitoring plan to monitor for any	***4.1.4 Subsurface Leak Detection and Monitoring Program***	

		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 one 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; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.	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 one mile of the facility area's outside boundary;	***4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring*** ***4.1.6 Baseline Sampling Program*** *4.1.6.1 Groundwater Baseline Sampling* *4.1.6.2 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;	**4.1 Testing and Monitoring Plan** ***4.1.1 Analysis of Injected CO_2 and Injection Well Testing***	

				4.1.1.1 CO_2 Analysis *4.1.1.2 Injection Well Integrity Tests* ***4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring*** ***4.1.6 Baseline Sampling Program;*** See Appendix C *4.1.6.1 Groundwater Baseline Sampling* *4.1.6.2 Soil Gas Baseline Sampling* ***4.1.7 Near-Surface Monitoring Plan*** ***4.1.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front*** *4.1.8.1 Direct Monitoring Methods* *4.1.8.2 Indirect Monitoring Methods* ***4.1.9 Quality Control and Surveillance Plan;*** See Appendix D	
	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 Liberty-1 Proposed Injection Well Casing and Cementing Programs*** *4.5.1.1 Liberty-1 (J-ROC1 File No. 37672) Proposed Injection Well* ***4.5.2 Unity-1 Proposed Injection Well Casing and Cementing Programs*** *4.5.2.1 4.5.2.1 Unity-1 Proposed Injection Well Schematic* ***4.5.3 NRDT-1 – Proposed Broom Creek CO_2-Monitoring Well Casing and Cementing Programs*** *4.5.3.1 NRDT-1 Proposed Monitoring Well 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 Well P&A Program** ***4.6.1 Liberty-1 Broom Creek CO_2 Injection Well Plugging and Abandonment*** *4.6.1.1 Liberty-1 (J-ROC1 File No. 37672) Injection Well-Plugging Schematic* *4.6.1.2 Tentative Plugging Procedures* ***4.6.2 Unity-1 Broom Creek CO_2 Injection Well Plugging and Abandonment*** *4.6.2.1 Unity-1 (proposed) Injection Well-Plugging Schematic* *4.6.2.2 Tentative Plugging Procedures* ***4.6.3 NRDT-1 Monitor Well Plugging and Abandonment*** *4.6.3.1 NRDT-1 Monitor Well-Plugging Schematic* *4.6.3.2 Tentative Plugging Procedures*	

	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; and	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* ***4.7.2 Postinjection Monitoring Plan*** ***4.7.3 Groundwater and Soil Gas Monitoring*** ***4.7.4 Monitoring of CO_2 Plume and Pressure Front*** *4.7.4.1 Schedule for Submitting Postinjection Monitoring Results* *4.7.4.2 Site Closure Plan* *4.7.4.3 Submission of Site Closure Report, Survey, and Deed*	
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;	**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, Tables 5-1 and 5-2) and NDAC § 43-05-01-11.3.	Table 5-1. Proposed Broom Creek Injection Well Operating Parameters (with total data between the two wells) Table 5-2. Proposed Broom Creek Injection Well Operating Parameters
	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	d. The proposed average and maximum bottom hole injection pressure to be utilized;	(see Table 5-1 below)	

Table 5-1. Proposed Broom Creek Injection Well Operating Parameters (with total data between the two wells)

Item	Values	Description/Comments
Injected Volume		
Total Injected Volume	76.64 million tonnes	Based on 4.0 MMt/year for the first 15 years and 3.5 MMt/year for the last 5 years for a total injection period of 20 years at an average daily injection rate of 10,577 tonnes/day (using 360 operating days per year).
Injection Rates		
Proposed Average Injection Rate	10,577 tonnes/day	Based on 4.0 MMt/year for the first 15 years and 3.5 MMt/year for the last 5 years for a total injection period of 20 years (using 360 operating days per year).
Calculated Maximum Daily Injection Rate	10,948 tonnes/day	Based on the 20 years of injection with a group injection constraint of 4.0 MMt/year for the first 15 years and 3.5 MMt/year for the last 5 years.

well tests and other studies that assess the risks of tensile failure

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;

e. The proposed average and maximum surface injection pressures to be utilized;

Table 5-2. Proposed Broom Creek Injection Well Operating Parameters

	Liberty-1	**Unity-1**	**Description/Comments**
Total Injected Volume, million tonne	36.42	41.04	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum bottomhole pressures (BHPs) of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Injection Rate			
Predicted Average Injection Rate, tonne/day	4988.2	5615.8	Based on total injected volumes for 20 years and using 360 operating days per year.
Maximum Predicted Daily Injection Rate, tonne/day	5162.6	5829	Based on the 20 years of injection with • A constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years with wells injecting independently. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
	8744.9	9260.6	Based on the 20 years of injection with: • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Pressure			
Formation Fracture Pressure at Top Perforation, psi	3371.3	3352.6	The injectivity test results fracture propagation formation fracture gradient of 0.712 psi/ft.
Average Predicted Operating Surface Injection Pressure, psi	1399	1431	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1. • A maximum surface injection pressure of 1,700 psi for both wells.
Maximum Wellhead Injection Pressure, psi	1700	1700	Maximum wellhead injection pressure is limited based on surface facility constraints and 90% of formation fracture pressure.
Average Predicted Operating BHP, psi	3008	2993	Based on the 20 years of injection with • A group injection constraint of 4.0 MMT/year for the first 15 years and 3.5 MMT/year for the last 5 years. • Well injection constraints of maximum BHPs of 3,035.1 psi for Liberty-1 and 3,018.3 psi for Unity-1.

							• A maximum surface injection pressure of 1,700 psi for both wells.	
				Maximum BHP, psi	3035.1	3018.3	Calculated maximum BHP using 90% of the propagation pressure from the injectivity test at the top of the perforation.	

	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;	See Table 4-8a below.

Table 4-8a. Logging Program for Broom Creek Injectors: Liberty-1 (J-ROC1 File No. 37672), Unity-1 (proposed). Note: Most logs were completed on J-ROC1 (Liberty-1). This logging program is planned for Unity-1 (proposed) and unless otherwise noted in the table.

Log	Justification	NDAC Section
Cased-Hole Logs: ultrasonic CBL (cement bond log), 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,* neutron,* GR, caliper) and SP** (spontaneous potential) *No density or neutron in surface section of Unity-1 (proposed) **No SP on J-ROC1.	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)*** ***No CMR on Unity-1 (proposed)	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])
Temperature Log	Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.	43-05-01-11.2(1c[2])
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 Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])

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Table 4-8b. Logging Program for NRDT-1 proposed monitoring well
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<tr><th>Log</th><th>Justification</th><th>NDAC Section</th></tr>
<tr><td>Cased-Hole Logs: Ultrasonic CBL, VDL, GR</td><td>Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Triple Combo and SP

*No density or neutron in surface section</td><td>Quantify 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.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>Temperature Log</td><td>Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Dipole Sonic</td><td>Identified mechanical properties, including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.</td><td>43-05-01-11.2(1c[1])</td></tr>
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Appendix B - WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS
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<td>NDAC 43-05-01-05 §1b(7)</td>
<td>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; and</td>
<td>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;</td>
<td>5.1 Proposed Completion Procedure to Conduct Injection Operations in the Broom Creek Injection Wells Liberty-1 (J-ROC1 File No. 37672) and Unity-1

Minnkota Power Cooperative (Minnkota) plans to construct two Broom Creek carbon dioxide (CO2) injection wells: 1) Liberty-1 (J-ROC1 File No. 37672) well reentry and 2) proposed Unity-1 well, with all wells designed by Oxy Low Carbon Ventures in compliance with Class VI UIC (underground injection control) injection well construction requirements. Plans to construct the second Broom Creek injection well, Unity-1, follow completion procedures similar to the Liberty-1 (J-ROC1 File No. 37672) well. The drilling of the cement plugs and casing of the wellbore for the Liberty-1 (J-ROC1 File No. 37672) well is included in the drilling program. The following proposed completion procedure outlines the steps necessary to complete both the Broom Creek wells for injection purposes (Tables 5-3 and 5-4, Figure 5-1, Figure 5-2, and Figure 5-3).</td>
<td>Table 5-3. Liberty-1 (J-ROC1 File No. 37672) Wellbore Surface and Proposed Longstring Casing Properties

Table 5-4. Unity-1 Proposed Casing Properties</td>
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	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 Proposed Completion Procedure to Conduct Injection Operations in the Broom Creek Injection Wells Liberty-1 (J-ROC1 File No. 37672) and Unity-1** Minnkota Power Cooperative (Minnkota) plans to construct two Broom Creek carbon dioxide (CO2) injection wells: 1) Liberty-1 (J-ROC1 File No. 37672) well reentry and 2) proposed Unity-1 well, with all wells designed by Oxy Low Carbon Ventures in compliance with Class VI UIC (underground injection control) injection well construction requirements. Plans to construct the second Broom Creek injection well, Unity-1, follow completion procedures similar to the Liberty-1 (J-ROC1 File No. 37672) well. The drilling of the cement plugs and casing of the wellbore for the Liberty-1 (J-ROC1 File No. 37672) well is included in the drilling program. The following proposed completion procedure outlines the steps necessary to complete both the Broom Creek wells for injection purposes (Tables 5-3 and 5-4, Figure 5-1, Figure 5-2, and Figure 5-3). **5.2 Proposed Completion Procedure for Broom Creek CO_2 Injectate Well** 1. Nipple up BOP (blowout preventer). 2. Test BOP. 3. Pick up work string and bit to clean out cement. 4. Run in the hole and tag the stage tool. 5. Circulate with brine, 10 ppg. 6. Drill out the stage tool and clean the casing until the top of the float collar. 7. Circulate with brine, 10 ppg. 8. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the Operator may require assessing the root cause and correcting it. 9. Pull BHA (bottomhole assembly) out of the hole. 10. Perform safety meeting to discuss logging and perforating operations. 11. Rig up logging truck. 12. Run cased-hole logs by program. Note: run CBL/VDL (cement bond log/variable density log) and USIT (ultrasonic imaging tool) logs without pressure as a first pass and run them with 1000 psi pressure as a second pass. Note: In case cementing logs show poor bonding in the cementing job, the results will be communicated to the North Dakota Industrial Commission (NDIC), and an action plan will be prepared. 13. Run oriented perforating guns to the injection target. An oriented gun should be used to avoid any damage to the external fiber optic. 14. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). The depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation. 15. Pull guns out of the hole. 16. Rig down logging truck. 17. Pick up straddle packer and run in the hole with work string. 18. Circulate with brine, 10 ppg. 19. Set packer to isolate the perforations. 20. Rig up acid trucks and equipment. 21. Perform cleaning of the perforations with acid. Adjust acid formulation and volumes with water samples and compatibility test. 22. Rig down acid trucks and equipment. 23. Perform an injectivity test/step rate test. 24. Unset packer and circulate hole. 25. Pull packer and work string out of the hole. 26. Rig up spooler and prepare rig floor to run upper completion. 27. Run completion assembly per program. 28. Circulate well with inhibited packer fluid. 29. Set packer 50 ft above the top perforations. 30. Install tubing sections, cable connector, and tubing hanger. 31. Rig up logging truck. 32. Run cased-hole logs through tubing by program. 33. Rig down logging truck. 34. Nipple down BOP.	

				35. Install injection tree. Note: Figure 5-4 illustrates the proposed wellhead schematic. 36. Rig down equipment. Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber optic will be run along the exterior of the long string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations. The proposed tubing design for the two wells is presented in Tables 5-5 and 5-6. 1. The packer depth will be adjusted with the final perforation depth interval. 2. The packer will be set 50 ft above the top perforations. 3. Packers are required to be nickel-plated with HNBR elastomers. 4. Inconel cable and quartz pressure and temperature gauges will be run in upper completion.	

Attachment 2

TUNDRA SGS – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO_2 Storage Facility Permit Application – Corrected

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September 2021

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NOMENCLATURE

AES	atomic emission spectrometry
AMS	accelerator mass spectrometry
ANSI	American National Standards Institute
AOR	area of review
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	ASTM (American Society for Testing and Materials) International
AVO	amplitude variation with offset
AZMI	above-zone monitoring interval
bbl	barrel
BHA	bottomhole assembly
BHP	bottomhole pressure
BHT	borehole temperature
BNI	BNI Coal, Inc.
BOP	blowout preventer
BOPE	blowout preventer equipment
bpm	barrels per minute
BTC	buttress-thread and coupled
CBL	cement bond log
CCP	corrosion control program
CCS	carbon capture and storage
CF	continuous flow
CFR	Code of Federal Regulations
cm	centimeter
CMG	Computer Modelling Group Ltd.
CMP	corrosion management program
CMR	combinable magnetic resonance
CO_2	carbon dioxide
C-ODTR	coherent optical time domain reflectometry
COW	control of well
CRDS	cavity ring down spectrometry
CSE	confined space entry
CVAA	cold-vapor atomic absorption
DAS	distributed acoustic sensing
dB	decibel
DIC	dissolved inorganic carbon
DMR	Department of Mineral Resources
DO	dissolved oxygen
DOC	dissolved organic carbon
DOT	U.S. Department of Transportation

Continued . . .

NOMENCLATURE (continued)

DSS	distributed strain sensing
DTS	distributed temperature sensing
EERC	Energy & Environmental Research Center
EM	electromagnetic
EOR	enhanced oil recovery
EOS	equation of state
EPA	U.S. Environmental Protection Agency
ERR	emergency or remedial response
ERRP	emergency and remedial response plan
°F	degree Fahrenheit
FADP	financial assurance demonstration plan
FID	flame ionization detector
FMI	formation microimaging
FOSV	full opening safety valve
FPD	flame photometric detector
FS	field superintendent
ft	foot
GC	gas chromatography
g/cm^3	gram per cubic centimeter
GEM	Generalized Equation-of-State Model
GFCI	ground fault circuit interrupter
GPa	gigapascal
GPS	global positioning system
GR	gamma ray
h	hour
HCR	high closing ratio
HID	helium ionization detector
HNBR	hydrogenated nitrile butadiene rubber
HPMI	high-pressure mercury injection
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
HSE	health and safety and the environment
Hz	hertz
IARF	infinite-acting radial flow
IBOPSV	inside BOP safety valve
ICEA	Insulated Cable Engineers Association
ICP	inductively coupled plasma
ID	inside diameter

Continued . . .

NOMENCLATURE (continued)

IEPA	Illinois Environmental Protection Agency
in.	inch
InSAR	interferometric synthetic aperture radar
IRMS	isotope-ratio mass spectrometry
JSA	job safety analysis
kg/m^3	kilogram per cubic meter
kHz	kilohertz
Klb	thousand pound
km	kilometer
L	liter
lb	pound
LCS	laboratory control sample
LEL	lower explosive limit
LOC	loss of containment
m	meter
mA	milliampere
m amsl	meter above mean sea level
MASP	maximum anticipated surface pressure
mD	millidarcy
MD	measured depth
MDT	modular dynamics testing
MEM	mechanical earth model
mg	milligram
mg/L	milligram per liter
mi	mile
mi^2	square mile
MI	move in
MICP	mercury injection capillary pressure
Minnkota	Minnkota Power Cooperative, Inc.
ML	local magnitude
mm	millimeter
MMI	modified Mercalli intensity
MMscf/d	million standard cubic foot per day
MMt	million tonne
MMt/yr	million tonne per year
MOC	management of change
mol%	mole percent
MPa	megapascal
MRV	monitoring, reporting, and verification
MRYS	Milton R. Young Station
m/s	meter per second
m/s^2	meter per square second

Continued . . .

NOMENCLATURE (continued)

ms	millisecond
MS	mass spectrometry
MVA	monitoring, verification, and accounting
MVTL	Minnesota Valley Testing Laboratories
NACE	National Institute of Corrosion Engineers
NAICS	North American Industry Classification System
NDAC	North Dakota Administrative Code
NDCC	North Dakota Century Code
NDDH	North Dakota Department of Health
NDIC	North Dakota Industrial Commission
NDSWC	North Dakota State Water Commission
NEC	National Electrical Code
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
nm	nanometer
NMPA	Northern Municipal Power Agency
NU	nipple up
O_2	oxygen
OD	outside diameter
OEM	original equipment manufacturer
O&G	oil and gas
OLCV	Oxy Low Carbon Ventures
ORP	oxidation reduction potential
OSHA	Occupational Safety and Health Administration
P&A	plug and abandon
PCOR	Plains CO_2 Reduction (Partnership)
PISC	postinjection site care
PLT	production logging tool
PM	project manager
PNC	pulsed-neutron capture
PNL	pulsed-neutron log
PPE	personal protective equipment
ppf	pound per foot
ppg	pound per gallon
ppm	part per million
ppmv	part per million volume
psi	pound per square inch
P/T	pressure/temperature
QA	quality assurance
QASP	quality assurance and surveillance plan
QC	quality control
QCSP	quality control and surveillance plan
RTD	resistance temperature detector

Continued . . .

NOMENCLATURE (continued)

RTU	remote terminal unit
RU	rig up
RWP	rated working pressure
§	section
s	second
SCADA	supervisory control and data acquisition
SDS	safety data sheet
SFP	storage facility permit
SGS	secure geologic storage
SIMOPS	simultaneous operations
SLRA	screening-level risk assessment
SMEs	subject matter experts
SP	spontaneous potential
Spf	shots per foot
ST	surveillance technician
SWC	sidewall coring
T&A	temporarily plugged and abandoned
TCD	thermal conductivity detector
TD	total depth
TDS	total dissolved solids
TF	task force
TIC	total inorganic carbon
TIH	trip in hole
TOC	total organic carbon
Tundra SGS	Tundra Secure Geologic Storage Site
TVD	true vertical depth
UCS	uniaxial compressive strength
UIC	underground injection control
μL	microliter
USDW	underground source of drinking water
USGS	U.S. Geological Survey
USIT	ultrasonic imaging tool
VDL	variable density log
VFD	variable-frequency drive
VOA	volatile organic analysis
VSP	vertical seismic profile
WHP	wellhead pressure
WSP	worker safety plan
wt%	weight percent
XRD	x-ray diffraction
XRF	x-ray fluorescence

TUNDRA SGS – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PERMIT APPLICATION SUMMARY

General Applicant and Project Information. Minnkota Power Cooperative, Inc. (Minnkota) and its partners prepared this supporting documentation for its storage facility and underground injection control (UIC) Class VI permit applications to establish two storage reservoirs and phased construction and operation of up to three injection wells located in Oliver County, North Dakota. The project for secure geologic storage (SGS) of carbon dioxide (CO_2) will be operated over a 20-year injection period and be named Tundra SGS. Minnkota is the project sponsor of Tundra SGS. Minnkota anticipates contributing a portion of the total equity of the proposed storage project, but the other equity participants have not yet been identified. As such, the application names Minnkota as the sole storage facility operator and applicant. However, at a time prior to construction of the Tundra SGS site infrastructure, Minnkota anticipates contributing these permits to the Tundra SGS project entity. Minnkota intends such a contribution to effect a transfer of owner and operatorship to the Tundra SGS project entity. Further, a transfer of ownership is treated as a minor modification upon filing of an application to amend for change in ownership in accordance with North Dakota Administrative Code (NDAC) §§ 43-05-01-06 and 12.1. The current mailing address for the Tundra SGS facility and Minnkota, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o Tundra SGS
5301 32nd Avenue South
Grand Forks, ND 58201

Minnkota is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member–owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota is also affiliated with the Northern Municipal Power Agency (NMPA), which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member–owners. Minnkota serves as the operating agent of the NMPA. Figure PS-1 provides a map showing the Minnkota and NMPA service territory.

Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The mine which provides the lignite coal for MRYS is owned and operated by BNI Coal, Inc. (BNI) and is adjacent to the MRYS facility. The lignite used as the fuel for electrical generation also serves as the primary source of the captured CO_2 that will be securely stored by Tundra SGS. The operation of Tundra SGS together with the carbon capture project are commonly referred to as Project Tundra. The standard industrial classification code for the principal products and services provided Minnkota is best reflected as North American Industry Classification System (NAICS) 221112, Fossil Fuel Electric Power Generation.

An organizational chart showing the relationships between Minnkota and its affiliated organizations is provided in Figure PS-2.

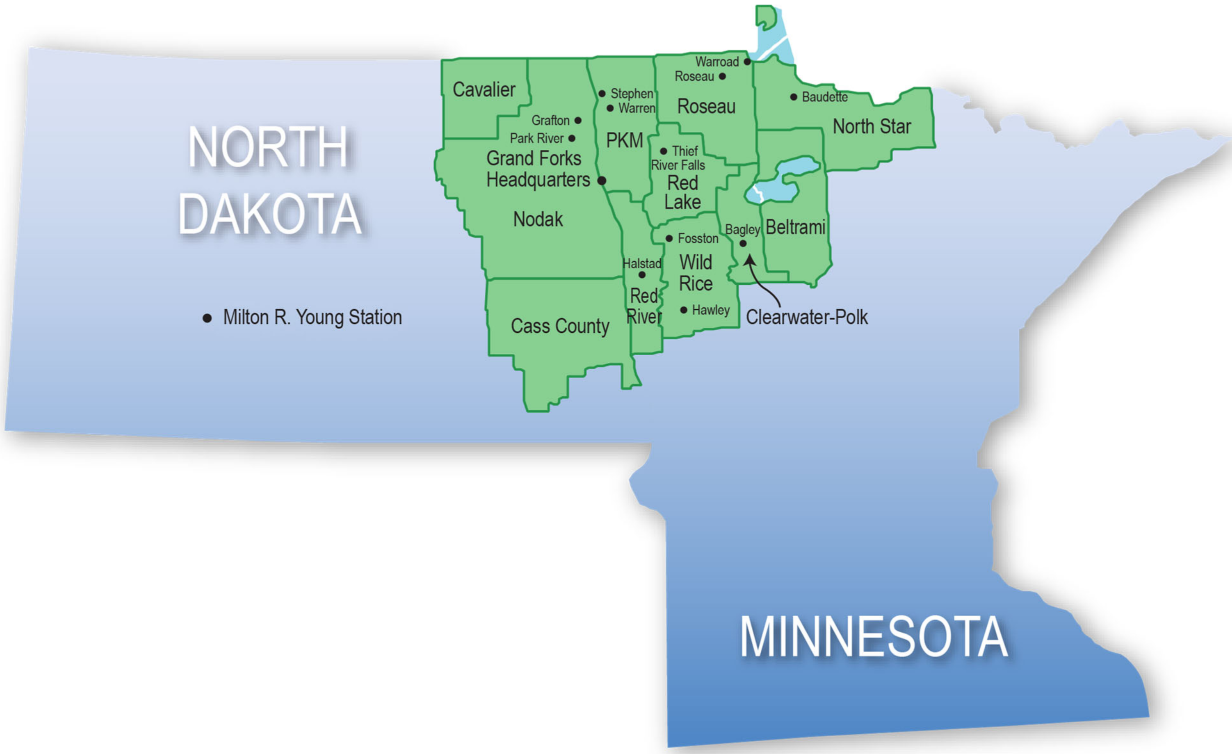

Figure PS-1. Map of the Minnkota and NMPA service territory.

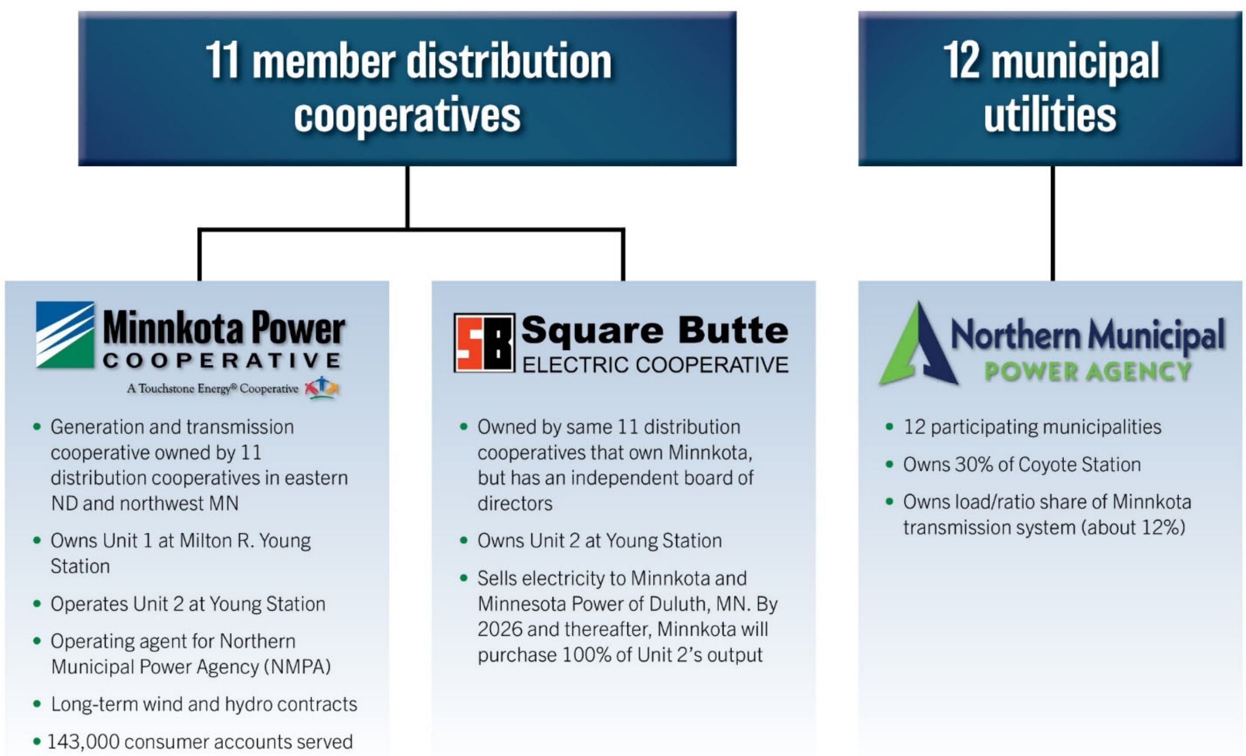

Figure PS-2. Chart showing the relationships between Minnkota and its affiliated organizations.

Minnkota proposes to initially conduct CO_2 storage operations in the Broom Creek Formation as Phase 1 of construction and operation of Tundra SGS. Two wells are proposed for Phase 1 injection of CO_2 into the Broom Creek Formation. Upon construction and operation of the two Broom Creek injection wells, validation of the Phase 1 operation and need for additional capacity will be considered in the decision to proceed with Phase 2 of development. Phase 2 of construction and operation may consist of one additional well for injection of CO_2 into the Black Island–Deadwood Formation. Alternatively, depending on the outcome of Phase 1 operation in the Broom Creek, a third injection well may be considered into the Broom Creek. Permit applications for the two proposed Phase 1 injection wells for the Broom Creek have been prepared and submitted. Since Tundra SGS is proposing a phased development approach for the site, the supporting documentation for the Phase 1 wells in the Broom Creek, as well as the Phase 2 injection well (one in the Black Island–Deadwood) is collectively provided within the application and attachments. This application and its supporting documents have been prepared in accordance with the North Dakota Century Code~~,~~ and NDAC. The applications and supporting documentation are based on currently available data, including regional and site-specific data derived from two stratigraphic test wells drilled by Minnkota in 2020 and one stratigraphic test well drilled by the Energy & Environmental Research Center (EERC) in 2015, all located within 5 mi of the proposed injection wells.

The proposed Tundra SGS injection site is approximately 3.4 mi southwest of the town of Center (Figure PS-3) and will include up to three injection wells, one dedicated monitoring well for the lowest underground source of drinking water (USDW), and associated surface facility infrastructure that will accept CO_2 transported via a CO_2 flowline. In addition, one deep subsurface monitoring well is proposed to be installed approximately 2 mi northeast of the Tundra SGS injection site. All the aforementioned surface facilities and underground equipment will be contained on Minnkota-owned property, and the injection site is within the MRYS fence line (Figure PS-3).

Storage Reservoir Boundary/Area of Review. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Black Island–Deadwood storage facilities. Minnkota defines the storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start of injection until the end of injection. The storage reservoir boundary is identified based on the computational model output of the areal extent of the subsurface CO_2 volume at the end of the injection period (20 years), in which a CO_2 saturation is predicted to be greater than or equal to 5%. To identify the storage reservoir boundaries, reservoir simulation software was used to model the coupled hydrologic, chemical, and thermal processes and chemical interactions of CO_2 with the aqueous fluids and rock minerals. The storage reservoir extent is determined from the numerical model, and the resulting map area is displayed in Figure PS-3.

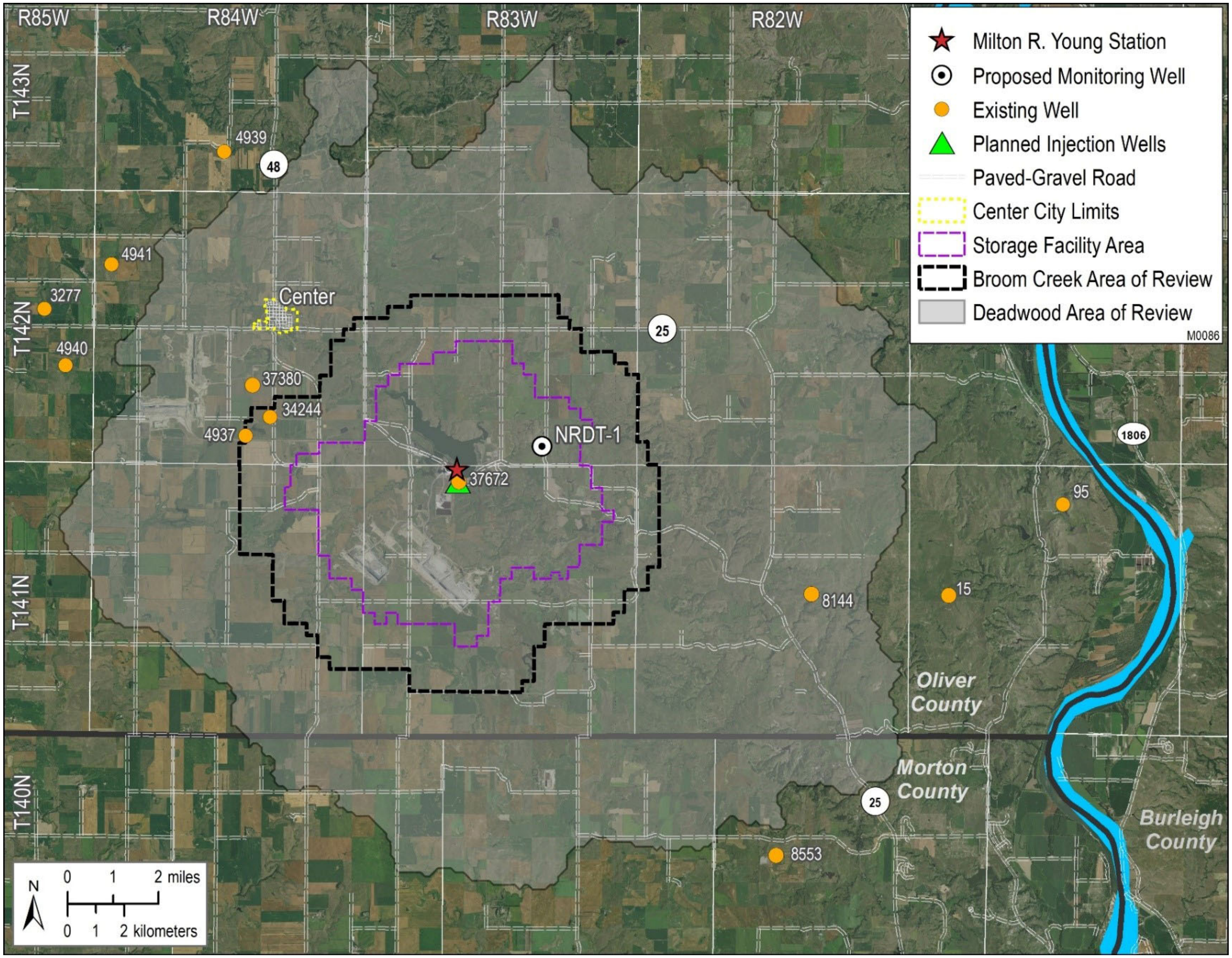

Figure PS-3. Project Tundra geologic storage of CO_2 project map.

The primary objective of the area of review (AOR) is to delineate the region encompassing the Tundra SGS site where USDWs may be endangered by the injection activity (NDAC § 43-05-01-01[4]). The AOR is generally defined as the horizontal extent of the combination of the CO_2 plume and the pressure front threshold caused by injection.

As shown in Figure PS-3, an AOR has been defined for each of the two targeted CO_2 storage horizons. These areas are used to identify the existence of any confining zone penetrations (i.e., existing wells that may penetrate the cap rock). There are five existing wellbores in the Black Island–Deadwood Formation AOR region. Three of those wellbores are the stratigraphic test holes drilled in the past 5 years as part of Tundra SGS geologic characterization efforts. Of these five existing wellbores, only three penetrated the cap rock of the Black Island–Deadwood Formation. Two of the wellbores that penetrate the Deadwood are two of the three stratigraphic test holes drilled for Tundra SGS characterization.

Of these existing wellbores, the remaining two do not penetrate the Black Island–Deadwood Formation. Within the Broom Creek Formation AOR, there are two existing wellbores, one of which is the same stratigraphic test well within the Black Island–Deadwood Formation AOR. This existing wellbore penetrates the Broom Creek Formation, and as discussed in Section 5.0, is proposed to be reentered and completed as one of the two Broom Creek Formation injectors, Liberty-1. Surface bodies of water and other pertinent surface features (including structures intended for human occupancy), administrative boundaries, and roads within the AOR are shown in Figure PS-3.

Minnkota also incorporated the AOR assessments into the proposed corrective action and monitoring plans. The deep subsurface-monitoring plan is tailored to each individual proposed AOR, while the near-surface-monitoring plan for the Broom Creek Formation extends to the boundary of the proposed Deadwood Formation AOR. The AOR assessments of these penetrating wells indicate that none could serve as conduits for the movement of fluids from the injection zone into USDWs. Therefore, no corrective actions on existing wells will need to be taken. Additionally, there are no subsurface cleanup sites, quarries, or Tribal lands within this area.

Construction and Operations Plan. The Tundra SGS project is designed to securely store the injected CO_2 within the storage reservoirs. At MRYS, the captured CO_2 stream will be at least 99% purity, dehydrated, and compressed to 1,800 psi before entering the CO_2 flowline. At these conditions, the CO_2 will be in a dense fluid phase, noncorrosive, and nonflammable. The approximately 0.25-mi (0.40-km) flowline will be 16 in. (40.64 cm) in outside diameter (OD) and have a maximum design flow rate of 4.3 MMT/yr (224 MMscf/d). Because of the short distance between the compressor and wellsite (0.25 mi), the CO_2 pressure is not anticipated to decrease significantly as the CO_2 travels the length of the flowline to the Tundra SGS site. The Broom Creek Formation injector wellhead pressure does not exceed 1,600 psi. Surface injection pressure into the Black Island–Deadwood storage zone will be increased to 2,800 psi using a booster pump downstream of the custody transfer metering station.

The Tundra SGS site design was optimized to receive CO_2 at an average operating rate of 4 MMt/yr, which represents an average annual capacity factor of 90% for the carbon capture plant. The operational design considers the need for redundancy for planned or unplanned outage of any of the wells for maintenance or repair. Two wells are proposed for Phase 1 in the Broom Creek storage reservoir (to be named Liberty-1 and Unity-1) in a twin-well design. Liberty-1 will be a reentry into one of Minnkota's former stratigraphic test wells (J-ROC1, NDIC File No. 37672, now plugged and abandoned) and will be completed as a vertical injector. Unity-1, the twin well to Liberty-1, will be completed as a deviated injector with bottomhole location offset 1000 ft from Liberty-1. These two wells will be operated together to receive CO_2 at an annual average of 4.0 MMt/yr, with a maximum rate of 4.3 MMt/yr.

The optional Phase 2 of construction and operation contemplates a third injector as a vertical injector for the Black Island–Deadwood Formation and will be operated to receive CO_2 at a maximum rate of 1.3 MMT/yr. The phased approach to construction and the maximum rates of the three injector wells and associated equipment are based on operational flexibility, which includes consideration of the planned maintenance, outage, and operating capacity of MRYS and carbon capture equipment, along with the planned maintenance and testing requirements of the Tundra SGS site equipment.

The injection wells will be built with a protection system that will control the injection of the CO_2 and provide a means to safely stop CO_2 injection in the event of an injection well or equipment failure. The injection process will be monitored by an integrated system of equipment and instrumentation that will be capable of detecting whether injection conditions are out of permitted limits and responding by either adjusting conditions or ceasing injection. The system is designed to operate automatically with manual overrides. Additionally, Minnkota has prepared a detailed worker safety plan, which provides the minimum safety programs, permit activities, and training requirements to implement during the construction, operation, and postinjection site care activities of the Tundra SGS site.

Testing and Monitoring Plan. An extensive monitoring, verification, and accounting (MVA) system will be implemented to verify that injected CO_2 is effectively contained within the injection zone. The objectives of the MVA program are to proactively account for corrosion and leakage in the well equipment and surface facilities, track the lateral extent of CO_2 within the injection zones, characterize any geochemical or geomechanical changes that occur within the injection and confining zones that may affect containment, and track the areal extent of the injected CO_2 through indirect monitoring techniques such as geophysical and surveillance methods. The monitoring network, shown in Figure PS-3 and described in Section 4.0, will be designed to account for and verify the location of CO_2 injected.

Emergency and Remedial Response Plan (ERRP). Minnkota developed a comprehensive ERRP for the Tundra SGS site, delineating what actions would be necessary in the unlikely event of an emergency at the Tundra SGS site or within the AOR. The ERRP describes the potential affected resources and provides that site operators know which entities and individuals are to be notified and what actions need to be taken to expeditiously mitigate any emergency and protect human health and safety and the environment, including USDWs. An attachment to the ERRP identifies and categorizes potential adverse event scenarios, and if an adverse event occurred, a variety of emergency or remedial responses are outlined, to be deployed depending on the circumstances (e.g., the location, type, and volume of a release) to protect USDWs.

Postinjection Site Care and Site Closure Plan (PISC). Postinjection monitoring will include a combination of groundwater monitoring, storage zone pressure monitoring, and geophysical monitoring of the Tundra SGS site. The monitoring locations, methods, and schedule are designed to show the position of the CO_2 plume and demonstrate that the CO_2 injected is within the storage reservoir and there is no endangerment to the USDWs.

The proposed monitoring program includes one monitoring well, which covers each of the injection and above confining zones to verify that CO_2 has not migrated into that interval. In addition, a groundwater well will be completed at the Tundra SGS site in the Fox Hills Formation to monitor this lowermost federal USDW. Monitoring of the site will continue for a minimum of 10 years after injection has ceased.

Financial Responsibility Plan. Minnkota has developed a plan to maintain financial responsibility for the construction, operation, closure, and monitoring of the proposed injection wells and undertake any emergency or remedial actions that may be necessary. To ensure that sufficient funds will be available, Minnkota has obtained an estimate for the cost of hiring a third party to undertake any necessary actions to protect USDWs within the AOR. Funding for performing any needed corrective actions will be deposited in a Tundra SGS trust fund that will be available during all phases of the project. Minnkota will also obtain a third-party insurance policy that would be available for conducting any emergency or remedial response actions.

Summary. Minnkota prepared its storage facility and Class VI UIC permit applications and supporting documentation to demonstrate that 1) the proposed Tundra SGS site comprises injection zones of sufficient areal extent, thickness, porosity, and permeability to safely receive the planned injection volume and rates of CO_2 over 20 years and 2) the confining and secondary confining zones are free of transmissive faults and fractures and of sufficient areal extent and integrity to vertically contain the injected CO_2at the proposed pressures and volumes without initiating or propagating fractures in the reservoir or confining zones. These findings are supported by the data and information gathered from coring, logging, sampling, and testing the subsurface characteristics in the three stratigraphic wells that provided site-specific geologic data as well as available regional data.

Minnkota has developed comprehensive construction and operations, testing and monitoring, injection well-plugging, and postinjection site care and site closure plans as well as an emergency and remedial response plan to protect USDWs. To ensure that sufficient funds are available to undertake these actions, Minnkota has also developed a financial responsibility plan.

Minnkota is confident that its permit applications and supporting documentation demonstrate compliance with the North Dakota Industrial Commission (NDIC) Underground Storage of Carbon Dioxide Rules and North Dakota Legislature's authorizing statute. Table PS-1 provides a crosswalk between the regulatory requirements in that rule and organization of Minnkota's supporting documentation.

Table PS-1. Crosswalk Between Applicable Regulatory Provisions in NDIC Rule and Tundra SGS Permit Application and Supporting Documents

NDIC Rule – Regulatory Requirements	Tundra SGS Permit Application
43-05-01-05. Storage Facility Permit Information	Sections 1.0, 2.0, 4.0, 5.0, and Appendixes A–C
43-05-01-05.1 Area of Review and Corrective Action	Sections 3.0, 4.2–4.3, and Appendixes A–B
43-05-01-13 Emergency Remedial Response	Section 4.2 and Appendix E
43-05-01-09 Well Permit Application Requirements	Sections 4.0, 5.0, and Form 25 (Northstar)
43-05-01-09.1 Financial Responsibility	Section 4.3 and Appendix G
43-05-01-11 Injection Well Construction and Completion Standards	Section 5.0
43-05-01-11.1 Mechanical Integrity	Sections 4.1 and 5.0
43-05-01-11.2 Logging, Sampling and Testing Prior to Injection Well Operation	Sections 2.1, 2.2, 5.0, and Appendix B
43-05-01-11.3 Injection Well Operating Requirements	Section 5.0
43-05-01-11.4 Testing and Monitoring Requirements	Section 4.1
43-05-01-11.5 Injection Well Plugging	Section 4.6
43-05-01-11.6 Injection Depth Waiver Requirements	*Not Applicable*
43-05-01-15 Storage Facility Corrosion Monitoring and Prevention Requirements	Section 4.1 and Appendix F
43-05-01-19 Post-Injection Site Care and Facility Closure Requirements	Section 4.7

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 required by North Dakota statute for geologic storage of carbon dioxide (CO_2) to make a good faith attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith attempt, it was able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of the pore space. 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, Minnkota submits the form of storage agreement attached hereto as Appendix H 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.

1.1 Storage Reservoir Pore Space

Minnkota Power Cooperative, Inc. (Minnkota) defines the proposed storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start until the end of injection. The storage reservoir vertical and horizontal boundaries are identified based on the computational model output of the areal extent of the CO_2 plume volume at the end of the injection period (20 years), in which a CO_2 saturation is predicted to be greater than or equal to 5%. The model utilizes applicable geologic and reservoir engineering information and analysis as detailed in Section 2.0 and Appendix A.

The operation inputs for the simulation scenarios assumes storage at the average designed injection rates, approximately 4.0 MMt/year injected into the Broom Creek storage reservoir for the first 15 years of operation and 3.5MMt/year for year 15 through year 20 of operation. The operation input for the Black Island–Deadwood simulation scenario assumes storage at the maximum designed injection rate of approximately 1.17 MMt/year for 20 years. These maximum rates were based on Minnkota's consideration of the planned maintenance, outage, and operating capacity of the Milton R. Young Station (MRYS) and carbon capture equipment along with the planned maintenance requirements and testing requirements of the Tundra SGS (secure geologic storage) site equipment. During Phase 1 operation of the Broom Creek storage facility, Minnkota will conduct ongoing validation and assessment of need for construction and operation of the Black Island–Deadwood.

1.1.1 Horizontal Boundaries

The proposed horizontal boundaries of the storage reservoirs, including an adequate buffer area, are defined by the simulated migration of the CO_2 plume, using the actual rate of injection from the start until the end of injection. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Deadwood storage facilities if needed. The horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off the maximum design life of the carbon capture equipment. The reservoir models will be updated regularly with operating data and the operator will provide evidence of the CO_2 plume migration as part of the reevaluations required under NDAC §§ 43-05-01-05.1 and 43-05-01-11.4. These reevaluations are to occur no later than every 5 years, thus the simulation output at 5 years of operation is indicated in Figure 1-1 to exemplify the buffer existing within the proposed storage facility area, allowing safe operation as proposed and contemplated. The stacked storage operations scenario option allows for coordination of the capacity of the Black–Island Deadwood with the Broom Creek capacity and provides further assurance of the contemplated operation within the defined storage reservoir boundary.

The simulated horizontal storage reservoir boundary results proposed for the Deadwood Formation are depicted in Figure 1-1.

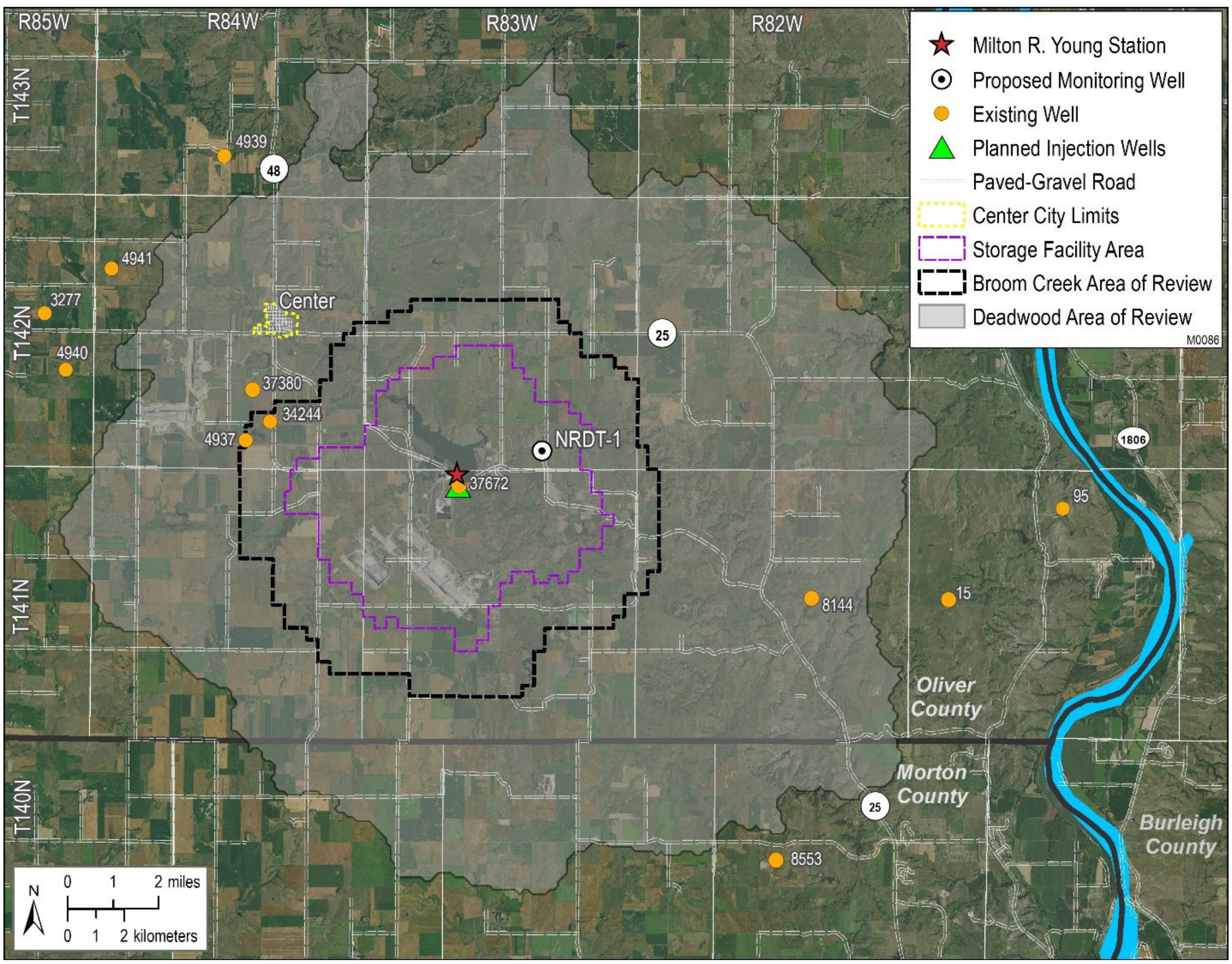

Figure 1-1. Deadwood storage facility area map.

1.1.2 Vertical Boundaries

The Tundra SGS site was designed using a stacked storage concept, where two storage reservoirs identified with varying vertical depths could be accessed by a common well site. A key benefit of this development approach is to minimize the surface land use impact by reducing the amount of surface facilities required for operation. Despite the significant overlap of pore space area between the Broom Creek and Deadwood reservoirs, two distinct SFPs are being requested, with the distinct vertical boundaries based upon geologic analysis and simulations which are further detailed and described in Section 2.0 of the respective SFP application supporting information.

The applicant requests amalgamation of the injection zone pore space within the Black Island, Deadwood E-member, and Deadwood C-member Sand intervals, as identified in Section 2.0, Figure 2-3. In addition to the injection zone, the applicant requests the permitted storage facility consist of the Icebox Formation as the upper confining zone and Deadwood B member shale as the lower confining zone (Section 2.0, Figure 2-3).

1.2 Persons Notified

Minnkota will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 mi of its outside boundary. Minnkota will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to 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 in accordance with North Dakota law (NDCC Chapter 47-31):

- A map showing the extent of the pore space that will be occupied by the CO_2 plume over the injection period, including the storage reservoir boundary and 0.5 mi (0.8 km) outside of the storage reservoir boundary with a description of the pore space ownership, surface owner, and pore space lessees of record (Figure 1-1).

- A table identifying all pore space (surface) owners, and lessees of pore space of record, their mailing addresses, and legal descriptions of their pore space landownership (Table 1-1).

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

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

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S., Grand Forks, ND 58201	Sec. 3-T141N-R83W Sec. 4-T141N-R83W Sec. 5-T141N-R83W Sec. 9-T141N-R83W Sec. 10-T141N-R83W Sec. 32-T142N-R83W Sec. 33-T142N-R83W Sec. 34-T142N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S., Grand Forks, ND 58201	Sec. 4-T141N-R83W Sec. 5-T141N-R83 Sec. 33-T142N-R83W
Oliver County Attn: County Auditor	Oliver County Courthouse, PO Box 188, Center, ND 58530	Sec. 5-T141N-R83W Sec. 34-T142N-R83W
BNI Coal, Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897	Sec. 8-T141N-R83W Sec. 17-T141N-R83W Sec. 31-T142N-R83W Sec. 32-T142N-R83W
Five D's, LLP	3009 Bayside Drive, Mandan, ND 58554	Sec. 8-T141N-R83W
Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 7-T141N-R83W Sec. 1-T141N-R84W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W Sec. 15-T141N-R83W Sec. 22-T141N-R83W
Larry F. & Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 16-T141N-R83W
Kasper J. Kraft & Donna M. Kraft	2845 35th Avenue SW, New Salem, ND 58563	Sec. 16-T141N-R83W
Kasper J. Kraft, Jr.	305 9th Street NW, Mandan, ND 58554	Sec. 16-T141N-R83W
Steve Kraft	2847 35th Avenue, New Salem, ND 58563	Sec. 16-T141N-R83W
Susan Henke	4235 20th Street SW, Stanton, ND 58571	Sec. 16-T141N-R83W
Allen Kraft	6155 12th Street SE, Bismarck, ND 58504	Sec. 16-T141N-R83W
Robin Schimke	9115 Paige Drive, Bismarck, ND 58503	Sec. 16-T141N-R83W
Oliver County	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 16-T141N-R83W
State of North Dakota - Dept. of Trust Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T141N-R83W
Five D's LLP	4609 Borden Harbor Drive SE, Mandan, ND 58554	Sec. 17-T141N-R83W
Jerald O. Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 17-T141N-R83W
Wayne A. Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W Sec. 19-T141N-R83W
Karen L. Reuther	1411 Pocatello Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Jeanette M. Reuther	P. O. Box 304, Center, ND 58530	Sec. 17-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 17-T141N-R83W
Brian Reinke	1106 East Highland Acres Road, Bismarck, ND 58501	Sec. 6-T141N-R83W
Benjamin Reinke	1215 Columbia Drive, Bismarck, ND 58504	Sec. 6-T141N-R83W
Elizabeth Wagendorf	948 Stryker Avenue, West St. Paul, MN 55118	Sec. 6-T141N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 6-T141N-R83W Sec. 1-T141N-R84W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 6-T141N-R83W
Heirs or Devisees of Alex Sorge, deceased	Center ND 58530	Sec. 32-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W Sec. 32-T142N-R83W
Oliver County Attn: Chairman	P.O. Box 188, Center, ND 58530	Sec. 4-T141N-R83W Sec. 32-T142N-R83W
ALLETE, INC.	30 W Superior St., Duluth, MN 55802-2030	Sec. 33-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 34-T142N-R83W
State of North Dakota	1707 N 9th St., Bismarck, ND 58501-5523	Sec. 34-T142N-R83W
Robert Reinke	1144 College Drive #201, Bismarck, ND 58501	Sec. 31-T142N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 2-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 10-T141N-R83W Sec. 11-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 11-T141N-R83W
Nancy Henke	P.O. Box 90, Hazen, ND 58545	Sec. 11-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 11-T141N-R83W
Peggy Gobar	504 Garden Avenue NW, West Fargo, ND 58078	Sec. 11-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Randy Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Janet K. Dohrmann and L.J. Dohrmann, as Trustees of The Janet and L.J. Fast Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 18-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Kent Reutherfkuf	3610 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Keith Reuther	3594 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Karen Shulz	13720 Chamy Dr., Reno, NV 89521	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 18-T141N-R83W Sec. 19-T141N-R83W
Martha Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Ave. SW, Center, ND, 58530	Sec. 18-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 19-T141N-R83W
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 19-T141N-R83W
Charles H. Kuether	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Charles H. Kuether	3555 28th Street, New Salem, ND 58563	Sec. 19-T141N-R83W
Erick G. Larson	50 Avalon Dr Unit 7323, Milford, CT 06460-8957	Sec. 19-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 22-T141N-R83W Sec. 27-T141N-R83W
Travis Klatt and Jessica Klatt, as joint tenants	2438 37th Ave. SW, Center, ND 58530	Sec. 1-T141N-R84W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 20-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 20-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 20-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 20-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 20-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 20-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 20-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 20-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 20-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 20-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 5850	Sec. 20-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 20-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Doll Farm Enterprises	3997 36th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 28-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Clementine Freisz	710 Pine Avenue, New Salem, ND 58563	Sec. 28-T141N-R83W
Sandra K. Orgaard	2810 26th Street, Center, ND 58530	Sec. 28-T141N-R83W
Roger A. Friesz	797 7th Street, Idaho Falls, ID 83401	Sec. 28-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Duane M. Friesz	4465 34th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Karen M. Porsborg	2720 37th Avenue SW, New Salem, ND 58563	Sec. 28-T141N-R83W
Michael J. Friesz	3463 County Road 87, New Salem ND, 58563	Sec. 28-T141N-R83W
Audrey A. Peterson	12719 Doris Drive, Black Hawk, SD 57718	Sec. 28-T141N-R83W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 21-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 21-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 21-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 21-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 21-T141N-R83W
Michael Pazdernik	P.O. Box 194, New Salem, ND 58563	Sec. 21-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 21-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 21-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 21-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 21-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 21-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 21-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 21-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 21-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 21-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 21-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 21-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 21-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
City of Center Park District	Center, ND 58530	Sec. 2-T141N-R84W
Barry A. Berger and Carrie Berger, as joint tenants	809 Main Street E, Center, ND 58530	Sec. 2-T141N-R84W
Dwight Wrangham and Linda Wrangham, as joint tenants	301 52nd St. SE, Bismarck, ND 58501	Sec. 2-T141N-R84W
BNI Coal, Ltd.	1637 Burnt Boat Drive, P.O. Box 897, Bismarck, ND 58502-0897	Sec. 2-T141N-R84W

Surface Owners, Pore Space Owners and Lessees of Pore Space	**Mailing Address**	**Legal Description**
Eugene Yantzer and Betty Yantzer, as joint tenants	2745 18th St. SW, Center, ND 58530	Sec. 2-T141N-R84W
Delmar Hagerott Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust under the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 2492	Sec. 29-T141N-R83W
Steven P. Kraft and Julie F. Kraft, as joint tenants	2847 35th Avenue, New Salem, ND 58563	Sec. 29-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 13-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R83W
Nancy Henke and Dwight Henke	P.O. Box 90, Hazen, ND 58545	Sec. 13-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane, Mandan, ND 58554	Sec. 13-T141N-R83W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 13-T141N-R83W
Rodney Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 13-T141N-R83W
Delvin Bueligen	709A 3rd Avenue SE, Mandan, ND 58554	Sec. 13-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 13-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 13-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 13-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 13-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 13-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R83W
Arline Orgaardz	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R83W
Mark Leischner and Susan Leischner	2866 Woodland Place, Bismarck, ND 58504-8922	Sec. 13-T141N-R83W
Mark Erhardt	P.O. Box 132, Center, ND 58530	Sec. 13-T141N-R83W
Burton & Etheleen Enterprises, LLC	3655 County Road 139, New Salem, ND 58563	Sec. 14-T141N-R84W
Lee Dresser	P.O. Box 683, Riverdale, ND 58565	Sec. 14-T141N-R84W
Jesse L. Lackman and Darcy J. Lackman Revocable Living Trust	2647 37th Avenue SW, Center, ND 58530	Sec. 14-T141N-R84W
David Porsborg and Karen Porsborg	2720 37th Avenue, New Salem, ND 58563	Sec. 24-T141N-R84W
Beverly Faul	1420 9th Avenue NE, McClusky, ND 58463	Sec. 24-T141N-R84W
Brad Bonnet	3444 110th Avenue NE, Bismarck, ND 58504	Sec. 24-T141N-R84W
Justin Kessler	6045 Lyndale Avenue S, #255, Minneapolis, MN 55419	Sec. 24-T141N-R84W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Adam Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Andrew Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Chad Porsborg	3206 Stonewall Drive, Bismarck, ND 58501	Sec. 24-T141N-R84W
Heather Bullinger	2602 10th Avenue SE, Mandan, ND 58554	Sec. 24-T141N-R84W
Christie Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Tina Sorge	4412 E Mulberry, #312, Ft. Collins, CO, 80524	Sec. 24-T141N-R84W
Jerald Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 24-T141N-R84W
Wayne Reuther	476 Glenwood Drive, Bismarck, ND 58504	Sec. 24-T141N-R84W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 24-T141N-R84W
Kent Reuther and Pam Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Kenneth W. Reinke and Darlene Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Minnkota Power Cooperative, Inc.	P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 3-T141N-R84W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 3200, Grand Forks, ND 58208-3200	Sec. 3-T141N-R84W
Agnes Dockter	2424 South 121st Street, Seattle, WA 98101	Sec. 15-T142N-R83W
Steve Schmidt and Julie Schmidt, as joint tenants	P.O. Box 1936, Center, ND 58530	Sec. 15-T142N-R83W
Mike Saba a/k/a Michael P. Saba	26560 N. Shore Pl., Hartford, SD 57033	Sec. 15-T142N-R83W
State of North Dakota, for the use and benefit of the State Highway Department	608 East Boulevard Avenue, Bismarck, ND 58505-0700	Sec. 15-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 23-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
State of North Dakota Board of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 36-T142N-R84W
Oliver County Attn: County Auditor	P.O. Box 188, Center, ND 58530-0188	Sec. 36-T142N-R84W
Minnkota Power Cooperative, Inc.	1822 State Mill Road, P. O. Box 13200", Grand Forks, ND 58208-3200	Sec. 36-T142N-R84W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 36-T142N-R84W
BNI Coal, Ltd.	P.O. Box 897, Bismarck, ND 58502	Sec. 36-T142N-R84W
Larry J. Doll and Faye Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 25-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Haag Brothers, a partnership consisting of Thomas Haag, Donald Haag, and Conrad Haag	3051 Highway 25, Center, ND 58530	Sec. 24-T142N-R84W
Wayne Haag and Jennifer Haag, as joint tenants	P.O. Box 184, Center, ND 58530	Sec. 24-T142N-R84W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Kenneth Schmidt	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt	3581 22 Street SW, Center, ND 58530	Sec. 19-T142N-R83W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Matthias A. Erhardt, trustee, or successor trustee(s), of the Matthias A. Erhardt Trust dated December 27, 1994	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Josephine Erhardt, trustee, or successor trustee(s), of the Josephine Erhardt Trust dated December 27, 1994	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Joey Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Jerry Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 1-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 1-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 1-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 12-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan, ND 58554	Sec. 12-T141N-R83W
Fred Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Raynold Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Walter Schwalbe	Center, ND 58530	Sec. 12-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 12-T141N-R83W
Nancy Henke and Dwight Henke, as joint life tenants	P.O. Box 90, Hazen, ND 58545	Sec. 12-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane N, Mandan, ND 58554	Sec. 12-T141N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 12-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 12-T141N-R83W
Peggy Gobar	504 Garden Ave. NW, West Fargo, ND 58078	Sec. 12-T141N-R83W
Annette Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W
Brent Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W
Randy Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Reda Renee Clinton and Stephanie A. Clarys, as joint tenants	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Michael P. Hilton	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Oliver County	Oliver County Courthouse, P.O. Box 188, Center, ND 58530	Sec. 14-T141N-R83W
John Barnhardt	1511 North 21st Street, Bismarck, ND 58501	Sec. 14-T141N-R83W
Gail M. Hilton	3195 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 14-T141N-R83W
Lowell Bueligen	13621 Homestead Lane Riverton, UT 84065	Sec. 14-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 14-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 14-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 14-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Dale Barnhardt	3199 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Jeff Erhardt ad Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 20-T142N-R83W
Matthias A. Erhardt, as trustee of the Matthias A. Erhardt Trust dated December 27, 1994	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Josephine Erhardt, as trustee of the Josephine Erhardt Trust dated December 27, 1994	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 20-T142N-R83W
Raymond Friedig, as personal representative of the Estate of Magdalen F. Friedig, deceased	523 South Anderson Street, Bismarck, ND 58504	Sec. 26-T142N-R83W
Carl Schwalbe	Center, ND 58530	Sec. 26-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Heirs or Devisees of the Estate of Loren Schwalbe, deceased	3520 81st Ave. SE, Unit 15, Jamestown, ND 58401	Sec. 26-T142N-R83W
Rolland Schwalbe	Center, ND 58530	Sec. 26-T142N-R83W
Randolph Middleton and Mary Middleton, as joint tenants	2298 32nd Ave SW, Center, ND 58530	Sec. 26-T142N-R83W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 27-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 28-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 28-T142N-R83W
Dale Barth	2255 33rd Ave SW, Center, ND 58530	Sec. 28-T142N-R83W
Dusty Backer	PO Box 411, Underwood, ND 58576	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 29-T142N-R83W
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Terrie Nehring	2234 35th Ave. SW, Center, ND, 58530	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 30-T142N-R83W
Minnkota Power Cooperative, Inc.	1822 Mill Road, P.O. Box 13200, Grand Forks, ND 58208-3200	Sec. 30-T142N-R83W
Ryan J. Weber	2241 29th Ave. SW, Center, ND 58530	Sec. 30-T142N-R83W
Darlene Voegele	P.O. Box 45, Stanton, ND 58571	Sec. 30-T142N-R83W
Bradley Dahl	602 Lehmkuhl St., PO Box 276, Center, ND 58530	Sec. 30-T142N-R83W
Brennan Price	3074 Highway 25, Center, ND 58530-1015	Sec. 35-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 36-T142N-R83W
Michelle Marie Ternes	3721 W Regent Drive, Bismarck, ND 58504	Sec. 35-T142N-R84W
Michael P. Dresser	3731 24th Street SW, Center, ND 58530	Sec. 35-T142N-R84W
BNI Coal, Ltd.	P.O. Box 897, Bismarck, ND 58502	Sec. 35-T142N-R84W
Oliver County, Attn: County Auditor & Hwy Dept.	P.O. Box 188, Center, ND 58530-0188	Sec. 34-T142N-R84W
BNI Coal, Ltd	P.O. Box 879, Minot, ND 58702	Sec. 34-T142N-R84W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 16-T142N-R83W
State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T142N-R83W
Luella C. Isaak	3347 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Burton Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Burton Lee Isaak, individually	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brenda Kitzan	3313 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brent J. Isaak	2065 33rd Avenue SW, Center, ND 58530	Sec. 16-T142N-R83W
Luella C. Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142N-R83W
Brent Isaak	2065 33rd Avenue SW, Center, ND 58530	Sec. 16-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 17-T142N-R83W
The State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T142N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 12-T141N-R84W
Brian Dresser	2574 37th Avenue SW, Center, ND 58530	Sec. 12-T141N-R84W
Frances Fuchs	2475 37th Avenue NW, Center, ND 58530	Sec. 12-T141N-R84W
Rosalie A. Dingus	400 Augsburg Avenue, Bismarck, ND 58504	Sec. 12-T141N-R84W
Mark R. Fuchs	18671 Fairweather, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jack B. Fuchs	15409 Rhododendron Drive, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jeff Erhardt and Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt and Kelly Jo Erhardt, as joint tenants	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Melvin Schoepp and Caroline Schoepp, as joint tenants	2023 Northridge Drive, Bismarck, ND 58503	Sec. 21-T142N-R83W
Larry Doll and Fay Doll, as joint tenants	3155 49th Ave., New Salem, ND 58563	Sec. 21-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND, 58501-5523	Sec. 21-T142N-R83W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 11-T141N-R84W
David O. Berger and Debra A. Berger, as joint tenants	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Melvin Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Caroline K. Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Larry Doll and Fay Doll, as joint tenants	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Larry Doll	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Grealing Starck and Deborah Stark, as joint tenants	3244 Highway 25, Center, ND 58530	Sec. 22-T142N-R83W
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 22-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 22-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W

Surface Owners, Pore Space Owners and Lessees of Pore Space	Mailing Address	Legal Description
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 22-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 22-T142N-R83W

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

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 5-T141N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1415 Louisiana Street, Suite 2400, Houston, TX 77002-7361	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1658 Cole Boulevard, Building #6; Suite 2, Golden, CO 80401	Sec. 5-T141N-R83W
Great Northern Properties L.P.	1101 N 27th Street, Suite 201, Billings, MT, 59101	Sec. 5-T141N-R83W
Susanna Skubinna	Egeland ND 58331	Sec. 5-T141N-R83W
Mildred Meili Miran	21500 Miran Farm Lane, Aldie, VA 20105	Sec. 5-T141N-R83W
Marilyn Meili	7681 East Vista Drive, Scottsdale, AZ 85250-6824	Sec. 5-T141N-R83W
Douglas L. Franklin	4409 S 292nd Street, Auburn, WA 98002	Sec. 5-T141N-R83W
R. C. Newkirk	4208 Lone Oak Drive, Fort Worth, TX 76107	Sec. 5-T141N-R83W
Vernon R. Young	2954 Chevy Chase Drive, Houston, TX 77019Z	Sec. 5-T141N-R83W
Charles W. LaGrave and Louis G. Kravits, as joint tenants	118 Weiss Court, Hercules, CA 94547	Sec. 5-T141N-R83W
Richard Haddaway	109 Estates Drive, Santa Fe, NM 87506	Sec. 5-T141N-R83W
Percy Lee Henderson	3032 Willing Avenue, Fort Worth, TX 76110	Sec. 5-T141N-R83W
W. H. Henderson	1016 S Main Street, Fort Worth, TX 76104	Sec. 5-T141N-R83W
K. C. Kyle, Jr.	P. O. Box 253, Carthage, TX 75633	Sec. 5-T141N-R83W
Catherine Westbrook	12 North Park, Randolph AFB, TX 78148	Sec. 5-T141N-R83W
Joseph Harrison Shelton, Jr.	18629 Reamer Road, Castro Valley, CA 94546	Sec. 5-T141N-R83W
Katherine S. Fulcher	1120 N Golder, Odessa, TX 79761	Sec. 5-T141N-R83W
C. H. Kopp and Blanche Kopp, as joint tenants	1609 E Cypress, Enid, OK 73701	Sec. 5-T141N-R83W
Stanley T. Staggs and Cora Staggs, as joint tenants	2233 NW 31 St., Oklahoma City, OK 73112	Sec. 5-T141N-R83W
Wyman Orlin Meigs	2408 Zion Park, Yukon, OK 73099-5939	Sec. 5-T141N-R83W
Robert Michael Westfall	No address of record	Sec. 5-T141N-R83W
Don Walter Westfall	No address of record	Sec. 5-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
First National Bank and Trust Company of Oklahoma City, Trustee under Agreement with Othel D. Westfall	c/o Boatmen's National Bank of Oklahoma, Bank of America, National Association (3510), Charlotte, NC, 100 North Tryon Street, Suite 170, Charlotte, NC 28202	Sec. 5-T141N-R83W
Charyl W. Loveridge and Margaret A. Loveridge, as joint tenants	701 Vandehei Avenue, Cheyenne, WY 82009-2553	Sec. 5-T141N-R83W
Dierdre A. (Reynolds) Shipman	6501 Deerview Trail, Durham, NC 27712	Sec. 5-T141N-R83W
John T. Reynolds	2835 Pond Apple, Schertz, TX 78154	Sec. 5-T141N-R83W
Mary L. (Reynolds) Hamlin	#9 Hickory Ridge, Texarkana, TX 75503	Sec. 5-T141N-R83W
Shauna I. (Reynolds) Lee	1127 Felicity Street, New Orleans, LA 70130	Sec. 5-T141N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 5-T141N-R83W
Red Crown Royalties, LLC	P. O. Box 888, Littleton, CO 80160-0888	Sec. 5-T141N-R83W
Tenneco Oil Company	P. O. Box 2511, Houston, TX 77252	Sec. 5-T141N-R83W
Tenneco Oil Company	1001 Louisiana, P. O. Box 2511, Houston, TX 77252-2511	Sec. 5-T141N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 5-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 5-T141N-R83W
United States of America	Unknown address	Sec. 8-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 8-T141N-R83W
Great River Energy Attn: Eric J. Olsen	12300 Elm Creek Boulevard N, Maple Grove, MN 55369-4718	Sec. 8-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201	Sec. 8-T141N-R83W
David Erhardt	13906 Round Oak Court. Houston, TX 77059	Sec. 8-T141N-R83W
Delphine Vetter	2317 79th Street SE, Linton, ND 58552	Sec. 8-T141N-R83W
Doretta Bornemann	511 County 27, Hazen, ND 58545	Sec. 8-T141N-R83W
Danita Deichert	3009 Bayside Drive, Mandan, ND 58554	Sec. 8-T141N-R83W
Dean P. Erhardt	120 Tennessee Walker Way, St. Peters, MO 63376	Sec. 8-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 8-T141N-R83W
Donna Barnhardt	8050 17th Avenue NE, Bismarck, ND 58501	Sec. 8-T141N-R83W
Linda Kilber	2928 Avenue B East, Bismarck, ND 58501	Sec. 8-T141N-R83W
Loretta Tabor	7100 Country Hills Drive, Bismarck, ND 58503	Sec. 8-T141N-R83W
John L. Kautzman	1314 22nd Street W, Williston, ND 58801-2139	Sec. 8-T141N-R83W
W. T. Brown	No street address of record, Newton, KS 67114	Sec. 8-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph MO 64501	Sec. 8-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 8-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Clay E. Kedrick	306 Morningside Lane, Newton, KS, 67114	Sec. 8-T141N-R83W
Clay E. Kedrick	P. O. Box 205, Newton, KS, 67114	Sec. 8-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 8-T141N-R83W
O. Sutorius	No address of record	Sec. 8-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS, 67114	Sec. 8-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 8-T141N-R83W
PEC Minerals LP	14860 Montfort Drive Suite 209, Dallas, TX, 75254	Sec. 8-T141N-R83W
Black Stone Minerals Company, L. P.	1001 Fannin, Suite 2020, Houston, TX, 77002-6709	Sec. 8-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-8006	Sec. 8-T141N-R83W
J. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 8-T141N-R83W
J. L. McMullen	127 N 4th St., Okemah, OK 74859-2456 AND 215 S 5th St., Okemah, OK 74859-3808	Sec. 8-T141N-R83W
Lily Stamper	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
George R. McKown	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 8-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 8-T141N-R83W
O. C. Fore	303 S Okfuskee Avenue, Wewoka, ND 74884	Sec. 8-T141N-R83W
Carl Files	No street address of record, Okemah, OK 74859	Sec. 8-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 8-T141N-R83W
Irene Kautzman	Center, ND 58530	Sec. 8-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 8-T141N-R83W
Breene Associates	1005 Ash Coulee Place, Bismarck, ND 58503	Sec. 8-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 8-T141N-R83W
Penelope Files	3387 W Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 8-T141N-R83W
Carolyn K. Files	P. O. Box 154, Bunn, NC 27508	Sec. 8-T141N-R83W
Kurt Von Files	143 Lake Royale, Louisburg, NC 27549	Sec. 8-T141N-R83W
Erika Lee Files	HC5, Box 103-1, Gainesville, MO 65655	Sec. 8-T141N-R83W
Robert Carl Files	1720 1/2 Reed Avenue, San Diego, CA, 92109	Sec. 8-T141N-R83W
Richard Irwin Files	1720 1/2 Reed Avenue, San Diego, CA, 92109	Sec. 8-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Janet K. Dohrmann and Jamie A. Fast, Co-Trustees of the Opp Family Mineral Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 7-T141N-R83W
Great Northern Properties LP	601 Jefferson Street; Suite 3600, Houston, TX 77002	Sec. 7-T141N-R83W
BNI Coal, Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897	Sec. 7-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 7-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO, 80111	Sec. 7-T141N-R83W
Meridian Minerals Company	2919 Allen Parkway, Houston, TX, 77019-2142	Sec. 7-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 7-T141N-R83W
James Schneider	RR #1 Box 56, Center, ND 58530	Sec. 7-T141N-R83W
Gail Schneider	RR #1 Box 56, Center, ND 58530	Sec. 7-T141N-R83W
Ida Schwalbe Estate c/o Rolland Schwalbe	3160 25th Street, Center, ND 58530	Sec. 7-T141N-R83W
Wilma Lueneburg Estate c/o Linda Lueneburg	3730 Lockport St., Bismarck, ND 58503	Sec. 7-T141N-R83W
Alvin Hagerott	3190 27th Ave., Center, ND 58530	Sec. 7-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 15-T141N-R83W
Delvin Bueligen/Delvin Bueligen and Jill Bueligen, as joint tenant	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 15-T141N-R83W
Lowell Bueligen/Lowell Bueligen and Tammy Bueligen, as joint tenants	13621 Homestead Lane, Riverton, UT 84065	Sec. 15-T141N-R83W
Rodella Hausauer/Rodella Hausauer and Barry Hausauer, as joint tenants	1611 Castillian Way, Mundelein, IL 60060	Sec. 15-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO, 80126	Sec. 15-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 15-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 15-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 15-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 15-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 15-T141N-R83W
Albert Hagerott	3190 27th St, Center, ND 58530-9559	Sec. 15-T141N-R83W
Mary Hagerott	1719 N Bell St, Bismarck, ND 58501-1531	Sec. 15-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 15-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 15-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 82647	Sec. 15-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 15-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 15-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 15-T141N-R83W
State of North Dakota - Dept. of Trust Lands - Board of University & School Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 16-T141N-R83W
State of North Dakota - Board of University & School Lands Attn: Commissioner of University and School Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T141N-R83W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 17-T141N-R83W
Central Dakota Humane Society	2104 37th St., Mandan, ND 58554	Sec. 17-T141N-R83W
David Erhardt	13906 Round Oak Court, Houston, TX 77059	Sec. 17-T141N-R83W
Delphine Vetter	2317 79th Street SE, Linton, ND 58552	Sec. 17-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Doretta Bornemann	511 County 27, Hazen, ND 58545	Sec. 17-T141N-R83W
Danita Deichert	3009 Bayside Drive, Mandan, ND 58554	Sec. 17-T141N-R83W
Dean P. Erhardt	120 Tennessee Walker Way, St. Peters, MO 63376	Sec. 17-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 17-T141N-R83W
Jerald O. Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 17-T141N-R83W
Wayne A. Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Karen L. Reuther	1411 Pocatello Drive, Bismarck, ND 58504	Sec. 17-T141N-R83W
Jeanette M. Reuther	P. O. Box 304, Center, ND 58530	Sec. 17-T141N-R83W
Donna Barnhardt	8050 17th Avenue NE, Bismarck, ND 58501	Sec. 17-T141N-R83W
Linda Kilber	2928 Avenue B East, Bismarck, ND 58501	Sec. 17-T141N-R83W
Loretta Tabor	7100 Country Hills Drive, Bismarck, ND 58503	Sec. 17-T141N-R83W
John L. Kautzman	1314 22nd Street W, Williston, ND 58801-2139	Sec. 17-T141N-R83W
W. T. Brown	No street address of record, Newton, KS 67114	Sec. 17-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph MO 64501	Sec. 17-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 17-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 17-T141N-R83W
O. Sutorius	No address of record	Sec. 17-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS 67114	Sec. 17-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 17-T141N-R83W
PEC Minerals LP	14860 Montfort Drive, Suite 209, Dallas, TX 75254	Sec. 17-T141N-R83W
Black Stone Minerals Company, L. P.	1001 Fannin, Suite 2020, Houston, TX 77002-6709	Sec. 17-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-6709	Sec. 17-T141N-R83W
J. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W
J. L. McMullen	127 N 4TH ST, Okemah OK 74859-2456 AND 215 S 5TH ST Okemah OK 74859-3808	Sec. 17-T141N-R83W
Lily Stamper	No street address of record, Okemah OK 74859	Sec. 17-T141N-R83W
George R. McKown	No street address of record, Okemah OK 74859	Sec. 17-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 17-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W
O. C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 17-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Carl Files	No street address of record, Okemah, OK 74859	Sec. 17-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 17-T141N-R83W
Irene Kautzman	Center, ND 58530	Sec. 17-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 17-T141N-R83W
Breene Associates	1005 Ash Coulee Place, Bismarck, ND 58503	Sec. 17-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 17-T141N-R83W
Penelope Files	3387 W Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 17-T141N-R83W
Carolyn K. Files	P. O. Box 154, Bunn, NC 27508	Sec. 17-T141N-R83W
Kurt Von Files	143 Lake Royale, Louisburg, NC 27549	Sec. 17-T141N-R83W
Erika Lee Files	HC5, Box 103-1, Gainesville, MO 65655	Sec. 17-T141N-R83W
Robert Carl Files	1720 1/2 Reed Avenue, San Diego, CA 92109	Sec. 17-T141N-R83W
Richard Irwin Files	1720 1/2 Reed Avenue, San Diego, CA 92109	Sec. 17-T141N-R83W
James Schneider	RR #1, Box 56, Center, ND 58530	Sec. 6-T141N-R83W
Gail Schneider	RR #1, Box 56, Center, ND 58530	Sec. 6-T141N-R83W
Ida Schwalbe Estate c/o Rolland Schwalbe	3160 25th Street, Center, ND 58530	Sec. 6-T141N-R83W
Wilma Lueneburg Estate c/o Linda Lueneburg	3730 Lockport St., Bismarck, ND 58503	Sec. 6-T141N-R83W
Alvin Hagerott	3190 27th Ave., Center, ND 58530	Sec. 6-T141N-R83W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 6-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 6-T141N-R83W
Brian Reinke	1106 East Highland Acres Road, Bismarck, ND 58501	Sec. 6-T141N-R83W
Benjamin Reinke	1215 Columbia Drive, Bismarck, ND 58504	Sec. 6-T141N-R83W
Elizabeth Wagendorf	948 Stryker Avenue, West St. Paul, MN 55118	Sec. 6-T141N-R83W
United States of America	Unknown address	Sec. 6-T141N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 6-T141N-R83W
Tenneco Oil Company	P. O. Box 2511, Houston, TX 77252	Sec. 6-T141N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 6-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 6-T141N-R83W
Duane C. Anderson	1321 Whispering Hill, Ada, OK 74820	Sec. 9-T141N-R83W
Corrine L. Dockter	507 S 8th Street, Lot #10, Bismarck, ND 58504	Sec. 9-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Vi Ann Olson	2130 27th Avenue S, Grand Forks, ND 58201	Sec. 9-T141N-R83W
Gary A. Anderson	110 Lakota Avenue, Center, ND 58530	Sec. 9-T141N-R83W
Willard C. Anderson	No address of record (Check with Duane, Corrine, Vi or Gary)	Sec. 9-T141N-R83W
Wallace R. Anderson	No address of record (Check with Duane, Corrine, Vi or Gary), Star Prairie, WI 54026	Sec. 9-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 32-T142N-R83W
Heirs or Devisees of Alex Sorge, deceased	Center ND 58530	Sec. 32-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 32-T142N-R83W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 32-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 32-T142N-R83W
Spindletop Exploraton Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 32-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 32-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 32-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 32-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 32-T142N-R83W
United States of America	Unknown address	Sec. 32-T142N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec.4-T141N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec.4-T141N-R83W
Anna Manny	Center, ND 58530	Sec.4-T141N-R83W
United States of America	Unknown address	Sec.4-T141N-R83W
Square Butte Electric Cooperative	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 33-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 33-T142N-R83W
ALLETE, INC.	30 W Superior St., Duluth, MN 55802-2030	Sec. 33-T142N-R83W
Anna Manny	Center, ND 58530	Sec. 33-T142N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 33-T142N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 33-T142N-R83W
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 33-T142N-R83W
AgriBank, FCB (f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul)	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 33-T142N-R83W
Floyd B. Sperry	No street address of record, Bismarck, ND 58501	Sec. 33-T142N-R83W
State of North Dakota N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 33-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Great Northern Properties Limited Partnership Attn: Steven K. Shirley	1101 N. 27th Street, Suite 201, Billings, MT 59101	Sec. 33-T142N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 33-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 34-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 34-T142N-R83W
Nick Ferderer	Flasher, ND 58535 AND 912 Summit Blvd, Bismarck ND 58504-5277	Sec. 34-T142N-R83W
Harry H. Ferderer	907 Cowl Street, Milton Freewater OR 97862-1682	Sec. 34-T142N-R83W
John R. Ferderer	115 C Street North, Richardton ND 58652	Sec. 34-T142N-R83W
Eleanor Falstad	Eleanor Falstad Estate, c/o Valerie Fast, 2495 15th St. NW, Coleharbor ND 58531-9449	Sec. 34-T142N-R83W
Joyce Ervin, as personal representative of the Estate of Marie M. McGirl, deceased	2073 Rayshire Street, Thousand Oaks CA 91362-2460	Sec. 34-T142N-R83W
Esther Ferderer, as personal representative of the Estate of Jake H. Ferderer, deceased	No address of record	Sec. 34-T142N-R83W
Dorene Rambur	500 North 17th Street, Bismarck ND 58501	Sec. 34-T142N-R83W
Norman D. Bunch	6900 Wedgewood Ct., Black Hawk, SD 57718-9680	Sec. 34-T142N-R83W
Kaspar Barth	Center ND 58530	Sec. 34-T142N-R83W
United States of America	Unknown address	Sec. 34-T142N-R83W
County of Oliver	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 34-T142N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 34-T142N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 34-T142N-R83W
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 34-T142N-R83W
Floyd B. Sperry	No street address of record, Bismarck, ND 58501	Sec. 34-T142N-R83W
AgriBank, FCB (f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul)	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 34-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312	Sec. 3-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 3-T141N-R83W
Pat Nassif	429 Sunset Place, Bismarck, ND 58504	Sec. 3-T141N-R83W
Fran Glasser	4735 Pintail Loop SE, Mandan, ND 58554	Sec. 3-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Real S. A. K.	2207 East Main, Suite #2, Bismarck, ND 58501	Sec. 3-T141N-R83W
Florian Emineth	No street address of record, Mandan, ND 58554	Sec. 3-T141N-R83W
Wm. M. Mutz	No street address of record, Mandan, ND 58554	Sec. 3-T141N-R83W
William K. Engelter	202 15th Street NW, Apt. 6, Mandan ND 58554-2075	Sec. 3-T141N-R83W
Great Northern Properties Limited Partnership Attn: Steven K. Shirley	1101 N. 27th Street, Suite 201, Billings, MT 59101	Sec. 3-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 3-T141N-R83W
Duane C. Anderson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Corrine L. Dockter	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Vi Ann Olson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Gary A. Anderson	740 N. 23rd Street, Bismarck, ND 58501	Sec. 3-T141N-R83W
Robert Reinke	1144 College Drive #201, Bismarck, ND 58501	Sec. 31-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 31-T142N-R83W
Nellie Dietz	New Salem ND 58563	Sec. 31-T142N-R83W
Eldon Reinke	Eldon Reinke Estate, c/o Colleen Reinke, 13239 71st Street SE, Lisbon ND 58054	Sec. 31-T142N-R83W
Lyle Reinke	c/o Colleen Reinke, 13239 71st Street SE, Lisbon ND 58054	Sec. 31-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 31-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 31-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 31-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 31-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 31-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 31-T142N-R83W
C. D. Griggs	230 Park Avenue, New York, NY 10169	Sec. 31-T142N-R83W
Lebert Lesch	Rt. 1, Box 134, Sheridan, WY 82801	Sec. 31-T142N-R83W
Lavern Heid	New Salem, ND 58563	Sec. 31-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center, ND 58530	Sec. 2-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 2-T141N-R83W
State of North Dakota N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 2-T141N-R83W
United States of America	Unknown address	Sec. 2-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 10-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Gertrude Schwalbe Estate c/o Susan Bohn, PR	16710 NE 41st Street, Redmond, WA 98052	Sec. 10-T141N-R83W
United States of America	Unknown address	Sec. 10-T141N-R83W
Duane C. Anderson	1321 Whispering Hill, Ada, OK 74820	Sec. 10-T141N-R83W
Corrine L. Dockter	624 S Hannifin Street; Apt. 3, Bismarck, ND 58504	Sec. 10-T141N-R83W
Vi Ann Olson	2130 27th Avenue S, Grand Forks, ND 58201	Sec. 10-T141N-R83W
Gary A. Anderson	315 Olier Avenue N, Center, ND 58530	Sec. 10-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 10-T141N-R83W
Delvin Bueligen/Delvin Bueligen and Jill Bueligen, as joint tenant	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 10-T141N-R83W
Lowell Bueligen/Lowell Bueligen and Tammy Bueligen, as joint tenants	13621 Homestead Lane, Riverton, UT 84065	Sec. 10-T141N-R83W
Rodella Hausauer/Rodella Hausauer and Barry Hausauer, as joint tenants	1611 Castillian Way, Mundelein, IL 60060	Sec. 10-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 10-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 10-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 10-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Lynn C. Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 10-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 10-T141N-R83W
Dollie Hagerot	744 Lake Avenue, Ortonville, MN 56278	Sec. 10-T141N-R83W
Albert Hagerott	3190 27th St, Center, ND 58530-9559	Sec. 10-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 10-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 10-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 10-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92674	Sec. 10-T141N-R83W
Alvin Hagerott	HC2 Box 244, Center ND 58530	Sec. 10-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 10-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 10-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 10-T141N-R83W
AgriBank, FCB f/k/a The Federal Land Bank and Farm Credit Bank of Saint Paul	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 10-T141N-R83W
Alan Schwalbe	3175 27th Street, Center, ND 58530	Sec. 11-T141N-R83W
Great Northern Properties L.P.	1415 Louisiana Street, Suite 2400, Houston, TX 77002-7361	Sec. 11-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 11-T141N-R83W
State of North Dakota - Board of University and School Lands	1707 N 9th Street, Bismarck, ND 58501-5523	Sec. 11-T141N-R83W
Julie Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 11-T141N-R83W
Nancy Henke	P. O. Box 90, Hazen, ND 58545	Sec. 11-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 11-T141N-R83W
Peggy Gobar	504 Garden Avenue NW, West Fargo, ND 58078	Sec. 11-T141N-R83W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 11-T141N-R83W
Randy Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 11-T141N-R83W
Janet K. Dohrmann and Jamie A. Fast, as Co-Trustees of The Opp Family Mineral Trust	9721 31st Street SW, Taylor, ND 58656	Sec. 18-T141N-R83W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 18-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Kent Reuther	3610 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W
Keith Reuther	3594 27th St. SW, New Salem, ND 58563	Sec. 18-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Karen Shulz	13720 Chamy Dr., Reno, NV 89521	Sec. 18-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 18-T141N-R83W
Martha Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Ave. SW Center ND 58530	Sec. 18-T141N-R83W
Peter Pfleger Jr.	No address of record	Sec. 18-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 18-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 18-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 18-T141N-R83W
Sandra Ohlhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 18-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 18-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 18-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Wittmann, AZ 85361	Sec. 18-T141N-R83W
Holli K. Taylor	28827 N. 254th Lane, Wittmann, AZ 85361	Sec. 18-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 18-T141N-R83W
Darrell Ray Buntin III	P.O. Box 167, Chino Valley, AZ 86323	Sec. 18-T141N-R83W
Amanda Marie Minick	4332 S. Fireside Trail, Gilbert, AZ 85297	Sec. 18-T141N-R83W
Lisa F. Pulse, as a purported heir to Angeline Bonogofsky, deceased	405 William Street, Miles City MT 59301-2336	Sec. 18-T141N-R83W
Donald Perry Bonogofsky, as a purported heir to Angeline Bonogofsky, deceased	1117 Palmer Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Gary Blase Bonogofsky, as a purported heir to Angeline Bonogofsky, deceased	1117 Palmer Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Brittany E. Bonogofsky	1820 N. Merriam Street, Miles City, MT 59301	Sec. 18-T141N-R83W
Duane J. Siegel	C65 100 3rd Street SW, Mandan, ND 58554	Sec. 18-T141N-R83W
Susan Jones	33800 NE Kern Court, Scappoose, OR 97056	Sec. 18-T141N-R83W
Larry F. Schmidt and Virginia Schmidt, as joint tenants	2631 35th Avenue SW, Center, ND 58530	Sec. 18-T141N-R83W
Dallas Engineering, Inc.	P. O. Box 80707, Fairbanks, AK 99708	Sec. 18-T141N-R83W
Breene Associates	P. O. Box 1773, Bismarck, ND 58501	Sec. 18-T141N-R83W
Carolyn Files	P.O. Box 154, Bunn, NC 27508	Sec. 18-T141N-R83W
Robert Files	1720-1/2 Reed Avenue, San Diego, CA 92109	Sec. 18-T141N-R83W
Richard Files	1720-1/2 Reed Avenue, San Diego, CA 92109	Sec. 18-T141N-R83W
Kurt Files	143 Lake Royale, Louisburg, NC 27549	Sec. 18-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Penney Files	3387 West Silver Springs Boulevard, Lot 13, Ocala, FL 34475	Sec. 18-T141N-R83W
Erika Files Hilliard	HC 5, Box 103-1, Gainesville, MO 65655	Sec. 18-T141N-R83W
J.C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
J.L. McMullen	127 N 4TH ST, Okemah OK 74859-2456 AND 215 S 5TH ST Okemah OK 74859-3808	Sec. 18-T141N-R83W
Lily Stamper	No street address of record, Okemah, OK 74859	Sec. 18-T141N-R83W
George R. McKown	No street address of record, Okemah, OK 74859	Sec. 18-T141N-R83W
Mabel M. Johnson	P. O. Box 114, Wewoka, OK 74884	Sec. 18-T141N-R83W
Gerthel B. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
Mrs. O.C. Fore	303 S Okfuskee Avenue, Wewoka, OK 74884	Sec. 18-T141N-R83W
Alexander Hamilton	2nd and Francis Streets, St. Joseph, MO 64501	Sec. 18-T141N-R83W
Nick N. Kouloures	No address of record	Sec. 18-T141N-R83W
Florence L. Hedrick	324 E 3rd Street, Newton, KS 67114	Sec. 18-T141N-R83W
Albert A. Goering	P. O. Box 366, Newton, KS 67114	Sec. 18-T141N-R83W
W.T. Brown	No street address of record, Newton, KS 67114	Sec. 18-T141N-R83W
Dean E. Stucky and O. Jean Stucky, as joint tenants	901 North Walnut, Medicine Lodge, KS 67104	Sec. 18-T141N-R83W
PEC Minerals LP	14860 Montfort Drive, Suite 209, Dallas, TX 75254	Sec. 18-T141N-R83W
Walter Duncan, Inc.	100 Park Avenue, Suite 1200, Oklahoma City, OK 73102-8006	Sec. 18-T141N-R83W
Black Stone Minerals Company, L.P.	1001 Fannin, Suite 2020, Houston, TX 77002-6709	Sec. 18-T141N-R83W
Barbara Endres	11449 SW 68th Court, Ocala, FL 34476	Sec. 18-T141N-R83W
Ellen Emley	6871 South Spotswood Street, Littleton, CO 80120	Sec. 18-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 19-T141N-R83W
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 19-T141N-R83W
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 19-T141N-R83W
Jerald Reuther	405 E. Denver Avenue, Bismarck, ND 58503	Sec. 19-T141N-R83W
Wayne Reuther	4746 Glenwood Drive, Bismarck, ND 58504	Sec. 19-T141N-R83W
Kent Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 19-T141N-R83W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 19-T141N-R83W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 19-T141N-R83W
Charles H. Kuether	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Charles H. Kuether	3555 28th Street, New Salem, ND 58563	Sec. 19-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert A Fryhling and Janice F. Fryhling, Trustees of the Fryhling Family Trust, dated August 15, 2002	2595 Calle Tres Lomas, San Diego, CA 92139	Sec. 19-T141N-R83W
Lila Wilson	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Lois Hohimer	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Madalyn Kraft	Route #1, Box 45, New Salem, ND 58563	Sec. 19-T141N-R83W
Central Dakota Humane Society	2104 37th Street, Mandan, ND 58554	Sec. 19-T141N-R83W
BNI Coal, Ltd.	2360 35th Avenue SW, Center, ND 58530-9499	Sec. 19-T141N-R83W
Earl Bodner	No address of record	Sec. 19-T141N-R83W
Erick G. Larson	50 Avalon Drive – Unit 7323, Milford CT 06460-8957	Sec. 19-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 27-T141N-R83W
Edward J. Koch	3359 Campstool Road, Cheyenne, WY 82007	Sec. 27-T141N-R83W
Randy L. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jacey Lee Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Gregory M. Messer	116 Pheasant Street, Bismarck, ND 58504	Sec. 27-T141N-R83W
Jennifer M. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jamie N. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Jesse C. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 27-T141N-R83W
Ronald F. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Heather A. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Ashley M. Messer	36 Santee Road, Lincoln, ND 58504	Sec. 27-T141N-R83W
Debra L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Dominic J. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Dayton L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 27-T141N-R83W
Magdalena Koch	1205 Sunset Drive, Mandan, ND 58554	Sec. 27-T141N-R83W
John R. Hatzenbuhler and Ida Hatzenbuhler, as joint tenants	Route 1, Mandan, ND 58554	Sec. 27-T141N-R83W
Roberts' Royalty LLC	12239 Treeview Lane, Farmers Branch, TX 75234-7809	Sec. 27-T141N-R83W
James H. Luther Royalty, LLC	717 S View Terrace, Alexandria, VA 22314	Sec. 27-T141N-R83W
BM Marcus Royalty LLC	3948 SW Greencastle Avenue, Oxford, IA 52322	Sec. 27-T141N-R83W
Mary Langdon	11707 Monica Lane, Houston, TX 77024	Sec. 27-T141N-R83W
Martha Bauman	1513 Gaston, Austin, TX 78703	Sec. 27-T141N-R83W
El Campo Energy Partners, LLC	8815 Chalk Knoll Drive, Austin, TX 78735	Sec. 27-T141N-R83W
Graham Shinnick	No street address or zip code of record, Detroit, MI	Sec. 27-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Moody, Trustee of the Alice H. Cordes Revocable Trust, dated January 11, 2007	2343 E Sierra Street, Phoenix, AZ 85028	Sec. 27-T141N-R83W
Jane Z. Hooker	4743 N 54th Street, Phoenix, AZ 85018-1905	Sec. 27-T141N-R83W
V. G. Perry	No street address, Detroit, MI 48127	Sec. 27-T141N-R83W
United States of America	No address of record	Sec. 22-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 22-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 22-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 22-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 22-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 22-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 22-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 22-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 22-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 22-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 22-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 22-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 22-T141N-R83W
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 22-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 22-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 22-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 22-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 22-T141N-R83W
Jack R. Hatzenbuhler and Helen Hatzenbuhler	3475 31st Street, Mandan, ND 58554	Sec. 22-T141N-R83W
Edward J. Koch	3359 Campstool Road, Cheyenne, WY 82007	Sec. 22-T141N-R83W
Randy L. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jacey Lee Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Gregory M. Messer	116 Pheasant Street, Bismarck, ND 58504	Sec. 22-T141N-R83W
Jennifer M. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jamie N. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Jesse C. Messer	3000 14th Avenue SE, Mandan, ND 58554	Sec. 22-T141N-R83W
Ronald F. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Heather A. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Ashley M. Messer	36 Santee Road Lincoln, ND, 58504	Sec. 22-T141N-R83W
Debra L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Dominic J. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Dayton L. Haugen	4010 Morning Star Drive S, P. O. Box 235, Mandan, ND 58554	Sec. 22-T141N-R83W
Magdalena Koch	1205 Sunset Drive, Mandan, ND 58554	Sec. 22-T141N-R83W
John R. Hatzenbuhler and Ida Hatzenbuhler, as joint tenants	Route 1, Mandan, ND 58554	Sec. 22-T141N-R83W
Roberts' Royalty LLC	12239 Treeview Lane, Farmers Branch, TX 75234-7809	Sec. 22-T141N-R83W
James H. Luther Royalty, LLC	717 S View Terrace, Alexandria, VA 22314	Sec. 22-T141N-R83W
BM Marcus Royalty LLC	3948 SW Greencastle Avenue, Oxford, IA 52322	Sec. 22-T141N-R83W
Mary Langdon	11707 Monica Lane, Houston, TX 77024	Sec. 22-T141N-R83W
Martha Bauman	1513 Gaston, Austin, TX 78703	Sec. 22-T141N-R83W
El Campo Energy Partners, LLC	8815 Chalk Knoll Drive, Austin, TX 78735	Sec. 22-T141N-R83W
Graham Shinnick	No street address, Detroit, MI 48127	Sec. 22-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Robert Moody, Trustee of the Alice H. Cordes Revocable Trust, dated January 11, 2007	2343 E Sierra Street, Phoenix, AZ 85028	Sec. 22-T141N-R83W
Jane Z. Hooker	4743 N 54th Street, Phoenix, AZ 85018-1905	Sec. 22-T141N-R83W
V. G. Perry	No street address, Detroit, MI 48127	Sec. 22-T141N-R83W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 1-T141N-R84W
Travis Klatt and Jessica Klatt, as joint tenants	2438 37th Ave. SW, Center, ND 58530	Sec. 1-T141N-R84W
Gary Leinius	204 Hager Avenue, Stanton ND 58571 AND 4958 Highway 200, Hazen ND 58545	Sec. 1-T141N-R84W
State of North Dakota - Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 1-T141N-R84W
Red Crown Royalties, LLC	1490 W. Canal Court, Suite 3000, Littleton, CO 80120	Sec. 1-T141N-R84W
Ida Schwable	HC02 Box 258, Center, ND 58530	Sec. 1-T141N-R84W
Alvin Hagerott	HC2 Box 244, Center, ND 58530	Sec. 1-T141N-R84W
Ernst R. Lueneburg	2903 Manitoba Lane, Bismarck, ND 58501	Sec. 1-T141N-R84W
Glacier Park Company	801 Cherry Street, Fort Worth, TX 76102	Sec. 1-T141N-R84W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 1-T141N-R84W
Tenneco Oil Company	P.O. Box 2511, Houston, TX 77252	Sec. 1-T141N-R84W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 20-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 20-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 20-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 20-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 20-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 20-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 20-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 20-T141N-R83W
Joseph Edwin Marcy	2133 SE 57th Avenue, Portland, OR 97214	Sec. 20-T141N-R83W
Nancy L. Carr	219 Mariners Way, Savannah, GA 31419-9308	Sec. 20-T141N-R83W
Charles L. Marsters	3903 Gershwin Avenue N, St. Paul, MN 55128-3010	Sec. 20-T141N-R83W
Beverly R. Buttram	5176 N Blackbird Way, Boise, ID 83714-1780	Sec. 20-T141N-R83W
Sandra Kaye Gish	1654 SW Sagebrush Court, Dallas, TX 97338-1262	Sec. 20-T141N-R83W
Michael Charles Marsters	3920 Miranda Drive, Paris, TX 75462-6648	Sec. 20-T141N-R83W
David S. Marsters	4205 Saint Andrews Place, New Albany, IN 47150-9691	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Ronald P. Tuning	13300 NE Whitlow Lane, Newberg, OR 97132-6723	Sec. 20-T141N-R83W
Daniel R. Cottrell, Surviving Trustee of The Cottrell Trust, a revocbale living trust, dated September 26, 1996, as restated on August 25, 2014	8330 Cason Road, Unit 219, Gladstone, OR 97027	Sec. 20-T141N-R83W
L. D. Jenkins c/o Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Willow Point Corporation c/o Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Gentry, LLC	4216 North Portland, Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Daniel Landeis and Carol Landeis	2735 Boundary Road, Bismarck, ND 58503	Sec. 20-T141N-R83W
Jessica Oakland	2218 LaForrest, Bismarck, ND 58501	Sec. 20-T141N-R83W
Jonica Norick	615 East Wachter Avenue, Bismarck, ND 58504	Sec. 20-T141N-R83W
Judy Dick and Brian T. Dick	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Jodi Gragg	4487 South Ireland Lane, Aurora, Co 80015	Sec. 20-T141N-R83W
Jeremiah Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Benjamen Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 20-T141N-R83W
Garrett Dick	598 East Dry Creek Place, Littleton, CO 80122	Sec. 20-T141N-R83W
Mandy Davis	8394 South Everett Way, #F, Littleton, CO 80128	Sec. 20-T141N-R83W
Roger Landeis and Diane Landeis	7752 South Columbine Street, Centennial, CO 80122	Sec. 20-T141N-R83W
Tamara Landeis	2836 Mount Carmel Road, Newnan, GA 30263	Sec. 20-T141N-R83W
Randy Landeis and Susan Corine	11096 W 104th Drive, Westminster, CO 80021	Sec. 20-T141N-R83W
Cory Lee Landeis	11625 Community Center Drive, Apt. 1311, Northglenn, CO 80233	Sec. 20-T141N-R83W
Carisa Nicole Landeis	436 North 5th Avenue, Brighton, CO 80601	Sec. 20-T141N-R83W
Donald Roerich and Justine Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Mason Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Memphis Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 20-T141N-R83W
Katherine Mosbrucker	404 NW 13th Street, Mandan, ND 58554	Sec. 20-T141N-R83W
Ralph P. Kautzman	Center, ND 58530 AND 1408 Central Avenue, Mandan ND 58554	Sec. 20-T141N-R83W
Irene Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 20-T141N-R83W
Robert J. Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 20-T141N-R83W
Winfrid Keller	728 Custer Drive, Mandan, ND 58554	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Douglas A. Keller, Trustee of the Winfrid and Alice Keller Family Trust	913 Saint Thomas Trail, Mandan, ND 58554	Sec. 20-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 20-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 20-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 20-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 20-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 20-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 20-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 20-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 28-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 28-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 28-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 28-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Manda, ND 58554	Sec. 28-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Whitman, AZ 85361	Sec. 28-T141N-R83W
Holli K. Taylor	28827 N 254th Lane, Whitman, AZ 85361	Sec. 28-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 28-T141N-R83W
Darrell Ray Buntin III	P. O. Box 167, Chino Valley, AZ 86323	Sec. 28-T141N-R83W
Marie Pfleger	717 Solano Drive, Prescott, AZ86301	Sec. 28-T141N-R83W
Dale P. Pfliger and Judy Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Mathias Pfliger	2508 10th Avenue SE, Mandan, ND 58554	Sec. 28-T141N-R83W
Aaron Pfliger	708 17th Street NW, Mandan, ND 58554	Sec. 28-T141N-R83W
Thomas Pfliger	806 Tower Place, Mandan, ND 58554	Sec. 28-T141N-R83W
Clementine Freisz	710 Pine Avenue, New Salem, ND 58563	Sec. 28-T141N-R83W
Sandra K. Orgaard	2810 26th Street, Center, ND 58530	Sec. 28-T141N-R83W
Roger A. Friesz	797 7th Street, Idaho Falls, ID 83401	Sec. 28-T141N-R83W
Duane M. Friesz	4465 34th Street, New Salem, ND 58563	Sec. 28-T141N-R83W
Karen M. Porsborg	2720 37th Avenue SW, New Salem, ND 58563	Sec. 28-T141N-R83W
Michael J. Friesz	3463 County Road 87, New Salem, ND 58563	Sec. 28-T141N-R83W
Audrey A. Peterson	12719 Doris Drive, Black Hawk, SD 57718	Sec. 28-T141N-R83W
Marshall & Winston, Inc.	P. O. Box 50880, Midland, TX 79710-0880	Sec. 28-T141N-R83W
Hancock Enterprises	P. O. Box 2527, Billings, MT 59103	Sec. 28-T141N-R83W
Fortin Enterprises, Inc.	P.O. Box 3129, Palm Beach, FL 33480	Sec. 28-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
DeKalb Energy Company	1625 Broadway Suite 1300, Denver, CO 80202-4713	Sec. 28-T141N-R83W
Anton Pfleger and Helen Pfleger	105 Division Street NW, Mandan, ND 58554	Sec. 21-T141N-R83W
LouAnn Nider	824 Lohstreter Road, Mandan, ND 58554	Sec. 21-T141N-R83W
Carol Pfleger Anderson	734 Aspen Place, Bismarck, ND 58503	Sec. 21-T141N-R83W
Sandra Olhauser	1829 San Diego Drive, Bismarck, ND 58504	Sec. 21-T141N-R83W
Sherry Marentette	7417 Marble Ridge, Austin, TX 78747	Sec. 21-T141N-R83W
Kari Ann Pfleger Warner	411 6th Avenue NW, Mandan, ND 58554	Sec. 21-T141N-R83W
Marla Brown	28925 North Red Bloom Court, Whitman, AZ 85361	Sec. 21-T141N-R83W
Holli K. Taylor	28827 N 254th Lane, Whitman, AZ 85361	Sec. 21-T141N-R83W
Myra Buntin	19425 Lower Territory Road, Prescott, AZ 86305	Sec. 21-T141N-R83W
Darrell Ray Buntin III	P. O. Box 167, Chino Valley, AZ 86323	Sec. 21-T141N-R83W
Amanda Marie Minick	4332 S Fireside Trail, Gilbert, AZ 85297	Sec. 21-T141N-R83W
Marie Pfleger	717 Solano Drive, Prescott, AZ 86301 AND 1487 Horseshoe Bend Drive, #37, Camp Verde, AZ 86322	Sec. 21-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 21-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 21-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 21-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 21-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 21-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 21-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 21-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 21-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 21-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center, ND 58530	Sec. 21-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 21-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 21-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 21-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	Sec. 21-T141N-R83W
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 21-T141N-R83W
Grace Ellen Janssen	204 Juniper Dr., Bismarck, ND 58503-0292	Sec. 21-T141N-R83W
Douglas D. Doll and Deberra K. Doll	3901 Faye Avenue N, Mandan, ND 58554	Sec. 21-T141N-R83W
Becky Jo Lemar	798 San Angelo Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
Wendy April Wittenberg	3032 Ontario Lane, Bismarck, ND 58503	Sec. 21-T141N-R83W
Danielle Kae Borseth	5025 Hitchcock Drive, Bismarck, ND 58503	Sec. 21-T141N-R83W
James D. Pazdernik and Bonita Pazdernik	3487 37th Avenue, New Salem, ND 58563	Sec. 21-T141N-R83W
Thomas Pazdernik	2582 Windsor Drive N, Mandan, ND 58554	Sec. 21-T141N-R83W
Matthew Pazdernik	2445 37th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Theresa Moravec	921 Mouton Avenue, Bismarck, ND 58505	Sec. 21-T141N-R83W
Michael Pazdernik	P. O. Box 194, New Salem, ND 58563	Sec. 21-T141N-R83W
Mark Pazdernik	22 3rd Street S, Carrington, ND 58421	Sec. 21-T141N-R83W
Daniel Landeis and Carol Landeis	2735 Boundary Road, Bismarck, ND 58503	Sec. 21-T141N-R83W
Jessica Oakland	2218 LaForrest, Bismarck, ND 58501	Sec. 21-T141N-R83W
Jonica Norick	615 East Wachter Avenue, Bismarck, ND 58504	Sec. 21-T141N-R83W
Judy Dick and Brian T. Dick	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W
Jodi Gragg	4487 South Ireland Lane, Aurora, CO 80015	Sec. 21-T141N-R83W
Jeremiah Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W
Benjamen Bigelow	8948 Carr Circle, Broomfield, CO 80021	Sec. 21-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Garrett Dick	598 East Dry Creek Place, Littleton, CO 80122	Sec. 21-T141N-R83W
Mandy Davis	8394 South Everett Way, #F, Littleton, CO 80128	Sec. 21-T141N-R83W
Roger Landeis and Diane Landeis	7752 South Columbine Street, Centennial, CO 80122	Sec. 21-T141N-R83W
Tamara Landeis	2836 Mount Carmel Road, Newnan, GA 30263	Sec. 21-T141N-R83W
Randy Landeis and Susan Corine	11096 W 104th Drive, Westminster, CO 80021	Sec. 21-T141N-R83W
Cory Lee Landeis	11625 Community Center Drive, Apt. 1311, Northglenn, CO 80233	Sec. 21-T141N-R83W
Carisa Nicole Landeis	436 North 5th Avenue, Brighton, CO 80601	Sec. 21-T141N-R83W
Donald Roerich and Justine Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Mason Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Memphis Roehrich	1131 Cannon Lane, Washburn, ND 58577	Sec. 21-T141N-R83W
Katherine Mosbrucker	404 NW 13th Street, Mandan, ND 58554	Sec. 21-T141N-R83W
Ralph P. Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 21-T141N-R83W
Irene Kautzman	1408 Central Avenue, Mandan, ND 58554	Sec. 21-T141N-R83W
Mrs. Emanuel Kautzman	No address of record, Yakima WA 98901	Sec. 21-T141N-R83W
Estate of George Hagel, deceased	P.O. Box 223, Center, ND 58530	Sec. 2-T141N-R84W
City of Center Park District	No street address and zip code of record, Center ND	Sec. 2-T141N-R84W
James Hagel	746 E. 4th Ave., Kennewick, WA 99336	Sec. 2-T141N-R84W
Gene Hagel	9131 Prairie Vista Dr. NE, Albuquerque, NM 87113	Sec. 2-T141N-R84W
Kathy Lipp	4744 Thornburg Dr., Bismarck, ND 58504	Sec. 2-T141N-R84W
Loretta Rath	2606 Village Drive, Bismarck, ND 58505	Sec. 2-T141N-R84W
Julie Zahn	404 1st St. SW, Beulah, ND 58523	Sec. 2-T141N-R84W
Betty Yantzer	2745 18th St. SW, Center, ND 58530	Sec. 2-T141N-R84W
Jackie Schwab	938 Elbowoods Dr., Hazen, ND 58545	Sec. 2-T141N-R84W
Janice Matthews	P.O. Box 626, Washburn, ND 58577	Sec. 2-T141N-R84W
United States of America	No address of record	Sec. 2-T141N-R84W
Estate of Nick M. Berger, deceased	2529 37th Avenue SW, Center, ND 58530	Sec. 2-T141N-R84W
State Treasurer, as Trustee of the State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 2-T141N-R84W
Karmen Boehm	907 Nishu Place, Hazen, ND 58545	Sec. 2-T141N-R84W
Karle Boehm	1017 Fayette Drive, Hazen, ND 58545	Sec. 2-T141N-R84W
Dwight Wrangham and Linda Wrangham, as joint tenants	301 52nd St. SE, Bismarck, ND 58501	Sec. 2-T141N-R84W
Eileen Rooney Hewgley, L.L.C.	427 South Boston Avenue, Suite 304, Tulsa, OK 74103	Sec. 2-T141N-R84W
RLand, L.L.C.	401 South Boston Avenue, Suite 2400, Tulsa, OK 74103	Sec. 2-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The L.F. Rooney III Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Patrick T. Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	No address of record	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Timothy P. Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The James Harris Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee OK 74401	Sec. 2-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees The Lucy Rooney Kapples Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 2-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L.F. Rooney III, as Co-Trustees of The Rebecca Finch Rooney Trust, created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 2-T141N-R84W
Osprey Resources, Inc.	P.O. Box 56449, Houston, TX 77256-6449	Sec. 2-T141N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, West Lake Hills, TX 78746	Sec. 2-T141N-R84W
Gonzaga University Law Dept. Scholarship	22H E. Euclid, Spokane, WA 99207	Sec. 2-T141N-R84W
J.C. Miller	508 Beacon Building, Tulsa, OK 74103	Sec. 2-T141N-R84W
Ralph M. Fahrenwald and Edna M. Fahrenwald, as joint tenants	3737 E. 45th Street, Tulsa, OK 74135	Sec. 2-T141N-R84W
Noah W. Millsap and Nell Rose Millsap, as joint tenants	1927 E. 33rd Place, Tulsa, OK 74105	Sec. 2-T141N-R84W
W.A. Dean and Fonda G. Dean, as joint tenants	1316 East 35th Place, Tulsa, OK 74105	Sec. 2-T141N-R84W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 29-T141N-R83W
Delvin Bueligen and Jill Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 29-T141N-R83W
Rodella Hausauer and Barry Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 29-T141N-R83W
Lowell Bueligen and Tammy Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 29-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 29-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 29-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 29-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 29-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 29-T141N-R83W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 29-T141N-R83W
Albert Hagerott	3190 27th Street, Center ND 58530-9559	Sec. 29-T141N-R83W
Mary Hagerott	Mary Hagerott Estate, c/o Justin Hagerott, 3192 27th Street SW, Center ND 58530	Sec. 29-T141N-R83W
Robert Edward Hagerott and Margaret Ruth Hagerott, Trustees, or their successors in trust, of the Robert Edward Hagerott Revocable Trust, dated February 14, 1997	86 Warren Street, Needham, MA 02492	Sec. 29-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Edward C. Hagerott and Rosemary T. Hagerott, Trustees, or their successors in trust, under the Edward C. Hagerott and Rosemary T. Hagerott Living Trust dated April 29, 1999	136 West Bonita Avenue, Sierra Madre, CA 91024	Sec. 29-T141N-R83W
James Richard Keddy and Margaret R. Keddy, and successors, as Trustees of the Keddy Family Trust, dated January 14, 1994	16331 Serenade Lane, Huntington Beach, CA 92647	Sec. 29-T141N-R83W
Thomas Price	1211 Imperial Dr, Bismarck, ND 58504-7570 AND 115 Lakeview Dr, Watford City, ND 58854-7810 AND PO Box 96, Wolverton, MN 56594-0096 AND PO Box 631, Spencer, IN 47460-0631	
Dorothy L. Keck, Trustee of the Albert E. and Dorothy L. Keck Family Trust, dated July 21, 1989	1256 Cain Lane, Escondido, CA 92027	Sec. 29-T141N-R83W
Grace Ellen Janssen	Center, ND 58530	Sec. 29-T141N-R83W
Alvin Hagerott	HC2, Box 244, Center, ND 58530	Sec. 29-T141N-R83W
Dora Porsborg	Mandan Villa, Mandan, ND 58554	Sec. 29-T141N-R83W
Nels Porsborg	Mandan Villa, Mandan, ND 58554	Sec. 29-T141N-R83W
Dora Porsborg and Nels Porsborg c/o Kenneth Porsborg and Myron Porsborg	Route 1, Box 47A, Mandan, ND 58554	Sec. 29-T141N-R83W
Great Northern Properties LP	601 Jefferson Street; Suite 3600, Houston, TX 77002	Sec. 29-T141N-R83W
Meridian Minerals Company	5613 DTC Parkway, Suite 1100, Englewood, CO 80111	Sec. 29-T141N-R83W
Meridian Minerals Company	2919 Allen Parkway, Houston, TX 77019-2142	Sec. 29-T141N-R83W
Fern Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 29-T141N-R83W
Steven P. Kraft and Julie F. Kraft, as joint tenants	2847 35th Avenue, New Salem, ND 58563	Sec. 29-T141N-R83W
Robert Mosbrucker	P. O. Box 745, Bothell, WA 98041	Sec. 29-T141N-R83W
Sandra Smith, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	1320 County Road 80, Mandan, ND 58558	Sec. 29-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Collette Friedt, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	802 Wagon Trail Street, Gillette, WY 82718	Sec. 29-T141N-R83W
Stacy Kautzman, Co-Trustee of the Kautzman Family Irrevocable Trust under agreement dated June 30, 2008	9301 Wentworth Drive, Bismarck, ND 58503	Sec. 29-T141N-R83W
Jean L. Kautzman	2130 41st Avenue SW, Center, ND 58530	Sec. 29-T141N-R83W
Jay Kautzman	2024 N 5th Street, Bismarck, ND 58501	Sec. 29-T141N-R83W
Julie Frye	1853 N 23rd Street, Bismarck, ND 58501	Sec. 29-T141N-R83W
Janet Anderson	15537 East Radcliffe Place, Aurora, CO 80015	Sec. 29-T141N-R83W
Jeanine Marcolina	3938 East San Pedro, Gilbert, AZ 85234	Sec. 29-T141N-R83W
Douglas H. Kautzman	3450 County Road 138, Mandan, ND 58554	Sec. 29-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND 58530	Sec. 13-T141N-R84W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 13-T141N-R84W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 13-T141N-R84W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 13-T141N-R84W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 13-T141N-R84W
Clifford Orgaard	11839 Forada Beach Road SE; Unit A, Alexandria, MN 56308	Sec. 13-T141N-R84W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 13-T141N-R84W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Lynn C. Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 13-T141N-R84W
Fern Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 13-T141N-R84W
Richard Bueligen	3022 Withers Drive, Mandan, ND 58554	Sec. 13-T141N-R84W
Norlan Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 13-T141N-R84W
Dollie Hagerott	744 Lake Avenue, Ortonville, MN 56278	Sec. 13-T141N-R84W
Annette Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R84W
Nancy Henke and Dwight Henke	P. O. Box 90, Hazen, ND 58545	Sec. 13-T141N-R84W
Brent Hatzenbihler	310 W Tonk, Gillette, WY 82718	Sec. 13-T141N-R84W
Melissa Hatlestad	2372 Harmon Lane, Mandan, ND 58554	Sec. 13-T141N-R84W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 13-T141N-R84W
Rodney Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 13-T141N-R84W
State of North Dakota Dept. of Trust Lands	1707 N 9th Street, Bismarck, ND 58501	Sec. 13-T141N-R84W
Mark Erhardt	P. O. Box 132, Center, ND 58530	Sec. 13-T141N-R84W
Margaret Erhardt	3685 27th Street, New Salem, ND 58563-9617	Sec. 13-T141N-R84W
Kathryn Erhardt	P. O. Box 132, Center, ND 58530	Sec. 13-T141N-R84W
Agnes Phagan	419 Mathias Street, Taft, TX 78390	Sec. 13-T141N-R84W
Isabelle Forster	851 4th Avenue E, Dickinson, ND 58601	Sec. 13-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Evangeline Bolton	1951 Carbon Ridge Street, Enumclaw, WA 98022	Sec. 13-T141N-R84W
Lorraine Bosch	851 4th Avenue E, Dickinson, ND 58601	Sec. 13-T141N-R84W
Ann Pasley	13838 162nd Avenue NE, Woodinville, WA 98072	Sec. 13-T141N-R84W
Scott Erhardt	3101 85M Avenue SW, Richardton, ND 58657	Sec. 13-T141N-R84W
Laura Kordonowy	2329 Main Street, Dickinson, ND 58601	Sec. 13-T141N-R84W
Alice Christianson	2585 Dakota Boulevard, Apt. 323, Dickinson, ND 58601	Sec. 13-T141N-R84W
Alice Frederick	Route 2 24C, Dickinson, ND 58601	Sec. 13-T141N-R84W
Marcus C. Erhardt	332 Wehrle Drive, Richardton, ND 58652	Sec. 13-T141N-R84W
Perry Erhardt	597 Twin Oaks Lane, Dallas, GA 30157	Sec. 13-T141N-R84W
Edward Erhardt	3105 85M Avenue SW, Richardton, ND 58652	Sec. 13-T141N-R84W
Wallace Erhardt	119 East Calgary Avenue, Bismarck, ND 58503	Sec. 13-T141N-R84W
Gloria Ciavarella	119 East Calgary Avenue, Bismarck, ND 58503	Sec. 13-T141N-R84W
Rose Erhardt	No street address of record, Dickinson, ND 58601	Sec. 13-T141N-R84W
Ronald P. Erhardt	No street address of record, Williston, ND 58801/58802/58803	Sec. 13-T141N-R84W
Rhoda P. Erhardt	2379 Snowshoe Court E, St. Paul, MN 55119	Sec. 13-T141N-R84W
Dorothy Mae Erhardt	Dickinson, ND 58601	Sec. 13-T141N-R84W
United States of America	No address of record	Sec. 14-T141N-R84W
Donald C. Erhard and Kathleen Erhardt	2955 37th Avenue SW, New Salem, ND 58563	Sec. 14-T141N-R84W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 14-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Raymond Schmidt, Sr. Estate	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 14-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 14-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 14-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655	Sec. 14-T141N-R84W
JoAnne Snow	329 Bedford Blvd., Bismarck, ND 58504	Sec. 14-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 14-T141N-R84W
Rose Royalty, LLC	6730 N Scottsdale Road; Ste. 270, Scottsdale, AZ 85253	Sec. 14-T141N-R84W
Cooper Land Family, LLC	460 Oak Hill Road, Chaska, MN 55318	Sec. 14-T141N-R84W
Kristoffer J. Land	12275 Berea Court, Poway, CA 92064	Sec. 14-T141N-R84W
Solveig K. Land, Trustee of the Solveig K. Land Revocable Trust Agreement, dated August 2, 2008	310 Parkway Court, Minneapolis, MN 55419	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Mike Golden	P. O. Box 2734, Bismarck, ND 58502	Sec. 14-T141N-R84W
A. G. Golden	P. O. Box 1853, Bismarck, ND 58502	Sec. 14-T141N-R84W
Peter Mosbrucker	No street address of record, New Salem, ND 58563	Sec. 14-T141N-R84W
Jesse L. Lackman and Darcy J. Lackman Revocable Living Trust	2647 37th Avenue SW, Center, ND 58530	Sec. 14-T141N-R84W
Raymond Mizak and Phyllis F. Mizak	794 E Gemini Place, Chandler, AZ 85249	Sec. 14-T141N-R84W
Armstrong Minerals, LLC	P. O. Box 1999, Dickinson, ND 58602	Sec. 14-T141N-R84W
Julie M. Fadden and Gordon W. Schnell, Co-Trustees of the Patrick Fadden Residuary Trust	1007 Highland Place, Bismarck, ND 58501	Sec. 14-T141N-R84W
Richard E. Haug	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
W. R. Everett	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
Michelle M. Miller	668 W 27th, Dickinson, ND 58601	Sec. 14-T141N-R84W
Dennis W. Yockim	P. O. Box 477, Williston, ND 58801	Sec. 14-T141N-R84W
Douglas C. McLeod	518 17th Street, Ste. 1525, Denver, CO 80202	Sec. 14-T141N-R84W
O. W. E. Oil Company	P. O. Box 422, Pauma Valley, CA 92061	Sec. 14-T141N-R84W
Crescent Energy, Inc.	Box 1413, Scottsdale, AZ 85252-1413	Sec. 14-T141N-R84W
TurmOil, Inc.	P. O. Box 5, Bismarck, ND 58502	Sec. 14-T141N-R84W
The Carter Investment Company	333 Clay Street, Ste. 3439, Houston, TX 77002	Sec. 14-T141N-R84W
Black Stone Minerals Company, L.P.	1001 Fannin, Ste. 2020, Houston, TX 77002	Sec. 14-T141N-R84W
William G. Seal and Marcellyn J. Seal	4662 S Troost, Tulsa, OK 74170	Sec. 14-T141N-R84W
Robert C. Simpson, Trustee of the Robert C. Simpson Living Trust created by declaration of trust dated April 5, 1999	P. O. Box 700216 Tulsa, OK, 74170-0216	Sec. 14-T141N-R84W
John Williard Forsyth c/o Benjamin Forsyth	3301 9th Street E Great Falls, MT, 59404	Sec. 14-T141N-R84W
Martha Ann Forsyth Thomas	34 Creekside Close, Nellysford, VA 22958	Sec. 14-T141N-R84W
Benjamin Ripley Forsyth	3301 9th Street E, Great Falls, MT 59404	Sec. 14-T141N-R84W
L. R. Forsyth	L. R. Boughton (f.k.a. L. R. Forsyth), 1566 Texakoma Park Road, Kingston OK 73439-9324	Sec. 14-T141N-R84W
Thomas D. Selby	P. O. Box 2344, Williston, ND 58801	Sec. 14-T141N-R84W
M. Sue Bruce and Clifford R. Bruce, Sr., as Co-Trustees of the M. Sue Bruce Declaration of Trust dated January 30, 2015	36 Greenridge Drive, Decatur, IL 62526-1404	Sec. 14-T141N-R84W
Charles F. Smith c/o Mary Sue Bruce	36 Greenridge Drive, Decatur, IL 62526-1404	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Al Nick	111 Church Street, Ferguson, MO 63135	Sec. 14-T141N-R84W
Al E. Nick, Trustee of the Modak Trust A	111 Church Street, Ferguson, MO 63135	Sec. 14-T141N-R84W
Michael J. Wetzel	7880 Shelbyville Road, Indianapolis, IN 45259	Sec. 14-T141N-R84W
Aqua Purple Reef, LLC	7582 Mulholland Drive, Los Angeles, CA 9004	Sec. 14-T141N-R84W
Mary Catherine Watson	8136 Bishops Lane, Indianapolis, IN 46217	Sec. 14-T141N-R84W
Arkoma Bakken, LLC	203 E Interstate 30, Rockwall, TX 75087-5402	Sec. 14-T141N-R84W
Jean M. Voltz	9006 River Ridge Drive, Texarkana TX, 75503	Sec. 14-T141N-R84W
Rial Genre and Lynnette Genre	367 5th Street SW, Dickinson, ND 58601	Sec. 14-T141N-R84W
Margaret Leone Sutton Revocable Trust Agreement dated April 10, 1993	201 W Gibson Street, West Liberty, IA 52776	Sec. 14-T141N-R84W
Lynn C. Wright c/o Marjorie E. McKim	911 East Madison, Mt. Pleasant, IA 52641	Sec. 14-T141N-R84W
Pledge Resources, LLC	P. O. Box 1032, Bismarck, ND 58502	Sec. 14-T141N-R84W
Herbert Weder	Highland, IL 62249	Sec. 14-T141N-R84W
Jay W. Boulanger	9th and Lemon Streets, Highland, IL 62249	Sec. 14-T141N-R84W
Wray Boulanger	9th and Lemon Streets, Highland, IL 62249	Sec. 14-T141N-R84W
Orville A. Winet and Nelda E. Winet, as joint tenants	R. R. 3, Highland, IL 62249	Sec. 14-T141N-R84W
Susan Kim Ballinger, Successor Trustee of the Sutton Family Revocable Trust dated January 10, 1985/Jane Sutton	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of The Deborah Lynn Sutton Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of The David Keith Sutton Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger, Trustee of, The Ashley and Steven Ballinger Trust dated August 7, 2017	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Susan Kim Ballinger	P. O. Box 1271, Catoosa, OK74015	Sec. 14-T141N-R84W
Steven Ballinger	P. O. Box 1271, Catoosa, OK 74015	Sec. 14-T141N-R84W
Missouri River Royalty Corporation	919 S 7th Street, Ste. 405, Bismarck, ND 58504	Sec. 14-T141N-R84W
Northern Pacific Royalties, LLC	P. O. Box 572, Bismarck, ND 58502	Sec. 14-T141N-R84W
Northern Energy Corporation	P. O. Box 2283, Bismarck, ND 58502	Sec. 14-T141N-R84W
Jane Ogilvie	23 Geneva Drive, Muscatine, IA 52761	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Mason W. Potter Estate, c/o Jane Ogilvie	23 Geneva Drive, Muscatine, IA 52761	Sec. 14-T141N-R84W
LARCO Resources, LLC	P. O. Box 821, Bismarck, ND 58502-0821	Sec. 14-T141N-R84W
Clark James Crawford	1930 Riverwood Drive, Bismarck, ND 58504	Sec. 14-T141N-R84W
Eliza A. Burkholder	111 Bellemont Road, Bloomington, IL 61701	Sec. 14-T141N-R84W
Chester C. Alexander and Ralph E. Alexander	1590 Martha Drive, Elgin, IL 60123	Sec. 14-T141N-R84W
Yank Litzelman	Olney, IL 62450	Sec. 14-T141N-R84W
Mabel Litzelman	Olney, IL 62450	Sec. 14-T141N-R84W
Bavendick Minerals & Royalty, LLC	P. O. Box 313, Bismarck, ND 58502-0313	Sec. 14-T141N-R84W
C. R. Hippard and Chas F. Hippard	108 Locust Street, Maroa, IL 61756	Sec. 14-T141N-R84W
Valerian L. Roberts	2921 Cronin Drive, Springfield, I, 62711	Sec. 14-T141N-R84W
Michael D. Glaspey and Joyce A. Glaspey	P. O. Box 77, Lignite, ND 58752	Sec. 14-T141N-R84W
Joe E. Harrison, Jr.	778 W Decatur Street, Decatur, I, 62522	Sec. 14-T141N-R84W
William C. Clements	Highland, IL 62249	Sec. 14-T141N-R84W
Sherry D. Wilkin and Paul W. Wilken	285 Falcon Drive E, Highland, IL, 62249	Sec. 14-T141N-R84W
Amelia R. Clements	No street address of record, Highland, IL 62249	Sec. 14-T141N-R84W
Shari R. Weber, Trustee of the Shari R. Weber Trust dated August 10, 2008	75-6100 Alii Drive, Kona Isle E 22, Kailua-Kona, HI 96740	Sec. 14-T141N-R84W
Betty Eileen Ferrel	3740 Pinebrook Circle, #107, Bradenton, FL 34209	Sec. 14-T141N-R84W
Rikki P. Doyle	3740 Pinebrook Circle, #207, Bradenton, FL 34209	Sec. 14-T141N-R84W
Marcy P. Stacy	5619 Open Gate Court, Cincinnati, OH 45247	Sec. 14-T141N-R84W
Bobby Gene Story	8749 N 600th Street, Newton, IL 62448	Sec. 14-T141N-R84W
Lee Eugene Story	7711 N 500th Street, Newton, IL 62448	Sec. 14-T141N-R84W
Paul D. Johnson, Trustee of the Declaration of Trust of Paul D. Johnson, dated April 5, 1996	105 N Lafayette, Newton, IL 62448	Sec. 14-T141N-R84W
Sandra K. Hartrich	13 Carriage Lane, Newton, IL 62448	Sec. 14-T141N-R84W
Lana Dhom	107 N Maple Street, Newton, IL 62448	Sec. 14-T141N-R84W
Bruce Hartrich	1209 Seasons Drive, Godrey, IL 62035	Sec. 14-T141N-R84W
Eric Hartrich	1137 Drewsbury Court, Smyrna, GA 30080	Sec. 14-T141N-R84W
Judith Ann Hartrich and Dennis Hartrich	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Julie Burns	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Bradley Hartrich	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Jill Han	212 Cherry Lane, White House, TN 37188	Sec. 14-T141N-R84W
Edward Kocher	16295 E 700th Avenue, Newton, IL 62448	Sec. 14-T141N-R84W
Scott A. Kocher	832 W 90th Avenue N, Conway Springs, KS 67031	Sec. 14-T141N-R84W
Matthew E. Kocher	4214 E State Hwy 234, Greenfield, IN 46140	Sec. 14-T141N-R84W
Gary Henry	257 Addison Way, Titisville, FL 32780	Sec. 14-T141N-R84W
Monica Snook	3406 Antietam Court, Edwardsville, IL 62025	Sec. 14-T141N-R84W
Melissa Cruz	13008 Pingry Place, Town & Country, MO 63131	Sec. 14-T141N-R84W
Melanie Byrkit	204 Magnolia Trace Drive, Ballwin, MO 63021	Sec. 14-T141N-R84W
Georgia Ann Upton	1783 Avenida Alta Mira, Oceanside, CA 92056	Sec. 14-T141N-R84W
John C. McElhiney	1720 Landisburg Road, Landisburg, PA 17040	Sec. 14-T141N-R84W
SHARK VENTURES, LLC	P. O. Box 2714, Bentonville, AR 72712	Sec. 14-T141N-R84W
Kent Littlejohn and Brenda Littlejohn	10777 N Friendship Road, Casey, IL 62420	Sec. 14-T141N-R84W
Jack L. Pitcher	6653 E 1800 Avenue, Montrose, IL 62445	Sec. 14-T141N-R84W
Melvin E. Pitcher	1065 Co. Rd. 000 N, Jewett IL 62436	Sec. 14-T141N-R84W
Marilyn J. James	24 Co. Rd. 1125 E, Jewett IL 62436	Sec. 14-T141N-R84W
Joyce Etnire	18931 Westfield Road, Charleston, IL, 61920	Sec. 14-T141N-R84W
Wayne Pitcher	11777 Destination Lane, Carthege, MO 64836	Sec. 14-T141N-R84W
Richard Pitcher	9000 U. S. Highway, Lot 575, Clermont, FL 34711	Sec. 14-T141N-R84W
Pam Goess	20 Lido Boulevard, Lake Grove, NY 11755	Sec. 14-T141N-R84W
Beverly Rosalee Shupe	206 N Marietta Street, Greenup, IL 62428	Sec. 14-T141N-R84W
Norma Elaine Edwards	262 Oak Avenue, Neoga, IL 62447	Sec. 14-T141N-R84W
Terry Eugene Warner	2537 Georgetown Road, Danville, IL 61832	Sec. 14-T141N-R84W
Stewart J. Schutte	6592 N 1075th Street, Robinson, IL 62454	Sec. 14-T141N-R84W
Tyler R. Tedford	10250 Wicklow Court, Fishers, IN 46040	Sec. 14-T141N-R84W
Kent A. Tedford	3823 N Ashland Avenue, #203, Chicago IL 60613	Sec. 14-T141N-R84W
David Porsborg and Karen Porsborg	2720 37th Avenue, New Salem, ND 58563	Sec. 24-T141N-R84W
Beverly Faul	1420 9th Avenue NE, McClusky, ND 58463	Sec. 24-T141N-R84W
Brad Bonnet	3444 110th Avenue NE, Bismarck, ND 58504	Sec. 24-T141N-R84W
Justin Kessler	6045 Lyndale Avenue S, #255, Minneapolis, MN 55419	Sec. 24-T141N-R84W
Adam Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Andrew Porsborg	2722 37th Avenue SW, New Salem, ND 58563	Sec. 24-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Chad Porsborg	3206 Stonewall Drive, Bismarck, ND 58501	Sec. 24-T141N-R84W
Heather Bullinger	2602 10th Avenue SE, Mandan, ND 58554	Sec. 24-T141N-R84W
Christie Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Tina Sorge	4412 E Mulberry, #312, Ft. Collins, CO 80524	Sec. 24-T141N-R84W
Jerald Reuther	405 E Denver Avenue, Bismarck, ND 58503	Sec. 24-T141N-R84W
Wayne Reuther	476 Glenwood Drive, Bismarck, ND 58504	Sec. 24-T141N-R84W
Keith Reuther	3594 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Karen Shulz	13720 Chamy Drive, Reno, NV 89521	Sec. 24-T141N-R84W
Kent Reuther and Pam Reuther	3610 27th Street SW, New Salem, ND 58563	Sec. 24-T141N-R84W
Dorothy Kessler	800 N Sewell Avenue, Miles City, MT 59301	Sec. 24-T141N-R84W
Dorothy Willem	1808 N Strevell, Miles City, MT 59301	Sec. 24-T141N-R84W
Jeannette Bonnet	1420 9th Avenue NW, McClusky, ND 58463	Sec. 24-T141N-R84W
Darlene Sorge	63 Lakeview Drive, Wheatland, WY 82201	Sec. 24-T141N-R84W
Robert Porsborg	415 1st Street E, Center, ND 58530	Sec. 24-T141N-R84W
Martha Reuther Estate, c/o Jerald Reuther	Martha Reuther Estate, c/o Jerald Reuther, 405 E Denver Avenue, Bismarck ND 58503 AND Martha Reuther Estate, c/o Jerald Reuther, New Salem ND 58563	Sec. 24-T141N-R84W
United States of America	No address of record	Sec. 10-T141N-R84W
Kenneth W. Reinke and Darlene Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
August W. Reinke Estate, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Lawrence Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Dora Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Walford Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Ervin Reinke, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Dora Schulte, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
Grace Weiss, c/o Kenneth W. Reinke	3841 25th Street SW, Center, ND 58530	Sec. 10-T141N-R84W
B. W. Henderscheid and Alice Henderscheid	3635 Hwy 200A, Center, ND 58530	Sec. 3-T141N-R84W
Gloria R. Albers	852 Bermuda Drive, Hemet, CA, 92543	Sec. 3-T141N-R84W
Shannon Wade Henke	8921 Island Road, Bismarck, ND 58503	Sec. 3-T141N-R84W
Karla Rae Henke	1238 Hyacinth Lane, Peachtree City, GA 30269	Sec. 3-T141N-R84W
Verlaine Gullickson	701 33rd Avenue N, Unit 411, Fargo, ND 58102	Sec. 3-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Agnes Dockter	2424 South 121st Street, Seattle, WA 98101	Sec. 15-T142N-R83W
Josephine McAdoo	No street address of record, Froid, MT 59226	Sec. 15-T142N-R83W
Anna Friesz	203 5th Avenue NE, Mandan, ND 58554	Sec. 15-T142N-R83W
Keith Vitek, as purported successor to the Estate of Clarence Vitek, deceased	P.O. Box 1214, Center, ND 58530	Sec. 15-T142N-R83W
Brenda Vitek, as purported successor to the Estate of Clarence Vitek, deceased	P.O. Box 1214, Center, ND 58530	Sec. 15-T142N-R83W
John Vitek	3002 South 208 Street, No. 8, Seattle WA, 98188	Sec. 15-T142N-R83W
Denisa Iwata f/k/a Denise Vitek	1458 Columbia Way 6, Seattle, WA 98178	Sec. 15-T142N-R83W
Sheila K. Naglich	11034 Crestwood Drive S, Seattle, WA 98178	Sec. 15-T142N-R83W
Gloria Iwata	1321 S. Puget Drive, E14, Renton, WA 98055	Sec. 15-T142N-R83W
Kathleen A. Rusich	4308 Lake Road, Apt. G, Killeen, WA 98146	Sec. 15-T142N-R83W
Sandra L. Vitek	10405 5th Avenue Southwest, Seattle, WA 98146	Sec. 15-T142N-R83W
Sacred Heart Hospice Donatory Corporation	1200 12th Street SW, Austin, MN 55912	Sec. 15-T142N-R83W
Karen O. Van Amburg, life tenant	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Jana Van Amburg, remainderman	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Matthew Van Amburg, remainderman	2620 - 214th Avenue SE, Sammamish, WA 98075	Sec. 15-T142N-R83W
Anne Cerulli, life tenant	13641 Alderwood Lane, 35B, Seal Beach, CA 90740	Sec. 15-T142N-R83W
Anthony James Cerulli, remainderman	2227 E. Everett Place, Orange, CA 92867	Sec. 15-T142N-R83W
Nathan Raymond Cerulli, remainderman	2227 E. Everett Place, Orange, CA 92867	Sec. 15-T142N-R83W
Black Stone Minerals Company, L.P.	1001 Fannin, Suite 2020, Houston, TX 77002	Sec. 15-T142N-R83W
Dorchester Minerals, L.P.	3838 Oak Lawn Avenue, Suite 300, Dallas, TX 75219	Sec. 15-T142N-R83W
Mike Saba a/k/a Michael P. Saba	26560 N. Shore Pl., Hartford, SD 57033	Sec. 15-T142N-R83W
State of North Dakota, for the use and benefit of the State Highway Department	608 East Boulevard Avenue, Bismarck, ND 58505-0700	Sec. 15-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 23-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 23-T142N-R83W
Williston Projects, Inc.	3345 Highway 132, Rayville, LA 71269	Sec. 23-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Nick Freidig	17220 Schuch Lane, Stanwood, WA 56201	Sec. 23-T142N-R83W
Leo Freidig	1106 W. 14th St., Willmar, MN no zip code of record56201	Sec. 23-T142N-R83W
Johanna Rambur Jackson	3420 11th Place N., Renton, WA 98056	Sec. 23-T142N-R83W
Murex Petroleum Corporation	515 N. Sam Houston Parkway East, Suite 485, Houston, TX 77060	Sec. 23-T142N-R83W
Alan G. Cypert	6467 Glennox St., Dallas, TX 75214	Sec. 23-T142N-R83W
Missiana L.L.C.	15311 Vantage Parkway West, Suite 201, Houston, TX 77032	Sec. 23-T142N-R83W
Matt Freidig Jr.	2202 E. Rosser, Bismarck, ND 58501	Sec. 23-T142N-R83W
Cynthia C. Fowler, as Trustee of The Cotton 4 Mineral Trust	1411 North Boulevard, Houston, TX 77006	Sec. 23-T142N-R83W
Michael H. Dunn	1128 South 7th Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
James M. Dunn	116 Center Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
Alice R. Dunn Thompson	116 Center Street, Bismarck, ND 58504	Sec. 23-T142N-R83W
Cynthia C. Fowler, as Trustee of The Cotton 6 Mineral Trust	1411 North Boulevard, Houston, TX 77006	Sec. 23-T142N-R83W
George E. Moss Jr. and John K. Moss, as joint tenants	4360 Worth Street, Los Angeles, CA 90063	Sec. 23-T142N-R83W
Alexander F. Rolle and Andrew Rolle, as Trustees of The Andrew Rolle O & G Trust	2105 Adair, San Marino, CA 91108	Sec. 23-T142N-R83W
Henry O. Bergloff	606 North Addison, Villa Park, IL 60181	Sec. 23-T142N-R83W
Raymond A. Bergloff	22712 Brenford Street, Woodland Hills, CA 91364	Sec. 23-T142N-R83W
Cleone I. Fredrickson	Box 9116, Brooks, OR 97305	Sec. 23-T142N-R83W
Laurence S. Bergloff	9900 Oakland Avenue South, Bloomington, MN 55420	Sec. 23-T142N-R83W
Beatrice L. Ottema	9901 Oakland Avenue South, Bloomington, MN 55420	Sec. 23-T142N-R83W
Alfred O. Bergloff	2528 Atlas Drive, Bismarck, ND 58501	Sec. 23-T142N-R83W
Mardi Albers, as purported successor to the Estate of Joyce Albers	P.O. Box 164, Grass Range, MT 59032	Sec. 23-T142N-R83W
Claudette Yantzer, as purported successor to the Estate of Joyce Albers	P.O. Box 180, Killdeer, ND 58640	Sec. 23-T142N-R83W
Daniel Bergloff	1232 W. 450 #46, Clearfield, UT 84015	Sec. 23-T142N-R83W
Norman Berglof	1232 W. 450 #46, Clearfield, UT 84015	Sec. 23-T142N-R83W
Vylo Raye Glasgow	2029 Canyon Drive, Billings, MT 59102	Sec. 23-T142N-R83W
Renee K. Hicks	16690 S.W. Vincent St., Aloha, OR 97007	Sec. 23-T142N-R83W
Constance M. Russell and Robert L. Russell, as Trustees of The Constance M. Russell Trust executed March 15, 1993	6000 NE Livingston Road, Camas, WA 98607	Sec. 23-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Keith H. Albers	2333 Portola Drive #46, Santa Cruz, CA 95062	Sec. 23-T142N-R83W
Roberta L. Herman	20247 Homestead Drive, Oregon City, OR 97045	Sec. 23-T142N-R83W
State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 36-T142N-R84W
John M. Haag and Beata Haag	P. O. Box 353, Center ND 58530	Sec. 36-T142N-R84W
Larry J. Doll and Faye Doll	5801 Lake Shore Est., Lot 9, Beulah, ND 58523	Sec. 25-T142N-R83W
Monsadius J. Hatzenbihler Estate, c/o Denise Brorby and Jill Bosch	265 93rd Street SE, Strasburg, ND 58573	Sec. 25-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court; Ste. 3000, Littleton, CO 80120	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W

Mineral Owners, Lessees and Operators	**Mailing Address**	**Legal Description**
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 25-T142N-R83W
Eileen Rooney Hewgley, L.L.C.	427 S Boston Avenue; Ste. 304, Tulsa, OK 74103	Sec. 25-T142N-R83W
RLand, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 25-T142N-R83W
Osprey Rersources, Inc.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 25-T142N-R83W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 25-T142N-R83W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 25-T142N-R83W
Frase-Tucker Resources, LLC	P. O. Box 994486, Redding, CA 96099	Sec. 25-T142N-R83W
Tenneco Oil Company	P. O. Box 3119, Englewood, CO 80155 AND 1001 Louisiana, P. O. Box 2511, Houston, TX 77252-2511	Sec. 25-T142N-R83W
John M. Haag and Beata Haag	P. O. Box 353, Center, ND 58530	Sec. 24-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 24-T142N-R84W
Eileen Rooney Hewgley, L.L.C.	427 S Boston Avenue; Ste. 304, Tulsa, OK 74103	Sec. 24-T142N-R84W
RLand, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 24-T142N-R84W
Osprey Rersources, Inc.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 24-T142N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 24-T142N-R84W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 24-T142N-R84W
Carlotta B. Tyler	Elk River MN 55330	Sec. 25-T142N-R84W
E. L. Gunberg	No street address, Minneapolis, MN 55111	Sec. 25-T142N-R84W
O. P. Curry	No street address, Minneapolis, MN 55111	Sec. 25-T142N-R84W
P. H. Phillips	5444 Fremont Ave S, Minneapolis, MN 55419-1625	Sec. 25-T142N-R84W
Albert A. Reed	No street address or zip code of record, Minneapolis, MN	Sec. 25-T142N-R84W
Frances R. Kary	1709 Linda Drive, Mandan, ND 58554	Sec. 25-T142N-R84W
Cecelia Hatzenbihler	P. O. Box 283, Center, ND 58530	Sec. 25-T142N-R84W
Elizabeth Hatzenbihler	P. O. Box 325, Center, ND 58530	Sec. 25-T142N-R84W
Joyce Barrick	835 Harrington Street SW, Hutchinson, MN 55350-3013	Sec. 25-T142N-R84W
Richard Himmelspach	8983 Sheridan Lake Road, Rapid City, SD 57702-9064	Sec. 25-T142N-R84W
Gary Himmelspach	4201 Old Red Trail NW, Mandan, ND 58554-1352	Sec. 25-T142N-R84W
Michele Curtis	710 3rd Avenue SE, Jamestown, ND 58401	Sec. 25-T142N-R84W
Robert Himmelspach	6298 Fox Run Drive, Idaho Falls, ID 83402-5876	Sec. 25-T142N-R84W
Mary Nelson	5004 Cornice Drive, Bismarck, ND 58503	Sec. 25-T142N-R84W
Becky Martin	10049 N 27th E, Idaho Falls, ID 83401-6437	Sec. 25-T142N-R84W
Beverly Moon	#4 Manor Lane, Rossville, GA 30741	Sec. 25-T142N-R84W
Jeanette Brown	HC 2, Box 154, Hensler, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt c/o Kenneth Schmidt	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Kenneth J. Schmidt, Personal Representative of the Monica Schmidt Estate	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 25-T142N-R84W
Joseph Schmidt	3581 22 Street SW, Center, ND 58530	Sec. 19-T142N-R83W
Kenneth J. Schmidt, Trustee of the Monica Schmidt Trust U/W DTD 1/18/2002	2205 36th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
Robert A. Wilbrandt, Executor of Harold M. Tripp Estate	P. O. Box 85, Crystal Lake, IL 60039	Sec. 19-T142N-R83W
Mary S. Tripp	P. O. Box 85, Crystal Lake, IL 60039	Sec. 19-T142N-R83W
Matthias A. Erhardt and Josephine Erhardt, as co-trustees of the Erhardt Family Trust dated June 13, 2006	2121 35th Avenue SW, Center, ND 58530	Sec. 19-T142N-R83W
June T. Nelson	15100 Interlachen Drive, # 212, Silver Springs, MD 20906	Sec. 19-T142N-R83W
Anna I. V. Kiebert	No address of record	Sec. 19-T142N-R83W
William V. Kiebert	No address of record	Sec. 19-T142N-R83W
Mary E. Tripp	No street address or zip of record. USPS.com for zip, Faribault, MN 55021	Sec. 19-T142N-R83W
Joey Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Jerry Nagel	RR1, Box 256, Center, ND 58530	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 1-T141N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 1-T141N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 1-T141N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan, ND 58554	Sec. 1-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan ND 58554	Sec. 1-T141N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 1-T141N-R83W
Richard A. Schwalbe and Lila M. Schwalbe, as joint tenants	HC 2, Box 254, Center, ND 58530	Sec. 12-T141N-R83W
Albert Schwalbe	502 3rd Ave. NW, Mandan, ND 58554	Sec. 12-T141N-R83W
Fred Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Raynold Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Walter Schwalbe	Center ND 58530	Sec. 12-T141N-R83W
Julie Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
Rodney J. Hatzenbihler	2660 30th Avenue, Center, ND 58530	Sec. 12-T141N-R83W
Nancy Henke and Dwight Henke, as joint life tenants	P.O. Box 90, Hazen, ND 58545	Sec. 12-T141N-R83W
Melissa Hatlestad	2372 Harmon Lane N, Mandan, ND 58554	Sec. 12-T141N-R83W
Travis Henke	965 Gregory Lane, Mountain Home, ID 83647	Sec. 12-T141N-R83W
Bonnie Schwab	3203 Mink Avenue, Gillette, WY 82716	Sec. 12-T141N-R83W
Peggy Gobar	504 Garden Ave. NW, West Fargo, ND 58078	Sec. 12-T141N-R83W
Annette Hatzenbihler	310 W. Tonk, Gillette, WY 82718	Sec. 12-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Brent Hatzenbihler	310 W. Tonk, Gillette, WY, 82718	Sec. 12-T141N-R83W
Randy Hatzenbihler	P.O. Box 325, Center, ND 58530	Sec. 12-T141N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523z	Sec. 12-T141N-R83W
United States of America	No address of record	Sec. 12-T141N-R83W
Reda Renee Clinton and Stephanie A. Clarys, as joint tenants	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Michael P. Hilton	3135 27th St. SW, Center, ND 58530	Sec. 14-T141N-R83W
Oliver County	Oliver County Courthouse, 115 W Main, Center, ND 58530	Sec. 14-T141N-R83W
John Barnhardt	1511 North 21st Street, Bismarck, ND 58501	Sec. 14-T141N-R83W
Gail M. Hilton	3195 27th St., Center, ND 58530	Sec. 14-T141N-R83W
Delmar Hagerott	3170 27th Street, Center, ND, 58530	Sec. 14-T141N-R83W
Arline Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Delvin Bueligen	709A 3rd Ave. SE, Mandan, ND 58554	Sec. 14-T141N-R83W
Lowell Bueligen	13621 Homestead Lane, Riverton, UT 84065	Sec. 14-T141N-R83W
Rodella Hausauer	1611 Castillian Way, Mundelein, IL 60060	Sec. 14-T141N-R83W
James Orgaard	9589 Brentford Drive, Highlands Ranch, CO 80126	Sec. 14-T141N-R83W
Clifford Orgaard	11839 Forada Beach Road SE, Unit A, Alexandria, MN 56308	Sec. 14-T141N-R83W
Steven Orgaard	2935 Manitoba Lane, Bismarck, ND 58501	Sec. 14-T141N-R83W
Michael Orgaard	3010 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Dale Barnhardt	3199 27th Street, Center, ND 58530	Sec. 14-T141N-R83W
Alan Schwalbe	3175 27th St., Center, ND 58530	Sec. 14-T141N-R83W
United States of America	No address of record	Sec. 14-T141N-R83W
Jeff Erhardt ad Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 20-T142N-R83W
"State of North Dakota N.D. Dept. of Trust Lands"	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 20-T142N-R83W
Federal Land Bank of Saint Paul	375 Jackson Street, P.O. Box 64949, St. Pau, MN 55164-0949	Sec. 20-T142N-R83W
General Council of the Assemblies of God	1445 N. Boonville Avenue, Springfield MO 65802-1894	Sec. 20-T142N-R83W
North Dakota District Council of the Assemblies of God	1724 North Grandview Lane, Bismarck ND 58503	Sec. 20-T142N-R83W
Matthias A. Erhardt and Josephine Erhardt, as co-trustees of the Erhardt Family Trust dated June 13, 2006	2121 35th Ave. SW, Center, ND 58530	Sec. 20-T142N-R83W
United States of America	No address of record	Sec. 20-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 26-T142N-R83W
Heirs or Devisees of the Estate of Loren Schwalbe, deceased	3520 81st Ave. SE, Unit 15, Jamestown, ND 58401	Sec. 26-T142N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 26-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 26-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 26-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 26-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 26-T142N-R83W
Sacred Heart Hospice Donatory Corporation	1200 12th Street SW, Austin, MN 55912	Sec. 26-T142N-R83W
John J. Krauth	Dumont MN 56236	Sec. 26-T142N-R83W
Larry Doll	3155 49th Avenue, New Salem, ND 58563	Sec. 26-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 26-T142N-R83W
T. F. Hodge	1113 Continental Bank Building, Fort Worth, TX No zip code of record	Sec. 26-T142N-R83W
Pierce Exploration & Production Corporation	1133 Bal Harbor Blvd., #1139, Punta Gorda, FL 33950	Sec. 26-T142N-R83W
Marshall & Winston, Inc.	P.O. Box 50880, Midland, TX 79710-0880	Sec. 26-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 26-T142N-R83W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 27-T142N-R83W
Kathryn S. Wilson	1941 St. Johns Road, Apt. #34, Seal Beach, CA 90740	Sec. 27-T142N-R83W
Margaret A. Flavin	1240 Fourth Avenue, Los Angeles, CA 90019	Sec. 27-T142N-R83W
Bradley Ferderer, as trustee of the Thomas A. Ferderer Residuary Trust	Heil, ND 58546	Sec. 28-T142N-R83W
Nick Ferderer	Flasher, ND 58535 AND 912 Summit Blvd, Bismarck ND 58504-5277	Sec. 28-T142N-R83W
Harry H. Ferderer	907 Cowl Street, Milton Freewater, OR 97862-1682	Sec. 28-T142N-R83W
John R. Ferderer	115 C Street North Richardton ND 58652	Sec. 28-T142N-R83W
Eleanor Falstad	2495 15th St. NW Coleharbor, ND 58531-9449	Sec. 28-T142N-R83W
Joyce Ervin, as personal representative of the Estate of Marie M. McGirl, deceased	2073 Rayshire Street, Thousand Oaks CA 91362-2460	Sec. 28-T142N-R83W
Esther Ferderer, as personal representative of the Estate of Jake H. Ferderer, deceased	No address of record	Sec. 28-T142N-R83W
Dorene Rambur	500 North 17th Street Bismarck ND 58501	Sec. 28-T142N-R83W
Norman D. Bunch	6900 Wedgewood Ct., Black Hawk, SD 57718-9680	Sec. 28-T142N-R83W
Kasper Barth	Center ND 58530	

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Dale Barth	2255 33rd Ave SW, Center, ND 58530	Sec. 28-T142N-R83W
Dusty Backer	PO Box 411, Underwood, ND 58576	Sec. 28-T142N-R83W
United States of America	No address of record	Sec. 28-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S., Grand Forks, ND 58208-3200 AND 1822 Mill Road, P. O. Box 13200, Grand Forks, ND 58208-3200	Sec. 29-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 29-T142N-R83W
Wayne Windhorst	P. O. Box 45, Stanton, ND 58571	Sec. 29-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 29-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY 12809	Sec. 29-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 29-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 29-T142N-R83W
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 29-T142N-R83W
J. F. Millard	5100 Aldrich Avenue South, Minneapolis, MN 55419	Sec. 29-T142N-R83W
Benischek Management, L.L.C.	3600 N. Harvey Parkway, Oklahoma City, OK 73118	Sec. 29-T142N-R83W
H. Gordon Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 29-T142N-R83W
Margaret W. Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 29-T142N-R83W
John H. Carton	Wolverine Tower, Battle Creek, MI	Sec. 29-T142N-R83W
Mack K. Lowrey	P. O. Box 393, Lancaster, TX 75146	Sec. 29-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 29-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 29-T142N-R83W
Minnkota Power Cooperative, Inc.	5301 32nd Avenue S, Grand Forks, ND 58201-3312 AND 1822 Mill Road, P. O. Box 13200, Grand Forks, ND 58208-3200	Sec. 30-T142N-R83W
Darlene Voegele	P. O. Box 45, Stanton, ND 58571	Sec. 30-T142N-R83W
John M. Haag and Beata Haag, as joint tenants	P. O. Box 353, Center ND 58530	Sec. 30-T142N-R83W
Osprey Resources, Inc.	PO Box 56449, Houston, TX 77256-6449	Sec. 30-T142N-R83W
Mary Michael Genung	885 Live Oak Ridge Road, West Lake Hills, TX 78746	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the L. F. Rooney III Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Patrick T. Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Timothy P. Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the James Harris Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Lucy Rooney Kapples Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney III, as co-trustees of the Rebecca Finch Rooney Trust	7 Spring Creek Road, Muskogee OK 74401	Sec. 30-T142N-R83W
Eileen Rooney Hewgley, L.L.C.	427 South Boston Avenue, Suite 304, Tulsa, OK 74103	Sec. 30-T142N-R83W
RLand, L.L.C.	401 South Boston Avenue, Suite 2400, Tulsa, OK 74103	Sec. 30-T142N-R83W
Gonzaga University Law Dept.	1224 E Euclid, Spokane, WA 99207	Sec. 30-T142N-R83W
Charles Kuether	3555 28th St., New Salem, ND 58563	Sec. 30-T142N-R83W
Doris Kuether	3555 28th St., New Salem, ND 58563	Sec. 30-T142N-R83W
Benischek Management, L.L.C.	3600 N. Harvey Parkway, Oklahoma City, OK 73118	Sec. 30-T142N-R83W
H. Gordon Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 30-T142N-R83W
Margaret W. Eason	203 Chestnut, Battle Creek, MI 49017	Sec. 30-T142N-R83W
John H. Carton	Wolverine Tower, Battle Creek, MI 49017	Sec. 30-T142N-R83W
Mack K. Lowrey	P. O. Box 393, Lancaster, TX 75146	Sec. 30-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 30-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 30-T142N-R83W
Spindletop Exploration Company, Inc.	P. O. Box 50787, Midland, TX 79710-0787	Sec. 30-T142N-R83W
Estate of Elizabeth Meader, deceased	116 Dix Ave., Kingsbury, NY No zip code of record	Sec. 30-T142N-R83W
Estate of Mildred Doyle, deceased	6 Tower Street, Red Hook, NY 12571	Sec. 30-T142N-R83W
Shirley A. Kilgour	6 Tower Street, Red Hook, NY 12571	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Denis A. Doyle	9 Spencer Drive, Red Hook, NY 12571	Sec. 30-T142N-R83W
Unknown trustee of the Frederick W. McCoy, Jr. Revocable Trust	PO Box 11215, St. Louis, MO 63105	Sec. 30-T142N-R83W
Hymen Cohen and Janis M. Cohen, as joint tenants	7301 Shaftesbury, University City, MO 63130	Sec. 30-T142N-R83W
Martha Buchheister	1748 Fremont Court, Ft. Collins, CO 80526	Sec. 30-T142N-R83W
DGHJLW Holdings, LLC	P.O. Box 33, Cleveland, NM 87715-0033	Sec. 30-T142N-R83W
Groundswell 45, LLC	P.O. Box 121, Kiowa, CO 80117	Sec. 30-T142N-R83W
AWerdel Minerals, LLC	1419 17th Street, Greeley, CO 80631	Sec. 30-T142N-R83W
J. Byron Werdel Resources, LLC	1419 17th Street, Greeley, CO 80631	Sec. 30-T142N-R83W
Shari R. Weber, as trustee of the Shari R. Weber Trust dated August 10, 2008	107 W. Cedar, P O Box 137, Robinson, IL 62454	Sec. 30-T142N-R83W
Betty Eileen Ferrel	3740 Pinebrook Circle, #107, Bradenton, FL 34209	Sec. 30-T142N-R83W
Rikkie P. Doyle	3740 Pinebrook Circle, #207, Bradenton, FL 34209	Sec. 30-T142N-R83W
Marcy P. Stacy	5619 Open Gate Court, Cincinnati, OH 45247	Sec. 30-T142N-R83W
Guy M. Simmons and Ruby P. Simmons, as joint tenants	820 North Cross St., Robinson, IL 62454	Sec. 30-T142N-R83W
Thomas E. Eaton, Sr.	7817 North 1150th Street, Newton, IL 62448	Sec. 30-T142N-R83W
Jacqueline R. Blakley	3207 Florence Drive, Champaign, IL, 61822-8011	Sec. 30-T142N-R83W
Lee. R. Martin	1602 South Lamar Street, Lakewood, CO 80226	Sec. 30-T142N-R83W
Kent Littlejohn and Brenda Littlejohn, as joint tenants	10777 N. Friendship Road, Casey, IL 62420	Sec. 30-T142N-R83W
O. E. Benefiel and Isabel Benefiel, as joint tenants	No street address of record, Newton, IL 62448	Sec. 30-T142N-R83W
Jerome Maginn and Mary Maginn, as joint tenants	Route #3, Newton, IL 62448	Sec. 30-T142N-R83W
Timothy J. Pulliam, as Trustee of the Timothy J. Pulliam Family Legacy Trust dated December 14, 2017	27701 Sycamore Creek Drive, Valencia, CA 91354	Sec. 30-T142N-R83W
Alonzo Walden and Buerryl Walden, as joint tenants	No street address of record, Hidalgo, IL No zip code of record	Sec. 30-T142N-R83W
Donald L. Long and Ledora M. Long, as joint tenants	R. R. 3, Newton, IL 62448	Sec. 30-T142N-R83W
Arnold L. Colpitts and Esther M. Colpitts, as joint tenants	No street address of record, Newton, IL No zip code of record	Sec. 30-T142N-R83W
Irma J. Goeckner, as Trustee of the Goeckner Living Trust dated January 24, 2011	7202 Torrington Way, Springfield, IL 62711	Sec. 30-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Alice Marlene Heaton	863 County Road 500 East, Toledo, IL 62468	Sec. 30-T142N-R83W
Todd David Clark	3301 Avondale Avenue, Knoxville, TN 37917	Sec. 30-T142N-R83W
David Deatherage and Myrtle Deatherage, as joint tenants	No street address of record, Oblong, IL 62449	Sec. 30-T142N-R83W
Estate of Belva L. Dalrymple, deceased	8929 State Route 555, Cutler OH 45724-5167	Sec. 30-T142N-R83W
Robert Lynn Dalrymple and Elizabeth J. Feuerstein, as joint tenants	5 West Fairview Street, Arlington Heights, IL 60005-2551	Sec. 30-T142N-R83W
Barbara Breen, as PR of the Estate of William Wallace Dalrymple, deceased	4 Stuart on Oxford, Rolling Meadows, IL 60008	Sec. 30-T142N-R83W
Kay Kirkpatrick	430 S. Elmwood, Oak Park, IL 60302	Sec. 30-T142N-R83W
Karen Quinn	518 S. Euclid, Oak Park, IL 60304	Sec. 30-T142N-R83W
Kathy Simandl	R.R. #2, Box 210, Menomonie, WI 54751	Sec. 30-T142N-R83W
George G. Vaught, Jr.	P.O. Box 13557, Denver, CO 80201-3557	Sec. 30-T142N-R83W
Paul L. McCulliss	P.O. Box 3248, Littleton, CO 80161-3248	Sec. 30-T142N-R83W
Glengarry Oil Company	PO Box 267, Lima, OH 45802	Sec. 30-T142N-R83W
Stewart J. Schutte	6592 N. 1075th Street, Robinson, IL 62454	Sec. 30-T142N-R83W
Tyler R. Tedford	10250 Wicklow Court, Fishers, IN 46040	Sec. 30-T142N-R83W
Kent A. Tedford	3823 N. Ashland Avenue, #203, Chicago, IL 60613	Sec. 30-T142N-R83W
Charles Sanders	301 North Wolfenberger Street, #1, Sullivan IN 47882-7211	Sec. 30-T142N-R83W
Thomas L. Frichtl and Elizabeth Frichtl, as joint tenants	11681 North 1300th Street, Newton IL 62448-3622	Sec. 30-T142N-R83W
Frank G. Mefford, Emogene Mefford, and Cheryl A. Mefford, as joint tenants	Rt. 1, Palestine, IL 62451	Sec. 30-T142N-R83W
James D. Stout, as trustee of the Carl H. Zwermann Trust	PO Box 714, Robinson IL 62454	Sec. 30-T142N-R83W
United States of America	No address of record	Sec. 30-T142N-R83W
Carl Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 35-T142N-R83W
Loren Schwalbe	603 3rd Ave. NE, Mandan ND 58554	Sec. 35-T142N-R83W
Rolland Schwalbe	HC 2 Box 258, Center ND 58530	Sec. 35-T142N-R83W
T. F. Hodge	1113 Continental Bank Building, Fort Worth, TX No zip code of record	Sec. 35-T142N-R83W
Pierce Exploration & Production Corporation	1133 Bal Harbor Blvd., #1139, Punta Gorda, FL 33950	Sec. 35-T142N-R83W
Marshall & Winston, Inc.	P.O. Box 50880 Midland, TX 79710-0880	Sec. 35-T142N-R83W
State of North Dakota, N.D. Dept. of Trust Lands	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 36-T142N-R83W
Michelle Marie Ternes	3721 W Regent Drive, Bismarck, ND 58504	Sec. 35-T142NR84W
Michael P. Dresser	3731 24th Street SW, Center, ND 58530	Sec. 35-T142NR84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Linda L. Ash	411B 32nd Avenue NW, Underwood, ND 58576	Sec. 35-T142NR84W
Thomas Dresser, Sr.	HC 2, Box 218", Center, ND 58530	Sec. 35-T142NR84W
USA - Dept. of Interior, Bureau of Land Management	1245 N 29th Street, Billings, MT 59101-0122	Sec. 34-T142N-R84W
Larry Bernard Dresser and Mary Dresser	RR 1, Box 80A", Washburn, ND 58577	Sec. 34-T142N-R84W
Thomas Dresser, Jr.	609 N Almon, #2028, Moscow, ID 83843	Sec. 34-T142N-R84W
Tammy L. Dresser	4810 16th Avenue SW, Apt. #206, Fargo, ND 58103	Sec. 34-T142N-R84W
Laura Ann Dresser	4810 Highway 7, Apt. #102, St. Louis Park, MN 55416	Sec. 34-T142N-R84W
Paul Ash	HC 1, Box 34", Underwood, ND 58576	Sec. 34-T142N-R84W
Dean Ash	HC 1, Box 34", Underwood, ND 58576	Sec. 34-T142N-R84W
Theresa Ash	HC 1, Box 34, Underwood, ND 58576	Sec. 34-T142N-R84W
Dale Barth	2255 33rd Ave. SW, Center, ND 58530	Sec. 16-T142NR83W
State of North Dakota		Sec. 16-T142NR83W
Luella C. Isaak	3347 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Burton Isaak	3345 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Bruce Isaak	1819 Xavier Street, Bismarck, ND 58501	Sec. 16-T142NR83W
Byron Isaak	2132 Terra Ridge Drive, Highlands Ranch, CO 80126	Sec. 16-T142NR83W
Brenda Kitzan	3313 Hwy 25, Center, ND 58530	Sec. 16-T142NR83W
Yolanda Bittner	3428 Highway 25, Center, ND 58530	Sec. 17-T142N-R83W
The State of North Dakota	1707 N 9th Street, Bismarck, ND 58501	Sec. 17-T142N-R83W
United States of America	No address of record	Sec. 12-T141N-R84W
Jolene Berger	3004 Manchester Street, Bismarck, ND 58504	Sec. 12-T141N-R84W
Brian Dresser	2574 37th Avenue SW, Center, ND 58530	Sec. 12-T141N-R84W
Frances Fuchs	2475 37th Avenue NW, Center, ND 58530	Sec. 12-T141N-R84W
Rosalie A. Dingus	400 Augsburg Avenue, Bismarck, ND 58504	Sec. 12-T141N-R84W
Mark R. Fuchs	18671 Fairweather, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Jack B. Fuchs	15409 Rhododendron Drive, Canyon Country, CA 91351	Sec. 12-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 12-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 12-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 12-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 12-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655 AND 203 S Prairie Lane, Mandan, ND 58554	Sec. 12-T141N-R84W
JoAnne Snow	329 Bedford Boulevard, Bismarck, ND 58504 AND 902 S Woodland Drive, Mandan, ND 58554	Sec. 12-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 12-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the L. F. Rooney III, Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Patrick T. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Timothy P. Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the James Harris Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Lucy Rooney Kapples Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Patrick T. Rooney, Timothy P. Rooney, James Harris Rooney, and L. F. Rooney, III, Co-Trustees of the Rebecca Finch Rooney Trust created by the Lucy T. Rooney 1992 GST Exempt Family Trusts under Trust Agreement dated August 18, 1992	7 Spring Creek Road, Muskogee, OK 74401	Sec. 12-T141N-R84W
Eileen Rooney Hewgley, L.L.C.	401 S Boston Avenue; Ste. 2400, Tulsa, OK 74103	Sec. 12-T141N-R84W
RLand, L.L.C.	P. O. Box 56449, Houston, TX 77256-6449	Sec. 12-T141N-R84W
Osprey Rersources, Inc.	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 12-T141N-R84W
Mary Michael Genung	885 Live Oak Ridge Road, Austin, TX 78746	Sec. 12-T141N-R84W
Gonzaga University Law Department	1224 E Euclid, Spokane, WA 99207	Sec. 12-T141N-R84W
J. C. Miller	508 Beacon Building, Tulsa, OK 74103	Sec. 12-T141N-R84W
Ralph M. Fahrenwald and Edna M. Fahrenwald	3737 E 45th Street, Tulsa, OK 74135	Sec. 12-T141N-R84W
Noah W. Millsap and Nell Rose Millsap	1927 E 33rd Place, Tulsa, OK 74105	Sec. 12-T141N-R84W
W. A. Dean and Fonda G. Dean	1316 E 35th Place, Tulsa, OK 74105	Sec. 12-T141N-R84W
Regina Husfloen	240 Bridge Avenue, Center, ND 58530	Sec. 12-T141N-R84W
Judith McNulty	P. O. Box 1173, Center, ND 58530	Sec. 12-T141N-R84W
Gary Hagel	3453 Thunderbird Lane, Bismarck, ND 58503	Sec. 12-T141N-R84W
Scott Hagel	275 Poplar Drive , Shoreview, MN 55126	Sec. 12-T141N-R84W
Dennis Hagel	506 W Main, Hazen, ND 58545	Sec. 12-T141N-R84W
Jay Kautzman	2024 N 5th Street, Bismarck, ND 58501	Sec. 12-T141N-R84W
Julie Fry	1853 N 23rd Street, Bismarck, ND 58501	Sec. 12-T141N-R84W
Janet Anderson	15537 E Radcliffe Place, Aurora, CO 80015	Sec. 12-T141N-R84W
Jeanine Marcolina	3938 E San Pedro, Gilbert, AZ 85234	Sec. 12-T141N-R84W
John Kautzman	P. O. Box 82, Center, ND 58530	Sec. 12-T141N-R84W
Jeff Erhardt and Mary Erhardt, as joint tenants	2161 34th Ave. SW, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Keith Erhardt and Kelly Jo Erhardt, as joint tenants	P.O. Box 1846, Center, ND 58530	Sec. 21-T142N-R83W
Melvin Schoepp and Caroline Schoepp, as joint tenants	2023 Northridge Drive, Bismarck, ND 58503	Sec. 21-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 21-T142N-R83W
AgriBank, FCB	375 Jackson Street, P.O. Box 64949, St. Paul, MN 55164-0949	Sec. 21-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Sacred Heart Hospice Donatory Corporation (as apparent successor to Robert Dunn)	1200 12th Street SW, Austin, MN 55912	Sec. 21-T142N-R83W
Richard E. Armentrout and Margaret Ann Armentrout, as joint tenants	255 Lynn Ave., Satellite Beach, FL 32937	Sec. 21-T142N-R83W
Burtis B. Conyne	No street address of record, Bismarck ND, No zip code of record	Sec. 21-T142N-R83W
Mary Dunn Lynch	No street address of record Austin, MN 55912	Sec. 21-T142N-R83W
Margaret E. Hagerott	No street address of record, Mandan ND 58554	Sec. 21-T142N-R83W
Michael H. Dunn	1128 South 7th Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
James M. Dunn	116 Center Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
Alice R. Dunn Thompson	116 Center Street, Bismarck, ND 58504	Sec. 21-T142N-R83W
Red Crown Royalties, LLC	1490 W Canal Court, Suite 3000, Littleton, CO 80120	Sec. 21-T142N-R83W
Frase-Tucker Resources, LLC	P.O. Box 994486, Redding, CA 96099	Sec. 21-T142N-R83W
United States of America	No address of record	Sec. 11-T141N-R84W
State of North Dakota, Department of Trust Lands	1707 N 9th Street, Bismarck, ND 58501-5523	Sec. 11-T141N-R84W
Lee Dresser	P. O. Box 683, Riverdale, ND 58565	Sec. 11-T141N-R84W
David O. Berger and Debra A. Berger, as joint tenants	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Great Northern Properties LP	1101 N 27th Street; Suite 201, Billings, MT 59101 AND 1658 Cole Boulevard, Building #6, Suite 2, Golden, CO 80401	Sec. 11-T141N-R84W
Meridian Land & Mineral Company	5613 DTC Parkway; Suite 1100, Englewood, CO 80111 AND 2919 Allen Parkway, Houston, TX 77019-2142	Sec. 11-T141N-R84W
Yvonne Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Terrence Schmidt	515 Nottingham Drive, Bismarck, ND 58504	Sec. 11-T141N-R84W
Randall Schmidt	4817 Roughrider Circle, Mandan, ND 58554	Sec. 11-T141N-R84W
Raymond Schmidt, Jr.	5735 Highland Road, Mandan, ND 58554	Sec. 11-T141N-R84W
Marsha Strecker	P. O. Box 105, South Heart, ND 58655 AND 203 S Prairie Lane, Mandan, ND 58554	Sec. 11-T141N-R84W
JoAnne Snow	329 Bedford Boulevard, Bismarck, ND 58504 AND 902 S Woodland Drive, Mandan, ND 58554	Sec. 11-T141N-R84W
Jeffrey Schmidt	3611 42nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Matt Berger and Rose Berger c/o David O. Berger"	2531 37th Avenue SW, Center, ND 58530	Sec. 11-T141N-R84W
Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Raymond Schmidt Estate c/o Margaret Schmidt	1305 2nd Street NW, Mandan, ND 58554	Sec. 11-T141N-R84W
Melvin Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Caroline K. Schoepp	3020 Daytona Drive, Bismarck, ND 58503	Sec. 22-T142N-R83W
Larry Doll	3155 49th Ave., New Salem, ND 58563	Sec. 22-T142N-R83W
Grealing Starck and Deborah Stark, as joint tenants	3244 Highway 25, Center, ND 58530	Sec. 22-T142N-R83W
Marie Mosbrucker	127 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Raymond Friedig	523 South Anderson Street, Bismarck, ND 58504	Sec. 22-T142N-R83W
Duane Friedig	1706 East Bowman Avenue, Bismarck, ND 58504	Sec. 22-T142N-R83W
Shirley Hilzendeger	110 Klein Avenue, Center, ND 58530	Sec. 22-T142N-R83W
Ann Doll	4601 McKenzie Drive SE, Mandan, ND 58554	Sec. 22-T142N-R83W
Richard C. Baulder, as Personal Representative of the Estate of Winifred M. Dunn, deceased	No street address of record, Austin, MN 55912	Sec. 22-T142N-R83W
Ryan Oil Company, LLC	P.O. Box 507, Evansville, IN 47703	Sec. 22-T142N-R83W
Derby Energy, L.L.C.	6420 Richmond Avenue, Suite 210, Houston, TX 77057	Sec. 22-T142N-R83W
State of North Dakota	1707 N 9th St, Bismarck, ND 58501-5523	Sec. 22-T142N-R83W
United States of America	No address of record	Sec. 22-T142N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
BNI Coal Ltd.	1637 Burnt Boat Drive, Bismarck, ND 58502-0897 AND P. O. Box 897, Bismarck, ND 58502 AND 16400 Saybrook Lane, Huntington, CA 92649	Sec. 3-T141N-R83W Sec. 5-T141N-R83W Sec. 6-T141N-R83W Sec. 7-T141N-R83W Sec. 8-T141N-R83W Sec. 9-T141N-R83W Sec. 15-T141N-R83W Sec. 16-T141N-R83W Sec. 17-T141N-R83W Sec. 18-T141N-R83W Sec. 19-T141N-R83W Sec. 20-T141N-R83W Sec. 21-T141N-R83W Sec. 22-T141N-R83W Sec. 28-T141N-R83W Sec. 29-T141N-R83W Sec. 3-T141N-R84W Sec. 10-T141N-R84W Sec. 11-T141N-R84W Sec. 12-T141N-R84W Sec. 13-T141N-R84W Sec. 14-T141N-R84W Sec. 24-T141N-R84W Sec. 15-T142N-R83W Sec. 16-T142N-R83W Sec. 17-T142N-R83W Sec. 19-T142N-R83W Sec. 20-T142N-R83W Sec. 21-T142N-R83W Sec. 22-T142N-R83W Sec. 28-T142N-R83W Sec. 29-T142N-R83W Sec. 30-T142N-R83W Sec. 32-T142N-R83W Sec. 33-T142N-R83W Sec. 25-T142N-R84W Sec. 34-T142N-R84W Sec. 35-T142N-R84W Sec. 36-T142N-R84W
BNI Coal, Ltd. (f/k/a Baukol-Noonan, Inc.)	1637 Burnt Boat Drive, Bismarck, ND 58502	Sec. 32-T142N-R83W
L. D. Jenkins c/o Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W

Mineral Owners, Lessees and Operators	Mailing Address	Legal Description
Willow Point Corporation c/o Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Gentry, LLC	4216 N Portland; Suite 104, Oklahoma City, OK 73112	Sec. 20-T141N-R83W
Otter Creek Mining Company, L.L.C.	2000 Schafer Street, Suite D, Bismarck, ND 58501	Sec. 15-T142N-R83W
Consolidation Coal Company	1800 Washington Road, Pittsburgh, PA 15241 AND Koppers Building, 436 7th Avenue, Pittsburgh, PA 15219	Sec. 11-T141N-R84W
William Coal Corporation	801 Wilmington Trust Building Wilmington, DE 19801	Sec. 11-T141N-R84W

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed Tundra SGS carbon dioxide (CO_2) storage project will be situated near the Milton R. Young Station (MRYS) southeast of Center, North Dakota (Figures 2-1 and 2-2). This project site is on the eastern flank of the Williston Basin.

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 (Peck, 2014; Glazewski, 2015).

The target CO_2 storage reservoirs addressed in this CO_2 storage facility permit for Tundra SGS are the predominantly sandstone horizons of the Black Island and Deadwood Formations, lying about 9,280 ft below MRYS. Shales of the Icebox Formation conformably overly the Black Island and serve as the primary confining zone (Figure 2-3). The continuous shales of the Deadwood Formation B member serve as the lower confining zone (Figure 2-3). Together, the Icebox, Black Island, and Deadwood Formations comprise this CO_2 storage complex for Tundra SGS (Table 2-1).

In addition to the Icebox Formation, there is 570 ft of impermeable rock formations between the Black Island Formation and the next overlying porous zone, the Red River Formation. An additional 7400 ft of section including several thousands of feet of impermeable intervals separate the Black Island and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-3).

2.2 Data and Information Sources

Several sets of data were used to characterize the injection and confining zones to establish their suitability for storage and containment of injected CO_2. Data sets used for characterization included both existing data (sources and uses are discussed within Section 2.2.1) and site-specific data acquired by the applicant to characterize the storage complex.

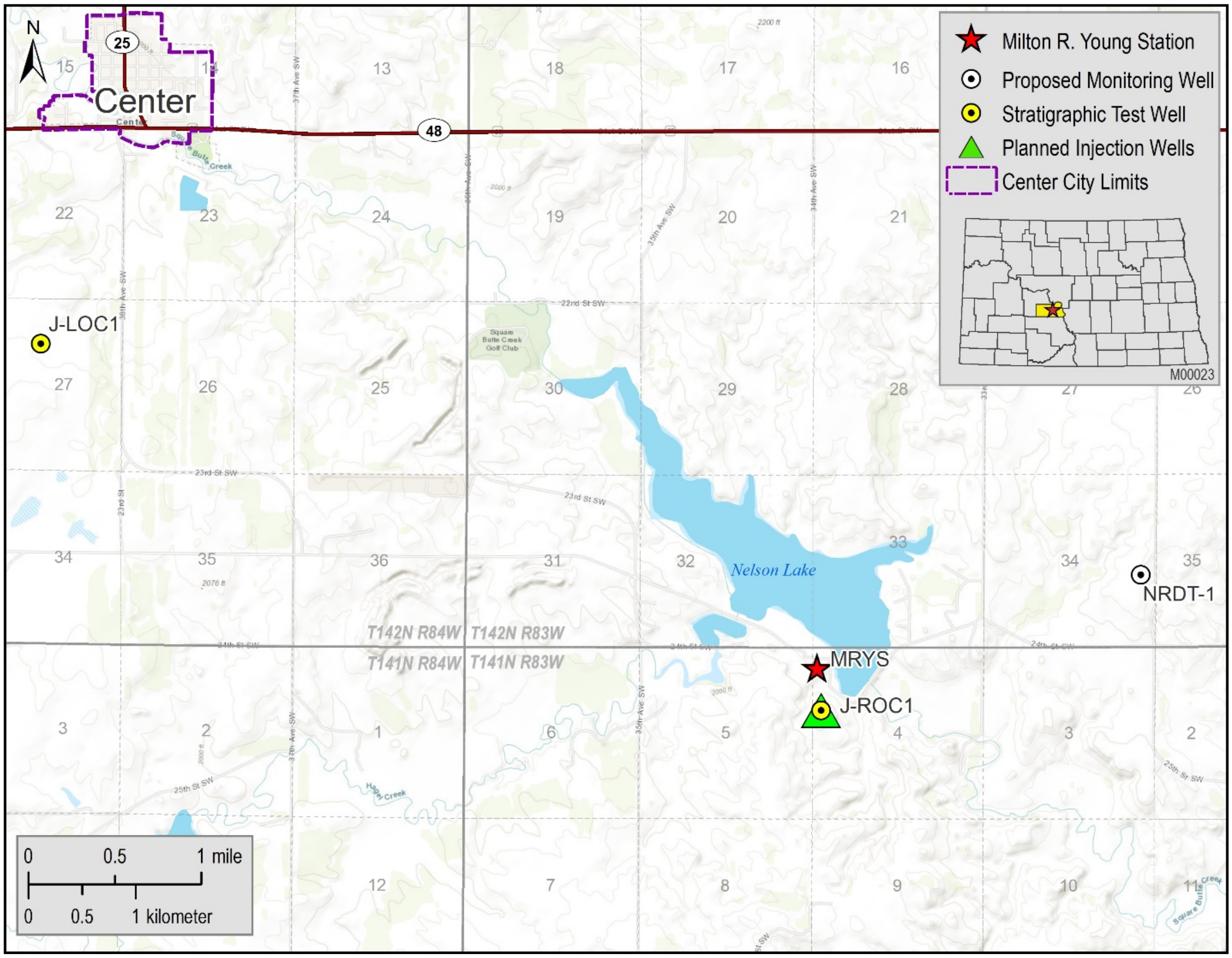

Figure 2-1. Topographic map of the Tundra SGS area showing well locations and MRYS.

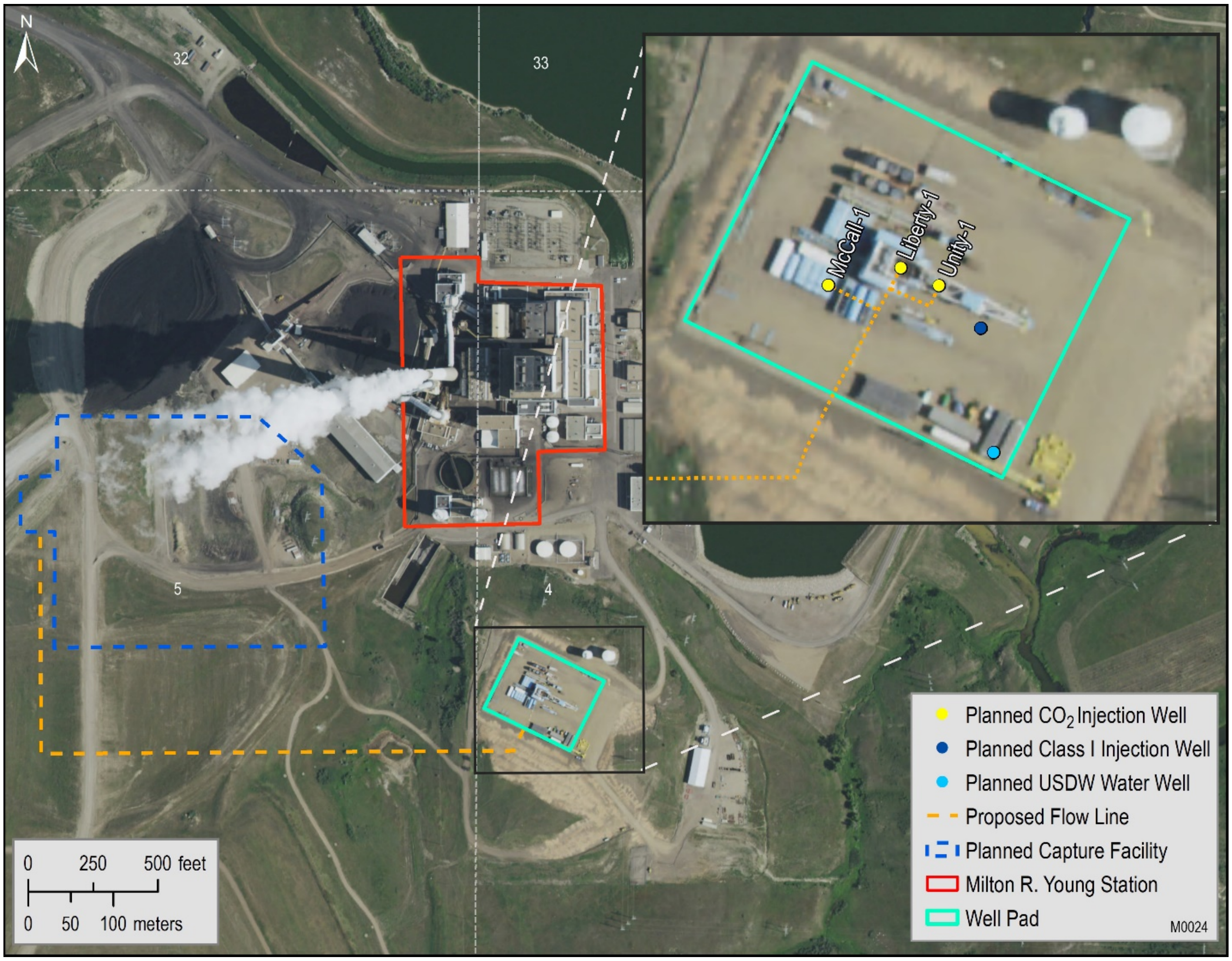

Figure 2-2. Topographic map of the proposed CO_2 flowlines and well pad layout.

2.2.1 Existing Data

Existing data used to characterize the geology beneath the Tundra SGS 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 13 wellbores within a 56-mi radius of the proposed storage site (Figure 2-4). These data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Existing laboratory measurements from Deadwood Formation core samples were available from one well: J-LOC1 (NDIC File No. 37380). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data. Two 3D surveys totaling 18.5 mi^2 (6.5-mi^2 west 3D and 12-mi^2 east 3D), encompassing the J-LOC1 and J-ROC1 wellsites, were examined to understand the heterogeneity and geologic structure of the Black Island and Deadwood Formations.

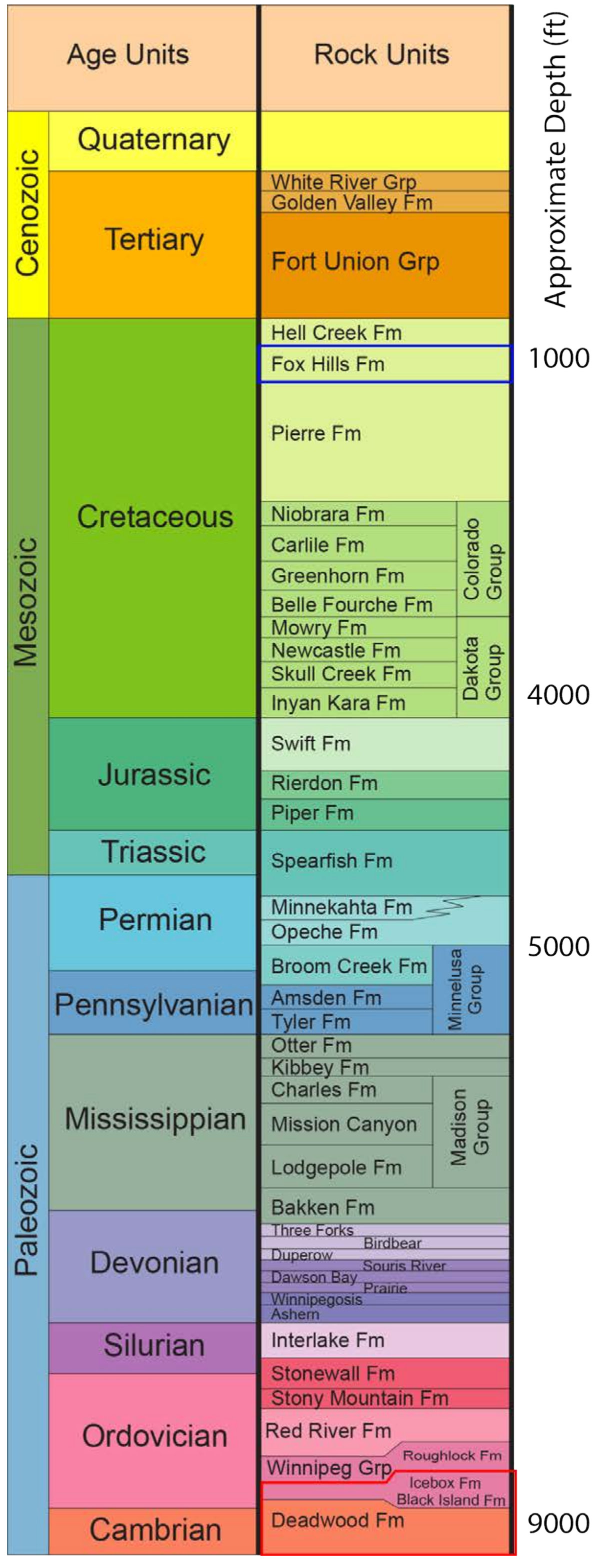

Figure 2-3. Stratigraphic column identifying the storage reservoir, confining zones, and lowest USDW addressed in this permit application for Tundra SGS.

Table 2-1. Formations Comprising the Tundra SGS CO_2 Storage Complex

	Formation	Purpose	Average Thickness at Tundra SGS Site, ft	Average Depth Tundra SGS Site, ft TVD	Lithology
Storage Complex	Icebox	Upper confining zone	118 (58 to 176)	9,308	Shale
	Black Island and Deadwood E member	Storage reservoir (i.e., injection zone)	118 (35 to 202)	9,427	Sandstone, shale, dolostone, limestone
	Deadwood C member sand	Storage reservoir (i.e., injection zone)	64 (40 to 88)	9,773	Sandstone
	Deadwood B member shale	Lower confining zone	34 (20 to 49)	9,791	Shale

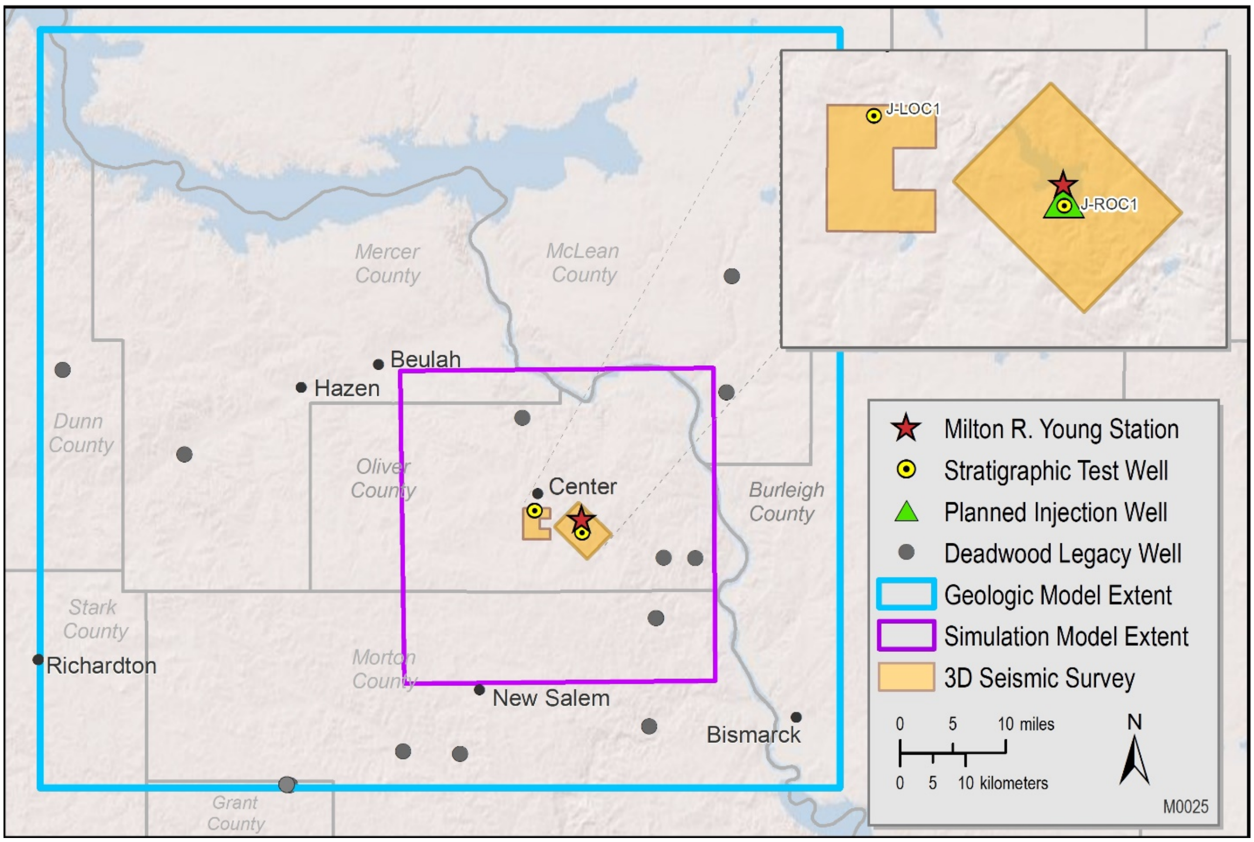

Figure 2-4. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

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 2020, the J-LOC1 and J-ROC1 wells were drilled specifically to gather subsurface geologic data to support the development of a CO_2 storage facility permit. J-LOC1 was drilled to a depth of 10,477 ft, and J-ROC1 was drilled to a depth of 9,893 ft. A downhole sampling and measurement program focused on the proposed storage complex (i.e., the Black Island and Deadwood Formations [Figure 2-5a and 2-5b]). Additional characterization efforts focused on the Inyan Kara Formation interval and Broom Creek Formation interval as potential CO_2 storage reservoirs.

Site-specific data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2 and were 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 the monitoring data with respect to potential subsurface risks (Section 4.1). Furthermore, these data guide and influence the design and operation of site equipment and infrastructure (Sections 4.5 and 5.0).

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the J-LOC1 and J-ROC1 wells along the entire open section of the wellbore. The logging suite included caliper, gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, spectral GR, a combinable magnetic resonance (CMR), and fracture finder 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 Precambrian. The site-specific formation top depths were added to the existing data of the 13 wellbores within a 56-mi 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 600 ft of core was collected in the Black Island and Deadwood storage complexes from J-LOC1, and 616 ft of core was collected from J-ROC1. This core was analyzed to characterize the lithologies of the Precambrian, Deadwood, Black Island, and Icebox Formations and correlated to well log data. Core analysis for the J-LOC1 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.

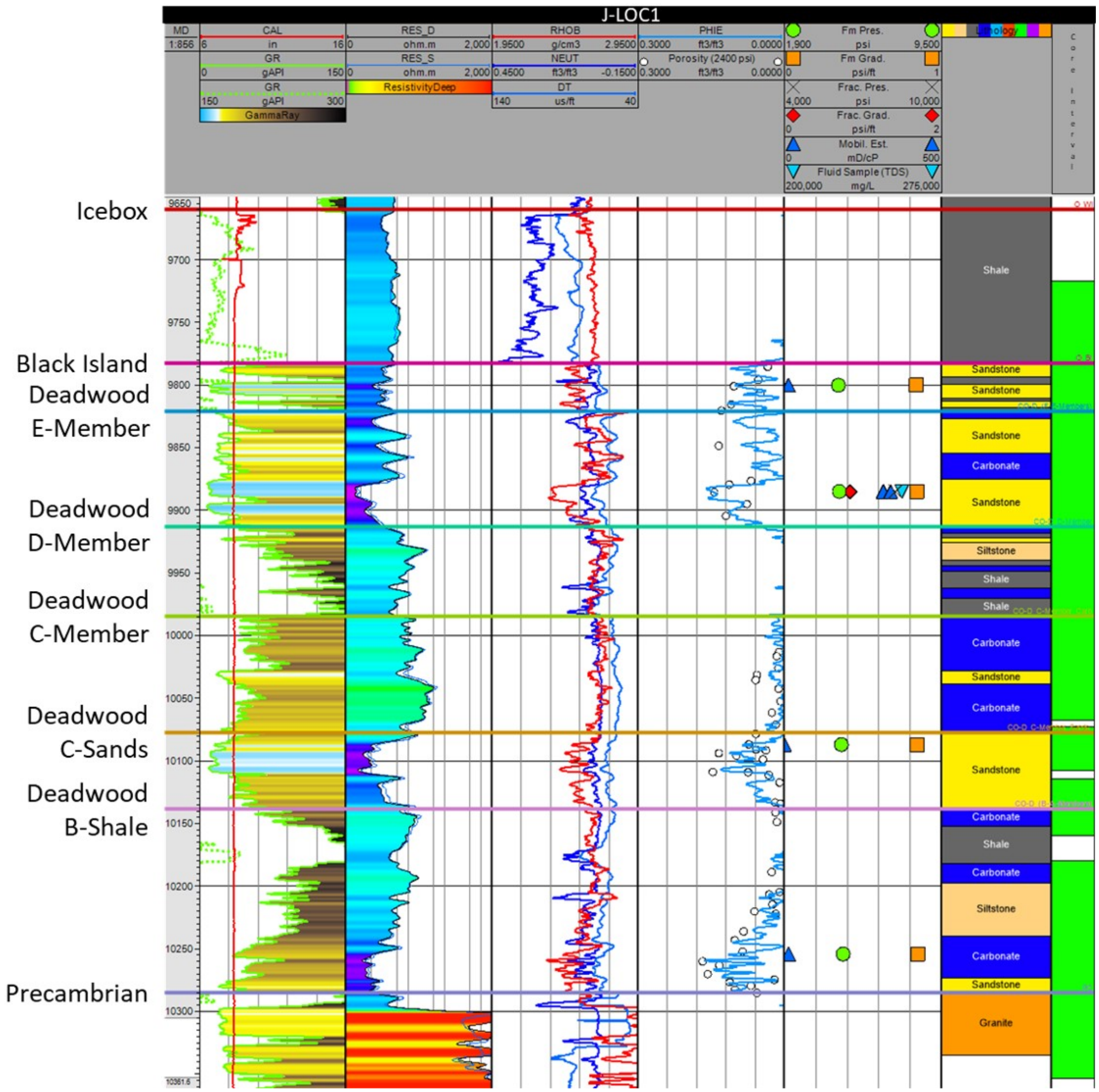

Figure 2-5a. Schematic showing vertical relationship of coring and testing intervals in the Icebox, Black Island, and Deadwood Formations and the Precambrian basement in the J-LOC1 well.

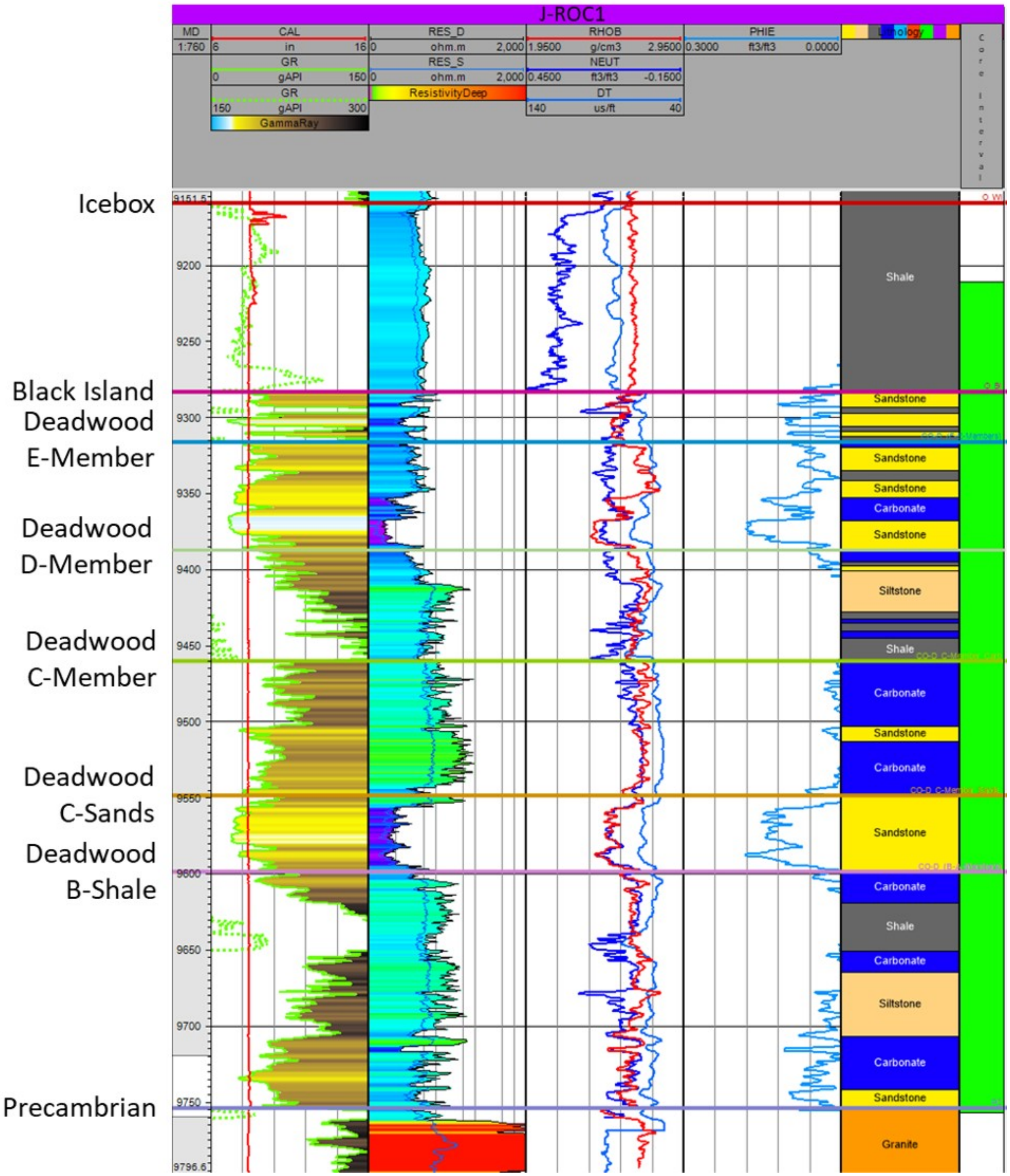

Figure 2-5b. Schematic showing vertical relationship of coring and testing intervals in the Icebox, Black Island, and Deadwood Formations and the Precambrian basement in the J-ROC1 well.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the J-LOC1 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 then used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

Pressure testing at J-LOC1 was performed with the Schlumberger MDT (modular formation dynamics testing) 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 pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection; see Appendix D, "Schlumberger, MDT." The MDT tool formation pressure measurements from the Black Island and Deadwood 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 2-2. Description of J-LOC1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth, ft	Temperature, °F
Icebox	9,751.17	182.97
	9,800.01	180.66
Black Island	9,884.89	182.94
Deadwood	9,885.14	180.68
	10,087.45	181.44
	10,254.12	184.26
Mean Black Island/Deadwood Temp., °F	182.00	
Deadwood Temperature Gradient, °F/ft	0.01*	

* The Black Island/Deadwood temperature gradient is an average of the MDT tool measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.

Table 2-3. Description of J-LOC1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth, ft	Formation Pressure, psi
Black Island	9,800.01	4,506.66
Deadwood	9,884.89	4,548.42
Deadwood	9,885.14	4,548.27
Deadwood	10,087.45	4,650.86
Deadwood	10,254.12	4,734.49
Mean Black Island/Deadwood Pressure, psi	4,597.74	
Deadwood Pressure Gradient, psi/ft	0.46*	

* The Black Island/Deadwood pressure gradient is an average of the MDT tool measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.

2.2.2.4 *Microfracture In Situ Stress Tests*

Using the Schlumberger MDT tool, microfracture in situ stress tests were performed in the J-LOC1 well. In situ reservoir testing measurements provide real-time formation pressure, formation temperature, fracture breakdown, propagation, and closure pressures. Microfracture in situ stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

Microfracture in situ stress tests were performed on the Icebox and Deadwood Formations in J-LOC1 (Table 2-4). The use of the dual-packer module on the MDT tool assembly to isolate the designated intervals tested a 1.5-ft section of the zone of interest. Fracture propagation pressures determined from the microfracture test in the J-LOC1 well were used to calculate pressure constraints related to the maximum allowable bottomhole pressure.

In the J-LOC1 wellbore, two microfracture in situ stress tests were performed in the Icebox Formation at 9,749.5 and 9,751.2 ft (Table 2-4). The interpretation of the results is provided in Section 2.4 Storage Reservoir Confinement Zone. Neither of the two tests attempted in the Icebox Formation were successful in depicting the formation breakdown pressure, with one predominant reason being the limitations of the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent rock and exhibits sufficient geologic integrity to contain the injected CO_2 stream. One microfracture in situ stress test was performed in the Deadwood Formation, at 9,885.1 ft, with interpretation of the results provided in Section 2.3 Storage Reservoir Injection Zone (Table 2-4).

Table 2-4. Description of J-LOC1 Microfracture In Situ Stress Tests

Formation	Test Depth	Breakdown Pressure		Propagation Pressure		Closure Pressure		Initial Shut-In Pressure	
	ft	psi	Gradient, psi/ft	Avg., psi	Gradient, psi/ft	Avg., psi	Gradient, psi/ft	Avg., psi	Gradient, psi/ft
Icebox	9,749.5	No observed formation breakdown. Maximum applied injection pressure = 10,984.9 psi							
	9,751.2	No observed formation breakdown. Maximum applied injection pressure = 10,867.24 psi							
Deadwood	9,885.1	8,231	0.833	7,450	0.754	7,393.55	0.748	N/A	

2.2.2.5 *Fluid Samples*

Fluid samples from the Deadwood Formation were collected from the J-LOC1 wellbore via the MDT tool (Appendix D, "Schlumberger Saturn 3D Radial Probe"). The sample was analyzed by Minnesota Valley Testing Laboratories, a state-certified lab, and confirmed by the Energy & Environmental Research Center (EERC). The sample collected at a depth of 9,884.9 ft had total dissolved solids of 256,000 mg/L. 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.

In situ pressure testing was performed in the Icebox Formation (upper confining zone) with the MDT tool. This test used the tool's large-diameter probe to test both the mobility and reservoir pressure (Appendix D). During the test, the formation was unable to rebound (build pressure) because of low (nearly zero) permeability. This result suggested that neither the reservoir pressure nor an in situ fluid sample could be measured or collected from the Icebox Formation. The testing results provide further evidence of the confining properties of the Icebox Formation, ensuring sufficient geologic integrity to contain the injected CO_2 stream.

2.2.2.6 Seismic Survey

A 5-mi-long seismic source test and 6.5-mi^2 3D seismic survey were acquired in 2019, and a 12-mi^2 3D seismic survey and 21 mi of 2D seismic lines were acquired in 2020 (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 2D seismic data provided a means to connect the two

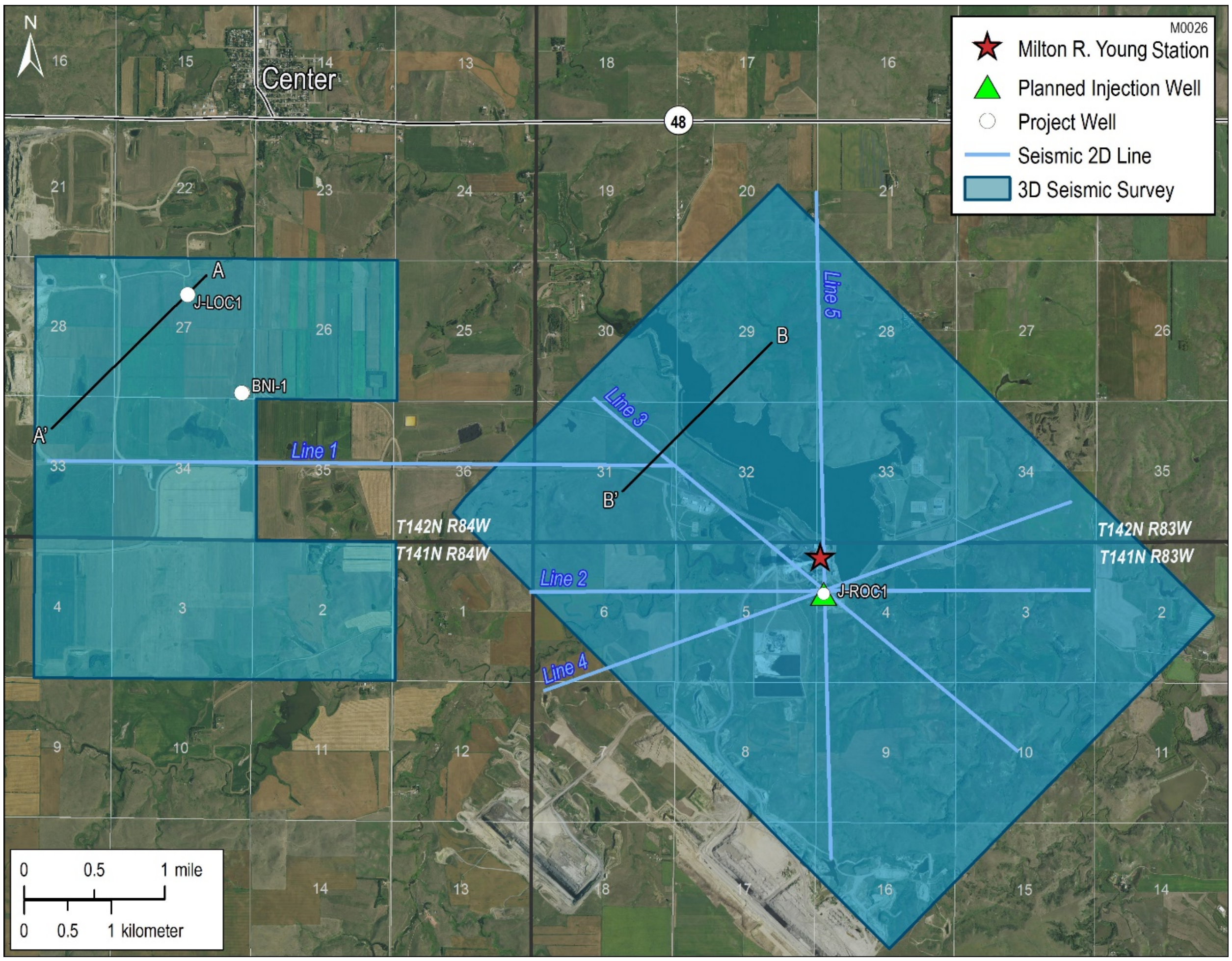

Figure 2-6. Map showing the 2D and 3D seismic surveys in the Tundra SGS area.

3D seismic data sets and ensure consistent interpretation across the entire Tundra SGS area. The seismic data were used for an assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement. Data products generated from the interpretation and inversion of the 3D seismic data were used as inputs into the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 4.0).

The 3D seismic data and J-LOC1 and J-ROC1 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 J-LOC1 and J-ROC1 sonic logs. 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 Black Island/Deadwood storage complex in the Tundra SGS area. There were also no structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Black Island Formation observed in the seismic data.

In addition, the 3D seismic data were used to gain a better understanding of interwell heterogeneity across the Tundra SGS area for petrophysical property distributions. Acoustic impedance volumes were created using the 3D seismic and petrophysical data from the J-LOC1 and J-ROC1 wells (e.g., dipole sonic and density logs) (Figure 2-7). The acoustic impedance volumes were used to classify lithofacies of the Deadwood Formation and distribute lithofacies through the geologic model as well as inform petrophysical property distribution in the geologic model.

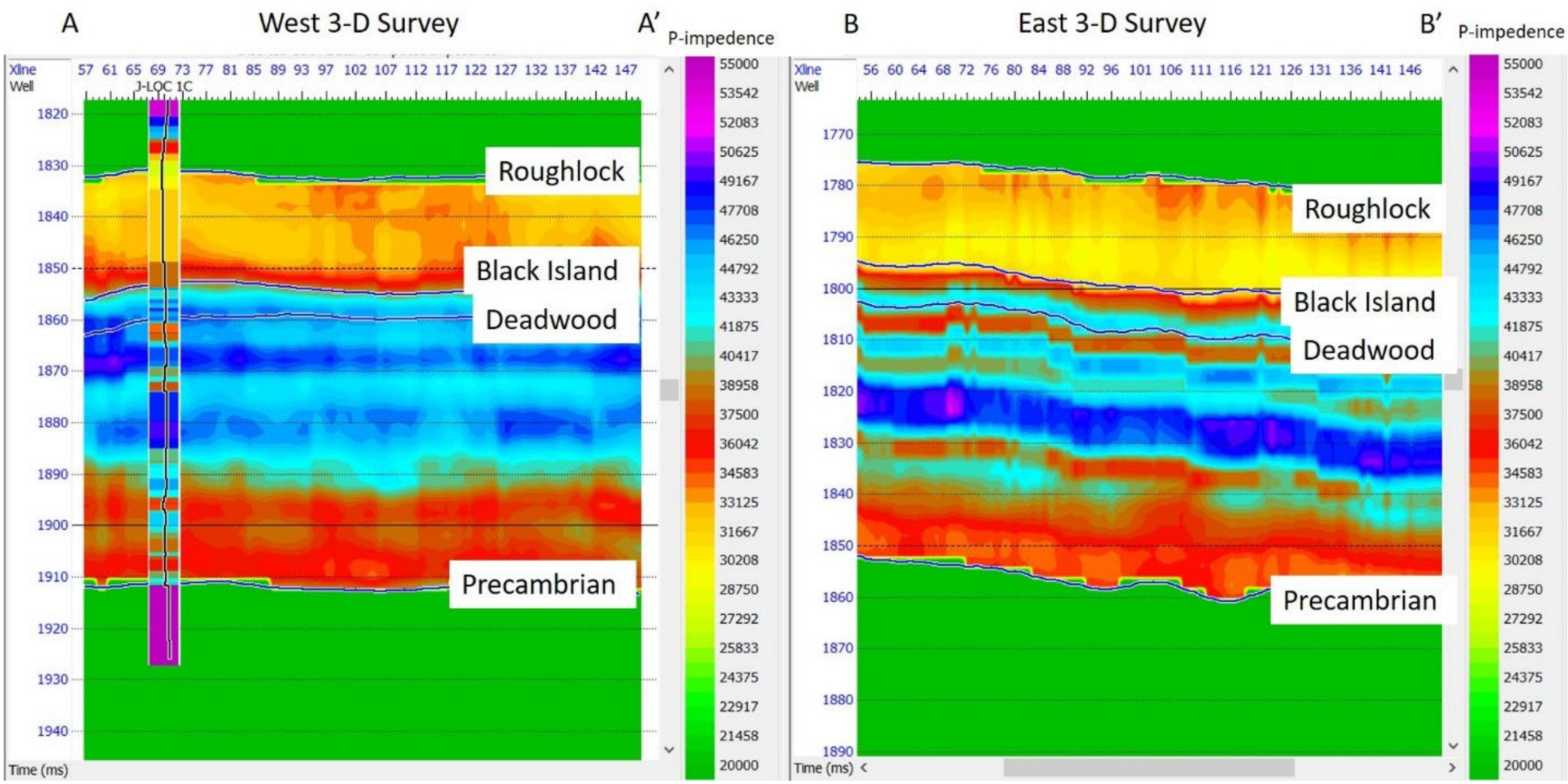

Figure 2-7. Left: cross section of the inverted acoustic impedance volume for the western seismic 3D survey that transects the J-LOC1 well. The acoustic impedance log calculated from the J-LOC1 sonic and density logs is shown on the inset panel. Right: cross section of the inverted acoustic impedance volume for the eastern 3D survey.

2.3 Storage Reservoir (injection zone)

Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3).

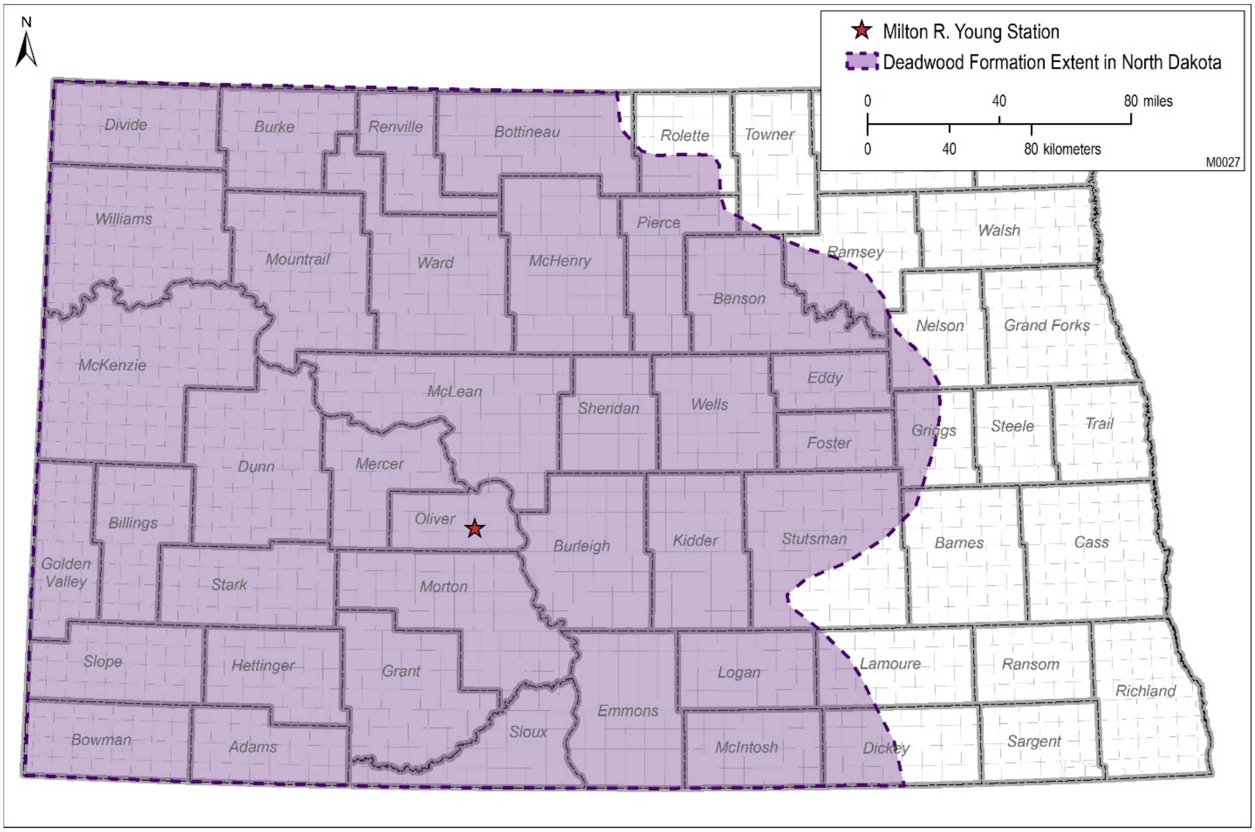

Figure 2-8. Areal extent of the Deadwood Formation in North Dakota (modified from Nesheim, 2012b).

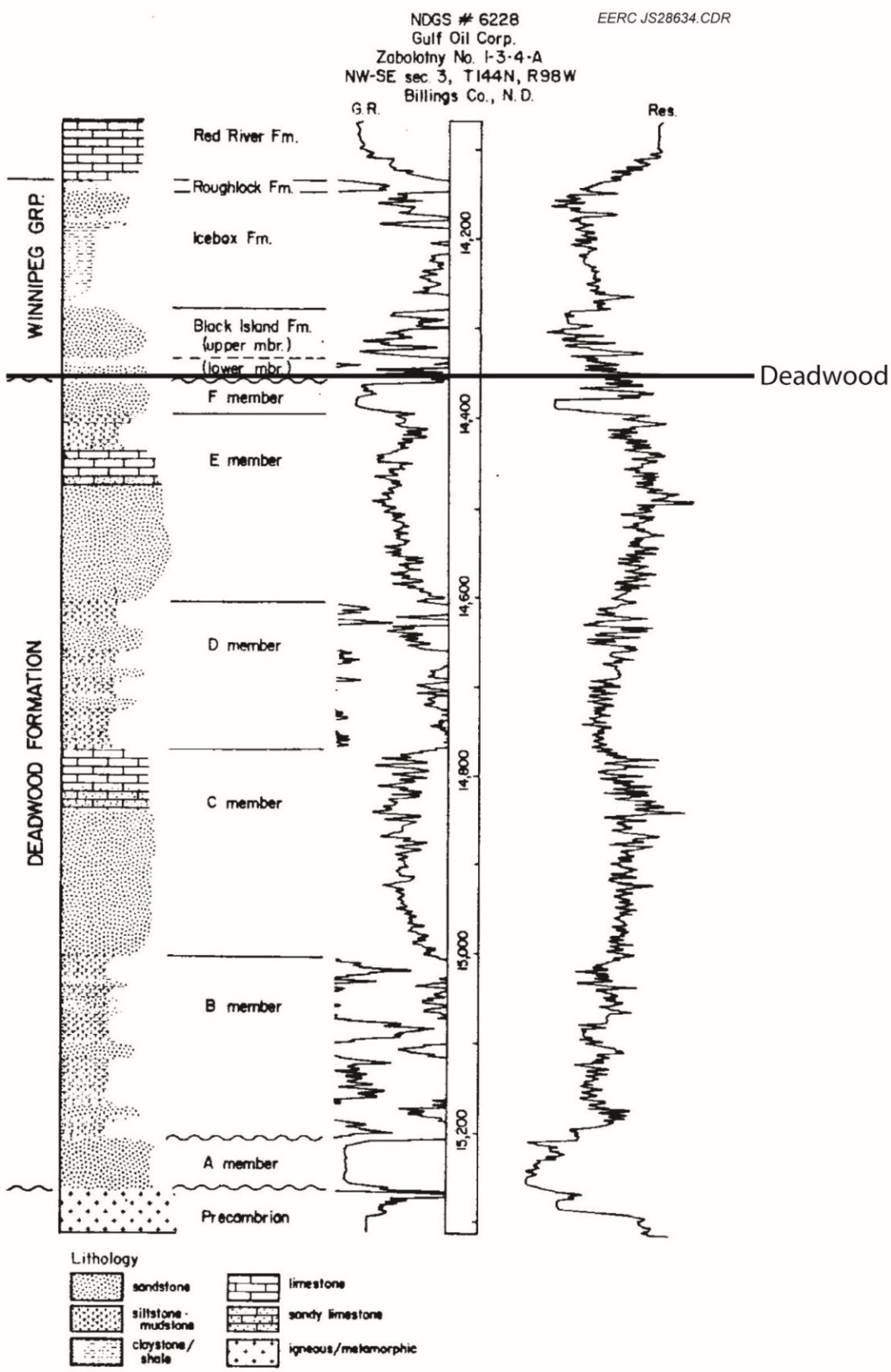

Figure 2-9. Type log showing the interpreted Deadwood members within the Williston Basin (Lefever and others, 1987).

At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10).

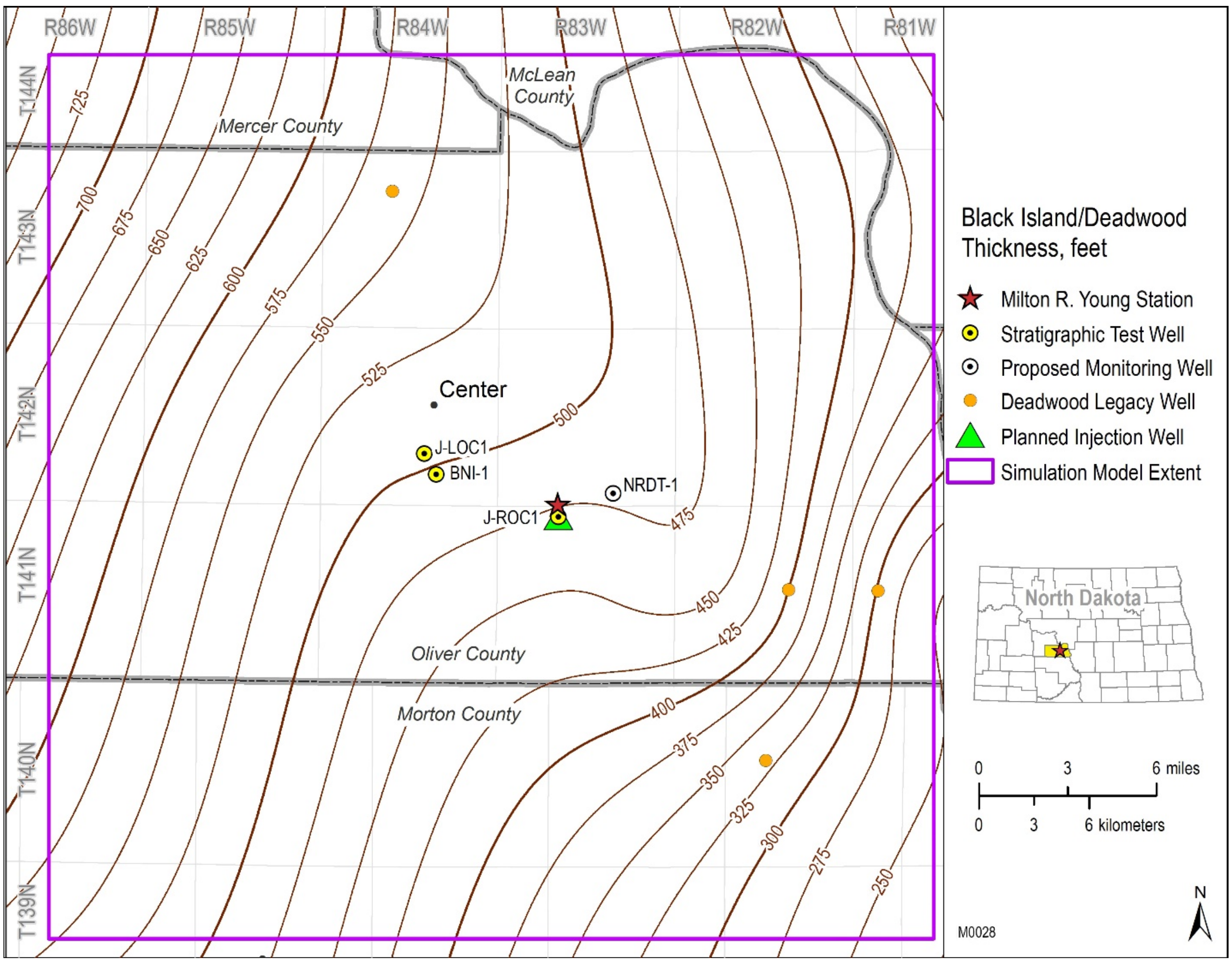

Figure 2-10. Isopach map of the Black Island and Deadwood Formations in the simulation model extent.

The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11):

- The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area.
- The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections.
- The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area.
- The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base.
- The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic.
- The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic.
- The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area.
- The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13).

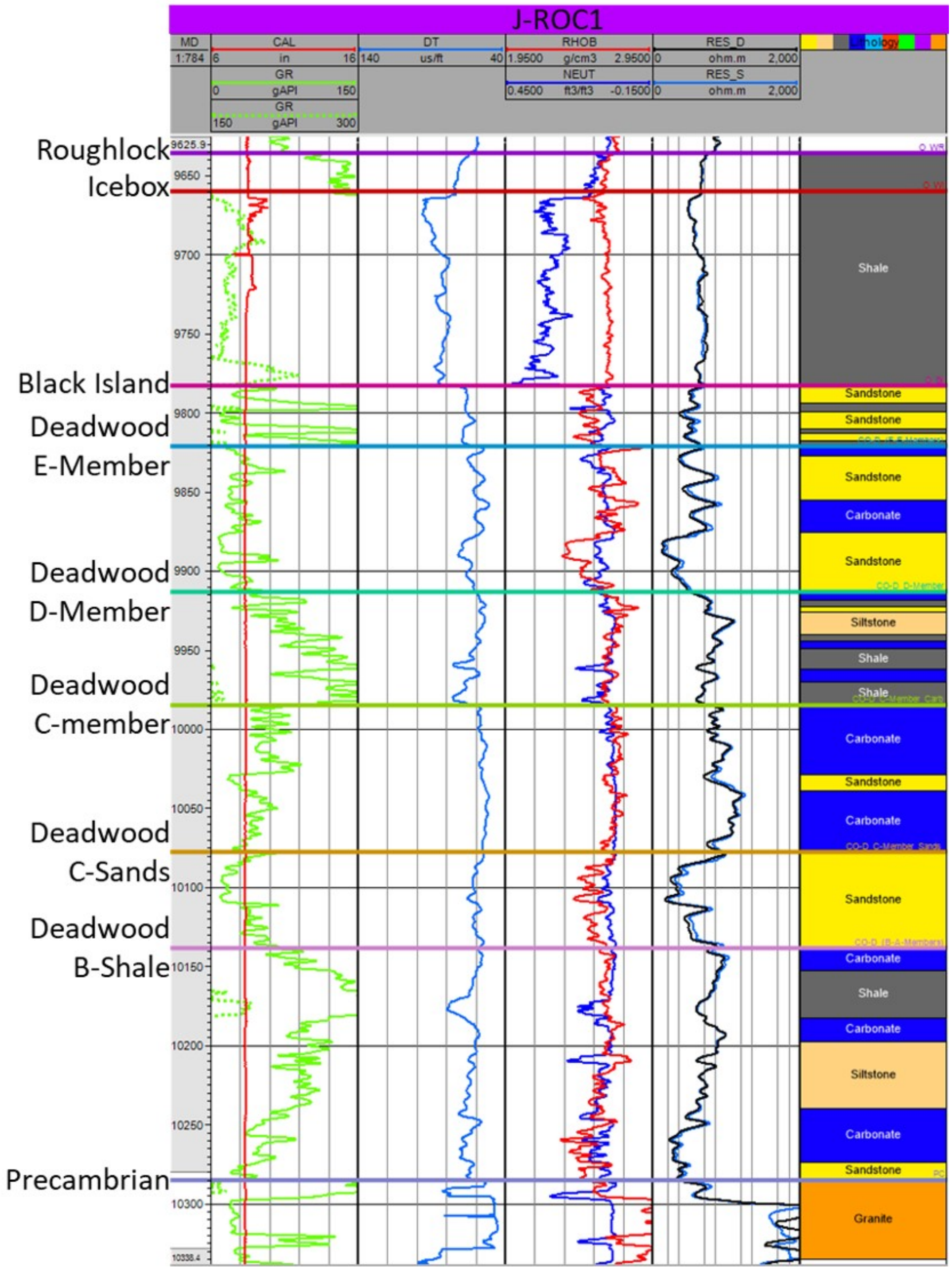

Figure 2-11. Well log display of the interpreted lithologies of the Roughlock, Icebox, Black Island, Deadwood, and Precambrian in J-ROC1.

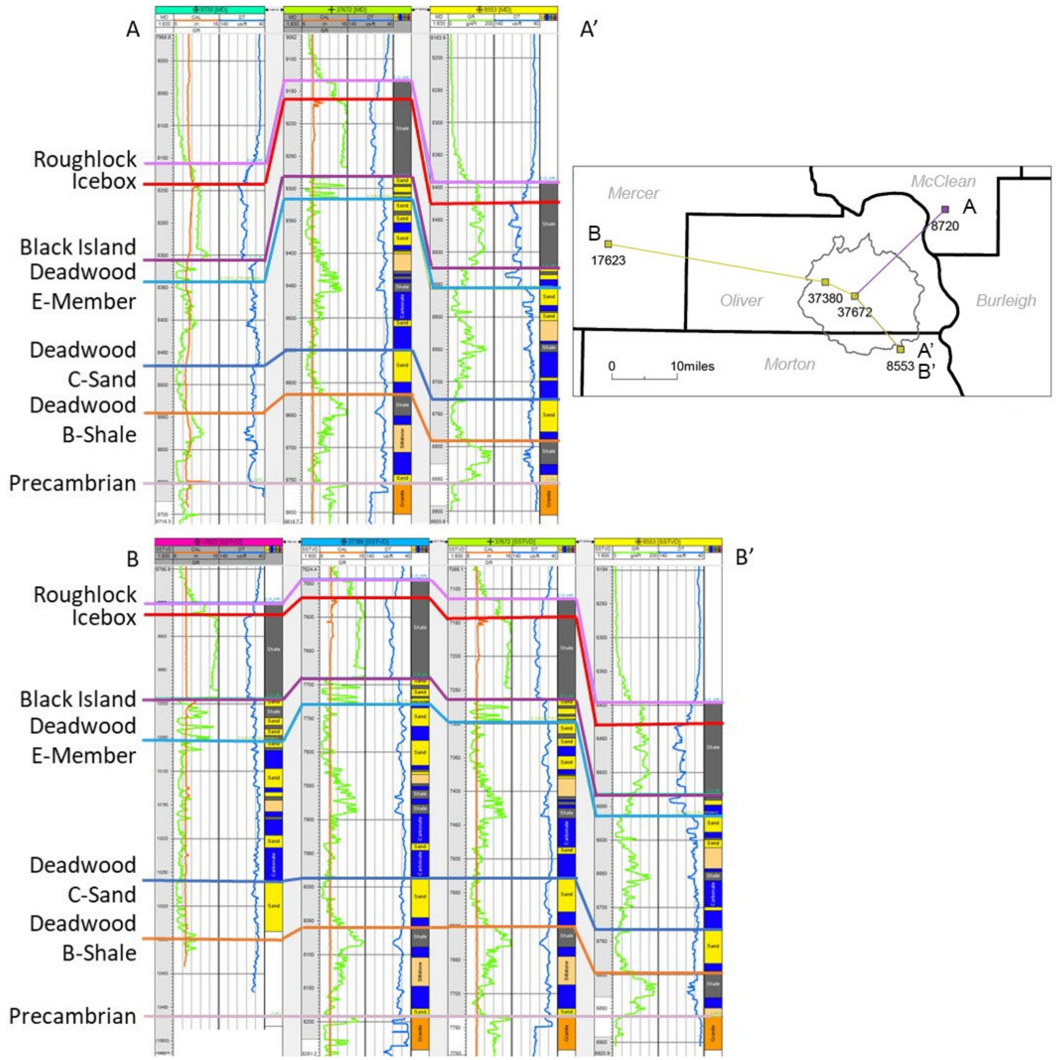

Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), 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.

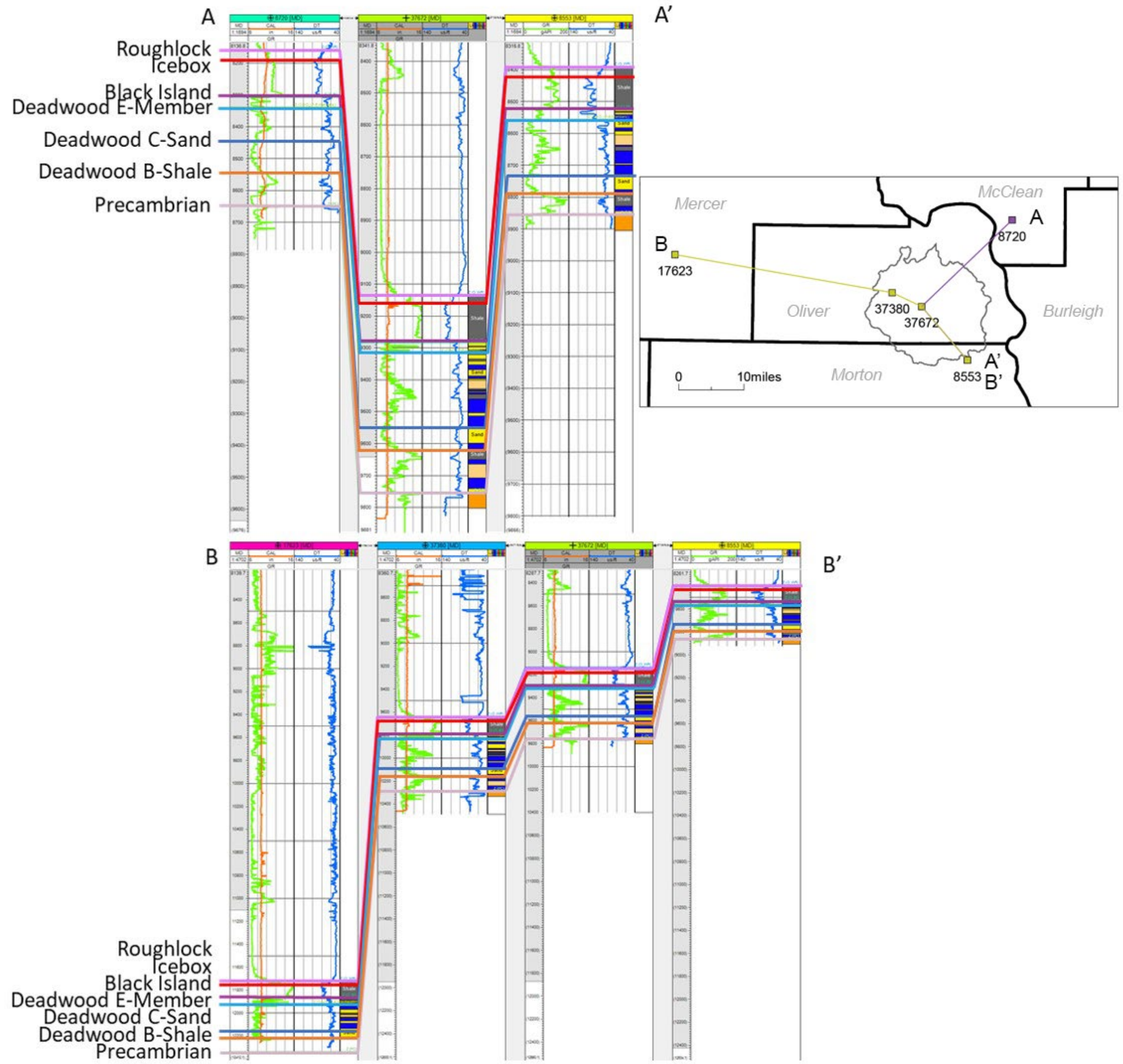

Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue).

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.

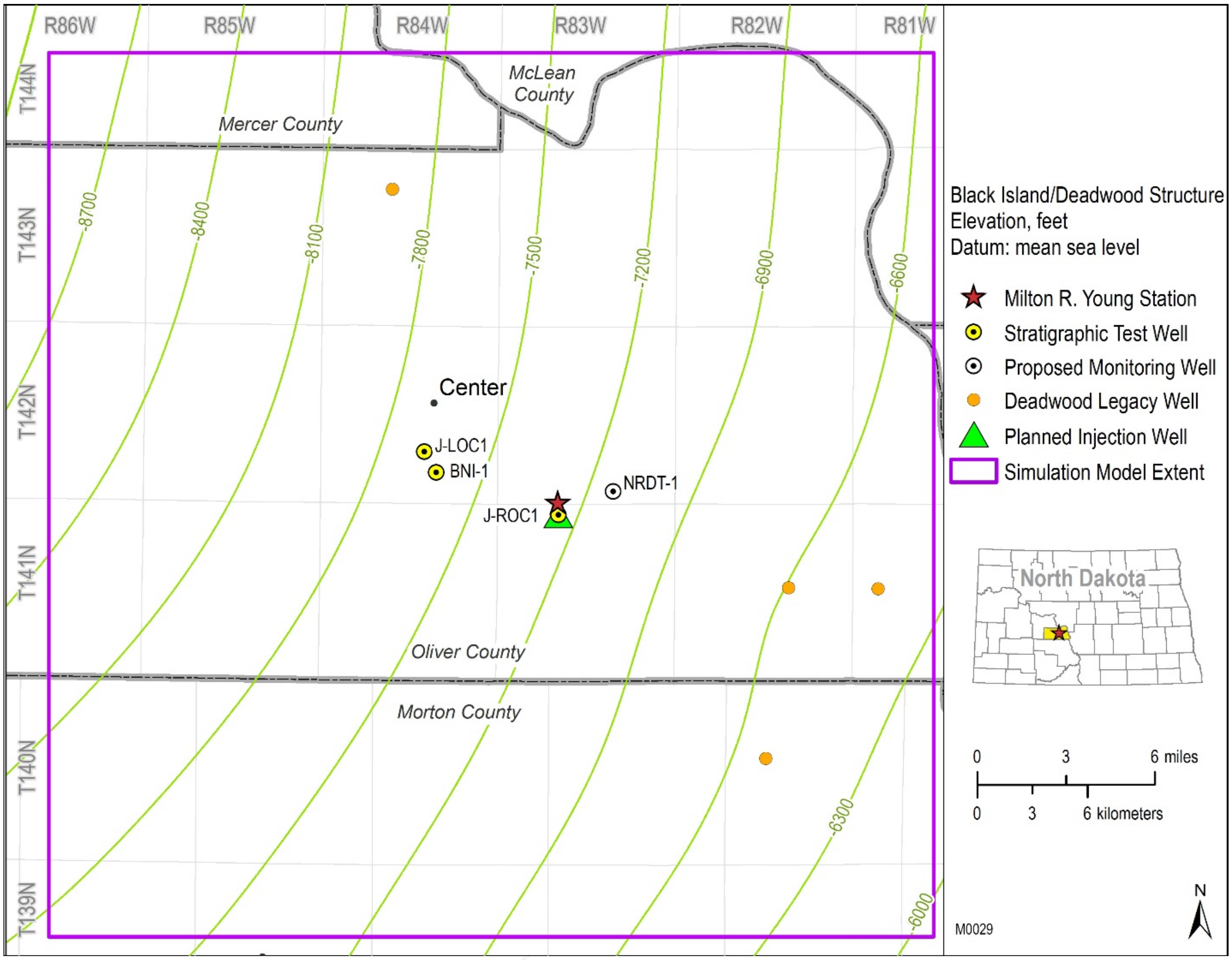

Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent.

Eighty-three 1-in.-diameter core plug samples were taken from the sandstone, limestone, and dolostone lithofacies of Deadwood members and Black Island core retrieved from the J-LOC1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation.

Analysis of eight core samples of Deadwood E member core from J-LOC1 showed porosity values ranging from 6.85% to 14.3% and permeability ranging from 0.0325 to 2,060 mD. Porosity and permeability measurements from the J-LOC1 Black Island core samples (five) have porosity values ranging from 3.4% to 10.3% and permeability ranging from 0.0019 to 157 mD (Table 2-5). The wide range in porosity and permeability reflects the differences between the sandstone, limestone, and dolostone lithofacies in the Deadwood E member.

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Black Island, Deadwood E member, and Deadwood C-sand member
Lithology	Sandstone, dolostone, limestone
Formation Top Depth, ft	9782.2, 9820.9, and 10,077.4
Thickness, ft	38.9, 92.3, and 60.9
Capillary Entry Pressure (CO_2/Brine), psi	0.16

Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Black Island (sandstone)	Porosity, %*	8.0 (3.4–10.3)	5.6 (1.1–14.8)
	Permeability, mD**	3.7 (0.0019–157)	0.805 (<0.0001–96.0)
Deadwood E Member (sandstone)	Porosity, %	10 (6.85–14.43)	7.0 (0–17.7)
	Permeability, mD	5.63 (0.0325–2,060)	3.88 (<0.0001–4549.2)
Deadwood C-Sand Member	Porosity, %	7.6 (1.01–14.69)	7.6 (0.3–17.2)
	Permeability, mD	11 (0.0018–1140)	7.03 (<0.0001–830.3)

* 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.

Analysis of 12 core samples from the sandstone portion of the Deadwood C-sand member core from J-LOC1 showed porosity values ranging from 1.01% to 14.69%, with an average of 7.6%. Permeability of the sandstone samples ranged from 0.0018 to 1,140 mD, with a geometric average of 11 mD (Table 2-5 and Figure 2-14).

Sandstone intervals in the Black Island and Deadwood Formations are associated with low GR, moderate density, average porosity (estimated from neutron, density, and sonic), low resistivity due to high brine salinity, and moderate compressional sonic velocity measurements. The dolostone and limestone intervals in the formation are associated with increased GR measurements compared to the sandstone intervals, in addition to high density, low porosity (estimated from neutron, density, and sonic), relatively high resistivity, and low sonic velocity measurements.

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model (Figure 2-15). The core sample measurements showed good agreement with the wireline logs collected from J-LOC1. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics shown in Table 2-5 were derived from a combination of the core analysis and the larger data set derived from offset well logs. A 5 multiplier for permeability was applied to the geologic model based on injection test results (Appendix A).

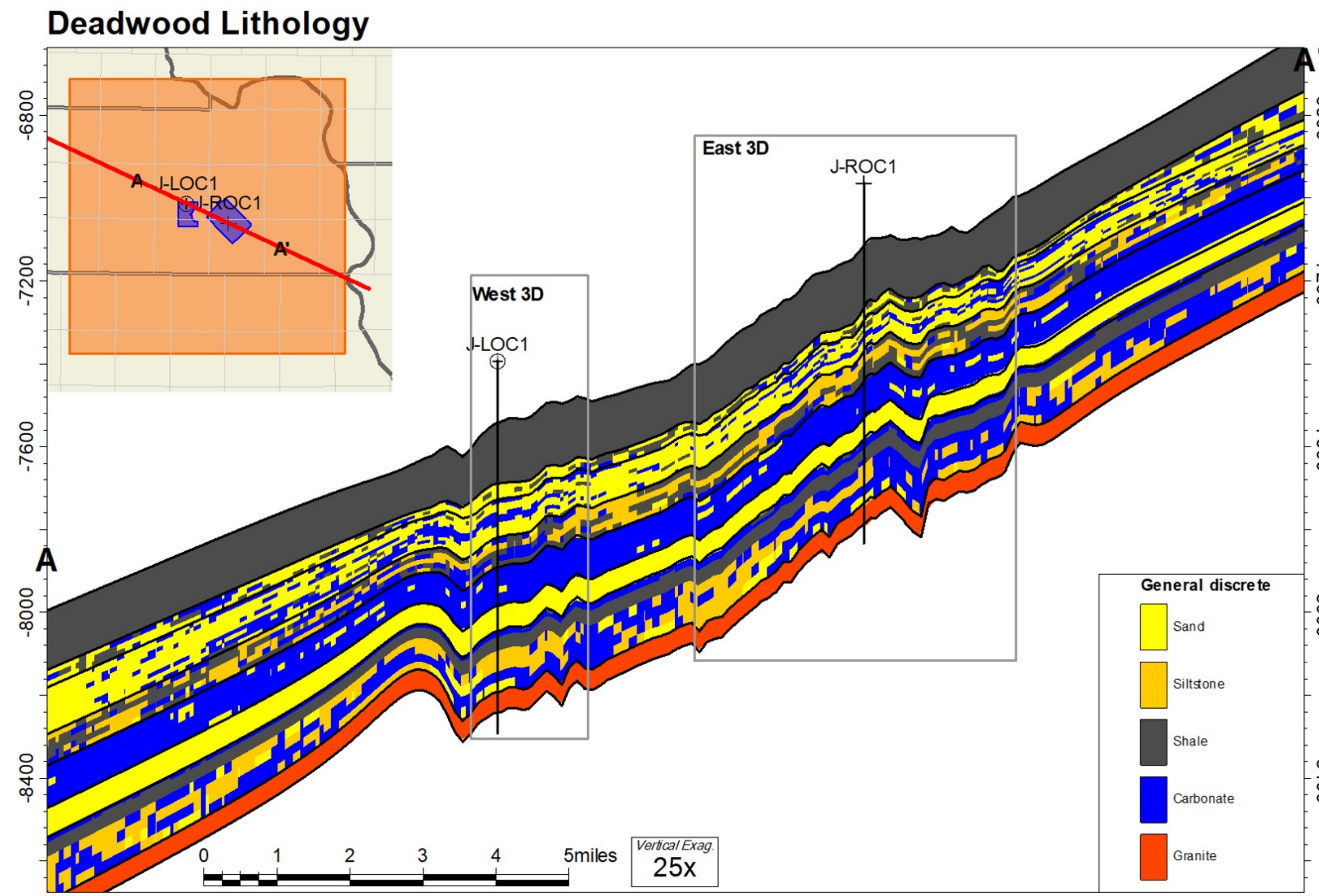

Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level.

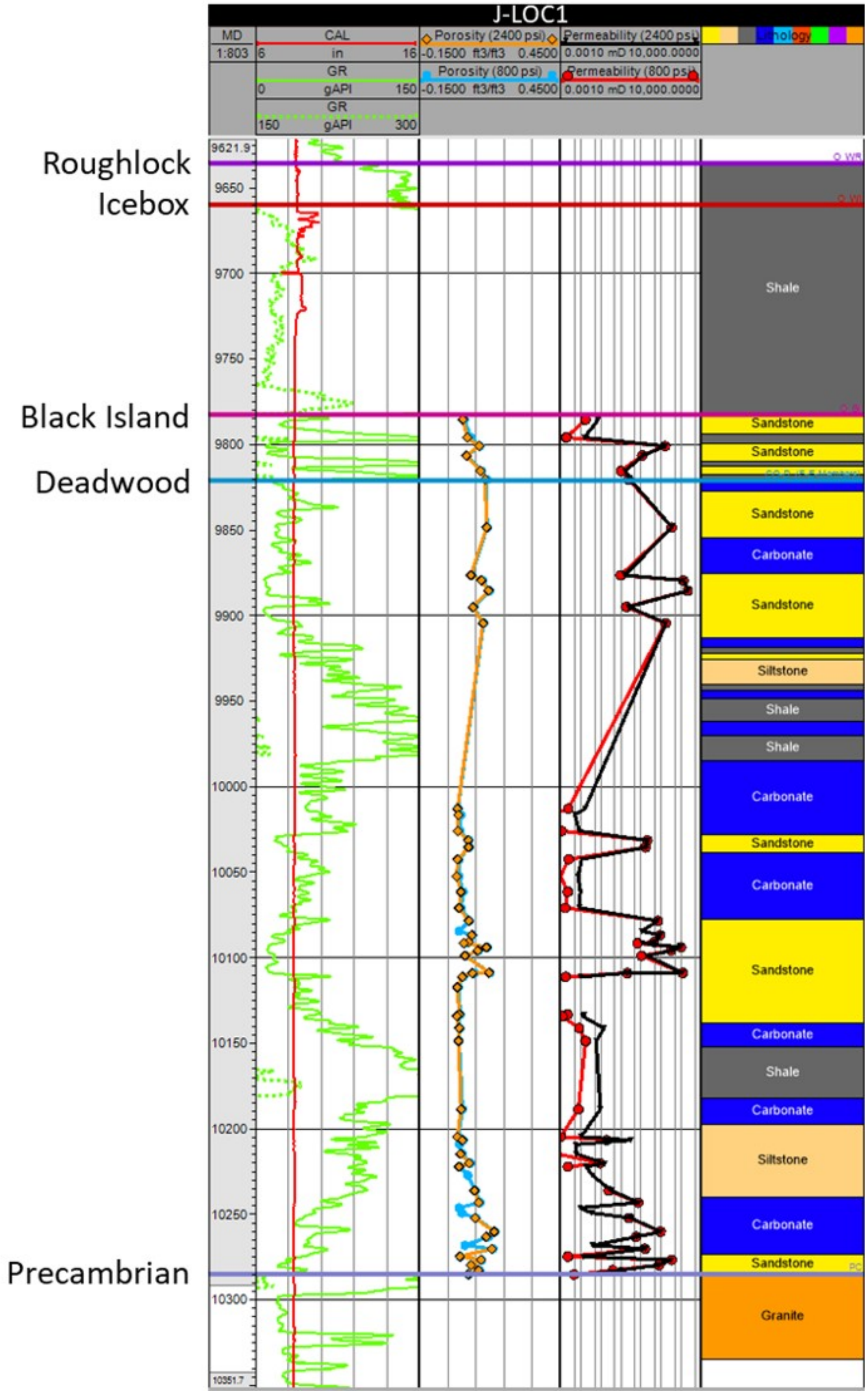

Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex.

Pressure testing in the Deadwood Formation included a total of four formation pressure measurements via an MDT tool in J-LOC1. All tests resulted in good agreement, with reservoir pressures recorded that ranged from 4,548.27 to 4,734.49 psi. These pressures were used to derive a pressure gradient of 0.46 psi/ft. This pressure gradient was used to calculate a formation pressure profile for use in the numerical simulations of CO_2 injection.

A microfracture in situ test was performed within the Deadwood Formation via the Schlumberger MDT tool in the J-LOC1 well. The test was conducted 64.14 ft below the top of the formation. The results of this test are shown in Table 2-6, with a supporting graph for derivation of averages in Figure 2-16.

Table 2-6. Deadwood Microfracture Results from J-LOC1

Depth, ft	9,885.1	
Pressure/Gradient	psi	psi/ft
Breakdown	8,231	0.833
Avg. Fracture Propagation	7450	0.754
Avg. Closure	7,393.55	0.748

The measured temperature of the Deadwood Formation in J-LOC1 was 181.44°F at a depth of 10,087.5 ft. Using an average surface temperature of 40°F, the resulting temperature gradient for the Deadwood Formation is 0.01°F/ft.

$$\frac{181.44°\text{F} - 40°\text{F}}{10087.5\text{ ft}} = 0.01°\text{F/ft} \qquad \text{[Eq. 1]}$$

Fluid samples collected via an MDT tool in J-LOC1 from the Deadwood Formation were analyzed by a state-certified lab and confirmed by the EERC. A description of the fluid sample is found in Section 2.2.2.5.

2.3.1 J-LOC1 Injectivity Tests

The J-LOC1 formation well testing was performed specifically to characterize the injectivity and obtain the breakdown pressure of the Deadwood Formation in December 2020. The well testing consisted of step rate test, extended injection test, and pressure fall-off test. The well was perforated from 9,880 to 9,890 ft with 4 shots per foot (spf) and 90° phasing. To record the bottomhole pressure, a downhole memory gauge was installed at a depth of 9,855 ft. The well test data were interpreted by GeothermEx, a Schlumberger Company.

The step rate test was performed with a total of ten injection rates. The initial injection rate was 2.00 barrels per minute (bpm), and the final injection rate was 10.5 bpm. From the step rate test evaluation, no definitive analysis can be concluded from this test, but injection at the higher rate was below fracture opening pressure. Figure 2-17 provides the step rate test data of the Deadwood Formation.

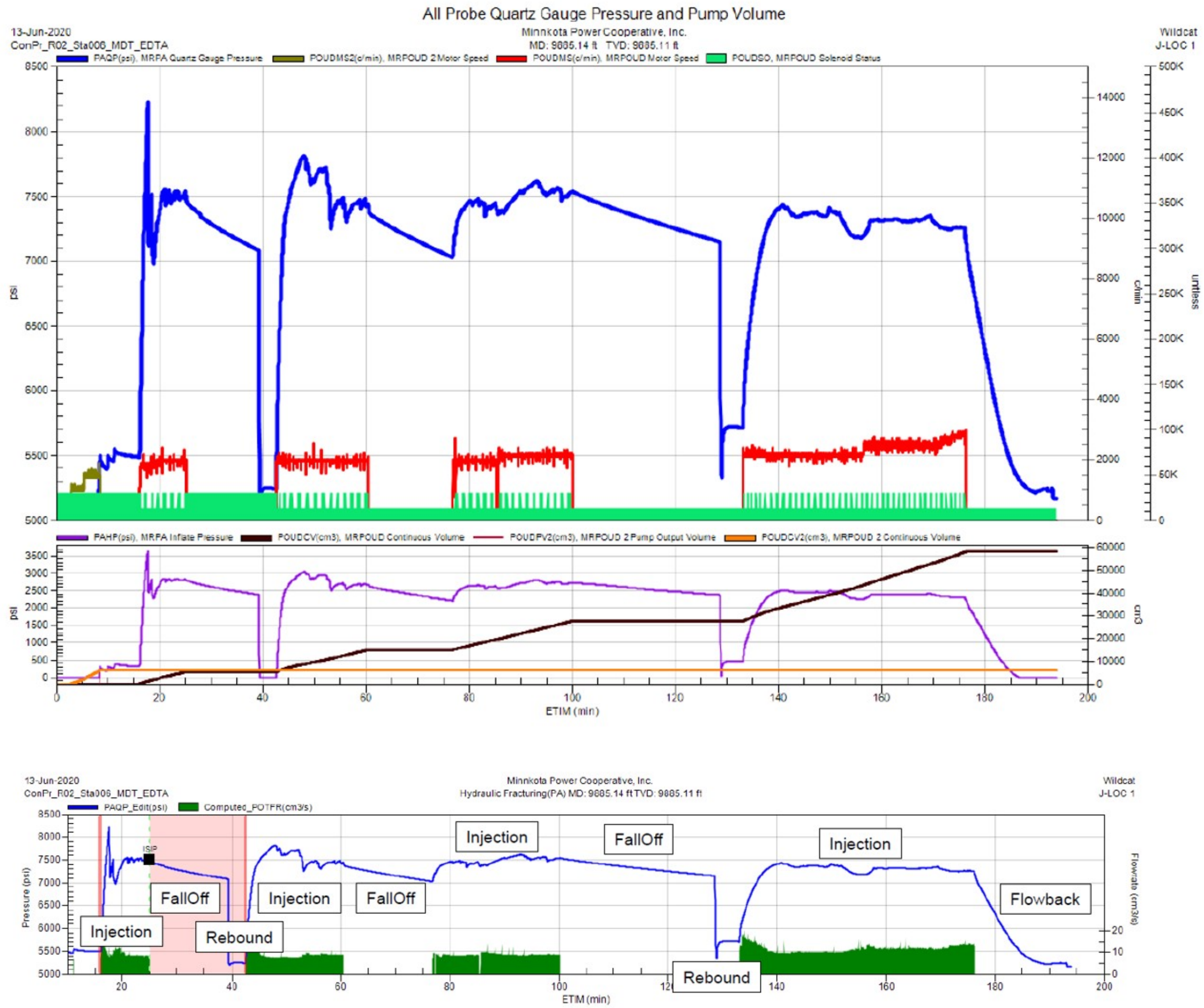

Figure 2-16. J-LOC1 Deadwood Formation MDT microfracture in situ stress pump cycle graph at 9,885.1 ft.

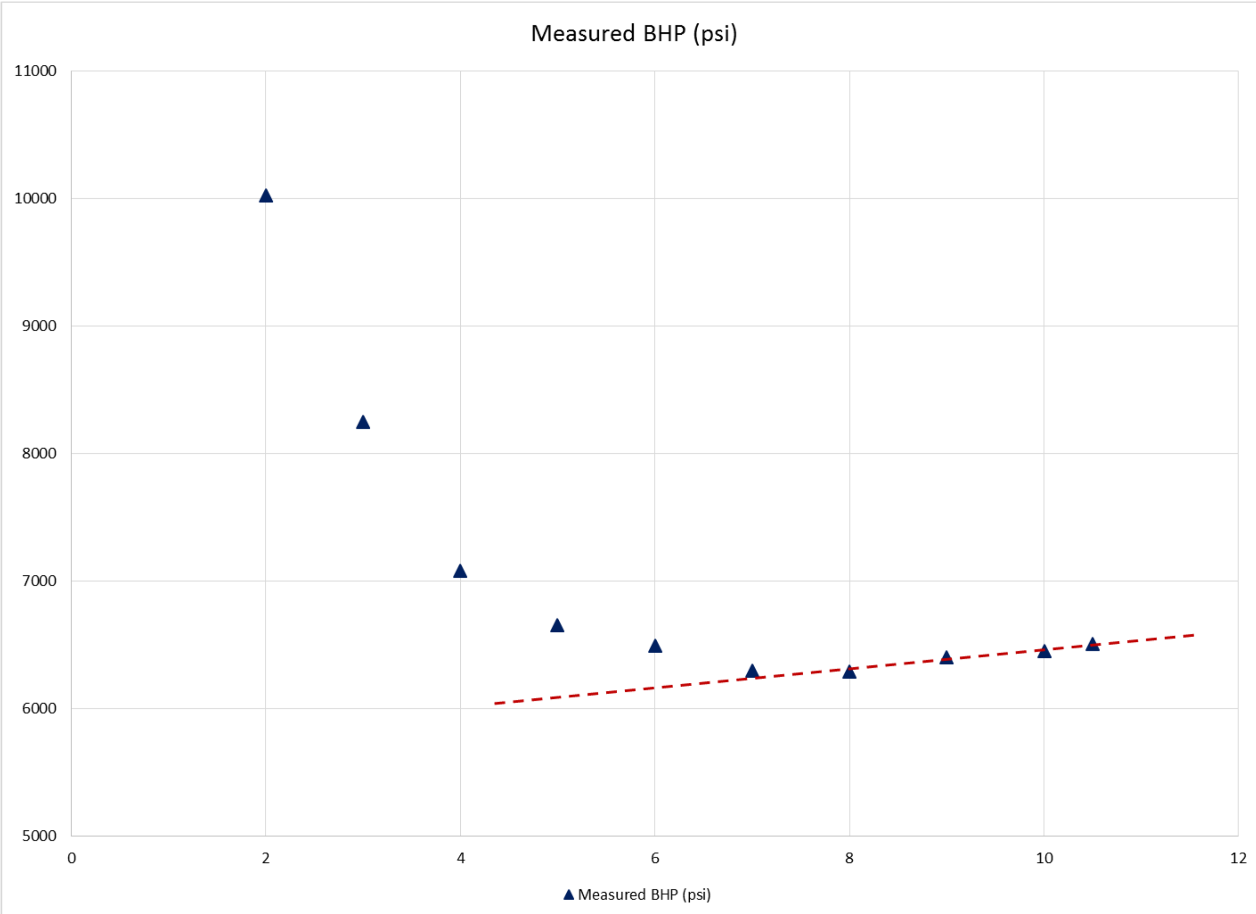

Figure 2-17. Step rate test data from the Deadwood Formation with no fracture opening pressure observed (courtesy of GeothermEx, a Schlumberger Company). The x-axis is injection rate in bpm while the y-axis is bottomhole injection pressure in psi.

A 12-hour extended injection rate was performed at a constant rate of 4.5 bpm followed by a 24-hour pressure fall-off test. The pressure fall-off data interpretation showed a permeability of 1,621 mD, with reservoir pressure of 4,521 psi. There was no lateral boundary observed from the pressure fall-off test within the radius of investigation of 9,183 ft, as shown in Figures 2-18 and 2-19. The Deadwood Formation well testing is summarized in Table 2-7.

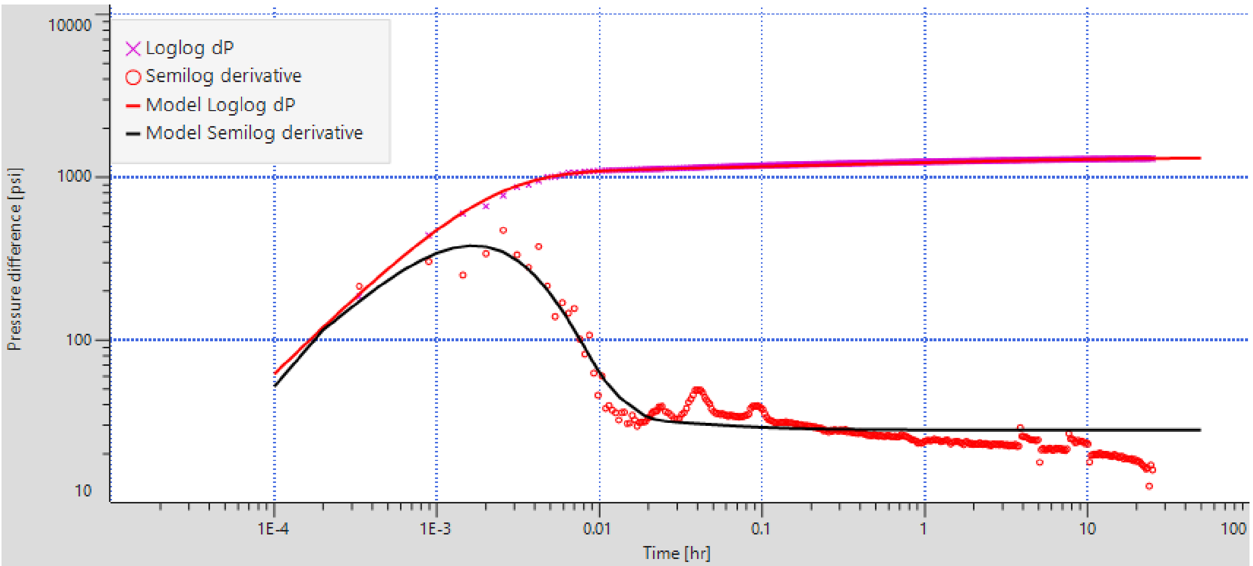

Figure 2-18. GeothermEx interpretation of the Deadwood Formation pressure fall-off test using Saphir – Kappa (courtesy of GeothermEx, a Schlumberger Company).

Formation	**Deadwood**
Perforation Interval (ft)	9,880 to 9,890
Estimated Formation Thickness (ft)	10
Tested Interval Thickness (ft)	10
Formation Transmissibility (mD.ft)	16,213
Formation Permeability (mD)	1,621
Skin Factor	13
Investigation Radius (ft)	9,183
Boundary Condition	Infinite Acting
Comments	Quality PFO test, good confidence in formation parameters assessed. Step rate test uninterpretable due to near well properties rapidly changing.

Figure 2-19. Deadwood well test summary of J-LOC1 well (modified from Schlumberger's presentation).

Table 2-7. J-LOC1 Deadwood Formation Test Summary

Parameters	Value	Unit
Reservoir Pressure	4,521	psi
Permeability	1,621	mD
Radius of Investigation	9,183	ft
Type of Boundary	Infinite acting	

2.3.2 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Deadwood Formation is composed of fine- to medium-grained sandstone and several interbeds of carbonates (dolostone and limestone). Seventy-eight depth intervals representing nearly 274 ft of the Deadwood Formation were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment below, thin sections and XRD provided an independent confirmation of the mineralogical constituents of the Deadwood Formation.

Thin-section analysis of the sandstone intervals shows that quartz (85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (5%), dolomite (5%), and calcite as cements (5%). Where present, calcite and dolomite are crystallized between quartz grains and obstruct the intercrystalline porosity. The contact between grains is long (straight) to tangential. The porosity due to quartz and feldspar dissolution ranges from 5% to 14%.

Four distinct carbonate intervals are notable. The first is the presence of a fine- to medium-grained dolostone (80%), with quartz of variable size and shape (10%) and calcite (10%) present. The porosity is not well-developed, averaging 5%. Diagenesis is expressed by dolomitization of the original calcite grains and dissolution of quartz 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 limestone (80%), dolomite 10%, and quartz (10%). Diagenesis is expressed by dolomitization of the original calcite grains. The porosity is mainly fracture-related and averages 2%.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Deadwood Formation core primarily comprises quartz, feldspar, dolomite, calcite, anhydrite, clay, and iron oxides (Figure 2-20).

XRF data are shown in Figure 2-21a and 2-21b for the Black Island and Upper Deadwood Formations. As shown, the majority of the Upper Deadwood sandstone, calcite, and dolomite intervals are confirmed through the high percentages of SiO_2, CaO, and MgO. The presence of certain percentages of CaO and SO_3 at 10,077 ft indicates a presence of anhydrite as cement. The formation shows very little clay, with a range of 0.5% to 10% being the highest detected.

2.3.3 Mechanism of Geologic Confinement

For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Deadwood Formation will be the cap rock (Icebox interval), 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), confining the CO_2 within the proposed storage reservoir, as identified in Figure 2-3. 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 (>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; therefore, this process 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.

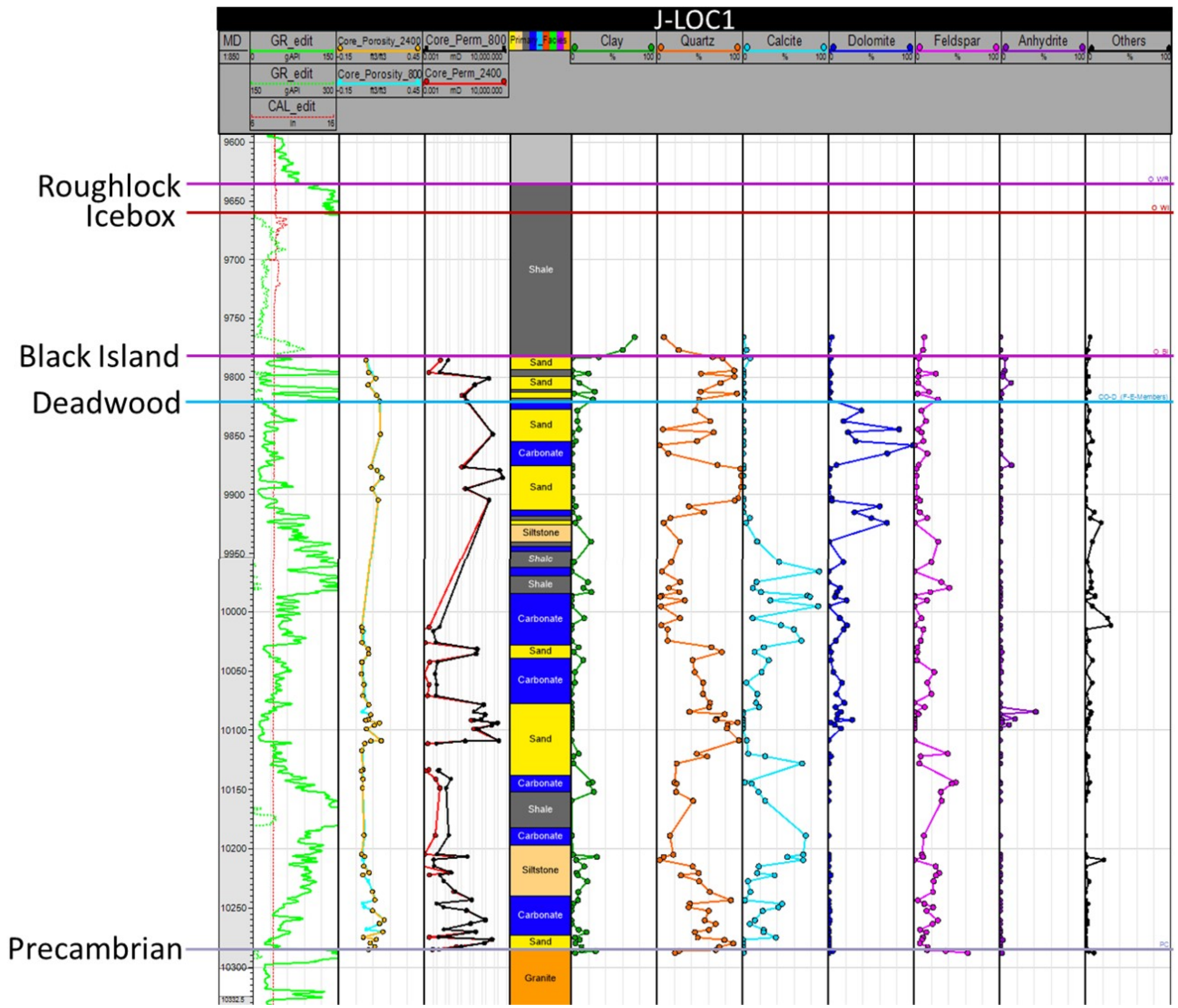

Figure 2-20. Laboratory-derived mineralogic characteristics of the Black Island and Deadwood Formations.

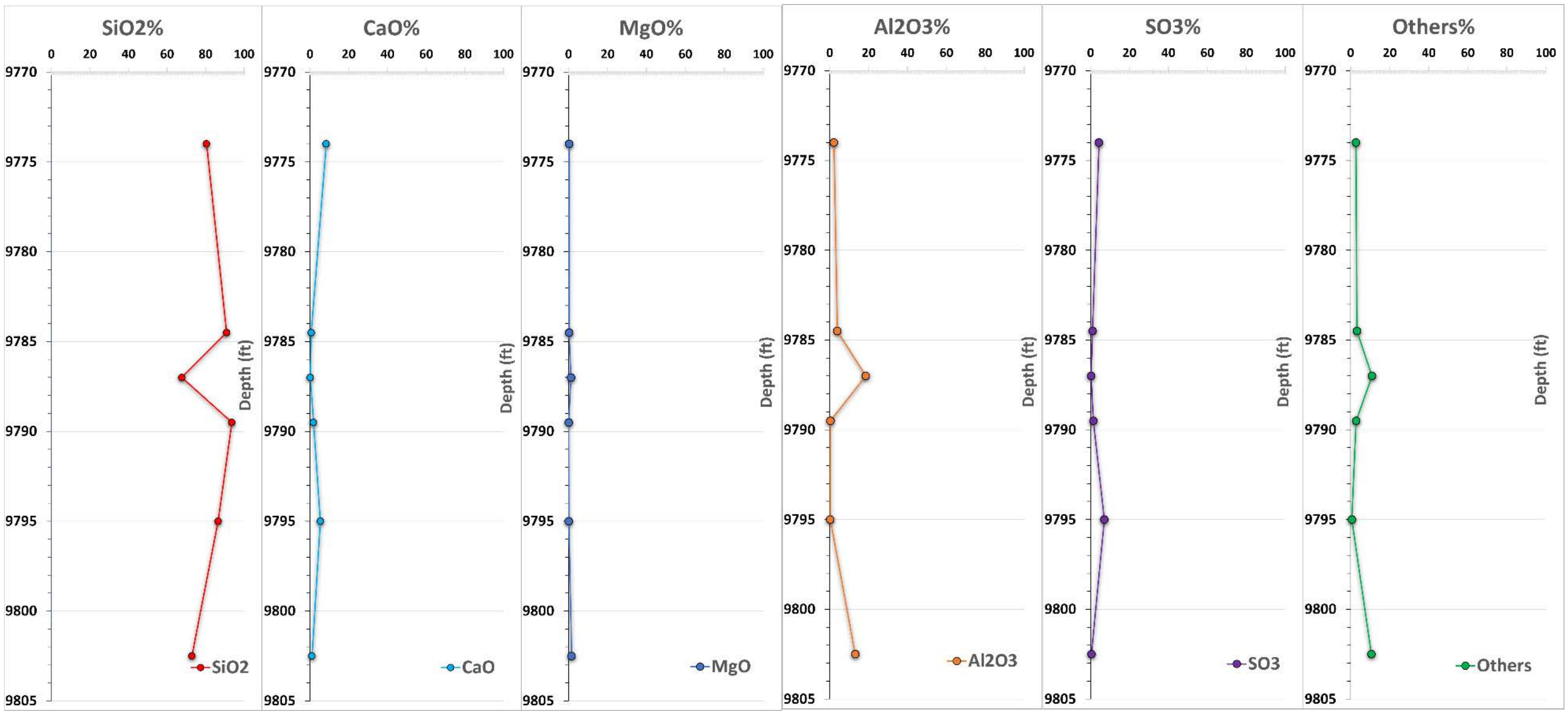

Figure 2-21a. XRF data from the Black Island Formation from J-LOC1.

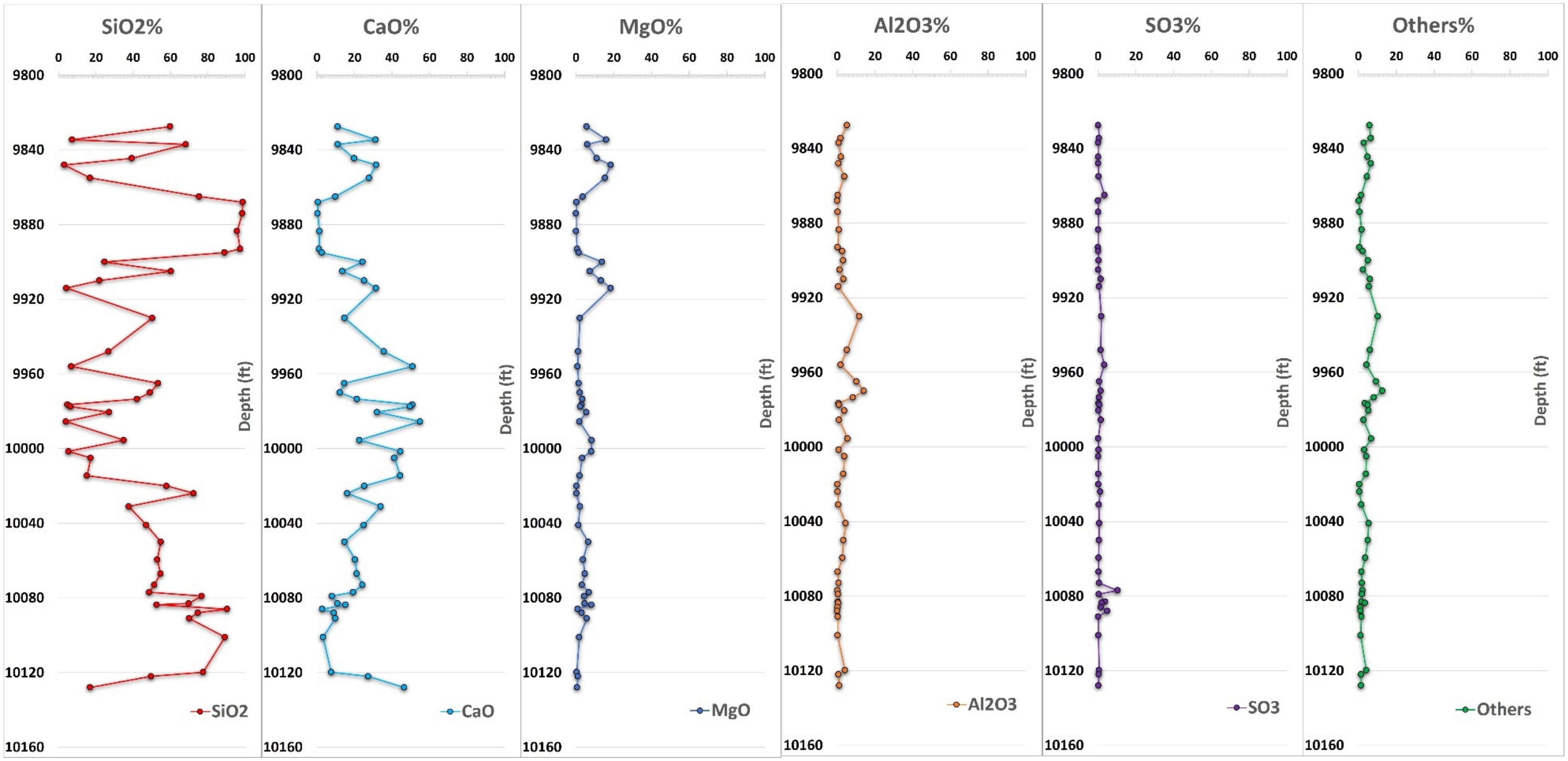

Figure 2-21b. XRF data from the Upper Deadwood Formation, including the C, D, and E members from J-LOC1.

2.3.4 *Geochemical Information of Injection Zone*

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

The injection zone, the Upper Deadwood sands and Black Island 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 injection scenario was rerun with the geochemical analysis option included, and the differences were compared to the scenario that was run without the geochemical option included. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful change to storage reservoir performance or mechanical properties of the storage formation.

The geochemistry case was constructed using the injection case simulation inputs and assumptions as well as honoring the average mineralogical composition of the Deadwood Formation rock materials (94% of bulk reservoir volume) and average formation brine composition (6% of bulk reservoir volume). XRD data from the JLOC-1 well core samples were used to inform the mineralogical composition of the Deadwood Formation used in the geochemical modeling (Table 2-8). The ionic composition of the formation water is listed in Table 2-9. The injection stream composition remained the same as the injection case simulation, assumed as 100% CO_2. The injection stream is expected to be 99.9% CO_2. The other constituents represent 0.1% in the stream and likely include nitrogen (N_2) and water vapor (H_2O). However, 100% CO_2 was assumed for computational efficiency in the geochemical simulation to investigate rock and fluid interaction in the saline storage formation. N_2 is known to be an inert gas, and water is already in the saline storage formation and will have little to no impact on the geochemical reactions. In the injection stream, argon (Ar) and oxygen vapor (O_2) may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation. The geochemistry case was run for the 20-year injection period followed by 94 years of postinjection shutdown and monitoring.

Table 2-8. XRD Results for JLOC-1 Deadwood Formation Core Samples

Mineral Data	Average %
Calcite	25.85
Dolomite	12.78
Quartz	32.94
Illite	4.7
K-Feldspar	8.54
Anhydrite	5.18
Ankerite	3.97
Other	6.04

Table 2-9. Deadwood Formation Water Ionic Composition, expressed as molality

Component	Molality
SO_4^{2-}	4.47E-3
K^+	0.03995
Na^+	3.58711
Ca^{2+}	0.17864
Mg^{2+}	0.02652
Fe^{2+}	3E-04
H^+	1.8836E-6
Cl^-	4.27731
HCO_3^-	0.03995
Al^{3+}	1E-05
SiO_2(aq)	1.0E-08

Figure 2-22 shows that reservoir performance results for the two cases are slightly different. As a result of geochemical reactions in the reservoir, there is an approximately 8% increase in cumulative injection potential. Wellhead injection pressure is slightly lower for the geochemistry case. Figure 2-23 shows the concentration of CO_2, in molality, in the reservoir after 20 years of injection. The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-24. The pH of the Deadwood native brine is 5.7 whereas the fluid pH declines to approximately 4.0 in the CO_2-flooded areas.

Figure 2-25 shows the mass of mineral dissolution and precipitation due to geochemical reactions in the model. Illite is the most prominent dissolution mineral, followed by anhydrite. Illite and anhydrite dissolution slows after Year 2042, the year in which injection ends. K-feldspar dissolves during the injection period but slowly begins to reprecipitate in the near-wellbore areas after injection. Calcite, quartz, and dolomite are the primary precipitation minerals. There is a small amount of net dissolution during the simulation period as somewhat larger quantities of minerals are dissolved rather than precipitated. Slow net dissolution continues after the injection period. Figures 2-26 and 2-27 provide an indication of the change in distribution of the mineral that has experienced the most dissolution (illite) and the mineral that has experienced the most precipitation (calcite), respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-25, there is an associated net increase in porosity of the affected area, as shown in Figure 2-28. However, the porosity change is small, less than 0.1% porosity units, equating to a maximum increase in average porosity from 6% to 6.1% after the 20-year injection period.

Results of the simulation show that geochemical processes will be at work in the Deadwood Formation during and after CO_2 injection. Mineral dissolution and some reprecipitation are expected to occur during the simulated time span of 114 years. Fluid pH will decrease in the area of the CO_2 accumulation from 5.7 to approximately 4.0, and there will be a slight net increase in system porosity. However, these changes create relatively small changes in reservoir performance parameters such as injection rate or wellhead injection pressure.

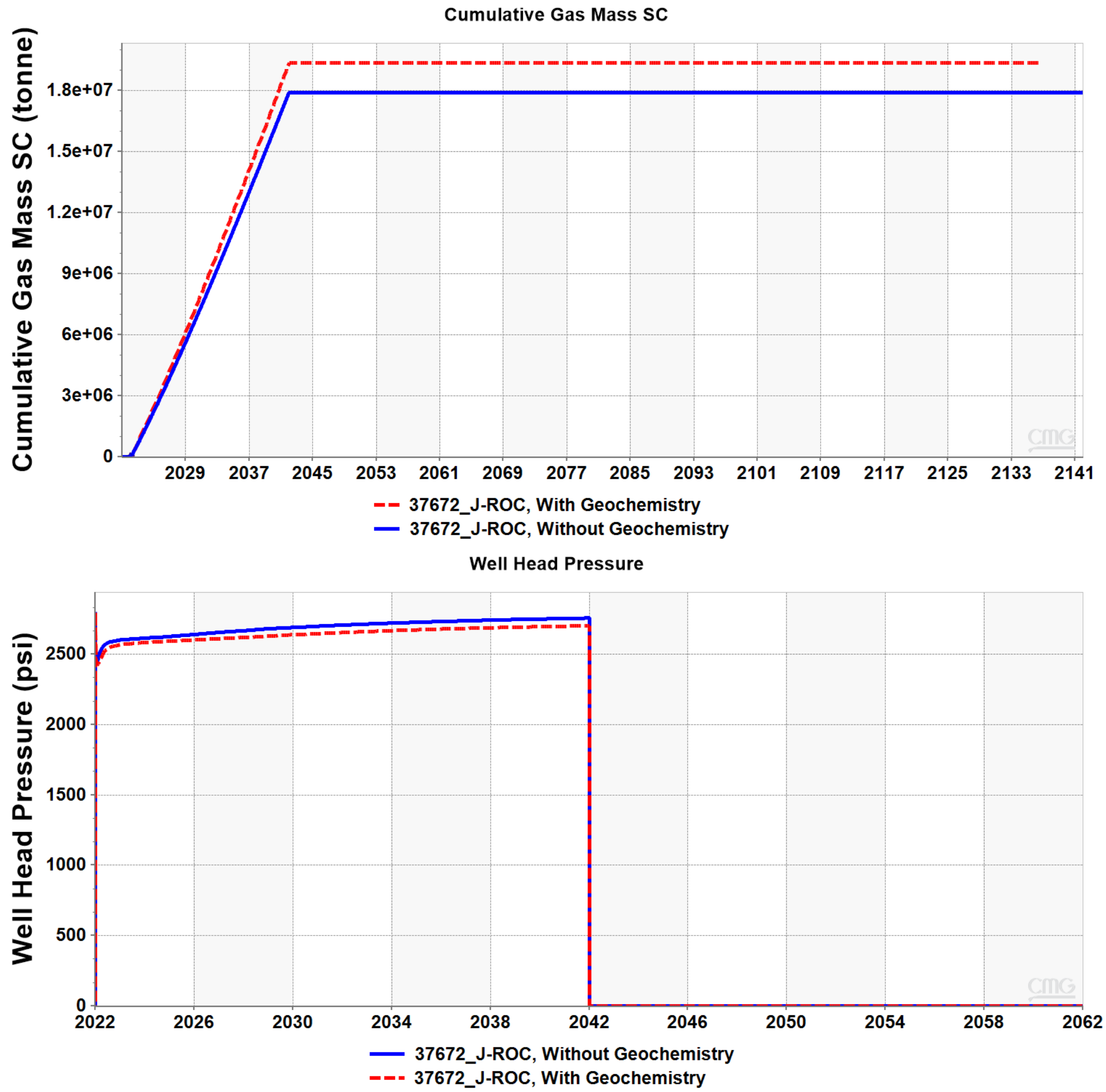

Figure 2-22. The upper graph shows cumulative injection vs. time. There is an increase in injection due to geochemical reactions. The lower graph shows wellhead injection pressure for the geochemistry case is slightly lower than for the injection case without geochemistry.

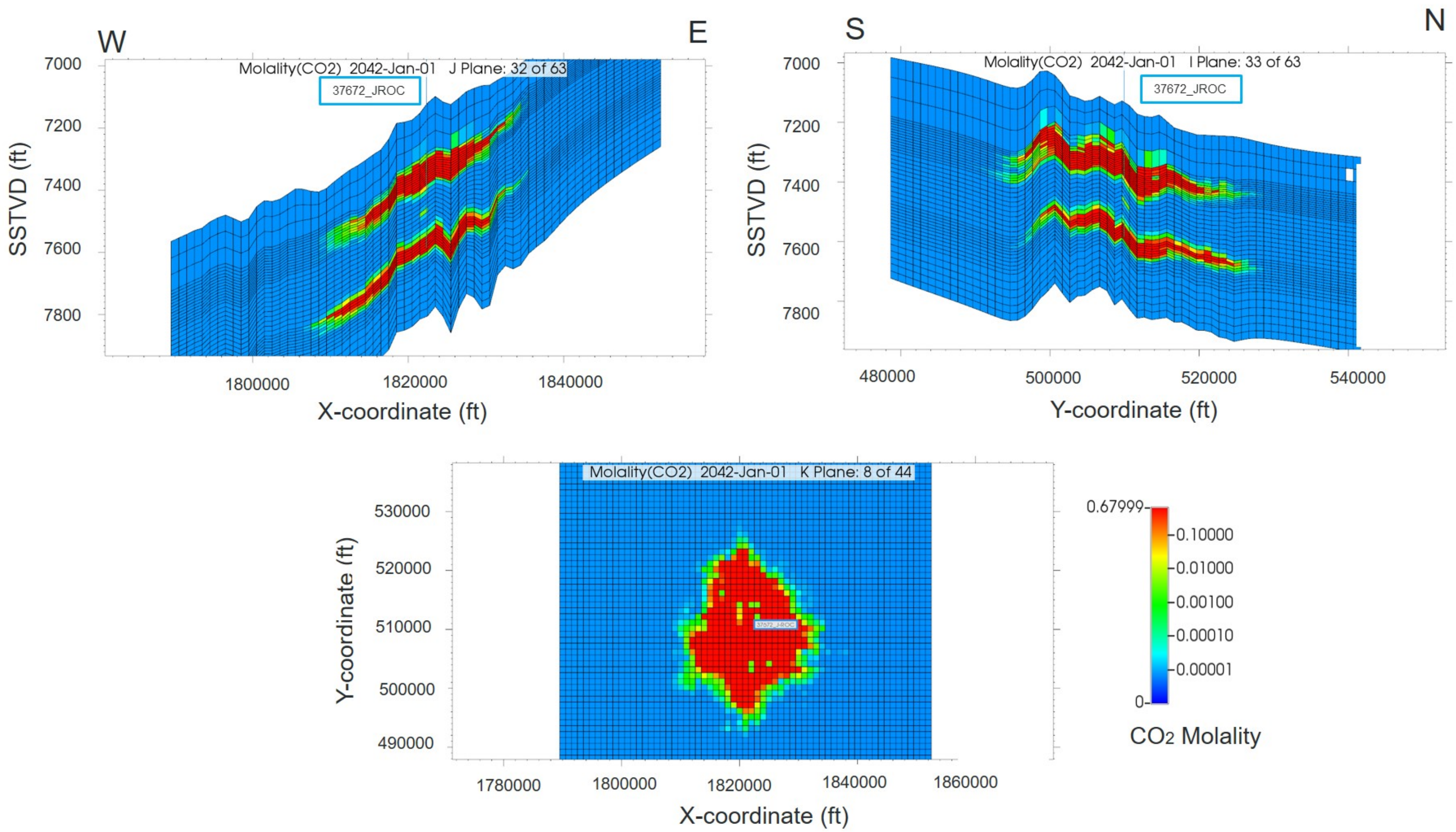

Figure 2-23. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality. Upper images are west–east and north–south cross sections. Lower image is a planar view of Simulation Layer 8.

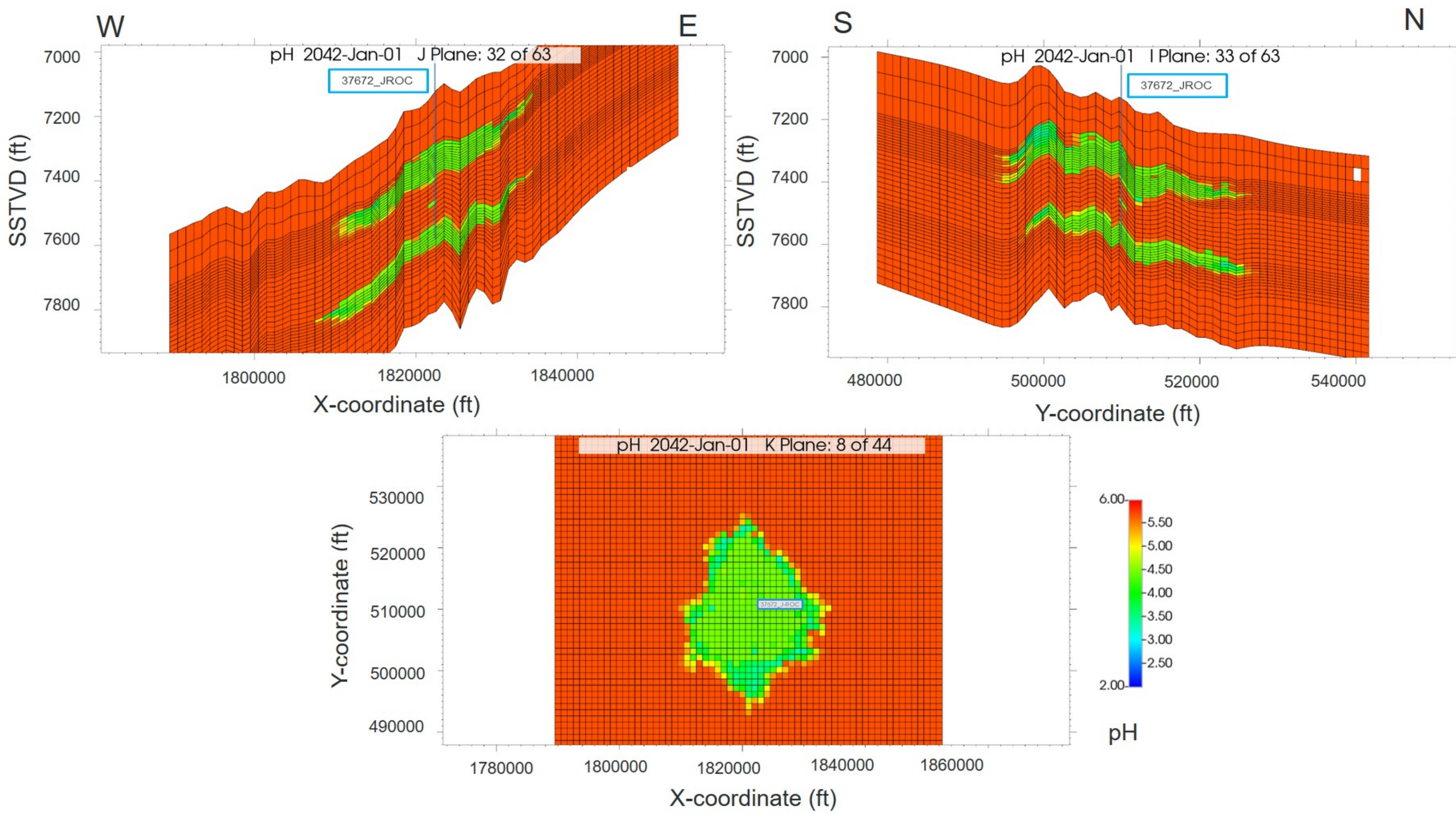

Figure 2-24. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine.

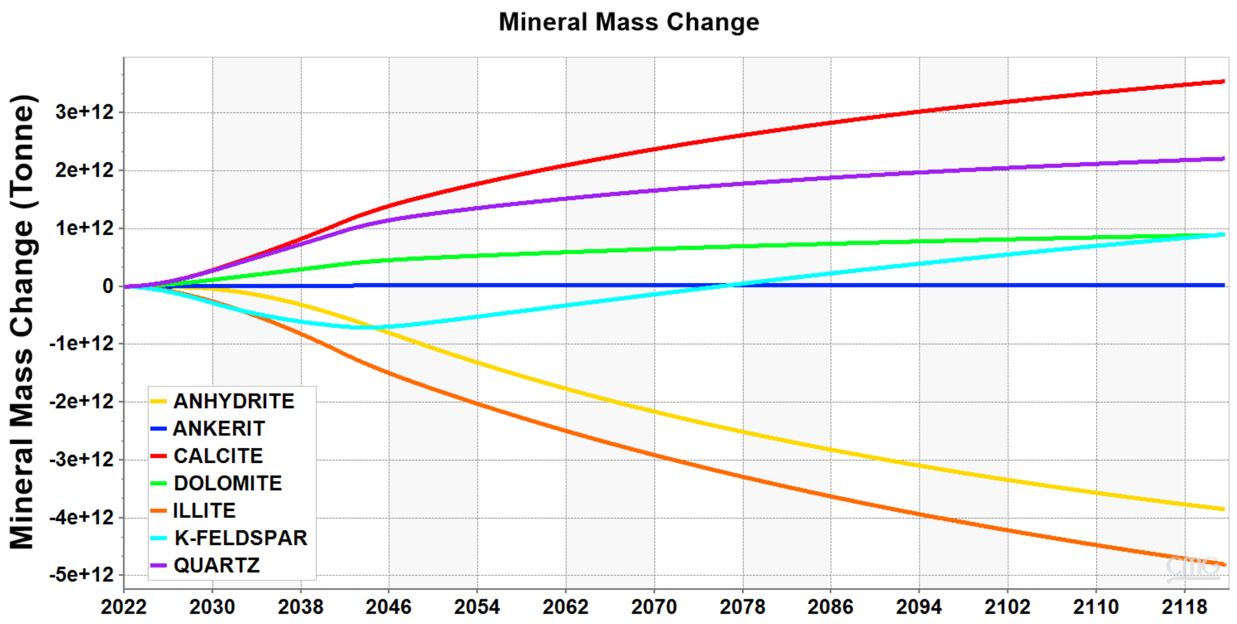

Figure 2-25. Dissolution and precipitation quantities of reservoir minerals due to CO_2 injection. Dissolution of illite and anhydrite with precipitation of calcite, quartz, and dolomite was observed. K-feldspar dissolves during the injection period but slowly begins to reprecipitate after injection.

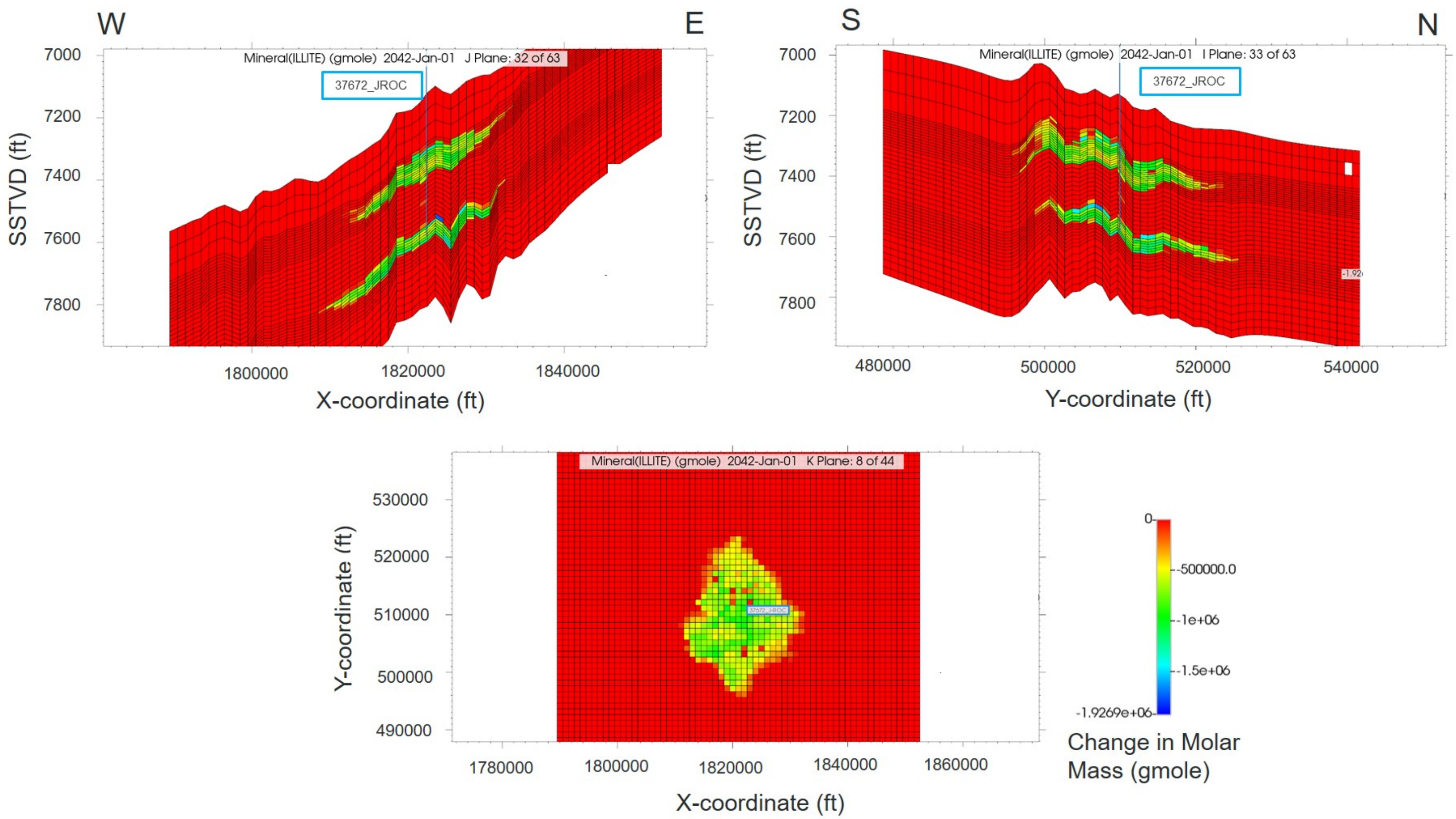

Figure 2-26. Molar distribution of illite, the most prominent dissolved mineral at the end of the injection period, shown in green. Compare to the molar CO_2 distribution in Figure 2-23.

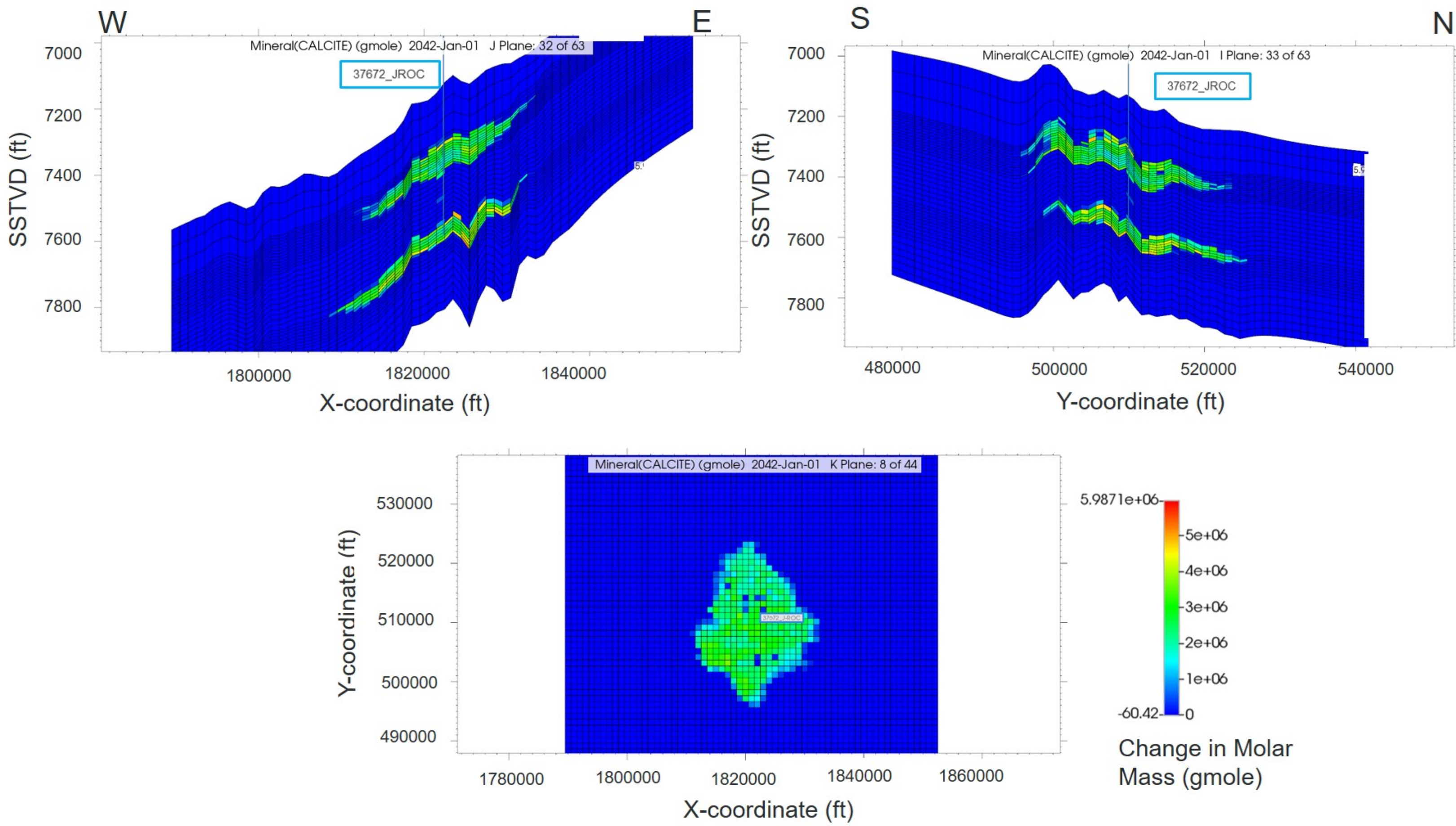

Figure 2-27. Molar distribution of calcite, the most prominent precipitated mineral at the end of the injection period. Compare to the molar CO_2 distribution in Figure 2-23.

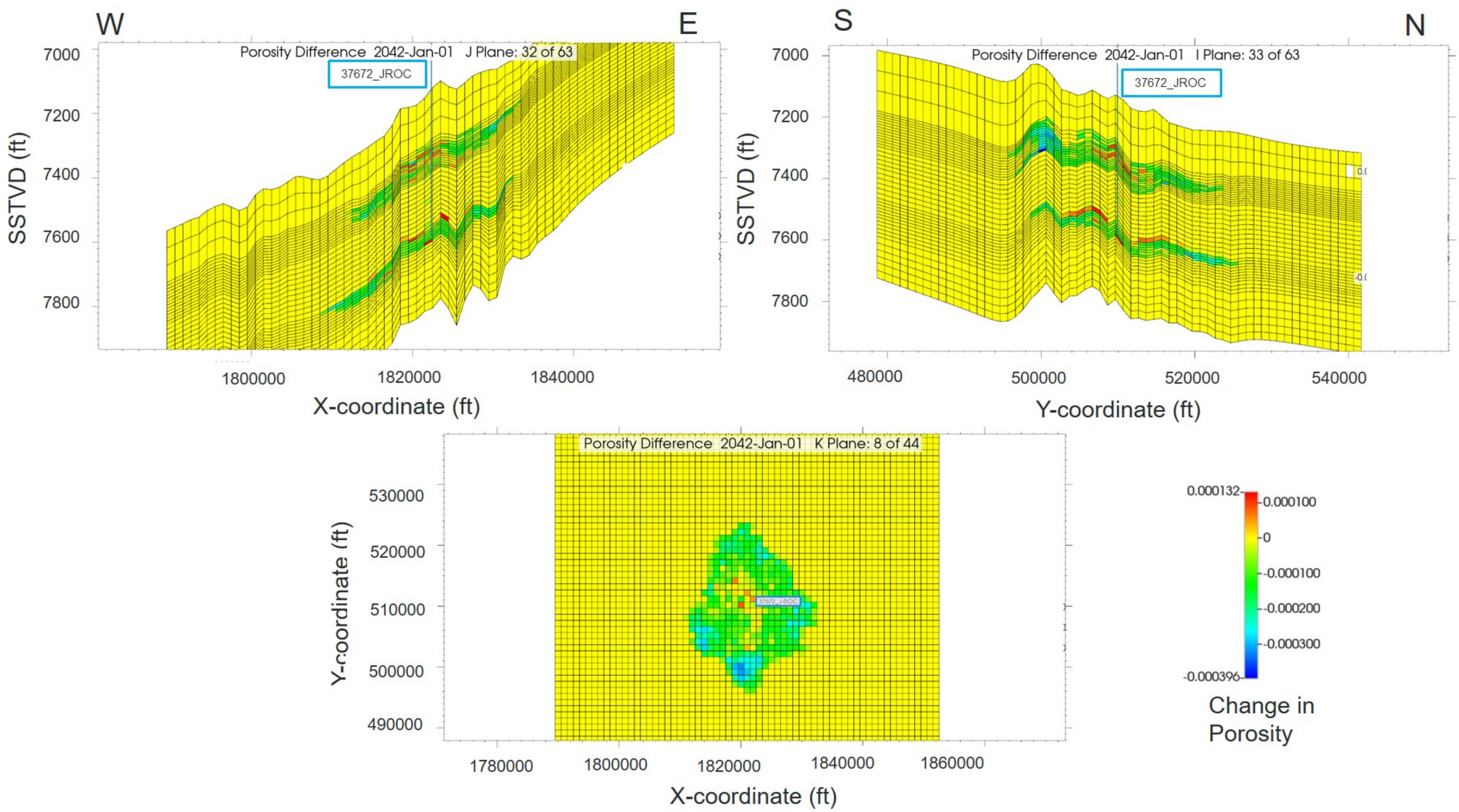

Figure 2-28. Change in porosity due to net geochemical dissolution after the 20-year injection period. Maximum porosity change is less than 0.1%. Compare to the molar CO_2 distribution in Figure 2-22.

2.4 Confining Zones

The confining zones for the Deadwood and Black Island Formations are the overlying Icebox Formation and underlying Deadwood B member shale (Figure 2-3, Table 2-10). All three units, the Icebox Formation, Deadwood B member shale, and Precambrian basement, consist of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones at the J-LOC1 Well

Confining Zone Properties		
	Icebox	Deadwood B member shale
	9,308	9,791
	3.6***	2.0
	845	176****

* 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.
*** Porosity and permeability values derived from HPMI (high-pressure mercury injection) testing.
**** No shale samples in the Deadwood were tested. Value is for a sample from a sandy–shale interval in the Deadwood D member

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Icebox consists of shale. This upper confining zone is laterally extensive across the project area (Figures 2-29 and 2-30) 9,308 ft below the land surface and 118 ft thick at the Tundra SGS site (Table 2-10 and Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The contact between the underlying sandstone of the Black Island Formation is conformable and can be correlated across the project area. The transition from the Icebox to the Black Island is indicated by a relatively low GR, low neutron, high density, and low compressional sonic across the contact (Figure 2-32).

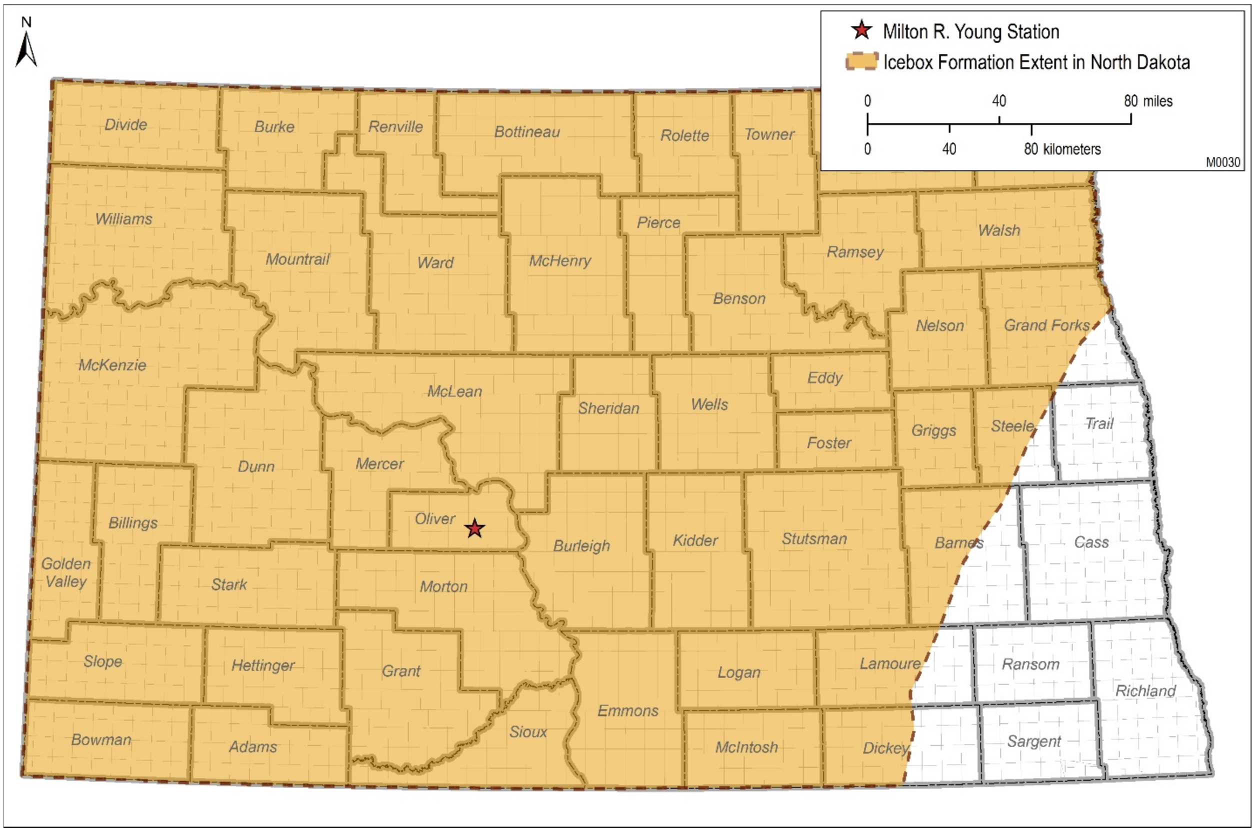

Figure 2-29. Areal extent of the Icebox Formation in western North Dakota (modified from Nesheim, 2012a).

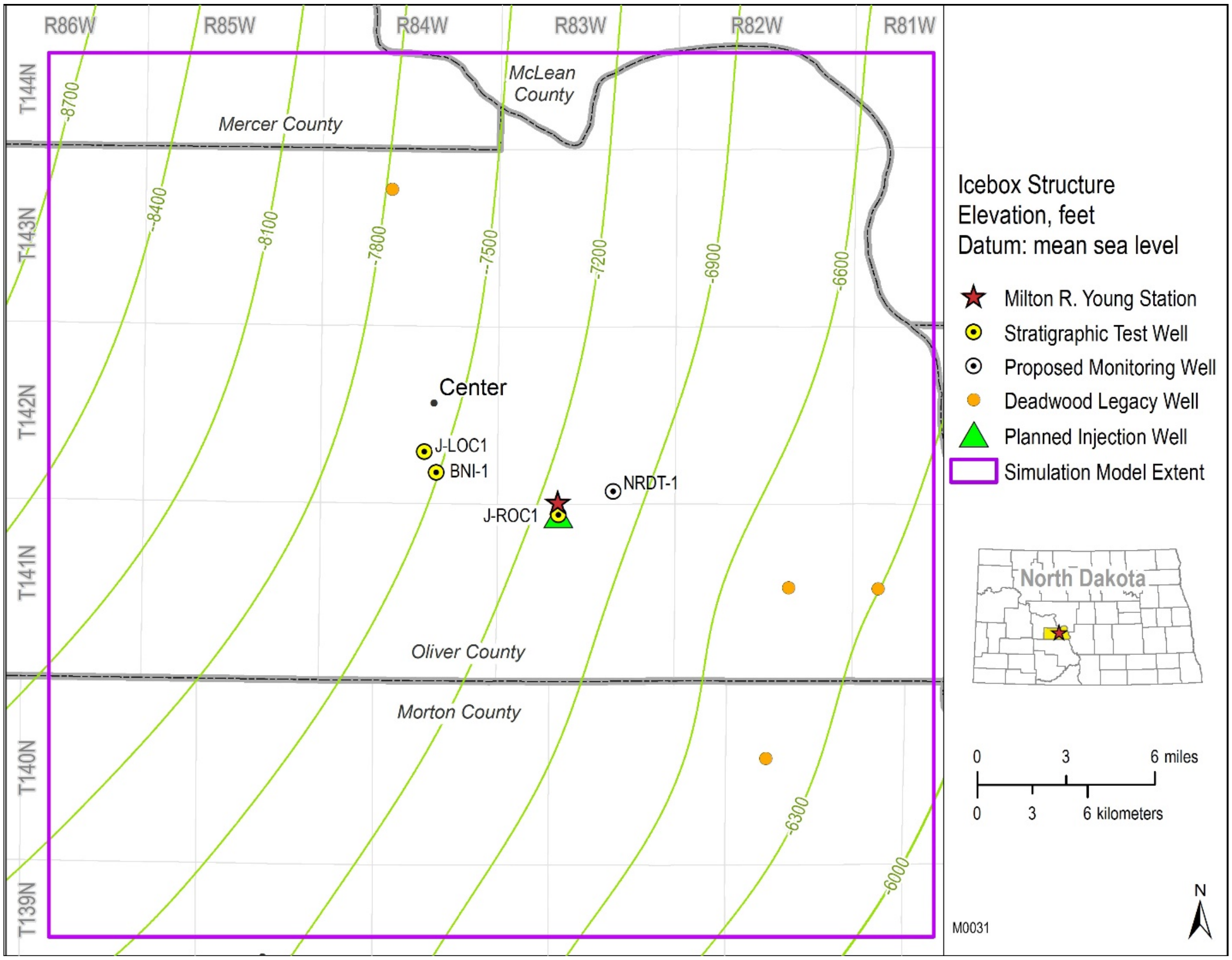

Figure 2-30. Structure map of the upper confining zone across the simulation model extent.

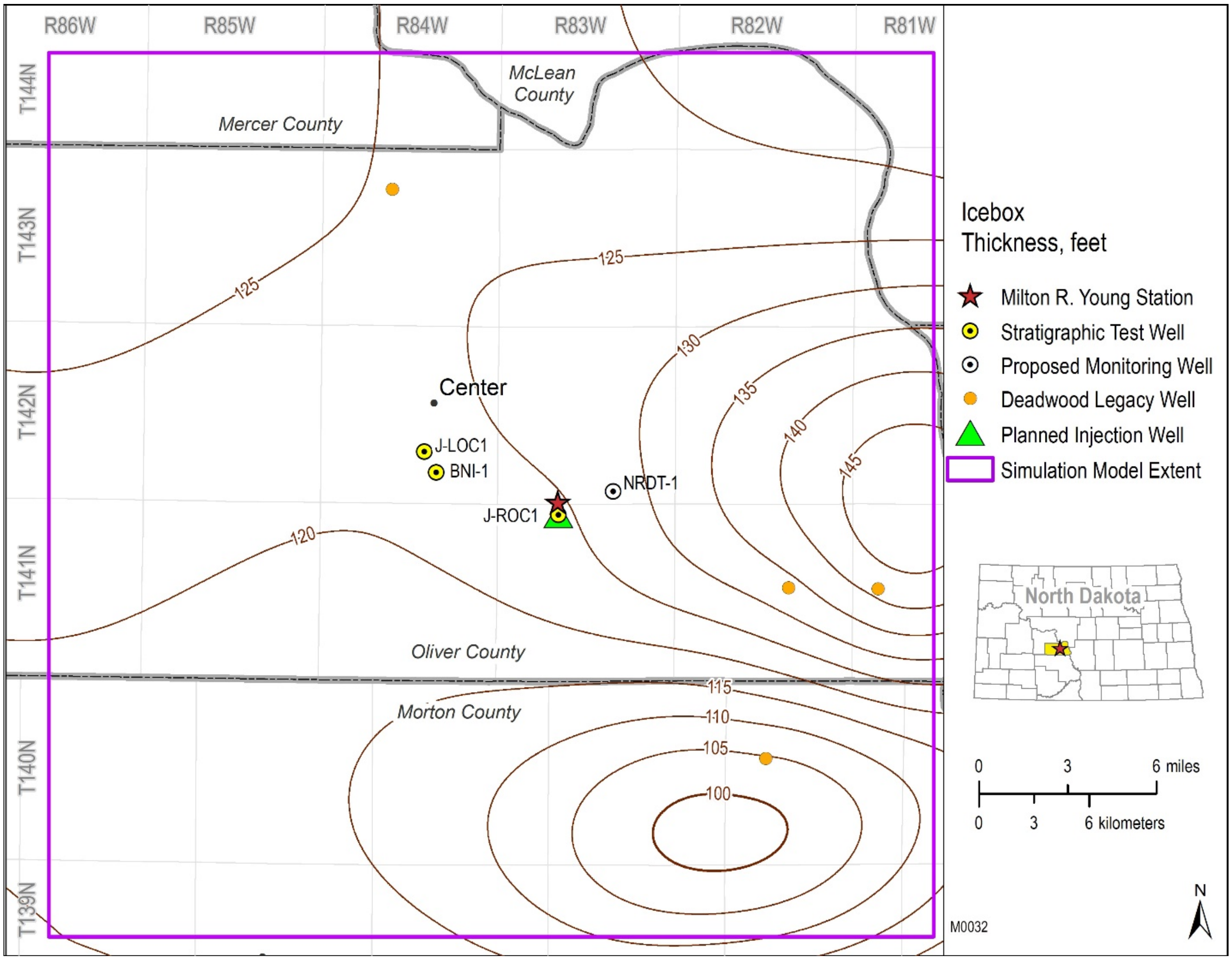

Figure 2-31. Isopach map of the upper confining zone across the simulation model extent.

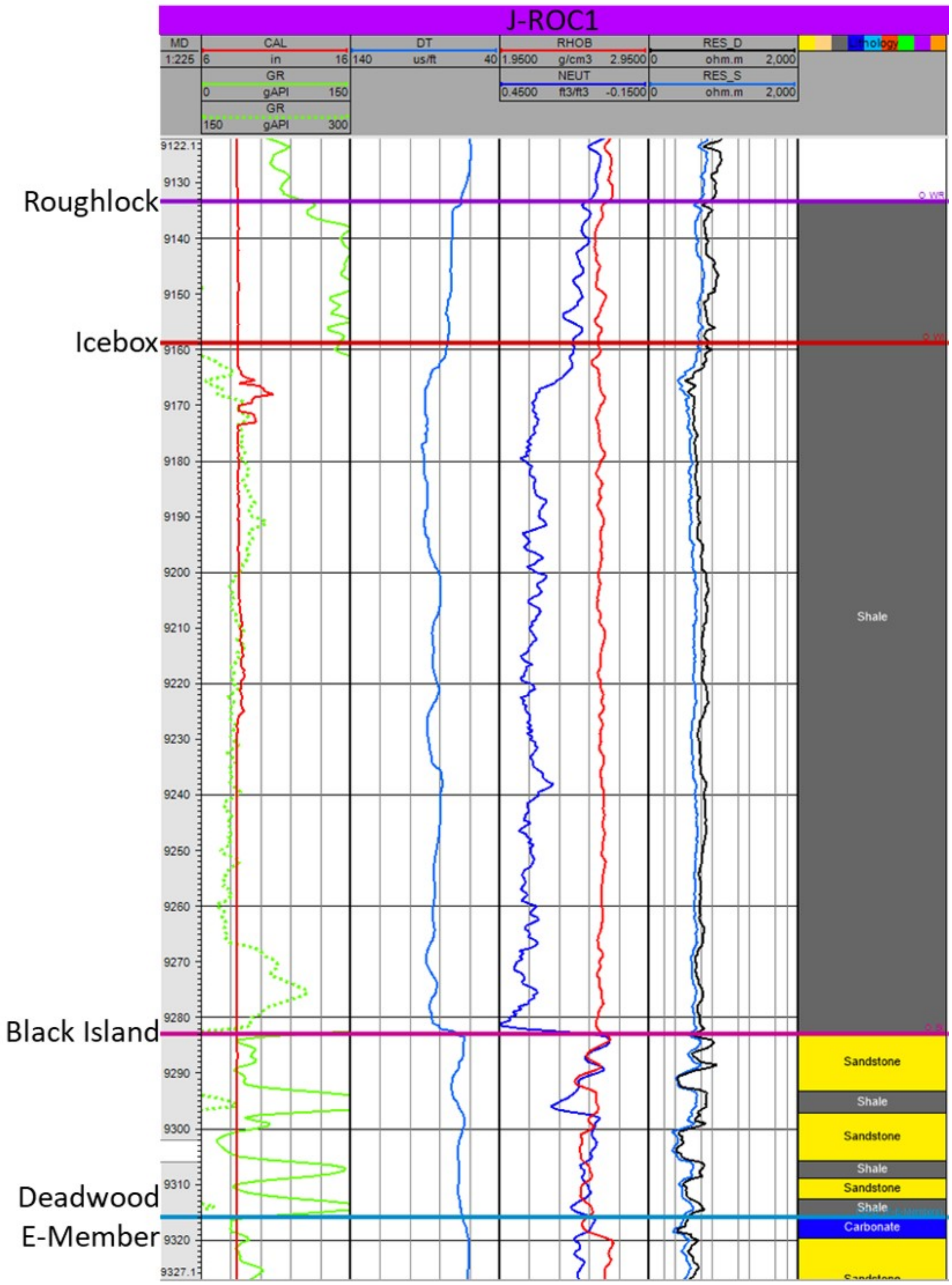

Figure 2-32. Well log display of the upper confining zone at the J-ROC1 well.

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 wellbore. Microfracture stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

For the J-LOC1 well, in the Icebox Formation at 9,749.5 and 9,751.2 ft, the MDT tool was unable to cause a breakdown in the formation with an applied maximum injection pressure of 10,984.9 and 10,867.24 psi, respectively (Figures 2-33 and 2-34). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent and exhibits sufficient geologic integrity to contain the injected CO_2 stream.

The Icebox Formation was not suitable to collect competent core samples from the J-LOC1 well core for the purposes of porosity and permeability laboratory tests; the samples would crush in the equipment. The formation was found to be tight, and porosity and permeability estimates were derived from HPMI testing for one sample (Table 2-11). The lithology of the cored sections of the Icebox Formation is primarily shale, with minor pyrite.

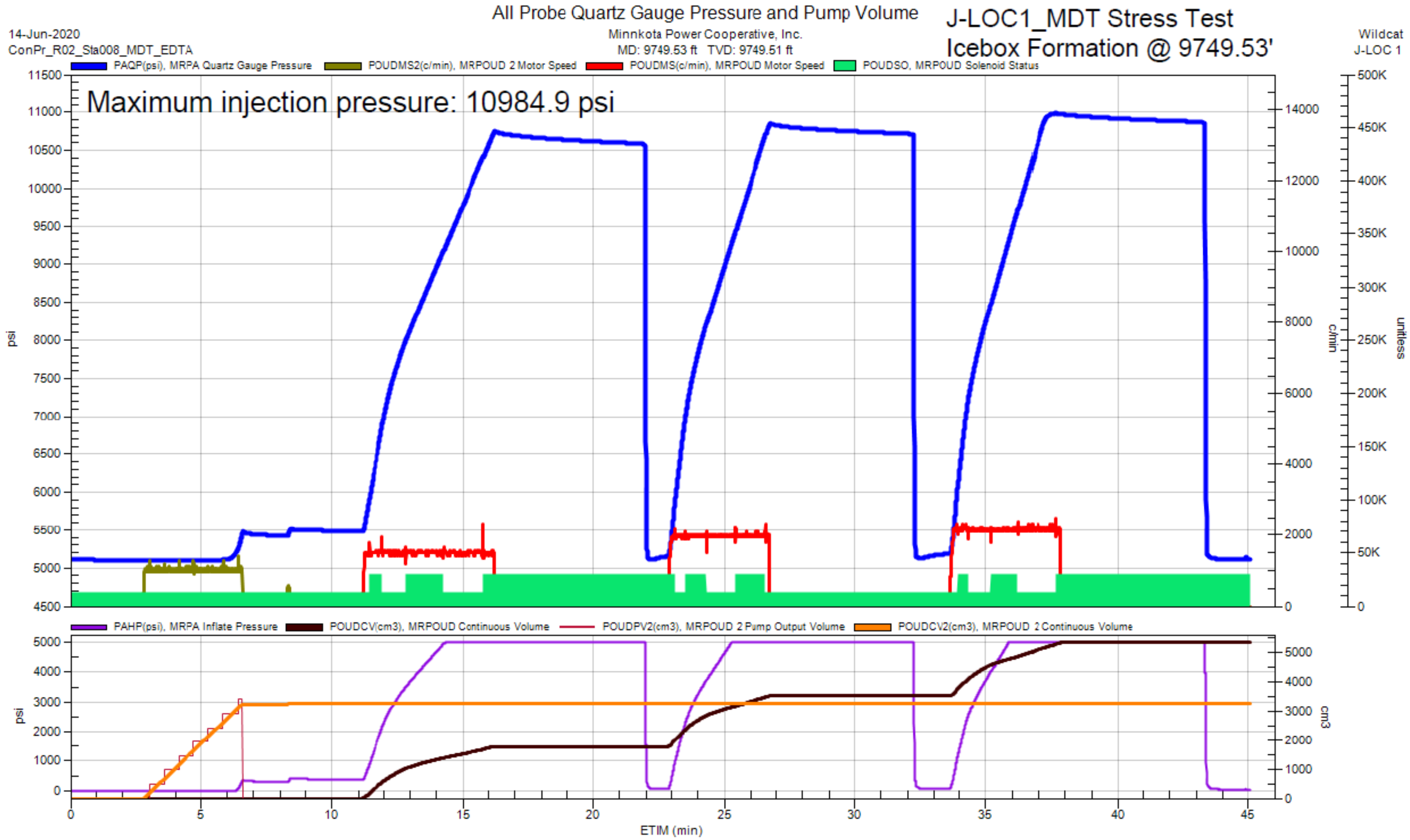

Figure 2-33. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,749.5 ft.

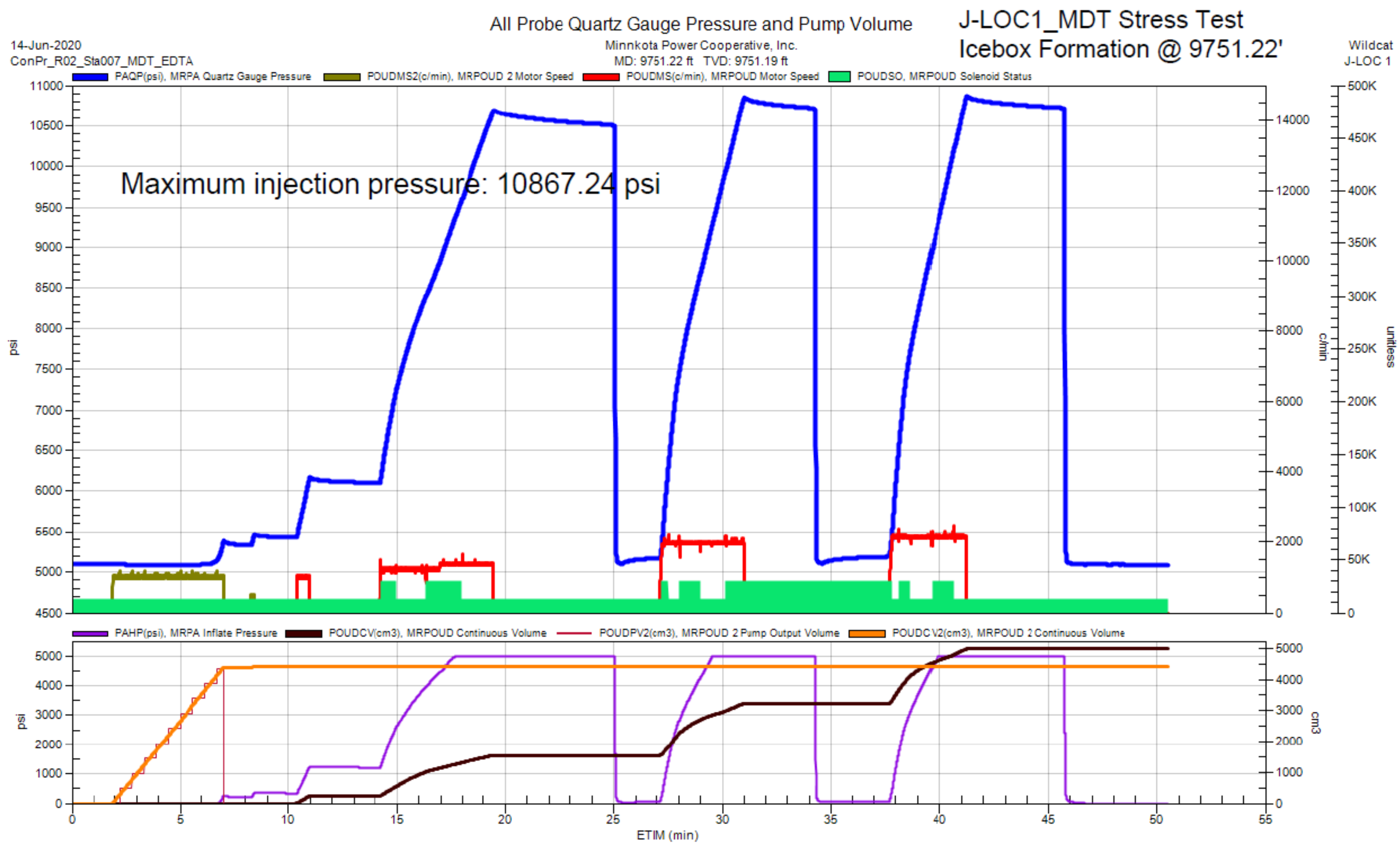

Figure 2-34. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,751.2 ft.

Table 2-11. Icebox Core Sample Porosity and Permeability from J-LOC1

Sample Depth, ft	Porosity, %	Permeability, mD
9,767	3.6*	0.000020*

* Derived from HPMI.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Icebox Formation is primarily shale. Thin sections were created from the base of the Icebox and the shales present in the Black Island Formation. The shales present in the Black Island Formation have characteristics similar to the shales of the Icebox Formation. The mineral components present are clay, quartz, feldspar, and iron oxides. The quartz grains are always surrounded by a clay matrix. The porosity and permeability measurements could not be performed because of the fissility of the rock. The porosity was estimated from HPMI analysis and equaled 3.6%. Log interpretations (Figure 2-31) and visual inspection of the collected core validate consistent mineral assemblage within the Icebox and Black Island Formations.

XRD data from the J-LOC1 well core supported facies interpretations from core descriptions and thin-section analysis. The Icebox Formation comprises clay, quartz, feldspar, and iron oxides.

XRF analysis of the Icebox Formation identified the major chemical constituents to be dominated by SiO_2 (53%), SO_3 (1.6%), CaO (0.26%), Al_2O_3 (24%), and MgO (1.9%), correlating well with the silicate- and aluminum-rich mineralogy determined by XRD (Table 2-12). This correlates with XRD, core description, and thin-section analysis.

Table 2-12. XRF Data for the Icebox Formation from the J-LOC1 Well

Sample Depth			
9,756 ft		9,767 ft	
Component	**Percentage**	**Component**	**Percentage**
SiO_2	50.51	SiO_2	57.01
Al_2O_3	26.11	Al_2O_3	22.55
SO_3	3.03	SO_3	0.30
CaO	0.16	CaO	0.36
MgO	1.83	MgO	1.97
Other	15.89	Other	15.18

2.4.1.2 Geochemical Interaction, Icebox Formation

Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 on the Icebox Formation, the primary confining zone for the Deadwood Formation. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. The results were calculated at grid cell centers located at 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Icebox was honored (Table 2-13). The formation brine composition was assumed to be the same as the known composition from the Deadwood injection zone below (Table 2-14). The injection stream composition was as described by Minnkota Power Cooperative (Minnkota) (Table 2-15). Three different exposure levels, expressed in moles per year, 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 expected actual exposure levels. This overestimate 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. Mineral Composition of the Icebox Formation Derived from XRD Analysis of JLOC-1 Core Samples (9773 ft MD)

Minerals, wt%	
Illite	18.2
Kaolinite	5.7
Chlorite	4.2
Montmorillonite	3.1
K-Feldspar	8.1
Quartz	59.3
Calcite	0.6
Pyrite	0.8

Table 2-14. Formation Water Chemistry from Deadwood Formation Fluid Samples from JLOC-1

pH	6	Total Dissolved Solids	256,000 mg/L
Total Alkalinity	72 mg/L $CaCO_3$	Calcium	8,610 mg/L
Bicarbonate	72 mg/L $CaCO_3$	Magnesium	1,210 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	87,000 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	2020 mg/L
Total Organic Carbon	14 mg/L	Iron	22.2 mg/L
Sulfate	491 mg/L	Manganese	2.85 mg/L
Chloride	17,500 mg/L	Barium	<5 mg/L
Nitrate	<0.1 mg/L	Strontium	0.32 mg/L

Table 2-15. Injection Stream Composition

Component Flows	ppmv	mol%
CO_2	804,195	0.999
H_2O	632	7.85E-04
N_2	163	2.02E-04
O_2	6	7.45E-06
H_2	0	0.00E+00
Ar	4	4.97E-06

The results showed relatively minor geochemical processes at work. Figures 2-35, 2-36, and 2-37 show results from the most extreme exposure case. Figure 2-35 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 and stabilizes at a level of 4.9. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 8. The pH is unaffected in Cell C3. Figure 2-36 shows change in mineral dissolution and precipitation in grams per cubic meter of rock. Dashed lines are for Cell C1, solid lines that are seen in the figure are from Cell C2, 1.0 to 2.0 meters into the cap rock. Any effects in Cell C3 are too small to represent at this scale. In Cell C1, K-feldspar is the primary dissolution mineral, which is primarily replaced by precipitation of illite, quartz, and montmorillonite. Similar, but lesser, effects are seen in Cell C2. Figure 2-37 shows change in porosity of the Icebox cap rock. During an initial model stabilization period, Cell C1 experiences an increase in porosity due to K-feldspar dissolution. However, the porosity gradually returns to its initial condition by Year 10. As the porosity scale shows, these changes are small, less than 0.0013 porosity units. Cells C2 and C3 experience no significant change in porosity during the 45 years of the simulation. The small net porosity changes from dissolution and precipitation in Cells C1 and C2, with essentially zero observed effect on Cell C3, suggest that geochemical change from exposure to CO_2 is very minor and will not cause substantive deterioration of the Icebox cap rock.

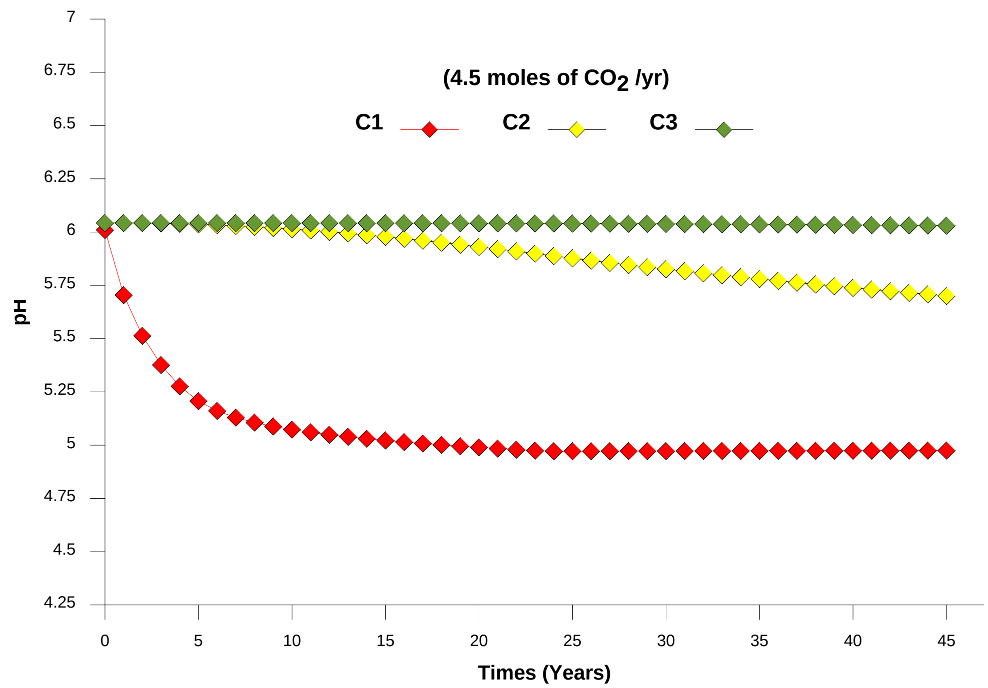

Figure 2-35. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1 at 0.5 meters above the base of the Icebox cap rock. Yellow line shows Cell C2 at 1.5 meters above the cap rock base. Green line shows Cell C3 at 2.5 meters above the cap rock base.

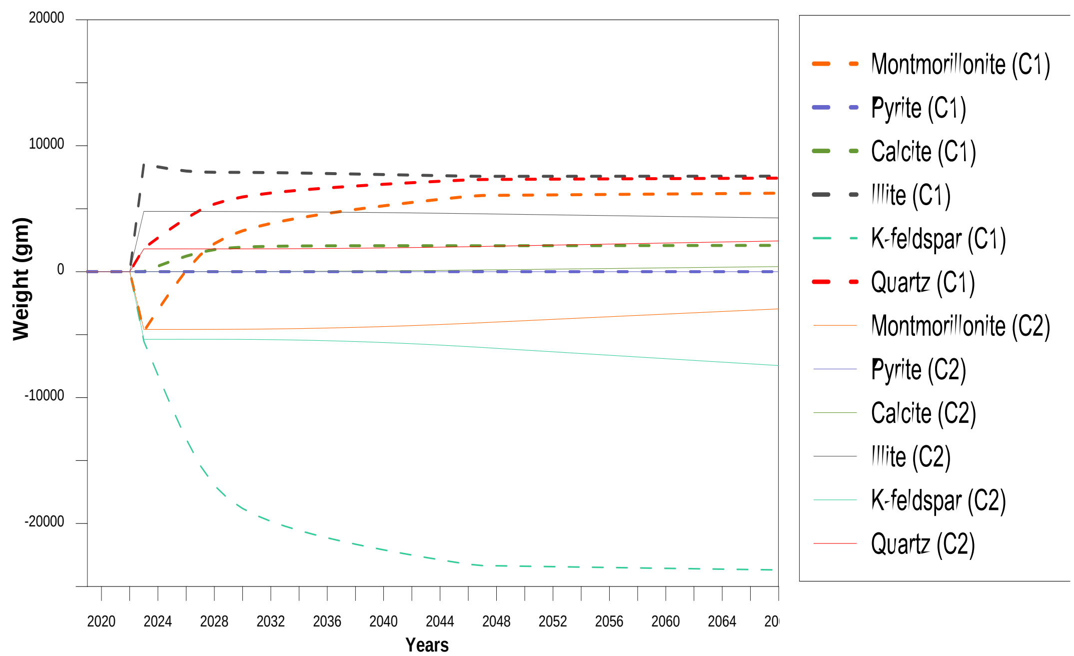

Figure 2-36. Dissolution and precipitation of minerals in the Icebox cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2 at 1.5 meters above the cap rock base. Results from Cell C3 at 2.5 meters above the caprock base are not shown as they are too small to be seen at this scale.

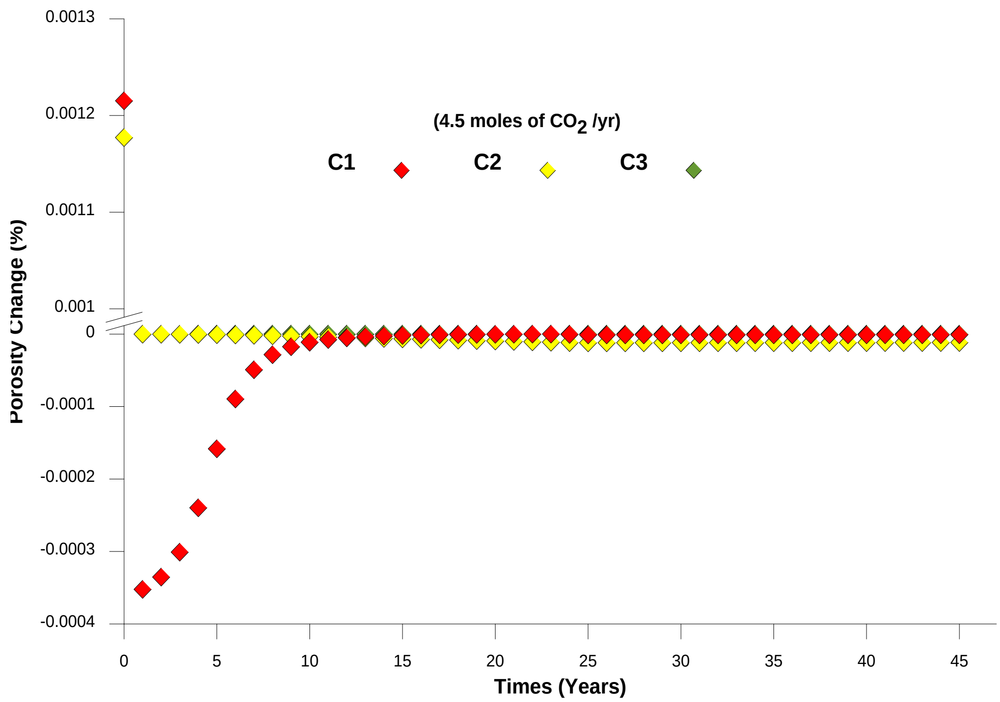

Figure 2-37. Change in percent porosity of the Icebox cap rock. Red line shows porosity change calculated for Cell C1at 0.5 meters above the cap rock base. Yellow line shows Cell C2 at 1.5 meters above the cap rock base. Green line shows Cell C3 at 2.5 meters above the cap rock base. Long-term change in porosity is minimal.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Icebox. Impermeable rocks above the primary seal include the Roughlock Formation and the Red River D member, which make up the first additional group of confining formations (Table 2-16). Together with the Icebox, these formations are 612 ft thick and will isolate the Deadwood/Black Island Formations fluids from migrating upward into the next permeable interval, the Red River A, B, and C members (see Figure 2-38). Above the Red River Formation, >1,000 ft of impermeable rocks act as an additional seal between the Red River and Broom Creek, the next proposed storage complex, 876 ft of impermeable rocks separate the Broom Creek from the Inyan Kara and an additional 2,545 ft of impermeable rocks separates the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-39). Confining layers above the Inyan Kara include the Skull Creek, Newcastle, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

No known transmissible faults are within these confining systems in the project area. These formations between the Deadwood, 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 (Downey, 1986; Downey and Dinwiddie,1988).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444
Opeche	Shale/mudstone	4,685	55	3,535
Amsden	Dolostone/anhydrite	4,974	247	3,824
Kibbey Lime	Limestone	5,384	31	4,234
Charles	Limestone/anhydrite	5,526	147	4,376
Bakken	Shale	6,926	10	5,776
Birdbear	Limestone	7,075	74	5,925
Duperow	Limestone/dolostone	7,149	272	5,999
Souris River	Dolostone/limestone	7,421	175	6,271
Dawson Bay	Dolostone	7,596	729	6,446
Gunton	Dolostone/limestone	8,325	39	7,175
Stoughton	Shale/limestone	8,364	91	7,214
Lower Red River	Limestone	8,645	488	7,495
Roughlock	Shale/limestone	9,133	25	7,983

Carbonates of the Red River A, B, and C members comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Red River represents the most likely candidate to act as an overlying pressure dissipation zone. The depth to the Red River Formation in the project area is approximately 8,438 ft, and the formation itself is about 450 ft thick. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Red River Formation.

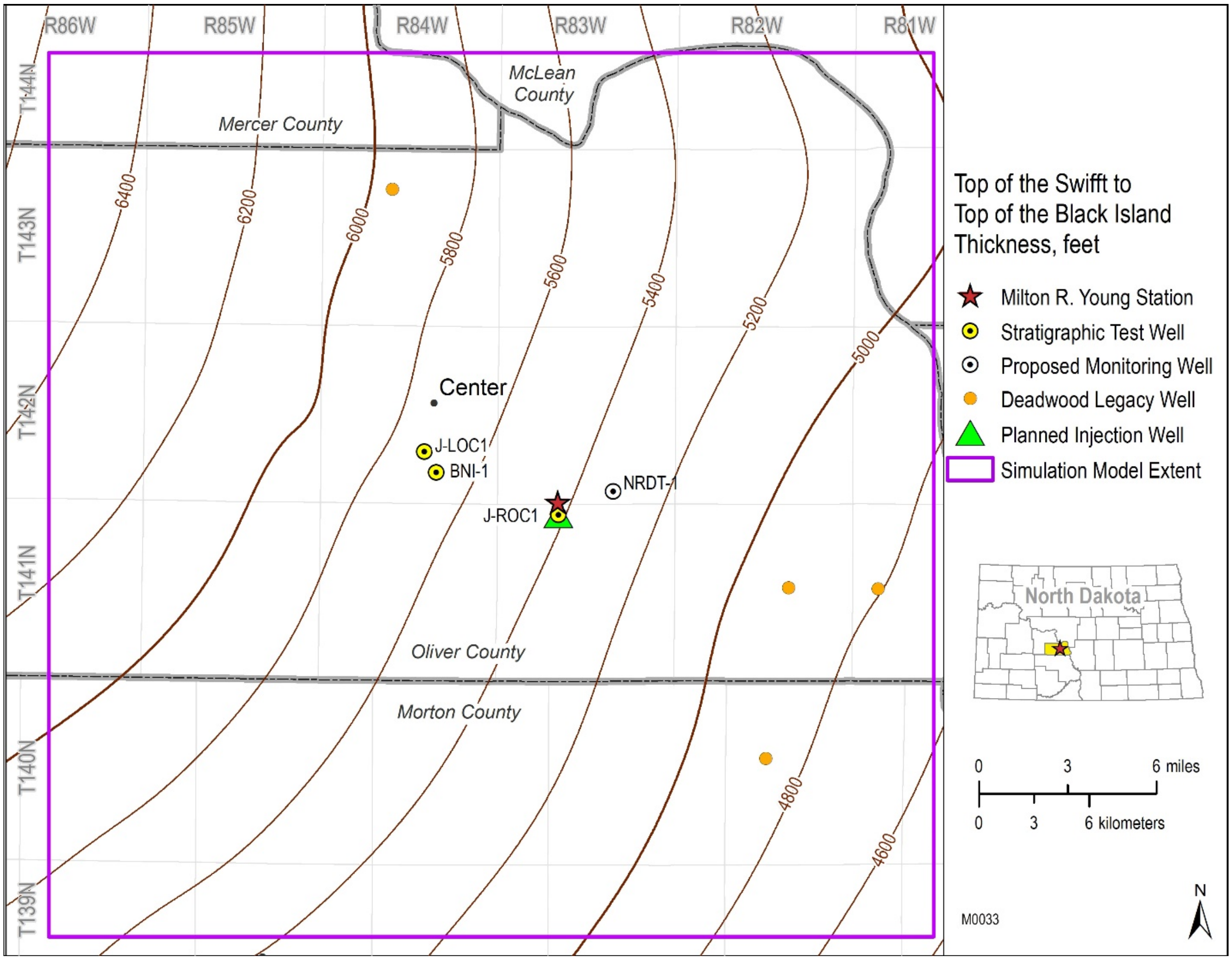

Figure 2-38. Isopach map of the interval between the top of the Black Island Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

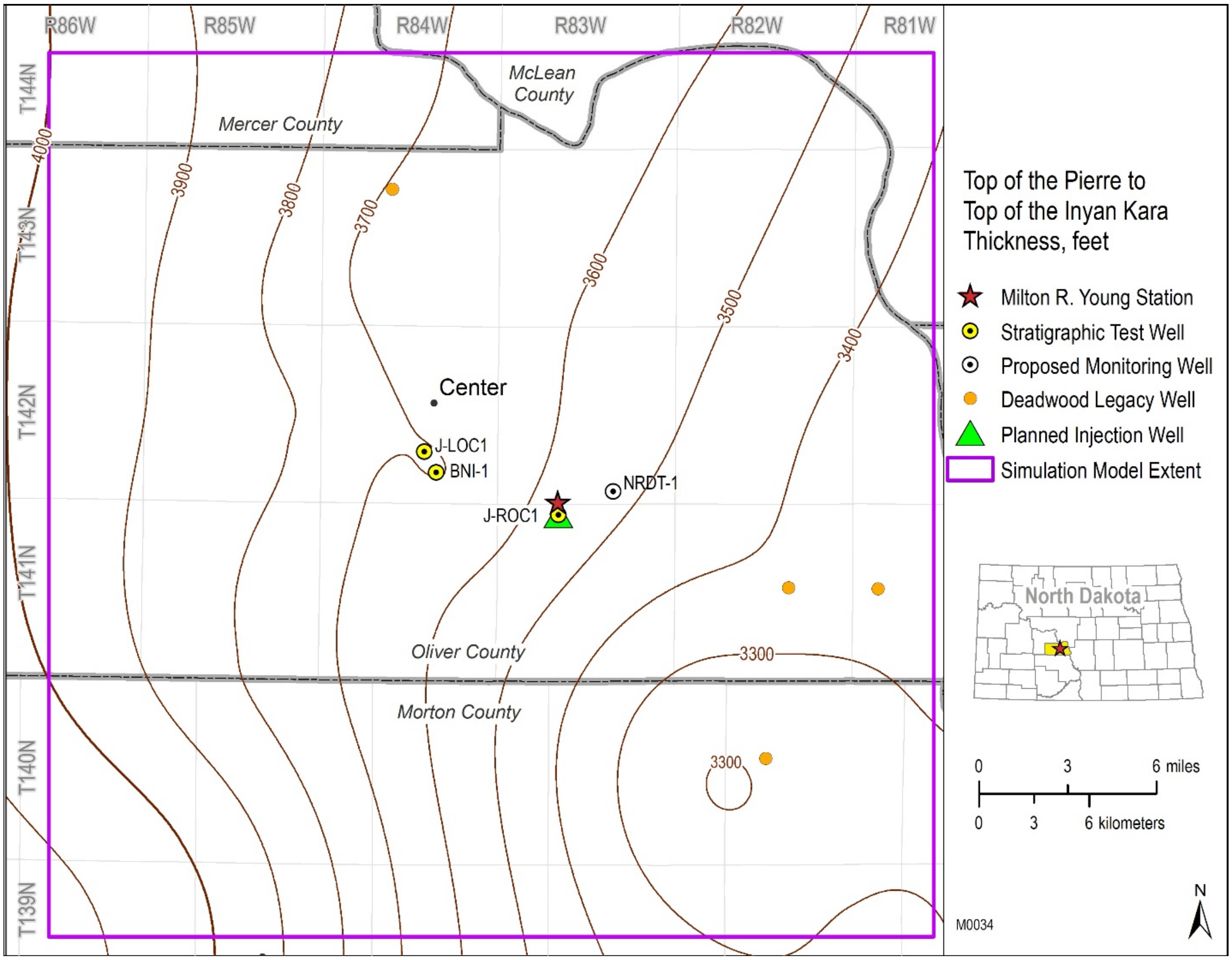

Figure 2-39. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member shale consists predominantly of shale with a consistent and correlative package of higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic across the project area. The shale within the Deadwood B member is 9,791 ft below the surface and 34 ft thick at the Tundra SGS site (Figures 2-40 and 2-41, Table 2-10).

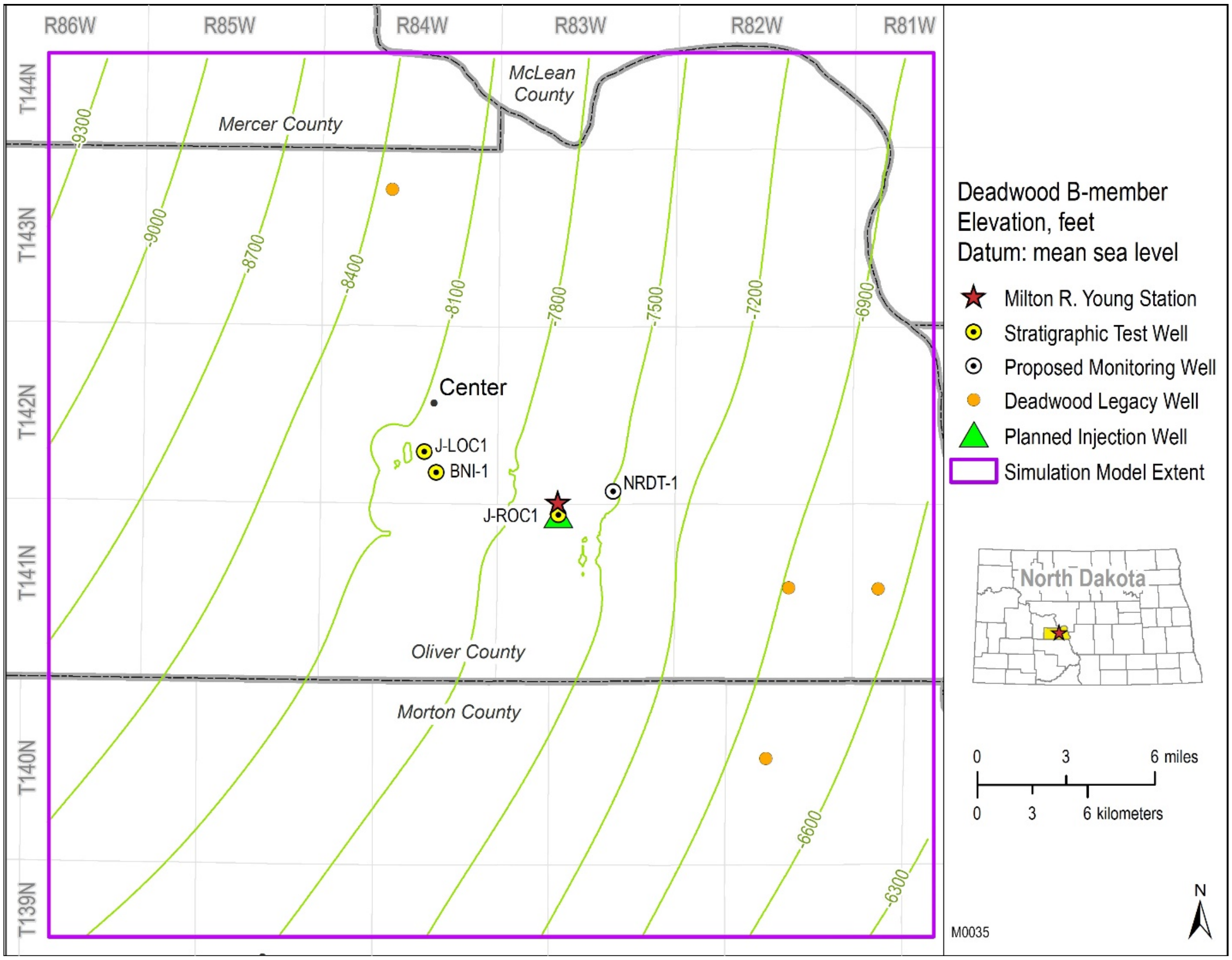

Figure 2-40. Structure map of the Deadwood B member shale across the greater Tundra SGS area.

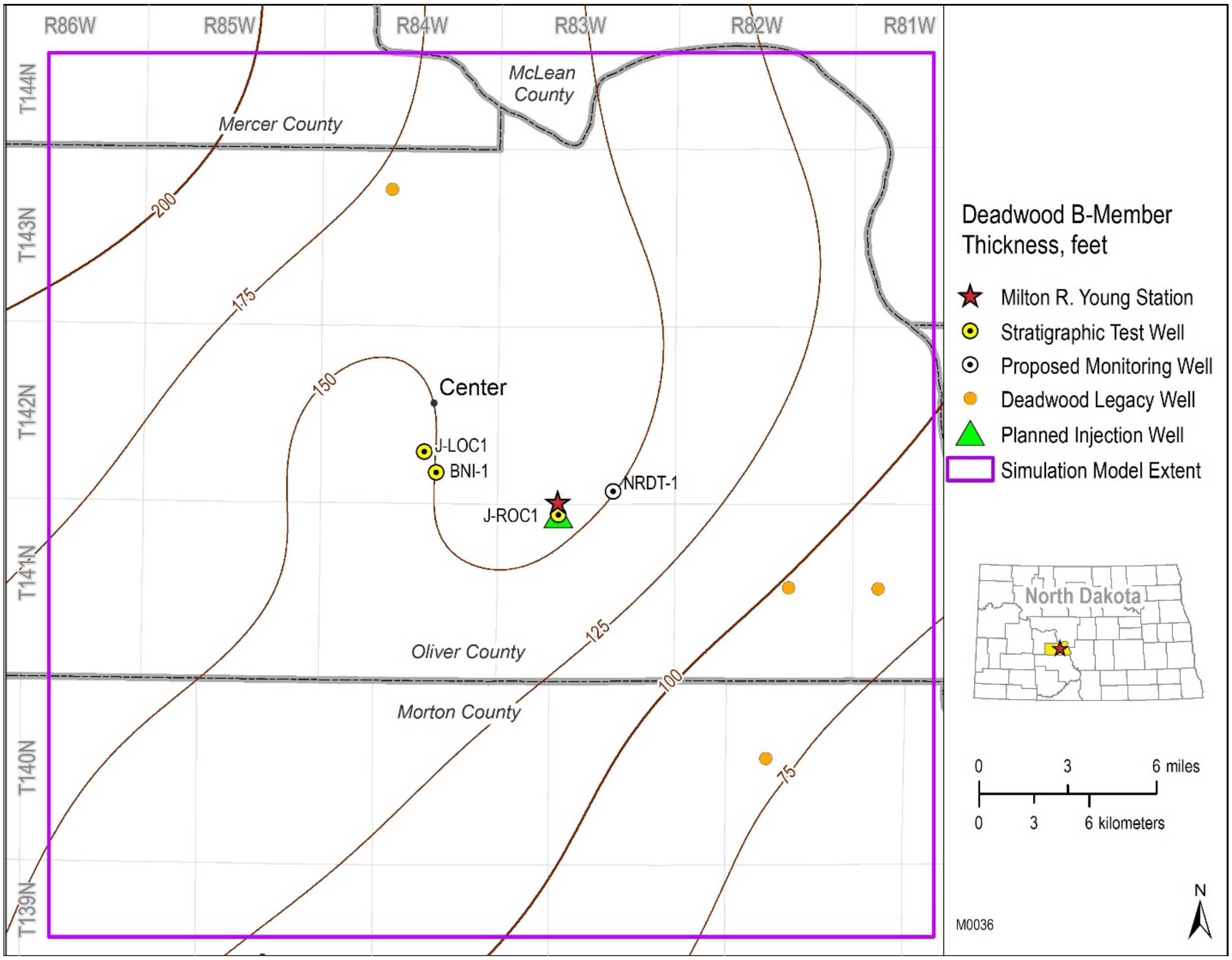

Figure 2-41. Isopach map of the Deadwood B member shale across the Tundra SGS area.

At 144 ft below the top of the Deadwood C-sand is an 80-ft-thick shaly layer of the Deadwood B member. Data acquired from the core plug samples taken from the Deadwood B member show porosity values ranging from 1.55% to 2.63% and permeability values from 0.0083 to 0.0177 mD (Table 2-17).

Table 2-17. Deadwood B Member Shale Core Sample Porosity and Permeability from J-LOC1

Sample Depth, ft	Porosity, %	Permeability, mD
10,152	1.84	0.0083
10,159.5	1.55	0.0177
10,181.5	2.63	0.0076
Range	1.55–2.63	0.0083–0.0177

2.4.3.1 Mineralogy

Thin-section analysis and well logs show that the Deadwood B interval comprises carbonates and shale facies. The carbonates are composed mainly of calcite minerals and fossils and then by feldspar and quartz. The Deadwood B shows a tight formation characteristic where the permeability ranges from 0.0094 and 3.18 mD and porosity ranges from 1% to 8%.

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

XRF data show the Deadwood B shale is mainly composed of CaO (35%), SiO_2 (30%), and Al_2O_3 (4%) (Table 2-18).

Table 2-18. XRF Data for the Deadwood B Shale from the J-LOC1 Well

Sample Depth			
10,159.5 ft		10,181.5 ft	
Component	**Percentage**	**Component**	**Percentage**
SiO_2	45.18	SiO_2	15.66
Al_2O_3	5.08	Al_2O_3	2.20
MgO	0.39	MgO	0.79
CaO	25.61	CaO	45.24
SO_3	0.75	SO_3	0.18
Other	5.40	Other	3.58

2.4.3.2 Geochemical Interaction, Deadwood B Shale

The Deadwood C-sand's underlying confining layer, the Deadwood B, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of five cells, each cell 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation and allowed to enter the system by advection and dispersion processes. The results were calculated at the center of each cell below the confining layer–CO_2 exposure boundary. The mineralogical composition of the Deadwood B was honored (Table 2-19). Formation brine composition was assumed the same as the known composition from the Deadwood sand injection zone above (previously shown in Table 2-14). The injection stream composition was as described by Minnkota (Table 2-15). The Deadwood B Formation temperature and pressure were adjusted from the Deadwood sand reservoir temperature and pressure conditions, 188°F and 4,357 psi, respectively. Two different pressure levels, 4,357 and 4,652 psi, were applied to the CO_2-saturated brine at the base of the Deadwood sand. These values represent the initial and potential pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. These simulations were run for 45 years to represent 20 years of injection plus 25 years postinjection.

Table 2-19. Mineral Composition of the Deadwood B Shale, derived from XRD analysis of JLOC-1 core samples Deadwood B Shale (10, 144 ft)

Minerals, wt%	
Illite/Muscovite	10.7
Glauconite	5.2
Clintonite	4.8
K-Feldspar	48.5
Quartz	20.2
Calcite	2.4
Chlorite	1.5
Kaolinite	1.3
Other	5.4

The results showed geochemical processes at work. Figures 2-42, 2-43, 2-44, and 2-45 show findings from the high-pressure, more extreme exposure case. Figure 2-42 shows change in fluid pH over 45 years of simulation time as CO_2 enters the system. Initial change in pH in all the cells from 6 to 5.8 is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines from its initial level of 6.0 to 5.3 after 4 years of injection and slowly declines further to 4.4 after the 25-year postinjection period. Similar, but progressively slower, pH change occurs for each cell that is more distant from the CO_2 interface. The pH for Cells 10–19 did not decline over the 45 years of simulation time. Figure 2-43 shows that CO_2 does not penetrate more than 9 meters (represented by Cell C9) within the 45 years simulated.

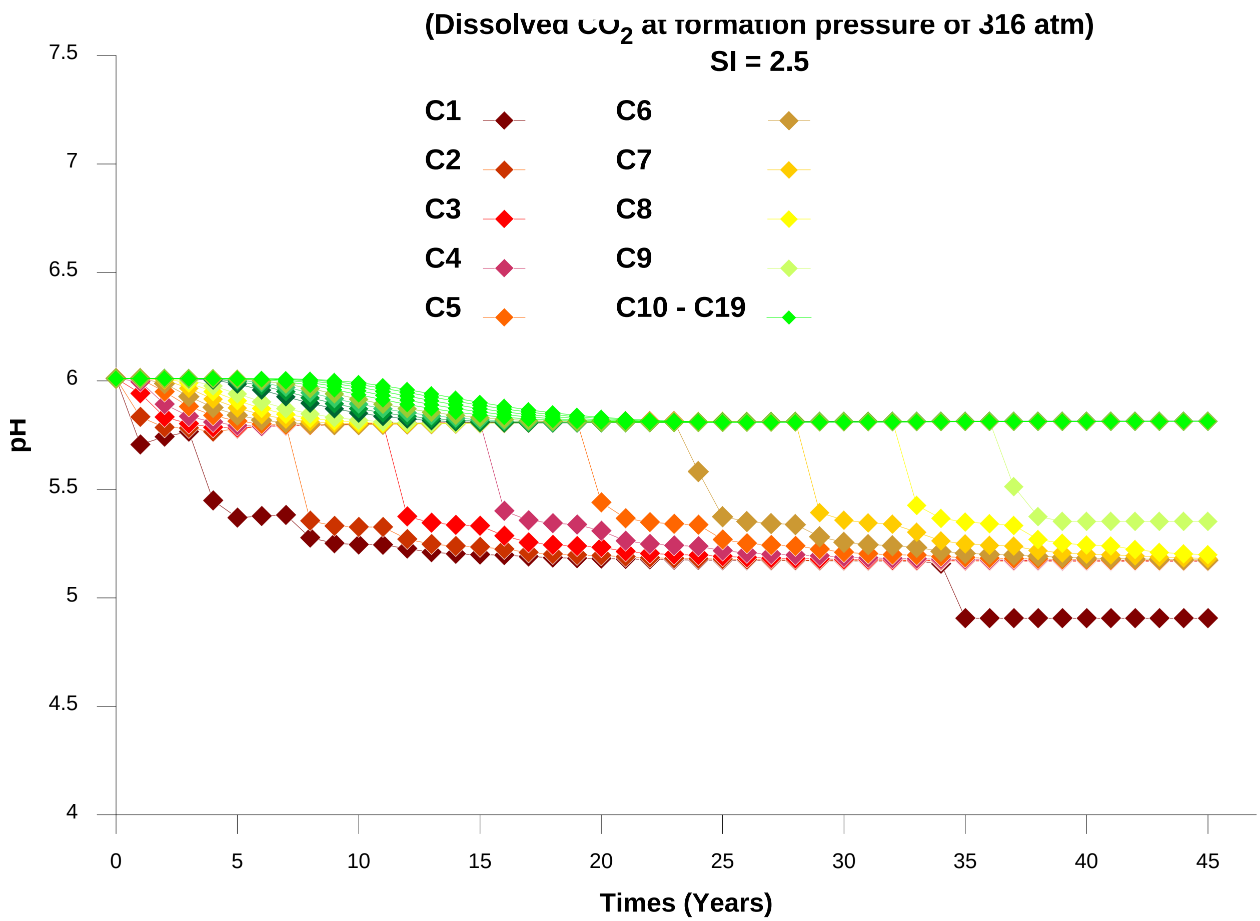

Figure 2-42. Change in fluid pH in the Deadwood B shale underlying confining layer. The red line shows the pH calculated at the center of Cell C1 at 0.5 meters below the Deadwood B top. The green line shows Cell C5 at 4.5 meters below the Deadwood B top.

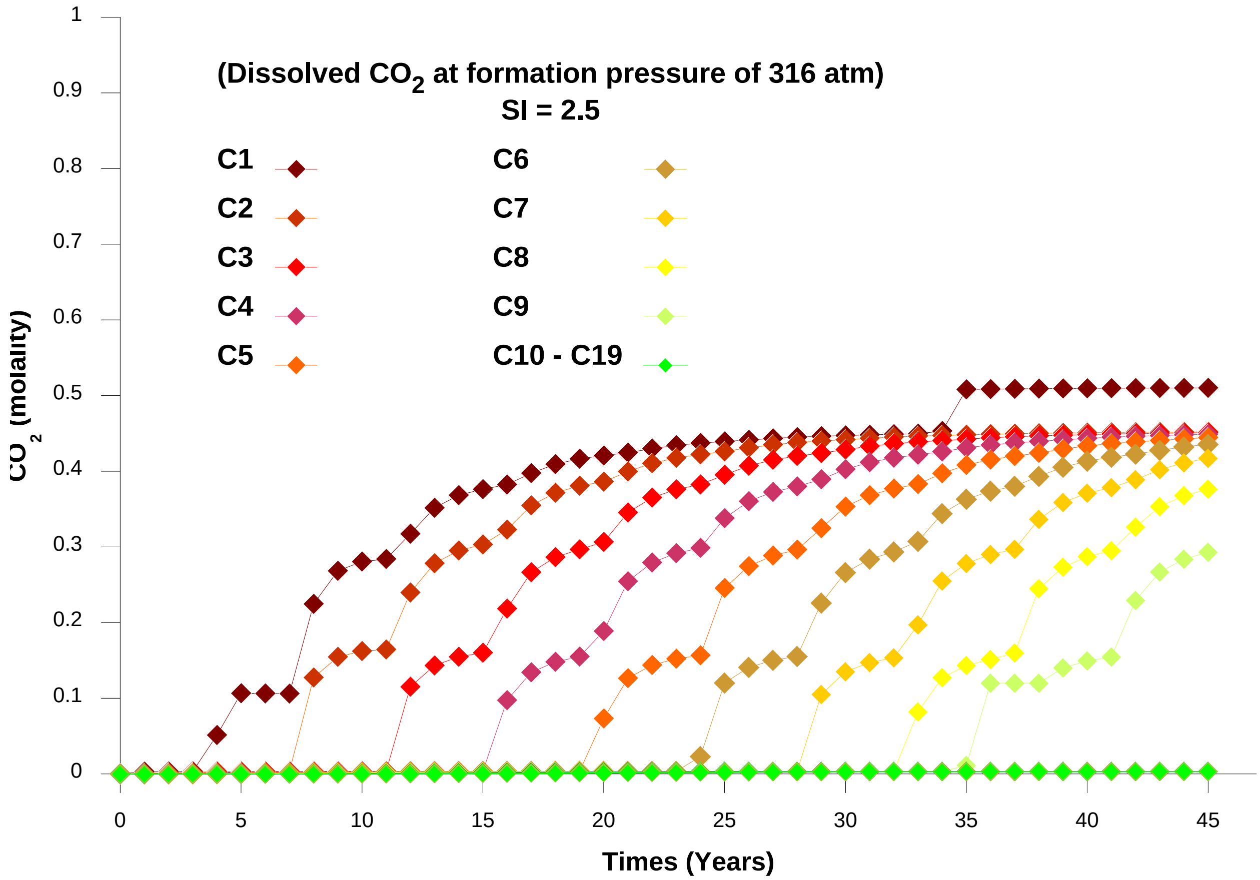

Figure 43. CO_2 concentration (molality) in the Deadwood B shale underlying confining layer for Cells C1–C19.

Figure 2-44 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cell C1, K-feldspar is the primary dissolution mineral, with minor chlorite. Illite and quartz precipitation largely replace that dissolution. The reaction rate in the C1 cell dramatically slows after approximately 9 years, and cell geochemistry stabilizes. As Cell C1 stabilizes, dissolution and precipitation begin in Cell C2, with minor amounts of chlorite dissolving and modest precipitation of dolomite.

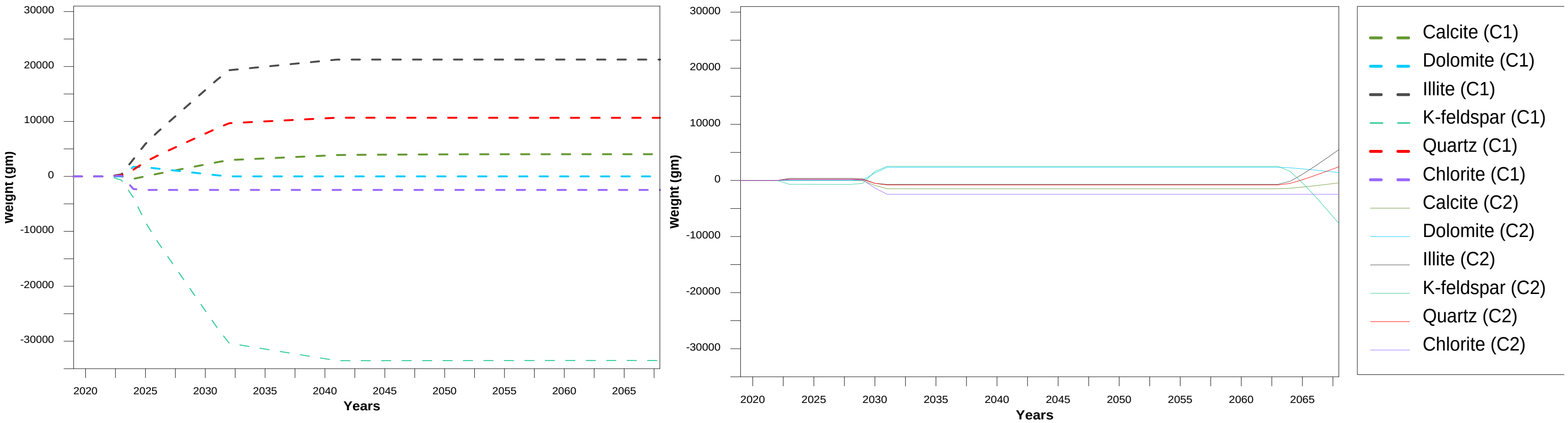

Figure 2-44. Dissolution and precipitation of minerals in the Deadwood B underlying confining layer. Dashed lines show results for Cell C1 at 0 to 1 meter below the Deadwood B top. Solid lines show results for Cell C2 at 1 to 2 meters below the Deadwood B.

Change in porosity (% units) of the Deadwood B underlying confining layer is displayed in Figure 2-45. The overall net porosity changes from dissolution and precipitation are minimal, less than a 0.2% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.1%, but this change is temporary, and the cell returns to its near-initial porosity value of 2.0%. Cells C2 and C3 undergo similar changes but with progressively longer time delay. At the end of the simulation, no significant net porosity changes were observed for these cells. These results suggest that the Deadwood B will not undergo significant geochemical change in the presence of CO_2 injection.

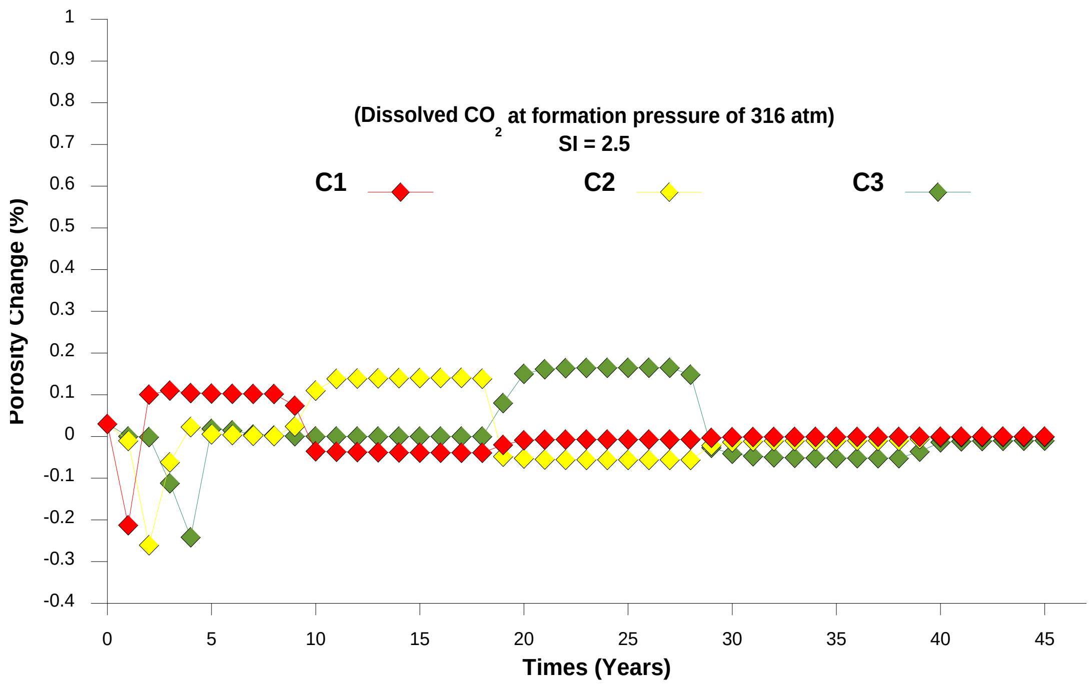

Figure 2-45. Change in percent porosity in the Deadwood B underlying confining layer. The red line shows porosity change for Cell C1 at 0 to 1 meter below the Deadwood B top. The yellow line shows Cell C2 at 1 to 2 meters below the Deadwood B top. The green line shows Cell C3 at 2 to 3 meters below the Deadwood B top. Long-term change in porosity is minimal and stabilized. Cells C4–C19 showed similar results, with net porosity change being less than 0.3%.

2.4.4 Geomechanical Information of Confining Zone

2.4.4.1 Fracture Analysis

Fractures within the Icebox Formation, the overlying confining zone, and Deadwood B Formation, the underlying confining zone, have been assessed during the description of the J-LOC1 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 Schlumberger's Quanta Geo log acquired during the drilling of the J-LOC1 well.

2.4.4.2 Fracture Analysis Core Description

Features within the Icebox Formation are primarily related to the compaction. There is no presence of natural fractures. Only the stylolites which are compaction-related exist; they vary in orientation and exhibit mainly horizontal and rare oblique trends.

In the Deadwood B Formation, rare closed-tension fractures were observed in the core interval and are commonly coincident with the observed horizontal compaction features (stylolite). Quartz is the dominant mineral found to fill observable fractures. The stylolites are well-represented, vary in orientation, and exhibit mainly a horizontal trend.

2.4.4.3 Borehole Image Fracture Analysis

Schlumberger's Quanta Geo 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 2-46 and 2-47 show two sections of the interpreted borehole imagery and primary features observed. The far-right track on Figure 2-46 demonstrates that the tool provides information on surface boundaries and bedding features and notes the presence of electrically conductive features that characterize the Icebox Formation. These are interpreted as stylolites. Figure 2-47 reveals the features that are clay-filled because of their electrically conductive signal. The logged interval of the Deadwood B shows that the main features present are stylolites, which are an indication that the formation has undergone a reduction in porosity in response to postdepositional stress.

The diagrams shown in Figures 2-48 and 2-49 provide the orientation of the electrically conductive features in the Icebox and Deadwood B Formations, respectively. As shown, the electrically conductive features are stylolites and have no preferred orientation.

Drilling-induced fractures were not identified either in the Icebox or Deadwood B Formations. However, breakouts were highlighted in the Precambrian basement and are oriented northwest–southeast (Figure 2-50), which is perpendicular to the maximum horizontal stress (SH_{max}).

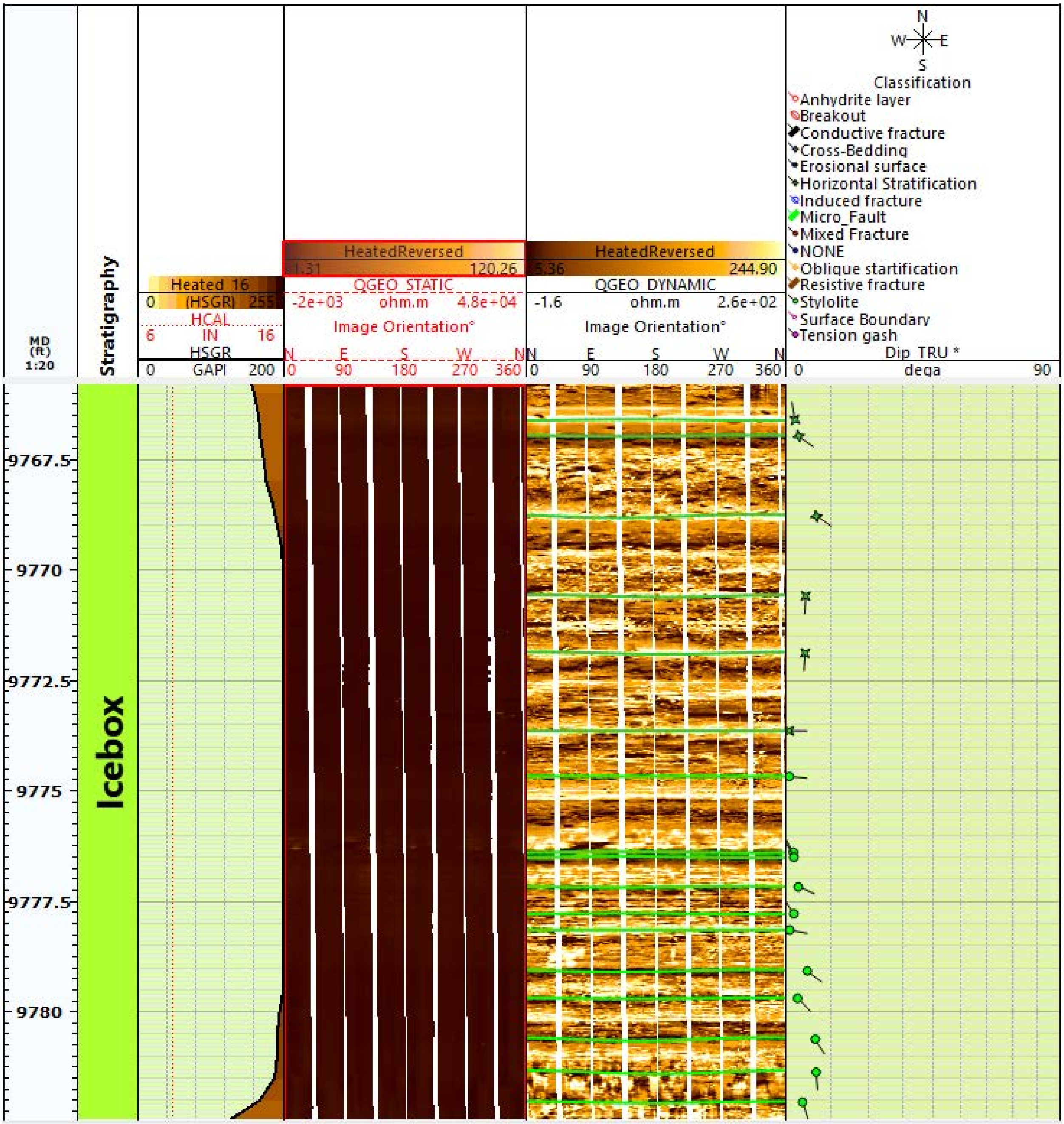

Figure 2-46. Examples of the interpreted Quanta Geo log for the J-LOC1 well. This example shows the common feature types seen in the Icebox Quanta Geo borehole image analysis.

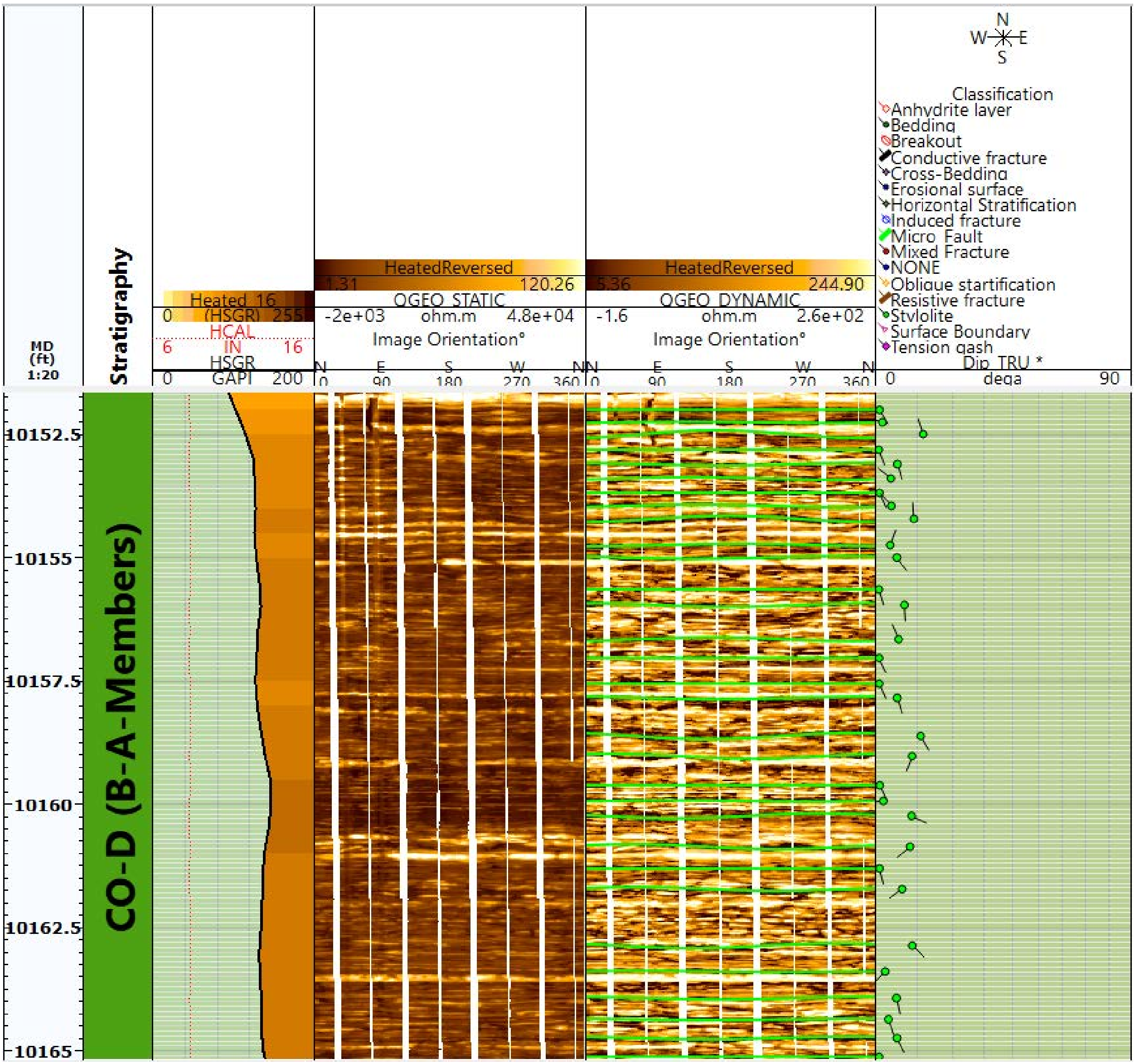

Figure 2-47. Examples of the interpreted Quanta Geo log for the J-LOC1 well. This example shows the common feature types seen in the Deadwood B Quanta Geo borehole image analysis.

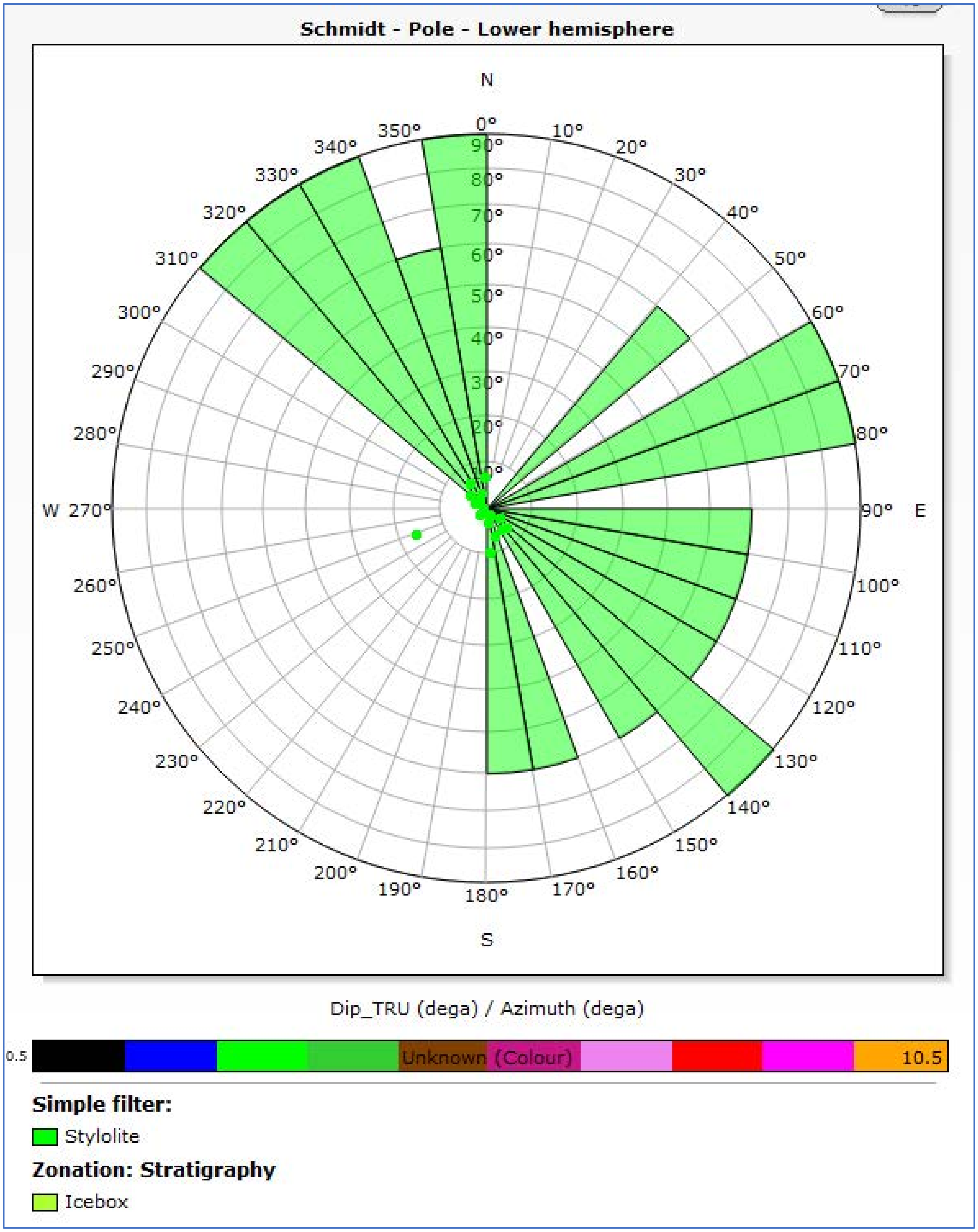

Figure 2-48. This example shows stylolites seen in the Icebox Formation.

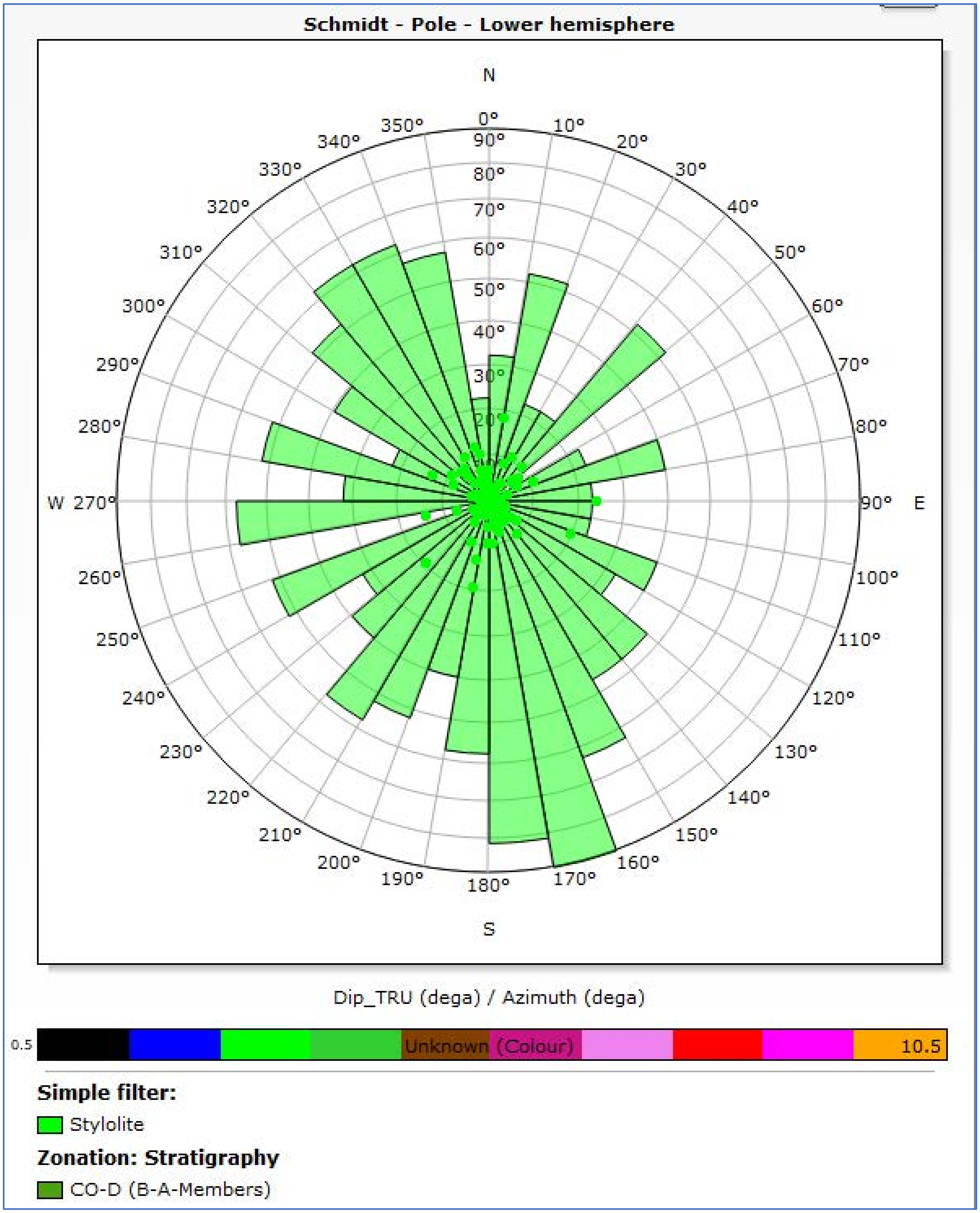

Figure 2-49. This example shows stylolites seen in the Deadwood B Formation.

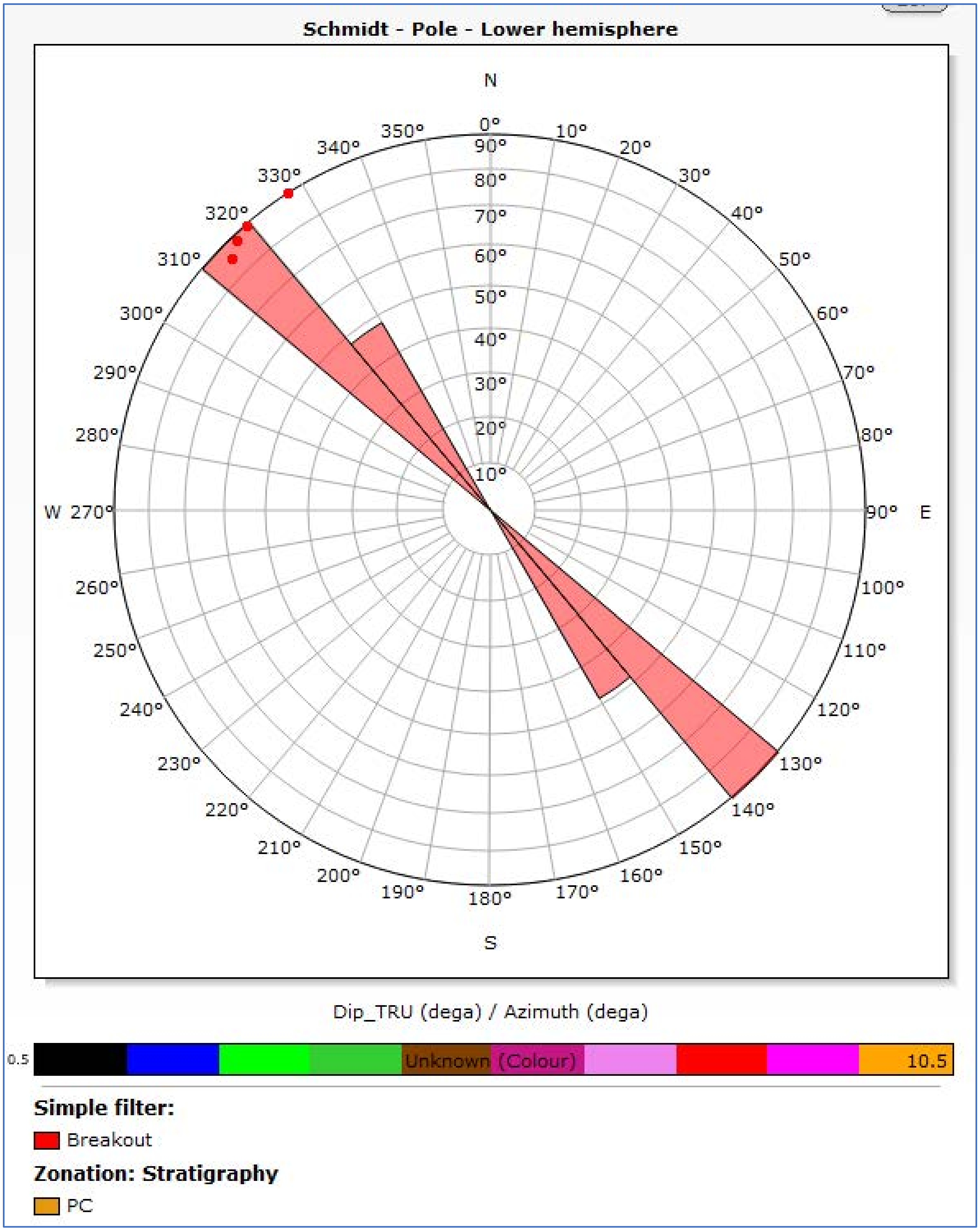

Figure 2-50. Breakout dip orientation in the Precambrian basement.

2.4.4.4 Stress

During drilling of the J-LOC1 well, an openhole MDT microfracture in situ stress test was completed to determine a formation breakdown pressure and minimum horizontal stress. The microfracture in situ stress test operation was performed using the MDT dual-packer module to obtain the formation breakdown pressure followed by multiple injection–falloff cycles to determine formation geomechanics properties. Within the Icebox Formation confining zone, two attempts were made at a depth of 9,749.51 and 9,751.19 ft to determine the formation breakdown pressure and closure pressure, which corresponds to the minimum horizontal stress. Unfortunately, these attempts were unsuccessful to achieve the formation breakdown pressure with an applied maximum injection pressure of 10984.9 and 10867.24 psi (Figure 2-51 and Figure 2-52). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module."

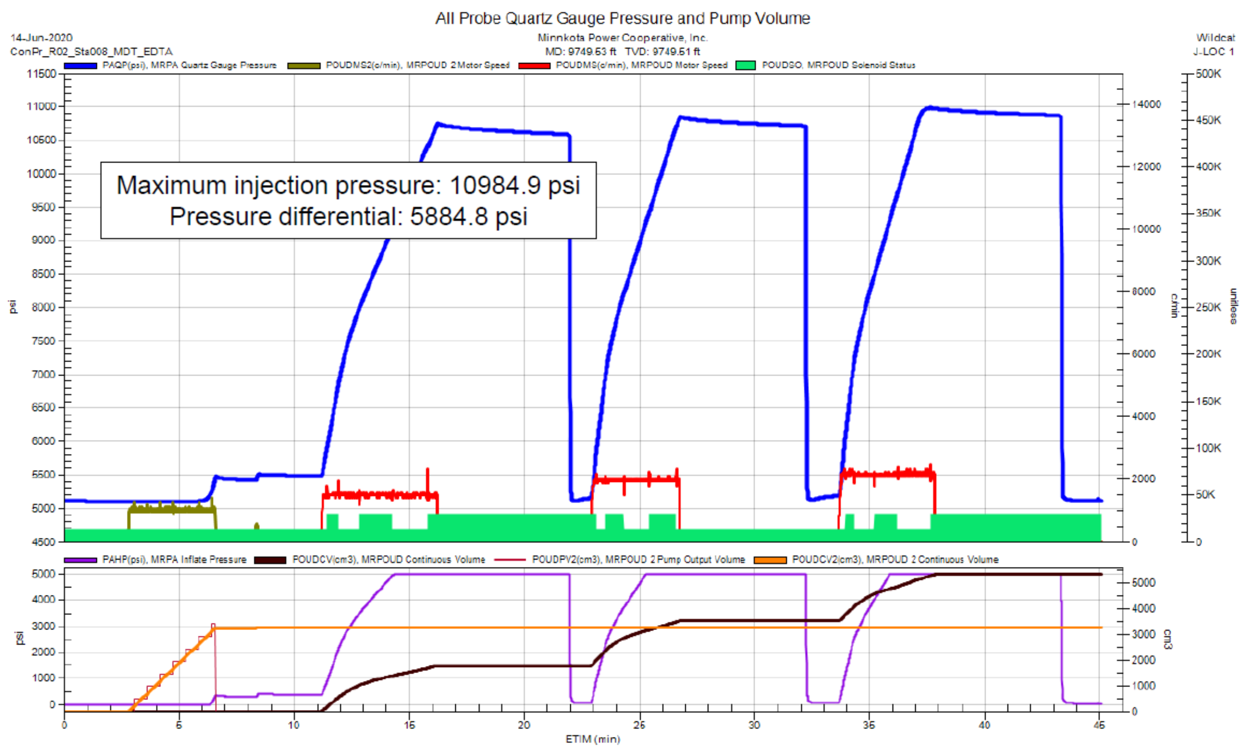

Figure 2-51. J-LOC1 Icebox MDT microfracture in situ stress test (first attempt) at 9,749.51 ft.

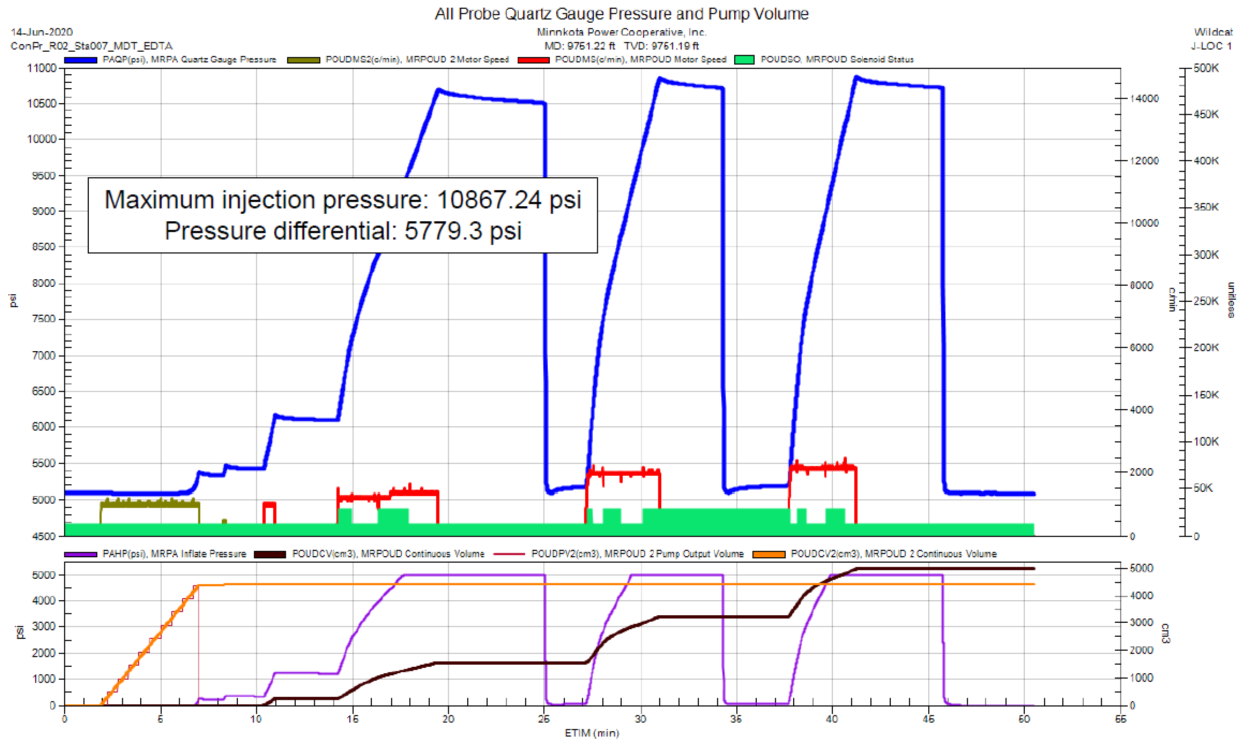

Figure 2-52. J-LOC1 Icebox MDT microfracture in situ stress test (second attempt) at 9,751.19 ft.

J-LOC1 openhole logging data were used to construct a 1D mechanical earth model (MEM) for different formations, including the Icebox Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties such as Young's modulus, Poisson's ratio, Shear modulus, and Bulk modulus were calculated based on the available well logs. The formation strength properties like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion were also estimated from the available data (Figure 2-53). Table 2-21 provides the summary of stresses in the Icebox Formation generated using the 1D MEM.

Table 2-21. Summary of Stresses in Icebox Formation

Depth, ft	Hydrostatic pressure, psi	Vertical Stress, psi	Minimum Stress, psi
9,665	4,349	10,543	6,853
9,780	4,401	10,675	6,557

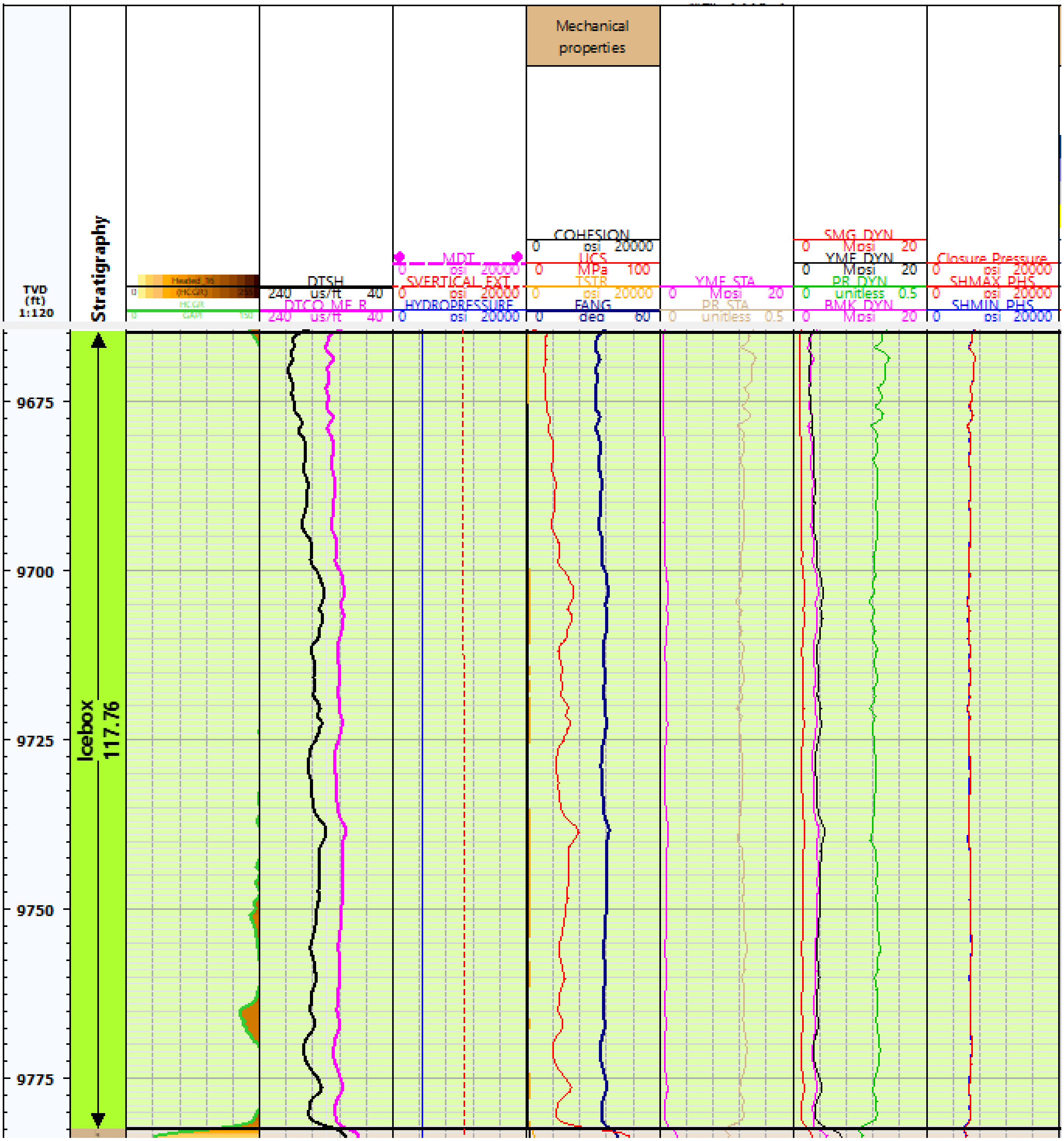

Figure 2-53. 1D MEM of the Icebox Formation.

2.4.4.5 Ductility and Rock Strength

Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Icebox and Deadwood B Formation cores in the J-LOC1. Icebox Formation samples were not testable. Plugs failed under minor stress because of the fissility of the rock. On the other hand, one sample from the Deadwood B Formation was tested and characterized by a porosity equal to 1.4% and a permeability of 0.001 mD. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5801.51 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material (Figure 2-54). Table 2-22 shows the sample parameters, while Tables 2-23 and 2-24 show the elastic, dynamic, and velocity parameters obtained at different confining pressures.

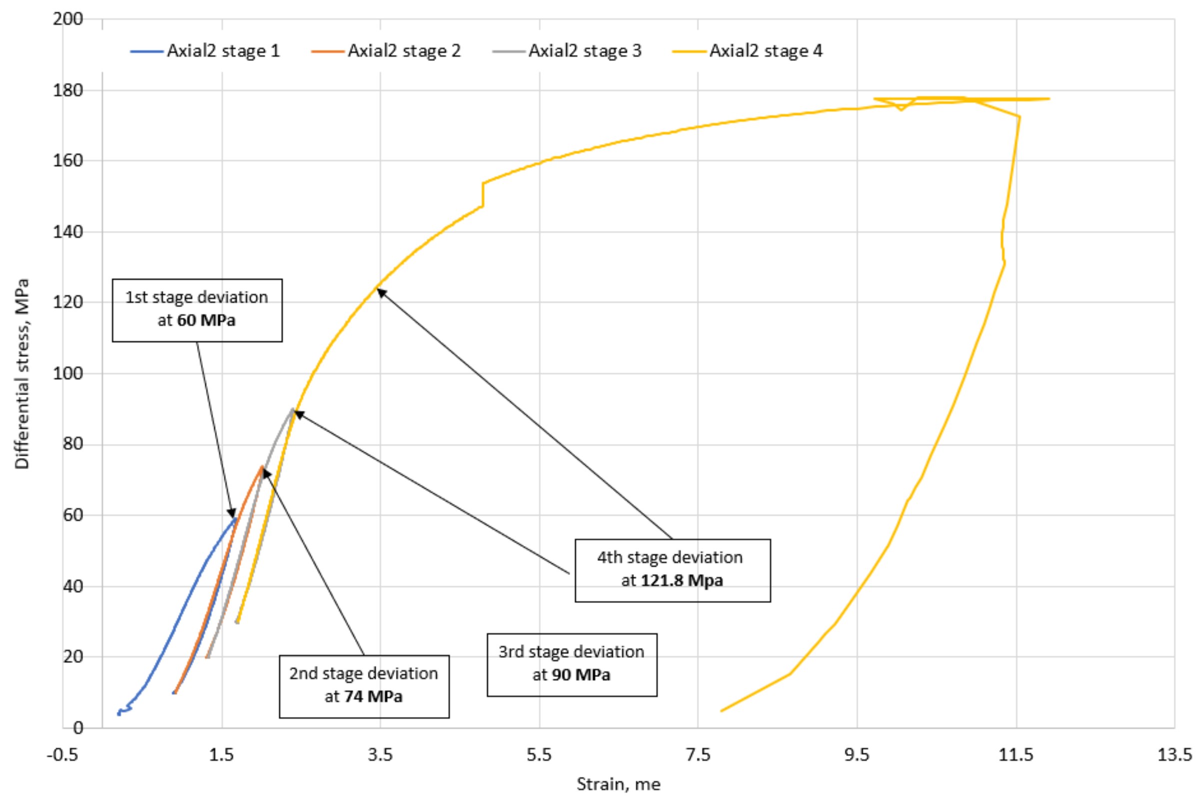

Figure 2-54. Results of multistage triaxial test performed at confining pressures exceeding 40 MPa (5,800 psi), providing information regarding the elastic parameters and peak strength of the rock sample. Failure occurred at the fourth-stage peak stress of 121.8 MPa.

Table 2-22. Sample Parameters

Sample and Experiment Information	
Formation: Deadwood B	Porosity: 1.4%
Dry Bulk Density: 2.765 g/cm^3	Pore Fluids: –
Diameter: 25.40 mm	Entered Length: 58.17 mm

Table 2-23. Elastic Properties Obtained Through Experimentation: E = Young's 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	9.9	66.75	0.189	35.81	28.06	73.22
2	20.3	20.0	68.77	0.246	51.74	31.60	93.88
3	30.2	29.8	71.50	0.275	64.93	34.30	110.67
4	40.3	29.8	77.00	0.227	46.97	31.38	88.81

Table 2-24. Velocity and Dynamic Properties Obtained Through Experimentation: Vp = P-Wave Velocity, Vs = Shear Wave Velocity, E = Young's Modulus, n = Poisson's Ratio

Ultrasonic Velocity Measurements at Different Confining Pressures							
Event	**Conf., MPa**	**Diff., MPa**	**Vp, m/s**	**Vs(X-direction) m/s**	**Vs(Y-direction) m/s**	**E, GPa**	**n, –**
0	2.7	–	5172	2712	2944	56.91	0.287
1	10.2	–	5576	2837	3031	62.29	0.309
2	20.2	–	5836	3076	3131	69.39	0.303
3	30.1	–	5943	3098	3174	71.08	0.307
4	40.2	–	5986	3106	3220	72.27	0.306

2.5 Faults, Fractures, and Seismic Activity

In the Tundra SGS 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. Features interpreted from the 3D seismic data, including paleochannels, a flexure, and a suspected fault in the Precambrian basement, are discussed in this section as well as the data that support the low probability that these features will interfere with containment. The following section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.

2.5.1 Interpreted Features

The analysis of 3D seismic data acquired specifically for Tundra SGS in 2019 and 2020 (Figure 2-6) revealed evidence for suspected paleochannels or preferential erosional zones at the top of the Precambrian basement. Maps of the seismic reflection event interpreted to be the Precambrian–Deadwood contact suggest these features are fairly linear in nature (Figure 2-55). In cross-sectional view of the seismic data, these features appear as depressions in the top of the Precambrian and the lower portion of the Deadwood (Figure 2-56 and 2-57). The isopach values depicted in Figure 2-58 suggest erosional relief on the Precambrian surface of nearly 460 ft. The absence of thickness changes in the Winnipeg or other formations overlying the Deadwood associated with these features suggest these features were filled in during the deposition of the Deadwood.

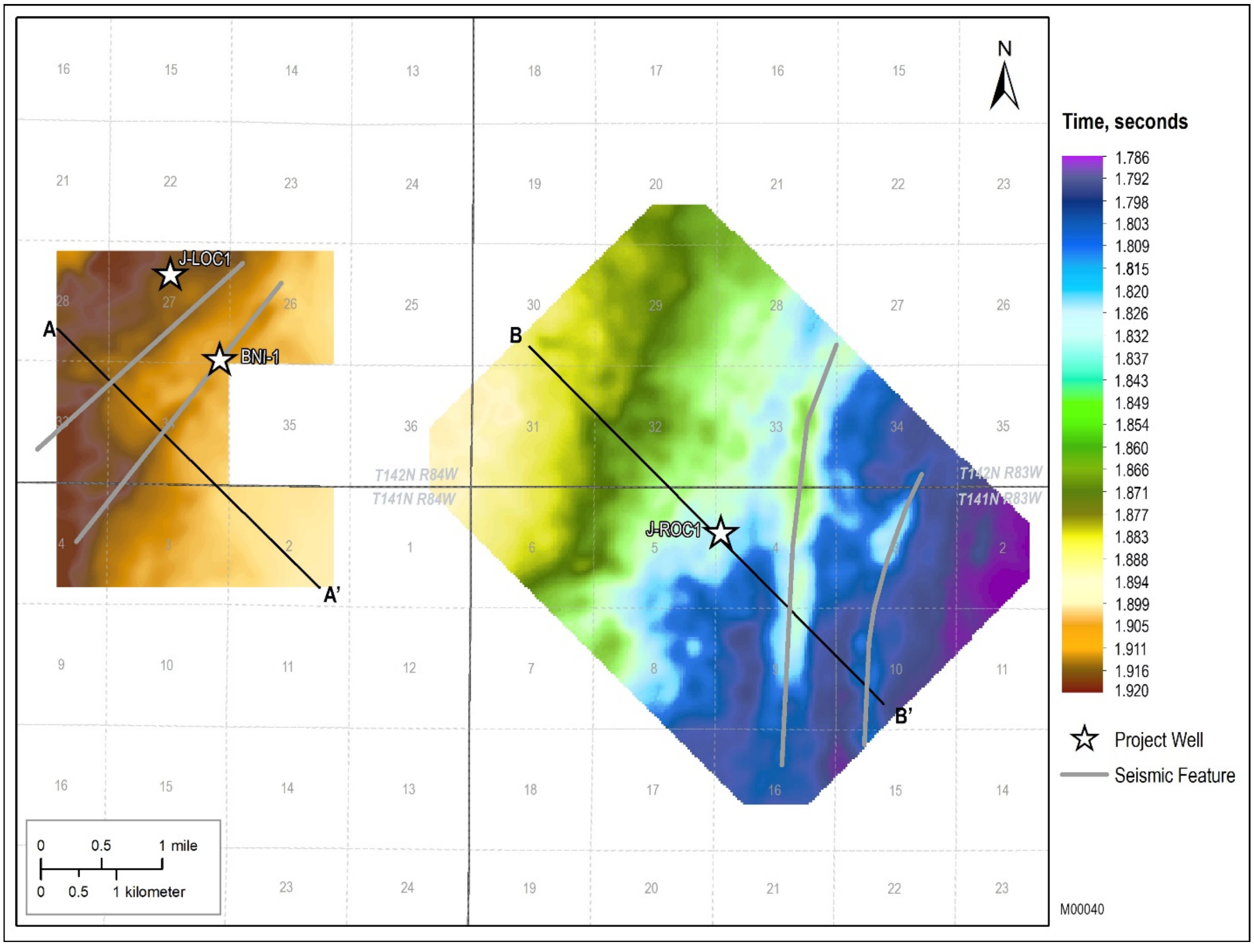

Figure 2-55. Map showing the time structure of the seismic reflection event interpreted to be the Precambrian–Deadwood contact.

In the western 3D seismic survey data, there is no indication that the identified features impact the intervals above the lower Deadwood. Additionally, there is no indication of offset reflections above or below these features in the western 3D seismic survey data that would suggest any deformation or movement associated with these features. There is no evidence to suggest that these interpreted paleochannel features have sufficient permeability or vertical extent to interfere with containment.

There is a flexure in the eastern 3D seismic data where the seismic reflections above the interpreted Precambrian–Deadwood boundary through the Red River Formation appear to dip or sag down (Figure 2-59). These depressions are interpreted to be draped over one of the interpreted paleochannels located at the Precambrian–Deadwood boundary (Figure 2-57). A deep structure was interpreted in the Precambrian basement below this paleochannel and flexure. This structure appears to be a low-dipping thrust fault that terminates at the top of the Precambrian basement (Figure 2-60). The location of this Precambrian fault provides evidence that there was likely

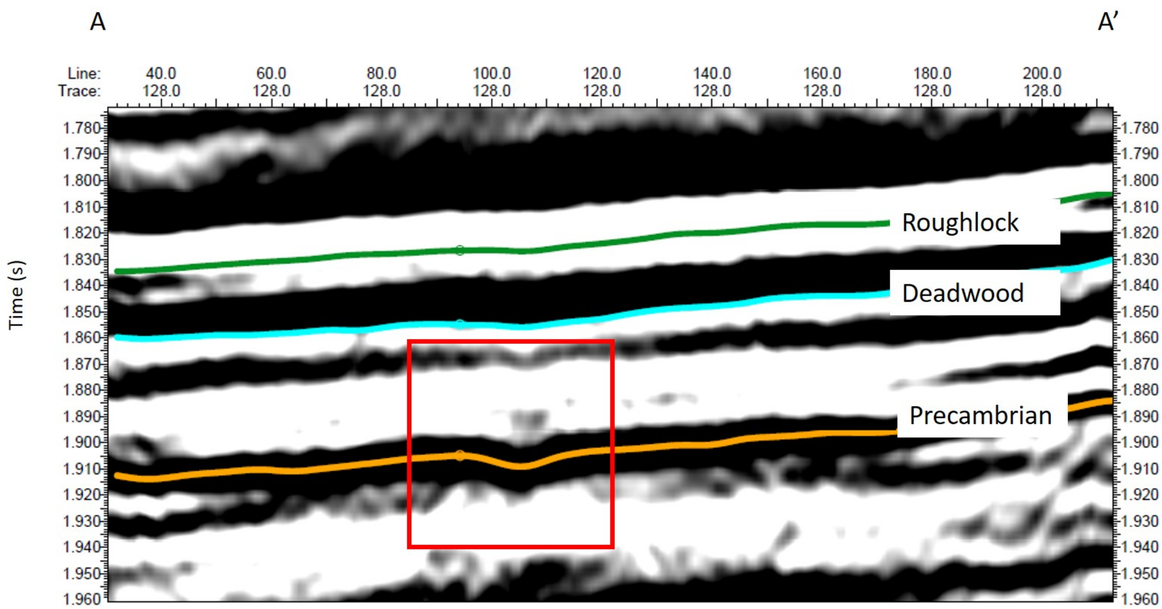

Figure 2-56. Cross-sectional view of the 3D seismic data through one of the linear trends in the West 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). The red box indicates the area that corresponds to the linear feature. Figure 2-55 shows the location of this cross section.

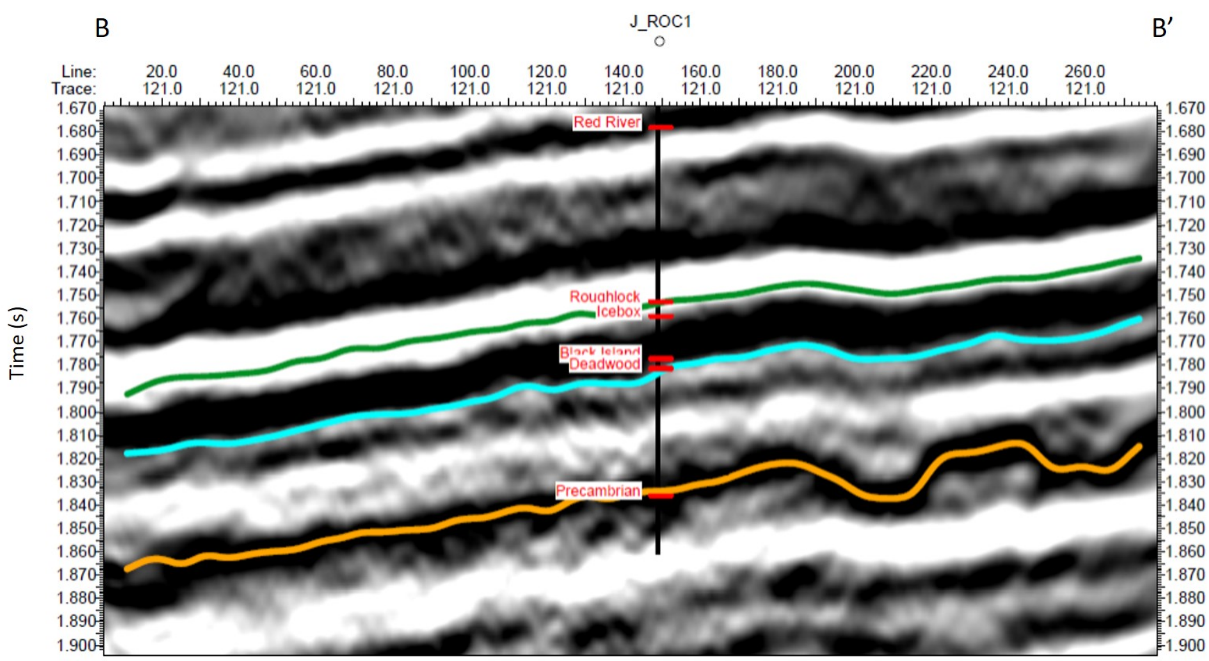

Figure 2-57. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). Depressions along the top of the Precambrian suggest the presence of paleochannels. Figure 2-55 shows the location of this cross section.

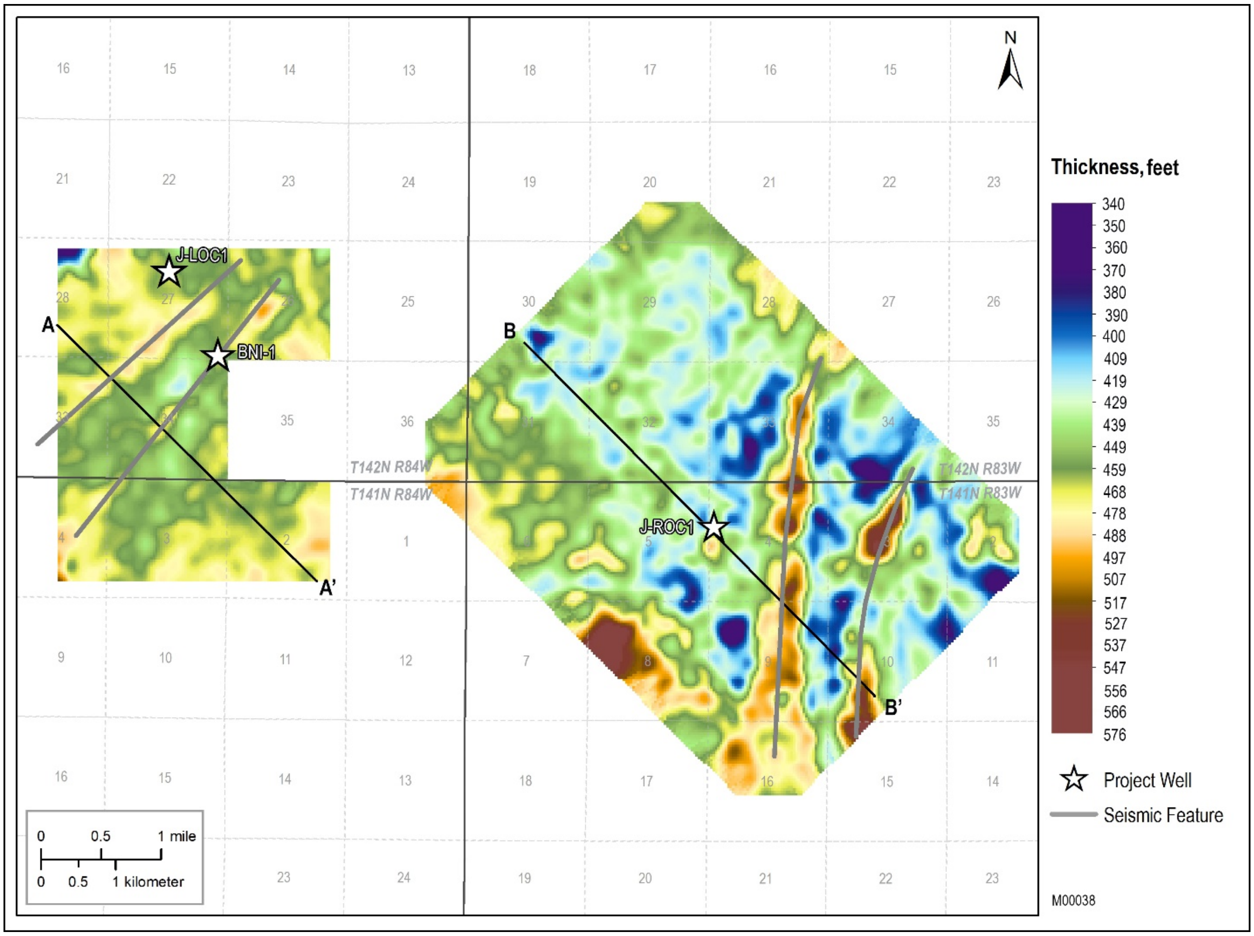

Figure 2-58. Map showing the thickness of the interval from the Precambrian erosional surface up through the top of the Deadwood Formation calculated using the seismic data. The linear trends correspond to areas of increased thickness.

preferential erosion along the exposed Precambrian fault trace during the deposition of the Deadwood Formation. The dip of the Precambrian fault is low-angle whereas the flexure above the paleochannel feature is near-vertical, supporting the interpretation of the fault terminating at the top of the Precambrian basement. The seismic interpretation indicates that the interpreted fault in the Precambrian basement is dipping at ~25 degrees relative to horizontal being 0 degrees. The flexure observed in the overlying sediments is likely associated with postdepositional differential compaction above the paleochannel or slump due to movement along this low-angle basement fault. There is no evidence to suggest that this flexural feature has sufficient permeability to interfere with containment.

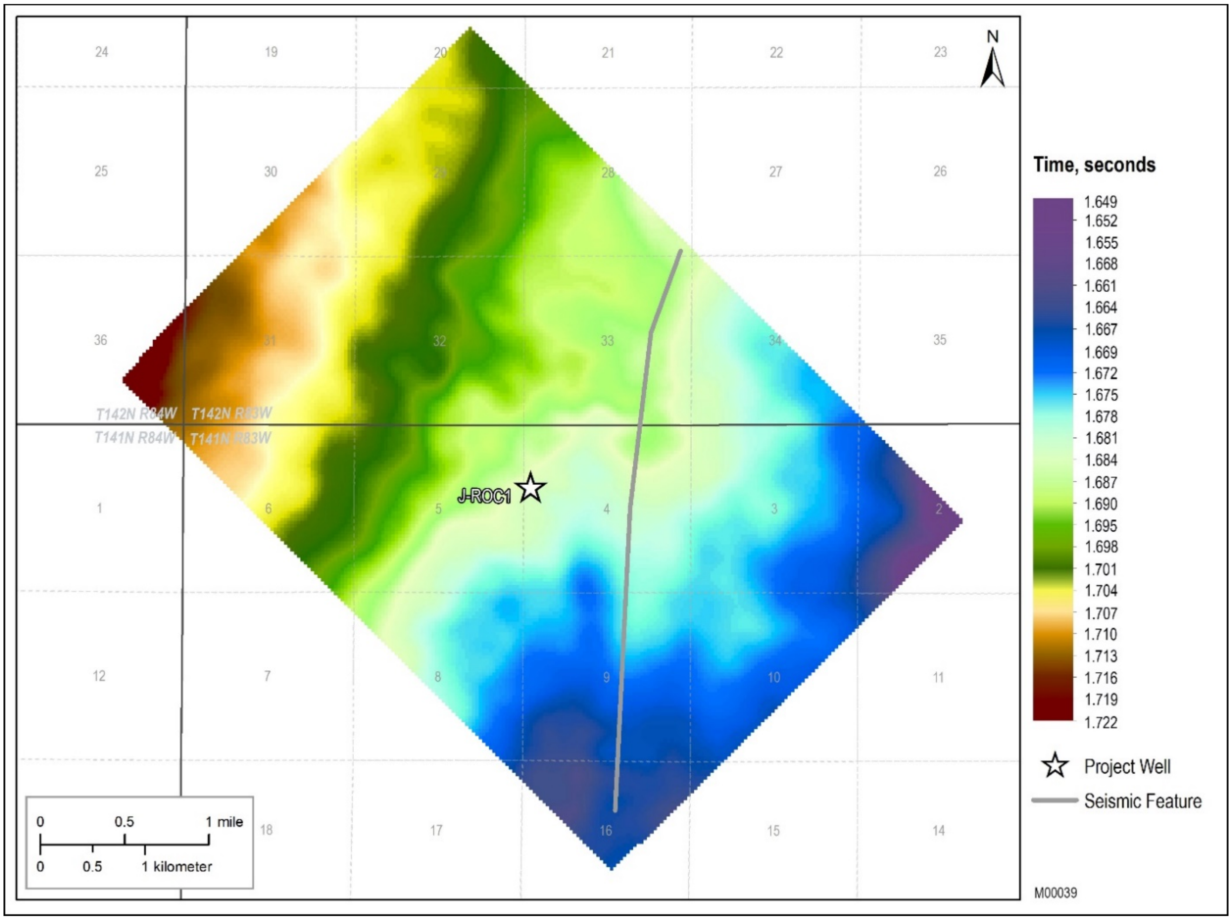

Figure 2-59. Map showing the time structure of the seismic reflection event interpreted to be the top of the Red River Formation. The line shows the location of the interpreted paleochannel that underlies the flexure.

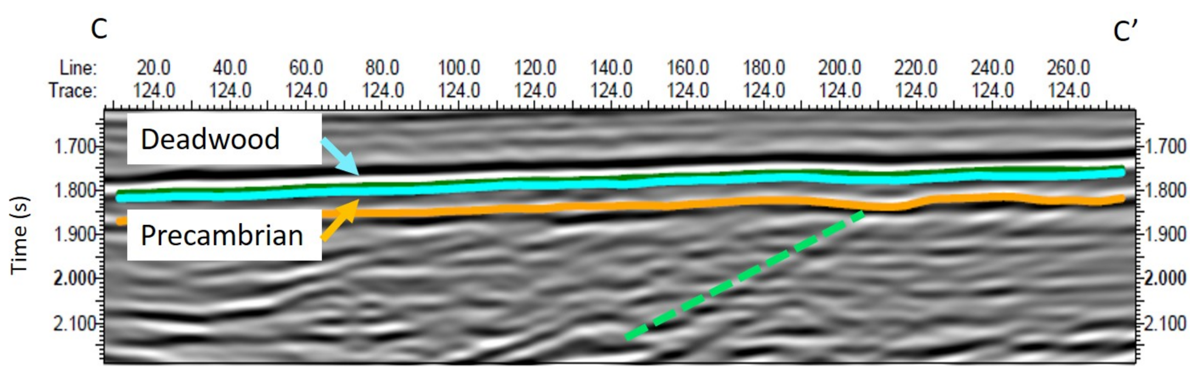

Figure 2-60. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Deadwood (blue) and Precambrian (yellow). The location of the interpreted low-angle thrust fault is shown by the green dashed line. Cross Section C-C’ runs parallel to Cross Section B-B’ shown in Figure 2-55 and is located 160 ft to the west of Cross Section B-B’.

2.5.5.1 Precambrian Fault Geomechanics Study

Geomechanical modeling was done to determine the potential risk of induced seismicity associated with the interpreted Precambrian fault and planned injection activities. The 3D seismic data were used to estimate the dip and strike of the interpreted fault, including uncertainty ranges on both for input into this modeling. A 1D stress model was built from the J-LOC1 well data using the density, compressional sonic, and shear sonic well logs. The pore pressure is assumed equivalent to hydrostatic pressure, with a slight overpressure in the Broom Creek Formation. Overburden stress was estimated by integrating the density data and projecting the density trend to surface. The principal horizontal stresses Sh_{min} and SH_{max} were estimated using the modified Eaton poroelastic model from Theircelin and Plumb (1994) and calibrated to closure pressure measurements in the Deadwood, Broom Creek, and Inyan Kara Formations. Static elastic rock property inputs were calibrated to core measurements. The most conservative approach was taken by choosing the largest differential stress model to conduct the analysis, as it represented the highest risk scenario. A stress trend was developed to represent a consistent stress trend through the Deadwood Formation that was an equivalent trend through the highest-magnitude stresses. For the purposes of failure analysis on the existing feature in the seismic interpretation, that stress trend was projected down into the Precambrian basement.

To understand the highest possible risk scenario, the scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data do not suggest that it does. Conservative estimates for friction coefficient (30) and cohesion (0) were used in this analysis. Given those conditions and the state of stress modeled in the Deadwood, the failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure on that feature (Figure 2-61).

The maximum expected pressure change in the Deadwood due to planned injection activities does not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 2-62). Additionally, the injection interval is approximately 120 ft above the Precambrian–Deadwood boundary and the expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data suggests planned injection activities will not cause induced seismicity.

Additionally, sensitivity analysis was run using the publicly available Fault Slip Potential tool using the inputs of friction coefficient, SH_{max} azimuth, fault dip, fault strike, pore pressure, SH_{max} magnitude, SH_{min} magnitude, and overburden magnitude. The results proved insensitive to all inputs except the dip of the fault. At the low-angle dip of the fault, there is very low risk of failure given the interpretation of the state of stress.

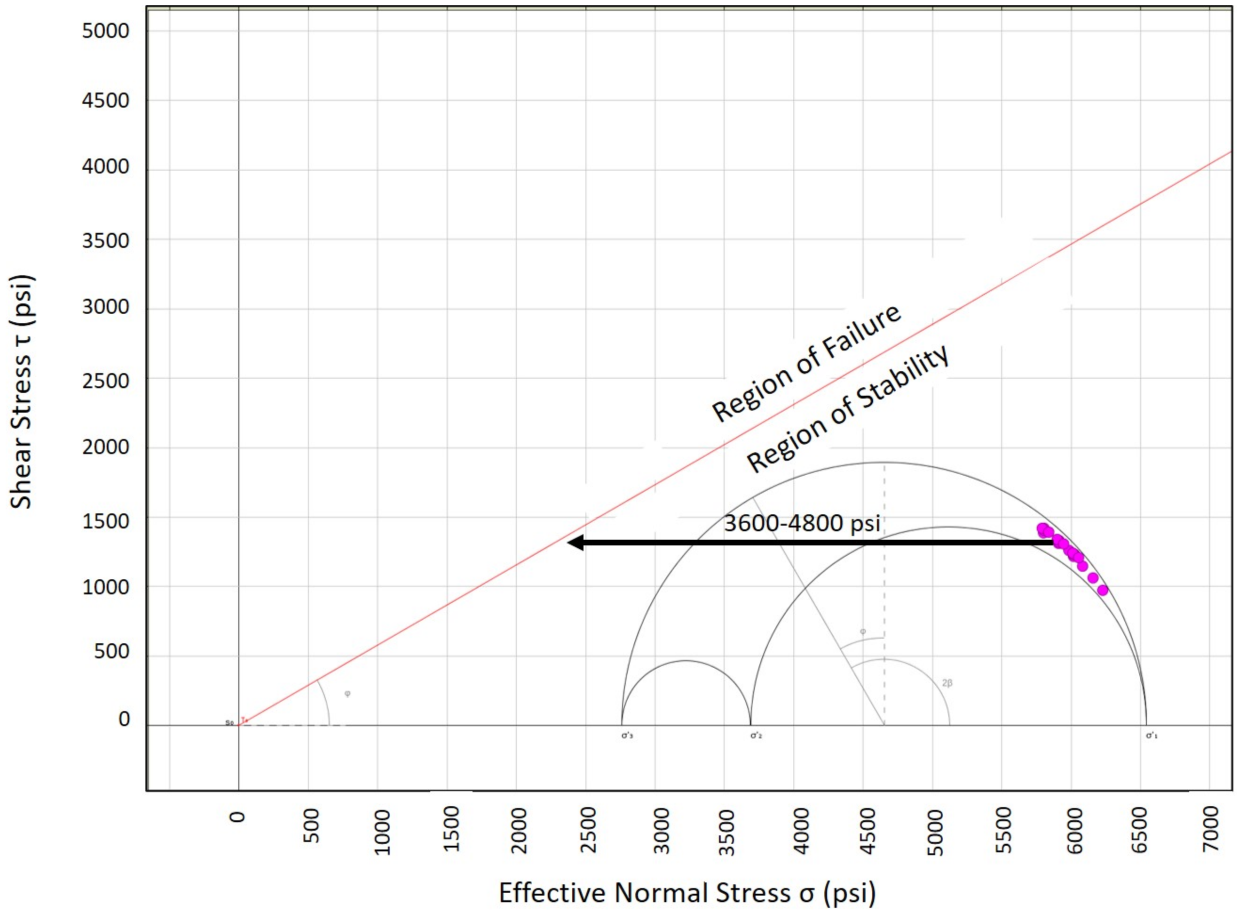

Figure 2-61. Mohr circle depiction of the stress state at the depth of the Deadwood Formation indicates a pressure window of 3,600 to 4,800 psi to create failure on the fault represented by the pink dots. Pink dots represent the strike and dip values for the fault interpreted from the seismic data relative to in situ stress orientations.

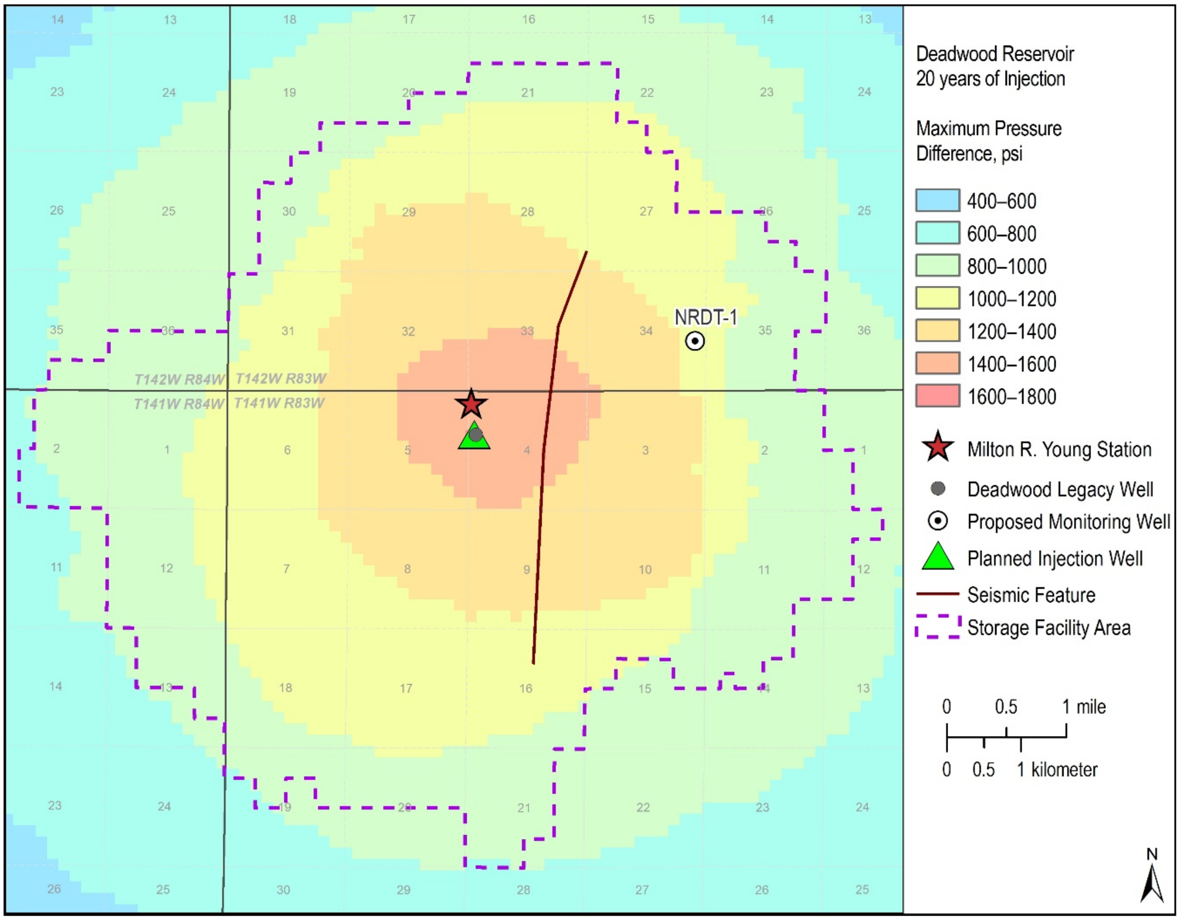

Figure 2-62. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line.

2.5.2 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 seismic events were detected within the North Dakota portion of the Williston Basin (Table 2-25) (Anderson, 2016). Of these 13 seismic events, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-63). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 mi from the J-ROC1 well near Huff, North Dakota (Table 2-25). The magnitude of this seismic event is estimated to have been 4.4.

Table 2-25. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mi	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to Tundra SGS J-ROC1 Well, mi
Sept 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	124.6
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	149.1
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	144.1
Aug 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold Southwest	D	67.4
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	156.0
Nov 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	61.6
Nov 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	166.5
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	164.9
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	39.6
May 13, 1947	3.7**	U	−100.90	46.00	Selfridge	J	74.9
Oct 26, 1946	3.7**	U	−103.70	48.20	Williston	K	140.2
April 29, 1927	0.2**	U	−102.10	46.90	Hebron	L	43.4
Aug 8, 1915	3.7**	U	−103.60	48.20	Williston	M	136.4

* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.

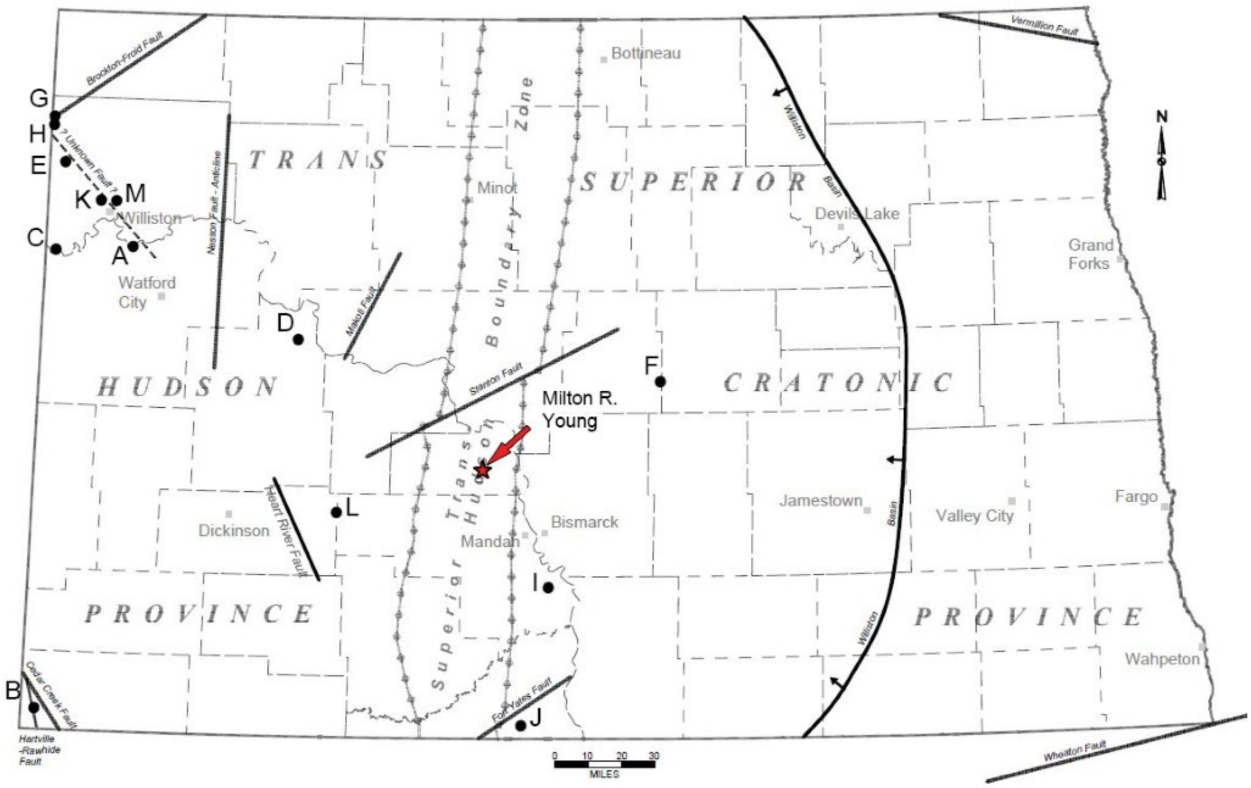

Figure 2-63. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations listed in Table 2-24.

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 damaging seismic events predicted to occur over a 10,000-year time period (Figure 2-64) (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 the injection wells in the Williston Basin. They noted only two historic seismic events in North Dakota that could be associated with nearby oil and gas activities. These results indicate relatively stable geologic conditions in the region surrounding the potential injection site. Based on the review and assessment of 1) the USGS studies, 2) the characteristics of the Black Island and Deadwood injection zone and upper and lower confining zones, 3) the low risk of induced seismicity due to the basin stress regime, and 4) the history of recorded seismic events, seismic activity is not expected to interfere with containment of the maximum volume of CO_2 proposed to be injected annually over the life of this project.

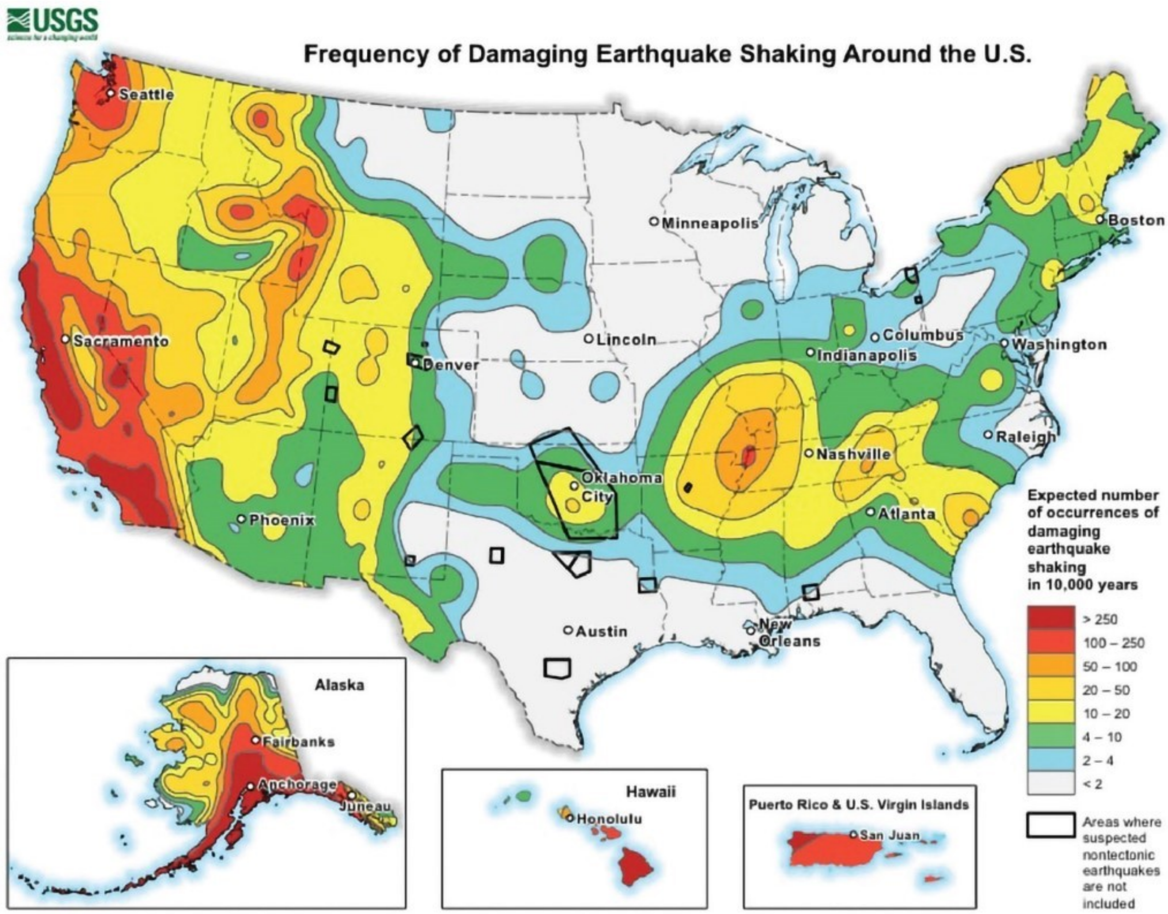

Figure 2-64. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S. Geological Survey, 2019).The map shows there is a low probability of damaging seismic events occurring in North Dakota.

2.6 Potential Mineral Zones

There has been no historic hydrocarbon exploration in, or production from, formations above the Deadwood Formation in the storage facility area. The only hydrocarbon exploration well near the storage facility area, the Herbert Dresser 1-34 (NDIC File No. 4937), was drilled in 1970 to explore potential hydrocarbons in the Charles Formation. The well was dry and did not suggest the presence of hydrocarbons. There are no known producible accumulations of hydrocarbons in the storage facility area.

Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations define shallow gas resources as “gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced.”

Lignite coal currently is mined in the area of the Center coal mine, operated by BNI Coal. The Center Mine currently mines the Hagel coal seam for use as fuel at Minnkota's MRYS. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation.

Thickness of the Hagel coal seam averages 7.8 ft in the area permitted to be mined but varies, with some areas exceeding 10 ft in thickness (Figure 2-65) (Ellis and others, 1999). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam, but currently the Hagel is the only economically minable seam with its thickness and overburden of 100 ft or less (Figure 2-66). The thickness of the Hagel and other coal seams in the Fort Union Group thicken and deepen to the west. The overlying Beulah–Zap coal seam pinches out farther to the west but is economically minable in the central part of Mercer County at North American Coal's Coteau Mine. The Hagel seam pinches out to the east, and there are no other coal seams mined farther east than the Hagel.

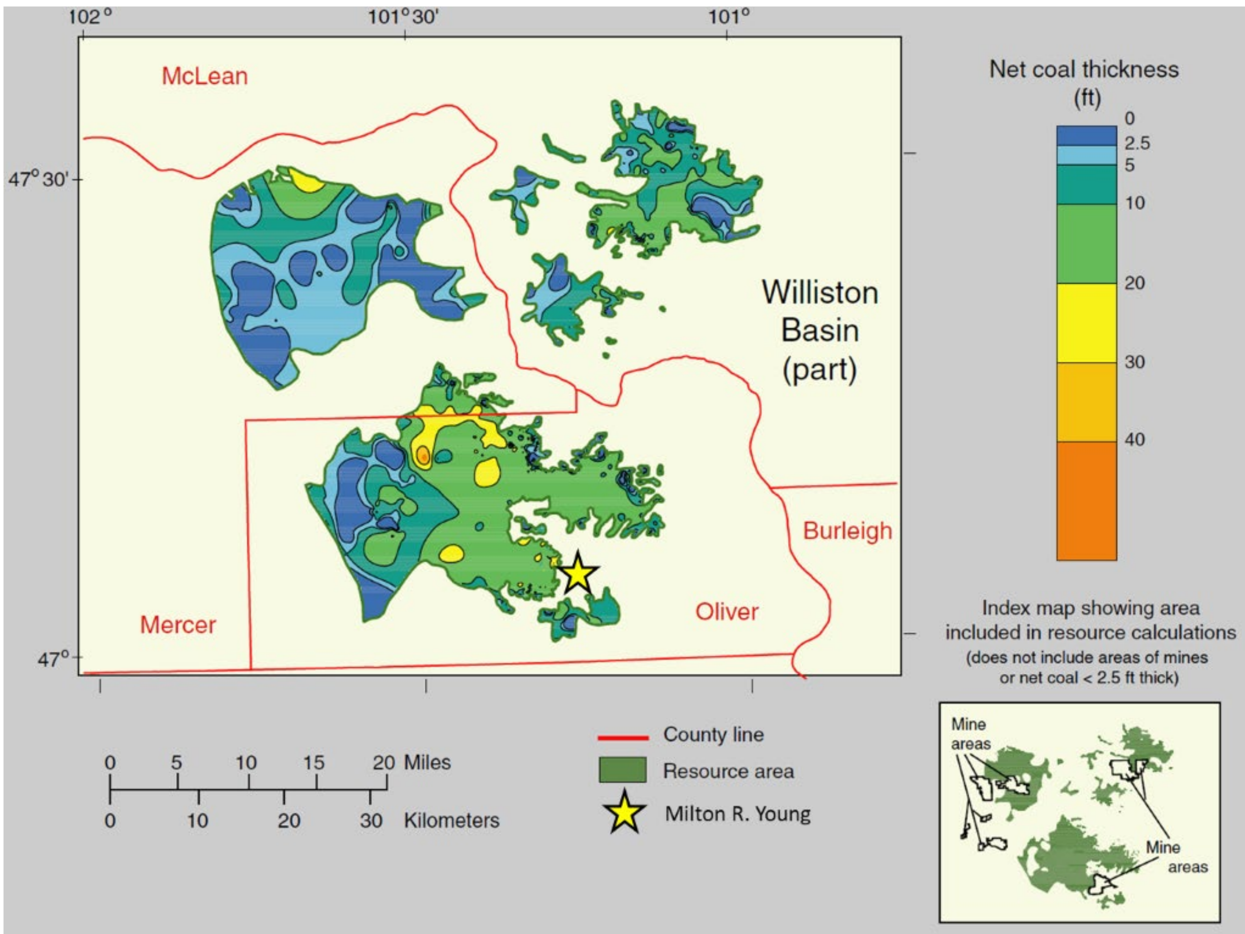

Figure 2-65. Hagel net coal isopach map (modified from Ellis and others, 1999).

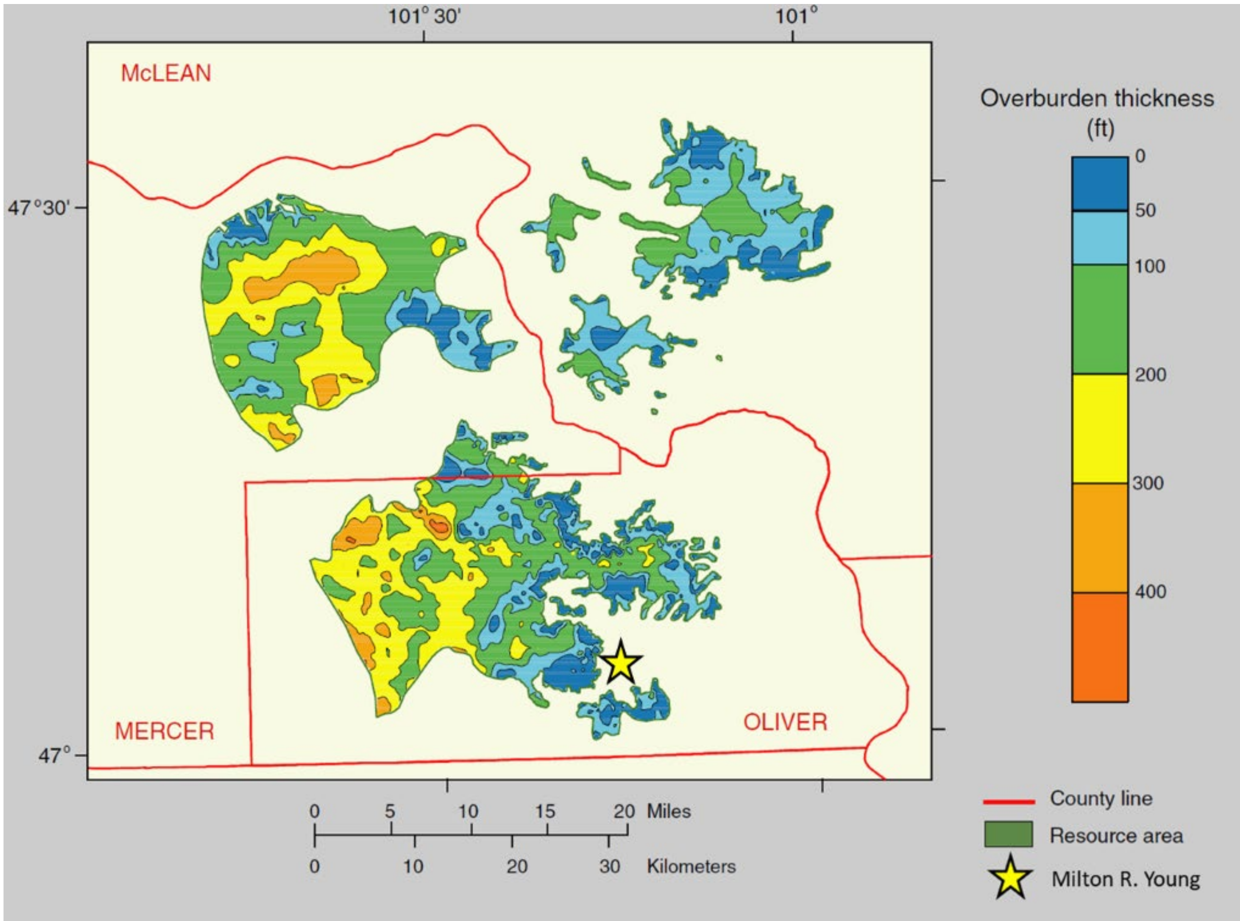

Figure 2-66. Hagel overburden isopach map (modified from Ellis and others, 1999).

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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[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 (Figure 3-1) 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 resultant pressure as the "critical threshold pressure." Application of the U.S. Environmental Protection Agency (EPA) method shows the critical threshold pressure increase at the top of the Deadwood Formation using site-specific data from J-ROC1 was determined to be 127 psi (Appendix A, Table A-4).

Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR.

NDAC § 43-05-01-05 subsection 1(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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.

This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 3-1.

3.1.2 Supporting Maps

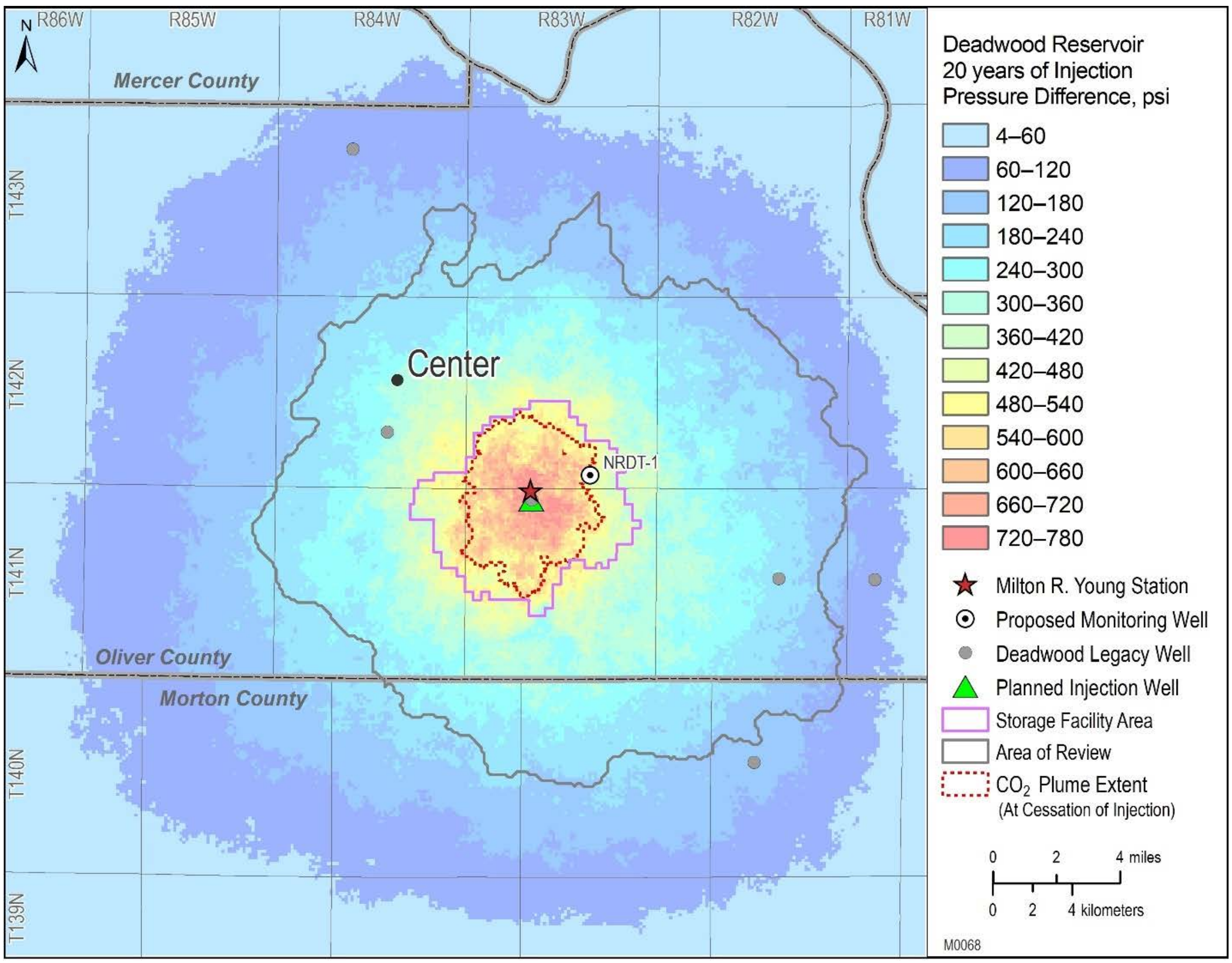


Figure 3-1. Pressure map showing the subsurface pressure influence associated with CO_2 injection in the Deadwood Formation. Shown is the CO_2 plume extent after 20 years of injection, storage facility area, and AOR boundary in relation to the subsurface pressure influence. Subsurface pressure subsides at the cessation of injection.

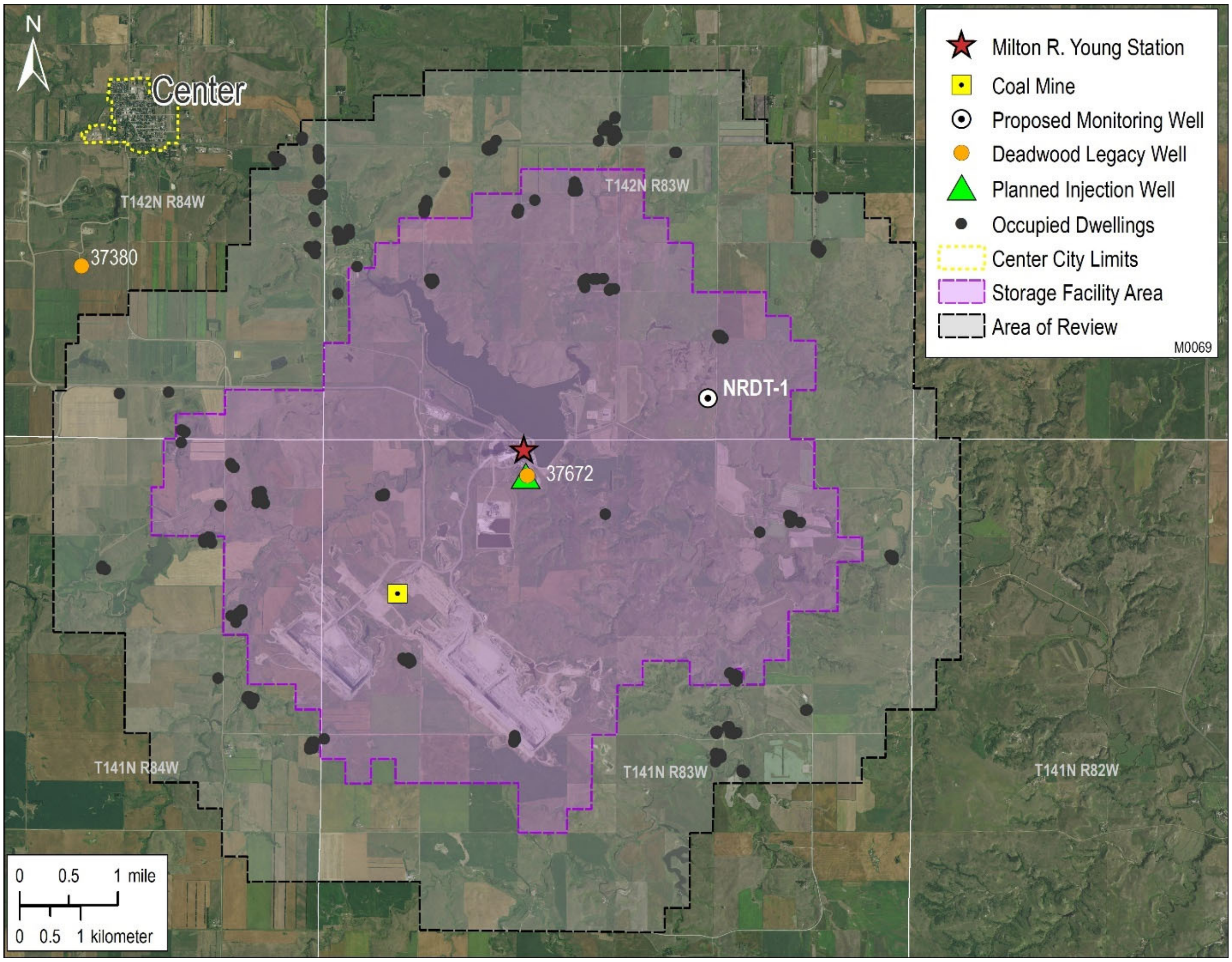


Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings.

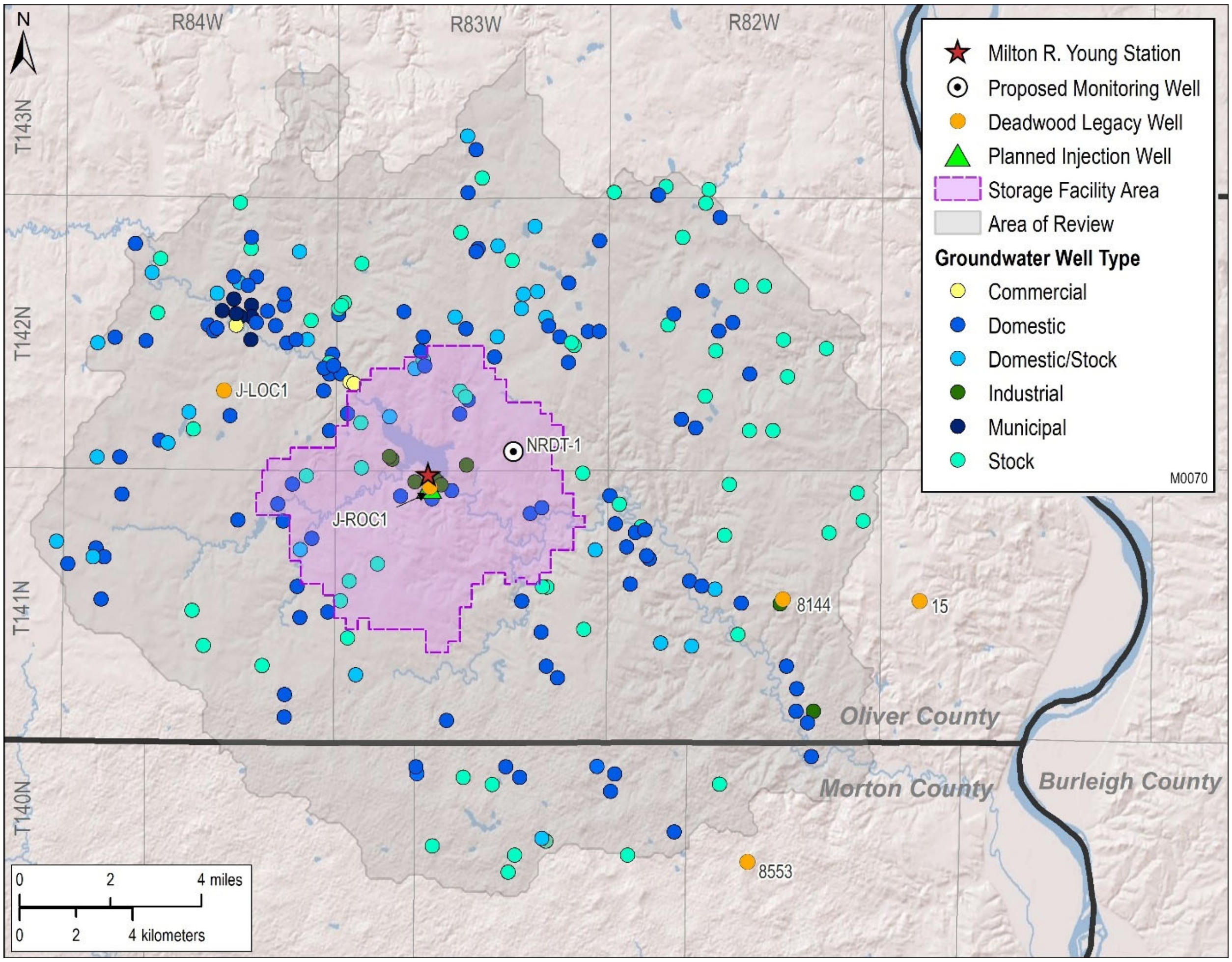


Figure 3-3. AOR map in relation to nearby legacy wells and groundwater wells. Shown are the storage facility area and AOR boundaries.

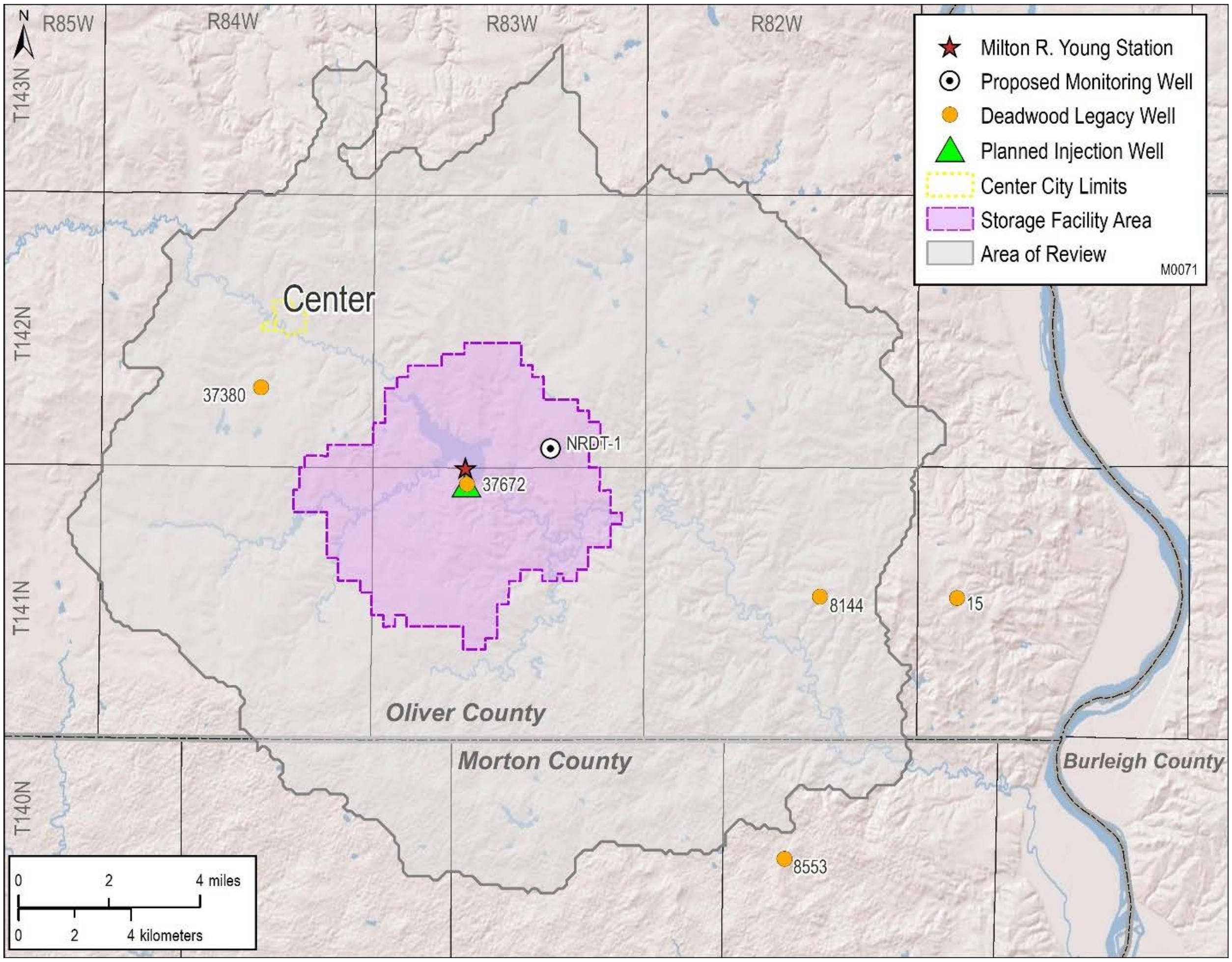


Figure 3-4. The AOR map in relation to nearby legacy wells. Shown are the storage facility area (purple boundary), Center city limits (yellow dotted boundary), and AOR (gray boundary). Orange circles represent nearby legacy wells near the project area, including within the AOR.

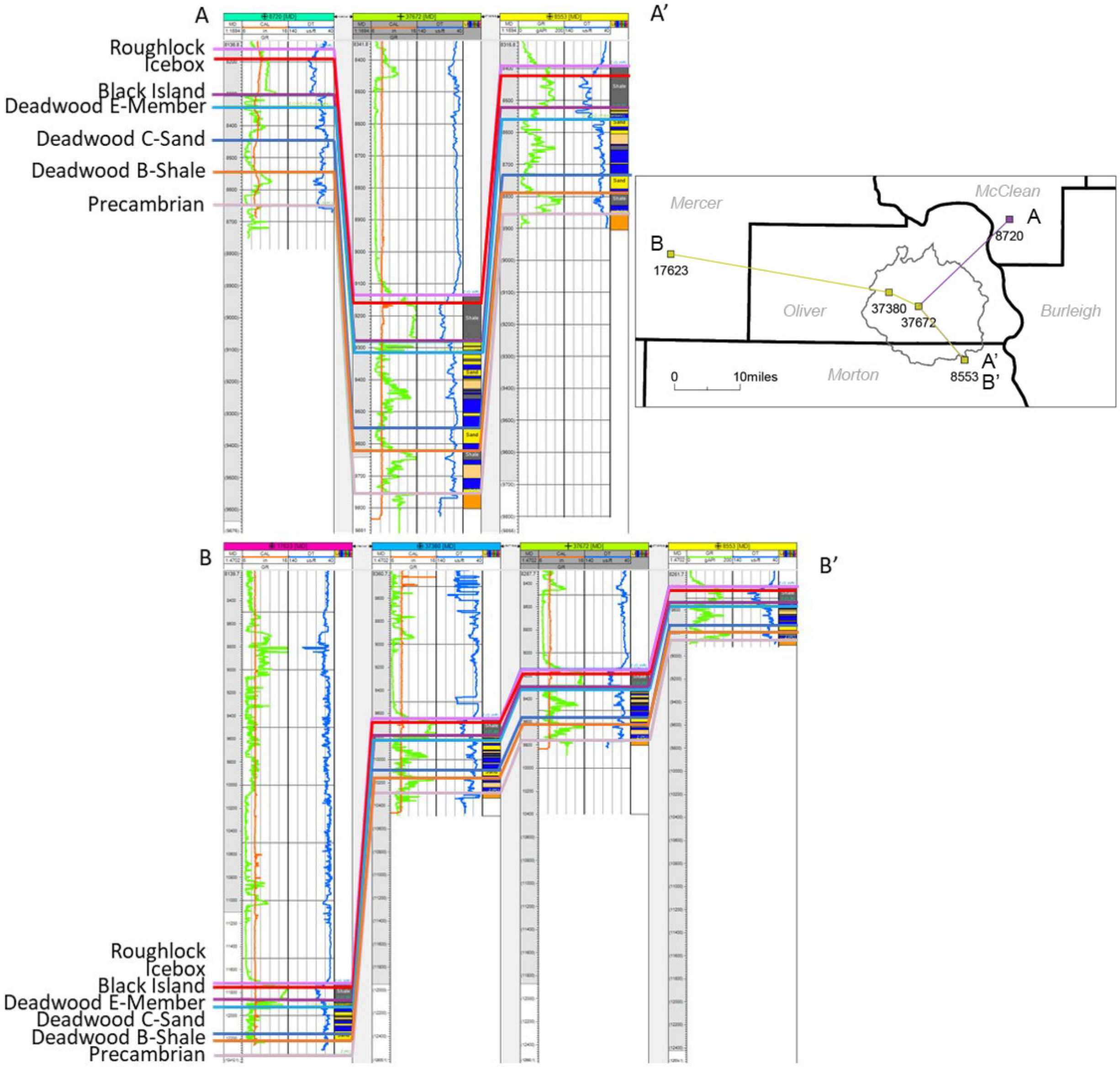


Figure 3-5. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement with an inset map demonstrating the location of the J-LOC1 and J-ROC1 wells. Logs displayed in tracks from left to right are 1) gamma ray (GR, green) and caliper (orange) and 2) delta time (blue), and 3) interpreted lithology log.

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 through 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	X	
Any Existing Aboveground Facilities		X
Roads	X	
State Boundary Lines		X
County Boundary Lines	X	
Indian Boundary Lines		X
**Other Pertinent Surface Features	X	

* Cathodic protection is planned with location TBD.
** Center, North Dakota, city limit boundary.

3.2 Corrective Action Evaluation

Table 3-2. Wells in AOR Evaluated for Corrective Action

NDIC[1] Well File No.	Operator	Well Name	Spud Date	Surface Casing OD, in,	Surface Casing Seat, ft	Long-String Casing, in.	Hole Direction	TD,[2] ft	TVD,[3] ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Corrective Action Needed
8144	Pennzoil Co.	Little Boot 15-44	2/14/1981	8.625	2,014	Openhole	Vertical	8,655	8,655	P&A	4/1/1981	141 N	82 W	15	SE/SE	Oliver	No
37672	Minnkota Power Cooperative, Inc. (Minnkota)	J-ROC1	9/8/2020	13.375	2,000	Openhole	Vertical	9,871	9,871	TA	10/27/2020	141 N	83 W	4	SW/NW	Oliver	No
37380	Minnkota	J-LOC1	5/14/2020	9.625	1,654	5.5	Vertical	10,470	10,470	TA	12/19/2020	141 N	83 W	27	SW/NE	Oliver	No

[1] North Dakota Industrial Commission.
[2] Total depth.
[3] True vertical depth.

Table 3-3. Little Boot 15-44 (NDIC File No. 8144) Well Evaluation

Well Name: Little Boot 15-44 (NDIC File No. 8144)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	8,500	8,600	100	35
2	7,720	7,820	100	35
3	7,200	7,300	100	35
4	6,500	6,600	100	35
5	5,450	5,550	100	35
6	5,050	5,150	100	35
7	4,300	4,500	200	100
8	1,587	2,800	1,213	424
9	2	12	10	10

Formation		Cement Plug Remarks
Name	Estimated Top (ft)	
Pierre	1,375	Cement Plug 9 isolates the surface.
8⅝" Casing Shoe	2,014	Cement Plug 8 isolates the surface casing shoe and above the Mowry Formation.
Greenhorn	2,803	
Mowry	3,177	Cement Plug 7 isolates below the Mowry and Inyan Kara Formations
Inyan Kara	3,434	
Swift	3,651	
Rierdon	4,038	
Broom Creek	4,400	Cement Plug 7 isolates above the Broom Creek Formation.
Kibbey Lime	5,051	
Icebox	8,440	Cement Plug 2 isolates above the Icebox and Deadwood Formations.
Deadwood	8,587	Cement Plug 1 isolates above the Deadwood Formation.

Spud Date: 2/14/1981
Total Depth: 8,655 ft (Deadwood Formation)

Surface Casing:
8⅝" 36# K-55 casing set at 2,014 ft, cement to surface with 935 sacks Class G cement.

Openhole P&A

Corrective Action: No corrective action is necessary. The Deadwood Formation is isolated mechanically by a series of balanced cement plugs and is located near the outside edge of the AOR. Monitoring at this location may be necessary depending on actual plume growth.

Table 3-4. J-ROC1 (NDIC File No. 37672) Well Evaluation

Well Name: J-ROC1 (NDIC File No. 37672)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	9,030	9,375	345	241
2	7,830	8,550	720	212
3	7,361	7,830	469	272
4	6,516	7,200	684	241
5	5,215	5,600	385	147
6	4,430	4,770	340	160
7	3,400	3,715	315	145
8	1,715	2,050	335	221
9	28	90	62	46

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
Pierre	1,150	Cement Plug 9 isolates the surface.
$13^3/_8$" Casing Shoe	2,000	Cement Plug 8 isolates the surface casing shoe.
Mowry	3,404	Cement Plug 7 isolates above the Inyan Kara Formation.
Inyan Kara	3,686	
Swift	3,865	
Spearfish/Opeche	4,688	Cement Plug 6 isolates above the Broom Creek and Spearfish/Opeche Formations.
Broom Creek	4,740	
Amsden	4,974	
Icebox	9,170	Cement Plug 1 isolates above the Deadwood Formation and is CO_2-resistant.
Deadwood	9,316	
Precambrian	9,762	

Spud Date: 9/8/2020
Total Depth: 9,871 ft (Precambrian Basement)

Surface Casing:
$13^3/_8$" 61# K-55 casing set at 2,000 ft, cement to surface with 1,207 sacks Class C cement.

Openhole TA

Corrective Action: No corrective action is necessary. The Deadwood Formation is isolated mechanically by a series of conventional and CO_2-resistant balanced cement plugs. Minnkota plans to convert this well into an injection well named Liberty-1 (J-ROC1 NDIC File No. 37672).

Table 3-5. J-LOC1 (NDIC File No. 37380) Well Evaluation

Well Name: J-LOC1 (NDIC File No. 37380)

Casing Program				
Section	Casing Outside Diameter (OD), in.	Weight, lb/ft	Casing Seat, ft	Grade
Surface	9⅝	40	1,654	K-55
Production	5½	23	10,450	L-80
				13Cr-95

Cementing Program				
Casing, in.	Cement Type	TOC, ft	Excess, %	Volume, sacks
9⅝	Class C	Surface	100	728
5½	Class G	2,920	100	1,160
	CO_2 - resistant	4,952		

Completion/Plugging Program			
Item	Description	Length (ft)	Top Depth (ft)
1	Wireline bailed cement	50	3,929
2	2AA CICR	1.73	3,979
3	Perforation	10	4,015
4	2AA CIBP	1.5	4,069
5	Wireline bailed cement	50	4,846
6	2AA CICR	1.73	4,896
7	Perforation	10	4,912
8	Wireline bailed cement	50	9,782
9	2AA CICR	1.73	9,832
10	Perforation	10	9,880

Spud Date: 5/14/2020
Total Depth: 10,470 ft (Precambrian Basement)
Cased-hole TA

Formation		Remarks
Name	Wireline Top (ft)	
Pierre	1,250	Surface and production casing and cement behind both strings isolate the surface section.
9⅝" Casing Shoe	1,654	
Mowry	3,585	Production casing, cement behind the casing, cast iron bridge plug, cast iron cement retainer (CICR), and cement above isolate the Inyan Kara Formation.
Inyan Kara	3,881	
Swift	4,057	
Opeche	4,879	Production casing, CO_2-resistant cement behind the casing, CICR and cement above isolate the Broom Creek Formation.
Broom Creek	4,906	
Amsden	5,210	
Icebox	9,665	Production casing, CO_2-resistant cement behind the casing, CICR and cement above isolate the Deadwood Formation.
Deadwood	9,821	
Precambrian	10,297	

Corrective Action: No corrective action is necessary. The Deadwood Formation is isolated mechanically by conventional and CO_2-resistant casing and cement. Perforations in the Deadwood, Broom Creek, and Inyan Kara are isolated by CICRs and cement on top. A mechanical integrity test (MIT) was witnessed and approved by North Dakota State Inspector, Jared Thune, on December 21, 2020.

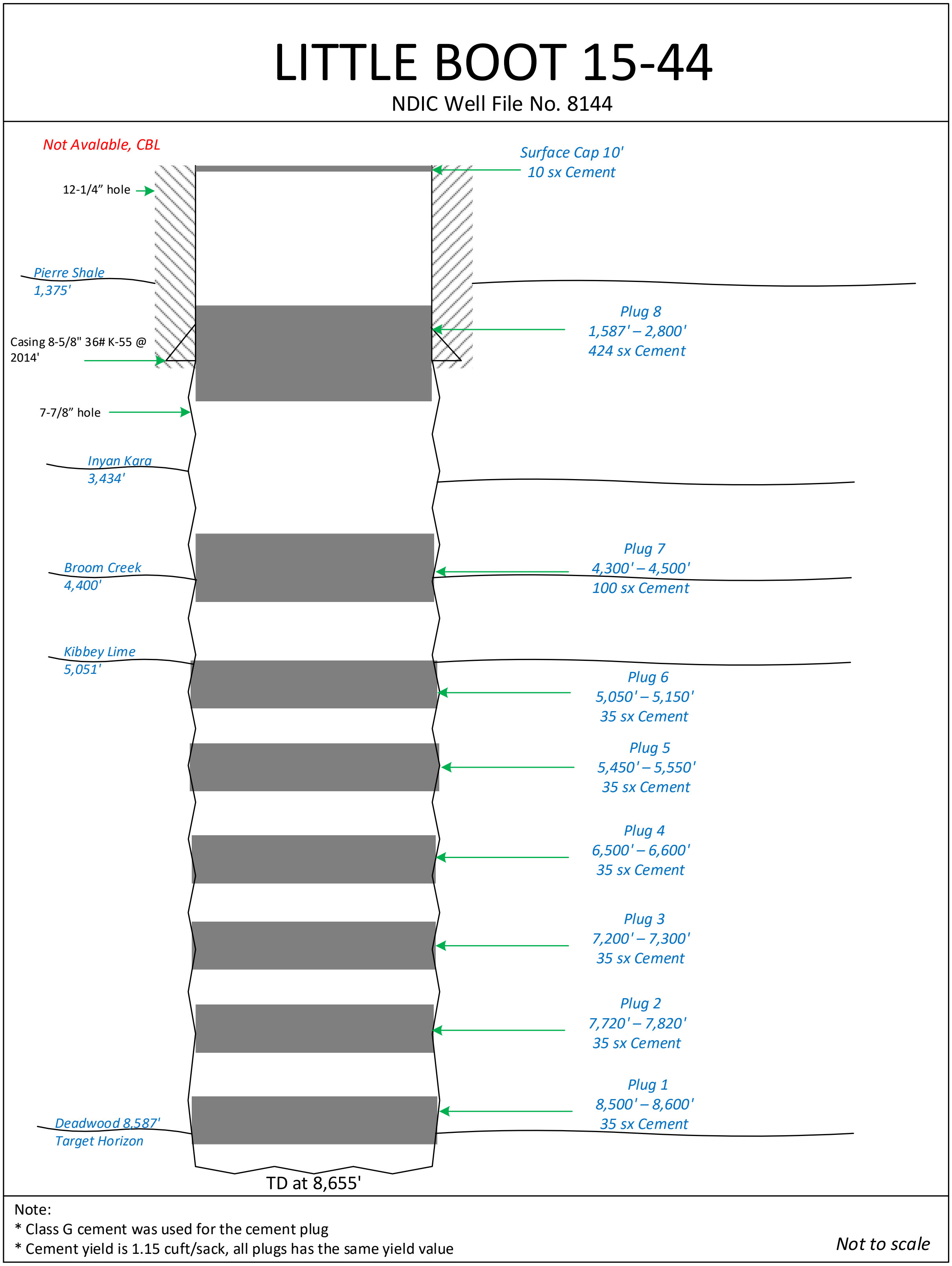


Figure 3-6. Little Boot 15-44 (NDIC File No. 8144) well schematic showing the location and thickness of cement plugs.

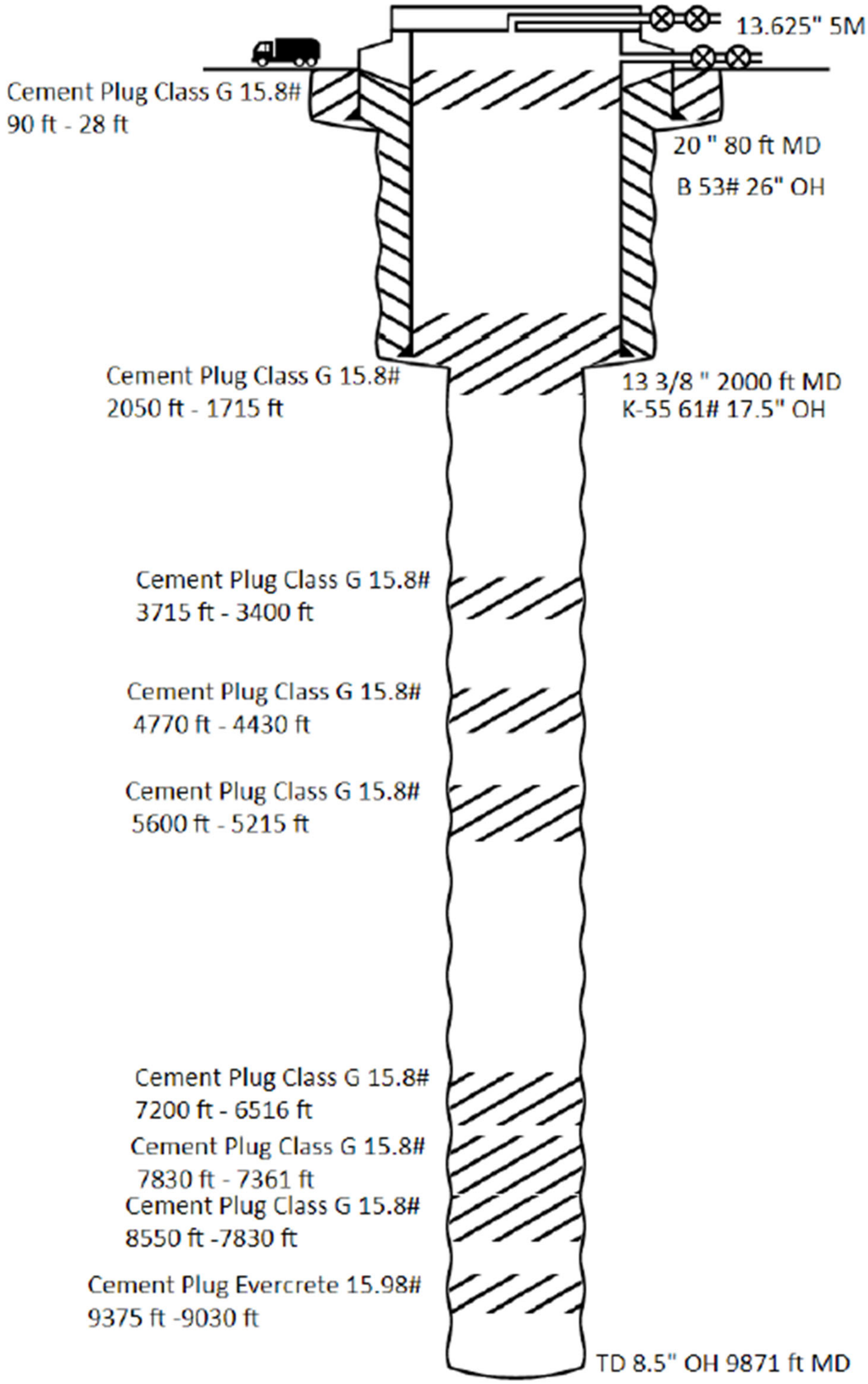


Figure 3-7. J-ROC1 (NDIC File No. 37672) well schematic showing the location and thickness of cement plugs.

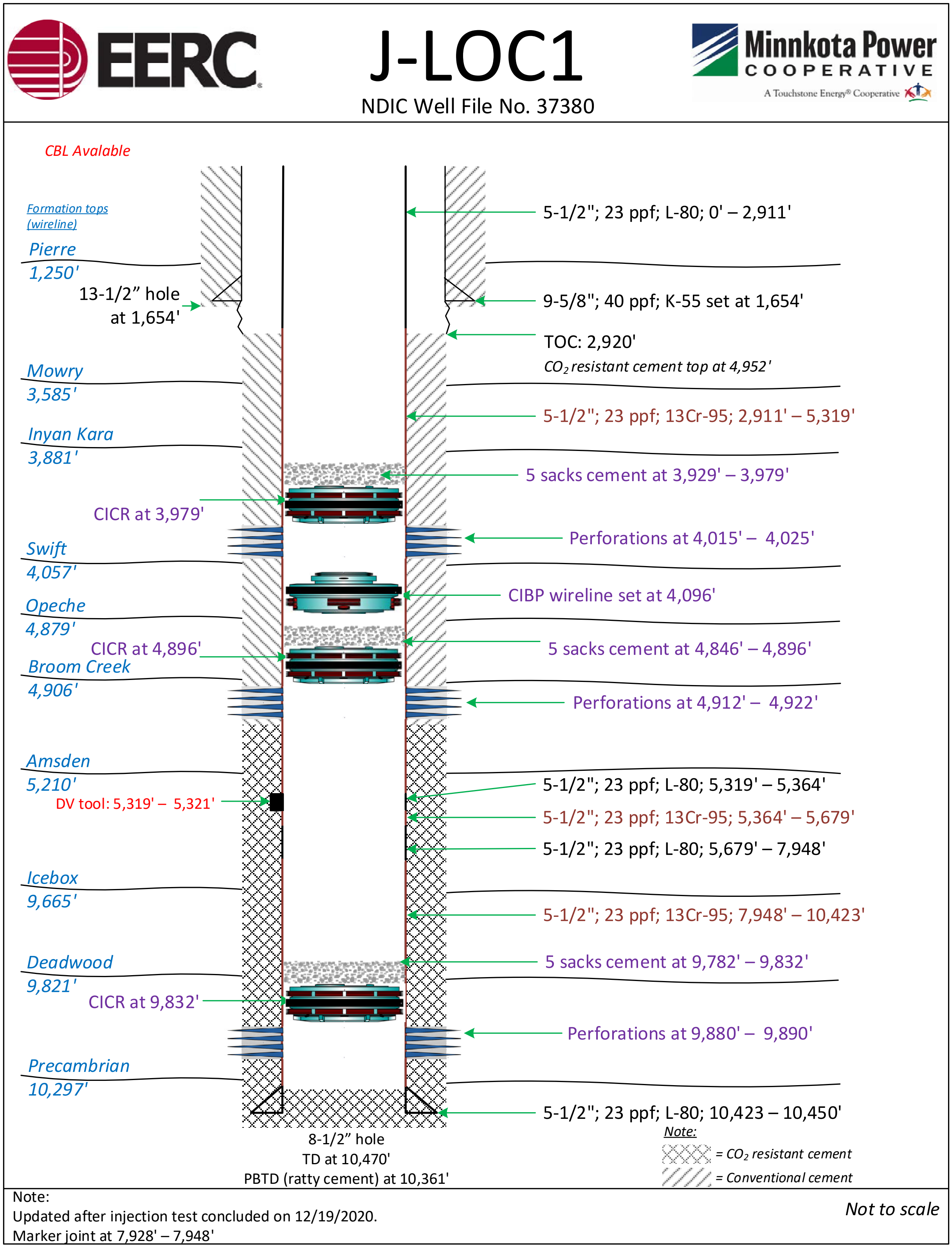


Figure 3-8. J-LOC1 (NDIC File No. 37380) as-constructed well schematic showing the final installation equipment used inside the wellbore to isolate perforations.

3.3 Reevaluation of AOR and Corrective Action Plan

Minnkota will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date.
- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.
- The protocol to conduct 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 deepest USDW in the AOR. The Icebox Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6).

3.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises 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 3-9). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 3-10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973).

Table 3-6. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline Member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444
Opeche	Shale/mudstone	4,685	55	3,535
Amsden	Dolostone/anhydrite	4,974	247	3,824
Kibbey Lime	Limestone	5,384	31	4,234
Charles	Limestone/anhydrite	5,526	147	4,376
Bakken	Shale	6,926	10	5,776
Birdbear	Limestone	7,075	74	5,925
Duperow	Limestone/dolostone	7,149	272	5,999
Souris River	Dolostone/limestone	7,421	175	6,271
Dawson Bay	Dolostone	7,596	729	6,446
Gunton	Dolostone/limestone	8,325	39	7,175
Stoughton	Shale/limestone	8,364	91	7,214
Lower Red River	Limestone	8,645	488	7,495
Roughlock	Shale/limestone	9,133	25	7,983

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 700 to 900 ft deep and 200 to 350 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 3-11).

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 1000 ft thick in the AOR (Thamke and others, 2014).

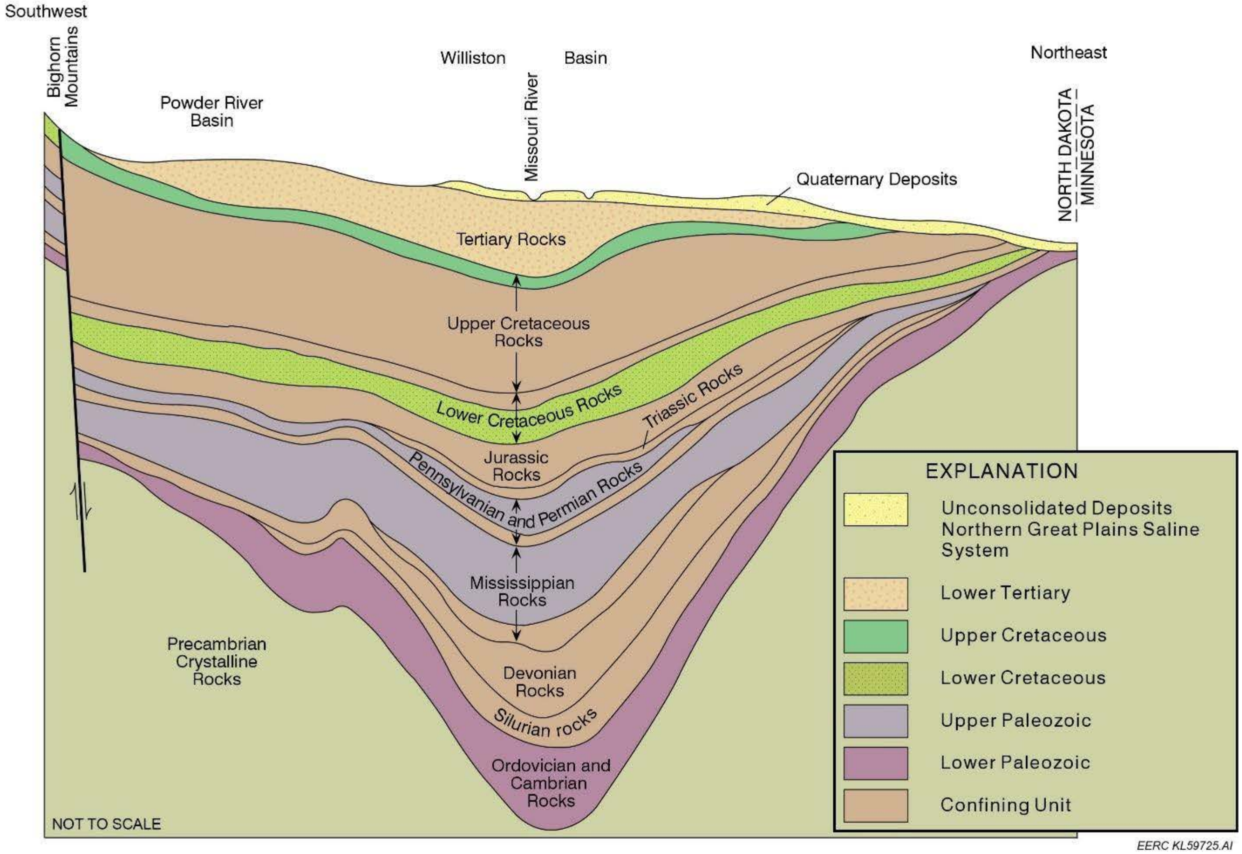


Figure 3-9. Major aquifer systems of the Williston Basin.

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
	Tertiary		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

Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

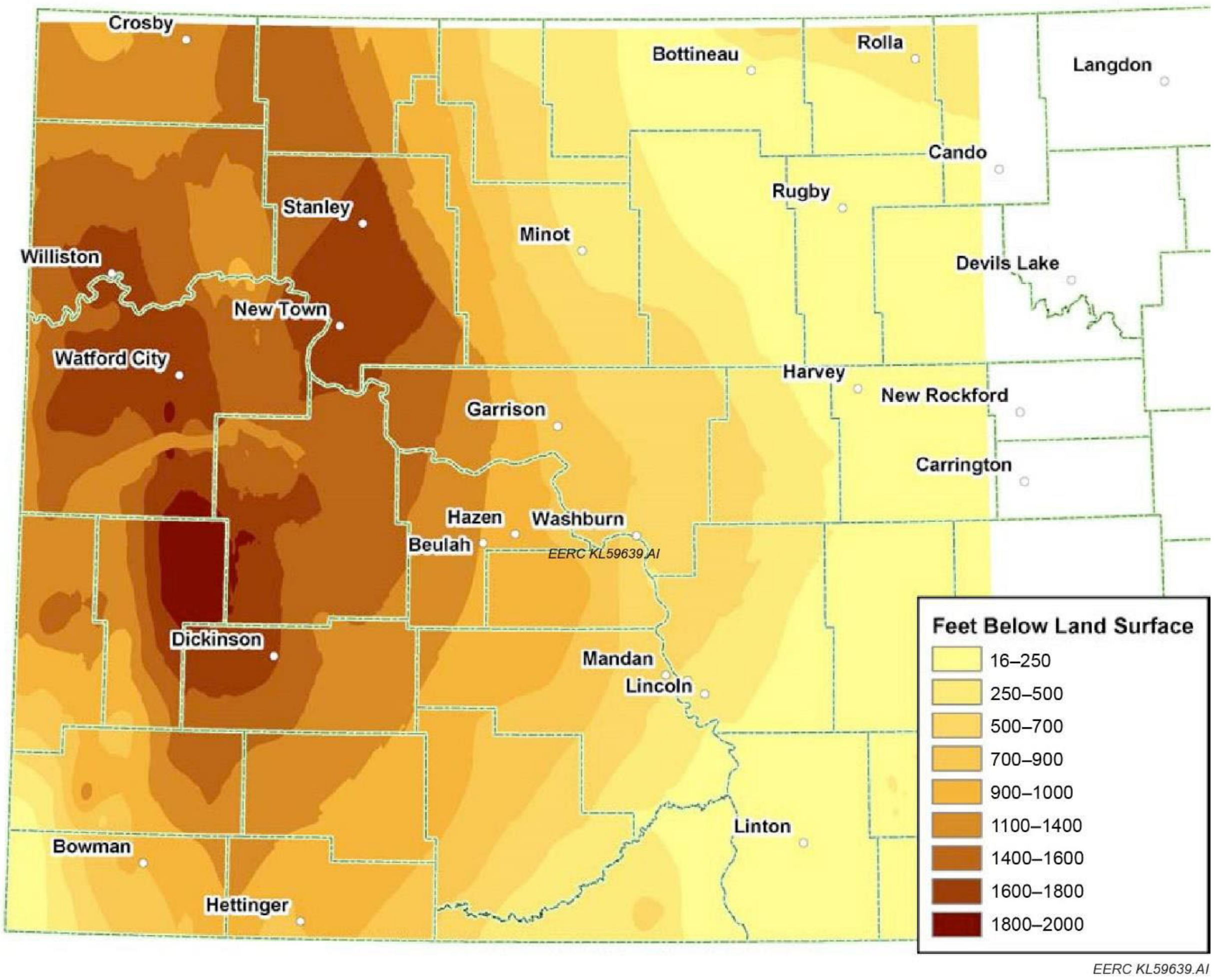


Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

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, which isolates 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 east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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.

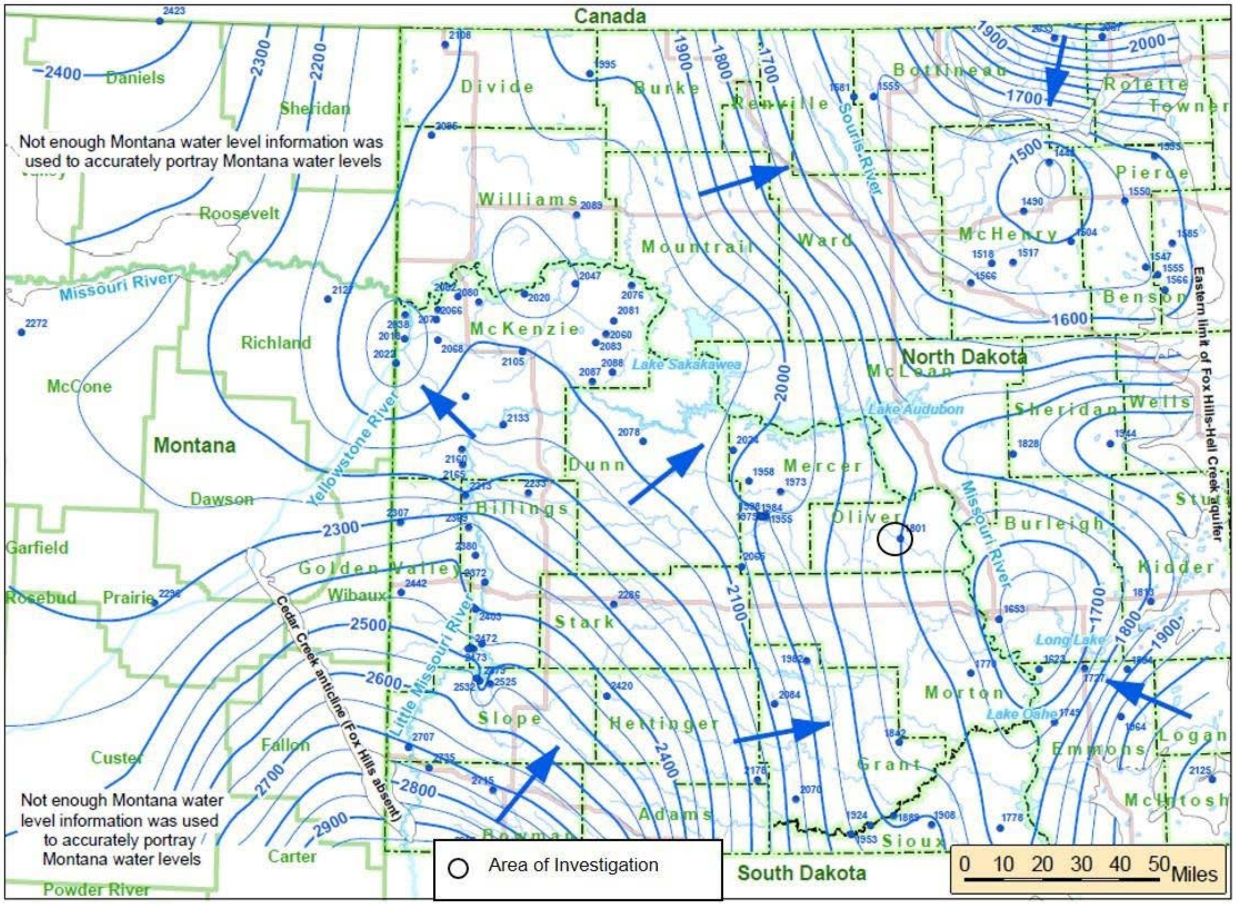


Figure 3-12. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the area of investigation in central Oliver County (modified from Fischer, 2013).

Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the McCall-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown.

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973).

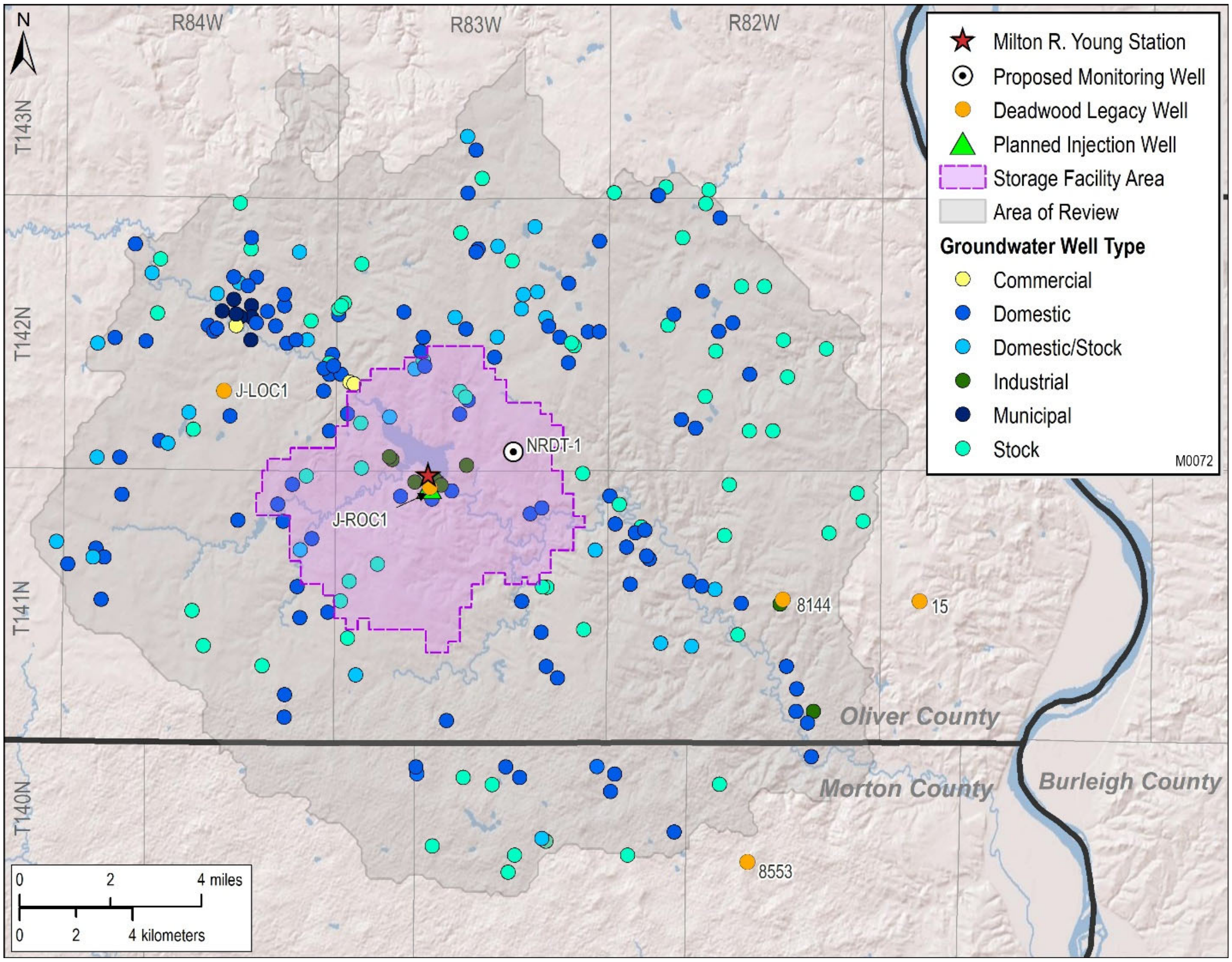


Figure 3-13. Map of water wells in the AOR in relation to the McCall-1 planned injection well, the NRDT-1 proposed monitoring well, storage facility area, AOR, and legacy oil and gas wells.

The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973).

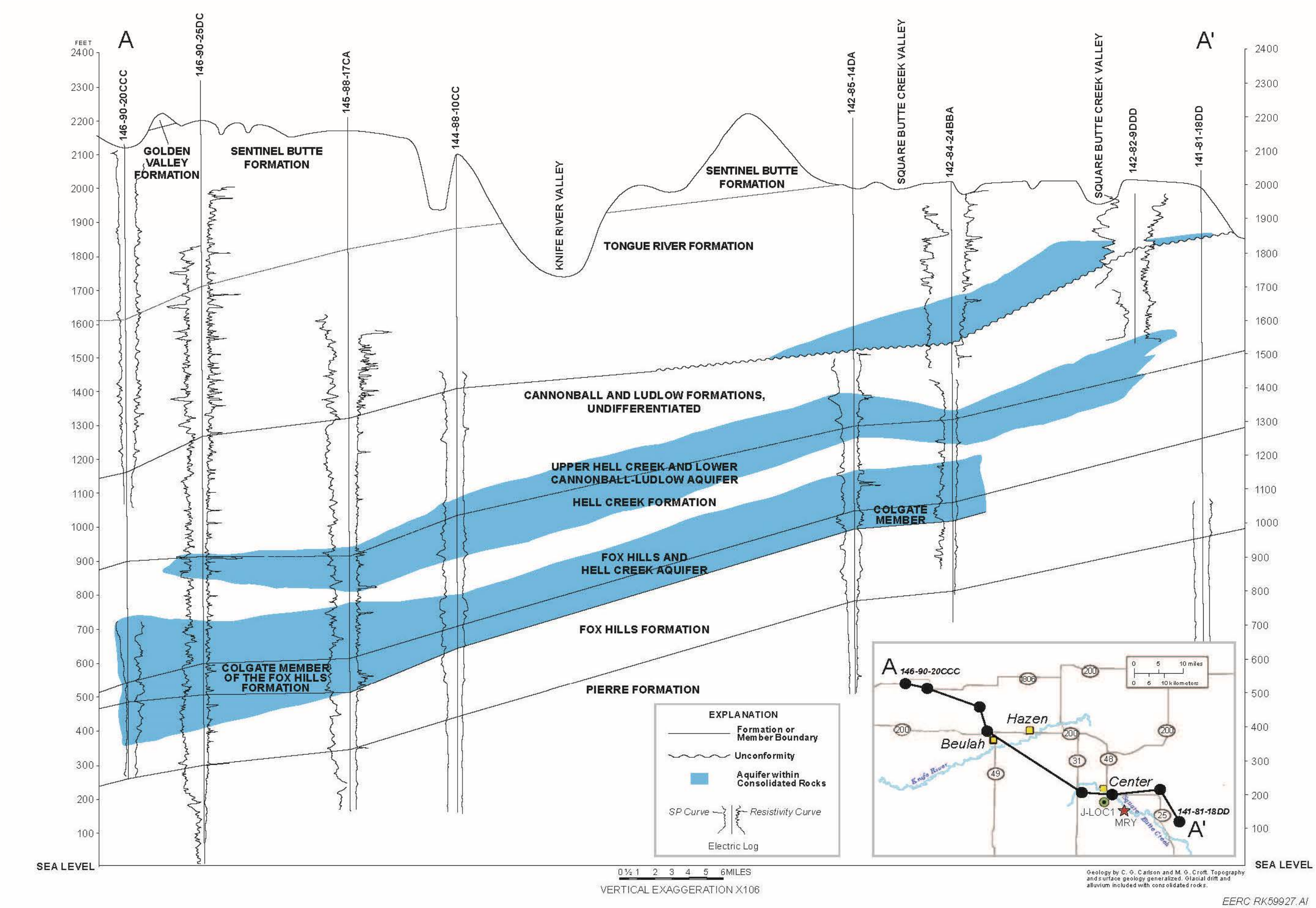


Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

3.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Deadwood Formation) and lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and carbonate formations of Ordovician, Silurian, Devonian, Carboniferous, Permian, Jurassic, and Cretaceous ages (Figure 3-9). The primary seal of the injection zone is the Ordovician-aged Icebox Formation with shales of the Ordovician-aged Roughlock and Stoughton, Mississippian–Devonian-aged Bakken, Permian-aged Opeche, Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Icebox 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection well, McCall-1 and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, 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 consist 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

Croft, M.G., 1973, Ground-water resources of Mercer and Oliver Counties, North Dakota: U.S. Geological Survey, County Ground Water Studies – 15.

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

The ten supporting plans of this permit application are listed in Table 4-1 and provided in this section of the application. To aid in the review of these plans, it should be noted that 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 the single subsection entitled Testing and Monitoring Plan. The other plans are presented in their respective subsections.

Table 4-1. Supporting Plans for Permit Application

Testing and Monitoring Plan
Corrosion Monitoring and Prevention Plan*
Surface Leak Detection and Monitoring Plan*
Subsurface Leak Detection and Monitoring Plan*
Emergency and Remedial Response Plan
Financial Assurance Demonstration Plan
Worker Safety 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 4.1).

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 (Ayash, Azzolina, and Nakles, technical memorandum, February 12, 2020). The SLRA was conducted through a series of work group sessions involving subject matter experts (SMEs) that were held from May 2018 through April 2019. The technical experts were asked to review 18 individual technical project risks and four nontechnical risks and assign them a probability of occurrence and assess their potential impacts on cost, schedule, health and safety, environment, permitting/compliance, and corporate image/public relations.

The technical risks were grouped into the following six risk categories: 1) injectivity (three risks), 2) storage capacity (two risks); 3) subsurface containment – lateral migration of carbon dioxide (CO_2) or formation water brine (one risk); 4) subsurface containment – propagation of subsurface pressure plume (two risks); 5) subsurface containment – vertical migration of CO_2 or formation water brine via injection wells, plugged and abandoned wells, monitoring wells, or faults/fractures (nine risks); and 6) induced seismicity (one risk). The risk assessment results indicated that there were currently no potential risks that would prevent the storage complexes evaluated in the feasibility study from serving as commercial-scale geologic CO_2 storage sites. While the results of the SLRA indicated that there are no risks that would preclude the commercial deployment of the project, it identified 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.

Using this SLRA as a starting point, a team consisting of representatives of Oxy Permian Risk, Low Carbon Ventures (LCV) engineers, Minnkota personnel, Energy & Environmental Research Center (EERC) staff, and BNI Energy engineers met to conduct further risk assessment of Tundra SGS proposed design and operations. The purpose of this review was to identify potential hazards based on facility design and operation.

The risk assessment process used for Project Tundra was developed specifically for this project based on consultation and agreement of risk team members. The agreed-upon approach used a combination of evaluating impact and probability level for a variety of impact categories to determine the overall risk level. These steps are performed for each of the identified risk scenarios developed as discussed in more detail below.

A total of 38 scenarios associated with the facility operation were evaluated. Thirteen (13) scenarios were identified to have a Risk Level 4 or higher which may be equivalent to a medium level risk, the yellow range identified on the risk matrix (Section 6. Risk Matrix). However, the team did not define high, medium, or low risk based on risk score. Further discussion of costing and actions related to the monitoring approaches identified in this section are included in the financial assurance demonstration plan (FADP).

4.1 Testing and Monitoring Plan

An extensive monitoring, verification, and accounting (MVA) system will be implemented to verify that the Tundra SGS project is operating as permitted and is not endangering USDWs. The objectives of the MVA program are to proactively account for and verify the location of CO_2 injected. This MVA plan 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) corrosion-monitoring and prevention plan, 2) surface leak detection and monitoring plan, and 3) 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 protecting the USDWs. An overview of these individual monitoring efforts is provided in Table 4-2 along with the structure/project area that is being monitored.

Pursuant to North Dakota Administrative Code (NDAC) § 43-05-01-11.4 subsection 1j, "Periodic reviews of the testing and monitoring plan by the storage operator to incorporate monitoring data collected, operational data collected, and the most recent area of review reevaluation performed. The storage operator shall review the testing and monitoring plan at least once every five years."

Table 4-2. Overview of Tundra SGS Monitoring Program for the Geologic Storage of CO_2

Monitoring Type	Tundra SGS Monitoring Program	Target Structure/ Project Area
Analysis of Injected CO_2	Compositional and isotopic analysis of the injected CO_2 stream	Upstream or downstream of the flowmeter
	Distributed temperature sensing (DTS)/distributed acoustic sensing (DAS) and distributed strain sensing (DSS)	Capture facility to the wellsite
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 area of review (AOR), dedicated Fox Hills monitoring well, and soil gas sampling and analyses	Near-surface environment, USDWs
Direct Reservoir Monitoring	Wireline logging, tubing-conveyed downhole pressure and temperature gauges, and casing-conveyed DTS (fiber optic)	Storage reservoir and primary sealing formation
Indirect Reservoir Monitoring	Time-lapse geophysical (seismic) surveys, inSAR[1] and passive seismic measurements	Entire storage complex
Internal and External Mechanical Integrity	Tubing-casing annulus pressure testing (internal), casing integrity tools (i.e., USIT[2]) (external)	Well infrastructure
Corrosion Monitoring	Flow-through corrosion coupon test system for periodic corrosion monitoring	Well infrastructure

[1] Interferometric synthetic aperture radar.
[2] Ultrasonic imager tool.

If needed, amendments to the testing and monitoring plan (i.e., technologies applied, frequency of testing, etc.) will be submitted for approval by the North Dakota Industrial Commission (NDIC). The 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.

4.1.1 Analysis of Injected CO_2 and Injection Well Testing

4.1.1.1 CO_2 Analysis

Prior to injection, Minnkota Power Cooperative , Inc. (Minnkota) will determine the chemical and physical characteristics of the CO_2 that has been captured for storage using appropriate analytical methods. The anticipated chemical composition is shown in Table 4-3.

Table 4-3. Proposed Composition of the Injection Stream (Minnkota)

Chemical Component	ppmv	mol%
CO_2	804,195	0.999
H_2O	632	7.85E-04
N_2	163	2.02E-04
O_2	6	7.45E-06
H_2	0	0.00E+00
Ar	4	4.97E-06

4.1.1.2 Injection Well Integrity Tests

Until the CO_2 injection well is plugged, Minnkota will monitor its external mechanical integrity with casing integrity tools. These casing integrity tools, either an USIT or electromagnetic (EM) log will be run on the injection well to establish the initial baseline external mechanical integrity. A casing integrity tool will be run annually at a minimum from 7800 ft TD (i.e., inclusive of the Deadwood injection interval) in the McCall-1 to verify the 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 at least once 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.

4.1.2 Corrosion Monitoring and Prevention Plan

The corrosion management program (CMP) includes identification of active and potential future damage mechanisms and their mitigation, control, and monitoring. The CMP is a major component of the mechanical integrity program and monitoring, reporting, and verification (MRV) plan.

For the purpose of the CMP document, the CCS (carbon capture and storage) hub was divided into the following systems:

- **CO_2 capture facility:** not included in the scope of this permit application.
- **CO_2 transportation flowline:** from the fence line of the CO_2-metering facility to the outlet at the well pad borders.
- **Surface piping, instrumentation, and pressure control equipment at the injection wellsite:** from the outlet of the main CO_2 flowline until the connection with the injection tree/wellhead.
- **Downhole equipment:** from the injection tree/wellhead to the reservoir. There are two categories for downhole equipment based on the service conditions: injector wells and in-zone monitoring wells.

4.1.2.1 *Corrosion Threat Assessment*

The corrosion threat assessment identifies which damage mechanism is currently active and likely to occur in systems or equipment along with the potential consequences of the damage.

4.1.2.2 *Identification of Critical Components and Operating Conditions*

This section identifies the different components included in the corrosion and monitoring plan as well as the fluid compositions, fluid state, operating pressures, temperatures, and flow rates to which the equipment will be exposed:

- For each system, the critical component or equipment is identified in Appendix F.

- A detailed description of the selected material and operating condition is specified by each component or equipment.

- Table 4-4 shows the CO_2 specifications for the Tundra SGS project.

Table 4-4. CO_2 Specifications for Tundra SGS Project

Stream Description	Compressed CO_2 Product to Battery
Stream Number	606
Temperature, °F	120
Pressure, psia	1,688.7
Components	
Component Flows	**Limits**
H_2O	632 ppmv
CO_2	99.90%
N_2	163 ppmv
Ar	4 ppmv
O_2	6 ppmv
H_2	0%
SO_2	<1 ppmv
NO_2	<1 ppmv
NO	30 ppmv

4.1.2.3 *Damage Mechanism*

This section defines the corrosion mechanisms currently active and likely to occur, along with the potential consequences of the damage.

Damage mechanisms are classified in the following four categories:

- **Internal corrosion**: results in loss of wall thickness of the equipment and piping due to the action of the contained fluid on the material of construction. The damage may be general or localized.

- **External corrosion**: results in loss of wall thickness of the equipment and piping due to the action of the environment on the materials of construction. The damage may be general or localized.

- **Environmental-assisted cracking**: caused by a specific combination of the environment, material of construction, and applied or residual stress. Cracking may originate from the inside (process side) or outside (environment side).

- **Mechanical and metallurgic damage:** results from the interaction of the material and process or external environment, such as brittle fracture, creep, erosion, and metal fatigue.

Appendix F summarizes the damage mechanism associated with each component or element during the analysis.

4.1.2.4 Corrosion Control Program (CCP)

For each component identified in the corrosion threat assessment and damage mechanism association, a set of mitigations, corrosion-monitoring techniques, inspections, data gathering, and analysis will be implemented. The CCP includes the following:

- Description of the system and damage mechanism
- Mitigations, if any
- Monitoring description
- Monitoring frequency
- Target limits for monitoring
- Person responsible for the analysis of the monitoring data
- Consequence of operation outside of target limits
- Remedial action outside of target limits
- Required period for remedial action

Appendix F includes the CCP matrix.

4.1.2.5 Annual Review

The operator shall prepare an annual CMP report, confirming the status of the actions and controls described in the CMP, highlighting any findings during inspections, and identifying the failure and root cause analysis. The CMP shall be reviewed more frequently if there are changes in the conditions that could lead to:

- An increase in severity of the active corrosion mechanism.
- A significant likelihood of any inactive corrosion mechanism being activated.

4.1.2.6 Data Management

The results of the corrosion threat assessment and CCP shall be recorded and available for review, according to the operator data management standard and systems.

4.1.3 Surface Leak Detection and Monitoring Plan

Surface components of the injection system, including the CO_2 transport flowline and wellhead, will be monitored using CO_2 leak detection equipment. The flowline from the capture facility to the wellhead will be monitored using a DTS/DAS and DSS fiber optic cable with an interrogator system to provide the ability to detect leaks along the flowline. The CO_2 detectors will be placed at the injection wellhead and key wellsite locations (e.g., flowline riser). Leak detection equipment will be integrated with automated 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, maintained for at least 10 years, and available to NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

4.1.4 Subsurface Leak Detection and Monitoring Plan

The monitoring plan for detecting subsurface leaks comprises the 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., residential drinking water wells, stock wells, etc.). The deep subsurface zone extends from the base of the deepest USDW to the bottom 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 deepest USDWs) environments are protected and that the CO_2 is safely and permanently stored in the storage reservoir. More specifically, for the Tundra SGS project, near-surface monitoring will include installation of one dedicated Fox Hills Formation monitoring well to detect if the deepest USDW is being impacted by operations as well as two soil gas profile stations, each located at the CO_2 injection (i.e., McCall-1 and NRDT-1) deep monitoring wellsites. In addition, existing groundwater wells within the AOR have been identified, and a set of domestic wells will be periodically sampled as outlined in the monitoring program. These monitoring efforts will provide additional lines of evidence to ensure the surface/near-surface environment is being protected and injected CO_2 is being safely and permanently stored in the storage reservoir.

Operational monitoring at the injection well (McCall-1), 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.

4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring

Surface and near-surface environments will be monitored 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 in the postoperational-monitoring time frame.

Using data from ongoing mine reclamation and power plant monitoring programs, Minnkota has achieved near-surface baseline sampling of the Tongue River aquifer near the injection site. The North Dakota State Water Commission (NDSWC) database was used to identify candidate wells within the AOR to complete an initial near-surface baseline sampling program, including seasonal sampling of existing groundwater wells (Figure 4-1). This baseline sampling program and results to date are described in detail in Section 4.1.6.

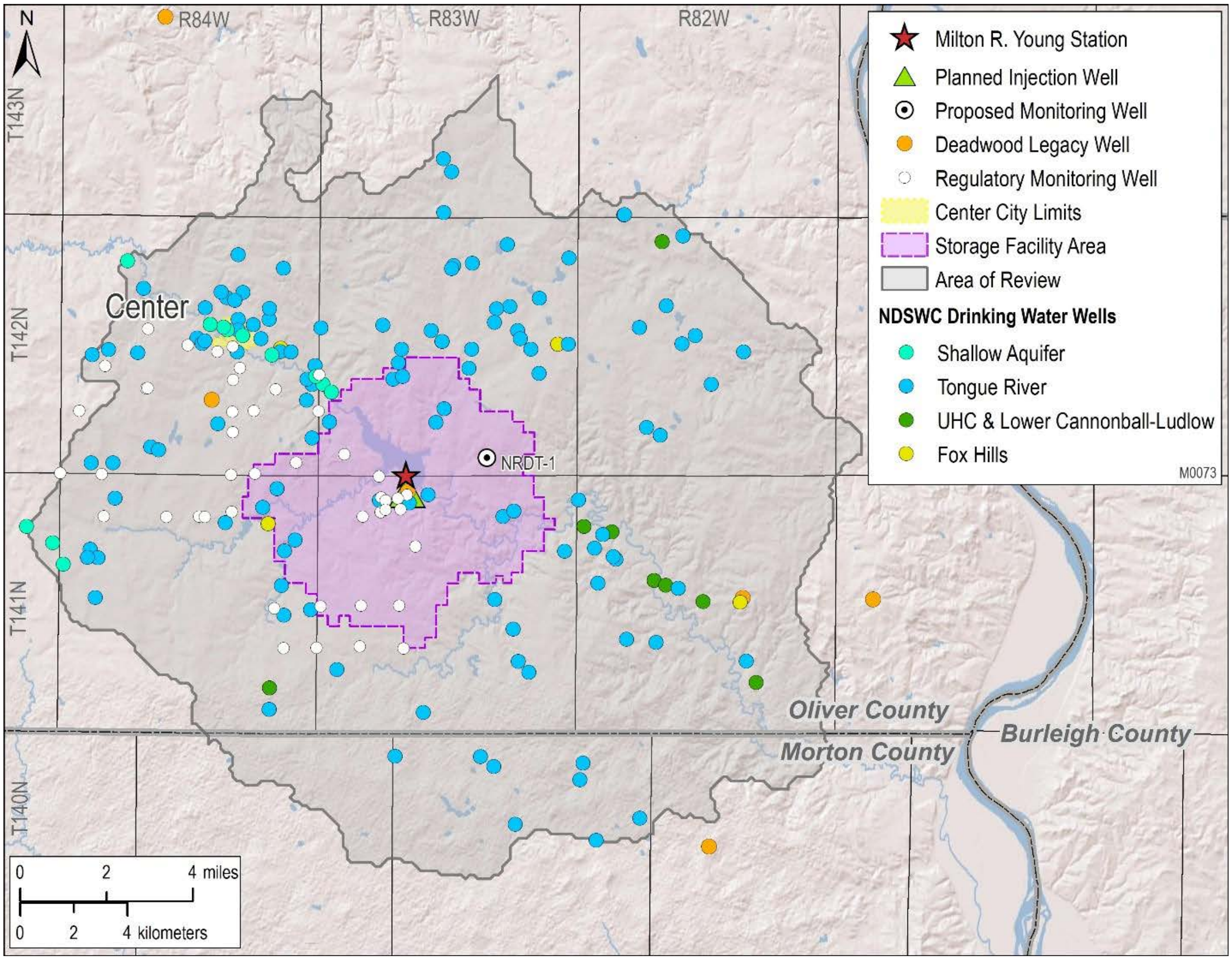


Figure 4-1. Minnkota will carry out initial sampling program for near-surface groundwater wells. Shown are existing regulatory monitoring wells to be used for baseline; all wells listed for drinking water in the NDSWC database by aquifer; the location of all plugged and abandoned (P&A) legacy oil and gas exploratory wells; city of Center, North Dakota; Milton R. Young Station (MRYS); and McCall-1 (proposed injector) and NRDT-1 (proposed monitoring well) in relation to the storage facility area and the AOR. The well drilled for baseline characterization and monitoring of the Fox Hills Formation will be located at the injection wellsite.

Prior to injection operations, one dedicated Fox Hills Formation monitoring well will be installed at the McCall-1 CO_2 injection wellsite. The Fox Hills Formation will be sampled seasonally, and baseline state-certified laboratory analyses will be provided to NDIC prior to injection. In addition, two soil gas profile stations will be installed: one near the McCall-1 injection wellsite and another near the deep monitoring wellsite (NRDT-1). Baseline soil gas analyses will be provided to NDIC prior to CO_2 injection operations.

The near-surface monitoring plan will focus on the dedicated Fox Hills Formation well, a subset of the existing groundwater wells characterized to establish baseline, and soil gas profile stations. The plan is described in Section 4.1.7.

4.1.6 Baseline Sampling Program

4.1.6.1 Groundwater Baseline Sampling

An initial baseline characterization of the shallow groundwater near the McCall-1 injection site has been completed by acquiring data from long-term regulatory monitoring in the Tongue River aquifer by Minnkota's MRYS and BNI Coal. Additional baseline characterization of existing groundwater wells within the AOR will be completed prior to CO_2 injection by collecting and characterizing seasonal samples of up to 16 groundwater wells taken from the five aquifer systems (i.e., Square Butte Creek, Otter Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek aquifers) underlying the AOR. The locations of these candidate wells are shown in Figure 4-2. The results of the existing regulatory program to be used for baseline measurements for TDS (total dissolved solids), pH, specific conductivity, and alkalinity are provided in Table 4-5, with comprehensive laboratory analyses for each well attached in Appendix C.

Future baseline sampling will include selected domestic wells in the Square Butte Creek, Tongue River, Upper Hell Creek–Lower Cannonball and Ludlow, and Upper Fox Hills–Lower Hell Creek aquifers and one U.S. Geological Survey (USGS) Fox Hills observation well. Verification of the domestic well status is under way, and final selection of domestic wells will be based on viability of the well (existence, depth, access, etc.) and landowner cooperation. The locations of these candidate wells are shown in Figure 4-2. Appendix C describes the selection method and well verification results for all well permits in the NDSWC database labeled domestic, domestic/stock, and municipal. Characterization of selected domestic wells and one USGS Fox Hills observation well will include the water quality parameters; anions; dissolved and total carbon, major cations, and trace metals; and isotope analysis to establish the natural partitioning of the groundwater constituents listed in Appendix C.

The results from these sampling efforts will provide a preoperational baseline of the groundwater quality in the four USDWs within the AOR of the CO_2 geologic storage project. The results will be submitted to NDIC before CO_2 injection occurs.

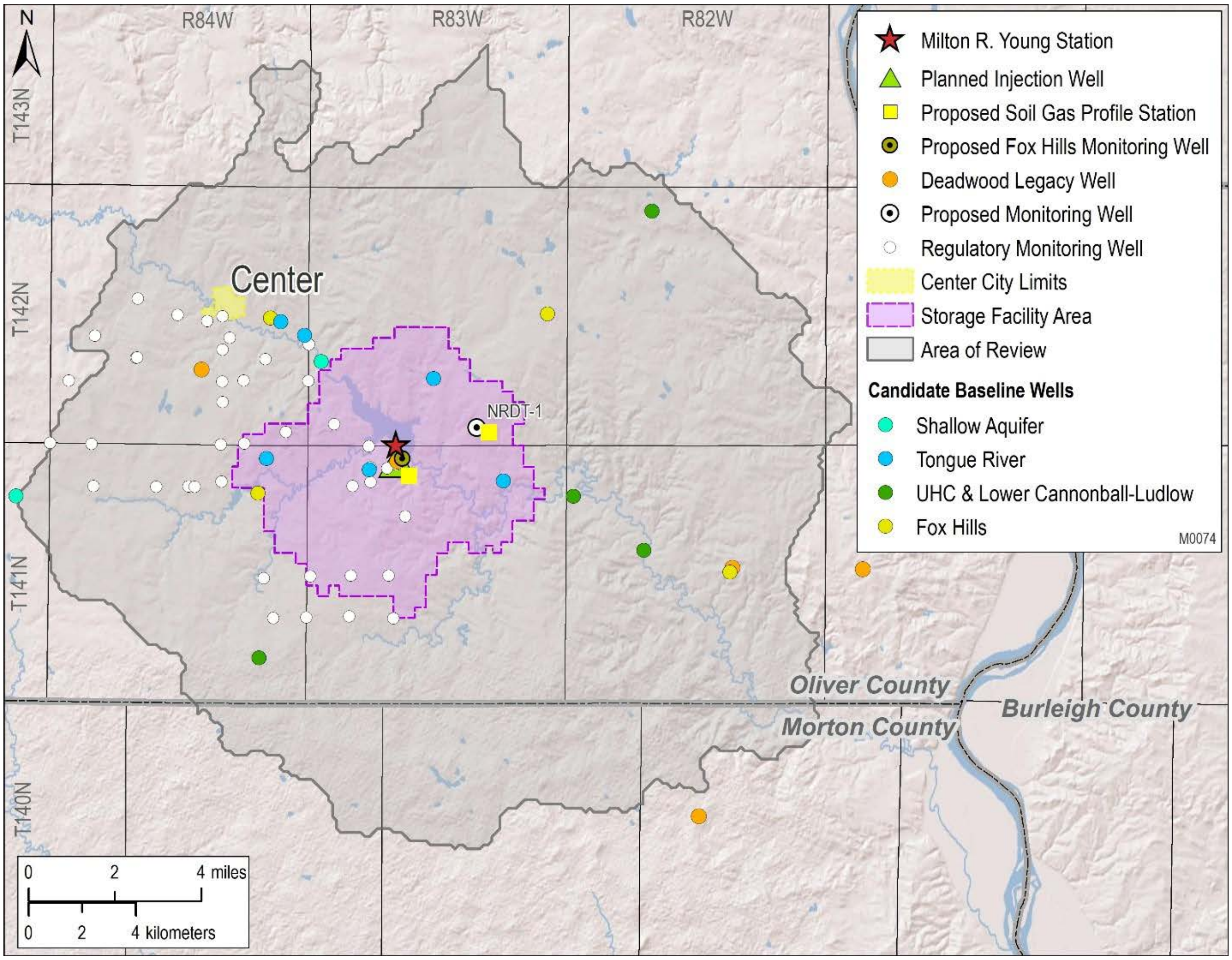


Figure 4-2. Tundra SGS project groundwater well sampling program to establish a groundwater baseline, including seasonal fluctuation, within the AOR. Shown are locations for existing regulatory monitoring well data and candidate options for additional baseline sampling by aquifer.

Table 4-5. Baseline Groundwater-Data

Parameter		TDS, mg/L*			pH			Specific Conductance, mS/cm			Alkalinity as $CaCO_3$, mg/L		
BNI Well No.	**Depth, ft**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**	**July 2018**	**July 2019**	**July 2020**
322A	21	525	726	532	6.19	6.6	6.6	801	980	832	118	124	165
324	88	360	817	745	7.8	7.8	7.8	649	1193	1182	188	345	369
363	82	1440	1500	1550	8.3	8.3	8.2	2446	2460	2454	1090	1110	1200
C1-1	129	706	699	698	8.4	8.4	8.4	1151	1123	1168	454	480	526
C7-1	184	1410	1480	1490	8.5	8.4	8.2	2105	2098	2096	985	1050	1120
C9-1	163	1520	1610	1430	8.2	8.3	8.3	2029	2032	2012	968	1030	1080
MRYS Well No.	**Depth, ft**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**	**May 2019**	**Sept. 2019**	**April 2020**
92-5A	185	800	790	780	8.75	8.9	8.94	1,131	1,184	1,129	488	520	499
92-6A	150	1,180	1,180	1,150	8.43	8.87	8.67	1,697	1,744	1,642	641	690	632
92-3	155	1,270	1,280	1,280	8.32	8.65	8.66	1,812	1,887	1,841	823	910	837
95-4	145	1,260	1,260	1,260	8.31	8.55	8.53	1,797	1,862	1,815	829	880	836
97-1	67	2,740	2,900	2,410	6.3	6.26	6.33	3,736	3,485	3,597	284	310	327
USGS Well No.	**Depth, ft**	**January 2021**			**January 2021**			**January 2021**			**January 2021**		
10	1,290	1,520			8.42			2,641			938		

* Calculation. For MRYS wells, calculated on reported field electrical conductivity.

4.1.6.2 Soil Gas Baseline Sampling

Soil gas sampling and analyses will be performed in order to establish baseline soil gas concentrations near the injection and deep monitoring wellsites in the AOR. Effective soil gas monitoring in reclaimed mine lands requires installation of soil gas profile stations, which will be located off of the well pads near the McCall-1 CO_2 injection and deep monitoring (NRDT-1) wellsites, as shown in Figure 4-3. The analyses, which determine the concentration of CO_2, O_2, and N_2, will be performed in accordance with ASTM International (ASTM) standard procedures (D5314) for soil gas sampling and analysis (ASTM International, 2006). In addition, isotopic analysis of the baseline soil gas samples will establish the natural source partitioning of the gases.

The sampling results from these efforts will provide a preoperational baseline of the soil gas chemistry of the vadose zone in the AOR of the CO_2 geologic storage project. Results will be submitted to NDIC.

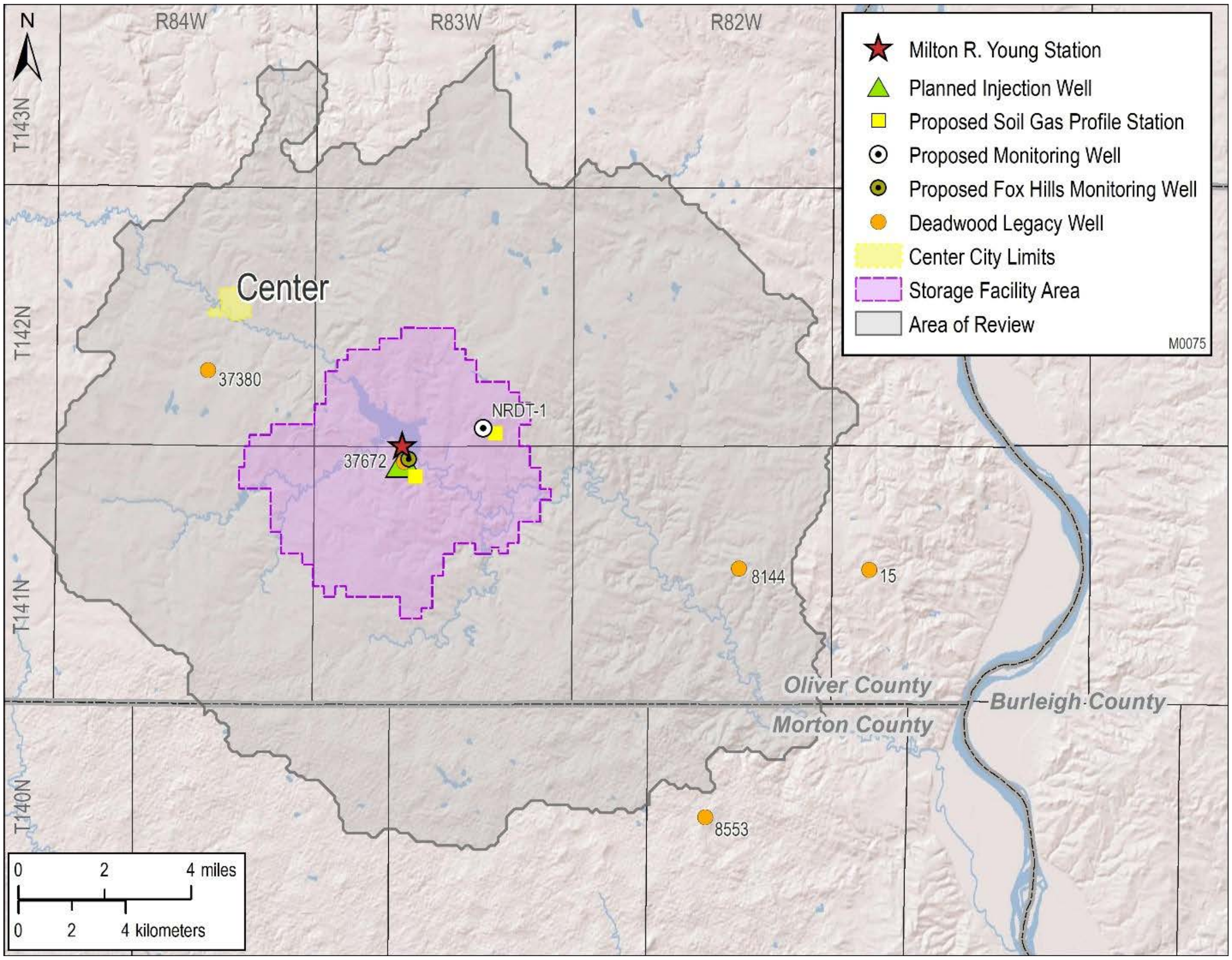


Figure 4-3. Minnkota will install soil gas profile stations and complete an initial soil gas-sampling program to establish baseline soil gas concentrations, including seasonal flucuation. The sample locations are near the CO_2 injection McCall-1 and deep monitoring NRDT-1 wellsites of the Tundra SGS project site.

4.1.7 Near-Surface (Groundwater and Soil Gas) Monitoring Plan

Prior to injection operations, Minnkota will drill and construct a dedicated groundwater-monitoring well in the Fox Hills Formation (i.e., deepest USDW) at the McCall-1 (proposed) CO_2 injection wellsite (Figure 4-4). Baseline Fox Hills Formation water samples will be collected from this monitoring well over a 1-year period prior to CO_2 injection, with the goal of securing these samples during each of the four seasons (spring, summer, fall, and winter). Minnkota plans to monitor the vadose zone by installing two soil gas profile stations, each one near the wellsites of the McCall-1 (proposed) CO_2 injection and NRDT-1 deep monitoring well pads (Figure 4-4). Minnkota will select a subset of existing groundwater wells, as outlined above, within the AOR boundary for periodic monitoring during CO_2 injection operations and postinjection monitoring (see Figure 4-4).

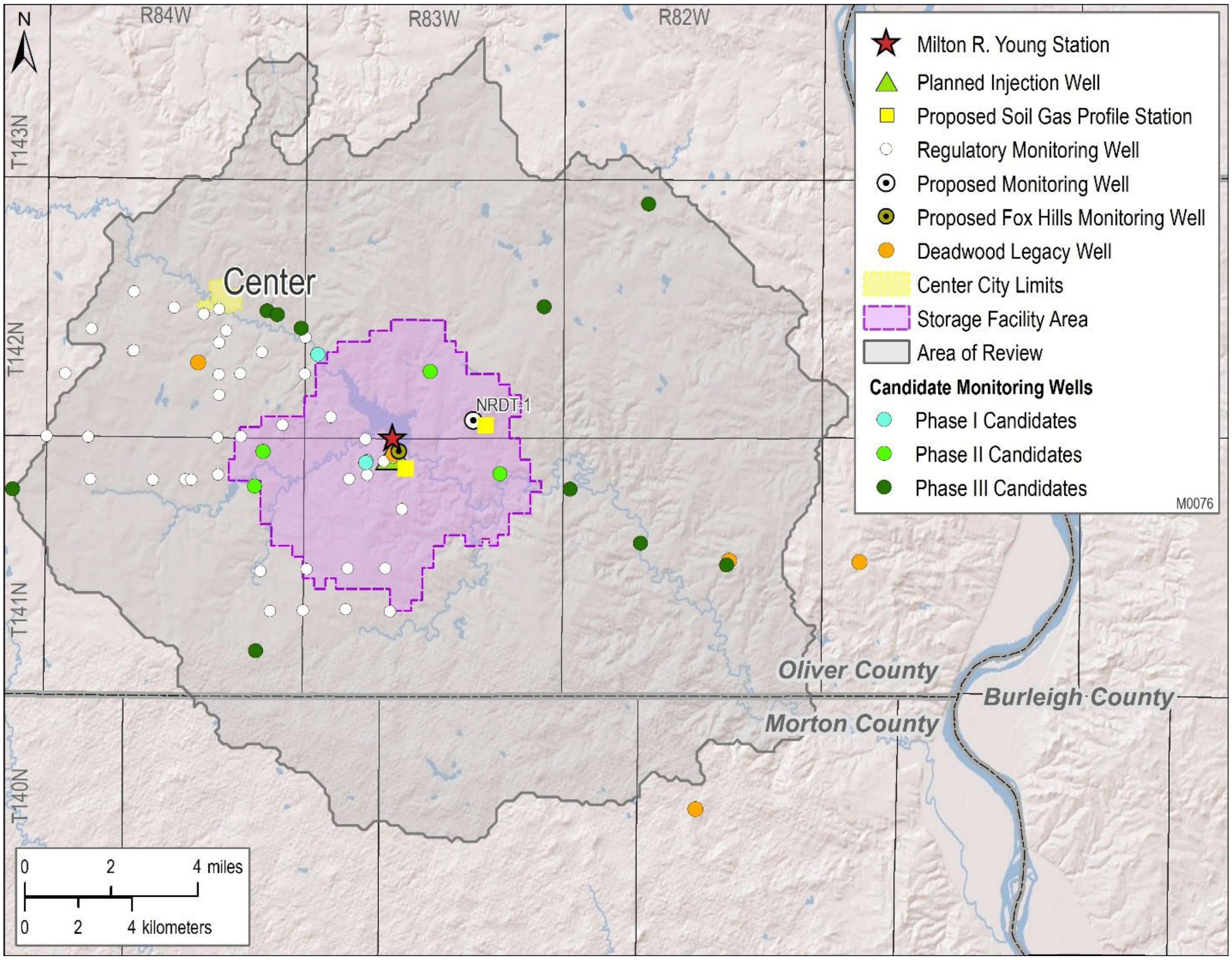


Figure 4-4. Tundra SGS project near-surface monitoring plan sample locations showing the Fox Hills Formation (deepest USDW) monitoring well, candidate groundwater wells to be sampled, and the two soil gas profile stations in and around the Tundra SGS project site.

During the first 3 years of CO_2 injection activities, the Fox Hills Formation monitoring well, soil gas profile stations (near the McCall-1 CO_2 injection and NRDT-1 deep monitoring wellsites), and select groundwater wells within the AOR will be sampled on an annual basis. All laboratory results will be filed with NDIC. If the results show no significant changes to water chemistry, the well-sampling frequency will be reduced to one sample every 5 years starting at Year 5 of the injection operations for all previously monitored wells.

As the areal extent of the CO_2 plume increases, monitoring of additional groundwater wells within the AOR will be phased in over time based on monitoring of the CO_2 plume in the injection zone. Each additional well will be sampled annually for 3 years. If the results show no significant changes to the water chemistry, the sampling frequency will be reduced to one sample at a 2-year interval and then at 5-year intervals thereafter. A detailed near-surface monitoring plan is presented in Table 4-6, including the frequency and duration of the sampling during each phase (i.e., preinjection, operational, and postoperational) of the geologic CO_2 storage project.

Table 4-6. Baseline (preinjection), Operational, and Postoperational Monitoring Frequency and Duration for Soil Gas, Groundwater, and Surface Air

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Soil Monitoring			
Soil Gas Profile Stations Soil Gas Probes	Duration: minimum 1 year Frequency: Sample 3–4 events per well to establish natural seasonal baseline. Soil gas profile stations at each location (near the McCall-1 CO_2 injection and NRDT-1 deep monitoring wellsites) will be sampled prior to initiation of CO_2 injection operations.	Duration: 20 years Frequency: 3–4 sample events per year at soil gas profile station locations (near the McCall-1 CO_2 injection and NRDT-1 deep monitoring wellsites) to account for natural seasonal fluctuation. Additional soil gas probe sampling may be conducted every 5 years based on monitoring and the expansion of the subsurface CO_2 plume in the injection zone.	Duration: minimum 10 years Frequency: 3–4 seasonal sample events at soil gas profile station locations (near the McCall-1 CO_2 injection and NRDT-1 deep monitoring wellsites) performed every 3 years following cessation of CO_2 injection.
Water Monitoring			
Groundwater (existing freshwater wells, e.g., domestic water wells, municipal wells, etc.)	Duration: minimum 1 year Frequency: minimum of one sample per year of select groundwater wells within the AOR. Groundwater wells are selected based on location, type, depth, aquifer, etc., to ensure a baseline of each groundwater horizon has been established prior to CO_2 injection.	Duration: 20 years Frequency: Sampling of select groundwater wells within the AOR will occur at a minimum of once per year during Years 1–3. Assuming the data are consistent during the first 3 years, monitoring frequency will decrease to one at a 2-year interval and then repeated at 5-year intervals thereafter. Additional monitoring wells will be phased in over time based on expansion of the subsurface CO_2 plume in the injection zone. Sampling frequency for added wells will follow the same structure as the original wells.	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.

Continued . . .

Table 4-6. Baseline (preinjection), Operational, and Postoperational Monitoring Frequency and Duration for Soil Gas, Groundwater, and Surface Air (continued)

Monitoring Type	Baseline (preinjection)*	Operational	Postoperational
Fox Hills Formation (deepest USDW)	Duration: minimum of 1 year Frequency: 3–4 sample events per well (establish seasonal fluctuation baseline). One Fox Hills Formation monitoring well (to be installed) located at the CO_2 injection wellsite (McCall-1).	Duration: 20 years Frequency: Sampling of Fox Hills monitoring well will occur at a minimum of once per year during Years 1–3. Assuming the data are consistent during the first 3 years, monitoring frequency will decrease to one at a 2-year interval and then repeated at 5-year intervals 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 under way 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.

4.1.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

Minnkota will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume (plume) and associated pressure front (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 4-7 and 4-8 will be used to characterize the plume and pressure within the AOR. Minnkota's testing and monitoring plan will include periodic reviews in which the monitoring data and operational data will be analyzed, AOR will be reevaluated and, if warranted, the testing and monitoring plan will be adapted to meet NDIC monitoring requirements.

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 plan is needed or modifications to the program are necessary to ensure proper monitoring of the storage performance is achieved and risk profile of the storage operations is addressed moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, these revisions will be incorporated into the permit following approval by NDIC. During the operational period, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Early monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 and pressure distribution relative to the permitted geologic storage facility. The early monitoring and operational data will be used for additional calibration of the geologic model and associated simulations. These calibrated simulations and model interpretations will be used to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

Table 4-7. Description of Tundra SGS Monitoring Program

Monitoring Type	Preoperational (baseline)	Operational	Postoperational
Storage Reservoir Monitoring			
Injection Well Monitoring (McCall-1) During Operations: • Flow Rates • Volumes • Surface Injection Pressure • Surface Injectate Temperature • Annulus Pressure Between Tubing and Long-String	Frequency: initial setup The maximum allowable injection pressure and annulus pressure will be derived from preoperational injection tests.	Duration: 20 years Frequency: continuous monitoring	Plug and Abandon (P&A) injection well at cessation of injection operations Continue to monitor annulus pressure in NRDT-1 well
• 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).	P&A injection well at cessation of injection operations. Monitor fluid levels until well is plugged.
Downhole Pressure and Temperature Monitoring			
Tubing-Conveyed Pressure and Temperature Gauges in McCall-1 and NRDT-1	Gauges provide baseline temperature and pressure of the injection zone (Deadwood).	Gauges provide continuous temperature and pressure monitoring of the injection zone (Deadwood).	Gauges provide continuous temperature and pressure monitoring of the injection zone (Deadwood) until plume stabilization. Monitoring will continue in the NRDT-1 well as part of postinjection site care and facility closure plan.
Wireline Logging and Retrievable Monitoring			
Pulsed-Neutron Log (PNL) (McCall-1 and NRDT-1)	Baseline PNL logging	PNL logging to ensure fluids are contained within storage interval and ground-truth 3D seismic monitors once every 5 years (in conjunction with timing of seismic monitor).	Log McCall-1 at cessation and before P&A and NRDT-1 well at cessation of injection and once every 5 years thereafter until plume stabilization (in conjunction with timing of seismic monitor).
External Mechanical Integrity: Casing Integrity Tools (i.e., USIT or EM Casing Inspection Tool (McCall-1 and NRDT-1)	Baseline casing inspection logging prior to injection.	Duration: 20 years Frequency: McCall-1 annual logging (minimum 7800 ft TD) across Deadwood injection interval. NRDT-1 5-year logging interval (during well workovers, if possible).	Duration: minimum 10 years postinjection Frequency: Perform during well workovers but not more frequently than once every 5 years in NRDT-1 well and N/A P&A McCall-1.

Continued . . .

Table 4-7. Description of Tundra SGS Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
Internal Mechanical Integrity: • Tubing-Casing Annulus Pressure Test	Mechanical integrity test – internal pressure testing. McCall-1 (proposed) and NRDT-1 (proposed)	Perform during well workovers but not more frequently than once every 5 years in McCall-1 (proposed) and NRDT-1 (proposed)	Duration: minimum 10 years postinjection Frequency: perform during well workovers but not more frequently than once every 5 years in NRDT-1 (proposed) well
External Mechanical Integrity: • Downhole Temperature	DTS AND Baseline temperature logging through the storage interval to surface McCall-1 (proposed) and NRDT-1 (proposed)	Continuous DTS OR, if fiber fails, annual temperature logging through the storage interval to surface NRDT-1 (proposed). Continuous DTS (surface – 7800 ft) OR, if fiber fails, annual temperature logging through the storage interval (7800 ft TD) McCall-1 (proposed).	Annual temperature logging in NRDT-1 (if fiber fails) until plume stabilization.
Pressure Fall-Off Test (injection zone)	Prior to injection at McCall-1 (proposed)	Every 5 years at McCall-1 (proposed)	Prior to P&A
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.	N/A
Geophysical Monitoring			
Time-Lapse Seismic	Existing baseline 2D and 3D seismic and integrated in reservoir model for site characterization. Existing 2D and 3D seismic covers the predicted extent of the CO_2 plume in the **early** monitoring of the site.	2D and/or 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 and every 5 years thereafter. If plumes exceed baseline data extents, additional baseline data will be acquired or 2D or 3D AVO (amplitude variation with offset) data can be used to monitor plume extents.	2D and/or 3D time-lapse seismic and/or AVO method will continue every 5 years as part of minimum 10-year post-CO_2 injection operations monitoring plan and until stability of plume is demonstrated.

Continued . . .

Table 4-7. Description of Tundra SGS Monitoring Program (continued)

Monitoring Type	Baseline (preoperational)	Operational	Postoperational
InSAR	Feasibility of surface deformation monitoring with InSAR – baseline data	To be determined. Continuous monitoring of ground elevation based on relative surface deformation with InSAR	To be determined. Continuous monitoring of ground elevation based on relative surface deformation with InSAR until storage facility achieves stabilization.
Passive Seismicity	Project will plan additional seismometer stations sufficient to confidently measure baseline seismicity 5 km from injection area.	The data collected in the surface seismometers will be continuously recorded and analyzed for potential seismicity magnitudes and hypocenter locations.	N/A

Table 4-8a. Logging Program for Deadwood Injector Well (McCall-1 [proposed])

Log	Justification	NDAC Section
Cased Hole Logs: ultrasonic CBL (cement bond log), VDL (variable-density log), GR (gamma ray), Temperature Log	Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo (resistivity, density,* neutron,* GR, caliper) and SP (spontaneous potential) *No density or neutron in surface section.	Quantify variability in reservoir properties such as resistivity and lithology. Identify the wellbore volume to calculate the required cement volume. Provide 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])
Temperature Log	Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.	43-05-01-11.2(1c[2])
Spectral GR	Identify clays and lithology that could affect injectivity.	43-05-01-11.2(2)
Dipole Sonic and 4-Arm Caliper	Identify mechanical properties including stress anisotropy. Provide 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	Quantify fractures in the Broom Creek and Black Island/Deadwood Formations and confining layers to ensure safe, long-term storage of CO_2.	43-05-01-11.2(1c[1])
MDT (modular dynamics testing) Fluid Sampling	Collect fluid samples from the Broom Creek and Deadwood Formations for geochemical testing and TDS quantification.	43-05-01-11.2(2)
MDT Formation Pressure Testing	Collect reservoir pressure tests to establish a pressure profile and mobility.	43-05-01-11.2(2)
MDT Stress Testing	Collect breakdown pressure, fracture propagation pressure, fracture closure pressure (minimum in situ stress) to establish injection pressure limits.	43-05-01-11.2(1c[1])
Sidewall Cores	Sidewall cores will be collected from the injection zones and associated confining zones.	43-05-01-11.2(2)

Table 4-8b. Logging Program for Deadwood Monitor Well (NRDT-1 proposed monitoring well)

Log	Justification	NDAC Section
Cased_Hole Logs: Ultrasonic CBL, VDL, GR, Temperature Log	Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.	43-05-01-11.2(1c[2])
Triple Combo and SP	Quantify variability in reservoir properties such as resistivity and lithology. Identify the wellbore volume to calculate the required cement volume. Provide 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])
Temperature Log	Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.	43-05-01-11.2(1c[2])
Dipole Sonic and 4-Arm Caliper	Identify mechanical properties including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	43-05-01-11.2(1c[1])

Tables 4-8a and 4-8b describe the logging programs for the Deadwood injector (McCall-1) and the monitoring (NRDT-1) wells (Figure 4-5). Included in the table is a description of logs collected. These wellbore data have been integrated with preoperational (baseline) 3D seismic and 2D seismic lines to provide a detailed reservoir and structural description for the geologic model and inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations. The simulated CO_2 plumes that are based on the current geologic model and simulations are shown in Figures 4-6 and 4-7. 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.

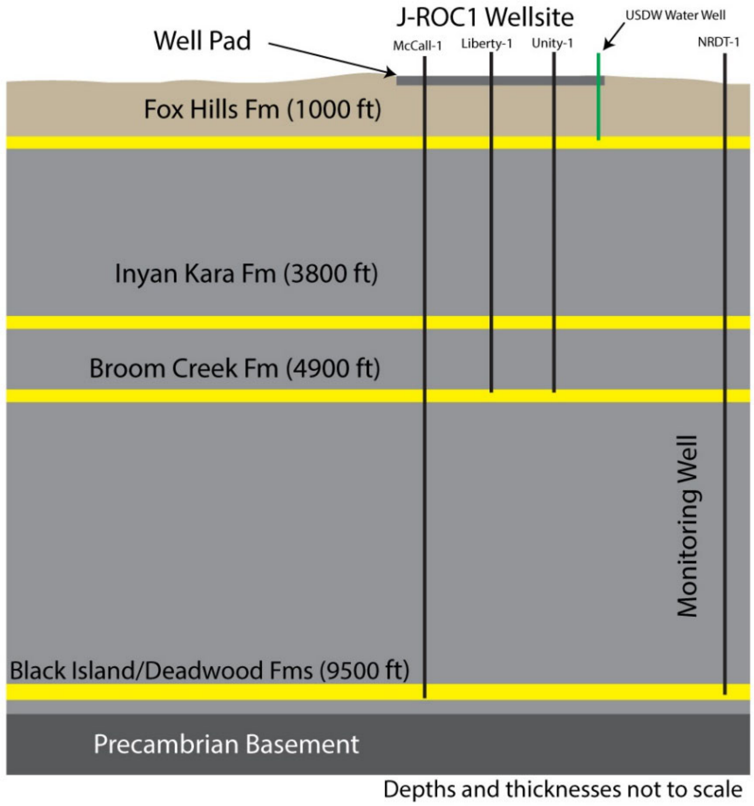


Figure 4-5. Monitoring schematic (not to scale) includes the location of the two Broom Creek injectors (Liberty-1 and Unity-1 [proposed]), the Deadwood injector (McCall-1 [proposed]), and monitoring well NRDT-1 (proposed).

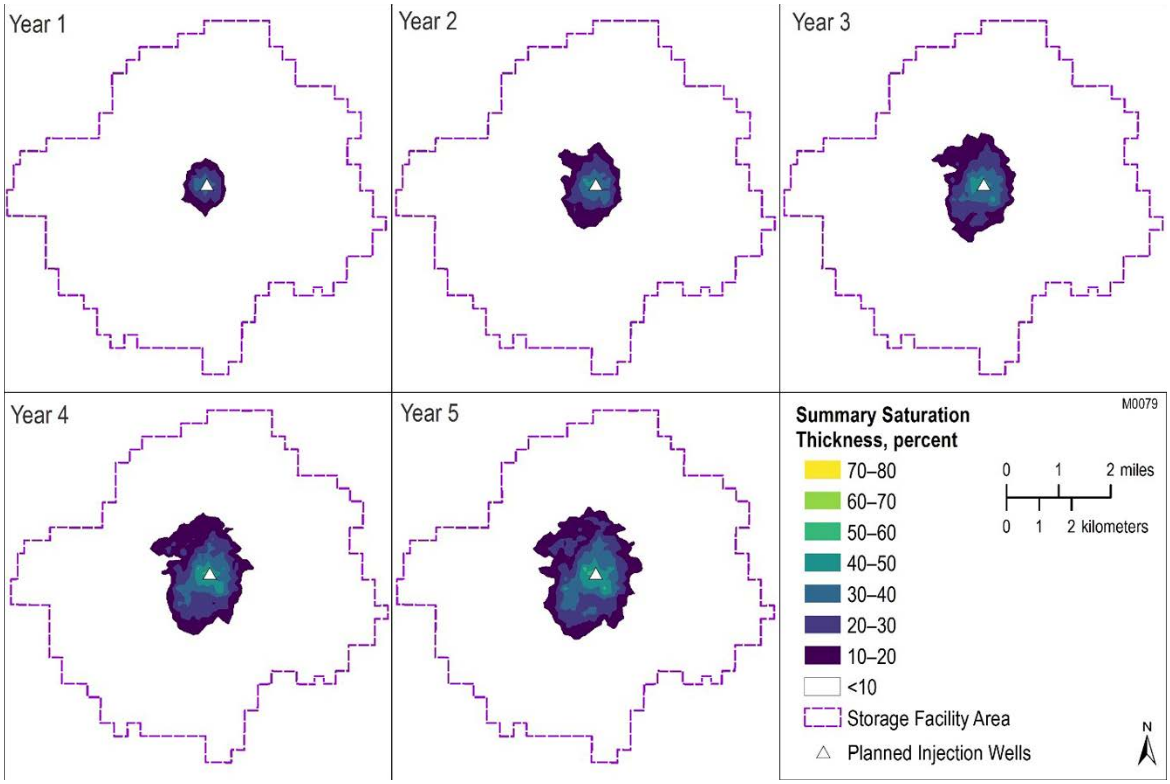


Figure 4-6. Simulated CO_2 plume saturation at the end of Years 1 through 5 after initial CO_2 injection.

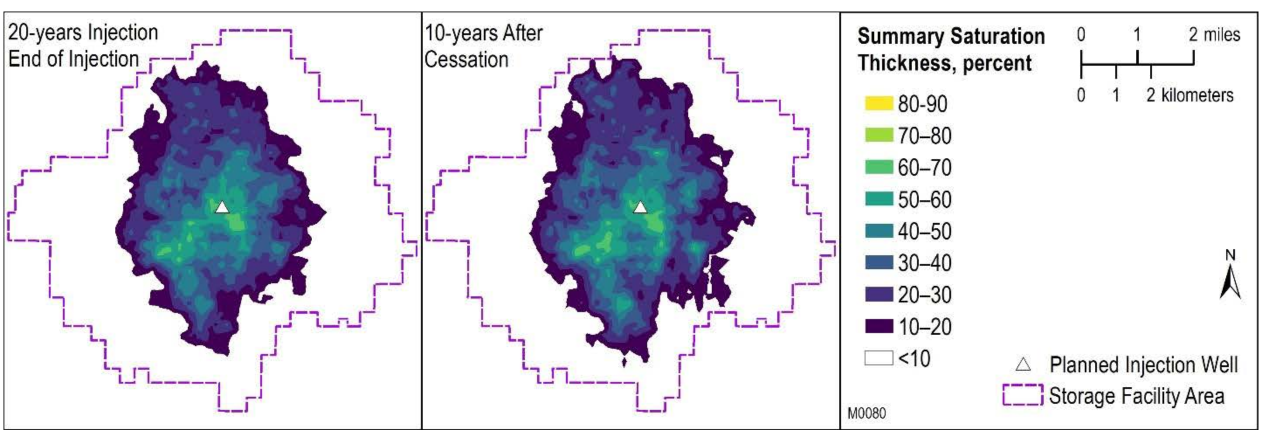


Figure 4-7. Simulated extent of the CO_2 plume at the cessation of injection and the postinjection stabilized plume.

4.1.8.1 Direct Monitoring Methods

To directly monitor and track the extent of the CO_2 plume within the storage reservoir, the injection (McCall-1) and monitoring (NRDT-1) wells will be equipped with tubing conveyed temperature (borehole temperature) and pressure (borehole pressure) gauges as well as casing deployed distributed fiber optics sensing systems (see Figures 4-8 and 4-9). Continuous reservoir temperature and pressure will be monitored in the Deadwood Formation and temperature in the overlying confining zone. Monitoring of the overlying interval can provide an early warning of out-of-zone migration of fluids, which provides sufficient time for the development and implementation of mitigation strategies to ensure these migrating fluids do not impact a USDW or reach the surface.

The fiber optic sensing system installed within the McCall-1 (proposed) and NRDT-1 proposed monitoring wells will be used to acquire continuous high-resolution temperature data. PNLs of the injection and monitoring wells will also be performed on a 5-year schedule basis to demonstrate that fluids are not moving beyond the sealing formations. Preoperational baseline PNL data will be collected in the injection and monitoring 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.

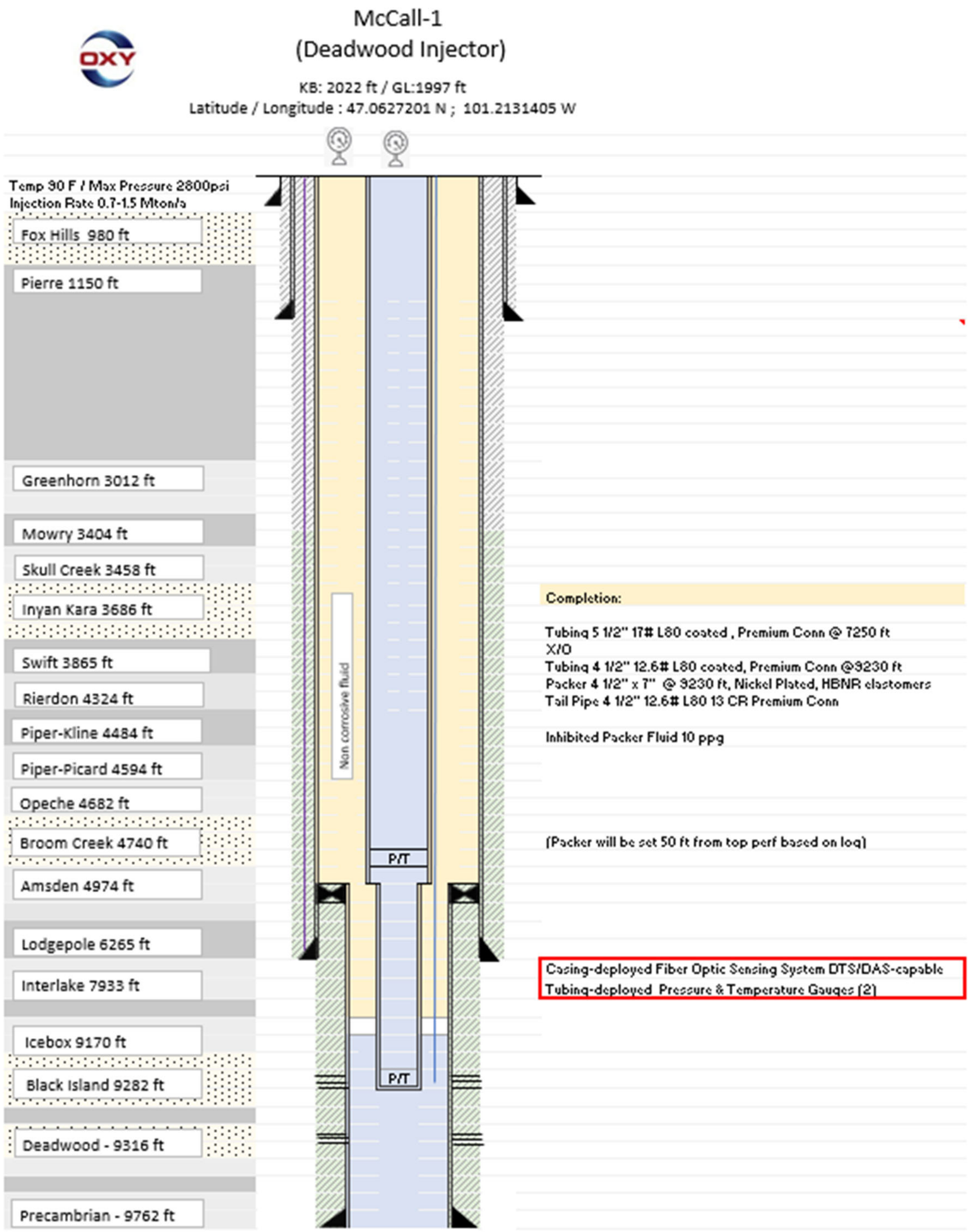


Figure 4-8. McCall-1 Deadwood injection wellbore schematic showing placement of tubing-deployed pressure and temperature-monitoring gauges and casing-deployed fiber optic sensing system (DTS/DAS-capable).

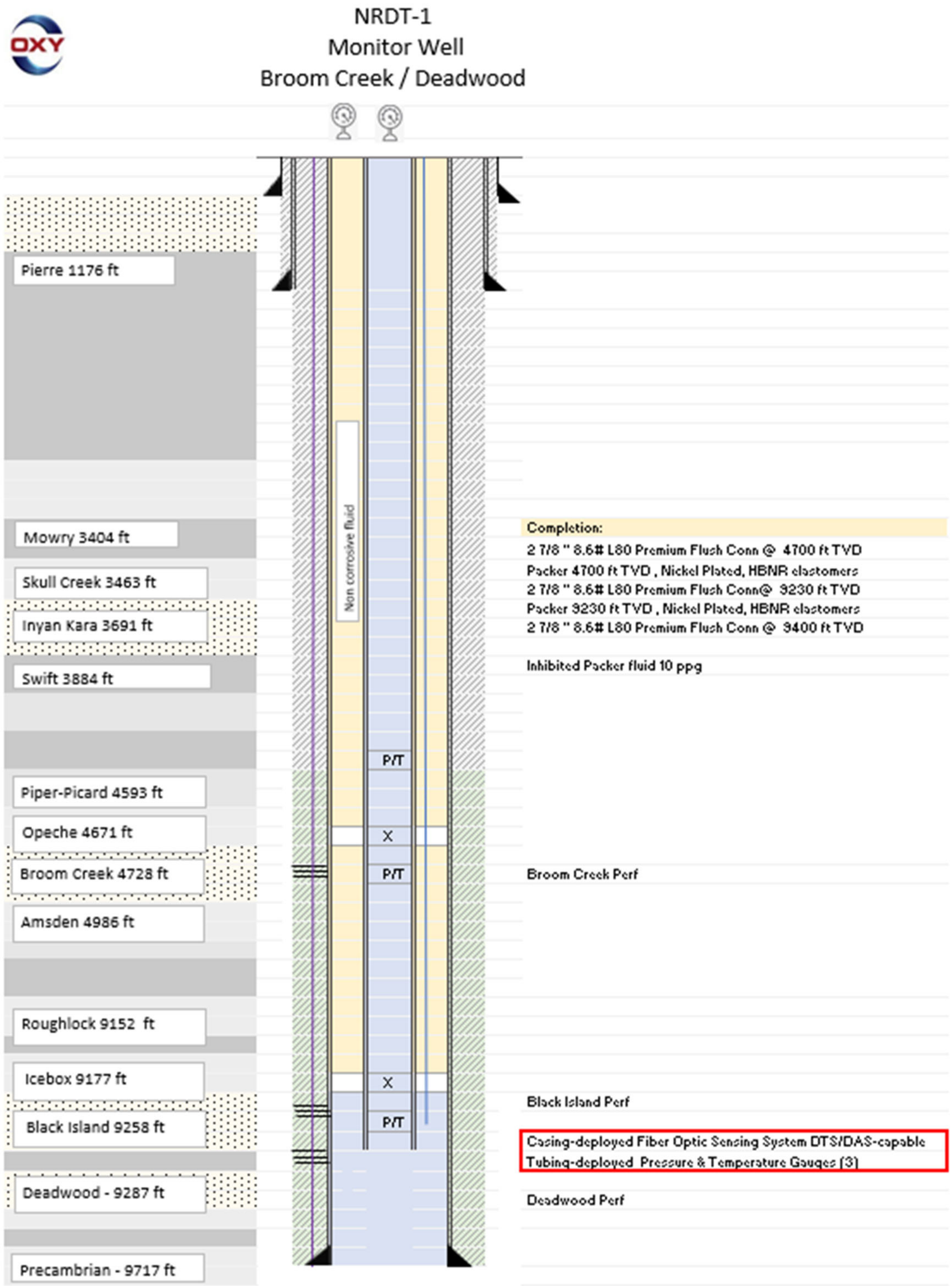


Figure 4-9. Broom Creek and Deadwood monitoring wellbore schematic showing placement of tubing-deployed pressure and temperature-monitoring gauges and casing-deployed fiber optic sensing system (DTS/DAS-capable).

4.1.8.2 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 4-10 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, repeat 2D and/or 3D seismic surveys (4D seismic) will be collected to monitor the extent of the CO_2 plume within the first 5 years of CO_2 injection.

The seismic surveys will also be interpreted for an AVO response for detecting seismic response related to the CO_2 plume. In later years of the operational period (e.g., 10–20 years) if the free-phase CO_2 plume falls outside of the baseline 3D outline, AVO methods, with 2D and 3D

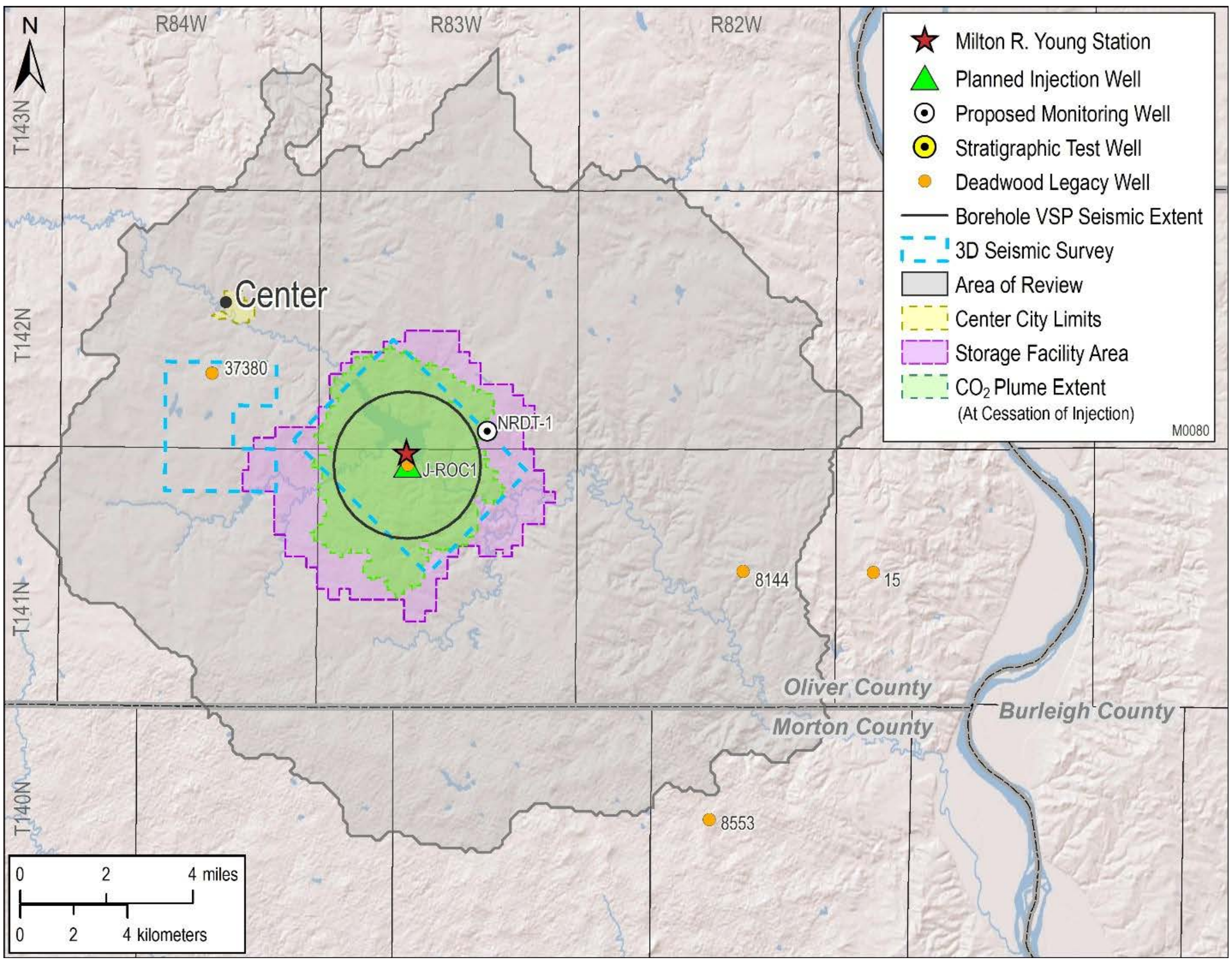


Figure 4-10. Simulated extent of the CO_2 plume at the end of injection operations in green. Surface seismic and borehole VSP seismic data outlines shown on the map will provide coverage for indirectly monitoring the predicted extents of the CO_2 plume over time.

prestack seismic, can be implemented as a standalone method for monitoring CO_2 migration. If it is found that the AVO method is not effective, the baseline 2D and/or 3D will need to be extended for sufficient time-lapse coverage. This seismic monitoring data will provide confirmation of the simulation predictions and confirm the extent 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 and/or AVO methods will be utilized during the postinjection period to confirm stabilization of the plume, as defined in Appendix A. The monitoring plan will be reevaluated at least every 5 years to determine if the testing and monitoring plan is sufficiently characterizing of the migrating CO_2 plume.

The time-lapse seismic response (4D seismic) and AVO method provide measurements of the change in fluid compressibility. Since CO_2 is a highly compressible fluid, it can be tracked with conventional seismic methods. Borehole seismic (3D vertical seismic profile [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 extent of 3D VSP coverage for the Deadwood Formation will be limited relative to the predicted plume extents. The 3D VSP method should be implemented early in the operational period (i.e., within the first 10 years) when the simulated plume extent is predicted to be well within the possible 3D VSP coverage. The maximum radius of the 3D VSP image area, as a rule of thumb, can be estimated to be approximately the equivalent of the depth of the formation being imaged. Once the radius of the injected plume exceeds the depth to the Deadwood Formation (~9,000 ft), the 3D VSP recorded in the injection well will not adequately monitor the plume. At this point, surface seismic (i.e., 4D seismic and/or AVO) is an appropriate method for monitoring the advancing plume.

Throughout the operational phase of injection operations, continuous monitoring of seismicity will be performed. Existing seismometer stations and additional stations will be installed ("array" of surface seismometers) sufficient to confidently measure baseline seismicity 5 km from injection. The data collected in the surface seismometers will be continuously recorded and analyzed for potential seismicity magnitudes and hypocenter locations. These seismometer stations with broadband sensors 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 (Vasco and others, 2020), which can detect small-scale surface ground deformation, has been shown to be one such technique for approximately mapping pressure distribution associated with subsurface fluid injection (Reed, 2021). 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 (Vasco and others, 2020). 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.

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 within 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.

4.1.9 Quality Control and Surveillance Plan

Minnkota has developed a quality control and surveillance plan (QASP) as part of the testing and monitoring plan. The QCSP is provided in Appendix D of this permit.

4.2 Emergency and Remedial Response Plan

Minnkota developed a comprehensive emergency and remedial response plan (ERRP) for the Tundra SGS site, indicating what actions would be necessary in the unlikely event of an emergency at the Tundra SGS site or within the AOR. The ERRP describes the potential affected resources and provides that site operators know which entities and individuals are to be notified and what actions need to be taken to expeditiously mitigate any emergency and protect human health, safety, and the environment (HSE), including USDWs.

This ERRP describes actions the operator of Tundra SGS shall take in the event of an emergency that could endanger any USDW within the project AOR during construction, operation, or postinjection site care. Such events may include unplanned CO_2 release or detection of unexpected subsurface movement of CO_2 or associated fluids in or from the injection zone.

This ERRP incorporates the risk analysis and evaluation of Tundra SGS, including monitoring wells, monitoring system, injection well network, and CO_2 flowline from the capture facility to the storage site. The ERRP is provided in Appendix E of this permit.

4.2.1 Description of Project Area

The Tundra SGS site includes mostly land associated with the coal-mining operation from BNI Coal, the area where MRYS is located, and land primarily used for agriculture activities (Figure 4-11). The closest highly populated area is Center, North Dakota, which is approximately 3.3 mi northwest of the Tundra SGS site.

The Tundra SGS project area consists of existing groundwater wells varying in type/use and located in shallow aquifers ranging in depth. Two wells penetrate the Fox Hills Formation (deepest USDW) and will be sampled (preinjection, operational, and postoperational) for periodic monitoring (ID 14108411AA and ID 14208424BBA). In addition, Minnkota will be installing a Fox Hills Formation monitoring well (NRDT-1) at the injection wellsite (McCall-1). Detailed information on the freshwater resources and protection of USDWs in the AOR can be found in Section 3.4 Protection of USDWs.

Section 2.6 in the Geologic Exhibits addresses any potential mineral zones within the project area.

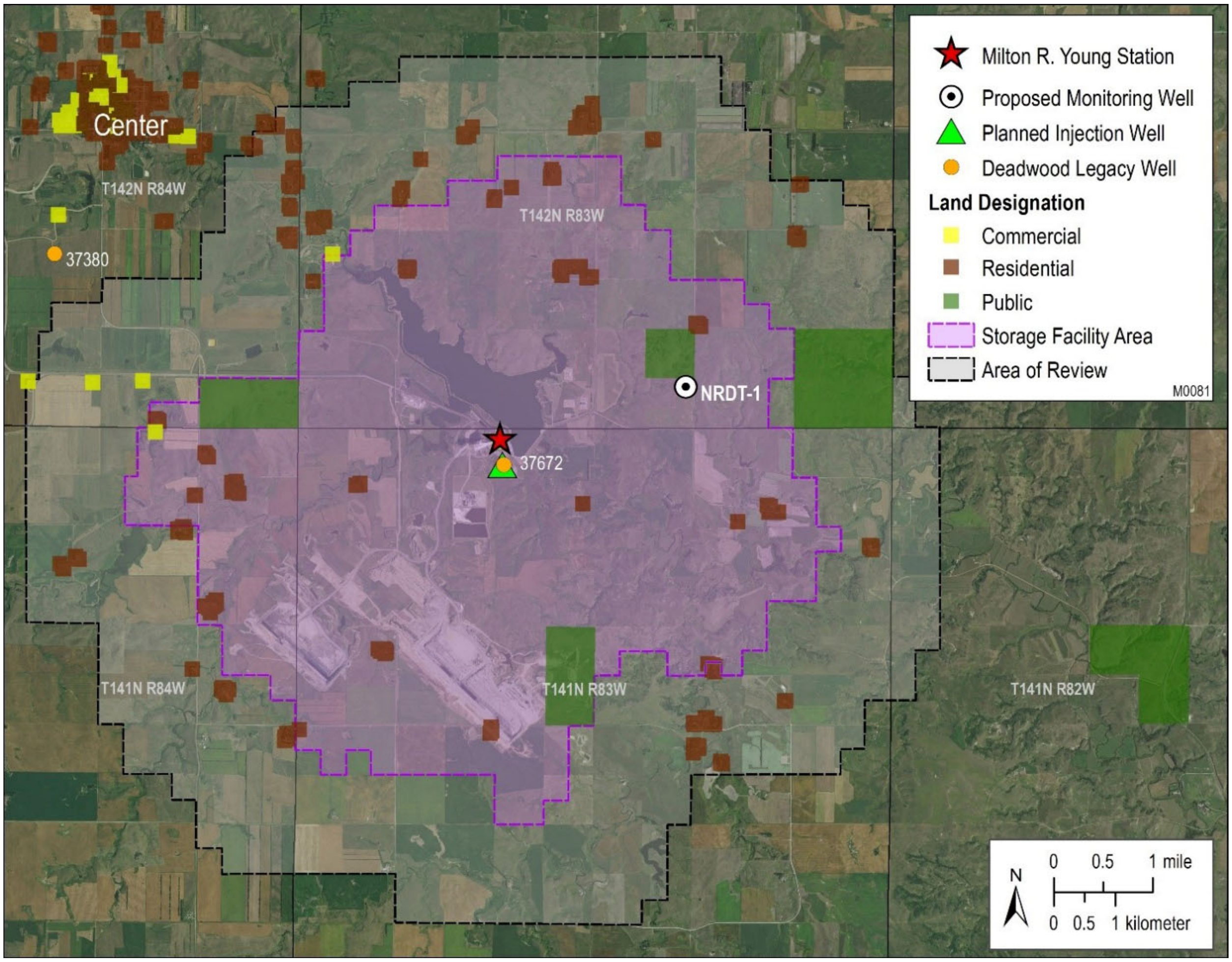


Figure 4-11. Residential, commercial, and public land use within 1 mi of the storage facility boundary.

4.2.2 Risk Identification and Severity

Several scenarios could activate an emergency response. This ERRP considers any adverse incident with the potential of causing personal injuries, USDW contamination, or property damage as an "event." The scope of response, actions, and order of activities will be proportional to the severity and impacts of the event and implemented as outlined in this ERRP. The events identified during technical reviews for the Tundra SGS are listed in Table 4-9. Appendix E contains a response protocol for each event identified in Table 4-9. The protocols may be modified and refined based on the specific circumstances and conditions of the event as well as any discussion with governmental authorities having jurisdiction.

Table 4-9. Risk Category Matrix

Construction Period • Well control event while drilling or completing the well with loss of containment • Movement of brine between formations during drilling • Presence of H_2S while drilling or completing the well
Injection Period • Loss of mechanical integrity (flowlines, injection, monitoring wells, disposal well) • Loss of containment (LOC): vertical migration of CO_2/brines via injection wells, monitor wells, Class I wells, P&A wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in flowlines, wells, and infrastructure • Monitoring equipment failure or malfunction • Induced seismicity • Seismic event • Other natural disaster
Postinjection Site-Care Period • Loss of mechanical integrity (monitoring wells) • LOC: vertical migration of CO_2/brines via monitoring, wells, Class I wells, P&A wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in monitoring wells • Monitoring equipment failure or malfunction • Natural seismicity • Other natural disaster

Event severity is classified as major emergency, serious emergency, and minor emergency, according to the Table 4-10 description.

Table 4-10 Severity Matrix

Consequence Degree of Severity	Definition
Major Emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. Example: well blowout while injecting
Serious Emergency	Event poses potential serious (or significant) near-term risk to human health, resources, or infrastructure if conditions worsen or no response actions are taken. Example: malfunction of monitoring equipment for pressure or temperature that may indicate a problem with the injection well and possible endangerment of public health and the environment
Minor Emergency	Event poses no immediate risk to human health, resources, or infrastructure. Example: higher pressure reading observed in monitoring wells, with no potential to move fluid

If information from the monitoring network, alarm system, field operators, or external reports evidences a potential leak of CO_2 or formation fluids from any well or surface facility including any pressure change or monitoring data which indicates the presence of a leak or loss of containment from the storage reservoir or concern for the mechanical integrity of the system, the following actions will be taken:

1. The project will activate the emergency and remediation response protocol consistent with this ERRP and circumstances of the event.

2. The NDIC Department of Mineral Resources (DMR) Underground Injection Control Program director (UIC program director) will be immediately notified within 24 hours of the event being discovered.

The UIC program director may allow the operator to resume injection prior to remediation if the storage operator demonstrates that the injection operation will not endanger USDWs.

4.2.3 Response Protocols

Discovery of an event triggers the corresponding response plan proposed in herein. Response plan actions and activities will depend upon the circumstances and severity of the event. The Tundra SGS operator will address an event immediately and, when required, will communicate the event to the UIC program director within 24 hours of discovery.

The protocols described in this document are conceptual and may be adjusted based on actual circumstances and conditions of the event and any previous communication with governmental authorities having jurisdiction.

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

For each of the scenarios identified in the risk screening, a detailed description of the mitigation and monitoring techniques is included in Appendix E.

4.2.4 Emergency Contacts

If an event is discovered, the Tundra SGS superintendent and HSE supervisor on duty will be notified immediately. The superintendent will be responsible for notifying off-site emergency response agencies and resources (Table 4-11). The superintendent shall also be responsible for notifying the UIC program director (Table 4-12) within 24 hours of initial discovery. Additional emergency response providers are listed in Table 4-13.

Table 4-11 Outside Emergency Response

	Agency	Location	Phone
Fire	Oliver County Rural Fire Protection District (volunteer department)	106 East Main Street, Center, ND	Phone: 911 or 701.794.3210
Ambulance	Oliver County Ambulance Service (volunteer basic life support service)	111 Main Street, Center, ND	Phone: 911– Ambulance Garage 701.794.8828 Cell 701.220.1329
Helicopter Air Care (MRYS ERT trains with Sanford AirMed and can be requested if needed, based on emergency)	Sandford AirMed	Bismarck, ND	Phone 911 or Sandford AirMed Dispatch 1.800.437.6886 Sioux Falls, SD, Office 844.424.7633
State Police	North Dakota Highway Patrol	600 East Boulevard Avenue Bismarck, ND	Phone: 911 or State Radio Dispatch 701.328.9921 Office 701.328.2447
Sheriff	Oliver County Sheriff Dave Hilliard	PO Box 362, Center, ND	Phone 911 Office 701.794.3450
Emergency Response Team (ERT)	MRYS Emergency Rescue Team	3401 24th Street Southeast, Center, ND	Phone 701.794.8711 or use the Plant Gaitronics intercom system to call “U1 Control Room” and report the emergency. The operator will sound the alarm for the ERT.

Table 4-12. NDIC DMR UIC Contact

Company	Service	Location	Phone
NDIC DMR	**Class VI/CCUS Supervisor**	Bismarck, ND	**701-328-8020**

Table 4-13. Potential Contractor and Services Providers (name available)

Company	Service	Location	Phone
Baranko Brothers	Excavation & Dirt Work/Hauling	Dickinson, ND	701-690-7279
Cyclone	Drilling rig	Gillette, WY	307-660-2370
Enerstar	Housing & Rentals	Bismarck, ND	701-934-1557
GeothermEx	Site Management/Drilling Supervisor Services	Houston, TX	281-769-4517
Schlumberger	Cementing,	Denver, CO	720-272-5288
	Core Analysis	Houston, TX	801-232-5799
	Direction & Measurements	Denver, CO	484-522-8434
	Products & Services	Denver, CO	517-755-9050
	Cameron Surface	Denver, CO/Minot,ND	970-260-4260
	Bits	Denver, CO/Williston, ND	303-518-6135
	Completions	Houston, TX	440-391-2711
Reservoir Group	Coring	Denver, CO/Houston, TX	832-350-5292
Rud Oil	Diesel	Center, ND	701-794-3165
Go Wireline	Wireline Tool/Fishing Services	Dickinson/Williston, ND	406-480-1086
MI SWACO	Drilling Fluids		661-549-3645
Sunburst Mudlogging	Logging/Geologic Services	Billings, MT	406-860-1228
Innovative Solutions	Solids Control	Williston, ND	701-770-0359
WellPro Inc	Fishing Equipment	Dickinson, ND	701-227-3737
Creek Oilfield Services	Waste Disposal/Casing Runnig/Supply	Williston/Bismarck, ND	701-590-5859 715-563-7543
Environmental Solutions	Cuttings Disposal	Belfield, ND	701-300-1156
Waste Management	Trash	Bismarck, ND	701-214-9741
ASK Transportations	Bulk fresh Water	Williston, ND	701-580-5627
Darby Welding	Welding	Dickinson, ND	701-483-5896
Panther PPT	Bop testing	Watford, ND	701-227-3737
Wyoming Casing	Casing Services	Williston, ND	701-290-8522
CCS	Tank Farm	Cody, WY	701-260-7780
MVTL Lab	Formation Fluids Collection	Bismarck, ND	701-204-5478
Petroleum Services	Casing (Float, Centralizer)	Williston, ND	701-770-1763

4.2.5 Emergency Communications Plan

Prior to the commencement of CO_2 injection operations, the Tundra SGS operator will communicate in writing with landowners living adjacent to the storage site to provide a summary of the information contained within this ERRP, including, but not limited to, information about the nature of the operations, operator contact list, potential risks, and possible response approaches.

An emergency contact list will be maintained during the life of the project. In the occurrence of an event, the superintendent will start the contact list and make sure that responsible, essential personnel are contacted. The operator's designated personnel will handle all event communications with the public.

The Tundra SGS operators will communicate adequate information to the public about any event to allow public understanding to the extent reasonably practicable, considering the circumstances leading to the event and any known environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate based upon the circumstances and severity of the event, which may include, but is not limited to, the following:

1. Event description and location.
2. Event investigation process, and response status (e.g., actions taken).
3. Whether there is any known impact to the drinking water or other environmental resources.
4. Any known injury to a person or property.

For protracted responses (e.g., passive monitoring or ongoing cleanups), the project will provide periodic updates on the progress of the response action(s).

4.2.6 ERRP Review

ERRP will be reviewed no less than:

a. Annually.
b. Following any significant changes to the Tundra SGS facility, such as AOR reevaluation or addition of injection or monitoring wells, on a schedule determined by the UIC program director.
c. When required by the UIC program director.

If the review indicates that no amendments to the ERRP are necessary, the Tundra SGS operator will provide the documentation supporting the "no amendment necessary" determination to the UIC program director.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to Tundra SGS as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

4.3 Financial Assurance Demonstration Plan

The FADP has been prepared in accordance with NDAC § 43-05-01-09.1. The FADP describes actions the operator of Tundra SGS has taken and shall take to ensure state and federal regulators that sufficient financial support is in place to:

a) Cover the cost of any corrective action that may be required at the geologic storage facility during any of its phases of operation, well plugging, postinjection site care and facility closure, ERR, and endangerment to USDWs.

b) Provide funds for routine monitoring and reporting activities by Minnkota during injection operations, closure activities, and an extended postclosure period as determined by regulatory agencies

While there are two separate storage reservoirs, these two separate reservoirs are commonly operated as dedicated Tundra SGS for a single CCS facility. The FADP was prepared to account for the entire operation of the Tundra SGS.

This FADP takes into account Tundra SGS storage facility permits and associated Class VI drilling permits in satisfying NDIC regulations contained in Title 43, Chapter 5, et seq. In preparing the FADP, U.S. Environmental Protection Agency (EPA) guidance was also considered in assessing the effectiveness of multiple qualifying financial instruments in the context of the Tundra SGS project, e.g., key aspects of long-term public confidence, optimization of stakeholder interests, and practicality of implementation.

Based on review and consideration of the available financial instruments contained in NDAC § 43-05-01-09.1, Minnkota proposes to use a combination of commercial insurance and a trust fund to fulfill the FADP requirements of the Class VI permits. The details contained in this FADP, along with supporting documentation, establish the approach Minnkota proposes to use to meet the financial responsibility requirements and that each of these instruments sufficiently addresses the activities and costs associated with the corrective action plan, injection well-plugging program, postinjection site care and facility closure, ERRP, and endangerment of USDWs.

Each of these instruments is described in full in subsequent subsections of this FADP and in Appendix G. Information related to the financial instruments will be updated on an annual basis and submitted to NDIC for review and approval as required under § NDAC 43-05-01-09.1.

4.3.1 Approach to Meeting Financial Responsibility Requirements

In accordance with the requirements contained in NDAC § 43-05-01-09.1, the FADP provides financial assurance sufficient to cover the activities identified in the corrective action plan, injection well-plugging program, postinjection site care and facility closure, ERRP and to address endangerment of USDWs. The following provides a summary description of the considerations and assessment approach for each component.

4.3.1.1 Corrective Action

According to § 43-05-01-05.1, corrective action involves inventorying and characterizing existing wells in the proposed AOR. The objective of corrective action assessment is planning actions to take, prior to and over the course of the project operation, on existing wells in order to proactively prevent the movement of fluid into or between USDWs. The detailed AOR can be found in Section 3.0 of this application. Minnkota has determined and asserts that there are no wells in the proposed AOR to which corrective action would be required prior to or during the course of the project operation or postclosure period. For the avoidance of doubt, if wells proposed as part of Tundra SGS operation require corrective action, such action and the costs relating thereto are included as part of the project operating cost.

4.3.1.2 Injection well plugging program

The plugging of injection wells as part of site program closure and as required by NDAC § 43-05-01-11.5 is included within the project cost and is covered within this FADP and proposed instruments. The specifics of the plugging program can be found in Section 4.6. Costs were estimated using work scopes provided by third-party industry experts and comparable actual third-party costs for performance of services and procurement of associated goods. These costs shall be disbursed through the trust as described herein, while the amount associated with well plugging shall be funded following commencement of the operation of the wells. The estimate covers the aggregated cost of abandoning three injector wells, including rig mobilization, rig rentals, cementing, logging and haulage. To ensure a conservative estimate, a 20% contingency was added, and no deductions were made for salvage value of materials.

4.3.1.3 Postinjection site care and Facility closure

Postinjection site care (PISC) and facility closure cost estimates include site monitoring and periodic reassessment of the AOR, facilities maintenance and power costs, and overhead and support costs. Details of the activities and actions contained in the PISC can be found Section 4.0. The largest element of the PISC cost estimate relates to seismic studies, which are required to be carried out at 5-year intervals to validate seismicity models, which are expected to cover an area of up to 25 mi^2.

4.3.1.4 Emergency and remedial response

The ERRP and associated detailed assessment can be found in Section 4.0. The ERRP assessment supports a determination that the likelihood of release of significant volumes of CO_2 from underground storage into the soil or the atmosphere, or significant volumes of saltwater into the environment, are considered remote. Multiple factors were considered in the development of the ERRP, including:

a) Extensive and independently verified analysis of the integrity of the storage mechanism.
b) Selection of qualified and experienced storage facility operator.
c) Selection of qualified and experienced drilling contractor.

Risk mitigation measures include:

a) Location of injection facilities away from urban population and in an industrial-zoned, brownfield property.
b) Continuous monitoring of transportation and injection systems.
c) Routine measurement and reporting of CO_2 volumes.

d) Physical security, barriers and signage around injection facilities.
e) Primary and secondary containment for leaked fluids at injection well pads.

In the interest of providing sufficient financial assurance, Minnkota has compiled cost estimates associated with a conservative hypothetical scenario wherein a significant volume of briny water arises to the surface injection operations. The scenario contemplates a reactive response approach; e.g., mobilization of response personnel and equipment would be upon discovery of such an event. This approach is considered appropriate because of the remoteness of the residual risk. Specific postoccurrence action is not determinable until occurrence; thus actual response to such an event would be based on its severity. Because of the remote likelihood, this single conservative scenario was compiled to account for the outer-limit cost estimate to satisfy event response. The scenario used for cost estimating assumed the optimal operating conditions (10 years of operation) requiring outer limit response and remediation costs. This conservative outer limit cost estimate was calculated and used as a basis for this FADP document.

Dual Utilization of the ERRP Trust Property

Upon authorization from NDIC to begin injecting CO_2 under the Class VI well permit(s), Minnkota must be prepared to undertake any emergency or remedial response (ERR) actions, although such actions are unlikely to be needed. Further, in accordance with North Dakota Century Code (NDCC) § 43-05-01-17, Minnkota must account for a one cent fee on each metric ton of carbon dioxide for administration of a storage facility fund and a fee of seven cents on each ton of CO_2 injected for a storage facility fund which can be utilized for post closure period activities (together referred to as "commission fee"). The average projected amount of CO_2 injected will be 4 MMt annually. Minnkota estimates a minimum of 12 years of operation and is permitting operation of the storage facility for 20 years of injection. Minnkota therefore estimates being required to pay a commission fee of $320,000.00 annually, with a total commission fee of $3,840,000.00 by year 12 of operation ($6,400,00.00 is the cumulative commission fee by Year 20). Minnkota's estimated total cost of ERR activities is $16,560,000.00, assuming conditions allowing a conservative outer-limit cost estimate (at least 10 years of operation), with $5,960,000.00 of the estimate funded by the trust. Since the ERR cost estimate exceeds the estimated 12-year commission fee[1] and ERR activities are unlikely to be needed, the account containing the ERR principal and any associated interest may be used at site closure for satisfying the commission fee and commission required closure activities calculated under NDCC § 43-05-01-17. Therefore, Minnkota proposes the account containing the ERR principal and any associated interest to be used at closure (or termination of the trust) to satisfy the commission fee. The trust agreement would allow the trustee to release an amount equal to the total commission fee upon written direction of NDIC from the principal and interest contained in the ERR account in an amount equal to the fee calculated in accordance with § 43-05-01-17 at the time NDIC issues the certificate of closure or termination of the trust, whichever occurs first.

Minnkota proposes that the account associated with the ERR account should be funded with an initial amount sufficient to cover the costs associated with the ERR activities upon issuance of authorization to operate a Class VI injection well. Minnkota proposes an initial funding of an amount equal to the net of the cost estimate for ERR activities less the calculated 12-year commission fee based upon the projected annual average injection rate of 4 MMt, $2,120,000.00.

[1] Commission fee would not exceed the fund principal amount until Year 18 of operation.

Minnkota will fully fund the ERR activities with seven equal installments annually of $548,572.00 made in the injection period, with the first installment prior to the 1-year anniversary of NDIC's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $5,960,000.00. However, if at any time NDIC determines the amount of the commission fee exceeds the principal amount then contained in the ERR account, then upon written direction from NDIC, grantor shall fund amounts sufficient to cover the commission fee calculated in accordance with NDCC § 43-05-01-17.

4.3.1.5 Endangerment of Drinking Water Sources

As discussed in the ERRP subsection, the risk of endangerment to USDW is considered remote. However, as part of the reactive response scenario contemplated in the ERRP cost estimate, Minnkota assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water. Because of precautions taken in the design for spill control and pollution prevention, the well pad design incorporates two liners and a berm that, in combination with the response strategy, would minimize this portion of environmental repair. Thus Minnkota assessed the second reactive scenario, which contemplates a subsurface leak scenario. This subsurface leak scenario has primary costs relate to groundwater delineation and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken.

4.3.2 Approach to Financial Risk

Minnkota formed a task force (TF) to understand and quantify project risks. The TF consisted of 14 members with relevant professional qualifications and experience in subsurface analysis, facilities engineering, drilling engineering, operations, finance, environmental protection, or risk engineering. The TF identified and quantified the likelihood and impact of multiple risks using industry-standard methodology and methods. Four working sessions, each between 3 and 4 hours in duration, were conducted, and the TF reached consensus on the assessment of risks underlying various aspects of the project. The findings of the TF support the understanding of financial risks and the approach to FADP described in this document.

4.3.3 Selected Elements of Minnkota's Analysis of Inherent Risks

The projected AOR includes mostly land associated with the coal-mining operations of BNI, the area where MRYS is located, and land primarily used for agriculture activities. Residents and man-made structures are scattered across the surface. The closest highly populated area is the town of Center, North Dakota, approximately 3.3 mi northwest of the proposed Tundra SGS facility boundary.

From the surface to the lowermost USDW—the Fox Hills Aquifer—the groundwater is considered a protected aquifer with <10,000 ppm TDS. The Fox Hills base is estimated at approximately 1,000 ft and is followed by a thick section of clays with a thickness of approximately 2,600 ft. These clays act as a seal until the next major permeable zone, the Inyan Kara. The Inyan Kara is an underpressured formation that is classified as an exempt aquifer under NDCC § 43-02-05-03 west of the 83W range line, and this formation is mostly targeted for water disposal wells in those areas. Approximately 900 ft of cap rock acts as a main seal between the Inyan Kara zone and the shallowest of the two injection reservoirs: the Broom Creek.

Inside the AOR, 64 water wells are located in shallow aquifers, providing water for the associated farms' livestock, irrigation, and localized consumption. Two wells that penetrate the Fox Hills Formation will be used as tools for monitoring the USDW (ID 14108411AA and ID 14208424BBA). The project will install one additional USDW well, as described in the monitoring plan, to sample underground water.

No producible mineral, oil, natural gas, or other reserves are reported in the AOR for the Deadwood Formation or overlying formations. As described in the AOR and corrective action section, for the Tundra SGS storage reservoir and drilling applications, there are three deep wells (one oil and gas [O&G] exploration, two stratigraphic) within or in proximity to the plume boundaries and the identified pressure front: these wells are identified as BNI-1 (API 33065000180000), Herbert Dresser 1-34 (API 33065000050000), and J-LOC1 (33065000190000). J-LOC1 will be converted to a pressure monitoring well for Tundra SGS or will be permanently abandoned, and the other two wells were analyzed and included in the risk assessment as well as in the corrective action plan.

4.3.4 Cost Estimates

Tables in this section provide a detailed estimate, in current dollars, of the cost of performing corrective action on wells in the AOR, plugging the injection well, postinjection site care and facility closure, and ERR. Table 4-14 is a summary of the cost estimates underlying the FADP document, identifying proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of Minnkota's intent and ability to fulfil its responsibilities.

Cost estimates assume that these costs would be incurred if a third party were contracted to perform these activities. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the postinjection period, e.g., the use of postinjection seismic surveys.

Table 4-14. Potential Future Costs Covered by Financial Assurance in $K

Activity	Total Cost	Covered by Special-Purpose Trust	Covered by Commercial Insurance	Details in Supporting Table
Corrective Action on Wells in AOR	$0	$0	$0	NA
Plugging Injection Wells	$2,025	$2,025	$0	Table 4-14-1
Postinjection Site Care	$10,285	$10,285	$0	Table 4-14-2
Site Closure	$1,554	$1,554	$0	Table 4-14-3
Emergency and Remedial Response	$16,560	$5,960	$10,600	Table 4-14-4
Endangerment of USDWs	$2,240	$0	$2,240	Table 4-14-5
Total	**$32,664**	**$19,824**	**$12,840**	

The values included in the FADP are based on cost estimates provided during the permit application development process and are based on the hiring of a third party to perform the services or procurement of goods associated with performance. Cost estimates are based upon historic price data from other projects managed by Oxy Low Carbon Ventures (OLCV), cost quotes from third-party companies, regulatory guidance documents, and professional judgment about the level of effort required to complete an activity. These values are subject to change during the course of the project to account for inflation of costs and any changes to the project that affect the cost of the covered activities. If the cost estimates change, Minnkota will adjust the value of the financial instruments, and any adjustment will be submitted for approval by NDIC as required under NDAC § 43-05-01-09.1(3).

Tables 4-14.1 through 4-14.6 provide detailed breakdowns of the future cost estimates provided in Table 4-14.

Table 4-14-1. Plugging Injection Wells

Activity	Cost
Mobilization and Location	$435,000
Rig Rates and Daily Cost	$467,000
Hauling and Disposal	$57,000
	$
Bit and Scrapers	
Casing Crew and Torque	
Sensors and Fiber Optic	
Cementing	$353,000
Perforating Cost	$
Pumping Truck and Acid	$
Wellhead Service	$60,000
Tangibles	$
Subtotal	**$1,577,000**
Contingency	**20%**
Tax	**7%**
Total Cost	**$2,025,000**

Notes:
- Costs are based on estimates of current contract day rates and materials.
- Costs are based on P&A of a total of three injector wells: two in the Broom Creek Formation and one in the Deadwood Formation.

Table 4-14-2. Postinjection Site Care

Activity	Cost
Monitoring and AOR Revisions (see Table 4-14-3)	$7,197,000
Overhead and Support	$1,388,000
Facilities Maintenance and Power	$1,700,000
Total	**$10,285,000**

Notes:
- Costs are based on estimates of current contract day rates and materials.
- Postinjection seismic survey conducted at 5-year intervals.

Table 4-14-3. Monitoring and AOR Revisions (part of postinjection site care)

Activity	Cost
Gas Soil Probes	$716,000
3D Seismic Survey – Time Lapse	$5,000,000
Water Sampling	$180,000
Saturation Log Monitoring Wells	$819,000
Annular Pressure Test	$100,000
AOR Assessment	$86,000
Casing Inspection Log Monitoring Wells	$160,000
Optical Gas Imaging	$72,000
Visual Inspection	$64,000
Total	**$7,197,000**

Table 4-14-4. Site Closure

Activity	Cost
Monitoring Well P&A	$764,000
Facilities Closure	$1,020,000
Total Site Closure	**$1,784,000**

Notes:
- Costs are based on estimates of current contract day-rates and materials.
- Costs are based on P&A of two monitoring wells.
- Facilities closure estimate includes abandonment in place of buried pipelines.

Table 4-14-5. Emergency and Remedial Response	
Activity/Item	**Cost**
Pump Trucks (twin pump)	$113,784
Frac Tanks	$48,000
Vacuum Truck	$36,000
Dozer	$18,600
Excavator	
Brine Disposal (no Class I)	
Water Transfer Pump and Personnel Package	
Light Towers, Trailers, Generator, Heaters, Communications, etc.	$7,690
Heater Packages	$36,000
Fuel Tank Storage	$3,400
Drill and P&A Relief Well in Broom Creek	$8,760,000
Special Well Control Team – (e.g., wild well/boots & coats)	$1,500,000
New Injector Well – Replacement (mob, drill and comp.)	$5,060,000
Original Injector Well Abandonment	$900,000
Total	**$16,559,874**

Notes:

- These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.
- A significant portion of these costs, should they be incurred, would be covered by commercial insurance which is an industry standard control of well (COW) coverage.
- Costs are based on estimates of current contract rates.

Table 4-14-6. Endangerment of USDWs	
Description	**Total Estimated Amount**
Subsurface Release to USDW	
General Response Actions	$6,000
Groundwater Delineation	$1,290,000
Irrigation/Domestic Well Sampling and Replacement	$131,000
Quarterly Groundwater Monitoring (10 years) and Reporting	$760,000
P&A of Groundwater-Monitoring Wells	$53,000
Total	**$2,240,000**

Notes:

- These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.
- Costs are based on estimates of current contract rates.

4.4 Worker Safety Plan

The worker safety plan (WSP) describes the minimum safety programs, permit activities, and training requirements to deploy during construction, operation, and postinjection site care periods. This document does not limit the application of additional programs and technologies that could improve the safety and performance of the operation.

This WSP incorporates the safety program for the Tundra SGS as a whole. It includes monitoring wells, monitoring system, injection well network, and CO_2 flowline of the storage facility.

4.4.1 Definitions

a. **Confined space** means a space large enough and so configured that an employee can bodily enter and perform assigned work, has limited or restricted means for entry or exit (for example, tanks, vessels, silos, storage bins, hoppers, vaults, and pits or spaces that may have limited means of entry), and is not designed for continuous employee occupancy. This definition could also apply to a trench, bellhole, cellar, or excavation.

   Some confined spaces are designated permit-required confined spaces: meaning entry into the space must be controlled through application of a confined space entry permit. A "yes" answer to *any one* of the following questions means the space must be designated "permit-required":

   - Does the space contain, or have the potential to contain, a hazardous atmosphere?
   - Does the space contain a material that has the potential for engulfing an entrant?
   - Does the space have an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or a floor that slopes downward and tapers to a smaller cross section?
   - Does the space contain any other recognized serious safety or health hazard?
   - The confined space entry (CSE) program is provided to protect authorized employees and contractors that will enter permit-required confined spaces.

b. **Contractor** means a company or person performing work, providing services, or supplying equipment at the work site, including its subcontractors.
c. **Hazardous energy** means energy sources, including electrical, mechanical, hydraulic, pneumatic, chemical, thermal, or other sources in machines and equipment, where the unexpected start-up or release of stored energy can result in serious injury or death.
d. **Operator** means the Tundra SGS or any Tundra SGS employee.
e. **Permitted work activities** means activities that require the use of a permit, including but not limited to, confined space entry, lockout/tagout, trenching and excavation, electrical, and hotwork, which require the use of a permit.
f. **Site manager/supervisor** means the operator designated representative in charge of the work site or work.
g. **Work site** means physical location under control of the operator where work is being performed on behalf of the operator.
h. **Work** means task or tasks to be executed by the operator or contractor.
i. **Visitor** means a person or person(s) present at the work site who are there for observational, not work purposes.

4.4.2 Stop Work Authority

Each operator and contractor has the right, obligation, authority, and responsibility to stop any work or action that is unsafe or, if continued, may result in adverse impact to the environment. No operator employee or contractor will be subject to discipline or sanction for stopping any work or action that they believe in good faith is unsafe or may result in adverse impact to the environment. Work must be stopped in a safe manner and immediately reported to the site manager/supervisor or operator representative. Appropriate actions will be taken to mitigate the hazard before the work will be allowed to commence. Every contractor will have a stop work authority program that advises their employees of their rights to use stop work authority.

4.4.3 Incident Notification and Response

The operator employee or contractor shall be required to immediately notify the site manager/supervisor (or designated operator representative) of all incidents involving injury or illness to a contractor, damage to operator or contractor equipment as a result of contractor activities at the work site, and any spill, release, or leak. Prompt investigation is required of all injuries, illnesses, equipment or property damage, environmental spills/releases, and other HSE-related incidents.

Unsafe conditions must be immediately reported to the operator. "Near-miss" incidents that could have resulted in injury or damage must be reported by the operator employee or contractor to the site manager/supervisor (or designated operator representative).

4.4.4 Incident Report and Investigation

An initial preliminary written incident report for all workplace incidents shall be submitted within 24 hours of occurrence, with known facts, to the site manager/supervisor (or the designated operator representative).

An investigation will be started as soon as possible following notification into all injuries, illnesses, equipment or property damage, leak, spill or release, or other HSE-related incidents. A written interim incident investigation report for all incidents will be provided every 7 calendar days until the final incident report is submitted to the site manager/supervisor (or the designated operator representative). The operator may participate in any investigation of incidents at any work site and will be permitted to reproduce all work site audits and incident investigations for the purposes of correction, training, investigation, and root cause analysis.

The final incident report shall include, at minimum, description of the incident, location, chronology, injury details, Occupational Health and Safety Administration (OSHA) classification, impact on people and the environment, protective equipment performance assessment, review of the process (design, operation, maintenance, and administrative control), identification of root cause, and recommendation for corrective actions. The operator shall provide timely notification to the site owner of all incidents involving injury or property damage and will provide weekly reports to the site owner that identify all incidents reported in the prior week.

All incident reports that result in formal notification to any government entity or authority shall be provided to the operator. Additionally, any investigations, inspections, or penalties assessed on the contractor by any government entity or authority, relating to or in connection with any work performed for the operator, shall promptly be provided to the operator.

4.4.5 Training

The contractor shall receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training shall be conducted by, or under the supervision of, an operator site supervisor/manager or an operator-designated representative. Trainers must be thoroughly familiar with the operations plan and ERRP.

The contractor shall conduct a training needs assessment that is representative of the contracted work site assignments. The contractor shall establish the type and frequency of training in a role and responsibility matrix by position (matrix). The contractor shall ensure that personnel have been given all core and special training identified in the matrix.

However, the following are minimum requirements regardless of position or work:

- All newly hired personnel need to attend onboarding training for the work site and fulfill the safety training according to the position before starting on the job.
- All operation employees shall participate in annual training to teach or reinforce how to perform the job, equipment functioning, and instrumentation.
- All employees shall participate in an annual refresher training for the emergency response procedures contained in the ERRP.
- Monthly briefings shall be provided to operations personnel according to their respective responsibilities and shall highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.
- Documentation of all training shall be retained by the contractor and made available for operator inspection upon request.

4.4.6 Contractor Qualification and Bridging Documents

The contractor shall have a qualification program and auditing process to ensure personnel are held to the same safety standards or higher than operator standards. A bridging document shall be created to align the safety program between operator’s and contractor’s policies if required.

4.4.7 General Health, Safety, and Welfare

The work site must be maintained so as not to create or otherwise contribute to an unhealthy working or living environment. To accomplish this objective, the operator and contractor shall ensure the following:

Information/Posting/Signs. All emergency, safety and operational information/postings/ signs shall be communicated in a format to ensure comprehension by the operator and visitors or contractors on the worksite in accordance with OSHA 29 Code of Federal Regulations (CFR) 1910.145, country, state/province, local, or international equivalent.

Job Safety Analysis. The contractor shall complete and review, with all affected parties, a job safety analysis (JSA) prior to performing any work. Anytime the job scope or conditions change, the contractor shall review and revise (if needed) the JSA with all affected parties.

Prejob Meeting. On work sites where simultaneous operations (SIMOPS) shall be conducted, daily prejob planning meeting(s) shall be held involving representatives from all potentially affected parties.

English Language Proficiency. At least one person per crew or work group assigned to the task must be fully capable of communicating in the English language (both in a verbal and written manner) such that they can perform the work safely. If required, an interpreter shall be provided.

Short Service Or New Hire. Short service personnel or new hires without experience shall be mentored and supervised by a senior professional and uniquely identified in the field (stickers and unique color hard hat). The employee shall fulfill core training before starting activities on the work site. Documentation of such mentoring/training must be retained and available for inspection upon request.

Medical Fitness/Personal Hygiene. Personnel shall be medically fit to safely perform the work they are expected to perform. The operator may audit to ensure that personnel maintain appropriate standards of personal hygiene during performance of the work.

Housekeeping. The contractor shall ensure good housekeeping practices are conducted at the work site by all personnel to provide for a safe and orderly working environment. Aisles, emergency exits, and controls must be always kept free of obstacles.

Machine Guarding. The contractor shall ensure that all equipment machine guarding (permanent, temporary and portable) is properly installed and maintained. Before removing guards to service guarded equipment, which should be isolated, locked out, tagged out, and verified to be nonfunctioning, see lockout/tagout procedure.

Portable Hand Tools. All portable hand tools shall have proper insulation, grounding, and guarding, in accordance with manufacturer requirements. All portable tools shall be properly maintained and used based on manufacturer original design and intended purpose. Tools shall be regularly inspected and damaged or worn tools shall be taken out of service. No homemade or modified hand tools shall be used on the work site.

Management of Change (MOC). The contractor shall have a formal MOC process implemented for all equipment (except for "replacement in kind"), process, and procedural changes. The contractor shall ensure no contractor's equipment is used or modified outside of the original equipment manufacturer-design specifications.

Clothing and Other Apparel. Ragged or loose clothing and jewelry (rings, watches without breakaway nonmetallic bands, necklaces, exposed piercings, etc.) are not to be worn when on the work site. Any clothing that becomes saturated with hazardous chemicals should be promptly removed.

First Aid/CPR. The contractor shall ensure sufficient First Aid/CPR and defibrillator equipment and trained personnel (National Safety Council, American Heart Association, Red Cross, etc.) are available at work site in accordance with OSHA 29 CFR 1910.151 or equivalent country, state/province, or local regulations. First Aid/CPR and defibrillator kit(s) containing an appropriate quantity of supplies shall be maintained on location at all times.

Transportation Safety. The contractor shall ensure that all modes of transportation are fit for purpose for travel to/from/within the work site. The contractor shall ensure compliance with all applicable country, state/province, and local regulations.

Industrial Hygiene

- The contractor will assess job duties to determine if hazards are present, or are likely to be present, which necessitate the use of engineering controls, administrative controls, or personal protective equipment (PPE).
- The contractor shall document this hazard assessment through a written certification that identifies the work site evaluated, person certifying that the evaluation has been performed, and date(s) of the hazard assessment. Documentation shall be retained by the contractor and made available to the operator upon request for inspection.
- Based on the results of this hazard assessment, the contractor may be required to perform an industrial hygiene assessment of the work site to determine the level of exposure to hazards (chemicals, lead, dust, noise, etc.).
- Appropriate measures shall be taken based on these assessments in order to safely manage operator, contractor, and visitor exposures.

4.4.8 Personal Protective Equipment

All contractors and visitors must wear appropriate PPE for the hazards present at the work site. Actual PPE requirements shall be determined in accordance with hazard/risk assessments, and safety data sheets (SDSs) must be provided for products that personnel might be exposed to at the work site ("Risk Assessment").

The following PPE, at a minimum, must be used by all operators or contractors at the work site, along with the appropriate training in the proper use and care of such PPE:

- Hard hats
- Safety glasses with side shields
- Protective footwear (safety-toed boots)
- Personal monitor(s) as needed based on risk assessments for H_2S or other hazardous materials

The following is a list of PPE that, based on the hazard/risk assessment, might be required for the work site and applicable standards/certifications that apply:

- Respiratory protection meeting OSHA 29 CFR 1910.134, National Institute for Occupational Safety and Health (NIOSH)-certified.
- Head protection meeting American National Standards Institute (ANSI) Z89.1 Type 1, Classes E and G.
- Eye and face protection appropriate for the work environment and hazards meeting ANSI Z87.1.

- Foot protection meeting ASTM F 2413 or international equivalent standard.
- Hearing protection meeting ANSI S3.19 standard.
- Hand protection (gloves) appropriate for the work environment, exposure, and hazards.
- Flame-retardant clothing certified to National Fire Protection Association (NFPA) 2112/(NFPA 70E Arc Flash PPE category for personnel performing electrical work) (as identified by regulation or local company management including but not limited to 29 CFR 1910.132, 1910.269, and 1910.335; ASTM 1506; NFPA 70E, 2112, and 2113).

Fire protection. The contractor shall, based on a risk assessment, provide and maintain fire protection equipment for the work. Fire protection shall comply with all local regulatory or equivalent NFPA requirements and be dedicated for firefighting use only.

4.4.9 Hand Safety

The contractors shall have a hand safety awareness-training program targeting topics such as pinch points, hold points, soft grips, cutting devices, proper hand tools, hot/cold conditions, chemical handling, etc.

Selection of appropriate hand protection should be based on an evaluation of the performance characteristics of the hand protection relative to the task(s) to be performed, conditions present, duration of use, and hazards and potential hazards identified.

Contractors are required to use appropriate hand protection when they encounter the following hand hazards:

- Thermal
- Sharp materials
- Electrical current
- Chemical exposure
- Impact
- Abrasive materials

4.4.10 Permitted Work Activities

The following are considered permitted activities and require a permit to be executed:

- **Hot work**. Any work that may introduce any source of ignition where flammable vapors may be present or will generate sufficient heat to ignite combustible and/or flammable materials and these materials will support combustion once ignited.

- **CSE**. Any CSE conducted on operator property must be done under a permit-required confined space program, which shall identify methods to comply with the requirements of OSHA Standard 1910.146.

- **Lockout/Tagout Procedure**. When any hazardous energy scenario is encountered, including but not limited to the following during performance of servicing or maintenance of equipment:

a. Removal or bypass of machine guards or other safety devices.
b. Placement or positioning of any part of the body in contact with the point of operation.
c. Placement or positioning of any part of the body in a danger zone associated with a machine's operating cycle.
d. When the release of stored energy that could injure the operator, contractor, visitor, or a member of the public if the isolated device (e.g., valve, breaker, etc.) were to be operated by mistake.

The following safe work practices are required:

a. Use of lockout/tagout controls to prevent the release of hazardous energy.
b. The equipment must be deenergized, and locks and tags must be applied to the energy-isolating devices.
c. All work involving isolation of hazardous energy must be done in accordance with 29 CFR 1910.147.

Excavation and Trenching. The contractor performing trenching and excavation activities on a work site must provide competent personnel capable of identifying existing and predictable hazards in the immediate surroundings. The contractor shall ensure that the competent person must be on-site during all excavation activities where the potential for injury exists. The competent person must also comply with all applicable OSHA construction regulations.

Preexcavation Notification Requirements. Injection and plant locations must have a means of receiving a written "ticket locate request" from a state one-call notification center. In addition, each location must have a 24-hour emergency telephone number, such as a plant location or answering service.

Electrical. The contractor performing electrical work activities shall provide qualified personnel. Qualified persons must be trained and knowledgeable of the construction and operations of the equipment or a specific work method and be trained to recognize and avoid the electrical hazards that might be present with respect to that equipment or work method.

Energized equipment to which a qualified or unqualified person might be exposed must be in an electrically safe work condition before an employee works within the limited approach or the arc flash protection boundaries. For cases where it is determined that the equipment cannot be placed in an electrically safe work condition, an energized electrical work permit must be completed and approved prior to commencing the work.

Energized work that is considered routine for diagnostic testing or troubleshooting is exempted from the energized electrical work permit requirements if there is an approved maintenance or operating procedure in place for the task.

Electrical Safety Program. The contractor shall have an electrical safety program that identifies the levels of all electrical and associated tasks to be performed and personnel position qualified to perform each of these tasks in accordance with OSHA/ National Electrical Code (NEC), American

Petroleum Institute (API) 500, NFPA 70E, or equivalent country, state/province, or local regulations.

Contractor electricians shall be qualified to perform electrical activities on contractor or operator equipment at the work site as required by local regulations or equivalent OSHA/NEC/NFPA 70E standards.

Contractors working in areas where there are electrical hazards shall be provided with and use protective equipment that is designed and constructed for the specific part of the body to be protected and work to be performed.

The contractor shall consider all overhead power lines to be energized unless proper measures have been taken for deenergizing. When work is being performed near energized overhead power lines, any part of the crane, boom, mast, gin poles, suspended loads, or machinery shall not be permitted within 10 ft (3 m) of the power lines. However, this safe working distance can be increased according to the voltage of the power lines (OSHA 29 CFR 1926.550, 1910.181, and 1910.269 or equivalent country, state/province, or local regulations).

The contractor shall ensure that all personnel will use only portable ladders, scaffolding, or other elevating devices made of nonconductive material when working around energized electrical equipment.

Precautions shall be taken to ensure that all equipment used is properly grounded and accidental contact with ungrounded electrical sources is prevented.

Contractor shall ensure all contractor electrical components, tools, and PPE are maintained in a safe working condition.

Temporary electrical power setup for the operation of tools and equipment shall be protected by ground fault circuit interrupter (GFCI) circuits.

4.4.11 Chemical, Hazardous, or Flammable Materials

SDSs. The contractor shall ensure that all chemical products/materials supplied to the work site are accompanied by the respective SDS upon delivery. The contractor shall provide the site supervisor/manager with an inventory of all chemical products/materials to be used along with copies of the related SDS documents. The operator shall have authority to prohibit any chemical product/material that is deemed unacceptable at the sole discretion of the operator.

The contractor shall instruct all personnel on the safe use of the chemical products/materials in accordance with an appropriate written hazard communication program as dictated by local/state/federal regulatory requirements.

The contractor shall ensure that SDSs for chemicals are reviewed by personnel prior to exposure.

Storage, Use, and Labeling of Chemicals, and Hazardous/Flammable Materials. The contractor shall ensure all hazardous and/or flammable materials/products are labeled, handled, dispensed and stored in accordance with OSHA 29 CFR 1910.106 and 1910.1200 or equivalent country, state/province, or local regulations.

All chemicals, paints, and hazardous/flammable materials shall be kept in appropriate containers, which are clearly labeled as to the respective contents, and stored in fit-for-purpose storage containers (uniquely identified, vented, etc.). Container labeling shall be consistent with OSHA, U.S. Department of Transportation (DOT), NFPA or equivalent country, state/province, or local regulation.

Hydrogen Sulfide. When the presence of hydrogen sulfide gas may exist at greater than 10 ppm in the wellbore, formation, facilities, or production stream, the contractor is responsible for ensuring that personnel are properly trained and qualified. Personal monitoring equipment shall be used by all personnel, and personal monitoring devices must be set to alarm at 10 ppm so that personnel are alerted to evacuate the area. The H_2S monitors shall be calibrated per manufacturer specifications, and at a minimum, personal H_2S monitors shall be “bump”-tested at least monthly.

4.4.12 Compressed Gas and Air Cylinders

Compressed gas cylinders shall be properly used, maintained, stored, handled, and transported as designated by OSHA 29 CFR 1910.101-106, 1910.252, 1910.253, and 1926.350 or equivalent country, state/province, or local regulations.

Compressed gas and air equipment shall be constructed in accordance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section VIII Edition 1968 or equivalent country, state/province, local or international laws or regulations. Equipment includes but is not limited to safety devices, flame arrestors, regulators, pressure gauges, check valves, pressure relief valves, labeling, etc.

All compressed gas cylinders shall be returned promptly to a suitable/designated storage area when not in use. Compressed gas cylinders shall be stored in the upright position and secured.

Protective caps shall be placed over the cylinder valves when not in use or being transported.

Compressed gas cylinders shall be stored away from heat, fire, molten metal, and electrical lines.

Compressed gas cylinders shall not be transported by mobile cranes unless a special carrier is used.

Oxygen and flammable gases shall be stored in areas separated by a minimum of 20 ft or fire barrier rated for 30 minutes.

Acetylene or liquid compressed gas cylinders shall never be used in a horizontal position, as the liquid may be forced out through the hose, causing a fire hazard or explosion.

Oxygen/acetylene cutting torch lines shall include flashback arrestors placed (at least) at the cylinder end. The preference is the arrestor be on the torch side.

Compressed air should not be used for cleaning clothing or parts of the body. If compressed air is used for cleaning, the discharge shall not exceed 30 psi (2.07 bar), and eye/face protection shall be worn.

4.4.13 Overhead/Outside Guarded Area

Lifting and Hoisting. When the contractor is working overhead, the area below shall be barricaded or other equivalent measures taken to protect workers on the work site. No one shall be permitted to pass under any suspended load.

Each lifting device shall identify the manufacturer, safe working load, service/manufactured date, and serial/identification number.

Lifting devices shall be managed in a formal maintenance program (i.e., in-service – out-of-service date, color-coding, rejection criteria, etc.).

Tail chains used on rig floor tuggers, winches, cranes, etc., must be attached to a certified lifting point and cannot be wrapped/choked around the load and/or back onto itself.

Tail chains are prohibited from use in all man-riding operations.

All other application of chains shall be consistent with original equipment manufacturer (OEM) ratings, design, and usage.

Lever-type load binders are prohibited for use on all work sites.

Homemade or modified lifting devices are prohibited for use on all work sites.

Tag lines shall be used when moving or lifting equipment.

Powered Lifting Device Safety. All contractors operating a powered lifting device (forklift, cranes, winches, gin pole trucks, etc.) shall maintain current certification/training in accordance with OSHA regulations or equivalent country, state/province, or local regulations. All powered lifting devices shall have a preuse inspection as required by local regulation or manufacturer recommendation.

Scaffolds or Platforms. All scaffolds or platforms used for installation and maintenance or removal of machinery and equipment shall be erected, maintained, and used in compliance with OSHA or a country, state/province, local, or international equivalent regulation. All scaffolds are to be inspected and tagged by a competent person prior to use and, subsequently, inspected by a competent person prior to each shift.

Safety Harnesses and Lifelines. When working outside of properly guarded work platforms, a full-body safety harness and lifeline, complete with shock-absorbing lanyard(s) or self-retracting lifeline, shall be provided by the contractor and worn by all workers when working above 6 ft (construction) or when walking on working surfaces higher than 4 ft (general industry) without proper guarding. The contractor shall have procedures, trained personnel, and equipment necessary to rescue workers who may be suspended from fall protection equipment following a fall.

4.4.14 Work Site Conduct

Firearms, Weapons, and Non-Work-Related Dangerous Materials. The possession of firearms, weapons, explosives, or non-work-related dangerous materials on work or while conducting work is strictly forbidden.

Drug, Alcohol, and Controlled Substance Requirements. The contractor shall have a written Drug and Alcohol Program that conforms to the Operator's Drug, Alcohol, and Controlled Substances Requirements, of which the contractor confirms receipt and understanding. The contractor shall comply with all governmental requirements, including all applicable federal, state, and local drug- and alcohol-related laws and regulations, including, without limitation, the applicable DOT regulations. The contractor shall have a drug and alcohol policy in place and a functioning drug and alcohol-testing program, which includes provisions for preemployment, postaccident, random, reasonable suspicion, return to duty, and follow-up testing as allowable under local, state, and federal law.

At a minimum, testing requirements and procedures, including testing mechanisms, substances, and cut-off levels, must comply with current DOT guidelines under 49 CFR Part 199 and/or 49 CFR Part 40. The contractor must have a non-DOT drug program. The contractor non-DOT Drug and Alcohol Program shall include preemployment/preaccess screening and drug testing, postincident testing, for-cause/reasonable suspicion testing, and random testing with an annual rate of at least 25% for drugs and 10% for alcohol. No alcoholic beverages are to be consumed on the work site. Any contractor determined to be under the influence of, in possession of, or distributing either drugs or alcohol will be discharged for the remainder of the work.

Smoking and Lighters/Matches. Smoking is not allowed in any facilities or vehicles owned by the operator or within at least 20 ft or more of any facility entrance or exit, windows, or air intake vents. Smoking is not allowed on any roof area. If permitted on the work site, lighters and matches should be stored in safe areas away from flammable or combustible materials. Electronic cigarettes are to be treated in the same manner and shall only be used in designated areas.

Inappropriate Behavior. Inappropriate behavior including, but not limited to, horseplay, practical jokes, offensive remarks, offensive gestures, harassment, etc., is prohibited while performing work or while on the work site. Contractors are expected to discharge any personnel engaged in fighting on the job site for the duration of the work. If any contractor is caught stealing from the operator or other contractors, those personnel are to be discharged and will be prohibited from returning to the work site.

4.5 Well Casing and Cementing Program

Minnkota plans to construct one CO_2 injection well (McCall-1 [proposed]) in the Deadwood Formation and one proposed monitoring well (NRDT-1) through the Deadwood Formation, as designed by OLCV in compliance with Class VI UIC injection well construction requirements. The target horizon for the injection well (McCall-1 [proposed]) is the Deadwood Formation, while the objective of the proposed monitoring well (NRDT-1) is to provide real-time pressure and temperature response from the Deadwood injection well (McCall-1) and Broom Creek injection wells (Liberty-1 (J-ROC1 file no. 37672) and Unity-1 [proposed]) based on actual injection operations.

The following information represents the proposed designs for the CO_2 injection well (McCall-1) (illustrated in Figure 4-12 and detailed in Tables 4-15–4-18) and monitoring well (NRDT-1) (illustrated in Figure 4-13 and detailed in Tables 4-19–4-22).

4.5.1 McCall-1 – Proposed Deadwood CO_2 Injection Well Casing and Cementing Programs

Tables 4-15 through 4-18 provide the casing and cement programs for the proposed Deadwood CO_2 injection well (McCall-1). The well construction materials will comply with NDAC § 43-05-01-11 (Injection Well Construction and Completion Standards).

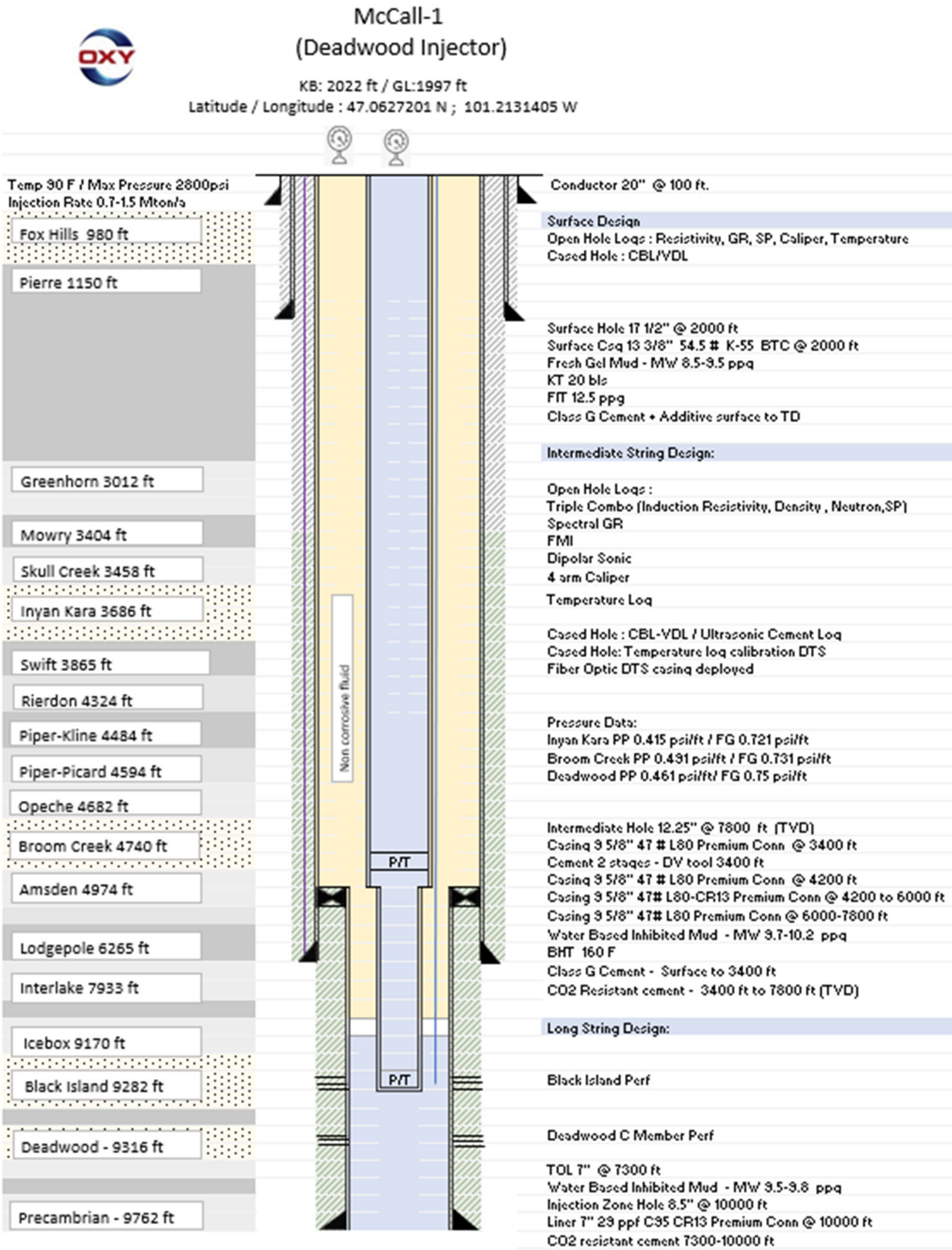


Figure 4-12. Proposed design of the McCall-1 Deadwood CO_2 injection wellbore schematic.

Table 4-15. McCall-1 Proposed Deadwood CO_2 Injection Well Information

Well Name:	McCall-1	NDIC No.:	TBD	API No.:	TBD
County:	Oliver County	**State:**	ND	**Operator:**	Minnkota Power Cooperative, Inc.
Location:	Section 4, T141N R83W	**Footages:**	TBD	**Total Depth:**	10,000'MD

Table 4-16. McCall-1 Proposed Deadwood CO_2 Injection Well Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Casing Seat	Casing Seat Measured Depth, ft	Grade, Connection*	Objective
Conductor	30	20	52.73	Surface formation	100	B, WELD-API 5L Specs	Prevent shallow groundwater and protect loose sediment near surface formations
Surface	17.50	13.375	54.5	Pierre	2,000	K-55, BTC	Cover shallow freshwater aquifers
Intermediate-1	12.25	9.625	47.0	Swift	4,200	L-80, premium	Cover shale formations
Intermediate-2	12.25	9.625	47.0	Mission Canyon State A	6,000	13CR-80, premium	Protect high-permeable formations with CO_2-resistant casing
Intermediate-1	12.25	9.625	47.0	Dawson Bay	7,800	L-80, premium	Cover shale formations
Production	8.50	7.00	29.0	Precambrian	10,000	13CR-C95, premium	Protect sandstone formations with CO_2-resistant casing

* BTC: buttress-thread and coupled, premium connection: gas-tight thread and coupled: vendor to be determined.

Table 4-17. McCall-1 Proposed Deadwood CO_2 Injection Well Casing Properties

Casing Description	Hole, in.	Depths ft	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Thread, in.
13.375" 54.5# K55 BTC	17.5	0–2,000	12.615	12.459	2,730	1,130	766	14.375
9.625" 47# L80 Premium Conn.	12.25	0–4,200	8.681	8.525	6,870	4,750	1,086	10.625
9.625" 47# L80 13Cr Premium Conn.	12.25	4,200–6,000	8.681	8.525	6,870	4,750	1,086	10.625
9.625" 47# L80 Premium Conn.	12.25	6,000–7,800	8.681	8.525	6,870	4,750	1,086	10.625
7" 29# C95 13Cr Premium Conn.	8.5	7,300–10,000	6.184	6.059	9,690	7,840	803	7.656

Table 4-18. McCall-1 Proposed Deadwood CO_2 Injection Well Cement Program

Section	Type	Depths (ft)	Density	Sx	Min. Excess	Cap	Vol	Yield
17.5" Hole	Class G cement with additives	0–1,500	12.5	822	50%	0.1237219	278	1.90
	Class G cement with additives	1,500–2,000	15.8	449	50%	0.1237219	93	1.16
12¼" Hole	Class G cement with additives	0–2,900	11.8–12.5	615	20%	0.0557819	194	1.77
	Class G cement with additives	2,900–3,400	14.8	164	20%	0.0557819	33	1.15
	DV tool @ 3,400 ft							
	CO_2-resistant cement	3,400–7,800	14.8	1343	20%	0.0557819	295	1.23
8½" Hole	CO_2-resistant cement	7,300–10,000	14.8	334	20%	0.022586	73	1.23

Note: Evaluate well condition to increase cement excess in case of losses. Centralization target 90%.

4.5.2 NRDT-1 – Proposed Deadwood CO_2-Monitoring Well Casing and Cementing Programs

The proposed design of the Deadwood CO_2-monitoring well (NRDT-1) is provided below in Figure 4-13.

Tables 4-19 through 4-22 provide the casing and cement programs for the proposed Deadwood CO_2-monitoring well (NRDT-1). The well construction materials will comply with NDAC § 43-05-01-11 (Injection Well Construction and Completion Standards).

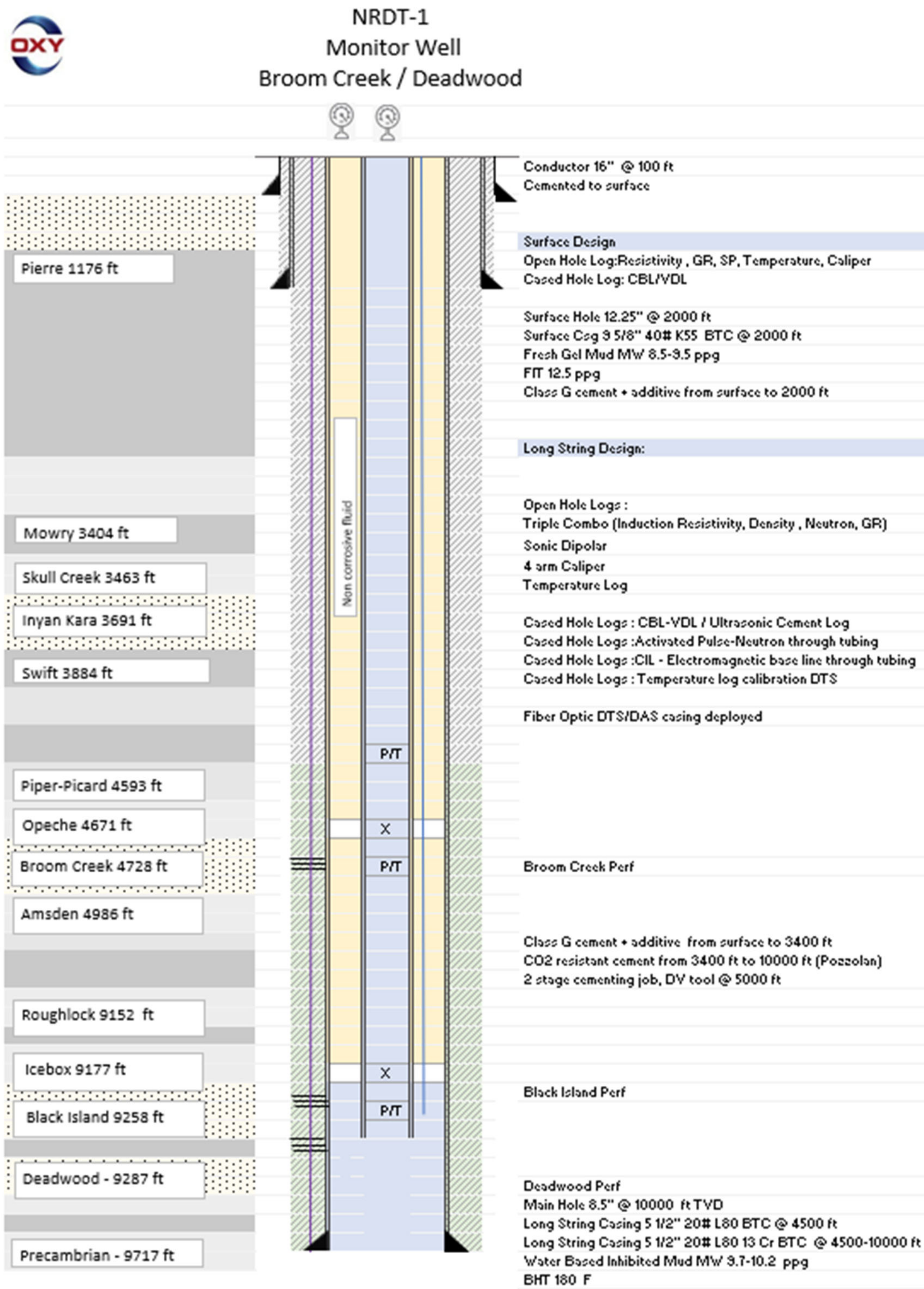


Figure 4-13. NRDT-1 proposed design of the Deadwood CO_2-monitoring wellbore schematic.

Table 4-19. NRDT-1 Proposed Deadwood CO_2-Monitoring Well Information

Well Name:	**NRDT-1**	**NDIC No.:**	**–**	**API No.:**	**–**
County:	**Oliver County**				Minnkota Power Cooperative

Table 4-20. NRDT-1 Proposed Deadwood CO_2-Monitoring Well Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Surface	12¼	9⅝	40.0	K-55	BTC	0	2,000	Protect shallow freshwater aquifers
Long-String	8½	5½	20.0	L-80	BTC	0	4,500	Protect low-permeable formations
Long-String	8½	5½	20.0	13CR-80	BTC	4,500	10,000	Protect high-permeable formations

Table 4-21. NRDT-1 Proposed Deadwood CO_2-Monitoring Well Casing Properties

Casing Description	Hole in.	Depths ft	Casing OD in.	Weight lb/ft	Grade	ID in.	Drift in.	Burst psi	Collapse psi	Tension Klb	Thread	OD Thread
9.625 in. 40 ppf K55 BTC	12.25	0–2,000	9.625	40	K55	8.835	8.679	3,950	2,570	630	BTC	10.625
5.5 in. 20 ppf L80 BTC	8.5	0–4,500	5.5	20	L80	4.778	4.653	9,190	8,830	466	BTC	6.05
5.5. in 20 ppf L80 13Cr BTC	8.5	4,500–10,000	5.5	20	L80 13Cr	4.778	4.653	9,190	8,830	466	BTC	6.05

Table 4-22. NRDT-1 Proposed Deadwood CO_2-Monitoring Well Cement Program

Section	Hole Size, in.	Type	Depth, ft	Density, ppg	Sacks of Cement	Excess	Vol, bbl	Yield, ft^3/sk
Surface	12.25	Class G cement with additives	0–1,500	12.5	370	50%	126	1.90
		Class G cement with additives	1,500–2,000	15.8	202	50%	42	1.16
Long-String	8.5	Class G cement with additives	0–3,400	11.8–12	528	20%	166	1.77
		CO_2-resistant cement	3,400–5,000	14.8	357	20%	78	1.23
		DV tool @ 5,000 ft						
		Class G cement with additives	5,000–8,500	11.8–12	543	20%	171	1.77
		CO_2-resistant cement	8,500–10,000	14.8	335	20%	73	1.23

4.6 Well P&A Program

Upon end of life for the McCall-1 (proposed) CO_2 injection well or completion of the project, Minnkota plans to P&A the CO_2 injection well (McCall-1 [proposed]) in the Deadwood Formation and one proposed monitoring well (NRDT-1) through the Deadwood Formation, designed by OLCV according to NDAC 43-05-01-11.5. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO_2 with water mixtures, and protect any USDWs. Table 4-23 provides the cement program for plugging the proposed Deadwood CO_2 injection well, McCall-1. Figure 4-14 is the schematic.

The injection zone, the Black Island/Deadwood Formation, and overlying seal will be isolated from upper zones and USDWs with CO_2-resistant cement. An external mechanical integrity log will be performed before plugging. In addition, the well will be flushed with brine to force CO_2 into the formation.

4.6.1 McCall-1 Deadwood CO_2 Injection Well P&A

1. After injection has ceased, the well will be flushed with a kill fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure.

2. Bottomhole pressure measurements will be taken using the installed downhole gauges. In the case where the gauges are not functional, the operator will run pressure gauges during the P&A process of the well.

3. An active pulse neutron log will be run, and the well will be pressure-tested to ensure integrity both inside and outside of the casing prior to plugging. Production logging tools (PLTs), tracers, noise, or temperature logs could be run in substitution.

4. If a loss of mechanical integrity is discovered, the well will be repaired prior to proceeding further with the plugging operations.

5. All casing in this well will have been cemented to surface at the time of construction and will not be retrievable at abandonment.

6. After injection is terminated permanently, the injection tubing and packer will be removed.

7. Then the balanced-plug placement method will be used to plug the well. A cement retainer will be used to isolate the perforation section to avoid flowback of formation fluids that could contaminate the plug.

Contingency: If, after flushing, the tubing and packer cannot be released, an electric line with tubing cutter will be used to cut off the tubing above the packer and packer will be left in the well. The cement retainer method will be used for plugging the injection formation below the abandoned packer.

8. All casing strings will be cut off at least 5' below the surface and plow line.

9. A blanking plate with the required permit information will be welded on top of the cutoff casing.

Table 4-23. McCall-1 Proposed Deadwood CO_2 Injection Well Plug and Abandonment Cement Plug Program

Description/Plug No.	1	2	3	4	5	6
Placement Method	Squeeze	Balance plug mix and pump				
Slurry Density	15.8	15.8	15.8	15.8	15.8	15.8
Type of Slurry	---------------------CO_2-resistant----------------------------				Class G + additive	
ID, in.	6.184	8.681	8.681	8.681	8.681	8.681
Slurry volume, bbl	50	24	56	48	42	5
Sacks of Cement by Plug	252	121	283	242	203	25
Plug Top, feet	9,100	7,000	4,500	3,300	1,700	0
Plug Bottom, feet	9,700	7,300	5,200	3,900	2,200	60

4.6.1.1 McCall-1 Injection Well-Plugging Schematic

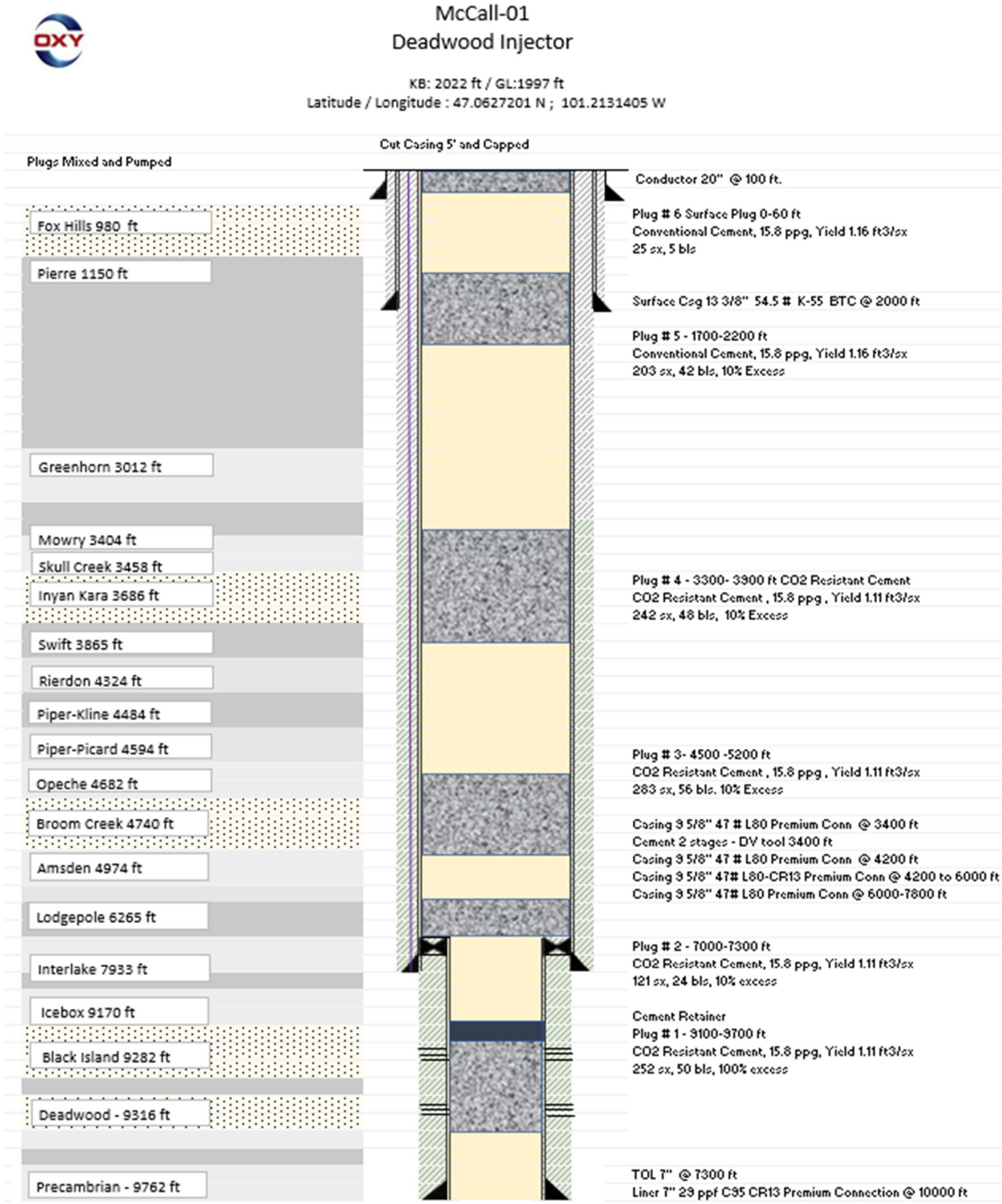


Figure 4-14. Proposed design of the Deadwood CO_2 injection well, McCall-1, P&A wellbore schematic.

4.6.1.2 *Tentative Plugging Procedures*

1. Move in (MI) rig onto McCall-1 well and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Record bottomhole pressure from downhole gauge and calculate the kill fluid density.

4. Test the pump and line to 5,000 psi. Fill the tubing with kill fluid (determined by the bottomhole pressure measurement). Bleeding off occasionally may be necessary to remove all air from the system. Monitor tubing pressure.

5. Test casing annulus to 1,500 psi, or NDIC approved test pressure, and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to the P&A.

6. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).

   Contingency: If the well is not dead or pressure cannot be bled off tubing, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill weight fluid until the well is dead. After the well is dead, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

7. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line, and make a cut on the tubing string just above packer. Make a cut above the packer at least 5 to 10 ft MD. Then pull the work string out of the hole and proceed to the next step. If problems are noted, update cement remediation plan. The cement retainer might be used to force out cement in case the packer cannot be removed.

8. Pick up work string, and trip in hole (TIH) with bit to condition wellbore.

9. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.

   a. Activate neutron log
   b. Noise log
   c. PLT
   d. Tracers
   e. Temperature log

10. TIH work string with cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

11. Mix and pump CO_2-resistant slurry to cover the Black Island/Deadwood Formations and isolate them from the upper formations. Disconnect from retainer, and check flow. Circulate.

12. Move work string to 7,300 ft, set balanced plug with CO_2-resistant slurry 15.8 ppg to the top of the 7-in. liner.

13. Pull work string to 5,200 ft. Set balance plug with CO_2-resistant slurry 15.8 ppg to isolate Broom Creek Formation from the Dakota Group.

14. Pull out to 300 ft above the plug and circulate. Wait on cement. Run in the hole and tag cement to validate top.

15. Pull work string to 3,900 ft and circulate. Set balanced plug with CO_2-resistant slurry 15.8 ppg to cover the Dakota Group and isolate it from the USDW, Fox Hills. Pull 300 ft above the plug. Wait on cement. Run in the hole and tag plug.

16. Set balanced plug with Class G cement + additive 15.8 ppg to cover the shoe of the surface casing. Pull out above the plug and circulate.

17. Set surface plug with Class G cement + additive, 15.8 ppg to isolate the top of surface casing.

18. Lay down all the work string. Rig down all equipment and move out. Cut the casing at 5 ft below the ground. Clean cellar to where a plate can be welded with well information.

19. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4.6.2 NRDT-1 Deadwood Monitor Well P&A

Upon completion of the project, as part of the closure plan of the facilities, the well will be plugged and abandoned according to NDAC § 43-05-01-11.5. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of CO_2 with water mixtures, and protect any USDWs.

NRDT-1 is located at the border of the projected CO_2 plume, which will minimize the probability that the CO_2 mixed with formation fluids will cause damage to the cement or proposed tubulars. The plugs are designed to isolate the Black Island/Deadwood perforations from the Broom Creek section and overlying seal until the USDW. An external mechanical integrity log will be performed before plugging. In addition, the well will be flushed with brine to force any formation fluid back into the reservoir.

Table 4-24 provides the plugging cement program for the proposed NRDT-1 Deadwood CO_2-monitoring well. Figure 4-15 shows the proposed schematic.

Table 4-24. NRDT-1 Proposed Deadwood CO_2-Monitoring Well Plug and Abandonment Cement Plug Program

Description/Plug No.	1	2	3	4	5
Placement Method	Squeeze	Squeeze	Balanced Plug	Balanced Plug	Balanced Plug
Slurry Density	15.8	15.8	15.8	15.8	15.8
Type of Slurry	-------------CO_2-resistant----------------			Class G + additive	
ID, in.	4.653	4.653	4.653	4.653	4.653
Slurry Volume, bbl	19	13	14	12	4
Sacks of Cement by Plug	96	64	70	56	18
Plug Top, ft	9,100	4,600	3,300	1,700	0
Plug Bottom, ft	9,700	5,000	3,900	2,200	160

4.6.2.1 NRDT-1 Monitor Well-Plugging Schematic

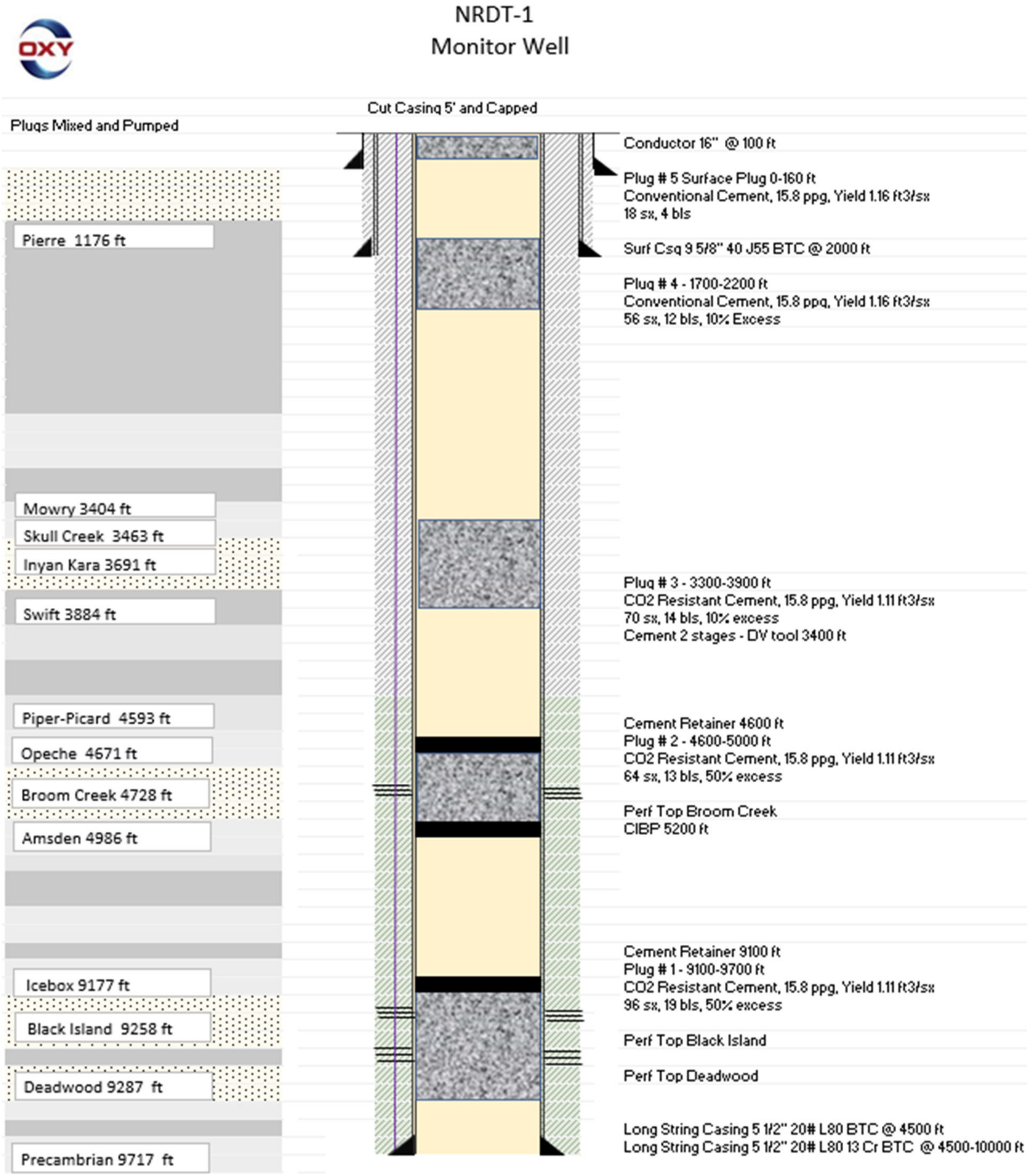


Figure 4-15. NRDT-1 proposed design of the CO_2 monitor well P&A wellbore schematic.

4.6.2.2 Tentative Plugging Procedures

1. Move-in (MI) rig onto NRDT-1 well and rig-up (RU).

2. Conduct and document a safety meeting.

3. Test the pump and line to 5,000 psi. Fill tubing with kill fluid. Bleeding off the system occasionally may be necessary to remove all the air. Monitor tubing pressure.

4. Test casing annulus to 1,500 psi, or approved NDIC pressure, and monitor it for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in the long string casing is identified, the operator will prepare a plan to repair the well prior to the plug and abandonment.

5. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or pressure cannot be bled off the tubing, RU slickline and set plug in the lower profile nipple below first packer. Circulate tubing and annulus with kill weight fluid until the well is dead. Then nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

6. Pull out of hole and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packers due to:

   a) Top Packer Stuck: Prepare plan to cut tubing above the top packer, 5 to 10 ft of MD. Mill/wash over the seals and OD of the top packer to release the string, until the bottom packer. Run fishing equipment and work fish out.
   b) Bottom Packer Stuck: If bottom packer is stuck, proceed to RU electric line and make cut on tubing string just above bottom packer pull the work string out of hole and proceed to next step. If problems are noted, update cement remediation plan.

7. Pick up work string, and TIH with bit to condition wellbore.

8. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.

   a. Activate neutron log
   b. Noise log
   c. PLT
   d. Tracers
   e. Temperature log

9. TIH with work string and cement retainer to the top of Plug 1. Circulate well, set retainer, and perform injectivity test. RU equipment for cementing operations.

10. Mix and pump CO_2-resistant slurry to cover the Black Island/Deadwood Formations and isolate them from the upper formations. Disconnect from retainer and check flow. Circulate.

11. Pull work string out of the hole.

12. Run CIBP 50 ft below the perf in Broom Creek ~5,000 ft.

13. TIH work string with work string and cement retainer to the top of Plug 2. Circulate well, set retainer and perform injectivity test. RU equipment for cementing operations.

14. Mix and pump CO_2 resistant slurry 15.8 ppg to isolate the Broom Creek Formation From the Dakota Group. Disconnect from retainer and check flow. Circulate.

15. Pull work string to 3,900 ft. Circulate. Set balanced plug, CO_2 resistant slurry 15.8 ppg to cover Dakota Group and isolate it from USDW Fox Hills. Pull 300 ft above the plug. Wait on cement. Run in the hole and tag plug.

16. Set balanced plug with Class G cement + additive 15.8 ppg to cover the shoe of the surface casing. Pull out above the plug and circulate.

17. Set surface plug with Class G cement + additive, 15.8 ppg to isolate the top of surface casing.

18. Lay down all work string. Rig down all equipment and move out. Cut the casing at 5 ft below surface. Clean cellar to where a plate can be welded with well information.

19. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

4.7 Postinjection Site and Facility Closure Plan

The PISC and facility closure plan describes the activities that Minnkota 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. The monitoring locations, methods, and schedule are designed to show the position of the CO_2 plume and demonstrate that the CO_2 injected is within the storage reservoir and there is no endangerment to USDWs.

Based on the 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), ensuring the safety of USDWs within the AOR. 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 and safety of USDWs. The nature and duration of that extension will be determined based upon 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 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 Deadwood 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 1.17 MMt per year, followed by a postinjection period of 10 years.

Figure 4-16 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 0 to 164.33 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 of the Deadwood Formation over the 10-year postinjection period is provided in Figure 4-17. 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 414.3 to 1,318.18 psi 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.

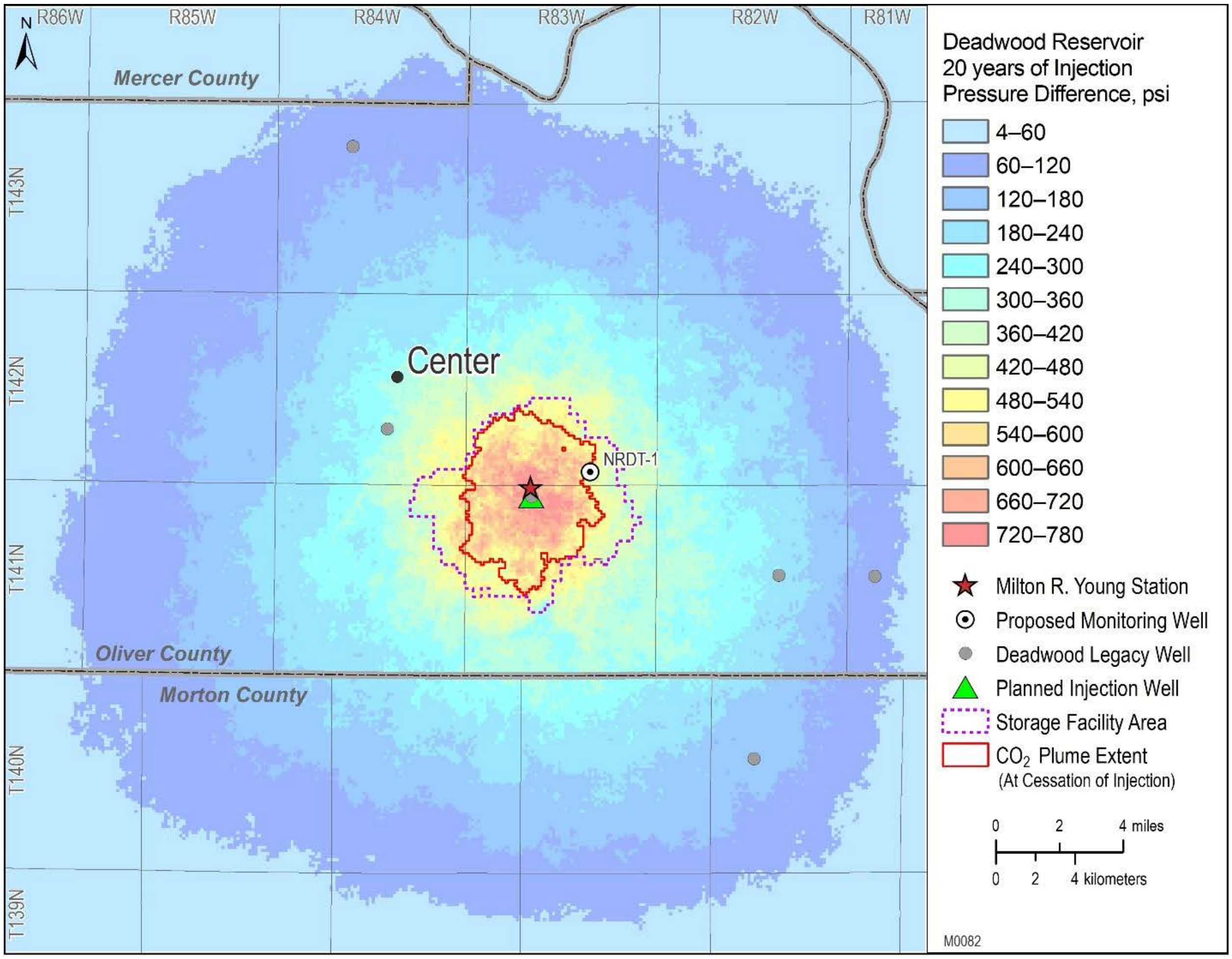


Figure 4-16. Predicted pressure increase in storage reservoir following 20 years of injection of 1.17 MMt per year of CO_2.

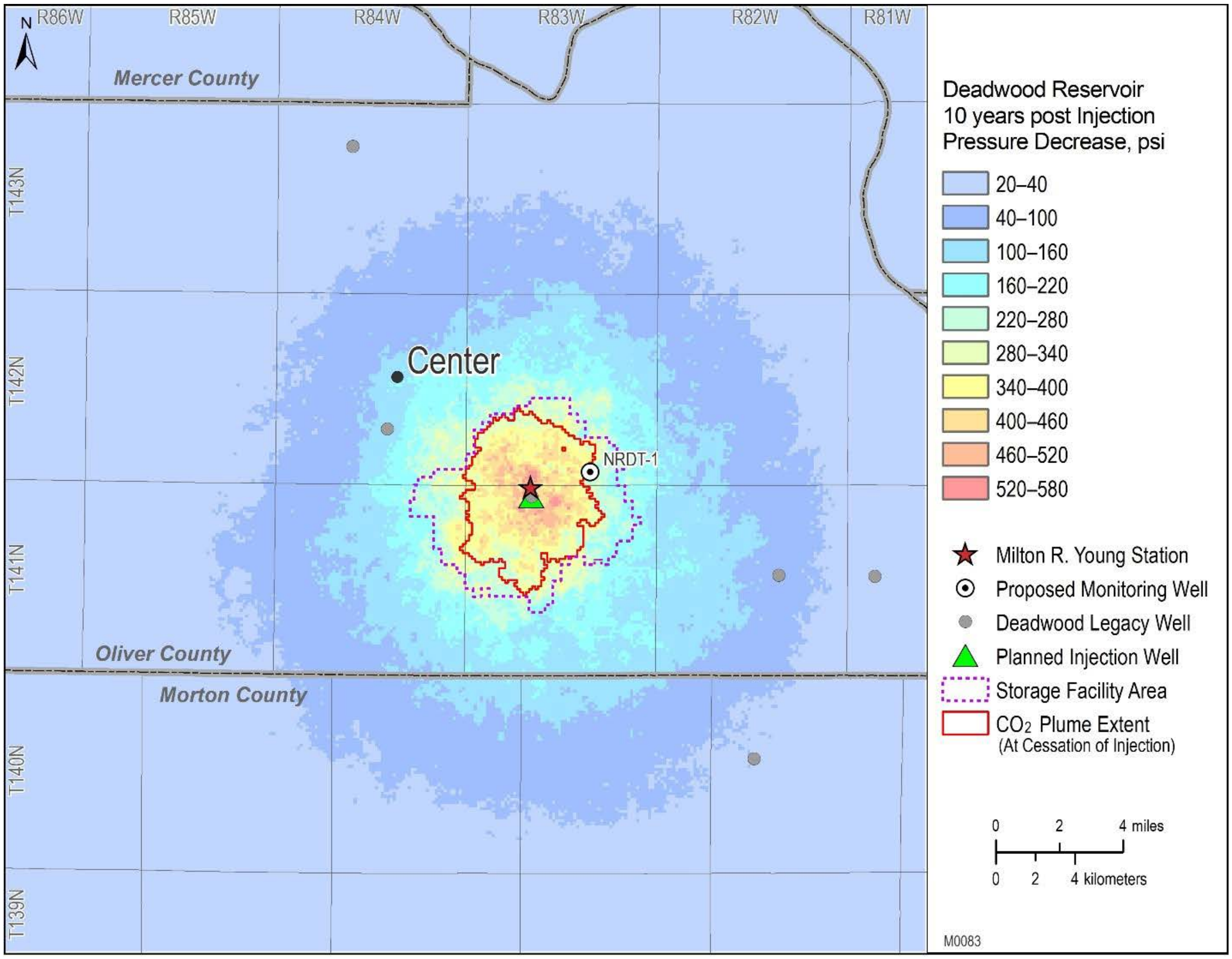


Figure 4-17. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

4.7.1.2 Predicted Extent of CO_2 Plume

Also shown in Figures 4-16 and 4-17 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 20 mi^2 at the end of CO_2 injection (see Figure 4-16). As shown in Figure 4-17, 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 4-16 and 4-17, 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 4-25. 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 4-25.

Table 4-25. Summary of 10-year Postinjection Site Care-Monitoring Program

Type of Monitoring	Frequency	Comments
	Near-Surface Monitoring	
Soil Monitoring		
Soil Gas Profile Stations (Soil Gas Location – see Figure 4-18)	Duration: minimum 10 years. Frequency: 3–4 seasonal sample events at soil gas profile stations performed every 3 years following cessation of CO_2 injection.	Located at the McCall-1 and NRDT-1 wells. See Figure 4-18.
Water Monitoring		
Groundwater Wells	Duration: minimum 10 years. Frequency: 3–4 sample events per year at the cessation of injection and 3–4 sample events as part of the final site closure assessment.	Sampling will be performed on all active and accessible freshwater groundwater wells within the AOR (see Figure 4-18).
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.
Storage Reservoir Monitoring		
Injection Well (McCall-1)	Monitor fluid levels until well is plugged.	Minnkota plans to P&A injection well (McCall-1) at cessation of injection operations.
	Downhole Pressure and Temperature Monitoring (NRDT-1)	
Distributed Fiber Optic Temperature (DTS)	Continuous.	DTS fiber will give continuous temperature profile for monitoring well NRDT-1 from the base of fiber to the surface until plume stabilization.
Pressure and Temperature Gauges in NRDT-1	Bimonthly.	Gauges provide continuous temperature and pressure monitoring of the injection zone (Deadwood) until plume stabilization. Monitoring will continue as part of the PISC and facility closure plan.
	Wireline Logging and Retrievable Monitoring (NRDT-1)	
PNL (McCall-1 and NRDT-1)	NRDT-1 at cessation of injection and once every 5 years thereafter until plume stabilization is demonstrated.	Log McCall-1 and NRDT-1 wells at cessation of injection.

Continued . . .

Table 4-25. Summary of 10-year Postinjection Site Care Monitoring Program (continued)

Type of Monitoring	Frequency	Comments
Well Integrity Test		
External Mechanical Integrity: USIT or Electromagnetic Casing Inspection Tool External Mechanical Integrity: Downhole Temperature	Duration: minimum 10 years postinjection. Frequency: Perform during well workovers but not more frequently than once every 5 years in NRDT-1. Annual temperature logging in NRDT-1 (if fiber fails) until plume stabilization.	Annually until the injection well is P&A.
DTS	Continuous.	Continuous DTS monitoring in NRDT-1 until P&A. DTS fiber provides continuous temperature profile from the base of fiber to the surface until plume stabilization.
Pressure Fall-Off Test (Injection Zone)	Prior to P&A.	
Geophysical Monitoring		
Time-Lapse Seismic	Perform 2D and/or 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	To be determined.	To be determined – continuous monitoring of ground elevation based on relative storage deformation with InSAR until storage facility achieves stabilization.

4.7.2 Groundwater and Soil Gas Monitoring

Two soil gas profile stations, two Fox Hills Formation (i.e., deepest USDW) monitoring wells, and various 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 4-18 identifies the location of the soil gas profile stations, 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 upon an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations.

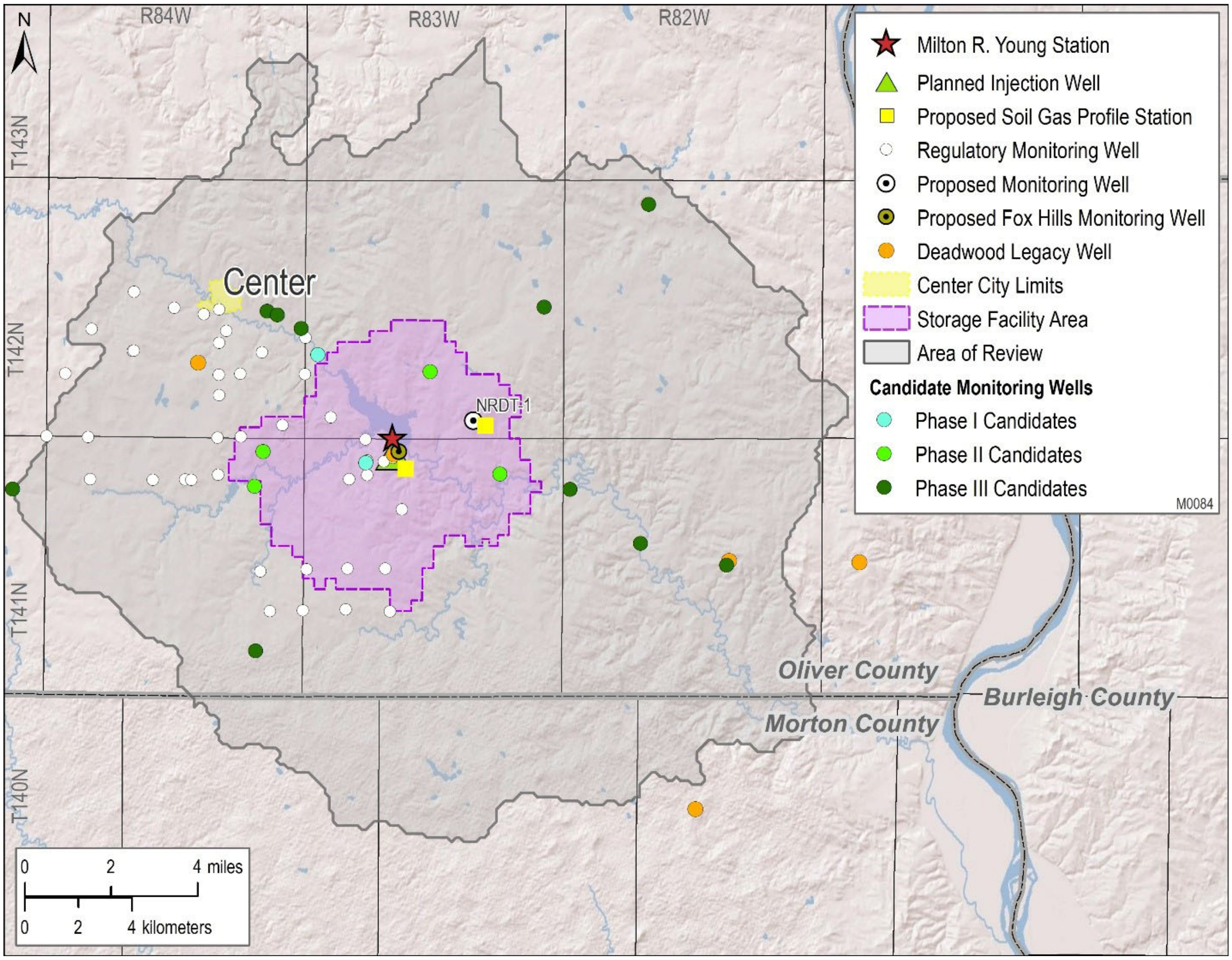


Figure 4-18. Location of soil gas and groundwater well sampling locations included in the PISC monitoring program.

4.7.3 Monitoring of CO_2 Plume and Pressure Front

Monitoring of the CO_2 plume location and storage reservoir pressure will be conducted during the PISC period using the methods summarized in Table 4-25, 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 3D seismic monitor [4D seismic]) that monitor CO_2 saturation. Figure 4-19 provides an aerial view of the extents of both the existing 3D seismic surveys and potential borehole seismic (or VSP) surveys as compared to the predicted areal extents of the CO_2 plume at the cessation of injection and stabilized plume.

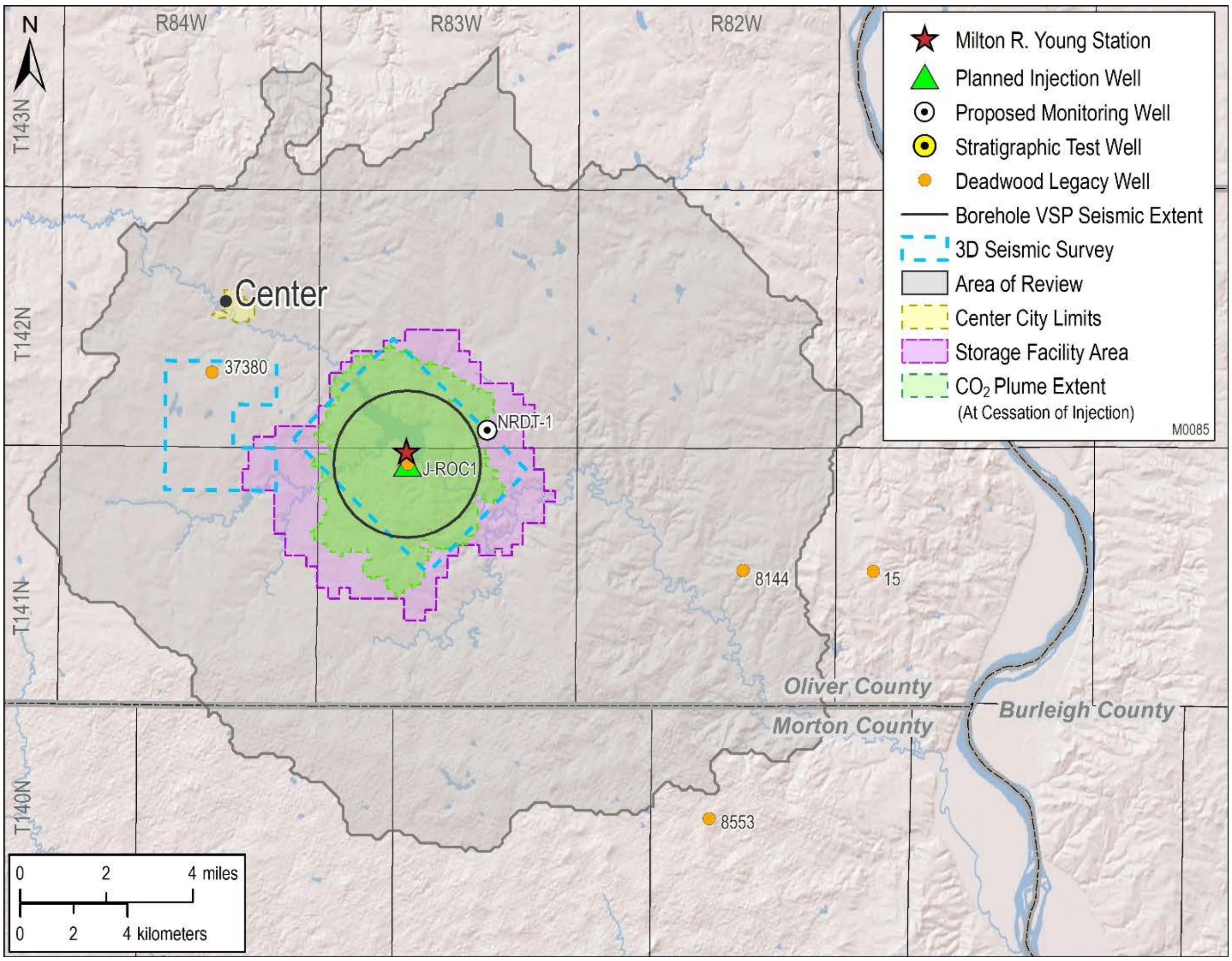


Figure 4-19. Areal extents of the 3D and borehole seismic surveys proposed during the PISC period in comparison to the areal extent of the CO_2 plume at cessation of injection.

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. Water sample analytical results will also be submitted to the ND State Water Commission.

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

Minnkota 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 PISC period. Site closure activities will include the plugging of all wells that are not targeted for use as future subsurface observation wells; decommissioning of storage facility equipment, appurtenances, and structures (e.g., structures/buildings, gravel pads, access roads, etc.) not associated with monitoring; and 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 PISC 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 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, Minnkota 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, Minnkota 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

ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.atsm.org (accessed December 2020).

Reed, S., Ge, J., Burnison, S.A., Bosshart, N.W., Hamling, J.A., and Gorecki, C.D., 2018, Viability of InSAR as a monitoring tool in challenging terrain: Bell Creek, Montana: Paper presented at the 14th International Conference on Greenhouse Gas Control Technologies (GHGT-14), Melbourne, Australia, October 21–25, 2018.

Vasco, D.W., Dixon, T.H., Ferretti, A., and Samsonov, S.V., 2020, Monitoring the fate of injected CO_2 using geodetic techniques: The Leading Edge, v. 39, no. 1, p. 29–37.

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. McCall-1 Proposed Deadwood Injection Well Operating Parameters

Predicted Metric	McCall-1	Description/Comments
		Injection Volume
Total Injected Volume, MMt	23.4	Based on 20 years of injection.
		Injection Rate
Predicted Average Injection Rate, tonnes per day	3,250	Based on total injected volumes for 20 years and using 365 operating days a year.
Maximum Predicted Daily Injection Rate, tonnes per day	3,865	Based on 20 years of injection.
		Pressure
Formation Fracture Pressure at Top Perforation, psi	6,866	The injectivity test results fracture closure gradient of 0.75 psi/ft.
Average Predicted Operating Surface Injection Pressure, psi	2,794	Based on 20 years of injection.
Maximum Wellhead Injection Pressure, psi	3,445	Maximum wellhead injection pressure is limited based on surface facility constraints and 90% of formation fracture pressure.
Average Predicted Operating Bottomhole Pressure (BHP), psi	6,139	Based on 20 years of injection.
Maximum BHP psi	6,179	Calculated maximum BHP using 90% of the closure pressure from the injectivity test at the top of the perforation. Maximum BHP is limited based on surface facility constraints.

5.1 Proposed Completion Procedure to Conduct Injection Operations in the Deadwood Injection Well

Minnkota Power Cooperative (Minnkota) plans to construct one carbon dioxide (CO_2) injection well (McCall-1) designed by Oxy Low Carbon Ventures in compliance with Class VI UIC (underground injection control) injection well construction requirements, as discussed in previous sections and drilled according to the proposed program in the permit to drill. The following proposed completion procedure outlines the steps necessary to complete a Deadwood well for injection purposes (Figure 5-1, Table 5-2).

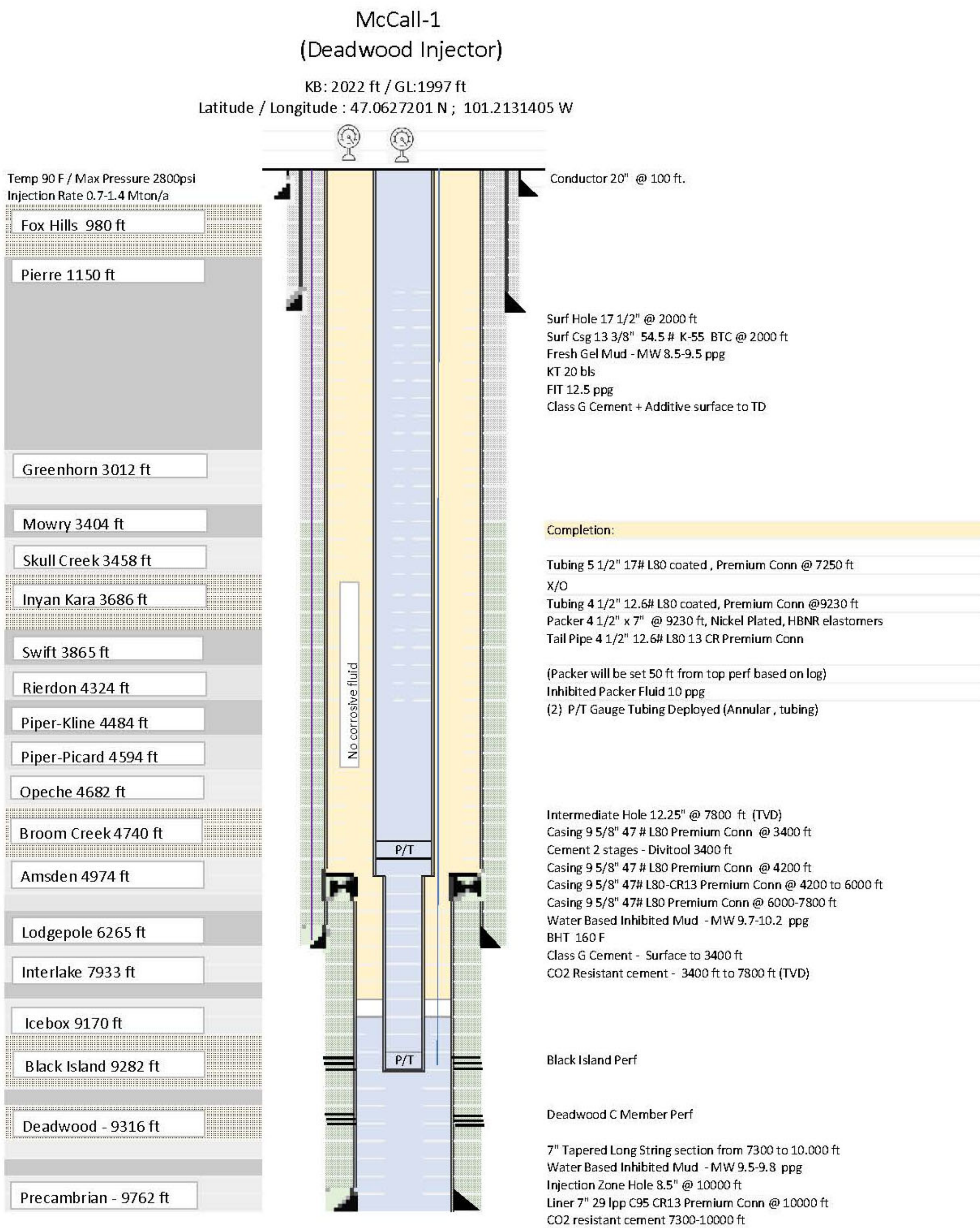


Figure 5-1. McCall-1_Deadwood injection well proposed completion wellbore schematic.

Table 5-2. McCall-1_Deadwood Injection Well Proposed Casing Properties

Casing Description ID	Hole, in.	Depths, ft	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Thread, in.
13.375" 54.5# K55 BTC	17.5	0–2,000	12.615	12.459	2,730	1,130	766	14.375
9.625" 47# L80 Premium Conn	12.25	0–4,200	8.681	8.525	6,870	4,750	1,086	10.625
9.625" 47# L80 13Cr Premium Conn	12.25	4,200–6,000	8.681	8.525	6,870	4,750	1,086	10.625
9.625" 47# L80 Premium Conn	12.25	6,000–7,800	8.681	8.525	6,870	4,750	1,086	10.625
7" 29# C95 13Cr Premium Conn	8.5	7,300–10,000	6.184	6.059	9,690	7,840	803	7.656

5.2 Proposed Completion Procedure for McCall-1_Deadwood CO_2 Injectate Well

1. Pick up work string with 8½" bit to clean cement on top of the tapered long string. Clean cement, circulate, and pull out of the hole.
2. Pick up work string with 6¾" and rotating scrapper to clean cement inside of the tapered long string. Clean cement to the top of the landing collar.
3. Circulate with brine 10 ppg.
4. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the Operator may require assessing the root cause and correcting it.
5. Pull bottomhole assembly (BHA) out of the hole.
6. Perform safety meeting to discuss logging and perforating operations.
7. Rig up logging truck.
8. Run cased hole logs by program. **Note:** run CBL/VDL (cement bond log/carriable-density log) and USIT (ultrasonic imaging tool) without pressure as a first pass and run it with 1,000 psi pressure as a second pass, if needed.

   Note: In case the cementing logs show poor bonding in the cementing job, the results will be communicated to the North Dakota Industrial Commission (NDIC), and an action plan will be prepared.

9. Run perforating guns to the injection target.
10. Perforate the Black Island and Deadwood Formation, minimum 4 spf (shots per foot). Depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation.
11. Pull guns out of the hole.
12. Rig down logging truck.
13. Pick up straddle packer and run in the hole with working string.
14. Circulate with brine 10 ppg.
15. Set packer in the Deadwood Formation to isolate the perforations.
16. Rig up acid trucks and equipment.
17. Perform cleaning of the perforations with acid (design volumes and pressures will be evaluated based on the well conditions once drilled). Adjust acid formulation and volumes with water samples and compatibility test.
18. Rig down acid trucks and equipment.

19. Perform an injectivity test/step rate test.
20. Unset packer and circulate hole.
21. Set packer in the Black Island Formation to isolate the perforations.
22. Rig up acid trucks and equipment.
23. Perform cleaning of the perforations with acid (design volumes and pressures will be evaluated based on the well conditions once drilled). Adjust acid formulation and volumes with water samples and compatibility test.
24. Rig down acid trucks and equipment.
25. Perform an injectivity test/step rate test.
26. Unset packer and circulate hole.
27. Pull packer and work string out of the hole.
28. Rig up spooler and prepare rig floor to run upper completion.
29. Run completion assembly per program.
30. Circulate well with inhibited packer fluid.
31. Set packer 50 ft above the top perforations.
32. Install tubing sections, cable connector, and tubing hanger.
33. Rig up logging truck.
34. Run cased hole logs through tubing by program.
35. Rig down logging truck.
36. Nipple down BOP (blowout preventer).
37. Install injection tree.
    Note: Figure 5-2 illustrates the proposed wellhead schematic
38. Rig down equipment.

Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber optic will be run and attached to the exterior of the intermediate casing. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Note: Tapered long string hanger should include top packer seal.

The McCall-1_Deadwood CO_2 Injection Well Proposed Tubing Design is detailed in the following section (Table 5-3).

Table 5-3. McCall-1_Deadwood CO_2 Injection Well Proposed Tubing Design

Description	Type, in.	Depths, ft	ID, in.	Burst, psi	Collapse, psi	Tension, Klb	OD Thread, in.
5.5" 20# L80 Coated Premium Conn	Tubing	0–7,250	4.778	9,190	8,830	466	6.05
4.5" 12.6# L80 Coated Premium Conn	Tubing	7,250–9,230	3.958	8,430	7,500	288	5.2
Packer 4.5" × 7"		50 ft above Perf.	Nickel-Plated, HNBR*				
4.5" 12.6# L80 13Cr Premium Conn	Tubing	9,230–9,400	3.958	8,430	7,500	288	5.2

* Hydrogenated nitrile butadiene rubber.

1. Packer depth will be adjusted with the final perforation depth interval.
2. Packer will be set 50 ft above top perforations.
3. Packer is required to be nickel-plated with HNBR elastomers.

4. Inconel cable along with quartz pressure and temperature gauges will be run in upper completion.

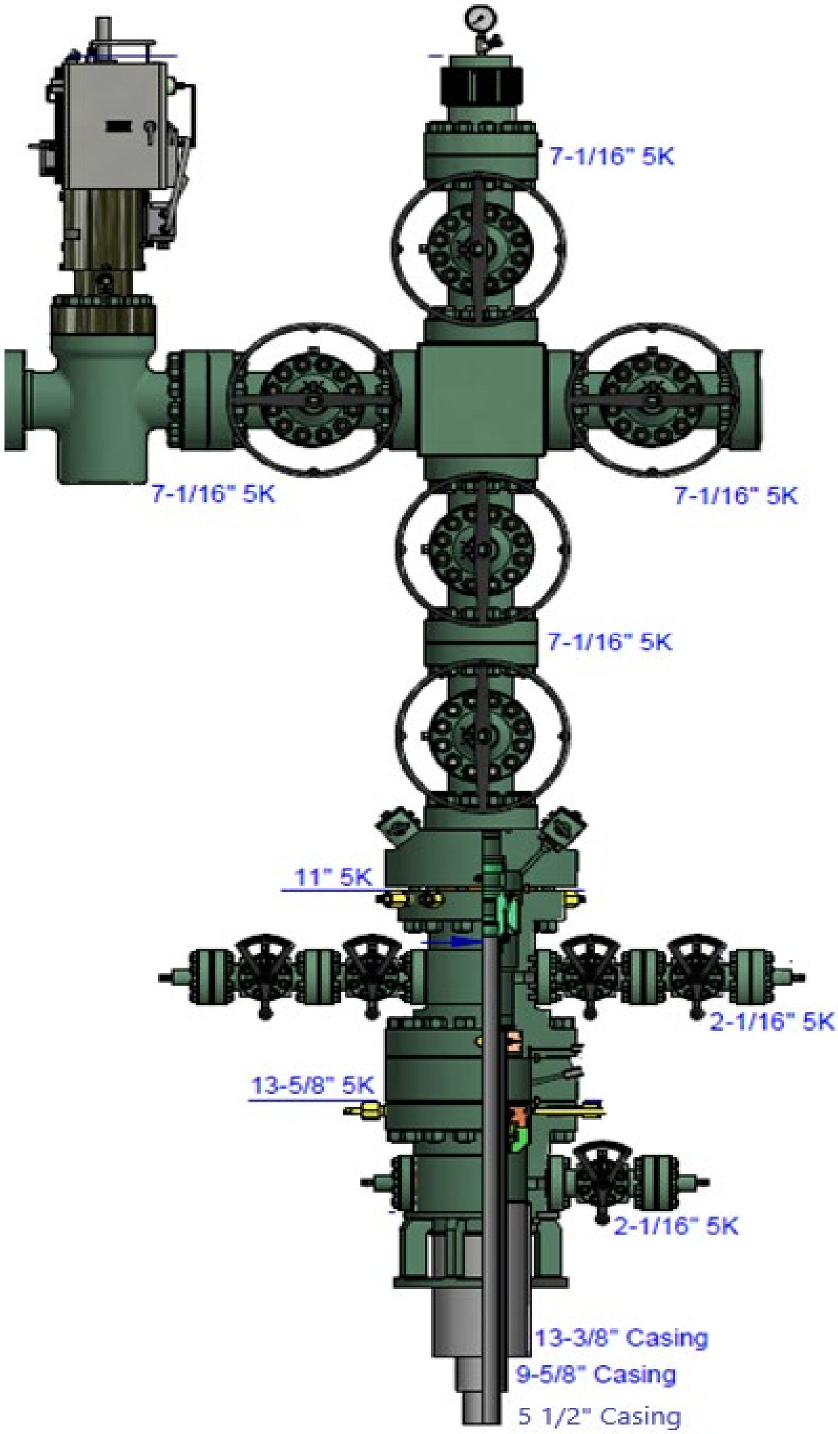


Figure 5-2. Proposed Deadwood injection well CO_2-resistant wellhead schematic.

5.3 Logging Program

The proposed logging program is detailed in Table 5-4.

Table 5-4. McCall-1_Deadwood CO_2 Injection Well Proposed Logging Program

Section	Type	Depth, ft
17½" Hole	**Open Hole:** Resistivity, GR (gamma ray), SP (spontaneous potential), Temperature	0–2,000
	Cased Hole: CBL/VDL	0–2,000
12¼" Hole	**Open Hole:**	
	Induction Resistivity	2,000–7,800
	Density	2,000–7,800
	Neutron	2,000–7,800
	Sonic Dipolar	2,000–7,800
	GR	2,000–7,800
	Caliper	2,000–7,800
	Temperature Log	2,000–7,800
	SP	2,000–7,800
	Spectral GR	2,000–7,800
	Full-Bore Formation Microimager	4,400–7,800
	Cased Hole:	
	CBL–VDL–Ultrasonic	2,000–7,800
	Temperature – Calibration DTS	0–7,800
8½" Hole	**Open Hole:**	
	Induction Resistivity	7,800–10,000
	Density	7,800–10,000
	Neutron	7,800–10,000
	Sonic Dipolar	7,800–10,000
	GR	7,800–10,000
	Caliper	7,800–10,000
	Temperature Log	7,800–10,000
	SP	7,800–10,000
	Spectral GR	8,500–10,000
	Full-Bore Formation Microimager	8,500–10,000
	10 SWC (sidewall coring: seals, injection zones)	Depth by log
	5 Fluid Samples (injection zones)	Depth by log
	25 MDT (modular formation dynamics tester: injection zones)	Depth by log
	Cased Hole:	
	CBL–VDL–Ultrasonic	7,300–10,000
	Casing Inspection Log – Through Tubing	0–10,000
	Active Pulse Neutron – Through Tubing	8,500–10,000

5.4 BOP Equipment (BOPE)

1. BOPE must be API-monogramed and adhere to API Standard 53, Specifications 16A and 16C~~,~~ at a minimum, and meet or exceed all applicable regulatory specifications (Figure 5-3).
2. BOPE other than annular preventers must have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
3. All BOPE stacks must incorporate a set of blind or blind/shear rams.
4. Blind rams must be located in the lower ram cavity of a two-ram stack or middle ram cavity of a three-ram stack.
5. Choke and kill line outlets must be located below the blind rams on either a three- or two-ram stack.
6. All rigs must have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace from the hole during all tripping operations, including casing or completion string running. Trip sheets must include number of joints or stands run into or pulled from the hole versus the calculated and actual displacements per step and running total as a minimum.
7. A full opening safety valve (FOSV) and an inside BOP safety valve (IBOPSV) must be always available on the rig floor for each drill pipe, drill collar size, and connection type in use. The FOSV is used to stab into the string and shut off flow through the drill string. The IBOPSV is used **above** the FOSV to prevent backflow through the drill string. The tools must remain in the fully open position until installed.

Note: This requirement is in addition to any integral safety valve in the top drive system inclusive of casing running operations. In the event of a power failure on a VFD (variable frequency drive) rig, it is impossible to slack off and make up the top drive to the string; therefore, an additional independent stabbing valve(s) is needed on the floor at all times.

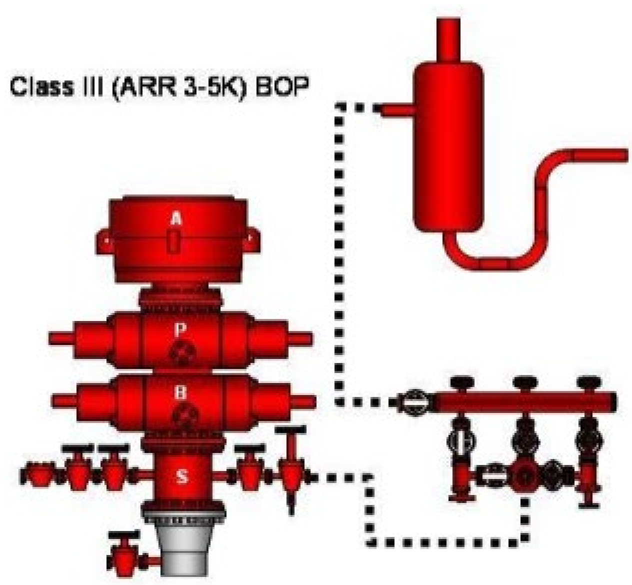


Figure 5-3. Proposed Deadwood Injection Well BOP schematic.

8. If a wireline lubricator is utilized for wireline operations, it should not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline must be available if a lubricator is not in use.
9. Pressure-energized metal ring gaskets must be used on flanged well control equipment. The gaskets must not be reused on equipment that will be nippled up on the wellbore.

5.4.1 Choke Manifolds and Kill Line

1. The choke manifold must be API-monogrammed, meet API Spec. 16C at a minimum, and meet or exceed all applicable regulatory specifications.
2. All BOPE must include a choke manifold with at least one remotely operated choke and one manual choke installed. The control panel must contain calibrated drill pipe and casing pressure gauges that must be both accurate and maintained. The choke manifold casing pressure should have the capability of being recorded on the rig drilling recorder. If necessary, for clear dialogue, an electronic means of direct communication with the driller should be in place. This equipment must be tested and calibration-checked at each casing shoe, as well as at every BOPE test, and will be logged on every BOPE test report.
3. Flare/vent lines must be as long as practical, a minimum of 150' from well center, as straight as possible, without sumps, collection areas, or uphill flow areas (to prevent fluids buildup and resulting backpressure), and securely anchored.

5.4.2 Closing Units

1. BOPE closing units must adhere to API Spec 16D and API STD 53 at a minimum and meet or exceed all applicable regulatory specifications.
2. BOPE control systems must include full controls on the closing unit~~,~~ and at least one remote control station. One control station must be located within 10 feet of the drillers console.
3. The BOPE closing unit must have two separate charging pumps with two independent power sources, as specified in API Spec. 16D, or N_2 bottle backup.
4. Closing units must have sufficient usable hydraulic fluid volume with pumps inoperative, to close one annular preventer, close all ram preventers, and open one HCR (high closing ratio) valve against zero wellbore pressure with 200 psi remaining pressure above the precharge pressure.

5.4.3 Pressure Testing

1. BOPE components (including the BOP stack, choke manifold, and choke lines) must be pressure-tested at the following frequency:
   a. When installed. If the BOPE is stump-tested, only the new connections are required to be tested at installation.
   b. Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due in the near future, consider testing BOPE prior to drilling H_2S, abnormal pressure, or any lost return zones in order to avoid testing while drilling these intervals.
   c. Anytime a BOPE connection seal is broken, the break must be pressure-tested.
   d. When utilizing tapered strings, variable bore-type rams and annular preventer must be pressure-tested with all tubing or drill pipe sizes anticipated to be used.

2. BOPE should be tested using a test plug or other means to isolate the casing and open hole from the test pressures. The casing head valve should be opened and monitored to avoid exerting BOPE test pressure on the casing or open hole.
3. BOP components must first be low-pressure-tested to between 250 and 350 psi. If during the test, the pressure exceeds 350 psi, the pressure must be bled off to 0 psi and the test restarted. Pressuring up beyond 350 psi can induce a seal and give a false test result.
4. BOPE components, excluding the annular preventer, must be tested to the lesser of Rated Working Pressure (RWP) or wellhead RWP, if less than BOPE RWP. The annular preventer must be tested to 70% of its RWP. In all cases, the test pressure must not exceed the RWP of any components being tested.
5. Use of a cup tester should be avoided. If a cup tester is utilized for BOP testing, consideration must be given to casing burst pressure and possible pressure applied to the casing string or open hole below the cup tester in the event of a leaking cup tester.
6. An accumulator closing test must be performed after the initial nipple up of the BOP, after any repairs that required isolation or partial isolation of the system, or at initial nipple up on each well.
7. During the course of drilling, the pipe rams must be functionally operated at least once every 24-hour period. The blind rams must be functionally operated each trip out of the wellbore.

5.4.4 Wellhead

- Casing head 13⅝" – 5K flanged.
- Two 2¹⁄₁₆" valves in casing head.
- Tubing spool 13⅝" 5K × 11" 10K flanged.
- Production tree assembly 7¹⁄₁₆" 10K FF: two master valves, cross, one swab valve, tubing hanger 11" × 7" FF.

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

Minnkota Power Cooperative's (Minnkota's) Tundra SGS (secure geologic storage) site located proximate to the Milton R. Young Station (MRYS) has been a focus of investigation of future potential commercial-scale carbon dioxide (CO_2) injection within the sandstones of the Black Island and Deadwood Formations. The Tundra SGS site is located near Center, North Dakota, in the south-central portion of the Williston Basin.

Multiple sets of publicly available data, including 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 surface seismic surveys, were also used in the model construction. Two 3D seismic surveys were collected over the Tundra SGS site, and two stratigraphic test wells were drilled to augment data available from offset wells in the study area. Data collected from these sources were incorporated into a geologic model of the Black Island and Deadwood Formations and the overlying and underlying sealing formations. Simulated CO_2 injection studies were conducted to determine the wellhead and downhole pressure response resulting from injection and displacement of injected CO_2 within the Black Island Formation and Deadwood Formation E and C Members. Reservoir conditions observed from the stratigraphic test wells were used to characterize and establish 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.

The well logs acquired in the J-LOC1 and J-ROC1 wells (NDIC file numbers 37380 and 37672, respectively) (Figure A-1) 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 Precambrian basement. Regional formation top depths from wellbores within a 56-mile radius around the proposed storage site were added to the J-LOC and J-ROC1 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 that served as inputs for geologic model construction.

Core samples obtained from the J-LOC1 wellbore were analyzed as inputs for modeling and simulation. These analyses included x-ray fluorescence (XRF), x-ray diffraction (XRD), thin sections, porosity, and flow measurements. Knowledge gained from these site-specific core data analyses and well logs collected from the J-LOC1 wellbore were used to determine Black Island and Deadwood 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 lithofacies properties of the injection zone. Eleven offset wells with porosity logs were used to inform petrophysical property distributions in addition to the core data from J-LOC1. The various data sets derived from J-LOC1 and J-ROC1 showed good agreement with the offset well data available near the J-LOC1 site.

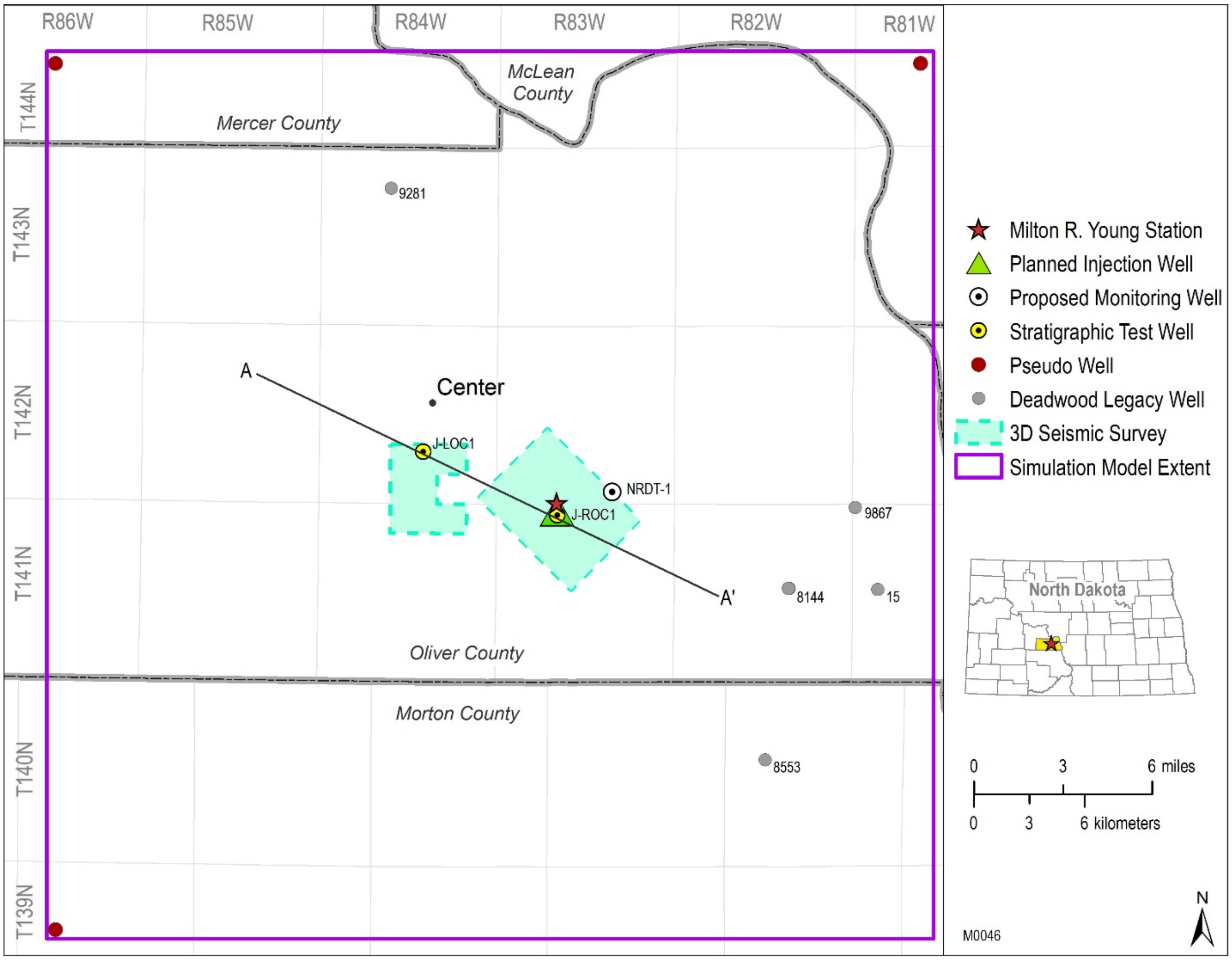


Figure A-1. Map of the geologic model boundary (purple polygon), seismic surveys (green polygons), pseudowells (NE-pseudo, NW-pseudo, and SW-pseudo represented as red circles) and nearby Deadwood wells.

A geologic model was constructed using Schlumberger's Petrel software suite (Schlumberger, 2020). 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 is a digital representation of the subsurface geology, including the proposed CO_2 storage reservoir and its primary confining zones. The upper confining zone includes (descending order) the Roughlock and Icebox Formations Figure (A-2). The upper 50 ft of the Precambrian basement was included to test confinement of injection pressure to the Deadwood B Member shale in simulation. Geologic properties were distributed within the 3D model 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 (bodies of rock with similar geologic characteristics) which were used to assign relative permeability curves 2) porosity, and 3) permeability.

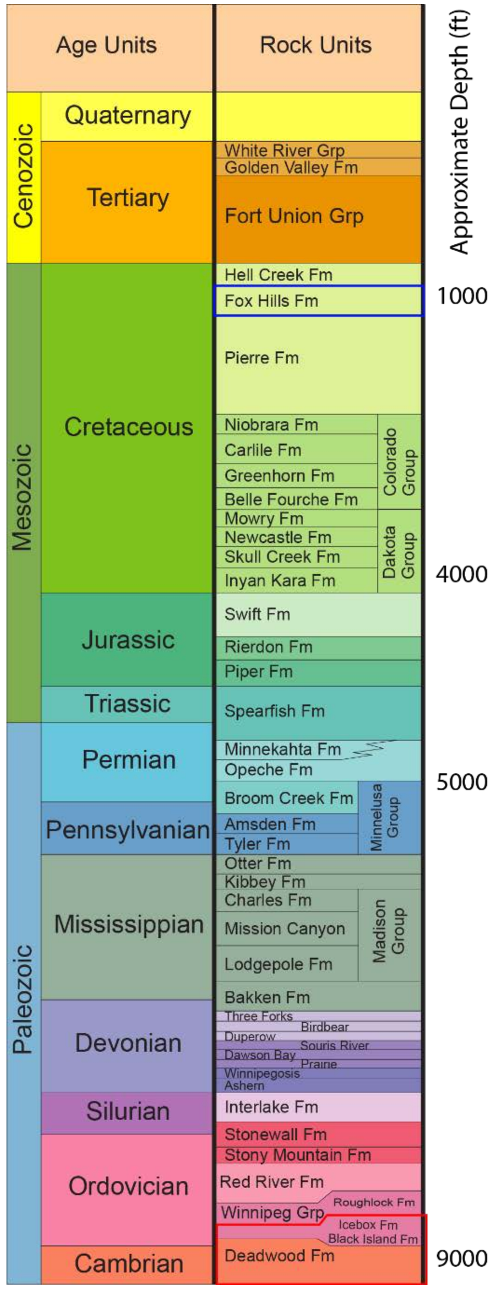


Figure A-2. Stratigraphic column identifying the storage reservoir and confining zones (red polygon) and lowest underground source of drinking water (blue polygon) for the geology underlying the Tundra SGS storage facility area.

The geologic model provided the basis for inputs of fluid flow simulations using Computer Modelling Group's (CMG's) GEM software (Computer Modelling Group, 2019). Fluid flow properties, such as the relative permeability and capillary pressures associated with each lithofacies, were determined by mercury injection capillary pressure (MICP) measurements of representative core samples from their respective formations, and then adjusted for the geomodel-inferred average porosity of each lithofacies in the model. Finally, the fluid flow simulation permeability was tuned using a permeability multiplier based on measured permeability during brine injectivity tests conducted within the injection zone. This tuned simulation to site-specific injectivity testing and core sample data was utilized to simulate expected CO_2 injection capacity and the resulting CO_2 plume and pressure plume throughout the project life and postinjection period.

GEOLOGIC MODEL DEVELOPMENT

The activities performed to characterize the injection zone, overlying formations, and underlying confining formations included data aggregation, structural modeling, data analysis, and property distribution. 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, geophysical well logs from nearby wells, and core sample measurements.

Structural Framework Construction

Schlumberger Petrel software was used to interpolate structural surfaces for the Icebox, Black Island, and Deadwood Formations and Precambrian basement. Input data included formation top depths from the online NDIC database and supported by conventions described in literature (LeFever and others, 1987), data collected from the J-LOC1 and J-ROC1 wells, and 3D seismic surveys conducted at the site. The interpolated structural data were used to constrain the model extent in 3D space.

Data Analysis and Property Distribution

Confining Zones (Icebox Formation, Deadwood B Member)

The Icebox Formation and Deadwood B Member were assigned shale lithofacies; classifications were determined as primary lithologic constituents through well log analysis. Porosity and permeability logs were upscaled to the model to serve as control points for property distributions. The control points were used in combination with variograms and Gaussian random function simulations to distribute properties. Variograms model spatial variance of data in lateral and vertical directions to allow for interpolation through geostatistical methods. A variogram with a major axis range of 6,500 ft, minor axis range of 6,000 ft, and an azimuth of 90° was used for the Icebox Formation. In the Deadwood B Member, a variogram with major and minor axis lengths of 5,000 ft with an azimuth of 0° was used. A vertical variogram length of 6 ft was used for all confining zones.

Injection Zone (Black Island and Deadwood Formations)

Seismic data were resampled to match the resolution of the geologic model grid and used to determine variogram direction and an estimate of ranges by creating a variogram map. A variogram map is a 2D representation of the variograms calculated for all directions (0°–359°) for the input data. Variogram mapping investigations indicated that geobody structures with the following dimensions are present in the Black Island Formation: major and minor axis ranges of 5,000 ft. In the Deadwood E Member, investigation indicated major axis range of 5,500 ft, minor axis range of 5,000 ft, and an azimuth of 155°. In the Deadwood C Member sandstone, investigation indicated major axis range of 6,000 ft, minor axis range of 5,500 ft, and an azimuth of 30°. Well logs recorded from J-LOC1 and J-ROC1 and offset wellbores served as the basis for deriving a vertical variogram length of 6 ft.

Available sonic well logs (ΔT) and bulk density (RHOB) in the area were transformed to acoustic impedance (AI) logs (AI = RHOB*1,000,000/ΔT) to aid in discovering trends between well log data and seismic AI data. The AI from 3D seismic surveys (east and west) was edited to remove edge effects. The east 3D AI range was rescaled into alignment of the west 3D prior to combining the volumes to account for the differences in acquisition methods.

The AI logs were smoothed to resolve vertical resolution differences between the seismic and well log resolutions. By using an arithmetic smoothing window centered on each depth point, the smoothed well log AI with a 40-ft sampling window, AI_40, provides the best correlation to the seismic AI and to well AI. A correlation coefficient of 0.609 was observed between the smoothed AI_40 logs and seismic AI. Also, a decent correlation of 0.7353 was seen between AI_40 and initial AI data (Figure A-3). This correlation allows for a high level of control when using seismic results to apply trends during property distributions.

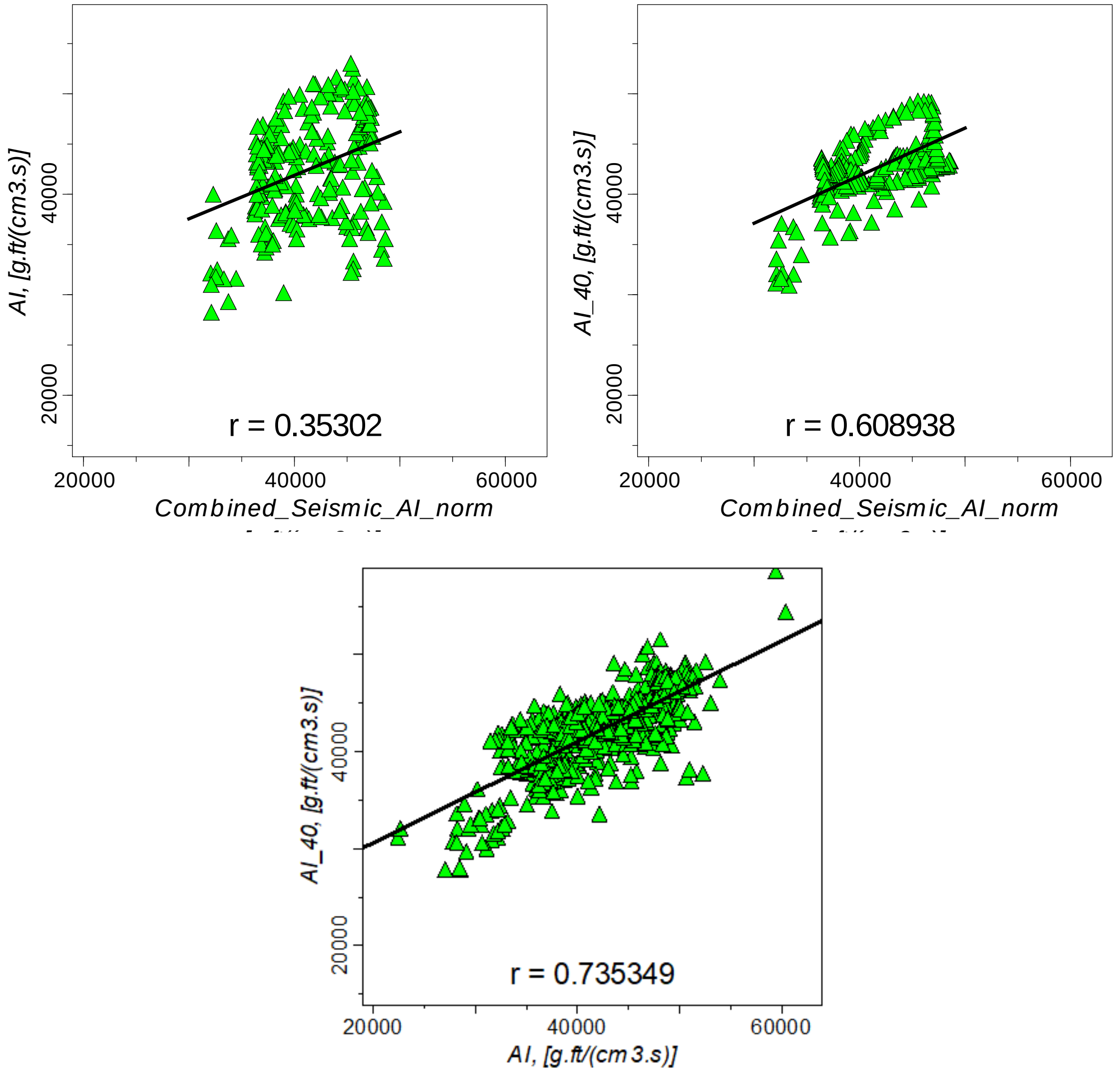


Figure A-3. Correlation coefficient between well log-derived AI and seismic AI data:
1) correlation coefficient of 0.3530 was determined based on the initial data (top left panel),
2) correlation coefficient of 0.6089 was determined after performing smoothing over a 40-ft window to resolve vertical resolution differences (top right panel), and 3) correlation coefficient of 0.7353 was determined based on the initial data (AI) and smoothed data (AI_40) (bottom).

The AI_40 logs were distributed over the seismic area using Gaussian random function simulation, the upscaled pointset, and variogram structures described previously for each zone. Then the AI logs were distributed throughout 3D volume using the same variogram parameters described previously and cokriged with the distributed AI_40 for each zone with a colocated cokriging coefficient of 0.75 (Figure A-4). The distributed AI property (Figure A-5) was used to distribute lithofacies and petrophysical properties to better link them to the seismic data.

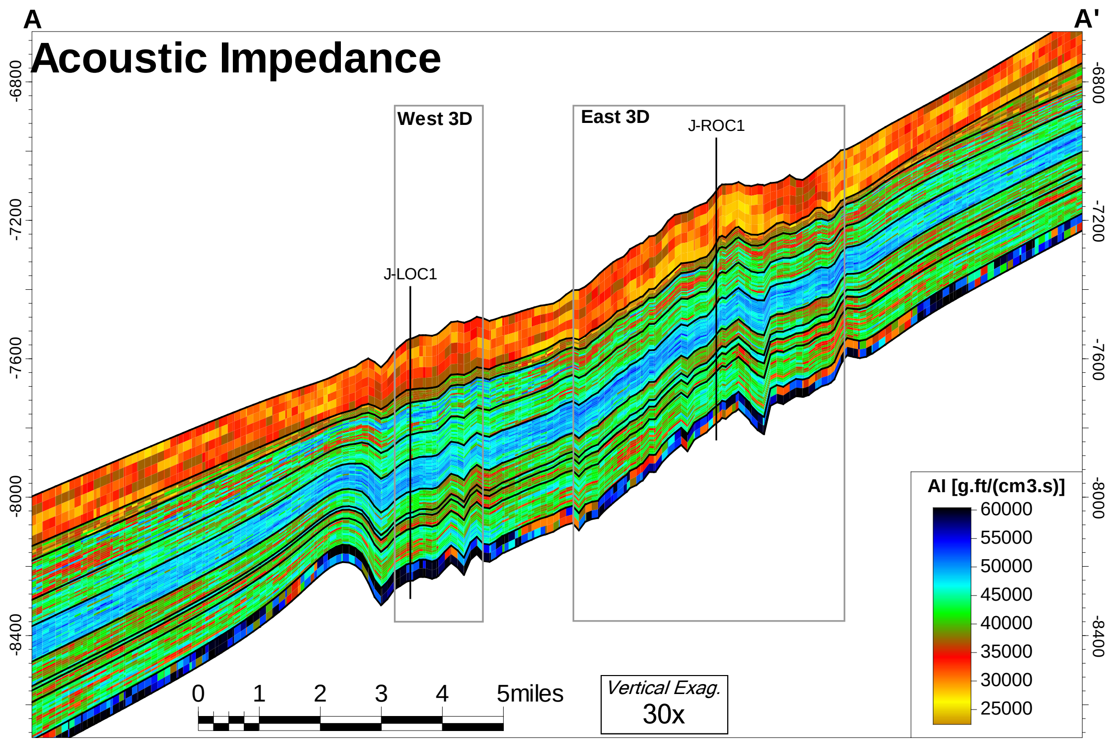


Figure A-4. Distributed AI property along the NW–SE cross section. The distributed property was used to distribute lithofacies and petrophysical properties to seismic data. Vertical units on the y-axis are displayed as feet below mean sea level (30× vertical exaggeration shown).

Because of the low count of well logs containing both ΔT and RHOB logs immediately near the J-LOC1 and J-ROC1 wellsites, three pseudowells were added to the geologic model: one at the northeast (NE-pseudo), one at the northwest (NW-pseudo), and one at the southwest (SW-pseudo) corners of the model boundary (Figure A-1). The well log AI, bulk density, neutron porosity, sonic, resistivity, gamma ray, effective and total porosity, volume of clay, and permeability data from offset wells from both outside and inside the bounds of the model were projected onto the pseudowells. The values of the offset well logs were weighted using inverse distance squared to project the ΔT and RHOB logs to the pseudowells. These data were used to help control AI distribution outside of the seismic boundary to the edges of the model boundary.

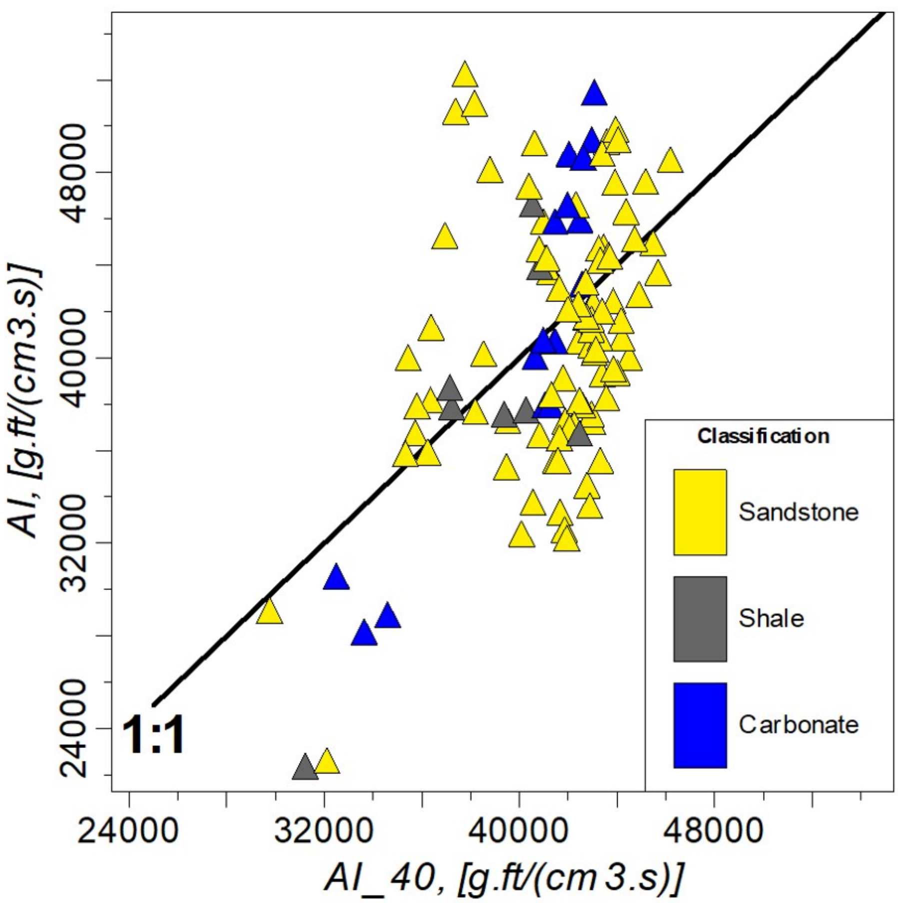


Figure A-5. Upscaled AI vs. upscaled AI_40 for Black Island Formation, Deadwood E Member, and Deadwood C Member sandstone. Points representing upscaled cells are colored by interpreted lithology: yellow represents sandstone, dark blue represents carbonate, and gray represents shale. AI_40 provided a better separation between sandstone facies and shale facies, while AI has a slight separation between carbonate and noncarbonate facies.

Lithofacies classification was determined from well log data and correlated with descriptions of core taken from the J-LOC1 well. Facies logs were upscaled into a structure grid with an average cell size of 500 ft × 500 ft × 5 ft (I, J, and K directions, respectively). Trend modeling was employed to build a 3D probability trend for each lithofacies utilizing the AI and smoothed AI (AI_40). The trend model used an isometric 10,000-ft variogram length and simple kriging type. Figure A-5 demonstrates the better facies separation between sandstone and nonsandstone facies using AI-40 rather than AI. The slight facies separation between carbonate and shale facies is seen using AI rather than AI_40. Along with the 3D probability trends for each facies, facies distributions were performed using sequential indicator simulation. Variogram models described previously guide the distribution of facies in each zone (Figures A-6 and A-7).

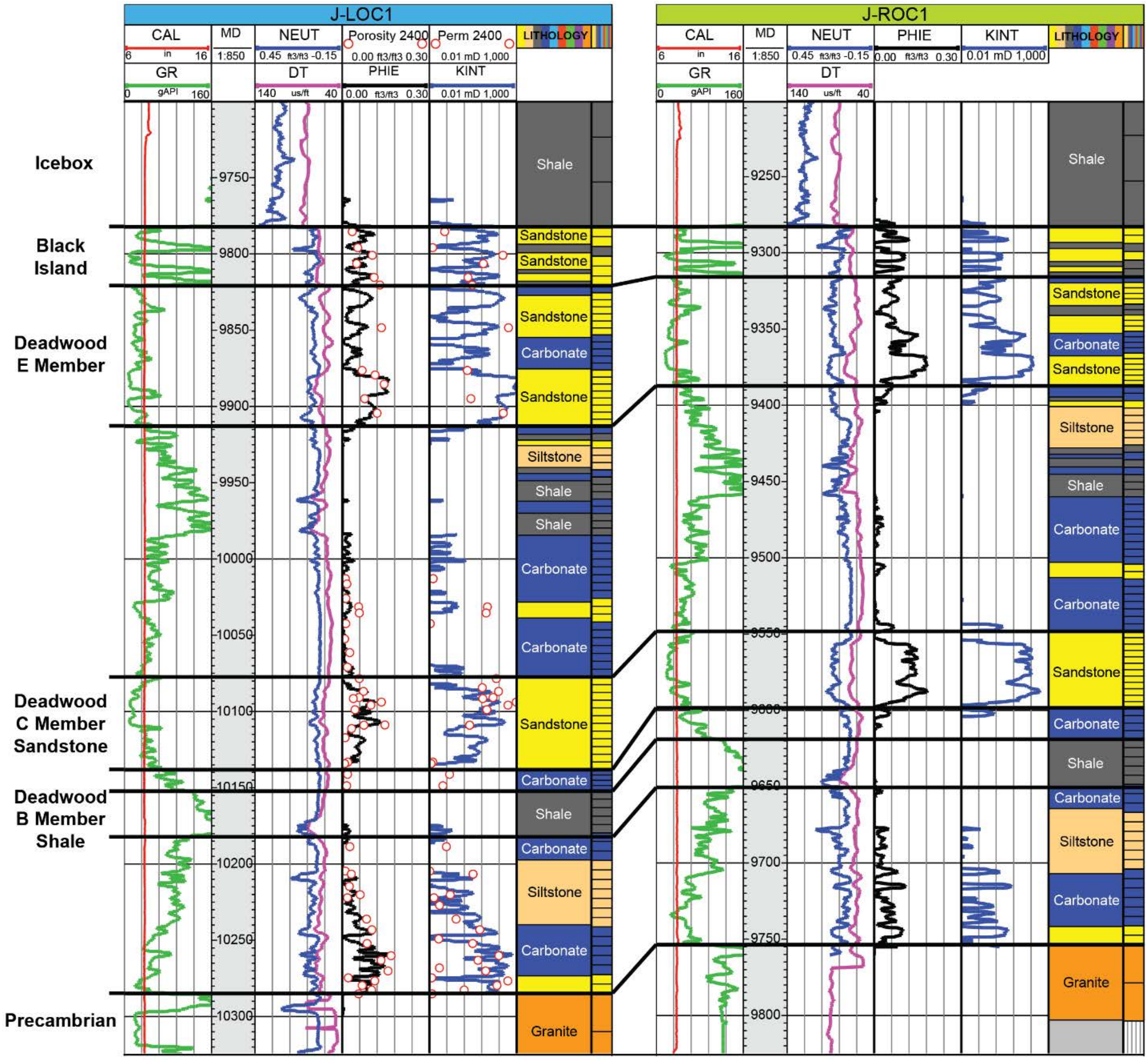


Figure A-6. Lithofacies classification in wells J-LOC1 and J-ROC1. Logs displayed in tracks from left to right are 1) gamma ray (green) and caliper (red), 2) measured depth in feet, 3) neutron porosity (dark blue) and delta time (purple), 4) effective porosity (black) and core porosity (red dots), 5) permeability (dark blue) and core permeability (red dots), 6) interpreted lithology log, and 7) upscaled lithology.

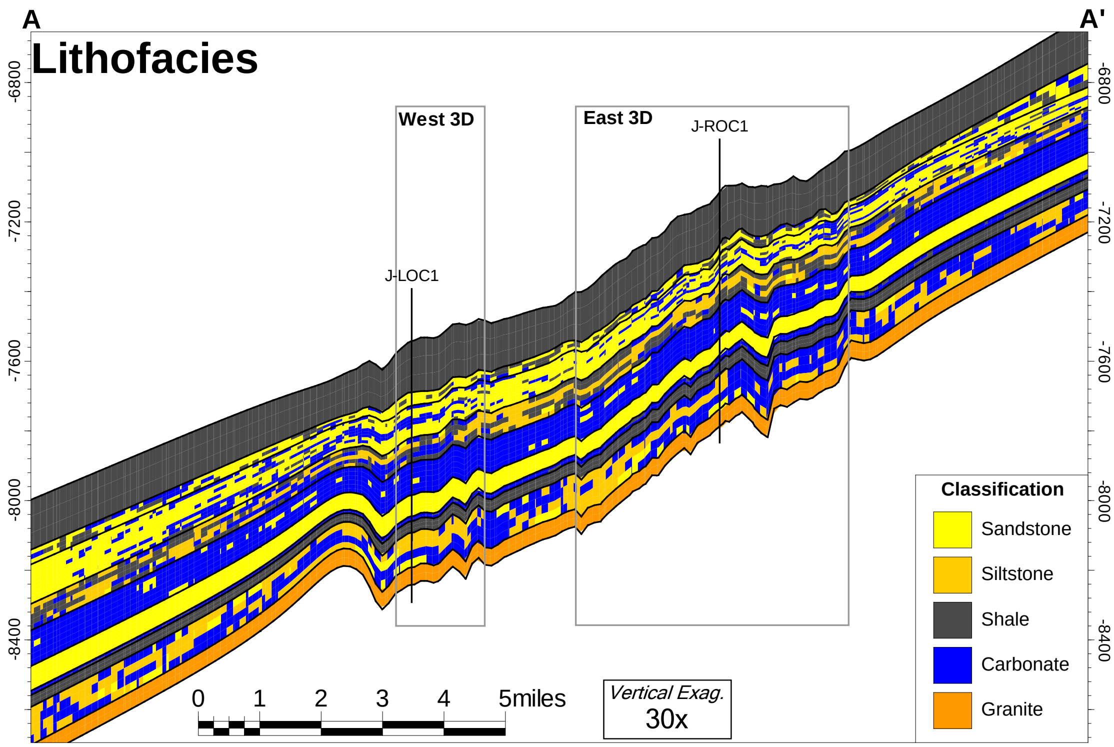


Figure A-7. Lithofacies distribution along the NW–SE cross section. Sandstone and carbonate distributions correlate well with the AI property. The heterogeneity observed across the seismic data is matched outside seismic control (Figure A-4). Vertical units on the y-axis represent feet below sea level (30× vertical exaggeration shown).

Prior to distributing the porosity and permeability properties, core porosity and permeability measurements from the J-LOC1 well were compared with effective porosity (PHIE) well logs and permeability estimated from the Wyllie–Rose (Wyllie and Rose, 1950) model utilizing the Morris–Biggs parameters (Morris and Biggs, 1967) to ensure good agreement between the two data sets (Figure A-6). Total porosity (PHIT) was upscaled to the model to be used as control points for distribution. PHIT was distributed by zone and lithology using Gaussian random function simulation and variogram models described previously and cokriged with AI volume using a correlation coefficient of -0.88. PHIE was distributed (Figure A-8) using the same variables as PHIT and cokriged to PHIT with a correlation coefficient for each zone and lithology. Intrinsic permeability (KINT) was distributed using the same variables and cokriged to PHIE volume.

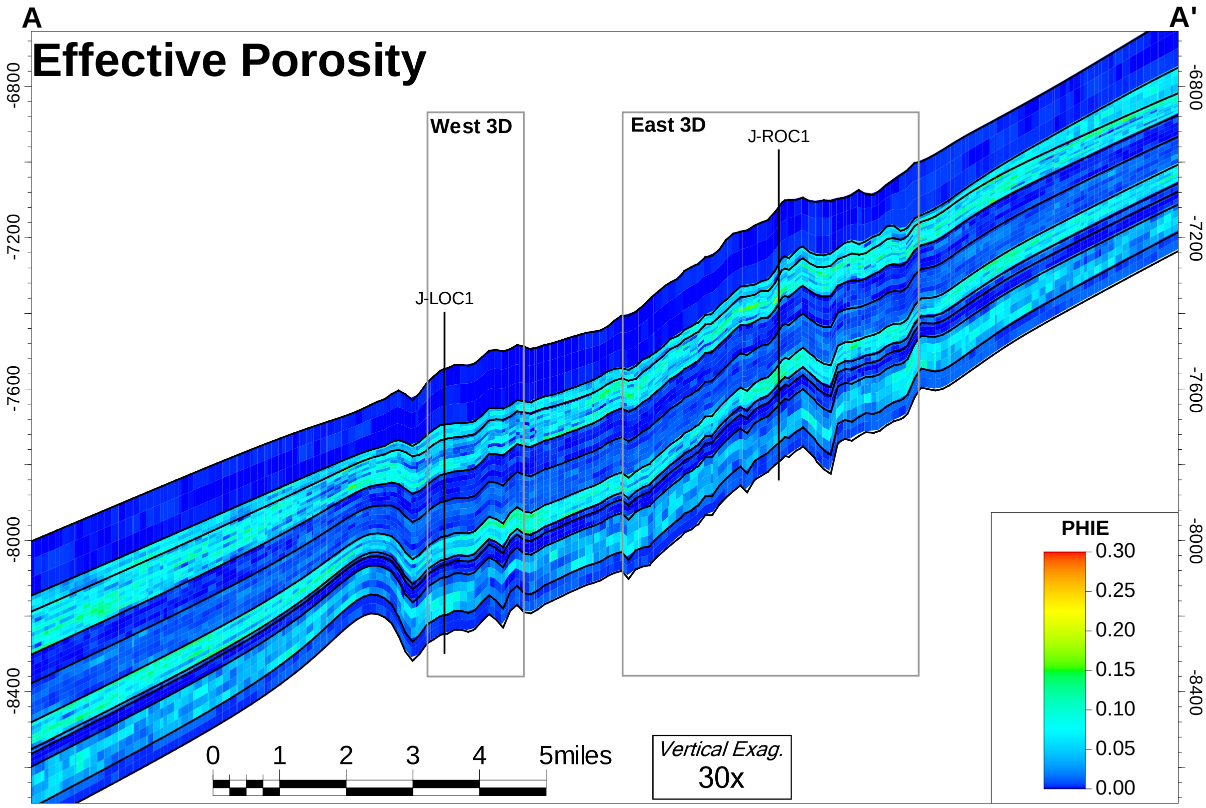


Figure A-8. Effective porosity distribution throughout the 3D gridded volume along NW-SE cross section. Units on the y-axis represent feet below sea level (30× vertical exaggeration shown).

Numerical Simulation

Numerical simulations of CO_2 injection into the Deadwood Formation were conducted using the geologic model described above (Figure A-9). Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both calculated temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. A compositional simulator is one of the most mechanistically accurate methods to solve compositional multiphase fluid flow processes. Compositional simulators utilize cubic equations of state, such as Peng–Robinson's, 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 (equation of state) simulator accounts for and estimates CO_2 solubility, residual gas trapping, and flow dynamics through a duration of time.

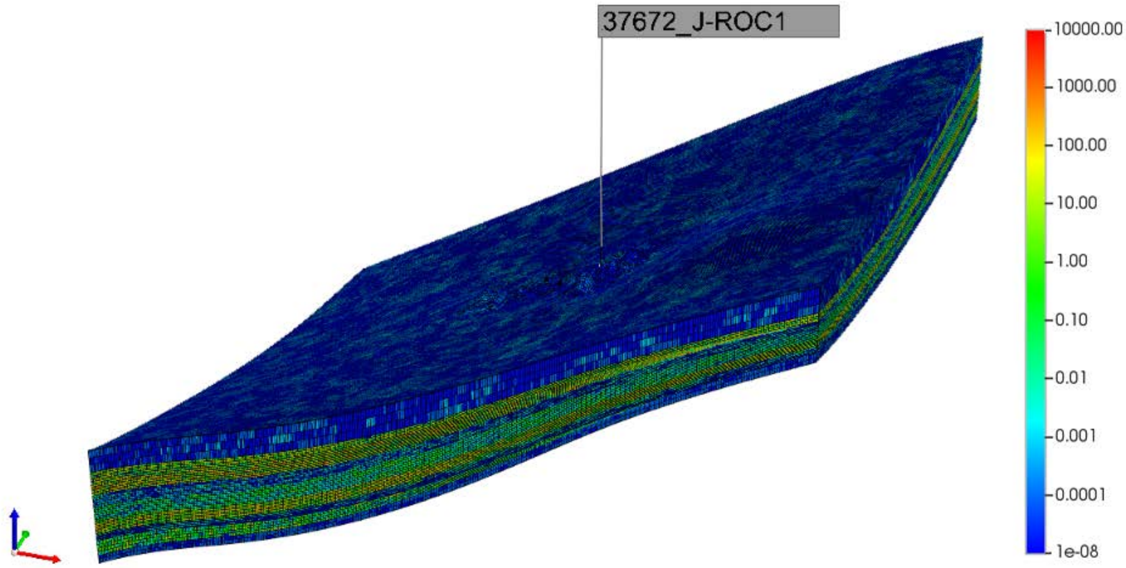
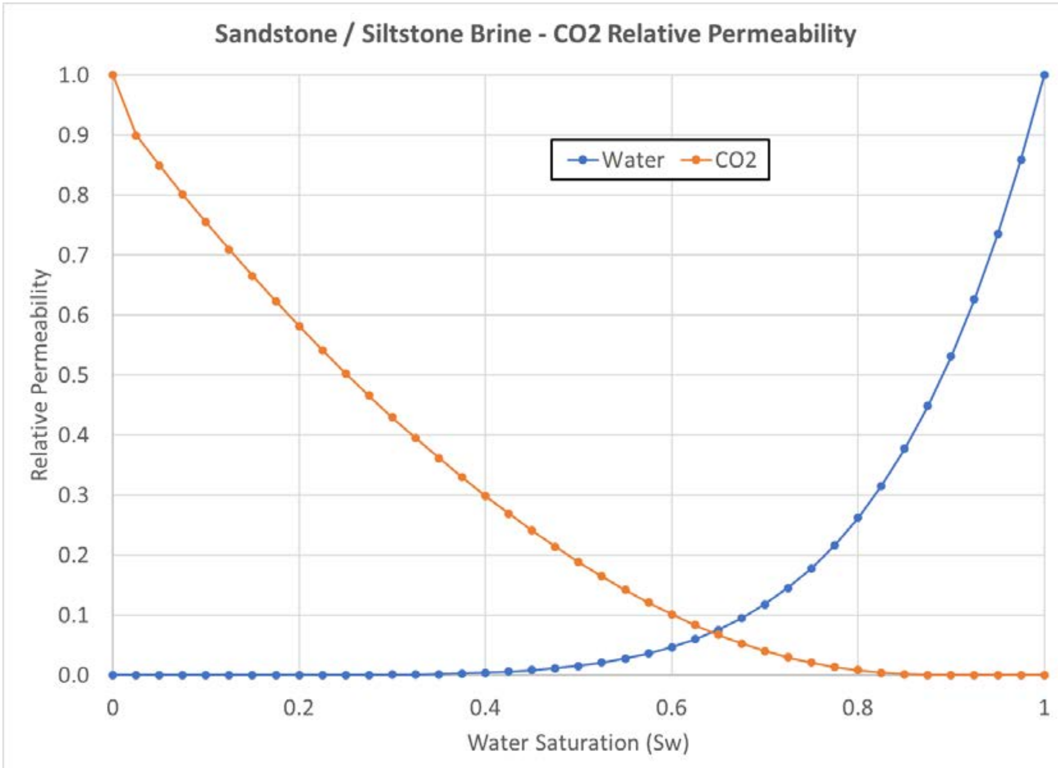


Figure A-9. The 3D view of the simulation model with the permeability property displayed. Note the low-permeability layers (dark blue) at the top and bottom of the figure. These layers represent the Icebox Formation (upper) and the Precambrian basement (lower). The varied permeability of the Black Island and Deadwood Formations is observed in between these layers. Vertical exaggeration is 40×.

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 256,000 ppm total dissolved solids (TDS). Simulations performed allowed CO_2 to dissolve into the native formation brine. Both the relative permeability and the capillary pressure data for the Deadwood were analyzed and generated for three representative rock types in the simulation (sandstone/siltstone, shale/granite, and carbonate/dolostone) through Core Labs MICP evaluation and Energy & Environmental Research Center (EERC) laboratory analysis (Figures A-10 through A-12). The MICP-measured capillary pressures were adjusted to CO_2–brine pressures based on theoretical predictions of CO_2–brine contact angles and interfacial tensions. These CO_2–brine capillary pressures were further adjusted to account for the simulation-predicted average porosity and permeability compared to the MICP sample measured porosity and permeability.



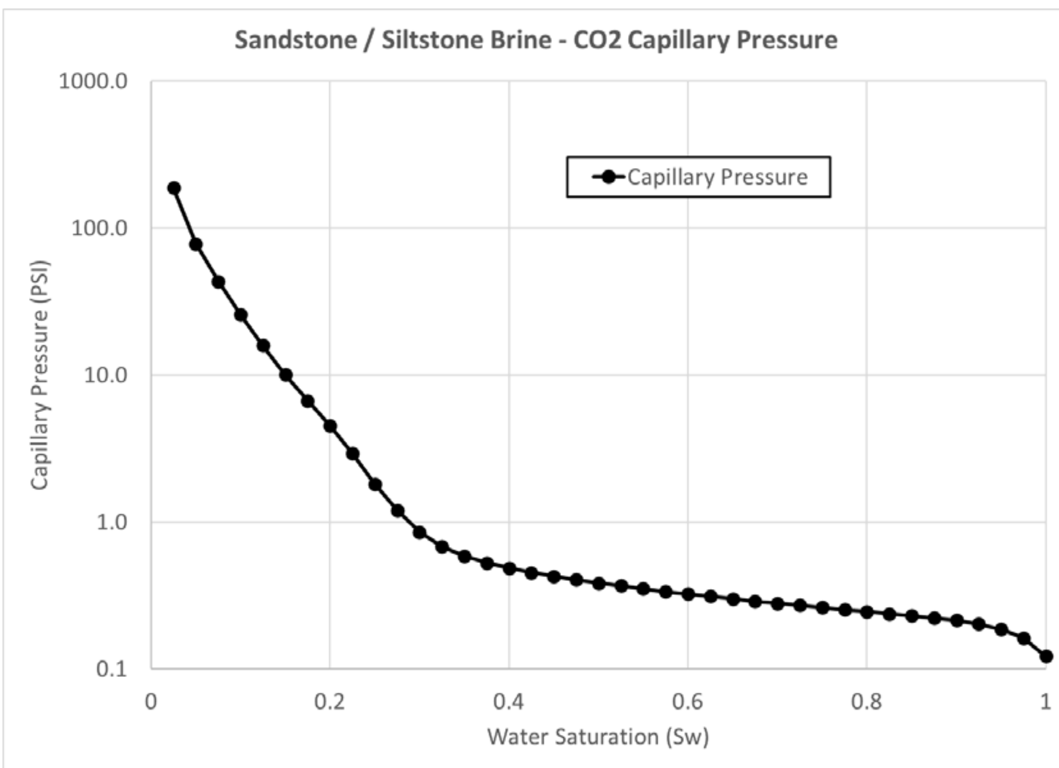
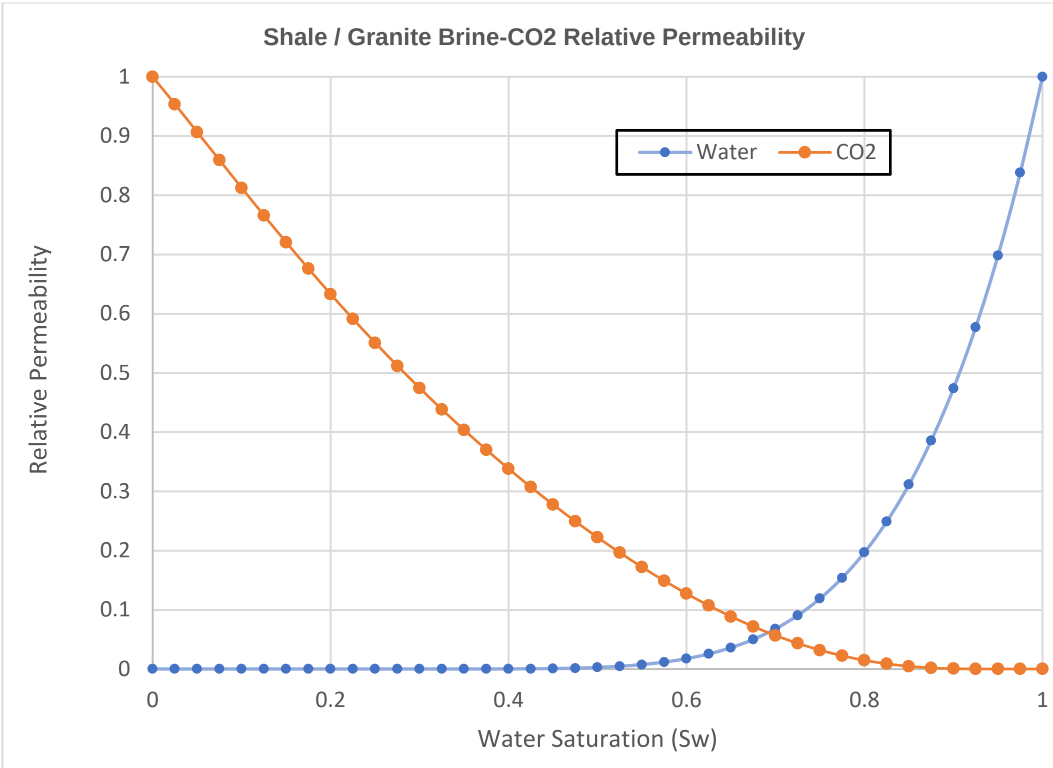


Figure A-10. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone and siltstone rock types in the Black Island and Deadwood Formations.



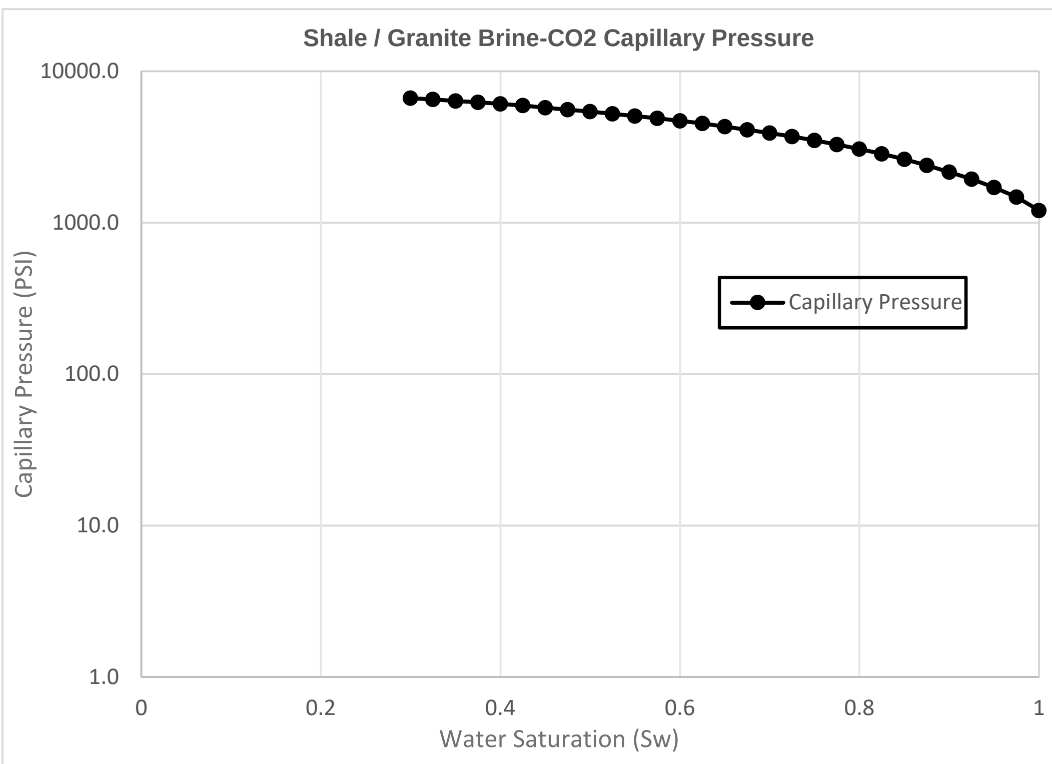
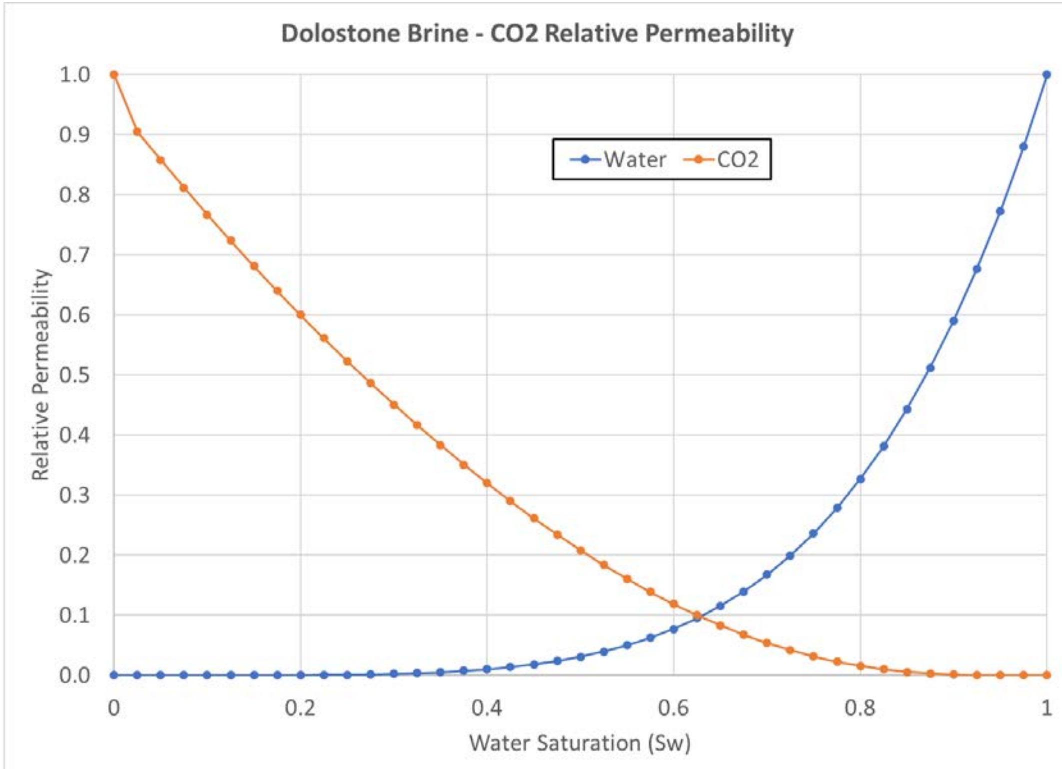


Figure A-11. Relative permeability (top) and capillary pressure curves (bottom) for the shale in the Icebox, Black Island, and Deadwood Formations and for the Granite in Precambrian.



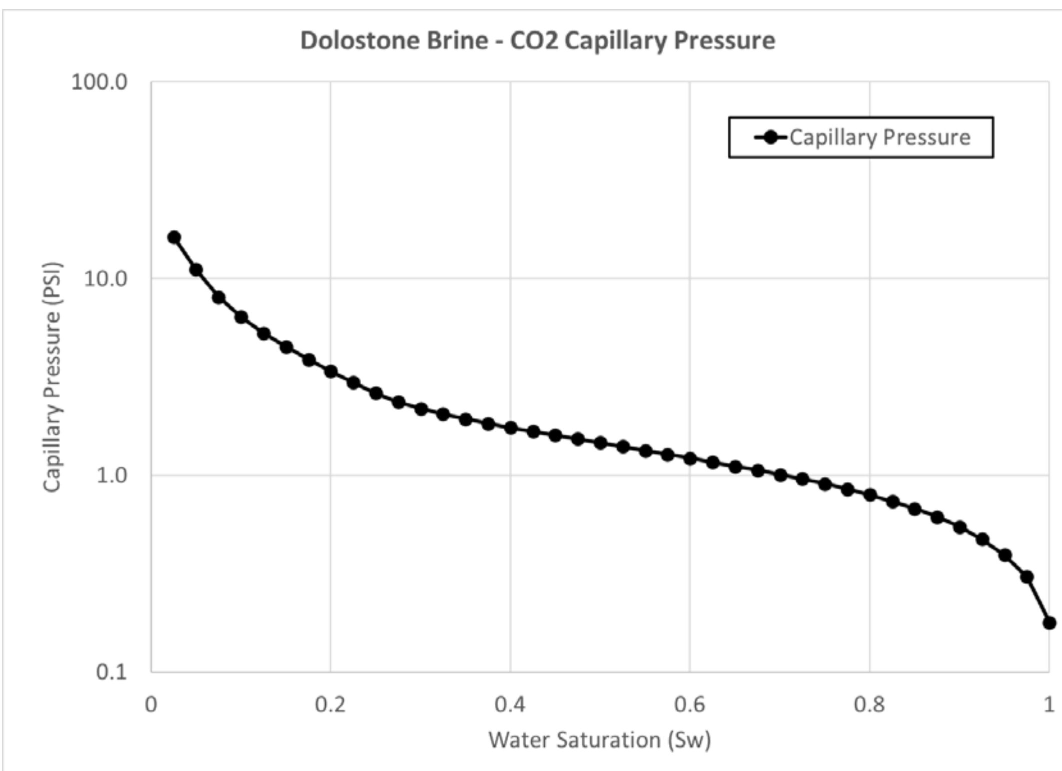


Figure A-12. Relative permeability (top) and capillary pressure curves (bottom) for the carbonate/dolostone rock type in the Black Island and Deadwood Formations.

Capillary entry pressure data included in the dynamic reservoir simulation model were derived from core testing. The capillary entry pressure value applied to the Ice Box shale layers in the model was determined by deriving a ratio between the reservoir quality index of Ice Box core samples and modelled properties to scale the capillary entry pressure value derived from core testing (Table A-1). The capillary entry pressure value derived from core sample testing, 0.16 psi, was applied to the Deadwood and Black Island sand lithologies in the model. A core sample was not collected from carbonate intervals in the Deadwood and Black Island, so capillary entry pressure data from Broom Creek carbonate samples was applied to the carbonate lithologies in the model in combination with a multiplication factor derived from the ratio of reservoir quality index between the core sample and modelled properties (Table A-1). Samples tested within the Deadwood and Black Island Formation included sandstone, shaly sandstone and shaly arkose lithologies. Therefore, the capillary entry pressure values from the Ice Box shale were used for the Deadwood and Black Island shale lithologies in the simulation model.

Table A-1. Core and Model Properties Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure Used in the Model

	Core			Model			
Formation	**Phi (fraction)**	**K, md**	**Capillary Entry Pressure, psi**	**Phi (fraction)**	**K, md**	**Capillary Entry Pressure, psi**	**Multiplication Factor**
Deadwood and Black Island (carbonate)	0.048	0.00478	27	0.050**	39.3**	0.3	0.011
Icebox (shale)	0.036	0.00002	845	0.008***	1.45E-06***	1450*	1.75

* Maximum value allowed in CMG is 1450 psi, the scaled capillary entry pressure (1480 psi) exceeded this.
** Pore volume weighted average.
*** Pore volume weighted average of Icebox shale and Precambrian used to calculate multiplication factor.

Temperature data recorded from logging the J-LOC1 wellbore were used to derive a temperature gradient of 0.01°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 J-LOC1 well was performed with a modular formation dynamics tester (MDT) logging tool. Multiple pressure readings recorded from the Black Island and Deadwood Formations were used to derive a pore pressure gradient of 0.46 psi/ft (Table A-2). Combined with depth, this gradient was used to distribute pressure throughout the geologic model.

Table A-2. MDT Pressure Measurements Recorded from the J-LOC1 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
9,800	4,507	0.46
9,885	4,548	0.46
9,885	4,548	0.46
10,087	4,651	0.46
10,254	4,734	0.46

* Measured depth.

Simulation model permeability was tuned globally by applying a multiplier to match reservoir properties estimated from a Deadwood Formation step rate test. Permeability multipliers were calculated by dividing the average permeability estimated from the injection test by the average model permeability over a certain distance from the J-LOC1 well. Using the model permeability averaged over a distance of approximately 750–1,250 ft from J-LOC1 and comparing it with the average permeability based on the injection test, the estimated multipliers ranged from 3.5−7.1×, with an average value of nearly 5×. Ultimately, a global multiplier of 5× was applied to the permeability properties before numerical simulations.

Table A-3 shows the general properties used for numerical simulation analysis in this study. The injection well, J-ROC1, is simulated as perforated across the entire Black Island Formation interval and across the Deadwood intervals C through E (the lowest two Deadwood intervals, A and B, were not perforated). The J-ROC1 well constraints and wellbore model inputs for the simulation model are shown in Table A-4.

Table A-3. Summary of Reservoir Properties in the Simulation Model

Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Icebox: 7.25×10^{-7} Black Island: 9.81 Deadwood: 31.65 Precambrian: 7.88×10^{-7}	Icebox: ~0.12 Black Island: ~5.48 Deadwood: ~3.81 Precambrian: ~0.74	~4,548.42	256,000	Open (infinite-acting)

Table A-4. Well Constraints and Wellbore Model in the Simulation Model

Primary Constraint, Wellhead Pressure	Secondary Constraint, Bottomhole Injection Pressure	Tubing Size	Wellhead Temperature	Downhole Temperature
2,800 psi	6,179 psi	5.5 in.	90°F	181°F

Simulation Results

Simulations of CO_2 injection with the given well constraints, listed in Table A-4, predicted that the injection bottomhole pressure (BHP) will not exceed 6,179 psi during injection operations, assuming a wellhead pressure (WHP) limit of 2,800 psi (Figure A-13). Results of a stress test performed by an MDT tool in the J-LOC1 wellbore, conducted at a depth of 9,885.1 ft MD, estimated a fracture closure pressure of 7,417 psi, resulting in a fracture closure gradient of 0.750 psi/ft. The closure pressure gradient was used to calculate maximum BHP constraints, based upon 90% of the fracture closure pressure. Cumulative CO_2 injection at the above-described pressure conditions was approximately 23.4 million metric tons (MMt) over the 20 years of injection. The resulting average injection rate of CO_2 injected into the Black Island and Deadwood Formations over the 20 years of simulated injection was 1.17 MMt per year (Figure A-14).

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. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), 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-15).

The pressure plume shown in Figure A-16 shows the distribution of pressure increase in the Deadwood Formation during the 20-year injection period. Figure A-16 shows the average increase in pressure after 20 years of injection. The largest increase will appear in the near-wellbore area, where the maximum increase of 1,620 psi is estimated.

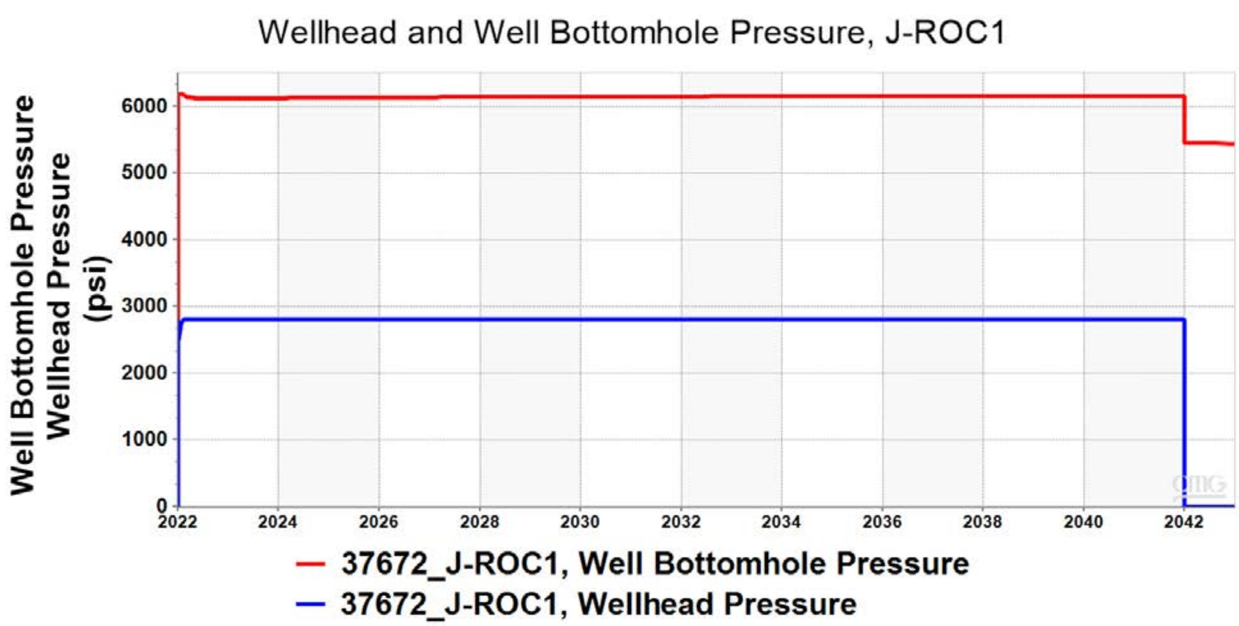


Figure A-13. WHP and BHP response with the expected injection rate.

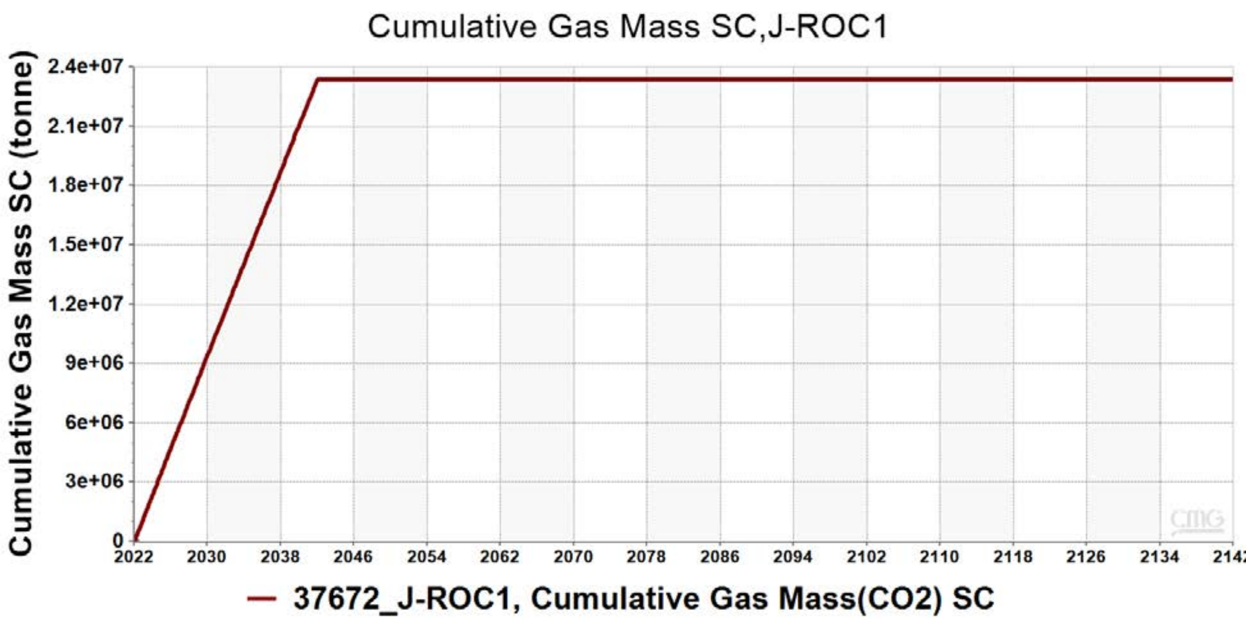


Figure A-14. Cumulative injected gas mass over 20 years of injection.

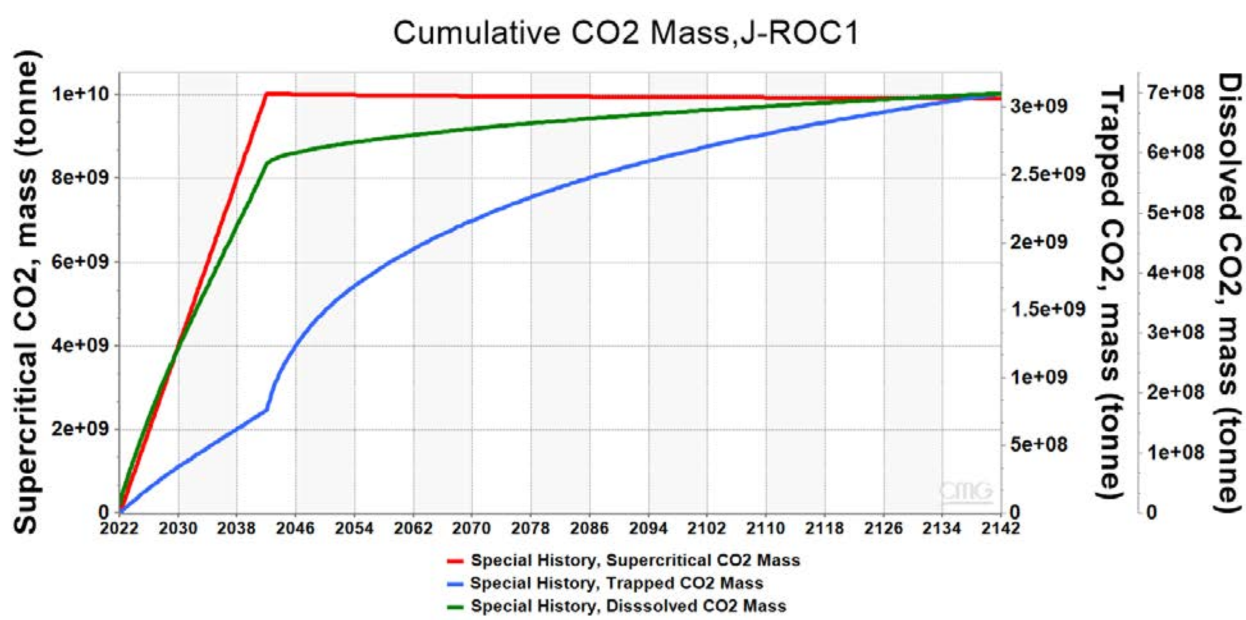


Figure A-15. Simulated total dissolved CO_2 in brine, supercritical-phase CO_2, and residually trapped CO_2.

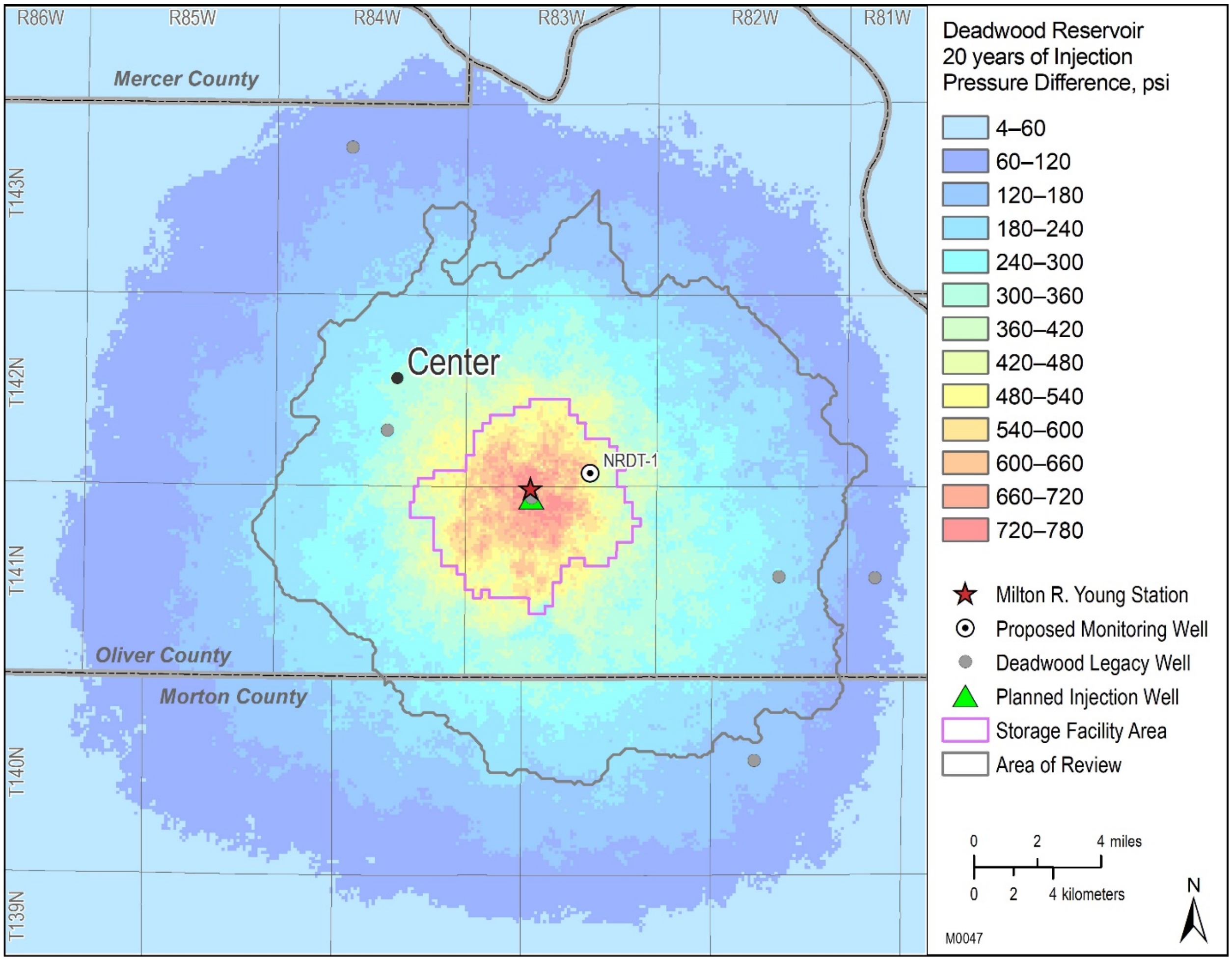


Figure A-16. Average pressure increase within the Deadwood Formation at the end of a simulated 20-year CO_2 injection operation.

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 Black Island and Deadwood Formations 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-17 and A-18 show the gas saturation changes between the end of injection and 20 years postinjection in the cross-sectional view.

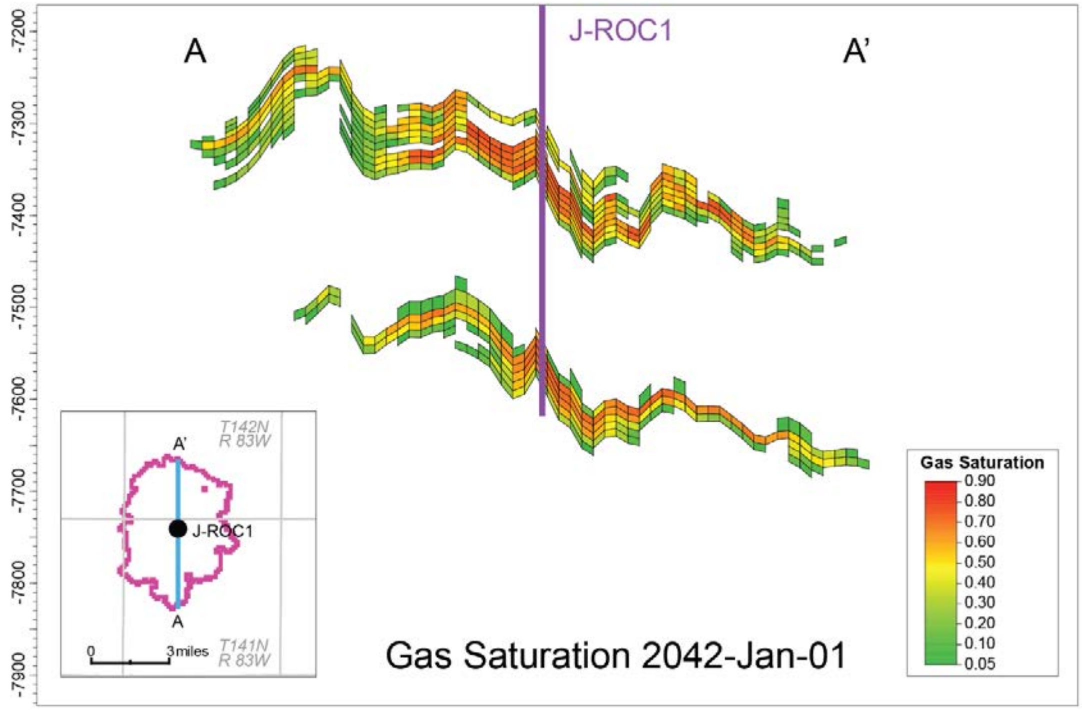


Figure A-17. CO_2 plume boundary and cross section at the end of injection displayed south to north through the J-ROC1 well.

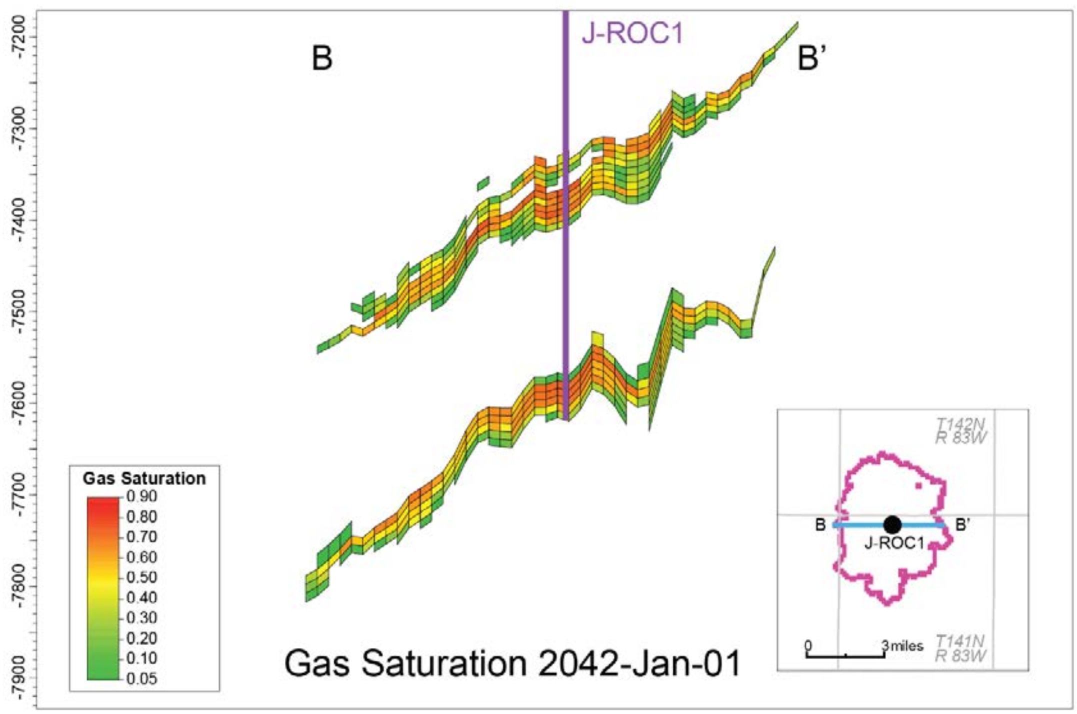


Figure A-18. CO_2 plume boundary and cross section at the end of injection displayed east to west through the J-ROC1 well.

Maximum Surface Injection Pressure

Injectivity in the Deadwood Formation is limited by the WHP and BHP constraints (90% of fracture closure pressure). The initial WHP of 1,700 psi was not sufficient to maximize injectivity while staying significantly below the maximum BHP constraint. An initial feasibility investigation by project partners suggested a step-up to the next compressor capacity (outlet pressure of 2,800 psi) is required to increase injection rate in Deadwood while staying at or below the maximum BHP. A WHP (surface) of 2,800 psi was considered to maximize injection in the simulation model.

The maximum surface pressure was reached in the simulations before the maximum BHP was encountered. At the maximum surface pressure of 2,800 psi, the peak predicted BHP response was observed to be 6,179 psi with an average of 6,139 psi as the BHP remains lower than the maximum BHP of 6,179 psi for most of the injection period (Figure A-19).

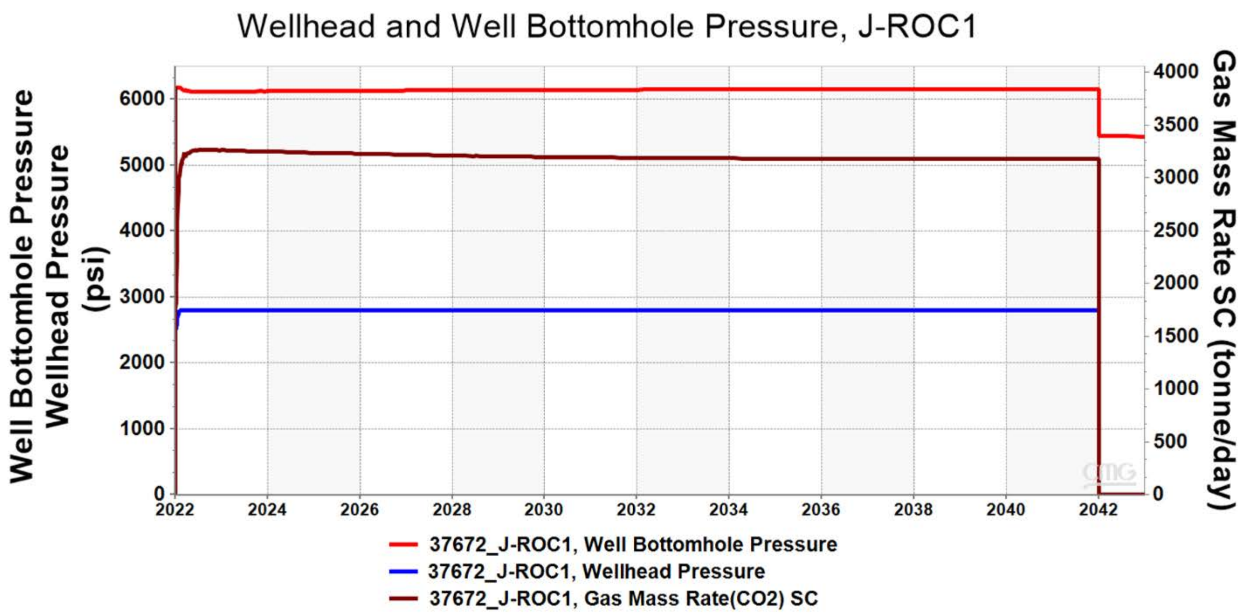


Figure A-19. Maximum pressure and rate response when the well is operated at its maximum safety rating, using 5.5-in. tubing.

DELINEATION OF THE AREA OF REVIEW

The AOR is defined as the region surrounding the geologic storage project where 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.

EPA (2013) Method 1 (*pressure front based on bringing injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (Thornhill and others, 1982). Under Method 1, the increase in pressure (ΔP) that may be sustained in the injection zone (critical pressure threshold) is given by:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

where P_u is the initial fluid pressure in the USDW, ρ_i is the storage reservoir fluid density (mg/m^3), g is the acceleration due to gravity (m/s^2), z_u is the representative elevation of the USDW (m amsl), z_i is the representative elevation of the injection zone (m amsl), P_i is the initial pressure in the injection zone (Pa), and $\Delta P_{i,f}$ is the critical pressure threshold.

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f} = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW, and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW. In the case of $\Delta P_{i,f} > 0$, the value of $\Delta P_{i,f}$ represents the amount of pressure increase that can be accommodated in the storage reservoir before brine would flow into the lowest USDW.

Critical Threshold Pressure Increase Estimation at J-ROC1

For the purposes of delineating the $\Delta P_{i,f}$ for the Tundra SGS study area, constant fluid densities for the lowermost USDW (the Fox Hills Formation) and the injection zone (the Deadwood Formation) were used. A density of 1,001 kg/m^3 was used to represent the USDW fluids, and a density of 1,177 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 Equation 1, formation depths and thicknesses from J-ROC1, and fluid density values from the nearby J-LOC1 stratigraphic test well (Table A-5). Using this method, the critical threshold pressure increase ($\Delta P_{i,f}$) at the top of the Deadwood Formation at the J-ROC1 well was determined to be 127 psi. Because $\Delta P_{i,f} > 0$, the value of $\Delta P_{i,f}$ represents the amount of pressure increase that can be accommodated in the storage reservoir before brine would flow into the lowest USDW.

Calculations 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-5 provides estimates of $\Delta P_{i,f}$ for various depths within the Deadwood Formation at J-ROC1. The same calculations were applied to the geologic model to determine $\Delta P_{i,f}$ for each cell, values from which were then compared against the difference in pressure predicted for each cell in the simulation

Table A-5. EPA Method 1 Critical Threshold Pressure Increase Calculated at the J-ROC1 Wellbore Location

Depth,* ft	m	P_i Injection Zone Pressure, MPa	P_u USDW Pressure, MPa	ρ_i Injection Zone Density, kg/m^3	Z_u USDW Base Elevation, m amsl	Z_i Reservoir Elevation, m amsl	$\Delta P_{i,f}$ Threshold Pressure Increase, MPa	psi
9,154	2,790	30.850	3.535	1,177	266	−2174	0.88	127
9,407	2,867	31.703	3.535	1,177	266	−2251	0.90	130
9,660	2,944	32.556	3.535	1,177	266	−2328	0.92	133

* Chosen depths represent the top, middle, and base of the Deadwood Formation at J-ROC1. Ground surface elevation is 609 m above mean sea level.

model at the end of injection (time of greatest increase in pressure since the beginning of simulated injection). A defined area of the simulation model around the injection well displays a 20-year pressure increase (ΔP) that is greater than the calculated $\Delta P_{i,f}$ for the cells in that area. The boundary between where $\Delta P_{I,f} > \Delta P$ and where $\Delta P_{I,f} < \Delta P$ delineates the line of critical threshold pressure increase and must be accounted for—in conjunction with the CO_2 areal extent—when determining AOR.

The storage reservoir is the maximum extent of the injected CO_2 or the maximum extent of the critical pressure, whichever is greater. At Tundra SGS, the line of critical threshold pressure increase plus 1 mile is the AOR, because the maximum extent of critical pressure is larger than the maximum extent of the injected CO_2. As shown in Figure A-20, the AOR is depicted by the gray shaded area, which includes the storage facility area (purple shaded area). Figure A-21 illustrates the land use within the AOR.

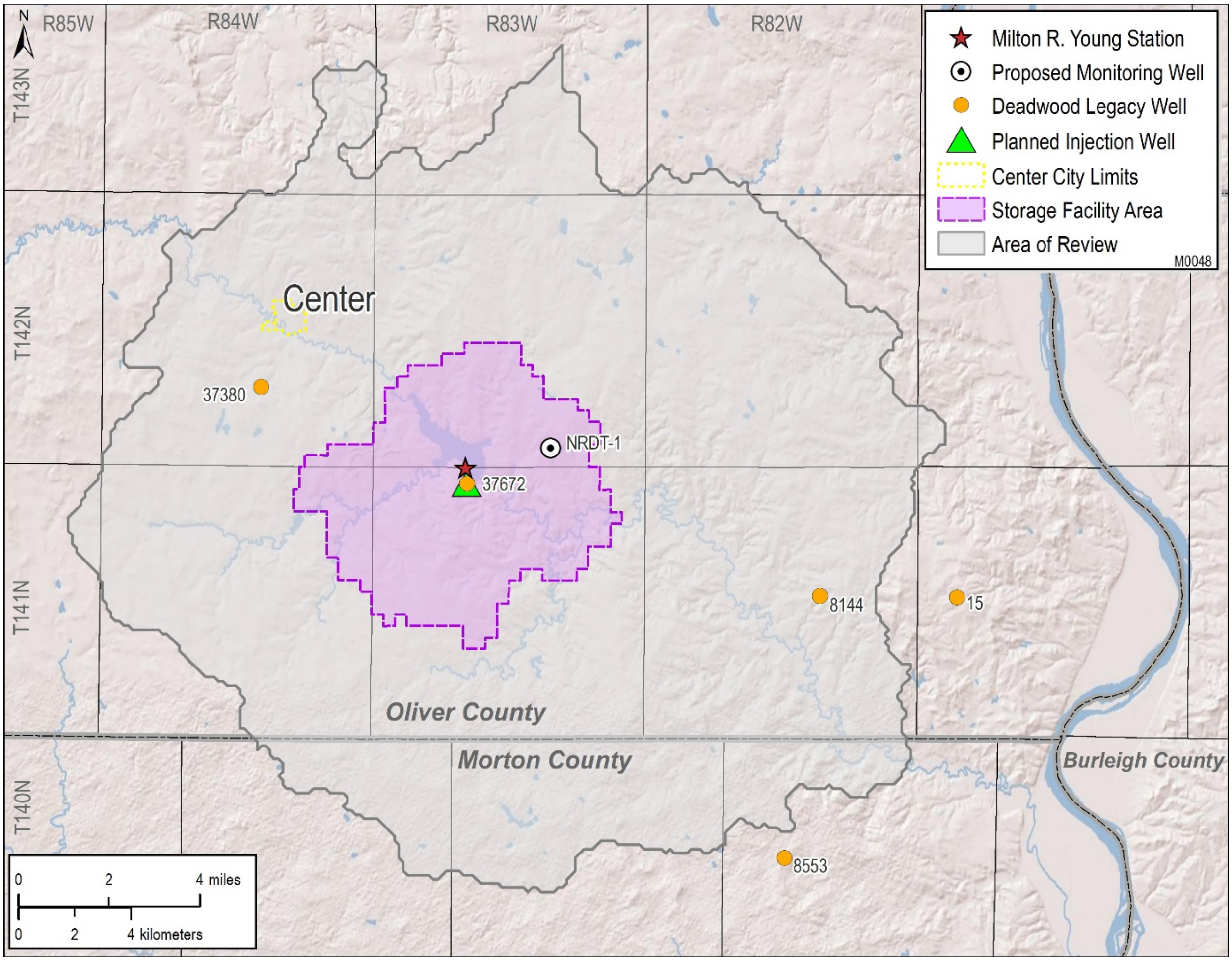


Figure A-20. Final AOR estimations of the Tundra SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), area of review (gray boundary and shaded area), and Center city limits (dotted yellow boundary). Orange circles represent legacy wells near the storage facility area.

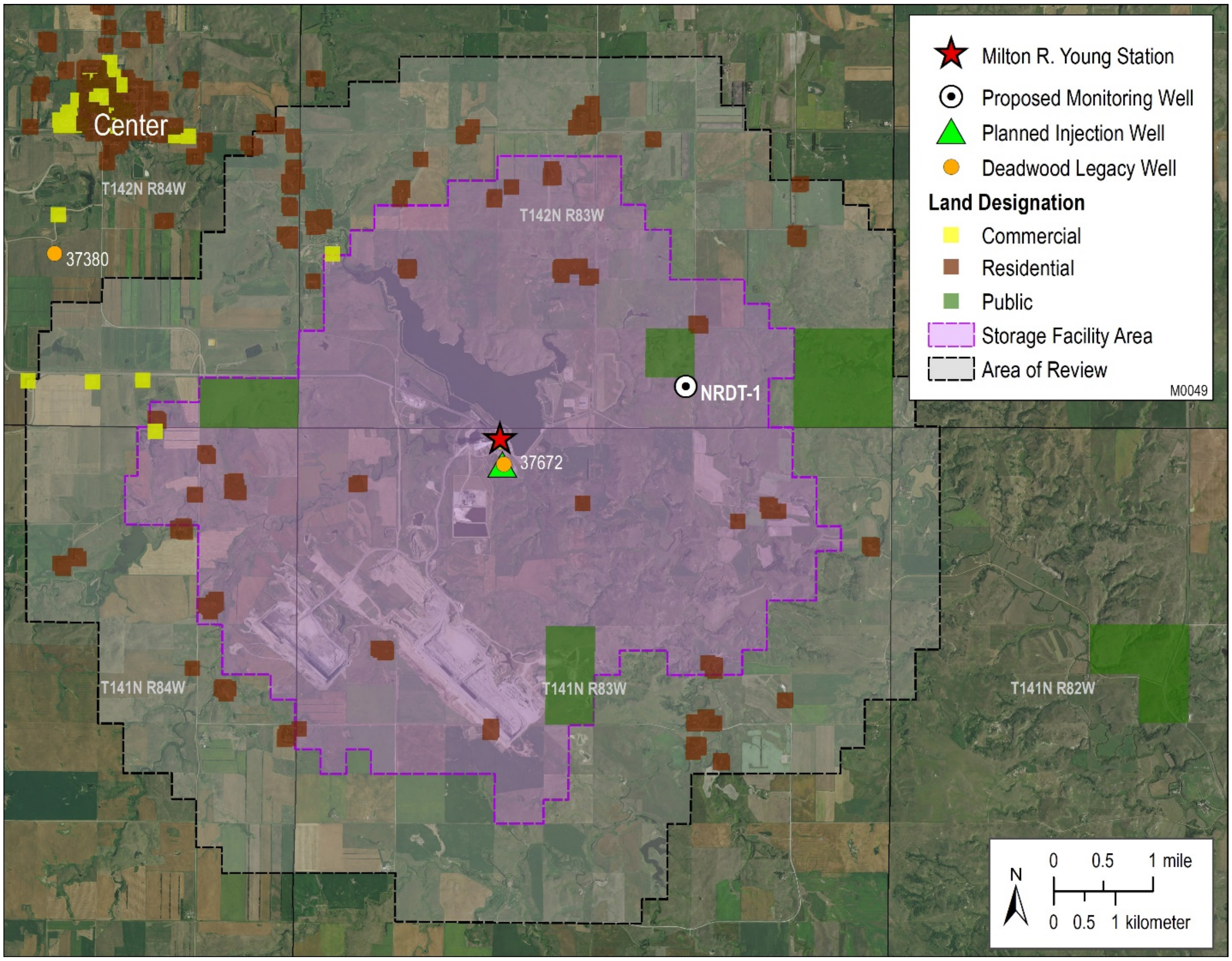


Figure A-21. Land use in and around the AOR of the Tundra SGS storage facility.

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APPENDIX B

WELL AND WELL FORMATION FLUID-SAMPLING LABORATORY ANALYSIS

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ANALYTICAL RESEARCH LAB - Final Results

Set Number: 54654
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020

July 24, 2020

Sample	Parameter	Result	
54654-05	**Deadwood 6/13/20**		
	Alkalinity, as Bicarbonate (HCO3-)	33.1	mg/L
	Alkalinity, as Carbonate (CO3=)	0	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	27.2	mg/L
	Aluminum	< 1000	µg/L
	Antimony	< 5	µg/L
	Arsenic	< 5	µg/L
	Barium	2990	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 5	µg/L
	Boron	54.0	mg/L
	Bromide	278	mg/L
	Cadmium	< 2	µg/L
	Calcium	8340	mg/L
	Chloride	153000	mg/L
	Chromium	< 40	µg/L
	Cobalt	< 20	µg/L
	Conductivity at 25°C	236000	µS/cm
	Copper	< 200	µg/L
	Dissolved Inorganic Carbon	5.9	mg/L
	Dissolved Organic Carbon	1010	mg/L
	Fluoride	< 5	mg/L
	Iron	25.2	mg/L
	Lead	93	µg/L
	Lithium	41.3	mg/L
	Magnesium	1260	mg/L
	Manganese	3300	µg/L
	Mercury	< 0.3	µg/L
	Molybdenum	< 25	µg/L
	Nickel	< 40	µg/L
	Phosphorus	< 10	mg/L
	Potassium	1800	mg/L
	Selenium	< 5	µg/L
	Silicon	< 10	mg/L

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Sample	Parameter	Result
54654-05	**Deadwood 6/13/20**	
	Silver	< 5 µg/L
	Sodium	91000 mg/L
	Strontium	248 mg/L
	Sulfate	504 mg/L
	Thallium	51 µg/L
	Thorium	< 10 µg/L
	Total Dissolved Solids	256000 mg/L
	Total Inorganic Carbon	12.1 mg/L
	Total Organic Carbon	1060 mg/L
	Uranium	< 5 µg/L
	Vanadium	< 20 µg/L
	Zinc	0.987 mg/L
54654-06	**Deadwood 6/13/20 duplicate**	
	Alkalinity, as Bicarbonate (HCO3-)	32.5 mg/L
	Alkalinity, as Carbonate (CO3=)	0 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	26.7 mg/L
	Aluminum	< 1000 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	2940 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	52.6 mg/L
	Bromide	283 mg/L
	Cadmium	< 2 µg/L
	Calcium	8350 mg/L
	Chloride	155000 mg/L
	Chromium	< 40 µg/L
	Cobalt	< 20 µg/L
	Conductivity at 25°C	236000 µS/cm
	Copper	< 200 µg/L

Distribution ______________________ Date __________

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Sample	Parameter	Result	
54654-06	**Deadwood 6/13/20 duplicate**		
	Dissolved Inorganic Carbon	6.0	mg/L
	Dissolved Organic Carbon	1000	mg/L
	Fluoride	< 5	mg/L
	Iron	24.7	mg/L
	Lead	93	µg/L
	Lithium	40.8	mg/L
	Magnesium	1240	mg/L
	Manganese	3230	µg/L
	Mercury	< 0.3	µg/L
	Molybdenum	< 25	µg/L
	Nickel	< 40	µg/L
	Phosphorus	< 10	mg/L
	Potassium	1790	mg/L
	Selenium	< 5	µg/L
	Silicon	< 10	mg/L
	Silver	< 5	µg/L
	Sodium	90300	mg/L
	Strontium	247	mg/L
	Sulfate	510	mg/L
	Thallium	52	µg/L
	Thorium	< 10	µg/L
	Total Dissolved Solids	257000	mg/L
	Total Inorganic Carbon	10	mg/L
	Total Organic Carbon	1060	mg/L
	Uranium	< 5	µg/L
	Vanadium	< 20	µg/L
	Zinc	0.887	mg/L

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Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result
54655-05	**Deadwood 6/13/20 (Total Metals)**	
	Aluminum	< 1000 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	3150 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	50.3 mg/L
	Cadmium	< 2 µg/L
	Calcium	8060 mg/L
	Chromium	< 40 µg/L
	Cobalt	< 20 µg/L
	Copper	< 200 µg/L
	Iron	22.5 mg/L
	Lead	92 µg/L
	Lithium	40.8 mg/L
	Magnesium	1200 mg/L
	Manganese	3140 µg/L
	Mercury	< 0.3 µg/L
	Molybdenum	< 25 µg/L
	Nickel	< 40 µg/L
	Phosphorus	< 10 mg/L
	Potassium	1740 mg/L
	Selenium	< 5 µg/L
	Silicon	< 10 mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ________________________ Date __________

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Sample	Parameter	Result
54655-05	**Deadwood 6/13/20 (Total Metals)**	
	Silver	< 5 µg/L
	Sodium	88500 mg/L
	Strontium	243 mg/L
	Thallium	51 µg/L
	Thorium	< 10 µg/L
	Uranium	< 5 µg/L
	Vanadium	< 20 µg/L
	Zinc	0.946 mg/L
54655-06	**Deadwood 6/13/20 duplicate (Total Metals)**	
	Aluminum	< 1000 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	3200 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	49.2 mg/L
	Cadmium	< 2 µg/L
	Calcium	8210 mg/L
	Chromium	< 40 µg/L
	Cobalt	< 20 µg/L
	Copper	< 200 µg/L
	Iron	22.8 mg/L
	Lead	96 µg/L
	Lithium	41.8 mg/L
	Magnesium	1210 mg/L
	Manganese	3120 µg/L
	Mercury	< 0.3 µg/L
	Molybdenum	< 25 µg/L
	Nickel	< 40 µg/L
	Phosphorus	< 10 mg/L
	Potassium	1770 mg/L
	Selenium	< 5 µg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ____________________ Date __________

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Contact Person: Lonny Jacobson

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Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result
54655-06	**Deadwood 6/13/20 duplicate (Total Metals)**	
	Silicon	< 10 mg/L
	Silver	< 5 µg/L
	Sodium	88700 mg/L
	Strontium	241 mg/L
	Thallium	52 µg/L
	Thorium	< 10 µg/L
	Uranium	< 5 µg/L
	Vanadium	< 20 µg/L
	Zinc	1.15 mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ____________________ Date __________

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MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1767
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:00
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Deadwood

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	15 Jun 20	JD
pH	* 6.0	units	N/A	SM4500 H+ B	15 Jun 20 17:00	HT
Conductivity (EC)	201590	umhos/cm	N/A	SM2510-B	15 Jun 20 17:00	HT
pH - Field	5.46	units	NA	SM 4500 H+ B	13 Jun 20 10:00	JSM
Temperature - Field	21.2	Degrees C	NA	SM 2550B	13 Jun 20 10:00	JSM
Total Alkalinity	72	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Bicarbonate	72	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Conductivity - Field	216320	umhos/cm	1	EPA 120.1	13 Jun 20 10:00	JSM
Total Organic Carbon	14.0	mg/l	0.5	SM5310-C	23 Jun 20 17:34	NAS
Sulfate	491	mg/l	5.00	ASTM D516-11	17 Jun 20 11:38	EV
Chloride	17500	mg/l	1.0	SM4500-Cl-E	17 Jun 20 9:50	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	18 Jun 20 8:37	EV
Ammonia-Nitrogen as N	60.4	mg/l	0.20	EPA 350.1	16 Jun 20 11:40	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Jun 20 12:37	MDE
Total Dissolved Solids	256000	mg/l	10	I1750-85	17 Jun 20 15:53	HT
Calcium - Total	8610	mg/l	1.0	6010D	16 Jun 20 13:25	MDE
Magnesium - Total	1210	mg/l	1.0	6010D	16 Jun 20 13:25	MDE
Sodium - Total	87000	mg/l	1.0	6010D	16 Jun 20 13:25	MDE
Potassium - Total	2020	mg/l	1.0	6010D	16 Jun 20 13:25	MDE
Iron - Total	22.2	mg/l	0.10	6010D	24 Jun 20 11:07	MDE
Manganese - Total	2.85	mg/l	0.05	6010D	24 Jun 20 11:07	MDE
Barium - Dissolved	< 5 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ

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

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MEMBER
ACIL

Report Date: 30 Jun 20
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Date Sampled: 13 Jun 20 10:00
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Deadwood

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 2.5 @	mg/l	0.05	6010D	23 Jun 20 12:02	SZ
Molybdenum - Dissolved	< 5 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Strontium - Dissolved	246	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Cadmium - Dissolved	0.0247	mg/l	0.0005	6020B	16 Jun 20 12:21	MDE
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Lead - Dissolved	0.0836	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE
Selenium - Dissolved	< 0.1 @	mg/l	0.0050	6020B	15 Jun 20 16:05	MDE
Silver - Dissolved	< 0.02 @	mg/l	0.0005	6020B	16 Jun 20 12:21	MDE

* 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:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX C

NEAR-SURFACE MONITORING PARAMETERS AND BASELINE DATA

C1. Near-Surface Monitoring: Groundwater and Soil Gas

Near-surface sampling discussed herein comprises 1) sampling of shallow groundwater aquifers (underground sources of drinking water [USDW]) 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.

C1-1. Groundwater Analysis Protocol

Baseline Groundwater Wells

Two laboratories will be used to analyze the water samples: 1) Minnesota Valley Testing Laboratories, Inc. (MVTL) for general parameters, anions, cations, metals (dissolved and total), and nonmetals (Tables C-1 and C-2) and 2) Isotech Laboratories, Inc., for isotopic signatures (Table C-3).

Table C-1. 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 C-2 for entire sampling list of total and dissolved metals.

Table C-2. Total and Dissolved Metals and Cation Measurements for Groundwater Samples

Major Cations	Minor and Trace Metals		
Calcium	Aluminum	Copper	Selenium
Magnesium	Antimony	Iron	Silicon
Potassium	Arsenic	Lead	Silver
Sodium	Barium	Lithium	Strontium
	Beryllium	Manganese	Thallium
	Bismuth	Mercury	Thorium
	Boron	Molybdenum	Uranium
	Cadmium	Nickel	Vanadium
	Chromium	Phosphorus	Zinc
	Cobalt		

Table C-3. Isotope Measurements for Groundwater Samples

Isotope	Units
$\delta^{2}H$ H_2O	‰[a]
$\delta^{18}O$ H_2O	‰
Tritium	TU[b]
$\delta^{13}C$ DIC	‰
^{14}C DIC	pMC[c]

[a] One tenth of a percent (0.1%).
[b] Tritium unit.
[c] Percent modern carbon.

C1-2. Soil Gas-Sampling and Analysis Protocol

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.

Soil Gas Profile Station Locations

Fixed soil gas profile stations will be installed for the sampling of soil gas adjacent to the well pads at the injection and monitoring wellsites J-ROC1 and MLR-1 prior to the initiation of CO_2 injection. A schematic of these soil gas profile stations is shown in Figure C-1. Each soil gas profile station contains three isolated gas-sampling screens 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 are as follows: sampling will not proceed until the screens have been purged and the composition of the soil gas has been determined to be stable. Following industry standards for landfill gas analysis, an on-site analysis of the soil gas will be conducted (RAE handheld meter) and a laboratory sample collected for the parameters identified in Table C-4. In addition, a sample will be collected and sent to Isotech Laboratories, Inc. (Champaign, Illinois) for isotopic analyses (see Table C-5).

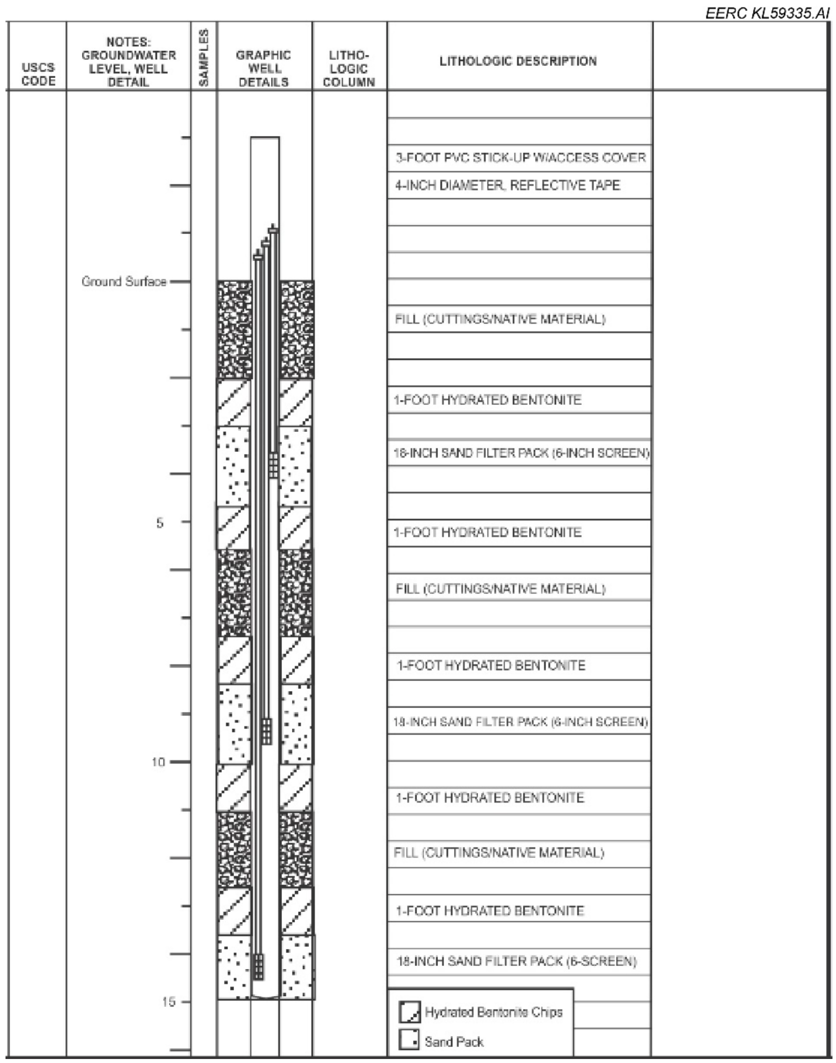

Figure C-1. Schematic of soil gas profile stations near the well pads for J-ROC1 and MLR-1.

Table C-4. 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 C-5. 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

C2. Near-Surface Water Well Verification

The North Dakota State Water Commission (NDSWC) drilling records provided the starting point for selecting baseline characterization and monitoring wells. Nearly 600 drilling records were included in the project area. Key well characteristics for further investigations were 1) potential as a drinking water source (i.e., labeled domestic, domestic/stock, and municipal) and 2) aquifer. Based on the database drilling records, most of the wells in the area draw from the Tongue River aquifer. As a result, wells labeled for purposes other than drinking water (e.g., stock, industrial, unknown) were included in the initial selection for the Fox Hills and Upper Hell Creek and Cannonball and Ludlow aquifers. The 42 well records fitting these criteria underwent review to verify their status (e.g., do they still exist? can they be sampled?). The verification process is ongoing. It is anticipated that up to 19 viable wells may be selected to characterize the baseline groundwater quality of the USDWs in the project area.

C3. Laboratory Analyses of Baseline Data
Existing monitoring well data have been compiled as one element of the baseline characterization effort. These data represent long-term regulatory monitoring associated with the BNI coal mine and MRYS power plant operations. Additionally, baseline sampling has begun in an existing observation well in the deepest USDW for in the USGS-managed Fox Hills observation well (NDSWC Well No. 3558) east of Center, North Dakota. The first of four anticipated baseline sampling events occurred on January 12, 2021.

Attached to this appendix are laboratory results from these three sources. They include the following:

1. 3 years of analyses from annual sampling of six mine land wells monitored by BNI

2. 3 years of analyses from five ash disposal pond wells monitored by MRYS.

3. Laboratory results from one sample of Fox Hills observation well 2558.

APPENDIX C-1

BNI COAL MONITORING WELL ANALYSES FOR BASELINE DATA

MINNESOTA VALLEY TESTING LABORATORIES, INC.
1126 North Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
2 North German 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

Report Date: 8 Aug 18
Lab Number: 18-W2083
Work Order #: 82-1752
Account #: 003022
Date Sampled: 17 Jul 18 12:47
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 322A
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 3.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 6.4	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	801	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	6.19	units	NA	SM 4500 H+ B	17 Jul 18 12:47	DJN
Temperature - Field	11.2	Degrees C	NA	SM 2550B	17 Jul 18 12:47	DJN
Total Alkalinity	118	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Bicarbonate	118	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Conductivity - Field	870	umhos/cm	1	EPA 120.1	17 Jul 18 12:47	DJN
Tot Dis Solids(Summation)	525	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	144	mg/l HCO3	NA	SM2320-B	19 Jul 18 17:00	Calculated
Total Hardness as CaCO3	415	mg/l	NA	SM2340-B	30 Jul 18 12:35	Calculated
Cation Summation	9.84	meq/L	NA	SM1030-F	30 Jul 18 12:35	Calculated
Anion Summation	8.25	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	8.79	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	0.70		NA	USDA 20b	30 Jul 18 12:35	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	277	mg/l	5.00	ASTM D516-07	20 Jul 18 14:32	EMS
Chloride	3.6	mg/l	1.0	SM4500-Cl-E	26 Jul 18 12:11	EV
Nitrate-Nitrite as N	0.25	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	96.2	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Magnesium - Total	42.4	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Sodium - Total	32.8	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Potassium - Total	2.1	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Iron - Dissolved	1.55	mg/l	0.10	6010D	27 Jul 18 11:25	BT
Manganese - Dissolved	0.28	mg/l	0.05	6010D	27 Jul 18 11:25	BT

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

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: 27 Aug 19
Lab Number: 19-W2683
Work Order #: 82-1966
Account #: 003022
Date Sampled: 29 Jul 19 14:40
Date Received: 30 Jul 19 15:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 322A

Temp at Receipt: 0.7C

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 6.6	units	N/A	SM4500 H+ B	31 Jul 19 18:00	SVS
Conductivity (EC)	980	umhos/cm	N/A	SM2510-B	31 Jul 19 18:00	SVS
pH - Field	6.21	units	NA	SM 4500 H+ B	29 Jul 19 14:40	JSM
Temperature - Field	14.4	Degrees C	NA	SM 2550B	29 Jul 19 14:40	JSM
Total Alkalinity	124	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Bicarbonate	124	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Conductivity - Field	1193	umhos/cm	1	EPA 120.1	29 Jul 19 14:40	JSM
Tot Dis Solids(Summation)	726	mg/l	12.5	SM1030-F	22 Aug 19 8:28	Calculated
Bicarb as HCO3	151	mg/l HCO3	NA	SM2320-B	31 Jul 19 18:00	Calculated
Total Hardness as CaCO3	561	mg/l	NA	SM2340-B	14 Aug 19 10:17	Calculated
Cation Summation	13.0	meq/L	NA	SM1030-F	16 Aug 19 18:14	Calculated
Anion Summation	11.3	meq/L	NA	SM1030-F	22 Aug 19 8:28	Calculated
Percent Error	6.94	%	NA	SM1030-F	22 Aug 19 8:28	Calculated
Sodium Adsorption Ratio	0.72		NA	USDA 20b	14 Aug 19 10:17	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	31 Jul 19 18:00	SVS
Sulfate	419	mg/l	5.00	ASTM D516-07	22 Aug 19 8:28	EV
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	31 Jul 19 10:28	EV
Nitrate-Nitrite as N	0.17	mg/l	0.10	EPA 353.2	31 Jul 19 14:48	EMS
Calcium - Total	130	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Magnesium - Total	57.4	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Sodium - Total	39.2	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Potassium - Total	2.0	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Iron - Dissolved	1.16	mg/l	0.10	6010D	16 Aug 19 18:14	SZ
Manganese - Dissolved	0.23	mg/l	0.05	6010D	16 Aug 19 18:14	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll 28 Aug 19 cc

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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The reporting limit was elevated for any analyte requiring a dilution as coded below:
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+ = Due to internal standard response

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MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2663
Work Order #: 82-2008
Account #: 003022
Date Sampled: 27 Jul 20 12:50
Date Received: 27 Jul 20 16:49
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: 322A
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 4.3C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 6.6	units	N/A	SM4500 H+ B	28 Jul 20 17:00	HT
Conductivity (EC)	832	umhos/cm	N/A	SM2510-B	28 Jul 20 17:00	HT
pH - Field	6.14	units	NA	SM 4500 H+ B	27 Jul 20 12:50	DJN
Temperature - Field	10.0	Degrees C	NA	SM 2550B	27 Jul 20 12:50	DJN
Total Alkalinity	165	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Bicarbonate	165	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Conductivity - Field	863	umhos/cm	1	EPA 120.1	27 Jul 20 12:50	DJN
Tot Dis Solids(Summation)	532	mg/l	12.5	SM1030-F	30 Jul 20 11:00	Calculated
Bicarb as HCO3	201	mg/l HCO3	NA	SM2320-B	28 Jul 20 17:00	Calculated
Total Hardness as CaCO3	423	mg/l	NA	SM2340-B	29 Jul 20 11:25	Calculated
Cation Summation	9.96	meq/L	NA	SM1030-F	3 Aug 20 13:38	Calculated
Anion Summation	8.68	meq/L	NA	SM1030-F	30 Jul 20 11:00	Calculated
Percent Error	6.87	%	NA	SM1030-F	3 Aug 20 13:38	Calculated
Sodium Adsorption Ratio	0.69		NA	USDA 20b	29 Jul 20 11:25	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	28 Jul 20 17:00	HT
Sulfate	253	mg/l	5.00	ASTM D516-11	29 Jul 20 12:30	EV
Chloride	3.5	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	0.13	mg/l	0.10	EPA 353.2	30 Jul 20 11:00	EV
Calcium - Total	99.3	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Magnesium - Total	42.6	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Sodium - Total	32.4	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Potassium - Total	1.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Iron - Dissolved	0.88	mg/l	0.10	6010D	3 Aug 20 13:38	MDE
Manganese - Dissolved	0.14	mg/l	0.05	6010D	3 Aug 20 13:38	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 4 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 8 Aug 18
Lab Number: 18-W2170
Work Order #: 82-1784
Account #: 003022
Date Sampled: 19 Jul 18 9:16
Date Received: 19 Jul 18 15:08
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 324

Temp at Receipt: 7.2C ROI

Event and Year: 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 7.8	units	N/A	SM4500 H+ B	23 Jul 18 17:00	SVS
Conductivity (EC)	649	umhos/cm	N/A	SM2510-B	23 Jul 18 17:00	SVS
pH - Field	7.47	units	NA	SM 4500 H+ B	19 Jul 18 9:16	DJN
Temperature - Field	9.28	Degrees C	NA	SM 2550B	19 Jul 18 9:16	DJN
Total Alkalinity	188	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Bicarbonate	188	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	23 Jul 18 17:00	SVS
Conductivity - Field	632	umhos/cm	1	EPA 120.1	19 Jul 18 9:16	DJN
Tot Dis Solids(Summation)	360	mg/l	12.5	SM1030-F	7 Aug 18 16:30	Calculated
Bicarb as HCO3	229	mg/l HCO3	NA	SM2320-B	23 Jul 18 17:00	Calculated
Total Hardness as CaCO3	92.1	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	6.53	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	6.09	meq/L	NA	SM1030-F	7 Aug 18 16:30	Calculated
Percent Error	3.47	%	NA	SM1030-F	7 Aug 18 16:30	Calculated
Sodium Adsorption Ratio	4.81		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	0.20	mg/l	0.10	SM4500-F-C	23 Jul 18 17:00	SVS
Sulfate	103	mg/l	5.00	ASTM D516-07	20 Jul 18 16:05	EMS
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	1.06	mg/l	0.10	EPA 353.2	7 Aug 18 16:30	EMS
Calcium - Total	20.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	10.0	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	106	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	3.1	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Jul 18 11:55	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Jul 18 11:55	SZ

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 19 Aug 19
Lab Number: 19-W2667
Work Order #: 82-1950
Account #: 003022
Date Sampled: 29 Jul 19 16:35
Date Received: 30 Jul 19 8:00
Sampled By: MVTL Field Services

Temp at Receipt: 6.8C ROI

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 324

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 7.8	units	N/A	SM4500 H+ B	30 Jul 19 17:00	SVS
Conductivity (EC)	1193	umhos/cm	N/A	SM2510-B	30 Jul 19 17:00	SVS
pH - Field	7.31	units	NA	SM 4500 H+ B	29 Jul 19 16:35	DJN
Temperature - Field	9.36	Degrees C	NA	SM 2550B	29 Jul 19 16:35	DJN
Total Alkalinity	345	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Bicarbonate	345	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Conductivity - Field	1224	umhos/cm	1	EPA 120.1	29 Jul 19 16:35	DJN
Tot Dis Solids(Summation)	817	mg/l	12.5	SM1030-F	8 Aug 19 15:19	Calculated
Bicarb as HCO3	421	mg/l HCO3	NA	SM2320-B	30 Jul 19 17:00	Calculated
Total Hardness as CaCO3	212	mg/l	NA	SM2340-B	8 Aug 19 15:19	Calculated
Cation Summation	14.0	meq/L	NA	SM1030-F	16 Aug 19 17:14	Calculated
Anion Summation	13.4	meq/L	NA	SM1030-F	2 Aug 19 14:11	Calculated
Percent Error	2.12	%	NA	SM1030-F	16 Aug 19 17:14	Calculated
Sodium Adsorption Ratio	6.63		NA	USDA 20b	8 Aug 19 15:19	Calculated
Fluoride	0.29	mg/l	0.10	SM4500-F-C	31 Jul 19 17:00	SVS
Sulfate	309	mg/l	5.00	ASTM D516-07	2 Aug 19 14:11	EMS
Chloride	3.8	mg/l	1.0	SM4500-Cl-E	31 Jul 19 9:52	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 Jul 19 14:03	EMS
Calcium - Total	47.0	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Magnesium - Total	23.0	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Sodium - Total	222	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Potassium - Total	4.8	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Iron - Dissolved	0.17	mg/l	0.10	6010D	16 Aug 19 17:14	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	16 Aug 19 17:14	SZ

* Holding time exceeded

CC

Approved by: Claudette K Carroll 20 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 7 Aug 20
Lab Number: 20-W2552
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 11:51
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 324

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 7.8	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	1182	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	7.54	units	NA	SM 4500 H+ B	21 Jul 20 11:51	DJN
Temperature - Field	9.58	Degrees C	NA	SM 2550B	21 Jul 20 11:51	DJN
Total Alkalinity	369	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	369	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	1174	umhos/cm	1	EPA 120.1	21 Jul 20 11:51	DJN
Tot Dis Solids(Summation)	745	mg/l	12.5	SM1030-F	5 Aug 20 8:19	Calculated
Bicarb as HCO3	450	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	173	mg/l	NA	SM2340-B	31 Jul 20 9:21	Calculated
Cation Summation	12.4	meq/L	NA	SM1030-F	31 Jul 20 9:21	Calculated
Anion Summation	12.8	meq/L	NA	SM1030-F	5 Aug 20 8:19	Calculated
Percent Error	-1.82	%	NA	SM1030-F	5 Aug 20 8:19	Calculated
Sodium Adsorption Ratio	6.68		NA	USDA 20b	31 Jul 20 9:21	Calculated
Fluoride	0.29	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	256	mg/l	5.00	ASTM D516-11	5 Aug 20 8:19	EV
Chloride	4.0	mg/l	1.0	SM4500-Cl-E	28 Jul 20 15:16	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:53	EMS
Calcium - Total	37.7	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Magnesium - Total	19.2	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Sodium - Total	202	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Potassium - Total	4.3	mg/l	1.0	6010D	31 Jul 20 9:21	MDE
Iron - Dissolved	0.16	mg/l	0.10	6010D	27 Jul 20 11:42	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	27 Jul 20 11:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 8 Aug 18
Lab Number: 18-W2086
Work Order #: 82-1752
Account #: 003022
Date Sampled: 17 Jul 18 12:22
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: 363
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 3.1C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 8.3	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	2446	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	7.94	units	NA	SM 4500 H+ B	17 Jul 18 12:22	DJN
Temperature - Field	14.8	Degrees C	NA	SM 2550B	17 Jul 18 12:22	DJN
Total Alkalinity	1090	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Bicarbonate	1090	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	18 Jul 18 17:00	SVS
Conductivity - Field	2395	umhos/cm	1	EPA 120.1	17 Jul 18 12:22	DJN
Tot Dis Solids(Summation)	1440	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	1330	mg/l HCO3	NA	SM2320-B	18 Jul 18 17:00	Calculated
Total Hardness as CaCO3	37.6	mg/l	NA	SM2340-B	30 Jul 18 12:35	Calculated
Cation Summation	26.7	meq/L	NA	SM1030-F	30 Jul 18 12:35	Calculated
Anion Summation	25.4	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	2.56	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	42.1		NA	USDA 20b	30 Jul 18 12:35	Calculated
Fluoride	0.84	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	164	mg/l	5.00	ASTM D516-07	20 Jul 18 14:32	EMS
Chloride	5.5	mg/l	1.0	SM4500-Cl-E	26 Jul 18 12:11	EV
Nitrate-Nitrite as N	0.26	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	7.8	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Magnesium - Total	4.4	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Sodium - Total	593	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Potassium - Total	6.9	mg/l	1.0	6010D	30 Jul 18 12:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	27 Jul 18 11:25	BT
Manganese - Dissolved	0.07	mg/l	0.05	6010D	27 Jul 18 11:25	BT

* Holding time exceeded

CC

Approved by: Claudette K Carroll 8 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2687
Work Order #: 82-1966
Account #: 003022
Date Sampled: 29 Jul 19 13:45
Date Received: 30 Jul 19 15:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: 363

Temp at Receipt: 0.7C

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 8.3	units	N/A	SM4500 H+ B	31 Jul 19 18:00	SVS
Conductivity (EC)	2460	umhos/cm	N/A	SM2510-B	31 Jul 19 18:00	SVS
pH - Field	7.97	units	NA	SM 4500 H+ B	29 Jul 19 13:45	JSM
Temperature - Field	13.4	Degrees C	NA	SM 2550B	29 Jul 19 13:45	JSM
Total Alkalinity	1110	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Bicarbonate	1093	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	31 Jul 19 18:00	SVS
Conductivity - Field	2426	umhos/cm	1	EPA 120.1	29 Jul 19 13:45	JSM
Tot Dis Solids(Summation)	1500	mg/l	12.5	SM1030-F	14 Aug 19 10:17	Calculated
Bicarb as HCO3	1330	mg/l HCO3	NA	SM2320-B	31 Jul 19 18:00	Calculated
Total Hardness as CaCO3	36.8	mg/l	NA	SM2340-B	14 Aug 19 10:17	Calculated
Cation Summation	28.5	meq/L	NA	SM1030-F	16 Aug 19 18:14	Calculated
Anion Summation	26.1	meq/L	NA	SM1030-F	2 Aug 19 14:31	Calculated
Percent Error	4.37	%	NA	SM1030-F	16 Aug 19 18:14	Calculated
Sodium Adsorption Ratio	45.5		NA	USDA 20b	14 Aug 19 10:17	Calculated
Fluoride	0.99	mg/l	0.10	SM4500-F-C	31 Jul 19 18:00	SVS
Sulfate	176	mg/l	5.00	ASTM D516-07	2 Aug 19 14:31	EMS
Chloride	5.9	mg/l	1.0	SM4500-Cl-E	31 Jul 19 10:28	EV
Nitrate-Nitrite as N	0.54	mg/l	0.10	EPA 353.2	31 Jul 19 14:48	EMS
Calcium - Total	7.8	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Magnesium - Total	4.2	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Sodium - Total	634	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Potassium - Total	5.0	mg/l	1.0	6010D	14 Aug 19 10:17	SZ
Iron - Dissolved	0.30	mg/l	0.10	6010D	16 Aug 19 18:14	SZ
Manganese - Dissolved	0.07	mg/l	0.05	6010D	16 Aug 19 18:14	SZ

* Holding time exceeded

CC
Approved by: Claudette K Carroll 28 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2657
Work Order #: 82-2008
Account #: 003022
Date Sampled: 27 Jul 20 13:43
Date Received: 27 Jul 20 16:49
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: 363
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 4.3C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 8.2	units	N/A	SM4500 H+ B	28 Jul 20 17:00	HT
Conductivity (EC)	2454	umhos/cm	N/A	SM2510-B	28 Jul 20 17:00	HT
pH - Field	7.94	units	NA	SM 4500 H+ B	27 Jul 20 13:43	DJN
Temperature - Field	11.0	Degrees C	NA	SM 2550B	27 Jul 20 13:43	DJN
Total Alkalinity	1200	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Bicarbonate	1200	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 17:00	HT
Conductivity - Field	2508	umhos/cm	1	EPA 120.1	27 Jul 20 13:43	DJN
Tot Dis Solids(Summation)	1550	mg/l	12.5	SM1030-F	30 Jul 20 10:43	Calculated
Bicarb as HCO3	1460	mg/l HCO3	NA	SM2320-B	28 Jul 20 17:00	Calculated
Total Hardness as CaCO3	53.6	mg/l	NA	SM2340-B	29 Jul 20 10:25	Calculated
Cation Summation	27.2	meq/L	NA	SM1030-F	3 Aug 20 12:38	Calculated
Anion Summation	28.4	meq/L	NA	SM1030-F	30 Jul 20 10:43	Calculated
Percent Error	-2.16	%	NA	SM1030-F	3 Aug 20 12:38	Calculated
Sodium Adsorption Ratio	35.4		NA	USDA 20b	29 Jul 20 10:25	Calculated
Fluoride	0.90	mg/l	0.10	SM4500-F-C	28 Jul 20 17:00	HT
Sulfate	195	mg/l	5.00	ASTM D516-11	29 Jul 20 12:30	EV
Chloride	12.1	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Jul 20 10:43	EV
Calcium - Total	10.6	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Magnesium - Total	6.6	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Sodium - Total	596	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Potassium - Total	6.8	mg/l	1.0	6010D	29 Jul 20 10:25	MDE
Iron - Dissolved	0.82	mg/l	0.10	6010D	3 Aug 20 12:38	MDE
Manganese - Dissolved	0.08	mg/l	0.05	6010D	3 Aug 20 12:38	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 4 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 2 Aug 18
Lab Number: 18-W2077
Work Order #: 82-1751
Account #: 003022
Date Sampled: 17 Jul 18 10:58
Date Received: 18 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: C1-1
Sample Site: Annual Groundwater Sampling
Event and Year: 2018

Temp at Receipt: 1.7C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	18 Jul 18	SVS
pH	* 8.4	units	N/A	SM4500 H+ B	18 Jul 18 17:00	SVS
Conductivity (EC)	1151	umhos/cm	N/A	SM2510-B	18 Jul 18 17:00	SVS
pH - Field	8.36	units	NA	SM 4500 H+ B	17 Jul 18 10:58	DJN
Temperature - Field	11.3	Degrees C	NA	SM 2550B	17 Jul 18 10:58	DJN
Total Alkalinity	454	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Bicarbonate	441	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 17:00	SVS
Conductivity - Field	1164	umhos/cm	1	EPA 120.1	17 Jul 18 10:58	DJN
Tot Dis Solids(Summation)	706	mg/l	12.5	SM1030-F	2 Aug 18 13:22	Calculated
Bicarb as HCO3	538	mg/l HCO3	NA	SM2320-B	19 Jul 18 17:00	Calculated
Total Hardness as CaCO3	25.3	mg/l	NA	SM2340-B	30 Jul 18 11:35	Calculated
Cation Summation	13.0	meq/L	NA	SM1030-F	30 Jul 18 11:35	Calculated
Anion Summation	11.9	meq/L	NA	SM1030-F	2 Aug 18 13:22	Calculated
Percent Error	4.13	%	NA	SM1030-F	2 Aug 18 13:22	Calculated
Sodium Adsorption Ratio	24.6		NA	USDA 20b	30 Jul 18 11:35	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	18 Jul 18 17:00	SVS
Sulfate	132	mg/l	5.00	ASTM D516-07	20 Jul 18 14:12	EMS
Chloride	4.3	mg/l	1.0	SM4500-Cl-E	18 Jul 18 12:12	EMS
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	2 Aug 18 13:22	EV
Calcium - Total	5.5	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Magnesium - Total	2.8	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Sodium - Total	284	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Potassium - Total	4.7	mg/l	1.0	6010D	30 Jul 18 11:35	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	27 Jul 18 10:25	BT
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	27 Jul 18 10:25	BT

* Holding time exceeded

Approved by: Claudette K. Carroll cc 7 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 19 Aug 19
Lab Number: 19-W2664
Work Order #: 82-1950
Account #: 003022
Date Sampled: 29 Jul 19 9:40
Date Received: 30 Jul 19 8:00
Sampled By: MVTL Field Services

Temp at Receipt: 6.8C ROI

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: C1-1

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 Jul 19	MDE
pH	* 8.4	units	N/A	SM4500 H+ B	30 Jul 19 17:00	SVS
Conductivity (EC)	1123	umhos/cm	N/A	SM2510-B	30 Jul 19 17:00	SVS
pH - Field	8.52	units	NA	SM 4500 H+ B	29 Jul 19 9:40	DJN
Temperature - Field	10.4	Degrees C	NA	SM 2550B	29 Jul 19 9:40	DJN
Total Alkalinity	480	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Bicarbonate	463	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 Jul 19 17:00	SVS
Conductivity - Field	1152	umhos/cm	1	EPA 120.1	29 Jul 19 9:40	DJN
Tot Dis Solids(Summation)	699	mg/l	12.5	SM1030-F	8 Aug 19 15:19	Calculated
Bicarb as HCO3	565	mg/l HCO3	NA	SM2320-B	30 Jul 19 17:00	Calculated
Total Hardness as CaCO3	21.3	mg/l	NA	SM2340-B	8 Aug 19 15:19	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	16 Aug 19 15:14	Calculated
Anion Summation	12.2	meq/L	NA	SM1030-F	2 Aug 19 13:49	Calculated
Percent Error	1.04	%	NA	SM1030-F	16 Aug 19 15:14	Calculated
Sodium Adsorption Ratio	25.9		NA	USDA 20b	8 Aug 19 15:19	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	31 Jul 19 17:00	SVS
Sulfate	124	mg/l	5.00	ASTM D516-07	2 Aug 19 13:49	EMS
Chloride	1.7	mg/l	1.0	SM4500-Cl-E	31 Jul 19 9:52	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 Jul 19 14:03	EMS
Calcium - Total	4.9	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Magnesium - Total	2.2	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Sodium - Total	275	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Potassium - Total	3.6	mg/l	1.0	6010D	8 Aug 19 15:19	SZ
Iron - Dissolved	0.18	mg/l	0.10	6010D	16 Aug 19 15:14	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	16 Aug 19 15:14	SZ

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 20 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 4 Aug 20
Lab Number: 20-W2669
Work Order #: 82-2018
Account #: 003022
Date Sampled: 28 Jul 20 10:08
Date Received: 28 Jul 20 14:25
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal - Center
Sample Description: C1-1
Sample Site: Annual Groundwater Sampling
Event and Year: 2020

Temp at Receipt: 2.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	28 Jul 20	HT
pH	* 8.4	units	N/A	SM4500 H+ B	28 Jul 20 18:00	HT
Conductivity (EC)	1168	umhos/cm	N/A	SM2510-B	28 Jul 20 18:00	HT
pH - Field	8.31	units	NA	SM 4500 H+ B	28 Jul 20 10:08	DJN
Temperature - Field	11.6	Degrees F	1	SM 2550B	28 Jul 20 10:08	DJN
Total Alkalinity	526	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Bicarbonate	522	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	28 Jul 20 18:00	HT
Conductivity - Field	1143	umhos/cm	1	EPA 120.1	28 Jul 20 10:08	DJN
Tot Dis Solids(Summation)	698	mg/l	12.5	SM1030-F	30 Jul 20 11:00	Calculated
Bicarb as HCO3	637	mg/l HCO3	NA	SM2320-B	28 Jul 20 18:00	Calculated
Total Hardness as CaCO3	26.7	mg/l	NA	SM2340-B	29 Jul 20 11:25	Calculated
Cation Summation	12.3	meq/L	NA	SM1030-F	3 Aug 20 13:38	Calculated
Anion Summation	12.7	meq/L	NA	SM1030-F	30 Jul 20 11:00	Calculated
Percent Error	-1.45	%	NA	SM1030-F	3 Aug 20 13:38	Calculated
Sodium Adsorption Ratio	22.5		NA	USDA 20b	29 Jul 20 11:25	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	28 Jul 20 18:00	HT
Sulfate	99.7	mg/l	5.00	ASTM D516-11	29 Jul 20 13:56	EV
Chloride	2.6	mg/l	1.0	SM4500-Cl-E	29 Jul 20 9:46	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Jul 20 11:00	EV
Calcium - Total	5.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Magnesium - Total	2.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Sodium - Total	267	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Potassium - Total	3.9	mg/l	1.0	6010D	29 Jul 20 11:25	MDE
Iron - Dissolved	1.71	mg/l	0.10	6010D	3 Aug 20 13:38	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	3 Aug 20 13:38	MDE

* Holding time exceeded

CC
4 Aug 2020

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 10 Aug 18
Lab Number: 18-W2160
Work Order #: 82-1776
Account #: 003022
Date Sampled: 18 Jul 18 10:00
Date Received: 19 Jul 18 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Project Name: BNI Coal-Center
Sample Description: C7-1

Temp at Receipt: 4.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 8.5	units	N/A	SM4500 H+ B	19 Jul 18 18:00	SVS
Conductivity (EC)	2105	umhos/cm	N/A	SM2510-B	19 Jul 18 18:00	SVS
pH - Field	8.02	units	NA	SM 4500 H+ B	18 Jul 18 10:00	DJN
Temperature - Field	11.5	Degrees C	NA	SM 2550B	18 Jul 18 10:00	DJN
Total Alkalinity	985	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Bicarbonate	957	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Carbonate	28	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Conductivity - Field	2091	umhos/cm	1	EPA 120.1	18 Jul 18 10:00	DJN
Tot Dis Solids(Summation)	1410	mg/l	12.5	SM1030-F	7 Aug 18 16:11	Calculated
Bicarb as HCO3	1170	mg/l HCO3	NA	SM2320-B	19 Jul 18 18:00	Calculated
Total Hardness as CaCO3	58.5	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	25.0	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	25.1	meq/L	NA	SM1030-F	7 Aug 18 16:11	Calculated
Percent Error	-0.31	%	NA	SM1030-F	7 Aug 18 16:11	Calculated
Sodium Adsorption Ratio	30.7		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	1.07	mg/l	0.10	SM4500-F-C	19 Jul 18 18:00	SVS
Sulfate	234	mg/l	5.00	ASTM D516-07	20 Jul 18 15:44	EMS
Chloride	20.2	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	7 Aug 18 16:11	EMS
Calcium - Total	10.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	7.9	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	540	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	7.1	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	4.02	mg/l	0.10	6010D	30 Jul 18 10:55	SZ
Manganese - Dissolved	0.09	mg/l	0.05	6010D	30 Jul 18 10:55	SZ

* Holding time exceeded

Approved by: Claudette K Carroll CC 10 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2712
Work Order #: 82-1976
Account #: 003022
Date Sampled: 30 Jul 19 9:07
Date Received: 31 Jul 19 8:00
Sampled By: MVTL Field Services

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: C7-1

Temp at Receipt: 7.3C ROI

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	31 Jul 19	MDE
pH	* 8.4	units	N/A	SM4500 H+ B	1 Aug 19 17:00	SVS
Conductivity (EC)	2098	umhos/cm	N/A	SM2510-B	1 Aug 19 17:00	SVS
pH - Field	7.97	units	NA	SM 4500 H+ B	30 Jul 19 9:07	DJN
Temperature - Field	9.19	Degrees C	NA	SM 2550B	30 Jul 19 9:07	DJN
Total Alkalinity	1050	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Bicarbonate	1030	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Carbonate	20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Conductivity - Field	2084	umhos/cm	1	EPA 120.1	30 Jul 19 9:07	DJN
Tot Dis Solids(Summation)	1480	mg/l	12.5	SM1030-F	14 Aug 19 13:17	Calculated
Bicarb as HCO3	1260	mg/l HCO3	NA	SM2320-B	1 Aug 19 17:00	Calculated
Total Hardness as CaCO3	55.5	mg/l	NA	SM2340-B	14 Aug 19 13:17	Calculated
Cation Summation	25.3	meq/L	NA	SM1030-F	26 Aug 19 10:38	Calculated
Anion Summation	27.1	meq/L	NA	SM1030-F	2 Aug 19 15:11	Calculated
Percent Error	-3.33	%	NA	SM1030-F	26 Aug 19 10:38	Calculated
Sodium Adsorption Ratio	31.9		NA	USDA 20b	14 Aug 19 13:17	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	1 Aug 19 17:00	SVS
Sulfate	252	mg/l	5.00	ASTM D516-07	2 Aug 19 15:11	EMS
Chloride	28.8	mg/l	1.0	SM4500-Cl-E	31 Jul 19 11:15	EV
Nitrate-Nitrite as N	< 2 @	mg/l	0.10	EPA 353.2	31 Jul 19 15:56	EMS
Calcium - Total	9.7	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Magnesium - Total	7.6	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Sodium - Total	547	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Potassium - Total	5.3	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Iron - Dissolved	7.52	mg/l	0.10	6010D	26 Aug 19 10:38	SZ
Manganese - Dissolved	0.17	mg/l	0.05	6010D	26 Aug 19 10:38	SZ

* Holding time exceeded

Approved by: Claudette K. Carroll CC 28 Aug 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 7 Aug 20
Lab Number: 20-W2541
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 8:23
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Sample Description: C7-1

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 8.2	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	2096	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	8.20	units	NA	SM 4500 H+ B	21 Jul 20 8:23	DJN
Temperature - Field	10.9	Degrees C	NA	SM 2550B	21 Jul 20 8:23	DJN
Total Alkalinity	1120	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	1120	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	2239	umhos/cm	1	EPA 120.1	21 Jul 20 8:23	DJN
Tot Dis Solids(Summation)	1490	mg/l	12.5	SM1030-F	27 Jul 20 11:17	Calculated
Bicarb as HCO3	1370	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	54.5	mg/l	NA	SM2340-B	24 Jul 20 13:45	Calculated
Cation Summation	24.3	meq/L	NA	SM1030-F	27 Jul 20 10:42	Calculated
Anion Summation	28.3	meq/L	NA	SM1030-F	27 Jul 20 11:17	Calculated
Percent Error	-7.64	%	NA	SM1030-F	27 Jul 20 11:17	Calculated
Sodium Adsorption Ratio	30.6		NA	USDA 20b	24 Jul 20 13:45	Calculated
Fluoride	1.06	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	258	mg/l	5.00	ASTM D516-11	22 Jul 20 15:38	EMS
Chloride	19.0	mg/l	1.0	SM4500-Cl-E	27 Jul 20 11:17	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:33	EMS
Calcium - Total	9.8	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Magnesium - Total	7.3	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Sodium - Total	519	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Potassium - Total	5.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Iron - Dissolved	13.5	mg/l	0.10	6010D	27 Jul 20 10:42	MDE
Manganese - Dissolved	0.35	mg/l	0.05	6010D	27 Jul 20 10:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 10 Aug 18
Lab Number: 18-W2163
Work Order #: 82-1776
Account #: 003022
Date Sampled: 18 Jul 18 11:13
Date Received: 19 Jul 18 8:00
Sampled By: MVTL Field Services

Project Name: BNI Coal-Center
Sample Description: C9-1

Temp at Receipt: 4.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	19 Jul 18	SVS
pH	* 8.2	units	N/A	SM4500 H+ B	19 Jul 18 18:00	SVS
Conductivity (EC)	2029	umhos/cm	N/A	SM2510-B	19 Jul 18 18:00	SVS
pH - Field	8.06	units	NA	SM 4500 H+ B	18 Jul 18 11:13	DJN
Temperature - Field	14.1	Degrees C	NA	SM 2550B	18 Jul 18 11:13	DJN
Total Alkalinity	968	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Bicarbonate	968	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	19 Jul 18 18:00	SVS
Conductivity - Field	2028	umhos/cm	1	EPA 120.1	18 Jul 18 11:13	DJN
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	7 Aug 18 16:30	Calculated
Bicarb as HCO3	1180	mg/l HCO3	NA	SM2320-B	19 Jul 18 18:00	Calculated
Total Hardness as CaCO3	111	mg/l	NA	SM2340-B	30 Jul 18 14:35	Calculated
Cation Summation	24.3	meq/L	NA	SM1030-F	30 Jul 18 14:35	Calculated
Anion Summation	27.7	meq/L	NA	SM1030-F	7 Aug 18 16:30	Calculated
Percent Error	-6.42	%	NA	SM1030-F	7 Aug 18 16:30	Calculated
Sodium Adsorption Ratio	20.7		NA	USDA 20b	30 Jul 18 14:35	Calculated
Fluoride	1.11	mg/l	0.10	SM4500-F-C	19 Jul 18 18:00	SVS
Sulfate	364	mg/l	5.00	ASTM D516-07	20 Jul 18 15:44	EMS
Chloride	25.5	mg/l	1.0	SM4500-Cl-E	26 Jul 18 14:56	EV
Nitrate-Nitrite as N	0.42	mg/l	0.10	EPA 353.2	7 Aug 18 16:30	EMS
Calcium - Total	21.0	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Magnesium - Total	14.3	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Sodium - Total	503	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Potassium - Total	8.4	mg/l	1.0	6010D	30 Jul 18 14:35	BT
Iron - Dissolved	0.79	mg/l	0.10	6010D	30 Jul 18 10:55	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Jul 18 10:55	SZ

* Holding time exceeded

CC
Approved by: Claudette K Carroll 10 Aug 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 27 Aug 19
Lab Number: 19-W2715
Work Order #: 82-1976
Account #: 003022
Date Sampled: 30 Jul 19 9:55
Date Received: 31 Jul 19 8:00
Sampled By: MVTL Field Services

Temp at Receipt: 7.3C ROI

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Sample Description: C9-1

Event and Year: 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	31 Jul 19	MDE
pH	* 8.3	units	N/A	SM4500 H+ B	1 Aug 19 17:00	SVS
Conductivity (EC)	2032	umhos/cm	N/A	SM2510-B	1 Aug 19 17:00	SVS
pH - Field	7.75	units	NA	SM 4500 H+ B	30 Jul 19 9:55	DJN
Temperature - Field	11.3	Degrees C	NA	SM 2550B	30 Jul 19 9:55	DJN
Total Alkalinity	1030	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Bicarbonate	1014	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	1 Aug 19 17:00	SVS
Conductivity - Field	1991	umhos/cm	1	EPA 120.1	30 Jul 19 9:55	DJN
Tot Dis Solids(Summation)	1610	mg/l	12.5	SM1030-F	14 Aug 19 13:17	Calculated
Bicarb as HCO3	1240	mg/l HCO3	NA	SM2320-B	1 Aug 19 17:00	Calculated
Total Hardness as CaCO3	148	mg/l	NA	SM2340-B	14 Aug 19 13:17	Calculated
Cation Summation	27.3	meq/L	NA	SM1030-F	26 Aug 19 11:38	Calculated
Anion Summation	29.6	meq/L	NA	SM1030-F	2 Aug 19 15:38	Calculated
Percent Error	-4.11	%	NA	SM1030-F	26 Aug 19 11:38	Calculated
Sodium Adsorption Ratio	18.7		NA	USDA 20b	14 Aug 19 13:17	Calculated
Fluoride	1.19	mg/l	0.10	SM4500-F-C	1 Aug 19 17:00	SVS
Sulfate	350	mg/l	5.00	ASTM D516-07	2 Aug 19 15:38	EMS
Chloride	61.6	mg/l	1.0	SM4500-Cl-E	31 Jul 19 11:15	EV
Nitrate-Nitrite as N	< 10 @	mg/l	0.10	EPA 353.2	31 Jul 19 15:56	EMS
Calcium - Total	28.3	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Magnesium - Total	18.8	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Sodium - Total	523	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Potassium - Total	8.4	mg/l	1.0	6010D	14 Aug 19 13:17	SZ
Iron - Dissolved	37.3	mg/l	0.10	6010D	26 Aug 19 11:38	SZ
Manganese - Dissolved	0.77	mg/l	0.05	6010D	26 Aug 19 11:38	SZ

* Holding time exceeded

CC
28 Aug 19

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Derrick Placek
BNI Coal
2360 35th Ave SW
Center ND 58530

Report Date: 7 Aug 20
Lab Number: 20-W2543
Work Order #: 82-1952
Account #: 003022
Date Sampled: 21 Jul 20 8:59
Date Received: 22 Jul 20 8:00
Sampled By: MVTL Field Services

Sample Description: C9-1

Temp at Receipt: 5.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	22 Jul 20	HT
pH	* 8.3	units	N/A	SM4500 H+ B	22 Jul 20 17:00	HT
Conductivity (EC)	2012	umhos/cm	N/A	SM2510-B	22 Jul 20 17:00	HT
pH - Field	8.20	units	NA	SM 4500 H+ B	21 Jul 20 8:59	DJN
Temperature - Field	9.91	Degrees C	NA	SM 2550B	21 Jul 20 8:59	DJN
Total Alkalinity	1080	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Bicarbonate	1080	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	22 Jul 20 17:00	HT
Conductivity - Field	2012	umhos/cm	1	EPA 120.1	21 Jul 20 8:59	DJN
Tot Dis Solids(Summation)	1430	mg/l	12.5	SM1030-F	5 Aug 20 8:19	Calculated
Bicarb as HCO3	1320	mg/l HCO3	NA	SM2320-B	22 Jul 20 17:00	Calculated
Total Hardness as CaCO3	92.4	mg/l	NA	SM2340-B	24 Jul 20 13:45	Calculated
Cation Summation	24.2	meq/L	NA	SM1030-F	27 Jul 20 10:42	Calculated
Anion Summation	26.9	meq/L	NA	SM1030-F	5 Aug 20 8:19	Calculated
Percent Error	-5.27	%	NA	SM1030-F	5 Aug 20 8:19	Calculated
Sodium Adsorption Ratio	23.0		NA	USDA 20b	24 Jul 20 13:45	Calculated
Fluoride	1.14	mg/l	0.10	SM4500-F-C	22 Jul 20 17:00	HT
Sulfate	210	mg/l	5.00	ASTM D516-11	5 Aug 20 8:19	EV
Chloride	32.4	mg/l	1.0	SM4500-Cl-E	27 Jul 20 11:17	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	23 Jul 20 11:53	EMS
Calcium - Total	17.2	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Magnesium - Total	12.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Sodium - Total	508	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Potassium - Total	7.0	mg/l	1.0	6010D	24 Jul 20 13:45	MDE
Iron - Dissolved	1.96	mg/l	0.10	6010D	27 Jul 20 10:42	MDE
Manganese - Dissolved	0.06	mg/l	0.05	6010D	27 Jul 20 10:42	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 7 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

APPENDIX C-2

MILTON R. YOUNG POWER STATION
MONITORING WELL ANALYSES
FOR BASELINE DATA

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

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

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 21 Sep 20
Lab Number: 20-W3411
Work Order #: 82-2509
Account #: 007048
Date Sampled: 9 Sep 20 13:33
Date Received: 10 Sep 20 8:10
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-5A

Temp at Receipt: 0.5C ROI

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Sep 20	HT
Total Suspended Solids	183	mg/l	2	USGS I3765-85	10 Sep 20 16:00	HT
Conductivity (EC)	1099	umhos/cm	1	SM2510B-11	10 Sep 20 17:00	HT
pH - Field	9.06	units	NA	SM 4500 H+ B	9 Sep 20 13:33	JSM
pH	* 8.9	units	0.1	SM4500-H+-B-11	10 Sep 20 17:00	HT
Temperature - Field	8.66	Degrees C	NA	SM 2550B	9 Sep 20 13:33	JSM
Total Alkalinity	510	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Phenolphthalein Alk	29	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Bicarbonate	451	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Carbonate	59	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Sep 20 17:00	HT
Conductivity - Field	1071	umhos/cm	1	EPA 120.1	9 Sep 20 13:33	JSM
Tot Dis Solids(Summation)	686	mg/l	12.5	SM1030-F	17 Sep 20 8:50	Calculatec
Total Hardness as CaCO3	34.8	mg/l	NA	SM2340B-11	14 Sep 20 13:15	Calculatec
Cation Summation	12.9	meq/L	NA	SM1030-F	15 Sep 20 9:55	Calculatec
Anion Summation	12.0	meq/L	NA	SM1030-F	17 Sep 20 8:50	Calculatec
Percent Error	3.42	%	NA	SM1030-F	17 Sep 20 8:50	Calculatec
Fluoride	0.50	mg/l	0.10	SM4500-F-C	11 Sep 20 17:00	HT
Sulfate	85.5	mg/l	5.00	ASTM D516-11	16 Sep 20 9:14	EV
Chloride	2.3	mg/l	1.0	SM4500-Cl-E-11	14 Sep 20 9:54	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	17 Sep 20 8:50	EV
Phosphorus as P - Total	0.23	mg/l	0.10	EPA 365.1	11 Sep 20 8:25	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Sep 20 15:01	MDE
Calcium - Total	5.2	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Magnesium - Total	5.3	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Sodium - Total	279	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Potassium - Total	2.2	mg/l	1.0	6010D	14 Sep 20 13:15	SZ
Iron - Dissolved	0.30	mg/l	0.10	6010D	15 Sep 20 9:55	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	15 Sep 20 9:55	MDE
Boron - Dissolved	0.34	mg/l	0.10	6010D	11 Sep 20 9:57	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Barium - Dissolved	0.0586	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 21 Sep 20
Lab Number: 20-W3411
Work Order #: 82-2509
Account #: 007048
Date Sampled: 9 Sep 20 13:33
Date Received: 10 Sep 20 8:10
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

Sample Description: 92-5A

Event and Year: Fall 2020

PO #: 200004

Temp at Receipt: 0.5C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	14 Sep 20 16:12	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	14 Sep 20 16:12	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	14 Sep 20 16:12	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 24 Sep 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:
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www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2873
Work Order #: 82-2147
Account #: 007048
Date Sampled: 6 Aug 20 15:55
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 97-1

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 7.1	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	3440	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	32	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	6.41	units	NA	SM 4500 H+ B	6 Aug 20 15:55	DJN
Temperature - Field	15.3	Degrees C	NA	SM 2550B	6 Aug 20 15:55	DJN
Total Alkalinity	376	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	376	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	3337	umhos/cm	1	EPA 120.1	6 Aug 20 15:55	DJN
Tot Dis Solids(Summation)	3000	mg/l	12.5	SM1030-F	13 Aug 20 9:30	Calculated
Total Hardness as CaCO3	2180	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculated
Cation Summation	52.2	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculated
Anion Summation	46.9	meq/L	NA	SM1030-F	13 Aug 20 9:30	Calculated
Percent Error	5.37	%	NA	SM1030-F	13 Aug 20 9:30	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	1810	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	59.0	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:30	SD
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	14 Aug 20 9:12	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	471	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	245	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	181	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	5.1	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	13.2	mg/l	0.10	6010D	10 Aug 20 16:07	SZ
Manganese - Dissolved	1.25	mg/l	0.05	6010D	10 Aug 20 16:07	SZ
Boron - Dissolved	0.36	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Barium - Dissolved	0.0423	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Beryllium - Dissolved	< 0.002 ^	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE
Cadmium - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2873
Work Order #: 82-2147
Account #: 007048
Date Sampled: 6 Aug 20 15:55
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 97-1

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	20 Aug 20 11:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	20 Aug 20 11:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	20 Aug 20 11:31	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC

Approved by: Claudette K. Carroll 25 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2869
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 16:40
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 95-4

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.7	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1792	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	< 2	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.55	units	NA	SM 4500 H+ B	5 Aug 20 16:40	DJN
Temperature - Field	8.77	Degrees C	NA	SM 2550B	5 Aug 20 16:40	DJN
Total Alkalinity	889	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	826	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	63	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1763	umhos/cm	1	EPA 120.1	5 Aug 20 16:40	DJN
Tot Dis Solids(Summation)	1100	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculatec
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculatec
Cation Summation	19.5	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculatec
Anion Summation	20.2	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Percent Error	-1.83	%	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Fluoride	1.13	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	109	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	6.2	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.15	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	442	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	2.4	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.46	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.0982	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2869
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 16:40
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 95-4

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 25Aug2020

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

MINNESOTA VALLEY TESTING LABORATORIES, INC.
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2868
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 14:57
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

PO #: 200004

Temp at Receipt: 0.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.8	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1822	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	< 2	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.66	units	NA	SM 4500 H+ B	5 Aug 20 14:57	DJN
Temperature - Field	9.14	Degrees C	NA	SM 2550B	5 Aug 20 14:57	DJN
Total Alkalinity	901	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	34	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	832	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	69	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1797	umhos/cm	1	EPA 120.1	5 Aug 20 14:57	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculatec
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340B-11	11 Aug 20 15:10	Calculatec
Cation Summation	19.7	meq/L	NA	SM1030-F	11 Aug 20 15:10	Calculatec
Anion Summation	20.6	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Percent Error	-2.24	%	NA	SM1030-F	13 Aug 20 9:14	Calculatec
Fluoride	1.63	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	117	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	6.2	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.26	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.4	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Sodium - Total	447	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 15:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	12 Aug 20 13:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.1072	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2868
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 14:57
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 25 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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= Due to concentration of other analytes
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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2867
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 11:01
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 92-6A

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	7 Aug 20	HT
pH	* 8.5	units	N/A	SM4500-H+-B-11	7 Aug 20 18:00	HT
Conductivity (EC)	1646	umhos/cm	N/A	SM2510B-11	7 Aug 20 18:00	HT
Total Suspended Solids	7	mg/l	2	USGS I3765-85	7 Aug 20 15:30	HT
pH - Field	8.84	units	NA	SM 4500 H+ B	5 Aug 20 11:01	DJN
Temperature - Field	8.22	Degrees C	NA	SM 2550B	5 Aug 20 11:01	DJN
Total Alkalinity	799	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Bicarbonate	783	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	7 Aug 20 18:00	HT
Conductivity - Field	1618	umhos/cm	1	EPA 120.1	5 Aug 20 11:01	DJN
Tot Dis Solids(Summation)	1090	mg/l	12.5	SM1030-F	13 Aug 20 9:14	Calculated
Total Hardness as CaCO3	11.2	mg/l	NA	SM2340B-11	11 Aug 20 14:10	Calculated
Cation Summation	17.3	meq/L	NA	SM1030-F	11 Aug 20 14:10	Calculated
Anion Summation	20.4	meq/L	NA	SM1030-F	13 Aug 20 9:14	Calculated
Percent Error	-8.21	%	NA	SM1030-F	13 Aug 20 9:14	Calculated
Fluoride	0.97	mg/l	0.10	SM4500-F-C	7 Aug 20 18:00	HT
Sulfate	211	mg/l	5.00	ASTM D516-11	10 Aug 20 11:25	SD
Chloride	2.3	mg/l	1.0	SM4500-Cl-E-11	7 Aug 20 12:19	SD
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	13 Aug 20 9:14	SD
Phosphorus as P - Total	0.13	mg/l	0.10	EPA 365.1	14 Aug 20 8:39	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	14 Aug 20 12:22	MDE
Calcium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Sodium - Total	392	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	11 Aug 20 14:10	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Aug 20 15:07	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Aug 20 15:07	SZ
Boron - Dissolved	0.39	mg/l	0.10	6010D	12 Aug 20 12:07	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Barium - Dissolved	0.0146	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 24 Aug 20
Lab Number: 20-W2867
Work Order #: 82-2147
Account #: 007048
Date Sampled: 5 Aug 20 11:01
Date Received: 7 Aug 20 8:00
Sampled By: MVTL Field Service

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-6A

Temp at Receipt: 0.2C

Event and Year: Fall 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	12 Aug 20 12:39	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Aug 20 12:39	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	12 Aug 20 12:39	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 25 Aug 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W774
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:17
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 92-5A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.8	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1129	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	371	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.94	units	NA	SM 4500 H+ B	23 Apr 20 13:17	DJN
Temperature - Field	8.45	Degrees C	NA	SM 2550B	23 Apr 20 13:17	DJN
Total Alkalinity	499	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	24	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	452	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	47	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1120	umhos/cm	1	EPA 120.1	23 Apr 20 13:17	DJN
Tot Dis Solids(Summation)	672	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	43.7	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	12.0	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	2.11	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.49	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	91.2	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	1.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	0.32	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.15	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	6.3	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	6.8	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	264	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	1.62	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.36	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Barium - Dissolved	0.0806	mg/l	0.0020	6020B	27 Apr 20 16:34	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 17:15	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 17:15	CC
Chromium - Dissolved	0.0040	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Lead - Dissolved	0.0016	mg/l	0.0005	6020B	27 Apr 20 13:50	CC

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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W774
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:17
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-5A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:50	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 17:15	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:50	CC

* Holding time exceeded

Approved by: Claudette K. Carroll CC 8May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 May 20
Lab Number: 20-W775
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 10:12
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 92-6A

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1642	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	12	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.67	units	NA	SM 4500 H+ B	23 Apr 20 10:12	DJN
Temperature - Field	7.93	Degrees C	NA	SM 2550B	23 Apr 20 10:12	DJN
Total Alkalinity	632	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	598	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	34	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1639	umhos/cm	1	EPA 120.1	23 Apr 20 10:12	DJN
Tot Dis Solids(Summation)	987	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	12.4	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	17.3	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	17.0	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	0.69	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.97	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	209	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	1.8	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.16	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	3.0	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	390	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.6	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.39	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Barium - Dissolved	0.0132	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC
Cadmium - Dissolved	< 0.0005	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	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W775
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 10:12
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

PO #: 200004

Temp at Receipt: 3.8C ROI

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-6A

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 10:20	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 10:20	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 10:20	CC

* Holding time exceeded

Approved by: Claudette K. Carroll CC 8 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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W776
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 16:51
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 200004

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1841	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	3	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.66	units	NA	SM 4500 H+ B	23 Apr 20 16:51	DJN
Temperature - Field	8.34	Degrees C	NA	SM 2550B	23 Apr 20 16:51	DJN
Total Alkalinity	837	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	26	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	785	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	52	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1822	umhos/cm	1	EPA 120.1	23 Apr 20 16:51	DJN
Tot Dis Solids(Summation)	1110	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	20.7	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	19.5	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	3.16	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	1.64	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	124	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	5.0	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.26	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	2.4	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.2	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	470	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.47	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.1085	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W776
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 16:51
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 92-3

Event and Year: Spring 2020

PO #: 200004

Temp at Receipt: 3.8C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

Approved by: Claudette K. Carroll 8 May 2020 CC

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

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MEMBER ACIL

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 May 20
Lab Number: 20-W777
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 15:09
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 95-4

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 8.6	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	1815	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	3	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	8.53	units	NA	SM 4500 H+ B	23 Apr 20 15:09	DJN
Temperature - Field	8.32	Degrees C	NA	SM 2550B	23 Apr 20 15:09	DJN
Total Alkalinity	836	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	798	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	38	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	1802	umhos/cm	1	EPA 120.1	23 Apr 20 15:09	DJN
Tot Dis Solids(Summation)	1090	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	9.77	mg/l	NA	SM2340-B	27 Apr 20 10:26	Calculated
Cation Summation	19.9	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	19.4	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	1.33	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	122	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	4.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	0.21	mg/l	0.10	EPA 365.1	1 May 20 7:57	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	2.1	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Magnesium - Total	1.1	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Sodium - Total	452	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Potassium - Total	2.5	mg/l	1.0	6010D	27 Apr 20 10:26	MDE
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.47	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.0992	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W777
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 15:09
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

PO #: 200004

Sample Description: 95-4

Temp at Receipt: 3.8C ROI

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 8 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W781
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:28
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

PO #: 200004

Temp at Receipt: 3.8C ROI

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 97-1

Event and Year: Spring 2020

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 Apr 20	SD
pH	* 6.7	units	N/A	SM4500 H+ B	24 Apr 20 17:00	SD
Conductivity (EC)	3597	umhos/cm	N/A	SM2510-B	24 Apr 20 17:00	SD
Total Suspended Solids	64	mg/l	2	I3765-85	24 Apr 20 16:40	HT
pH - Field	6.33	units	NA	SM 4500 H+ B	23 Apr 20 13:28	JSM
Temperature - Field	10.3	Degrees C	NA	SM 2550B	23 Apr 20 13:28	JSM
Total Alkalinity	327	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Bicarbonate	327	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 Apr 20 17:00	SD
Conductivity - Field	3447	umhos/cm	1	EPA 120.1	23 Apr 20 13:28	JSM
Tot Dis Solids(Summation)	3130	mg/l	12.5	SM1030-F	30 Apr 20 8:44	Calculated
Total Hardness as CaCO3	2200	mg/l	NA	SM2340-B	27 Apr 20 11:26	Calculated
Cation Summation	53.1	meq/L	NA	SM1030-F	30 Apr 20 9:58	Calculated
Anion Summation	48.8	meq/L	NA	SM1030-F	30 Apr 20 8:44	Calculated
Percent Error	4.20	%	NA	SM1030-F	30 Apr 20 9:58	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	24 Apr 20 17:00	SD
Sulfate	1960	mg/l	5.00	ASTM D516-11	29 Apr 20 9:08	EV
Chloride	51.9	mg/l	1.0	SM4500-Cl-E	27 Apr 20 10:57	EV
Nitrate-Nitrite as N	0.11	mg/l	0.10	EPA 353.2	30 Apr 20 8:44	EV
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	1 May 20 8:34	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	29 Apr 20 12:59	MDE
Calcium - Total	475	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Magnesium - Total	246	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Sodium - Total	196	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Potassium - Total	5.3	mg/l	1.0	6010D	27 Apr 20 11:26	MDE
Iron - Dissolved	12.3	mg/l	0.10	6010D	30 Apr 20 9:58	MDE
Manganese - Dissolved	1.33	mg/l	0.05	6010D	30 Apr 20 9:58	MDE
Boron - Dissolved	0.34	mg/l	0.10	6010D	28 Apr 20 12:30	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Barium - Dissolved	0.0440	mg/l	0.0020	6020B	27 Apr 20 15:50	CC
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 1 May 20
Lab Number: 20-W781
Work Order #: 82-0961
Account #: 007048
Date Sampled: 23 Apr 20 13:28
Date Received: 24 Apr 20 7:28
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota - CCWDF

Sample Description: 97-1

Event and Year: Spring 2020

PO #: 200004

Temp at Receipt: 3.8C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Apr 20 13:10	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Apr 20 13:10	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Apr 20 13:10	CC

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 8 May 2020

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 3 Oct 19
Lab Number: 19-W3428
Work Order #: 82-2442
Account #: 007048
Date Sampled: 5 Sep 19 14:18
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF - Hagel

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	27	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	3485	umhos/cm	1	SM2510-B	20 Sep 19 17:00	CC
pH - Field	6.26	units	NA	SM 4500 H+ B	5 Sep 19 14:18	DJN
pH	* 7.1	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	14.1	Degrees C	NA	SM 2550B	5 Sep 19 14:18	DJN
Total Alkalinity	310	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	310	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	4146	umhos/cm	1	EPA 120.1	5 Sep 19 14:18	DJN
Tot Dis Solids(Summation)	3180	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	2320	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	55.1	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	49.1	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	5.76	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	0.11	mg/l	0.10	SM4500-F-C	20 Sep 19 17:00	CC
Sulfate	1990	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	52.8	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.10	mg/l	0.10	EPA 365.1	13 Sep 19 9:13	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	510	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	254	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	186	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	5.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	14.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	1.32	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.34	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Barium - Dissolved	0.0360	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Chromium - Dissolved	< 0.005 ^	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Amended 5 Oct 19 (Pb result) - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 3 Oct 19
Lab Number: 19-W3428
Work Order #: 82-2442
Account #: 007048
Date Sampled: 5 Sep 19 14:18
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF - Hagel

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	2 Oct 19 13:37	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	2 Oct 19 13:37	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	2 Oct 19 13:37	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

cc 5OCT19

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3421
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 14:05
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-5A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	20	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1184	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.90	units	NA	SM 4500 H+ B	5 Sep 19 14:05	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	9.19	Degrees C	NA	SM 2550B	5 Sep 19 14:05	DJN
Total Alkalinity	520	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	440	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	80	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1131	umhos/cm	1	EPA 120.1	5 Sep 19 14:05	DJN
Tot Dis Solids(Summation)	695	mg/l	12.5	SM1030-F	19 Sep 19 11:36	Calculated
Total Hardness as CaCO3	19.5	mg/l	NA	SM2340-B	19 Sep 19 11:36	Calculated
Cation Summation	12.9	meq/L	NA	SM1030-F	19 Sep 19 11:36	Calculated
Anion Summation	12.2	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	2.70	%	NA	SM1030-F	19 Sep 19 11:36	Calculated
Fluoride	0.48	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	86.8	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	1.2	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 14:42	EV
Phosphorus as P - Total	0.14	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	3.7	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Magnesium - Total	2.5	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Sodium - Total	287	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Potassium - Total	1.8	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.34	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0350	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	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 sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3421
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 14:05
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-5A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed		Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19	9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19	9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE

* Holding time exceeded

CL
Approved by: Claudette K. Carroll 1 OCT 19

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3422
Work Order #: 82-2441
Account #: 007048
Date Sampled: 4 Sep 19 16:01
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-6A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	3	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1744	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.87	units	NA	SM 4500 H+ B	4 Sep 19 16:01	DJN
pH	* 8.9	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.07	Degrees C	NA	SM 2550B	4 Sep 19 16:01	DJN
Total Alkalinity	690	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	610	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	80	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1685	umhos/cm	1	EPA 120.1	4 Sep 19 16:01	DJN
Tot Dis Solids(Summation)	1050	mg/l	12.5	SM1030-F	19 Sep 19 11:36	Calculated
Total Hardness as CaCO3	13.1	mg/l	NA	SM2340-B	19 Sep 19 11:36	Calculated
Cation Summation	18.0	meq/L	NA	SM1030-F	19 Sep 19 11:36	Calculated
Anion Summation	18.3	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	-0.85	%	NA	SM1030-F	19 Sep 19 11:36	Calculated
Fluoride	0.99	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	216	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	1.5	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	3.1	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Sodium - Total	407	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Potassium - Total	2.6	mg/l	1.0	6010D	19 Sep 19 11:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.40	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0121	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

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www.mvtl.com

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3422
Work Order #: 82-2441
Account #: 007048
Date Sampled: 4 Sep 19 16:01
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-6A

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed		Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19	9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19	9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19	9:30	MDE

* Holding time exceeded

Approved by: Claudette K Carroll   CC 1 OCT 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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! = Due to sample quantity
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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3423
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 16:15
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	< 2	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1887	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.65	units	NA	SM 4500 H+ B	5 Sep 19 16:15	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.78	Degrees C	NA	SM 2550B	5 Sep 19 16:15	DJN
Total Alkalinity	910	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	850	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	60	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1823	umhos/cm	1	EPA 120.1	5 Sep 19 16:15	DJN
Tot Dis Solids(Summation)	1140	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	20.2	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	20.9	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	-1.69	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	1.64	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	124	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	4.5	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	2.4	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	458	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	0.17	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Barium - Dissolved	0.0978	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3423
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 16:15
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Sep 19 9:30	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Sep 19 9:30	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Sep 19 9:30	MDE

* Holding time exceeded

CC
Approved by: Claudette K. Carroll 1OCT19

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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CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3424
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 17:59
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	6 Sep 19	EMS
Total Suspended Solids	< 2	mg/l	2	I3765-85	6 Sep 19 14:26	EMS
Conductivity (EC)	1862	umhos/cm	1	SM2510-B	18 Sep 19 11:30	CC
pH - Field	8.55	units	NA	SM 4500 H+ B	5 Sep 19 17:59	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	6 Sep 19 9:52	EMS
Temperature - Field	8.62	Degrees C	NA	SM 2550B	5 Sep 19 17:59	DJN
Total Alkalinity	880	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Phenolphthalein Alk	20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Bicarbonate	840	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Carbonate	40	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	12 Sep 19 7:15	CC
Conductivity - Field	1800	umhos/cm	1	EPA 120.1	5 Sep 19 17:59	DJN
Tot Dis Solids(Summation)	1200	mg/l	12.5	SM1030-F	19 Sep 19 12:36	Calculated
Total Hardness as CaCO3	10.4	mg/l	NA	SM2340-B	19 Sep 19 12:36	Calculated
Cation Summation	24.0	meq/L	NA	SM1030-F	19 Sep 19 12:36	Calculated
Anion Summation	20.1	meq/L	NA	SM1030-F	12 Sep 19 7:15	Calculated
Percent Error	8.87	%	NA	SM1030-F	19 Sep 19 12:36	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	18 Sep 19 11:30	CC
Sulfate	113	mg/l	5.00	ASTM D516-07	11 Sep 19 10:52	EV
Chloride	4.4	mg/l	1.0	SM4500-Cl-E	6 Sep 19 15:09	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	9 Sep 19 15:02	EV
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	13 Sep 19 8:37	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Sep 19 14:02	EMS
Calcium - Total	2.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Sodium - Total	545	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Potassium - Total	2.7	mg/l	1.0	6010D	19 Sep 19 12:36	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	10 Sep 19 15:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	10 Sep 19 15:03	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	24 Sep 19 13:54	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Barium - Dissolved	0.1012	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	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 sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 1 Oct 19
Lab Number: 19-W3424
Work Order #: 82-2441
Account #: 007048
Date Sampled: 5 Sep 19 17:59
Date Received: 6 Sep 19 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota - CCWDF

PO #: 190093

Sample Description: 95-4

Temp at Receipt: 3.7C

Event and Year: Fall 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 Sep 19 15:16	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	30 Sep 19 15:16	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	30 Sep 19 15:16	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll   CC 1OCT19

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1534
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 14:41
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 92-3

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1812	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	< 2	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.32	units	NA	SM 4500 H+ B	28 May 19 14:41	DJN
Temperature - Field	8.38	Degrees C	NA	SM 2550B	28 May 19 14:41	DJN
Total Alkalinity	823	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	25	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	772	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	51	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1813	umhos/cm	1	EPA 120.1	28 May 19 14:41	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	10.3	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	22.1	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	19.0	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	7.59	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.63	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	116	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	5.3	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.30	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	2.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	503	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.5	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.47	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.1104	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1534
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 14:41
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-3

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

lc

Approved by: Claudette K. Carroll 28 Jun 19

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1535
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 16:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Project Name: Minnkota-CCWDF

Sample Description: 95-4

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1797	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	< 2	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.31	units	NA	SM 4500 H+ B	28 May 19 16:23	DJN
Temperature - Field	8.33	Degrees C	NA	SM 2550B	28 May 19 16:23	DJN
Total Alkalinity	829	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	25	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	779	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	50	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1796	umhos/cm	1	EPA 120.1	28 May 19 16:23	DJN
Tot Dis Solids(Summation)	1110	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	9.19	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	21.7	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	18.9	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	6.99	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.15	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	104	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	5.2	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	1.7	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.2	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	494	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.47	mg/l	0.10	6010D	4 Jun 19 12:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0984	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1535
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 16:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 95-4

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll CC 28 Jun 19

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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\# = Due to concentration of other analytes
\+ = Due to internal standard response

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1533
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 12:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 92-6A

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 8.8	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1697	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	3	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	28 May 19 12:23	DJN
Temperature - Field	7.85	Degrees C	NA	SM 2550B	28 May 19 12:23	DJN
Total Alkalinity	641	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	580	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	61	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1692	umhos/cm	1	EPA 120.1	28 May 19 12:23	DJN
Tot Dis Solids(Summation)	1080	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	10.3	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	19.6	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	17.9	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	4.60	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	1.01	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	241	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	2.2	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	2.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	1.3	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	445	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	2.5	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 12:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 12:03	SZ
Boron - Dissolved	0.41	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0130	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	0.0011	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

RL = Method Reporting Limit

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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1533
Work Order #: 82-1235
Account #: 007048
Date Sampled: 28 May 19 12:23
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

PO #: 190093

Temp at Receipt: 3.2C

Project Name: Minnkota-CCWDF

Sample Description: 92-6A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

CC

Approved by: Claudette K. Carroll 28 Jun 19

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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1532
Work Order #: 82-1235
Account #: 007048
Date Sampled: 29 May 19 12:10
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

PO #: 190093

Temp at Receipt: 3.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

Sample Description: 92-5A

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 9.0	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	1131	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	44	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	8.75	units	NA	SM 4500 H+ B	29 May 19 12:10	DJN
Temperature - Field	9.13	Degrees C	NA	SM 2550B	29 May 19 12:10	DJN
Total Alkalinity	488	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	35	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	417	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	71	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	1137	umhos/cm	1	EPA 120.1	29 May 19 12:10	DJN
Tot Dis Solids(Summation)	693	mg/l	12.5	SM1030-F	13 Jun 19 13:56	Calculated
Total Hardness as CaCO3	2.50	mg/l	NA	SM2340-B	13 Jun 19 13:56	Calculated
Cation Summation	13.6	meq/L	NA	SM1030-F	13 Jun 19 13:56	Calculated
Anion Summation	11.6	meq/L	NA	SM1030-F	5 Jun 19 9:47	Calculated
Percent Error	7.88	%	NA	SM1030-F	13 Jun 19 13:56	Calculated
Fluoride	0.53	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	85.4	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	2.0	mg/l	1.0	SM4500-Cl-E	5 Jun 19 9:47	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:09	EMS
Phosphorus as P - Total	0.16	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	1.0	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Magnesium - Total	< 1	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Sodium - Total	310	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Potassium - Total	1.7	mg/l	1.0	6010D	13 Jun 19 13:56	SZ
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 19 12:03	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 19 12:03	SZ
Boron - Dissolved	0.37	mg/l	0.10	6010D	4 Jun 19 11:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Barium - Dissolved	0.0325	mg/l	0.0020	6020B	14 Jun 19 10:46	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	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

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

Report Date: 17 Jun 19
Lab Number: 19-W1532
Work Order #: 82-1235
Account #: 007048
Date Sampled: 29 May 19 12:10
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 92-5A

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	11 Jun 19 15:27	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	12 Jun 19 10:10	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	11 Jun 19 15:27	MDE

* Holding time exceeded

CC
28 Jun 19

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 19 Jun 19
Lab Number: 19-W1539
Work Order #: 82-1251
Account #: 007048
Date Sampled: 29 May 19 8:54
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

PO #: 190093

Temp at Receipt: 3.2C

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

Sample Description: 97-1

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	30 May 19	SVS
pH	* 6.6	units	N/A	SM4500 H+ B	30 May 19 17:00	SVS
Conductivity (EC)	3736	umhos/cm	N/A	SM2510-B	30 May 19 17:00	SVS
Total Suspended Solids	108	mg/l	2	I3765-85	30 May 19 15:27	SVS
pH - Field	6.30	units	NA	SM 4500 H+ B	29 May 19 8:54	DJN
Temperature - Field	10.6	Degrees C	NA	SM 2550B	29 May 19 8:54	DJN
Total Alkalinity	284	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Bicarbonate	284	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	30 May 19 17:00	SVS
Conductivity - Field	3920	umhos/cm	1	EPA 120.1	29 May 19 8:54	DJN
Tot Dis Solids(Summation)	3140	mg/l	12.5	SM1030-F	13 Jun 19 14:56	Calculated
Total Hardness as CaCO3	2200	mg/l	NA	SM2340-B	13 Jun 19 14:56	Calculated
Cation Summation	54.6	meq/L	NA	SM1030-F	13 Jun 19 14:56	Calculated
Anion Summation	48.4	meq/L	NA	SM1030-F	5 Jun 19 10:24	Calculated
Percent Error	6.00	%	NA	SM1030-F	13 Jun 19 14:56	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	30 May 19 17:00	SVS
Sulfate	1960	mg/l	5.00	ASTM D516-07	31 May 19 10:32	EMS
Chloride	67.5	mg/l	1.0	SM4500-Cl-E	5 Jun 19 10:24	EV
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	30 May 19 11:26	EMS
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	31 May 19 10:19	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	5 Jun 19 13:06	EMS
Calcium - Total	453	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Magnesium - Total	259	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Sodium - Total	228	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Potassium - Total	5.9	mg/l	1.0	6010D	13 Jun 19 14:56	SZ
Iron - Dissolved	14.7	mg/l	0.10	6010D	5 Jun 19 13:03	SZ
Manganese - Dissolved	1.38	mg/l	0.05	6010D	5 Jun 19 13:03	SZ
Boron - Dissolved	0.41	mg/l	0.10	6010D	4 Jun 19 12:18	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Barium - Dissolved	0.0425	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Beryllium - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	18 Jun 19 11:57	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

Report Date: 19 Jun 19
Lab Number: 19-W1539
Work Order #: 82-1251
Account #: 007048
Date Sampled: 29 May 19 8:54
Date Received: 30 May 19 8:00
Sampled By: MVTL Field Services

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Project Name: Minnkota-CCWDF

PO #: 190093

Sample Description: 97-1

Temp at Receipt: 3.2C

Event and Year: May 2019

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	17 Jun 19 23:06	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	17 Jun 19 23:06	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	17 Jun 19 23:06	MDE

* Holding time exceeded

^ Elevated result due to instrument performance at the lower limit of quantification (LLOQ).

CC
Approved by: Claudette K. Carroll 28 Jun 19

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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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3108
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 11:04
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	62	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	3574	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	6.28	units	NA	SM 4500 H+ B	25 Sep 18 11:04	DJN
pH	* 6.5	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	9.46	Degrees C	NA	SM 2550B	25 Sep 18 11:04	DJN
Total Alkalinity	296	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	296	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	3600	umhos/cm	1	EPA 120.1	25 Sep 18 11:04	DJN
Tot Dis Solids(Summation)	2960	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	2240	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	54.3	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	44.6	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	9.77	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.10	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	1780	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	58.0	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.10	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	485	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	251	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	201	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	5.5	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	13.5	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	1.43	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.35	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0496	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	0.0007	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

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! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3108
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 11:04
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 10 OCT 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3109
Work Order #: 82-2513
Account #: 007048
Date Sampled: 24 Sep 18 18:02
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	18	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1198	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.80	units	NA	SM 4500 H+ B	24 Sep 18 18:02	DJN
pH	* 8.9	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.57	Degrees C	NA	SM 2550B	24 Sep 18 18:02	DJN
Total Alkalinity	513	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	449	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	64	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1118	umhos/cm	1	EPA 120.1	24 Sep 18 18:02	DJN
Tot Dis Solids(Summation)	690	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	3.25	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	13.4	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	11.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	6.23	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.50	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	72.1	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	1.4	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	0.11	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.12	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	1.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	< 1	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	305	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	1.8	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.36	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0357	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3109
Work Order #: 82-2513
Account #: 007048
Date Sampled: 24 Sep 18 18:02
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

CC
10 OCT 18

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
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CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3110
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 10:41
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	9	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1717	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.75	units	NA	SM 4500 H+ B	25 Sep 18 10:41	DJN
pH	* 8.8	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	7.77	Degrees C	NA	SM 2550B	25 Sep 18 10:41	DJN
Total Alkalinity	654	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	36	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	581	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	73	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1681	umhos/cm	1	EPA 120.1	25 Sep 18 10:41	DJN
Tot Dis Solids(Summation)	1010	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	13.3	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	18.2	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	17.3	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	2.40	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	0.95	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	200	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	2.3	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.17	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	3.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	410	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.4	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.38	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.0142	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

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

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3110
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 10:41
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

Approved by: Claudette K Carroll CC 10 OCT 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3111
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 13:07
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	2	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1864	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	25 Sep 18 13:07	DJN
pH	* 8.6	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.42	Degrees C	NA	SM 2550B	25 Sep 18 13:07	DJN
Total Alkalinity	862	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	798	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	64	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1847	umhos/cm	1	EPA 120.1	25 Sep 18 13:07	DJN
Tot Dis Solids(Summation)	1130	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	10.9	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	21.2	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	19.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	3.20	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	1.61	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	117	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	5.9	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	2.4	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	480	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.3	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.46	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.1182	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3111
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 13:07
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

CC
Approved by: Claudette K. Carroll 10 OCT 18

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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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3112
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 14:50
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	25 Sep 18	SVS
Total Suspended Solids	6	mg/l	2	I3765-85	25 Sep 18 17:38	SVS
Conductivity (EC)	1852	umhos/cm	1	SM2510-B	25 Sep 18 18:00	SVS
pH - Field	8.43	units	NA	SM 4500 H+ B	25 Sep 18 14:50	DJN
pH	+ 8.6	units	0.1	SM4500 H+ B	25 Sep 18 18:00	SVS
Temperature - Field	8.33	Degrees C	NA	SM 2550B	25 Sep 18 14:50	DJN
Total Alkalinity	866	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Phenolphthalein Alk	33	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Bicarbonate	800	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Carbonate	66	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	26 Sep 18 18:00	SVS
Conductivity - Field	1831	umhos/cm	1	EPA 120.1	25 Sep 18 14:50	DJN
Tot Dis Solids(Summation)	1120	mg/l	12.5	SM1030-F	3 Oct 18 12:23	Calculated
Total Hardness as CaCO3	10.0	mg/l	NA	SM2340-B	3 Oct 18 11:42	Calculated
Cation Summation	20.9	meq/L	NA	SM1030-F	5 Oct 18 10:46	Calculated
Anion Summation	19.8	meq/L	NA	SM1030-F	3 Oct 18 12:23	Calculated
Percent Error	2.69	%	NA	SM1030-F	5 Oct 18 10:46	Calculated
Fluoride	1.12	mg/l	0.10	SM4500-F-C	26 Sep 18 18:00	SVS
Sulfate	110	mg/l	5.00	ASTM D516-07	26 Sep 18 16:04	EMS
Chloride	6.0	mg/l	1.0	SM4500-Cl-E	28 Sep 18 15:33	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	3 Oct 18 12:23	EV
Phosphorus as P - Total	0.20	mg/l	0.10	EPA 365.1	27 Sep 18 14:00	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	28 Sep 18 13:16	EV
Calcium - Total	2.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Magnesium - Total	1.1	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Sodium - Total	474	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Potassium - Total	2.2	mg/l	1.0	6010D	3 Oct 18 11:42	BB
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Oct 18 10:46	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Oct 18 10:46	SZ
Boron - Dissolved	0.45	mg/l	0.10	6010D	2 Oct 18 16:33	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Barium - Dissolved	0.1108	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Sep 18 21:07	BB
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Sep 18 21:07	BB

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 5 Oct 18
Lab Number: 18-W3112
Work Order #: 82-2513
Account #: 007048
Date Sampled: 25 Sep 18 14:50
Date Received: 25 Sep 18 15:49
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 2.1C

Event and Year: Sept 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	27 Sep 18 18:24	BB
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	27 Sep 18 18:16	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	27 Sep 18 18:24	BB

* Holding time exceeded

CC
10 OCT 18

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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# = Due to concentration of other analytes
! = Due to sample quantity
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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1293
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 13:07
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	91	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	4017	umhos/cm	1	SM2510-B	24 May 18 17:00	SVS
pH - Field	6.10	units	NA	SM 4500 H+ B	22 May 18 13:07	DJN
pH	* 6.5	units	0.1	SM4500 H+ B	24 May 18 17:00	SVS
Temperature - Field	12.3	Degrees C	NA	SM 2550B	22 May 18 13:07	DJN
Total Alkalinity	247	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Bicarbonate	247	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 17:00	SVS
Conductivity - Field	3890	umhos/cm	1	EPA 120.1	22 May 18 13:07	DJN
Tot Dis Solids(Summation)	3890	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	2110	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	54.0	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	64.1	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-8.55	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	< 0.1	mg/l	0.10	SM4500-F-C	24 May 18 17:00	SVS
Sulfate	2740	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	73.9	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	< 0.1	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	384	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	280	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	258	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	6.2	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	9.59	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	1.34	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.35	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0518	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1293
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 13:07
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 97-1

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

cc
Approved by: Claudette K Carroll 16 Jun 18

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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CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1294
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 12:40
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	8	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1193	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.99	units	NA	SM 4500 H+ B	23 May 18 12:40	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	9.21	Degrees C	NA	SM 2550B	23 May 18 12:40	DJN
Total Alkalinity	522	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	32	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	459	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	63	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1123	umhos/cm	1	EPA 120.1	23 May 18 12:40	DJN
Tot Dis Solids(Summation)	731	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	12.5	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	13.1	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-2.40	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	0.48	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	128	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	1.2	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.13	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	287	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	1.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.39	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0328	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1294
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 12:40
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-5A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

Approved by: Claudette K. Carroll
CC
16 Jun 18

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 concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1295
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 15:11
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	17	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1718	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.98	units	NA	SM 4500 H+ B	22 May 18 15:11	DJN
pH	* 9.0	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	8.04	Degrees C	NA	SM 2550B	22 May 18 15:11	DJN
Total Alkalinity	669	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	43	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	582	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	87	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1593	umhos/cm	1	EPA 120.1	22 May 18 15:11	DJN
Tot Dis Solids(Summation)	1080	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	18.3	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	18.8	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-1.43	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	0.93	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	259	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	1.8	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.19	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 12:11	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	419	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.6	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.43	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0124	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1295
Work Order #: 82-1116
Account #: 007048
Date Sampled: 22 May 18 15:11
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-6A

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

cc
16 Jun 18

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

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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1296
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 16:24
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	3	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1869	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.58	units	NA	SM 4500 H+ B	23 May 18 16:24	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	9.21	Degrees C	NA	SM 2550B	23 May 18 16:24	DJN
Total Alkalinity	868	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	29	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	809	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	59	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1796	umhos/cm	1	EPA 120.1	23 May 18 16:24	DJN
Tot Dis Solids(Summation)	1150	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	11.6	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	20.6	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	20.6	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	-0.02	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	1.55	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	148	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	4.7	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.29	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 13:12	EV
Calcium - Total	2.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	1.3	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	466	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.5	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.51	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.1043	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

RL = Method Reporting Limit

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! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1296
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 16:24
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 92-3

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

cc

Approved by: Claudette K. Carroll 16 Jun 18

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

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CERTIFICATION: ND # ND-00016

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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1297
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 14:26
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	24 May 18	EMS
Total Suspended Solids	8	mg/l	2	I3765-85	24 May 18 15:34	SVS
Conductivity (EC)	1851	umhos/cm	1	SM2510-B	24 May 18 18:00	SVS
pH - Field	8.60	units	NA	SM 4500 H+ B	23 May 18 14:26	DJN
pH	* 8.7	units	0.1	SM4500 H+ B	24 May 18 18:00	SVS
Temperature - Field	8.97	Degrees C	NA	SM 2550B	23 May 18 14:26	DJN
Total Alkalinity	873	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Phenolphthalein Alk	30	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Bicarbonate	812	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Carbonate	61	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	24 May 18 18:00	SVS
Conductivity - Field	1767	umhos/cm	1	EPA 120.1	23 May 18 14:26	DJN
Tot Dis Solids(Summation)	1130	mg/l	12.5	SM1030-F	6 Jun 18 11:49	Calculated
Total Hardness as CaCO3	< 6.62	mg/l	NA	SM2340-B	30 May 18 17:43	Calculated
Cation Summation	20.5	meq/L	NA	SM1030-F	5 Jun 18 11:32	Calculated
Anion Summation	20.3	meq/L	NA	SM1030-F	6 Jun 18 11:49	Calculated
Percent Error	0.49	%	NA	SM1030-F	6 Jun 18 11:49	Calculated
Fluoride	1.07	mg/l	0.10	SM4500-F-C	24 May 18 18:00	SVS
Sulfate	132	mg/l	5.00	ASTM D516-07	6 Jun 18 11:49	EMS
Chloride	4.9	mg/l	1.0	SM4500-Cl-E	25 May 18 10:58	RAG
Nitrate-Nitrite as N	< 0.1	mg/l	0.10	EPA 353.2	31 May 18 11:27	EMS
Phosphorus as P - Total	0.22	mg/l	0.10	EPA 365.1	29 May 18 14:02	EMS
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	1 Jun 18 13:12	EV
Calcium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Magnesium - Total	< 1	mg/l	1.0	6010D	30 May 18 17:43	BT
Sodium - Total	471	mg/l	1.0	6010D	30 May 18 17:43	BT
Potassium - Total	2.4	mg/l	1.0	6010D	30 May 18 17:43	BT
Iron - Dissolved	< 0.1	mg/l	0.10	6010D	5 Jun 18 11:32	SZ
Manganese - Dissolved	< 0.05	mg/l	0.05	6010D	5 Jun 18 11:32	SZ
Boron - Dissolved	0.50	mg/l	0.10	6010D	29 May 18 9:21	BT
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Barium - Dissolved	0.0970	mg/l	0.0020	6020B	29 May 18 17:35	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	29 May 18 17:35	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

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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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
www.mvtl.com

MEMBER ACIL

CERTIFICATE of ANALYSIS - STATE

Scott Hopfauf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Report Date: 6 Jun 18
Lab Number: 18-W1297
Work Order #: 82-1116
Account #: 007048
Date Sampled: 23 May 18 14:26
Date Received: 24 May 18 8:00
Sampled By: MVTL Field Services

Project Name: Minnkota-CCWDF

PO #: 180247

Sample Description: 95-4

Temp at Receipt: 3.9C

Event and Year: May 2018

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	30 May 18 17:07	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	29 May 18 17:35	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	29 May 18 17:35	CC

* Holding time exceeded

CC
16 Jun 18

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

APPENDIX C-3

FOX HILLS OBSERVATION WELL 3558
ANALYSES
FOR BASELINE DATA

MINNESOTA VALLEY TESTING LABORATORIES, INC.

MVTL

1126 N. Front St. ~ New Ulm, MN 56073 ~ 800-782-3557 ~ Fax 507-359-2890
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

Amended 2Feb21 (TDS)

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 28 Jan 21
Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	12 Jan 21	HT
pH - Field	8.42	units	NA	SM 4500 H+ B	12 Jan 21 12:45	JSM
Temperature - Field	11.8	Degrees C	NA	SM 2550B	12 Jan 21 12:45	JSM
Total Alkalinity	938	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Bicarbonate	912	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Carbonate	26	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	12 Jan 21 17:00	HT
Conductivity - Field	2641	umhos/cm	1	EPA 120.1	12 Jan 21 12:45	JSM
Tot Dis Solids(Summation)	1520	mg/l	12.5	SM1030-F	15 Jan 21 11:45	Calculated
Nitrate as N	< 0.2	mg/l	NA	EPA 353.2	14 Jan 21 9:17	Calculated
Bromide	2.83	mg/l	0.100	EPA 300.0	14 Jan 21 22:24	RMV
Total Organic Carbon	1.7	mg/l	0.5	SM5310C-11	22 Jan 21 17:28	NAS
Dissolved Organic Carbon	1.7	mg/l	0.5	SM5310C-96	22 Jan 21 17:28	NAS
Fluoride	3.54	mg/l	0.10	SM4500-F-C	12 Jan 21 17:00	HT
Sulfate	< 5	mg/l	10.0	ASTM D516-11	15 Jan 21 8:50	EV
Chloride	323	mg/l	2.0	SM4500-Cl-E-11	13 Jan 21 11:25	EV
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 9:17	EV
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	14 Jan 21 7:59	EV
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	15 Jan 21 8:17	EV
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	13 Jan 21 11:16	MDE

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

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Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	4.0	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Magnesium - Total	< 1	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Sodium - Total	630	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Potassium - Total	2.8	mg/l	1.0	6010D	15 Jan 21 11:45	MDE
Lithium - Total	0.186	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Total	< 0.1	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Iron - Total	0.40	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Silicon - Total	5.04	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Total	0.16	mg/l	0.10	6010D	20 Jan 21 10:36	MDE
Zinc - Total	< 0.05	mg/l	0.05	6010D	20 Jan 21 10:36	MDE
Boron - Total	2.87	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Calcium - Dissolved	3.7	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Magnesium - Dissolved	< 1	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Sodium - Dissolved	670	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Potassium - Dissolved	3.2	mg/l	1.0	6010D	15 Jan 21 9:45	MDE
Lithium - Dissolved	0.102	mg/l	0.020	6010D	21 Jan 21 15:22	MDE
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Iron - Dissolved	0.25	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Silicon - Dissolved	5.12	mg/l	0.10	6010D	26 Jan 21 9:37	MDE
Strontium - Dissolved	0.15	mg/l	0.10	6010D	20 Jan 21 9:36	MDE
Zinc - Dissolved	< 0.05	mg/l	0.05	6010D	20 Jan 21 9:36	MDE
Boron - Dissolved	2.85	mg/l	0.10	6010D	26 Jan 21 10:46	MDE
Antimony - Total	< 0.001	mg/l	0.0010	6020B	14 Jan 21 19:47	MDE

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Lab Number: 21-W40
Work Order #: 82-0072
Account #: 007033
Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Barium - Total	0.0966	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Copper - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Lead - Total	0.0006	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Manganese - Total	0.0088	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Molybdenum - Total	0.0058	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	14 Jan 21 19:47	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	14 Jan 21 19:47	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	14 Jan 21 19:47	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	15 Jan 21 14:56	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Barium - Dissolved	0.0954	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

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Date Sampled: 12 Jan 21 12:45
Date Received: 12 Jan 21 14:35
Sampled By: MVTL Field Services

Project Name: Center USGS Well

PO #: B. Botnen

Sample Description: USGS Well

Temp at Receipt: 8.9C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Manganese - Dissolved	0.0081	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Molybdenum - Dissolved	0.0058	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	15 Jan 21 14:56	MDE
Silver - Dissolved	< 0.001 ^	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	15 Jan 21 14:56	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	15 Jan 21 14:56	MDE

^ 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

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APPENDIX D

TESTING AND MONITORING – QUALITY CONTROL AND SURVEILLANCE PLAN

TESTING AND MONITORING – QUALITY CONTROL AND SURVEILLANCE PLAN
Tundra SGS (Secure Geological Storage)

1. PROJECT MANAGEMENT AND SURVEILLANCE PROCESS

From conception to closure, Tundra SGS operation will include the participation of multidisciplinary teams of government representatives, researchers , operator staff, consultants, and subcontractors. Each of these teams are highly specialized and recognized in their specific areas of expertise, providing technical and economic inputs to the project in order to ensure a safe, successful, and efficient operation.

Characterization of the reservoirs, seals, and subsurface features has been done by experienced professionals in geosciences from the Energy & Environmental Research Center (EERC), Oxy Low Carbon Ventures (OLCV), Schlumberger, etc., led by Minnkota Power Cooperative, Inc., applying the latest technology in logging and testing equipment as well as industry recognized software and techniques for modeling and simulations.

The main flowline, surface equipment, and well designs comply with industry standards for carbon dioxide (CO_2) material selection and operating conditions to guaranty mechanical integrity of the system during the life of the project and have been prepared by specialized companies such as Burns & McDonnell and OLCV.

Monitoring programs for leak detection, corrosion, and surveillance have been tailored for the site to ensure protection of underground sources of drinking water (USDWs), the environment, and communities; ensure the mechanical integrity of storage; maximize operating time; and extend the life of the assets. These plans incorporate best practices and recommendation for carbon capture and storage projects worldwide as well as the experience of years of development in enhanced oil recovery (EOR) fields.

As part of the quality control (QC) process, during testing and surveillance, most of the samples collected and data gathered will be analyzed, processed, validated, or witnessed by third parties independent and outside of the operator staff.

For specialized data such as seismicity and distributed temperature sensing (DTS), the project will have additional support from the provider of the selected technologies to perform QC and verification of the data as well as calibration of the systems as needed.

Sensors, transducers and controllers will be connected in a central platform (supervisory control and data acquisition [SCADA] system) to monitor the operating conditions, set alarms for malfunction, and establish safety protocols in case of abnormal conditions in the system. Data interfaces will be created for equipment that is not linked directly to the SCADA system, to be integrated in a unique surveillance platform.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the project will be stored in a central database to provide support for area of review (AOR) reviews, quality assurance (QA) programs, and reporting.

The project established a key staffing position that will ensure reliable operation with the highest standard of quality and surveillance procedures as well as accurate storage evaluation and reporting. Some of the staff will be dedicated full time to the operation, and others will be as required by AOR reviews, maintenance activities, or specific activities of the project.

Once the project is in operation, the Tundra SGS operator will maintain a contact list with the specific names of the individuals in each position and will keep that list updated.

1.1 Operator Organizational Chart

Figure D-1 shows the operator organizational chart for Tundra SGS.

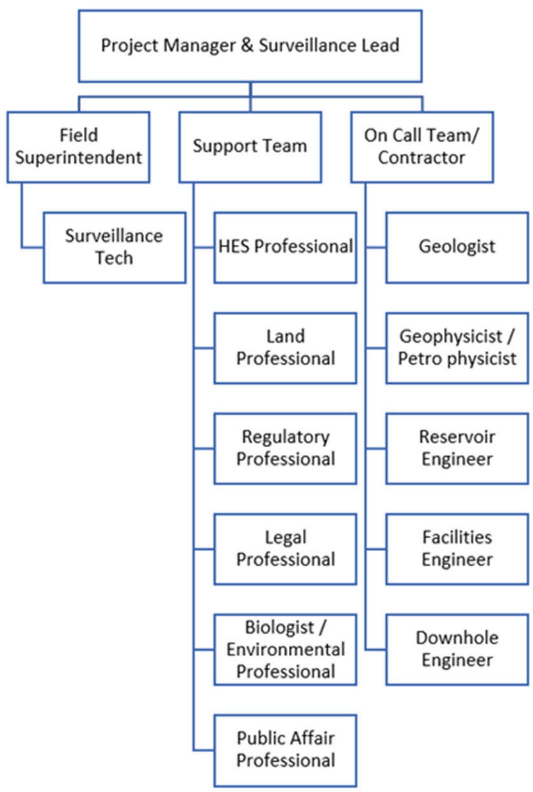


Figure D-1. Operator organizational chart.

A brief description of full-time positions is as follows:

- Project Manager: The project manager (PM) plays a central role in the implementation of all data gathering and analysis for the Tundra SGS project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans. The PM is responsible to enforce the data validation process and perform surveillance on the site.

- Field Superintendent: The field superintendent (FS) is responsible to ensure operating procedures are followed and any deviation from set parameters is corrected. The FS is responsible to verify surveillance is being performed and data are being communicated and reported properly. The FS is responsible to ensure all personnel comply with the safety worker plan and policies of the operator. The FS is the focal point for activation of the emergency response and remedial plan. The FS is responsible to coordinate personnel and contractors on the site.

- Surveillance Technician: The surveillance technician (ST) is responsible for the surveillance of the system on the field. The position is 24/7 and requires an experience SCADA operator to monitor the sequestration complex, clear alarms, and troubleshoot deviation from normal operation.

Additional to the key staffing positions and specialized consultants identified in the above sections, the project will have the support of additional subcontractors based on the scope of the work to be performed.

1.2 Data Verification and Validation

The project will establish a standardized program to validate the data and acquisition methods. The program will verify that collected data are reasonable, were processed and analyzed correctly, and are free of errors. Peer reviews or third-party consultant will be used as a QC mechanism to verify the information. If issues are identified during a peer review, they will be addressed and corrected by the data owner. If an error is identified in data under validation, in addition to correcting the error, affected work products and management decisions will be identified, affected users will be notified, and corrective actions will be coordinated to ensure that the extent of the error's impact is fully addressed.

1.3 Management of Change (MOC)

The project will implement a MOC procedure to communicate and document any deviation from facilities designs, policies, operational parameters, standard operating procedures, etc. The MOC procedure aims to control major deviations in cost.

1.4 Contractor Requirements

Each contractor will follow a qualification process defined by the operator, before being authorized to execute work in the site. Each contractor providing service to Tundra SGS must provide a copy of its QA/QC and safety management program before it is qualified to perform the work and might be audited by the operator's subject matter experts. All contractors are required to comply with the

Worker Safety Program described in this permit as well as the operator's policies at the working site. The operator reserves the right to inspect and audit contractors' operation and quality program to guaranty safety and quality programs are being followed.

1.5 Special Training/Certifications

Wireline logging, indirect geophysical methods, and some nonroutine sampling will be performed by trained, qualified, and certified personnel, according to the service company's requirements.

Routine injectate and groundwater sampling will be performed by trained personnel; no specialized certifications are required. Some special training will be required for project personnel, particularly in the areas of pulsed-neutron capture (PNC) logging interpretation, certain geophysical methods, certain data acquisition/transmission systems, and certain sampling technologies.

Training of project staff will be conducted by existing project personnel knowledgeable in project-specific sampling procedures. Training documentation will be maintained as project QA records.

1.6 Documentation, Records and Reporting

All data and project records will be stored electronically on secure servers and routinely backed up. Reporting will comply with North Dakota Administrative Code (NDAC) § 43-05-01-18.

2. TESTING AND MONITORING TECHNIQUES QA/QC

2.1 Logging Program

The logging program is described in detailed in the testing and monitoring section of the permit. These activities are executed by specialized contractors with proven technology in the oil and gas industry. Calibration and QC of the tools will follow specific protocols and procedures based on the provider. Example of data sheets for the different formation evaluation tools are included in the Appendix D-1 of this document as reference only.

2.1.1 Ultrasonic Casing Inspection Tool, Isolation Scanner, and Electromagnetic Pipe Examiner

For mechanical integrity evaluation, the Tundra SGS monitoring program proposed ultrasonic and electromagnetic tools that evaluate the conditions of the tubulars in the well and provide information about thickness, ovality, ruptures, potential corrosion, etc. Table D-1 provides basic data for each tool.

2.1.2 Pulsed-Neutron Logging

Pulsed-neutron logging is considered a proven technique to detect gas saturation in reservoirs. Advances in the technology have improved the accuracy of the tool to track the movement of the CO_2 plumes in the reservoir and evaluate flow conformance. Table D-2 shows basic specifications of the tools based on the provider.

Table D-1. Types of Data Provided by Individual Tools

Logging Type	Isolation Scanner	USIT	EM Pipe Xaminer	EM Pipe Scanner	CAST-XR
Logging Speed	2,700 ft/h	1800 ft/h	900 ft/h	1,800–3,600 ft/h	3,600 ft/h
Range of Measurement	0 to 10 Mrayl	0 to 10 Mrayl		1.5 in.	0–10 Mrayl
Temperature Rating	350°F	350°F	350°F	302°F	350°F
Casing Size Min.	4 ½ in.	4½ in.	2.38 in.	2⅞ in.	4.67 in.
Outside Diameter	3.37 in.	3.375 in.	1.69 in.	2.125 in.	3.625 in.
Weight	333 lb	333 lb	87 lb	110 lb	316 lb
1st Pipe Defect Detection Accuracy			1%	± 0.05 in	
1st Pipe (2Cs) Accuracy			2% or 0.015 in		
Total Metal Thickness 1.2 In (3Cs) Overall Average			7%		
Total Metal Thickness 1.8 In (4Cs) Overall Average			10%		

Table D-2. Data Specifications for the Pulsed-Neutron Logging Tool

Logging Type	Pulsar[1] – Neutron	TMD3D[2] Pulse Neutron
Acquisition	Real time	Real time
Logging Speed	200–3,600 ft/h	60–1,800 ft/h
Depth of Investigation		10–14 in.
Vertical Resolution		24 in.
Range of Measurement	0 to 60 pu	5 to 60 pu
Mud Type Limitations	None	None
Temperature Rating	350°F	300°F
Pressure Rating	15,000 psi	15,000 psi
Casing Size Min.	2⅜ in.	2 in.
Casing Size Max.	9⅝ in.	16 in.
Outside Diameter	1.72 in.	1.69 in.
Length	18.3 ft	14.25 ft
Weight	88 lb	35 lb

[1] Pulsar – Schlumberger technology.
[2] TMD3D – Halliburton technology.

2.2 Mud-Logging Sampling

Mud-logging samples must be collected from surface to final total depth (TD), every 30 ft maximum. The samples must be washed, dried, and placed in standard envelopes, and packed in the correct order into standard sample boxes. The sample boxes must be identified with a label indicating operator, well name, well file number, API number, and location and depth of samples and forwarded to the state core and sample library within 30 days of the completion of drilling operations.

2.3 Coring or Sidewall Coring (SWC) Sampling

The coring program is described in detailed in the specific drilling and completion program of the wells. The coring provider must provide tools in good condition and according to the program discussed with the technical team. Operators reserve the right to inspect the tools and request a replacement if substandard conditions are detected. The coring provider must provide the tools to cut, retrieve, and stabilize the core to get the maximum possible recovery factor. All cores or SWCs taken shall be preserved, placed in a standard core box, and the entire core forwarded to the state core and sample library, free of cost, within 180 days after completion of drilling operations.

2.4 MDT In Situ Stress Testing

The Schlumberger MDT (modular dynamics testing) tool delivers real-time formation temperature and pressure measurements and fluid sampling. The tools for formation pressure measurements incorporate a wireline-conveyed tester with a dual packer module, with two probes for pressure measurements, pumps, a flow control module, and sample chambers (Appendix D-2). Reservoir pressure measurements require inserting a probe into the reservoir and withdrawing a small amount of fluid. The pressure gauge is exposed to many temperature and pressure changes and has high resolution to accurately measure the dynamic conditions. Precise flowline control during testing and sampling ensures monophasic flow, delivering accurate permeability. In situ reservoir stress testing measurements provide formation breakdown, propagation, and closure pressures.

The dual-packer module (MRPA) is used to isolate formation intervals to provide enhanced data because the cross-sectional area of the isolated interval is greater than the standard MDT probe. This small interval lowers the wellbore storage effects. The MRPA is used to take pressure measurements and fluid samples in unconsolidated formations.

The MDT tool allows the measurements of the in situ reservoir stresses without breaking into confining zones. The tool creates a controlled fracture in the isolated zone and measures the related pressure response. The created fracture plane is perpendicular to the direction of the minimum in situ stress. The fracture is reopened and closed for measurement repeatability, with several constant rate injection cycles. The repeated cycles assist the fracture to grow beyond hoop stresses to sense far-field stresses accurately.

MDT interpretation software provides real-time plotting of pressure, resistivity, and optical properties versus time. This capability is essential for real-time QC and ongoing optimization of the job. Using the InterACT* wellsite-monitoring and control system provides real-time data transfer to remote sites.

2.4.1 Tool Limitations

Schlumberger's dual-packer mechanical specifications were set with a maximum differential pressure between the upper packer and the hydrostatic pressure of 5500 psi (Appendix D-3). This limited the maximum injection pressure during the microfracture stress tests in the formations, which caused certain tests to be unsuccessful.

2.5 Formation Pressure and Fluid Sampling

The self-sealing Saturn * 3D radial probe delivers circumferential flow in the formation around the wellbore to obtain representative formation fluid samples and provides downhole fluid analysis and complete pressure surveys (Appendix D-4). In the water-based mud environment, the MDT flowline resistivity measurement helps discriminate between fluid contaminated by mud filtrate and formation oil or freshwater. Formation pressure testing similarly requires fluid withdrawal.

2.6 Analysis of Injected CO_2

The CO_2 injection stream will be continuously monitored at the surface for pressure, temperature, and flow as part of the instrumentation and control systems of the site. Quarterly samples will be collected and analyzed to track CO_2 composition and purity. Based on the anticipated composition of the CO_2 stream, a list of parameters has been identified for analysis.

Additional to the parameters listed in Table D-3, isotopic signatures of the CO_2 stream will be analyzed as baseline for potential use in monitoring techniques.

Table D-3. CO_2 Stream Analysis

Parameter	Frequency
Pressure, psi	Continuous
Temperature, °F	Continuous
CO_2, %	Quarterly
Water, ppm	Quarterly
Nitrogen, ppm	Quarterly
Oxygen, ppm	Quarterly
Argon, ppm	Quarterly
Hydrogen, %	Quarterly
Sulfur Dioxide SO_2, ppm	Quarterly
Nitrogen Dioxide NO_2, ppm	Quarterly
Nitric Oxide NO, ppm	Quarterly
	Quarterly

2.6.1 Sampling and Custody

CO_2 sampling will be performed upstream or downstream of the flowmeter. Sampling procedures will follow contractor protocols to ensure the sample is representative of the injectant, and samples will be processed, packaged, and shipped to the contracted laboratory following standard sample handling and chain-of-custody guidance (U.S. Environmental Protection Agency [EPA] 540-R-09-03 or equivalent). Sampling tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers.

Once the samples are analyzed, the laboratory will be responsible of properly disposed containers and residues.

2.6.2 Equipment and Calibration

For sampling, field equipment will be maintained, serviced, and calibrated in accordance with manufacturer recommendations. Spare parts that may be needed during sampling will be included in supplies on hand during field sampling. For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory in accordance with method-specific protocols and the laboratory's QA program. The Tundra SGS operator reserve the right to audit the protocols and methods of the selected laboratory prior to awarding the work.

Calibration of all laboratory instrumentation/equipment will be the responsibility of the analytical laboratory in accordance with method-specific protocols and the laboratory's QA program, which will be reviewed by the alliance prior to contract award.

2.6.3 Personnel and Training

Sampling will be performed by trained personnel from the laboratory at the beginning of the operation, and the field staff will be trained in the procedures and protocols to take the samples.

2.6.4 Analytical Method

Table D-4 shows analytical parameters and methods.

Table D-4. Example Analytical Parameters and Methods

Analytical Parameter	Analytical Method	Detection Limit	Typical Precision/Accuracy
Water	GC/HID[2]	1 ppm to 100%	± 10%
	GC/TCD	1 ppm to 100%	± 1% of full scale
	GC/TCD	1 ppm to 100%	± 1% of full scale
	GC/TCD	1 ppm to 100%	± 1% of full scale
Hydrogen	GC/TCD	1 ppm to 100%	± 1% of full scale
Sulfur Dioxide	GC/FPD[3]		
Nitrogen Dioxide	Colorimetric	0.2 to 5 µL/L (ppmv)	
		0.2 to 5 µL/L (ppmv)	± 20%
Hydrogen Sulfide	GC/FPD	0 to 500 ppm	± 2% of full scale

[1] GC/TCD – gas chromatography with a thermal conductivity detector.
[2] GC/HID – gas chromatography with helium ionization detector.
[3] GC/FDP – gas chromatography with flame photometric detector.

Additional to compositional gas, the samples will be analyzed during the baseline period to identify the isotopes in Table D-5.

Table D-5. Isotopes to Be Identified During Baseline Sampling

Hydrocarbons	Method
$\delta^{13}C$ and ^{14}C of CO_2	GC–IRMS, AMS for ^{14}C

GC–IRMS, AMS = gas chromatography–isotope-ratio mass spectrometry/accelerator mass spectrometry.

2.6.4 Quality Control

If CO_2 composition shows abnormal values during the testing period, the project will perform a validation of the sampling process. A new sample will be collected by the laboratory technician and sent to the testing facilities for verification.

2.7 Corrosion Coupons

Samples of injection well materials (coupons) will be monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Coupons shall be collected and sent quarterly to a third-party company for analysis conducted in accordance with NACE (National Institute of Corrosion Engineers) Standard SP-0775-2018-SG to determine and document corrosion wear rates based on mass loss.

2.7.1 Sampling and Custody

Prior to installation of the corrosion-monitoring flow-through corrosion coupon test system, the following information should be recorded: coupon serial number, installation date, identification (ID) of the location in the system, and orientation of the coupon and holder. The coupon should be handled carefully to avoid contamination.

The field operator will collect the coupons and identify them by serial number, date, company name, ID of the location, ID of where the coupon was removed from, and the field operator name. The field operator will visually inspect the coupon for signs of erosion, pitting, scale, or other damage and take a photograph before packing the sample. The coupon will be protected from contamination by oxidation and handling, placing the coupon in a moisture-proof or special envelope impregnated with volatile corrosion inhibitor, and shipped immediately to the laboratory for analysis.

There is no special training required to collect the coupons; however, the field operator will be trained in best practices to keep the coupon for contamination, and process refreshers will be provided as part of the continuous training process.

2.7.2 Equipment and Calibration

The preparation, cleaning, and evaluation of the corrosion specimens will be handled by a certified third-party contractor and will follow NACE RP0775-2005 or equivalent. The contractor is responsible for the calibration and maintenance of the measurement equipment as well as the disposal of the samples when the analysis is finished.

2.7.3 Analytical Method

Table D-6 shows the analytical methods to be used for sampling.

Table D-6. Analytical Method to Be Used for Sampling

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

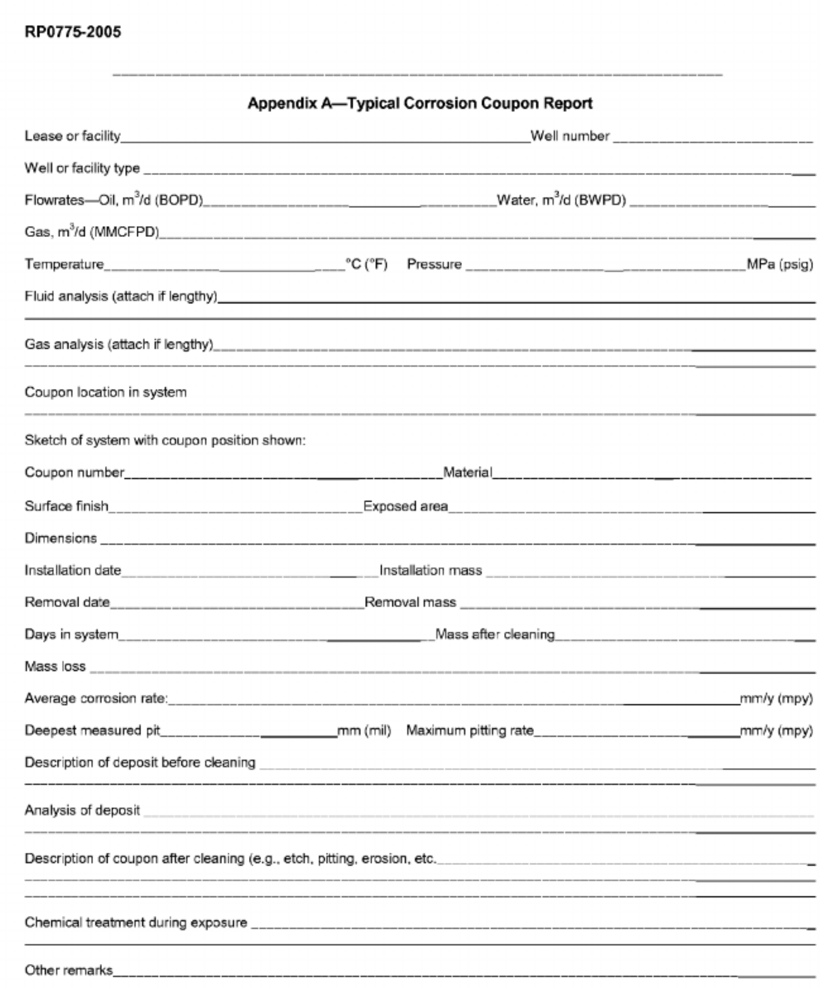
NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations.

2.7.4 Quality Control

The operators reserve the right to audit the QA/QC procedures prior to awarding the work to a contractor and during the execution of the service to ensure the quality and safety program are being followed.

2.7.5 Typical Corrosion Coupon Report

Figure D-2 provides an example typical corrosion coupon report.


RP0775-2005

Appendix A—Typical Corrosion Coupon Report

Lease or facility________ Well number________

Well or facility type________

Flowrates—Oil, m^3/d (BOPD)________ Water, m^3/d (BWPD)________

Gas, m^3/d (MMCFPD)________

Temperature________ °C (°F) Pressure________ MPa (psig)

Fluid analysis (attach if lengthy)________

Gas analysis (attach if lengthy)________

Coupon location in system________

Sketch of system with coupon position shown:

Coupon number________ Material________

Surface finish________ Exposed area________

Dimensions________

Installation date________ Installation mass________

Removal date________ Removal mass________

Days in system________ Mass after cleaning________

Mass loss________

Average corrosion rate:________ mm/y (mpy)

Deepest measured pit________ mm (mil) Maximum pitting rate________ mm/y (mpy)

Description of deposit before cleaning________

Analysis of deposit________

Description of coupon after cleaning (e.g., etch, pitting, erosion, etc.________

Chemical treatment during exposure________

Other remarks________

Figure D-2. Example typical corrosion coupon report.

2.8 Soil Gas Sampling

The method for soil gas sampling is described in Appendix C of the permit. The samples will be sent to a specialized laboratory to determine gas composition and perform isotopic analysis to characterize the fluid and get a fingerprint for appropriation. In between sampling events, a handheld device should be enough for routine monitoring purposes, which could be done monthly.

2.8.1 Analytical Method

Compositional analysis of the gases includes chromatographic determination of the concentrations of fixed gases and hydrocarbons listed in Table D-7.

Table D-7. Fixed Gas and Hydrocarbons for Compositional Analysis

Fixed Gases		**Method**
Nitrogen	N_2	GC
Oxygen	O_2	GC
Argon	Ar	GC
Carbon Dioxide	CO_2	GC
Carbon Monoxide	CO	GC
Hydrogen	H_2	GC
Helium	He	GC
Hydrocarbons		**Method**
Methane	CH_4	GC
Ethane	C_2H_6	GC
Ethylene	C_2H_4	GC
Propane	C_3H_8	GC
Propylene	C_3H_6	GC
Isobutane	iC_4H_{10}	GC
Normal Butane	nC_4H_{10}	GC
Isopentane	iC_5H_{12}	GC
Normal Pentane	nC_5H_{12}	GC
Hexanes Plus	C_6+	GC

In addition to compositional gas analysis, the samples will be analyzed during the baseline period to identify the isotopes in Table D-8.

Table D-8. Isotopes to Be Identified During Baseline Sampling

Hydrocarbons	**Method**
$\delta^{13}C$ and ^{14}C of CO_2 and CH_4	GC–IRMS, AMS for ^{14}C
δD of CH_4.	GC–IRMS

Isotopes are different forms of the same element, differing only in the number of neutrons in the nucleus of the atom. Although some isotopes are unstable and decay radioactively, most are stable. Isotopes are valuable tools to distinguish the source of the element and create a fingerprint of the gas.

2.8.2 Equipment and Calibration

Calibration will be performed in accordance with manufacturer protocol. Sampling will be performed by trained or specialize personnel from the lab at the beginning of the operation, and the field operator will be trained in the process to be able to take samples and monitor gas composition with handheld devices as routine operation.

2.9 Water Sampling

2.9.1 Sampling and Custody

2.9.1.1 Sampling Flowing Surface Waters (rivers, streams, drainage ditches)

- Surface water samples at both flowing water and still water sites will be collected using the nonisokenetic (bottles or bailers) sampling method. Field measurement instruments will be calibrated in accordance with manufacturer instructions.

- Before samples are collected, the sample-wetted portions of most of the collection and processing equipment require a field rinse with native water. Field rinsing helps to condition sampling equipment to the sample environment. Rinsing also serves to ensure that all cleaning solution residues have been removed. An area of low-flow turbidity should be located at the sampling site to partially fill and rinse the bottle sampler, trying to avoid getting sand or sediment in the sampler.

- Location and site conditions will be recorded on the field data sheets (i.e., GPS [global positioning system] coordinates, air temperature, wind speed, precipitation, and barometric pressure). An area will be identified in the flowing water body where the water is well mixed laterally and vertically. In general, downstream samples should be collected first followed by upstream samples to minimize disturbance of bottom sediments. Extreme caution should be taken wading in fast-flowing water, and every attempt should be made to utilize a sampling device that does not require wading. In general, personnel shall not wade into flowing water when the product of depth (in feet) and velocity (in feet per second) equals 10 or greater. If flow data are not available, personnel shall not exceed a water depth of knee height. For sample locations that are considerable distance from the shoreline, a boat, dock, or bridge may be employed for sampling.

- Using a bottle, the sample should be collected by standing downstream of the bottle. Care must be taken to avoid collecting particulates that might be resuspended as the result of wading.

- Following the manufacturer instructions for the YSI multiparameter meter and the HANNA chemistry kits, the following measurements should be taken on the first sample collected: temperature, pH, conductivity, dissolved oxygen (DO), total dissolved solids (TDS), oxidation reduction potential (ORP), CO_2, alkalinity calcium carbonate ($CaCO_3$), and chloride (Cl). Measurements should be recorded on the field data sheet.

- Sample containers should be filled and samples filtered and/or preserved according to instructions in Section 7.0. Date and time of sampling should be recorded on the field data sheet.

- Samples should be labeled with the name of the person sampling, sample description, date, and time. The chain-of-custody form should also be completed.

- Any unusual conditions or deviations from the sampling procedure should be documented on the field data sheet.

2.9.1.2 Sampling Still Waters (lakes, reservoirs, ponds, marshes)

- Since still waters have a greater tendency to stratify than rivers or streams, it is important to collect a vertical sample near the bottom of the body of water without disturbing the sediment.

- If the body of water is so large that the sampling locations cannot be reached from the bank, it may be necessary to use a small boat to reach the sampling area.

- If using a bailer or bottle, the sampler should be slowly lowered to the desired depth while minimizing disturbance of the water column, the sample collected, and the sampler slowly raised to the surface. Sampling should be repeated until enough water is collected for the sample bottles.

- If using a peristaltic pump, the pump sample tubing (attached to a weighted line) should be lowered to the desired sampling depth. The pump should be turned on, and about three sample tubing volumes should be pumped to rinse and condition the pump, tubing, and other sample collection or processing equipment. The rinse should be discarded.

- Following the manufacturer instructions for the multiparameter meter and the chemistry kits, the following measurements should be taken on the first sample collected: temperature, pH, conductivity, DO, TDS, ORP, CO_2, alkalinity ($CaCO_3$), and Cl. Measurements should be recorded on the field data sheet.

- Flow should be direct sampled into collection container(s) until sufficient sample volume has been collected to fill sample bottles.

- Sample containers should be filled and samples filtered and/or preserved. Date and time of sampling should be recorded on the field data sheets.

- Samples should be labeled with the name of person sampling, sample description, date, and time. A chain-of-custody form should be completed.

- Any unusual conditions or deviations from the sampling procedure should be documented on the field data sheet.

2.9.1.3 Ground Water Sampling

Purging the well removes standing and/or stagnant water from the well casing. The purpose of purging is to reduce chemical and biochemical artifacts caused by the materials used for well installation and well construction and by reactions occurring within an open borehole or annular space between a well casing and borehole wall. The rule of thumb is to remove a minimum of three well casing volumes while monitoring field parameters until they stabilize before actual samples can be collected. The well diameter, water level, well bottom depth, and purge volume should be recorded on the field data sheet. At a minimum, three well volumes should be purged while monitoring the temperature, pH, and conductivity until the readings have stabilized. If the readings have stabilized after three well volume purges and meet the criteria in Table D-9, sample collection can proceed. If readings are not stable after three volumes, purge should continue until they are stable, but ten purge volumes should not be exceeded before collecting samples. Those instances when readings are not stable prior to sample collection should be documented. The following stability criteria for the measurements are the allowable variation among five or more field measurements.

Table D-9. Field Measurement Stability Criteria

Field Measurement	Stability Criteria
pH	± 0.1 standards units
Temperature, °C	± 0.5°C
Conductivity, mS/cm	± 5%

2.9.2 Equipment and Calibration

For groundwater sampling, field equipment will be maintained, serviced, and calibrated according to the manufacturers' recommendations. Spare parts that may be needed during sampling will be included in supplies on hand during field sampling. For all laboratory equipment, testing, inspection, maintenance, and calibration will be the responsibility of the analytical laboratory according to method-specific protocols and the laboratory's QA program.

2.9.3 Personnel and Training

Water testing will be performed by personnel of a certified laboratory following the specific methods approved by EPA or other standard. The operator might audit the procedures and results of the selected laboratory with a third party to improve QC.

2.9.4 Analytical Method

Where possible, methods are based on standard protocols from EPA or Standard Methods for the Examination of Water and Wastewater. Laboratories shall have standard operating procedures for the analytical methods performed (Table D-10).

Table D-10. Analytic Method and Parameters that May Be Used During Testing

Parameter	Analytical Method
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si, Zn, Sr	ICP–AES, EPA Method 200.7 or similar
Trace Metals: Sb, As, Cd, Cr, Cu, Pb, Se, Tl	ICP–MS, EPA Method 200.8 or similar
Cyanide (CN-)	EPA 335.4, olorimetry
Mercury	EPA 245.1, CVAA
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, PO_4^{3-}, NO_3^-	Ion chromatography, EPA Method 300.1, 4110B or similar
Total and Bicarbonate Alkalinity (as $CaCO_3^{2-}$)	Titration, Standard Methods 2320B
Hardness—Total, as $CaCO_3$, mg/L	Automated colorimetric, EPA 130.1
Gravimetric TDS	Gravimetric method Standard Methods 2540C
Water Density	ASTM International D5057 or equivalent
Total Inorganic Carbon (TIC)	SW846 9060A or equivalent
Dissolved Inorganic Carbon (DIC)	SW846 9060A or equivalent
Total Organic Carbon (TOC)	SW846 9060A or equivalent
Dissolved Organic Carbon (DOC)	SW846 9060A or equivalent
Volatile Organic Analysis (VOA)	SW846 8260B or equivalent
Methane	RSK-175 Mod headspace GC/FID or equivalent
Stable Carbon Isotopes $^{13/12}C$ (^{113}C) of DIC in Water	Gas bench and CF-IRMS for $^{13/12}C$
Radiocarbon 14C of DIC in Water	AMS for ^{14}C
Hydrogen and Oxygen Isotopes $^{2/1}H$ (δ) and $^{18/16}O$ (^{118}O) of Water	CRDS H_2O
Carbon and Hydrogen Isotopes (^{14}C, $^{13/12}C$, $^{2/1}H$) of Dissolved Methane in Water	Offline prep and dual inlet IRMS for ^{13}C; AMS for ^{14}C
Compositional Analysis of Dissolved Gas in Water (including N_2, CO_2, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, iC_4H10, nC_4H_{10}, iC_5H_{12}, nC_5H_{12}, and C_{6+})	GC, modified ASTM 1945D
pH	pH electrode, EPA 150.2, D1293
Temperature	2550B
Conductivity	2510B
Specific Conductance	EPA 120.1

ICP–AES = inductively coupled plasma atomic emission spectrometry; ICP–MS = inductively coupled plasma mass spectrometry; LCS = laboratory control sample; GC/MS = gas chromatography–mass spectrometry; GC/FID = gas chromatography with flame ionization detector; AMS = accelerator mass spectrometry; CRDS = cavity ring down spectrometry; IRMS = isotope ratio mass spectrometry; CVAA: cold-vapor atomic absorption; CF–IRMS: continuous flow isotope ratio mass spectrometry.

2.9.5 Quality Control

QC of the sampling and results will follow the protocols established in the analytical method for testing. The Tundra SGS operator reserves the right to audit the lab procedures and protocols to validate the methods are being follow and the results are accurate.

2.10 CO_2 Flowline Monitoring with Fiber Optics

2.10.1 Equipment and Calibration

Fiber optic cables are installed on the flowline for continuous conditioning monitoring. This method is accurate, continuous, and can detect leaks, movement of the flowline due to seismic activities, ground erosion, etc. The main characteristics are as follows:

- Distributed acoustic sensing (DAS): Various DAS technologies are used in the market; the most common is based on coherent optical time domain reflectometry (C-OTDR). C-OTDR utilizes Rayleigh back-scattering, allowing acoustic frequency signals to be detected over long distances. The interrogator sends a coherent laser pulse along an optical fiber (sensor cable). Scattering sites within the fiber causes the fiber to act as a distributed interferometer with a gauge length like the pulse length. Acoustic disturbance on a fiber generates microscopic elongation or compression of the fiber (microstrain), which causes a change in the phase relation and/or amplitude. Before the next laser pulse can be transmitted, the previous pulse must have had time to travel the full length of the fiber and for its reflections to return. Hence, the maximum pulse rate is determined by the length of the fiber. Therefore, acoustic signals can be measured that vary at frequencies up to the Nyquist frequency, which is typically half of the pulse rate. As higher frequencies are attenuated very quickly, most of the relevant ones to detect and classify events are in the lower of the 2-kHz range.

- Distributed temperature sensing (DTS): DTS uses fiber optic sensor cables, typically over lengths of several kilometers, that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS utilizes the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in some scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The anti-Stokes Raman signal changes its amplitude significantly with changing temperature; the Stokes Raman signal is relatively stable. The *position* of the temperature reading is determined by measuring the arrival timing of the returning light pulse similar to a radar echo.

- Distributed stain sensing (DSS): DSS detects change in strain along the flowline due to shifting soil, erosion, frost, and seismic activities.

2.10.2 Resolution and Accuracy

Multiple strands of optical fibers in a sheath are installed to take care of the monitoring requirements listed above. A single standard-range temperature sensor can measure up to 9 mi (15 km) of fiber with 3-ft (1-m) resolution, update data in just a few seconds, and resolve temperatures to 0.018°F (0.01°C). The DAS/strain sensor can measure 25 mi in intervals of 6.5 ft to give multiple data alongside the pipe.

Table D-11. Technical Specifications for DTS Sensor

Parameter	
Number of Channels	12 SE or 6 DE
Total Fiber Length (SE)	9 mi
Spatial Resolution	3 or 6 ft
Sample Spacing	15. or 3 ft
Temperature Repeatability	±1.8°F in 12 s
Operating Temperature	32° to 104°F
Non-Operating Temperature	−4° to 149°F
Humidity	5% to 85% relative

Table D-12. Technical Specifications for Intelligence Vibration Sensor/Strain

Parameter	
Number of Channels	1 SE
Total Fiber Length (SE)	25 mi
Lost Budget	18.5 dB
Output	Full aperture seismic waveform or vibration logs
Measurement Parameter	Strain
Operating Wavelength	1550 nm
Range	25 mi
Output Spatial Interval	6.6, 16.4 and 32.8 ft
Output Time Interval	0.1, 0.25, 0.5, 1 and 2 ms
Low-Frequency Limit	5 Hz
Operating Temperature	32° to 113°F
Storing Temperature	−4° to 158°F

2.10.3 Quality Control

The fiber optic cable is governed by American National Standards Institute (ANSI)/Insulated Cable Engineers Association (ICEA) S-87-640 and ANSI/ICEA S104-696 standards. The size and construction details of the cable and installation details will be decided during detailed design of the flowline in consultation with the vendor specialized in the engineering and installation of fiber optic cables.

2.11 Continuous Recording of Injection Pressures, Rate, Temperature, and Volume

Injection pressure and temperature will be continuously measured at the surface via real-time pressure/temperature (P/T) instruments installed in the CO_2 flowline near the interface with the wellhead. The pressure will be measured by electronic pressure transmitter, with analog output mounted on the CO_2 line associated with each injection well (example technical specifications shown in Table D-13). The temperature will be measured by an electronic temperature transmitter mounted in the CO_2 line at a location near the pressure transmitter, and both transmitters will be located near the wellhead (Table D-14).

Table D-13. Technical Specifications for Surface Pressure Gauges

Parameter	
Calibrated Working Pressure Range	0 to 3,000 psi
Pressure Resolution	0.001 psi
Type of Sensor	4–20-mA output transmitter; static measurement; 4-wire

Table D-14. Technical Specifications for Surface Temperature Gauges

Parameter	
Calibrated Working Temperature Range	0 to 150°F
Temperature Accuracy	±0.0055%
Temperature Resolution	0.01°F
Type of Sensor	4–20-mA output; RTD

RTD = resistance temperature detector.

Continuously recorded injection parameters will be reviewed and interpreted on a regular basis, to evaluate the injection stream parameters against permit requirements (example technical specifications found in Table D-15). Trend analysis will also help evaluate the performance (e.g., drift) of the instruments, suggesting the need for maintenance or calibration.

Table D-15. Technical Specifications for Multivariable Pressure Transmitter

Parameter	
Mass Flow Rate Accuracy	±0.075%
Differential Pressure	−1000 to 1000 in H_2O (−2.5 to 2.5 bar)
Static Pressure Type	Gauge
Static Pressure Range Url	3,626 psi
Temperature Range	−328° to 1562°F
Type of Equipment	Orifice meter with multivariable transmitters and direct process variable outputs for static pressure, differential pressure, and temperature

The flow rate of CO_2 injected into the well field will be measured by flowmeter skids with senior orifice meters (Table D-16). A total of three meters will be supplied. Each well will have a dedicated meter. Piping and valving will be configured to permit the calibration of each flowmeter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flowmeter skid.

Table D-16. Technical Specifications for Senior Orifice

Senior Orifice	
Sizing	8-in., 16-in. ranges, flow rate by manufacturer
Temperature Range	−50° to 200°F
Tolerance	Based on manufacturer manual

The flowmeters will be connected to the main CO_2 storage site SCADA system for continuous monitoring and control of the CO_2 injection rate into each well. The flow rate into each well will be controlled using a flow control valve located in the CO_2 pipeline associated with each well.

Pressure and temperature gauges will be deployed on tubing above and below the injection packer to monitor in real-time bottomhole conditions. The gauges and cables will be selected to comply with CO_2 service conditions, and the data will be integrated in the SCADA system and the surveillance platform. Table D-17 shows an example of technical specifications for downhole gauges.

Table D-17. Technical Specifications for Downhole Sensors P/T

Parameter	
Pressure of Sensor	Quartz/Inconel® Carriers
Pressure Accuracy	± 0.02%
Pressure Repeatability	≤0.01% of full scale
Temperature Sensor	Quartz/Inconel carriers
Temperature Accuracy	±0.5°C
Temperature Resolution	0.005°C
Operating Temperature Ranges	−20° to 200°C
Sample Rate	1 s
Inconel Cable	Required

2.12 Annular Pressure Testing

Annular pressure testing is used to validate mechanical integrity in the system. Tests will be performed at least once every 5 years in injectors and monitoring wells, when tubing and packer are pulled for workover, or when the monitoring systems indicate a potential mechanical integrity issue.

To start the test, the well is shut in to stabilize the pressures (injectors). The testing equipment is connected to the annular valves, and surface lines are tested to 1500 psi above the testing pressure. The operator must ensure there are no surface leaks from the pumping unit to the wellhead valve. Any air in the system is bled. If needed, the annular I completed with packer fluid and corrosion inhibitor (it should require minimum amount if so). Initial tubing and casing pressure are recorded. The well will be tested to 1000 psi in the annular, and the pressure should not decrease more than 10% in 30 minutes. Tubing and casing pressure is monitored continuously. Final tubing and casing pressure are recorded and pressure and volume bled.

If the pressure decreases more than 10%, the pressure is bled, the surface connection tested, and the test repeated. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the director.

Surface gauges should be calibrated according to manufacturer recommendations and should have a pressure range which will allow the test pressure to be near the midrange of the gauge. Additionally, the gauge must be of sufficient accuracy and scale to allow an accurate reading of a 10% change. The test results will be documented and store in the centralized database of the project for reporting and documentation.

2.13 Fall-Off Test in Injector Wells

Pressure fall-off testing will be conducted upon completion of the injection wells to characterize reservoir hydrogeologic properties and aquifer response model characteristics as well as changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Pressure fall-off testing will also be conducted at least once 5 years after injection for AOR review. Specifically, the objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect well/reservoir performance.

2.13.1 Testing Method

Controlled pressure fall-off tests are conducted by terminating injection for a designed period/duration of time. The pressure fall-off test is then started with shutting in the well by closing the surface wellhead valve(s) and maintaining continuous monitoring of the surface and downhole pressure recovery within the well/test interval system during the fall-off/recovery period. The designed duration of the pressure fall-off recovery test is a function of a number of factors, including the exhibited preoperational injection reservoir test response characteristics, injection well history prior to termination (i.e., injection duration, rate history), and potential pressure interference effects imposed by any surrounding injection wells completed within the same reservoir. Because of the potential impact of injection rate variability on early-time pressure fall-off recovery behavior, its recommended that injection rates and pressures be uniform and held constant prior to initiating a pressure fall-off test.

Upon shutting-in the well, pressure measurements are monitored continuously in real time, both downhole (within or in the proximity to the injection reservoir) and at the surface wellhead location. Temperature measurements taken during the test may assist in data interpretation. Bottomhole reservoir pressure measurements may be less subject to data scatter, and because of the compressible nature of supercritical and liquid CO_2, bottomhole gauges should be the least affected by wellbore effects. Wellhead (surface) pressure measurements may be sufficient if a positive pressure is maintained at the surface throughout the test.

The duration of the shut-in period used in conducting the pressure fall-off test should be extended sufficiently beyond wellbore storage effects and when the pressure recovery is indicative of infinite-acting radial flow (IARF) conditions. The establishment of IARF conditions is best determined by using pressure derivative diagnostic analysis plots (Boudet and others, 1989; Spane, 1993; Spane and Wurstner, 1993) and is indicated when the log–log pressure derivative/recovery time plot forms a horizontal line. When IARF pressure fall-off conditions are indicated, the pressure response versus log of fall-off/recovery time becomes a straight line on a standard semi-log plot.

EPA (2012) recommends a general rule-of-thumb of extending pressure fall-off tests a factor of three to five beyond the time required to reach radial flow conditions, while Earlougher (1977) suggests extending recovery periods between 1 and 1.5 log cycles beyond when the pressure response starts to deviate from purely wellbore storage response characteristics (i.e., a unit slope, 1:1 on a standard log–log pressure fall-off recovery plot).

For projects like the Tundra SGS Broom Creek Formation that will use more than one injection well completed in the same reservoir, special considerations need to be taken to execute the pressure fall-off testing to minimize the pressure response impacts from neighboring injection wells in the well recovery response. For the neighboring injection wells (i.e., those not being tested), EPA (2012) recommends that injection at these wells either be terminated prior to initiating the pressure fall-off test for a duration exceeding the planned shut-in period or injection rates at the neighboring wells be held constant and continuously recorded prior to and during the fall-off recovery test. Following the fall-off test, owners or operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well. These pulses will demonstrate communication between the wells, and if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

No specialized sample/data-handling procedures are required. Electronic sensor data (e.g., pressure data) will be recorded on data loggers. All electronic data and field records will be transferred and stored on secure servers at the conclusion of each test.

2.13.2 Analytical Methods

Quantitative analysis of the pressure fall-off test response recorded following termination of injection for the test well provides the basis for assessing near well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots established prior to the operational injection of CO_2 and periodic fall-off tests conducted during the operational injection phases can be used to determine whether significant changes in well or injection reservoir conditions have occurred. Diagnostic derivative plot analysis (Boudet and others, 1989; Spane, 1993; Spane and Wurstner, 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

The plotting of downhole temperature concurrent with the observed fall-off test pressure is also useful diagnostically for assessing any observed anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures responding differently than registered within the probe sensor), erroneous fall-off pressure response results maybe be derived. As previously discussed, concurrent plotting of downhole temperature and pressure fall-off responses is commonly useful for assessing when temperature anomalies may be affecting pressure fall-off/recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log–log and semi-log plots of observed pressure change and/or pressure derivative plots versus recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity, etc.) based on characteristic diagnostic fall-off pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard and others (2009).

Early pressure fall-off recovery response corresponds to flow conditions within and in the proximity of the wellbore, while later fall-off recovery response is reflective of progressively more distant reservoir conditions from the injection well location. Significant divergence in pressure fall-off response patterns from previous pressure fall-off tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure fall-off tests for discerning possible changes to well and reservoir conditions is presented by EPA (2002).

Quantitative analysis of the pressure fall-off test data can be used to determine formation hydraulic property characteristics (e.g., permeability, transmissivity) and well skin factor (additional pressure change effects due to altering the permeability/storativity conditions of the reservoir/well injection interval boundary). Determination of well skin is a standard result for pressure fall-off test analysis and described in the standard well test analysis texts such as that by Earlougher (1977). Software programs are also commercially available for analyzing pressure fall-off tests. Significant changes in well and reservoir property characteristics (as determined from pressure fall-off analysis), compared to those used in site computational modeling and AOR delineation, may signify a reevaluation of the AOR.

2.13.3 Instrument/Equipment Calibration and Frequency

All field equipment will be visually inspected and tested prior to use. Spare instruments, batteries, etc., will be stored in the field support trailer.

Pressure gauges that are used to conduct fall-off tests will be calibrated in accordance with manufacturer recommendations. In lieu of removing the injection tubing to regularly recalibrate the downhole pressure gauges, their accuracy might be demonstrated by comparison to a second pressure gauge, with current certified calibration, that will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves, based on annual calibration checks (using the second calibrated pressure gauge) developed for the downhole gauge, can be used for the purpose of the fall-off test. If used, these calibration curves (showing all historic pressure deviations) will accompany the fall-off test data.

2.14 CO_2 Leak Detector

An infrared gas detector will be installed closed to the wellheads of the injector wells and the monitoring well. This sensor will be the interface with the surveillance system to set alarms and provide information on potential leaks at the surface. An example of sensor technical specifications is described in the following data sheet as a reference only (Figure D-3). Final selection of the technology will consider the integration of all the sensors and transducers in a unique surveillance system. Calibration and maintenance protocols will be based on manufacturer specifications and will be performed by specialized professionals. Table D-18 shows referential technical specifications for the CO_2 leak detector.

2.15 DTS Fiber Optic Array Downhole

DTS for downhole application follows the same physical principle discussed for flowline monitoring in the previous sections. The fiber optic is run alongside the casing as an umbilical, and it is protected with clamps and a centralizer to avoid any damage while deploying in the well. The fiber is connected on surface to an interrogator to convert the signal to temperature values, and data are transmitted to the monitoring platform in real time to perform surveillance.

The maintenance and calibration of the equipment will be performed in accordance with manufacturer manuals and will be the responsibility of the provider of the technology. Tables D-19 and D-20 show referential technical specification for DTS systems and fiber optic cable.

2.16 Time-Lapsed 3D Seismic Survey

3D surface seismic is a proven deep reflection technique utilizing seismic sources and receivers to produce full volumetric images of subsurface structure including reservoir and overburden. Under favorable circumstances, 3D surface seismic can offer spatial resolution down to a few meters or less. It offers an effective means of imaging compressible fluids (i.e., CO_2) in the subsurface. A key application of surface seismic methods for monitoring purposes is the time-lapse 3D (4D) seismic method, in which a number of repeat surveys are acquired, enabling changes in fluid distribution to be mapped through time. This has been used successfully in the oil industry to image fluid changes in hydrocarbon reservoirs for a number of years. The technique produces reflections that correspond to P-wave acoustic impedance boundaries in the subsurface. These are commonly associated with boundaries between different rock units, so reflectivity is an effective proxy for subsurface structure. Because of its physical properties, CO_2 in the free (gaseous or fluid) state is highly compressible, which enhances reflectivity over a range of underground storage situations and is particularly well-suited to seismic imaging methods.

2.16.1 Equipment and Calibration

Seismic acquisition and processing are performed by highly specialized companies and crews that provide the equipment, procedures, and QC protocols based on the technology selected for acquisition and parameters for processing the data. As such, these parameters are verified by the client with a parameter sheet, as shown in Figure D-4.

S5000 **Gas Monitor**

Specifications

General Monitors by MSA

Product Specifications		
COMBUSTIBLE GAS SENSOR TYPE	Catalytic bead (Passive comb., XCell comb.) Infrared (IR400)	
TOXIC GAS & OXYGEN SENSOR TYPE	**XCell Toxic**	Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Chlorine (Cl_2), Sulfur Dioxide (SO_2)
	Passive MOS, Echem, **XCell Toxic**	Hydrogen Sulfide (H_2S)
	XCell O_2	Oxygen (O_2)
	Infrared	Carbon Dioxide (CO_2)
	Electrochem	Ammonia (NH_3), Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Nitric Oxide (NO), Nitrogen Dioxide (NO_2)
SENSOR MEASURING RANGES	**Combustible**	0-100% LEL (CB, IR)
	Cl_2	0-5, 0-10, 0-20 ppm
	CO	0-100, 0-500, 0-1000 ppm
	CO, H_2-resistant	0-100 ppm
	CO_2	0-2000, 0-5000, 0-10000, 0-30000, 0-50000 ppm
	H_2	0-1000 ppm
	HCl	0-50 ppm
	HCN	0-50 ppm
	H_2S	0-10, 0-20, 0-50, 0-100, 0-500 ppm
	NH_3	0-100 ppm, 0-1000 ppm
	NO	0–100 ppm
	NO_2	0-10 ppm
	O_2	0-25%
	SO_2	0-25, 0–100 ppm
APPROVALS CLASSIFICATION	*See manual for complete CSA listings.*	
DIVISIONS (US/CAN)	Class I, Div/Zone 1&2, Groups A, B, C & D T5/T4; Class II, Div/Zone 1&2, Groups E, F & G, T6; Class III Type 4X, IP66	
US ZONES	Class I, Zone 1 AEx db IIC T5 Gb Class I, Zone 2 AEx nA nC IIC T4 Gc Zone 21 AEx tb IIIC T85°C Db	
CANADIAN ZONES/ ATEX/ IECEx	Ex db IIC T5 Gb Ex nA nC IIC T4 Gc Ex tb IIIC T85°C Db	
CE MARKING DIRECTIVES	Complies with EMC, RED, ATEX	
WARRANTY	**S5000 transmitter**	2 years
	XCell Sensors	3 years
	Passive comb., MOS, IR400, IR700	2 years
	Echem Sensors	Varies by gas
APPROVALS	CSA, FM**, ATEX, IECEx, INMETRO, ABS, DNV-GL Marine, CE Marking. Complies with C22.2 No. 152, FM 6320, ANSI/ISA/CSA/IEC/EN 60079-29-1, ANSI/ISA 12.13.01. Suitable for SIL 2.	

Dimensions	
HOUSING (W x H x D)	6.37" x 5.38" x 4.25" (162 x 137 x 108 mm)
W/PASSIVE SENSOR	6.37" x 7.62" x 4.25" (162 x 193 x 108 mm)
W/DIGITAL SENSOR	6.37" x 10.4" x 4.25" (162 x 265 x 108 mm)
W/IR400 IR SENSOR	14.8" x 6.0" x 4.25" (375 x 152 x 108 mm)
WEIGHT	8 lb. (3.6 kg), 316 SS

Environmental Specifications		
OPERATING TEMPERATURE RANGE	**Transmitter**	-55°C to +75°C
	CB (sintered, Zones)	-40°C to +70°C
	CB (screened, Div)	-40°C to +75°C
	MOS (sintered, Zones)	-40°C to +70°C
	MOS (screened, Div)	-40°C to +75°C
	IR (CSA)	-40°C to +75°C
	IR (ATEX/IECEx)	-60°C to +75°C
	XCell (Comb)	-55°C to +60°C
	XCell (Toxic/O_2)	-40°C to +60°C
STORAGE TEMPERATURE RANGE	**Housing, IR400, IR700, passive sensors**	-50°C to +85°C
	XCell sensors	-40°C to +60°C
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell sensors, IR400, IR700**	10-95%
	Passive combustible	0-95%
	Passive H_2S	15-95%

Mechanical Specifications			
INPUT POWER	24 VDC nominal, 12 to 30 VDC		
SIGNAL OUTPUT	Dual 4-20 mA current source or sink, HART, Modbus, Bluetooth. *Optional: w/o Bluetooth*		
RELAY RATINGS	5A @ 30VDC; 5A @220 VAC (3X) SPDT – fault, warn, alarm		
RELAY MODES	Common, discrete, horn		
NORMAL MAX POWER		**Without Relays**	**With Relays**
	Passive comb.	5.0 W	6.0 W
	Passive MOS	9.8 W	10.8 W
	IR400/IR700	7.9 W	8.9 W
	XCell comb.	5.0 W	6.0 W
	XCell toxic & O_2	2.6 W	3.6 W
	IR400/IR700 + XCell comb.	10.8 W	11.8 W
	IR400/IR700 + XCell toxic or O_2	8.6 W	9.6 W
	Dual XCell toxic or O_2	3.3 W	4.3 W
	Dual XCell comb.	7.4 W	8.4 W
	XCell comb. + XCell toxic or O_2	5.7 W	6.7 W
STATUS INDICATORS	4-digit scrolling LED, icons depicting fault, warn, alarm, Bluetooth, 1 and 2 to indicate sensor reading displayed		
RS-485 OUTPUT	Modbus RTU, suitable for linking up to 128 units or up to 247 units with repeaters		
BAUD RATE	2400, 4800, 9600, 19200, 38400, 115200		
HART	HART 7, Device Description (DD) and Device Type Manager (DTM) available		
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, calibration faults, analog output mismatch fault		
CABLE REQUIREMENTS	3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*		

*** See manual for FM-approved sensors*

Specifications subject to change without notice.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

1465-21-MC / 03.2021

*MSA**safety**.com/detection*

Figure D-3. Example data sheet of sensor technical specifications.

Table D-18. Technical Specifications for CO_2 Leak Detector

Type of Sensor	Infrared
Measurement Ranges	
Combustible	0–100% lower explosive limit (LEL)
CO_2	0–2,000, 0–5,000, 0–10,000, 0–30,000 ppm
Resolution	1% LEL
Response Time	T50 <4 s, T90 < 9 s
Approval Classification	Class I, Div/Zone 1&2, Groups A,B,C,D T5/T4
Operating Ranges	−40°to 50°C
Relative Humidity	10%–95%

Table D-19. Technical Specification for DTS

Parameter	
Spatial Resolution	1 m (3.2 ft) across entire measurement range
Sampling Resolution	Down to 0.5 m (1.6 ft) across entire measurement range
Temperature Resolution	0.1°C (0.18°F)
Accuracy	±0.5°C (± 0.9°F)
Measurement Range	Up to 12 km
Measurement Temperature Range	−250° to 400°C
Measurement Times	10 s to 24 h
Dynamic Range	30 dB
Operating Environment	−10° to 60°C, humidity 0–95% noncondensing

Table D-20. Technical Specifications for Fiber Optic Cable

Parameter	
Tensile Strength	2,372 lb
Yield Strength	2,018 lb
Strain @ Yield	0.31%
Hydrostatic Pressure	23,872 psi
Burts Pressure	28,050 psi
Working Pressure	20,526 psi
Static Bend Radius	3.2 in.

SAExploration

ZLand Gen2 Transcriber Parameter Sheet

Project Name:	**Carbonsafe Phase III 2D/3D**	Test Line: ☐ Yes ☒ No
Project Co-ordinate system:	NAD_1927_StatePlane_North_Dakota_South_FIPS_3302	
Transcriber Script Projection:		
Acquisition Schedule:	☒ Continuous	☐ Scheduled: Start: Finish:
Acquisition Parameters:	Sample Rate	☐0.5ms ☐1ms ☒2ms ☐4ms
	Pre-Amp Gain	☐0dB ☐6dB ☐12dB ☐18dB ☐24dB ☐30dB ☒36dB
	Anti-Alias Filter	☒ Linear ☐Minimum
*Note no low cut filter is not recommended by Fairfield Nodal.	Low Cut Filter	☒ 1-60Hz (1Hz) ☐None (Not recommended)
Pre-Start Instrument Tests:	☐ All gains and sample rates ☒Production Parameters Only	
Source Type:	☒ Vibroseis ☐ Dynamite ☐ OnSeis © ☐ Other:Passive	
	Vibroseis Sweep Length:	3 x 20 seconds
Record Length:	5 seconds total	
Wireline Regularity: N/A	☐ Weekly ☐ Monthly ☐ Other (Post Startup wirelines can be requested after project completion)	
Aux Channels Required:	☒ Timebreak ☐ Pilot ☐ Spare Pilot	
*Note: 2 Pilots is SAE Standard for Vib	☒ Others: TBD, reference marks, uphole	
Sensor to be used:	☒ Internal 10hz DTCC SOLO ☐ External: SM24 6x1	
Deliverable Data:	☒ Shot Gather RAW ☒ Shot Gather Correlated ☐Stacked	
*Note: Correlation will be done with 3rd party software.	☐ Receiver Gather (Combed)	
	☒ Continuous Receiver Gather (Record length: ☒30 Sec ☐60Sec)	
Supporting Documents:	☒ Data Output Logs ☒ Deployment File ☒ Receiver File	☐ Other:
Data Delivery Address:	One copy: Earth Signal Processing Ltd., Attn: Brendan Smith, 1600, 715 – 5th Avenue SW Calgary, Alberta, Canada T2P 2X6 One copy: Minnkota Power Cooperative, Attn: Dan Laudal, 5301 32nd Ave. S., Grand Forks, ND 58201	

Figure D-4. Example parameter sheet.

2.17 Geophone Array for Seismicity

Based on the information provided by the U.S. Geological Survey (USGS), the North Dakota area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex or nearby infrastructure. Seismicity history was discussed in Section 2.0 of the permit.

Change of in situ stresses on existing faults caused by human activities (e.g., mining, dam impoundment, geothermal reservoir stimulation, wastewater injection, hydraulic fracturing, and CO_2 sequestration) may induce earthquakes on critically stressed fault segments. To monitor potential induced seismicity due to the injection of CO_2 in the area. The project will plan to continuously monitor seismicity magnitudes and hypocenter locations through sufficiently supplementing existing available stations. The existing 3D seismic and velocity data in the AOR provide additional confidence for locating the hypocenter of measurable seismicity. Other sources of impulsive seismic noise (i.e., large commercial vehicles, mine blasts, etc.), recorded with the proposed seismometer array, can be easily discriminated from potential seismicity related to injection operations.

2.17.1 Personnel and Equipment

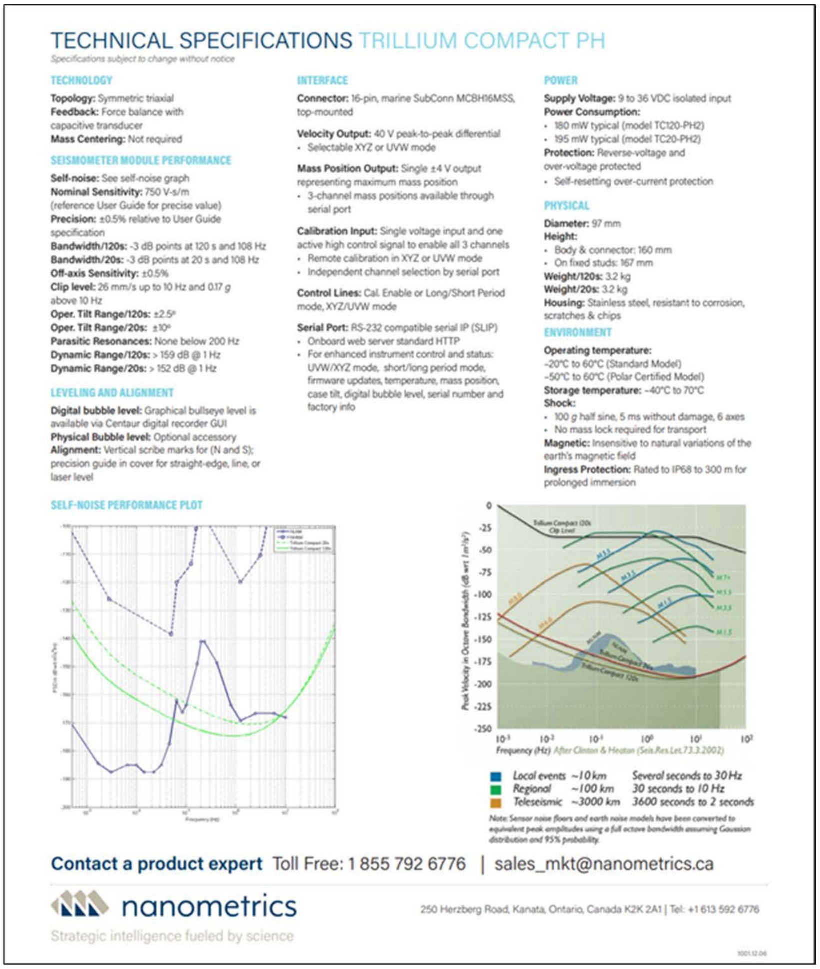
The design and installation of the seismometer station array is performed by specialized contractors including the following activities:

- Project management support to design seismometer array, model network performance, coordinate permitting and equipment installation, testing and maintenance, and ensuring optimum execution of project.
- Field operation to deploy surface seismic station instrumentation, power and communication systems, data quality, and commissioning.
- Data acquisition, system configuration, and processing setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst review and alert notifications for events at or above predetermined magnitude thresholds over the seismic area.

The equipment proposed for seismic station includes the following:

- Broadband sensors
- Data logger
- Solar power system and back-up battery
- Communication system
- Cabling
- Mounting equipment

Figure D-5 shows technical specifications for the broadband seismometer as a reference. Figure D-6 shows an example of setup for data acquisition, transfer, storage, and analysis.



TECHNICAL SPECIFICATIONS TRILLIUM COMPACT PH

Specifications subject to change without notice

TECHNOLOGY

Topology: Symmetric triaxial
Feedback: Force balance with capacitive transducer
Mass Centering: Not required

SEISMOMETER MODULE PERFORMANCE

Self-noise: See self-noise graph
Nominal Sensitivity: 750 V-s/m (reference User Guide for precise value)
Precision: ±0.5% relative to User Guide specification
Bandwidth/120s: -3 dB points at 120 s and 108 Hz
Bandwidth/20s: -3 dB points at 20 s and 108 Hz
Off-axis Sensitivity: ±0.5%
Clip level: 26 mm/s up to 10 Hz and 0.17 *g* above 10 Hz
Oper. Tilt Range/120s: ±2.5°
Oper. Tilt Range/20s: ±10°
Parasitic Resonances: None below 200 Hz
Dynamic Range/120s: > 159 dB @ 1 Hz
Dynamic Range/20s: > 152 dB @ 1 Hz

LEVELING AND ALIGNMENT

Digital bubble level: Graphical bullseye level is available via Centaur digital recorder GUI
Physical Bubble level: Optional accessory
Alignment: Vertical scribe marks for (N and S); precision guide in cover for straight-edge, line, or laser level

INTERFACE

Connector: 16-pin, marine SubConn MCBH16MSS, top-mounted

Velocity Output: 40 V peak-to-peak differential
- Selectable XYZ or UVW mode

Mass Position Output: Single ±4 V output representing maximum mass position
- 3-channel mass positions available through serial port

Calibration Input: Single voltage input and one active high control signal to enable all 3 channels
- Remote calibration in XYZ or UVW mode
- Independent channel selection by serial port

Control Lines: Cal. Enable or Long/Short Period mode, XYZ/UVW mode

Serial Port: RS-232 compatible serial IP (SLIP)
- Onboard web server standard HTTP
- For enhanced instrument control and status: UVW/XYZ mode, short/long period mode, firmware updates, temperature, mass position, case tilt, digital bubble level, serial number and factory info

POWER

Supply Voltage: 9 to 36 VDC isolated input
Power Consumption:
- 180 mW typical (model TC120-PH2)
- 195 mW typical (model TC20-PH2)

Protection: Reverse-voltage and over-voltage protected
- Self-resetting over-current protection

PHYSICAL

Diameter: 97 mm
Height:
- Body & connector: 160 mm
- On fixed studs: 167 mm

Weight/120s: 3.2 kg
Weight/20s: 3.2 kg
Housing: Stainless steel, resistant to corrosion, scratches & chips

ENVIRONMENT

Operating temperature:
-20°C to 60°C (Standard Model)
-50°C to 60°C (Polar Certified Model)
Storage temperature: -40°C to 70°C
Shock:
- 100 *g* half sine, 5 ms without damage, 6 axes
- No mass lock required for transport

Magnetic: Insensitive to natural variations of the earth's magnetic field
Ingress Protection: Rated to IP68 to 300 m for prolonged immersion

SELF-NOISE PERFORMANCE PLOT

Contact a product expert Toll Free: 1 855 792 6776 | sales_mkt@nanometrics.ca

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Figure D-5. Reference technical specifications for broadband seismometer.

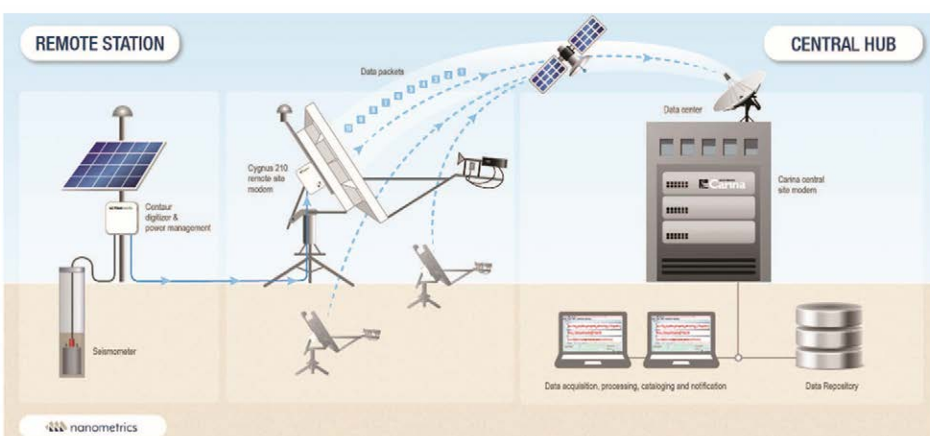

Figure D-6. Example setup for data acquisition, transfer, storage, and analysis.

2.17.2 Traffic Light System

While the historical seismicity of the project area indicates few earthquakes in the area, the operator intends to maintain a surface array for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. This seismic monitoring will be conducted with a surface array deployed to ensure detection of events above ML 2.0, with epicentral locations within 5 km of the injection well.

If an event is recorded by either the local private array or the public national array to have occurred within 5 km of the injection well, the operator would implement its response plan subject to detected earthquake magnitude limits defined below so as to eliminate or reduce the magnitude and/or frequency of seismic events.

- For events above ML 2.0 within 5 km of the injection well, the operator will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity.

- For events above ML 4.0 within 5 km of the injection well, the operator will stop injection and perform an inspection in surface facilities and wells. If there is no damage, the operator will reduce the injection rate by not less than 50% and perform a detailed analysis to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

If the event is not related to the storage facility operation, the operator will resume normal injection rates.

- For events above ML 4.5 within 5 km of the injection well, the operator will stop injection. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. The operator will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis is conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

If the event is not related to the storage facility operation, and previously approved by the regulators, the operator will resume normal injection rates in steps, increasing the surveillance.

2.18 InSAR Method for Surface Deformation

Geodetic methods, like interferometric synthetic aperture radar (InSAR) (Vasco and others, 2020), can detect small-scale surface deformation and has been shown to approximately map pressure distribution associated with subsurface fluid injection (Reed and others, 2018). InSAR is widely available and allows for multiple nonunique interpretations requiring integration with other monitoring methods (e.g., time-lapse seismic). InSAR requires continuous satellite coverage with consistent surface reflectivity (Klemm and others, 2010). 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.

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APPENDIX D-1

DATA SHEET FOR FORMATION EVALUATION TOOLS

S5000 **Gas Monitor**

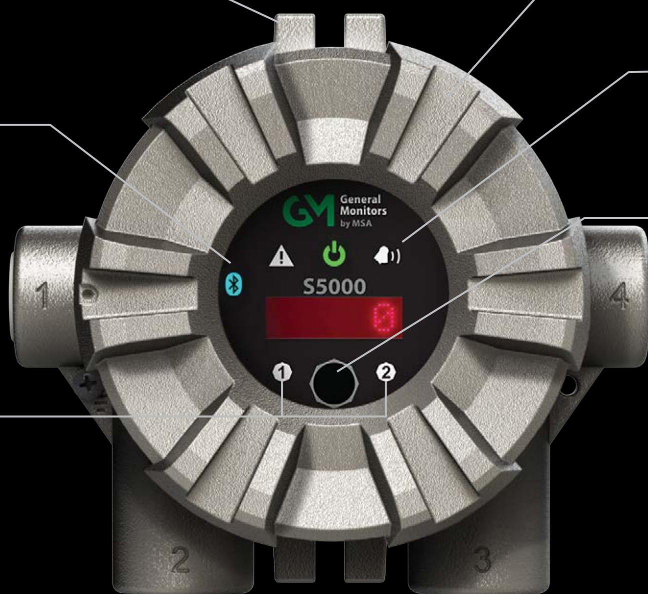
Extreme Durability. Anytime. Anywhere.

General Monitors

Simple retrofits have identical footprint and wiring to S4000 Gas Monitor series.

Bluetooth® wireless technology allows mobile device to act as HMI screen and controller via the X/S Connect App.

Dual sensor capability increases detection coverage without increasing CAPEX expense. Remote mount gas sensors up to 100 m away.



Wide operating temperature for extreme environments (-55°C to +75°C).

Instrument status indicators illuminate power, fault, and alarm conditions.

Intuitive user experience with industry-first touch-button interface or familiar magnetic interface.

X/S Connect App

Reduce setup time by at least 50% with the X/S Connect App.

Advanced Sensor Technology

POWERED BY XCell® SENSORS WITH TruCal® TECHNOLOGY

- Patented XCell H_2S and CO Sensors with TruCal technology extend calibration cycles for as long as 2 years, actively monitor sensor integrity, and compensate for environmental factors and electrochemical sensor drift.
  - **Diffusion Supervision** sends acoustic signal every 6 hours to check that sensor inlet isn't obstructed so gas can reach the sensor.
  - Worry-free operation; automatically self-checks four times per day.
- Three-year warranty and five-year expected life for XCell Sensors.
- **SafeSwap** enables safe and quick XCell Sensor replacement without powering off gas detector.

Applications

- Compressor stations
- CNG maintenance facilities
- Drilling and production platforms
- Fuel loading facilities
- LNG/LPG processing and storage
- Oil well logging
- Petrochemical
- Refineries

MSA
The Safety Company

WE KNOW WHAT'S AT STAKE.

S5000 **Gas Monitor**

Sensor Specifications

General Monitors by MSA

Electrochemical Sensors

Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
Ammonia - 100	0 - 100 ppm	25 - 100 ppm	0.1 ppm	< 20 Sec	< 60 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Ammonia - 1000	0 - 1000 ppm	190 - 1000 ppm	10 ppm	< 20 Sec	< 300 Sec	< +/- 15%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Carbon Monoxide - 100	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 500	0 - 500 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 1000	0 - 1000 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - H2 Resistant	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Chlorine - 5	0 - 5 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 10	0 - 10 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 20	0 - 20 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2
Hydrogen	0 - 1000 ppm	250 - 1000 ppm	10 ppm	< 40 Sec	< 185 Sec	< +/- 10%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Chloride	0 - 50 ppm	25 - 50 ppm	1 ppm	< 30 Sec	< 120 Sec	< +/- 35%	<1% FS / Month	-30 C (-22 F)	40 C (104 F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Cyanide	0 - 50 ppm	25 - 50 ppm	1 ppm	< 8 Sec	< 30 Sec	< +/- 15%	<1% FS / Month	-20 C (-4 F)	40 C (40 F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Sulfide - 10	0 - 10 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 50	0 - 50 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 100	0 - 100 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	<23 Sec	< +/- 1%	<1% FS / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 500	0 - 500 ppm	20 - 500 ppm	1 ppm	< 20 Sec	< 60 Sec	< +/- 10%	<1% FS / Month	-40 C (-40 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Nitric Oxide	0 - 100 ppm	2.5 - 100 ppm	0.5 ppm	< 5 Sec	< 20 Sec	<+/-15%	<1% FS / Month	-30 C (-22 F)	50C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Nitrogen Dioxide	0 - 10 ppm	1.5 - 10 ppm	0.1 ppm	< 30 Sec	< 60 Sec	< +/- 10%	<1% FS / Month	-40 C (-40 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Oxygen/Oxygen (FM)	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< +/- 1% Vol	<0.2 % Vol / Year	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen (Low)	0 - 25%	2 - 25%	0.10%	< 10 Sec	< 30 Sec	< +/- 10%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 1
Sulfur Dioxide - 100	0 - 100 ppm	25 - 100 ppm	1 ppm	< 10 Sec	< 30 Sec	< +/- 15%	<1% FS / Month	-30 C (-22 F)	50 C (122 F)	Echem	2 Years	1 Year	Div/Zone 2
Sulfur Dioxide - 25	0 - 25 ppm	5 - 25 ppm	0.1 ppm	< 3 Sec	< 6 Sec	< +/- 1%	<1% FS / Month	-40 C (-40 F)	60 C (140 F)	XCell	5 Years	3 Years	Div/Zone 2

XCell Catalytic Bead Sensors

Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
Methane (5.0 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Propane (2.1 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Heptane (1.05 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Nonane (0.8 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Hydrogen (4.0 %)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Methane (4.4 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Propane (1.7 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Heptane (0.85 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1
Nonane (0.7 % EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< +/- 1% LEL	<5% LEL / Year	-55 C (-67 F)	60 C (140 F)	XCell Cat Bead	5 Years	3 Years	Div/Zone 1

** At ambient conditions*

S5000 **Gas Monitor**

Sensor Specifications

General Monitors by MSA

Infrared Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
IR400 0-100 % LEL Propane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Hexane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Pentane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Ethylene	0 - 100% LEL	N/A	1% LEL	< 2 Sec	< 4 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	60 C (140 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Butane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Ethane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% by Volume Methane	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Methane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Propane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Hexane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100 % LEL Ethylene EN	0 - 100% LEL	N/A	1% LEL	< 2 Sec	< 4 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-40 C (-40 F)	60 C (140 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Butane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR400 0-100% LEL Ethane EN	0 - 100% LEL	N/A	1% LEL	< 1.5 Sec	< 3 Sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	N/A	-60 C (-76 F)	75 C (167 F)	IR400	5+ Years	2 Years	Div/Zone 1
IR700 0-2000 ppm Carbon Dioxide	0-2000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-5000 ppm Carbon Dioxide	0-5000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-10000 ppm Carbon Dioxide	0-10000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-30000 ppm Carbon Dioxide	0-30000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1
IR700 0-50000 ppm Carbon Dioxide	0-50000 ppm	N/A	1% LEL	< 4 Sec	< 9 Sec	+5% FS @ <50% FS; +10% FS @ >50% FS	N/A	-40 C (-40 F)	50 C (122 F)	IR700	5+ Years	2 Years	Div/Zone 1

Passive Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min	Max				
10058-1	0 - 100% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	75 C (167 F)	Cat Bead Screened	3-5 Years	2 Years	Div/Zone 1
11159-8	0-20% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	70 C (158 F)	Cat Bead Sintered	3-5 Years	2 Years	Div/Zone 1
11159-1	0 - 100% LEL	N/A	1% LEL	< 10 sec	< 30 sec	+3% LEL @ <50% LEL; +5% LEL @ >50% LEL	<5% FS / Year	-40 C (-40 F)	70 C (158 F)	Cat Bead Sintered	3-5 Years	2 Years	Div/Zone 1
50448-9	0-20 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
50448-5	0-50 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
50448-1	0-100 ppm	N/A	1 ppm	< 14 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	75 C (167 F)	MOS Screened	3-5 Years	2 Years	Div/Zone 1
51457-9	0-20 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1
51457-5	0-50 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1
51457-1	0-100 ppm	N/A	1 ppm	< 30 sec	n/a	+ 2 ppm or 10% of applied gas	N/A	-40 C (-40 F)	70 C (158 F)	MOS Sintered	3-5 Years	2 Years	Div/Zone 1

** At ambient conditions*

S5000 **Gas Monitor**

Specifications

General Monitors by MSA

Product Specifications		
COMBUSTIBLE GAS SENSOR TYPE	Catalytic bead (Passive comb., XCell comb.) Infrared (IR400)	
TOXIC GAS & OXYGEN SENSOR TYPE	**XCell Toxic**	Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Chlorine (Cl_2), Sulfur Dioxide (SO_2)
	Passive MOS, Echem, XCell Toxic	Hydrogen Sulfide (H_2S)
	XCell O_2	Oxygen (O_2)
	Infrared	Carbon Dioxide (CO_2)
	Electrochem	Ammonia (NH_3), Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Nitric Oxide (NO), Nitrogen Dioxide (NO_2)
SENSOR MEASURING RANGES	**Combustible**	0-100% LEL (CB, IR)
	Cl_2	0-5, 0-10, 0-20 ppm
	CO	0-100, 0-500, 0-1000 ppm
	CO, H_2-resistant	0-100 ppm
	CO_2	0-2000, 0-5000, 0-10000, 0-30000, 0-50000 ppm
	H_2	0-1000 ppm
	HCl	0-50 ppm
	HCN	0-50 ppm
	H_2S	0-10, 0-20, 0-50, 0-100, 0-500 ppm
	NH_3	0-100 ppm, 0-1000 ppm
	NO	0–100 ppm
	NO_2	0-10 ppm
	O_2	0-25%
	SO_2	0-25, 0–100 ppm
APPROVALS CLASSIFICATION	*See manual for complete CSA listings.*	
DIVISIONS (US/CAN)	Class I, Div/Zone 1&2, Groups A, B, C & D T5/T4; Class II, Div/Zone 1&2, Groups E, F & G, T6; Class III Type 4X, IP66	
US ZONES	Class I, Zone 1 AEx db IIC T5 Gb Class I, Zone 2 AEx nA nC IIC T4 Gc Zone 21 AEx tb IIIC T85°C Db	
CANADIAN ZONES/ ATEX/ IECEx	Ex db IIC T5 Gb Ex nA nC IIC T4 Gc Ex tb IIIC T85°C Db	
CE MARKING DIRECTIVES	Complies with EMC, RED, ATEX	
WARRANTY	**S5000 transmitter**	2 years
	XCell Sensors	3 years
	Passive comb., MOS, IR400, IR700	2 years
	Echem Sensors	Varies by gas
APPROVALS	CSA, FM**, ATEX, IECEx,INMETRO, ABS, DNV-GL Marine, CE Marking. Complies with C22.2 No. 152, FM 6320, ANSI/ISA/CSA/IEC/EN 60079-29-1, ANSI/ ISA 12.13.01. Suitable for SIL 2.	

Dimensions	
HOUSING (W x H x D)	6.37" x 5.38" x 4.25" (162 x 137 x 108 mm)
W/PASSIVE SENSOR	6.37" x 7.62" x 4.25" (162 x 193 x 108 mm)
W/DIGITAL SENSOR	6.37" x 10.4" x 4.25" (162 x 265 x 108 mm)
W/IR400 IR SENSOR	14.8" x 6.0" x 4.25" (375 x 152 x 108 mm)
WEIGHT	8 lb. (3.6 kg), 316 SS

Environmental Specifications		
OPERATING TEMPERATURE RANGE	**Transmitter**	-55°C to +75°C
	CB (sintered, Zones)	-40°C to +70°C
	CB (screened, Div)	-40°C to +75°C
	MOS (sintered, Zones)	-40°C to +70°C
	MOS (screened, Div)	-40°C to +75°C
	IR (CSA)	-40°C to +75°C
	IR (ATEX/IECEx)	-60°C to +75°C
	XCell (Comb)	-55°C to +60°C
	XCell (Toxic/O_2)	-40°C to +60°C
STORAGE TEMPERATURE RANGE	**Housing, IR400, IR700, passive sensors**	-50°C to +85°C
	XCell sensors	-40°C to +60°C
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell sensors, IR400, IR700**	10-95%
	Passive combustible	0-95%
	Passive H_2S	15-95%

Mechanical Specifications			
INPUT POWER	24 VDC nominal, 12 to 30 VDC		
SIGNAL OUTPUT	Dual 4-20 mA current source or sink, HART, Modbus, Bluetooth. *Optional: w/o Bluetooth*		
RELAY RATINGS	5A @ 30VDC; 5A @220 VAC (3X) SPDT – fault, warn, alarm		
RELAY MODES	Common, discrete, horn		
NORMAL MAX POWER		**Without Relays**	**With Relays**
	Passive comb.	5.0 W	6.0 W
	Passive MOS	9.8 W	10.8 W
	IR400/IR700	7.9 W	8.9 W
	XCell comb.	5.0 W	6.0 W
	XCell toxic & O_2	2.6 W	3.6 W
	IR400/IR700 + XCell comb.	10.8 W	11.8 W
	IR400/IR700 + XCell toxic or O_2	8.6 W	9.6 W
	Dual XCell toxic or O_2	3.3 W	4.3 W
	Dual XCell comb.	7.4 W	8.4 W
	XCell comb. + XCell toxic or O_2	5.7 W	6.7 W
STATUS INDICATORS	4-digit scrolling LED, icons depicting fault, warn, alarm, Bluetooth, 1 and 2 to indicate sensor reading displayed		
RS-485 OUTPUT	Modbus RTU, suitable for linking up to 128 units or up to 247 units with repeaters		
BAUD RATE	2400, 4800, 9600, 19200, 38400, 115200		
HART	HART 7, Device Description (DD) and Device Type Manager (DTM) available		
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, calibration faults, analog output mismatch fault		
CABLE REQUIREMENTS	3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*		

*** See manual for FM-approved sensors*

Specifications subject to change without notice.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

APPENDIX D-2

SCHLUMBERGER MDT BROCHURE

Schlumberger

MDT Modular Formation Dynamics Tester

Quality fluid samples
and highly accurate
reservoir pressures

Applications

- Formation pressure measurement and fluid contact identification
- Formation fluid sampling
- Permeability measurement
- Permeability anisotropy measurement
- Mini-drillstem test (DST) and productivity assessment
- In-situ stress and minifrac testing

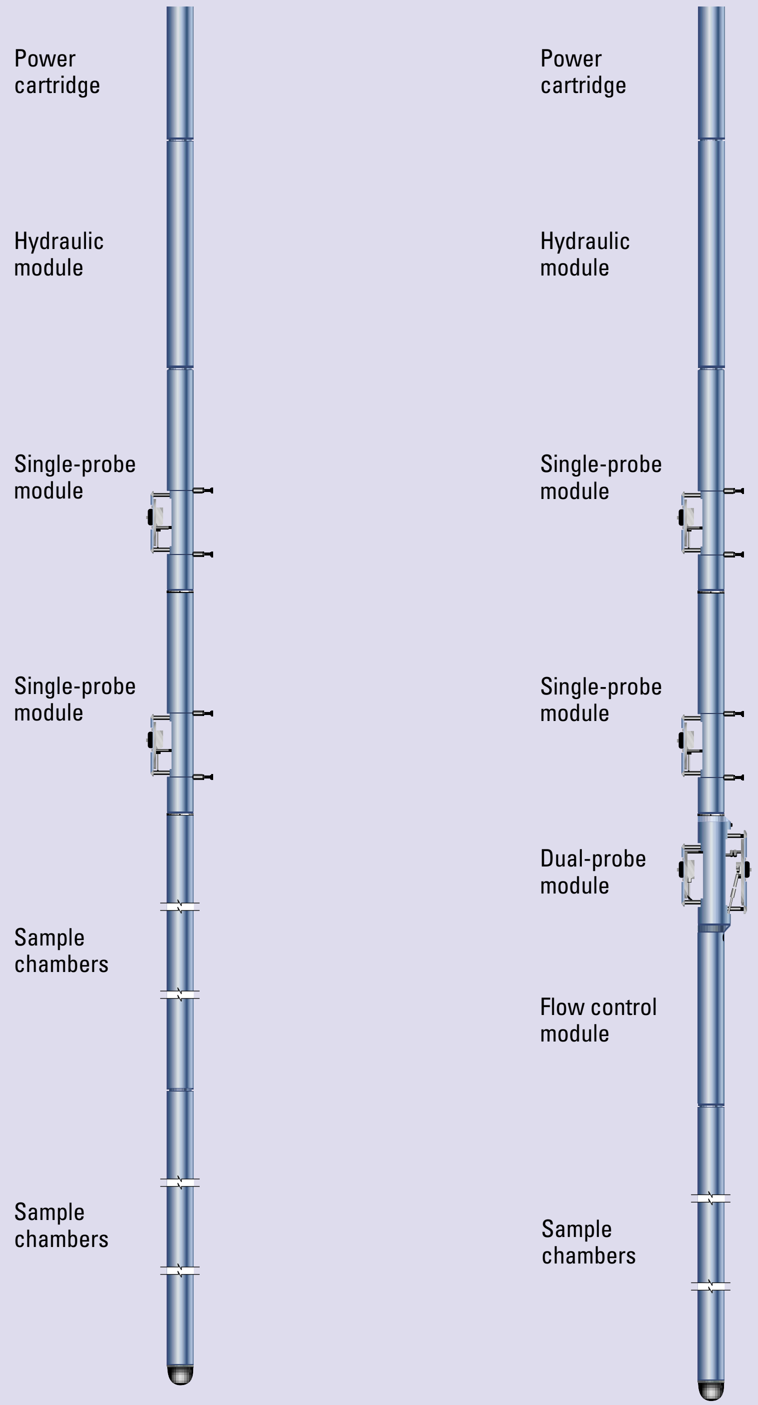
Benefits

- Testing and sampling in low permeability, laminated, fractured, unconsolidated and heterogeneous formations
- Fast, repeatable pressure measurements
- Faster tests in low permeability—reduced seal losses and probe plugging
- Pressure, volume and temperature (PVT) formation fluid samples
- Downhole fluid differentiation
- Real-time fluid gradients, permeability and contamination assessment

Features

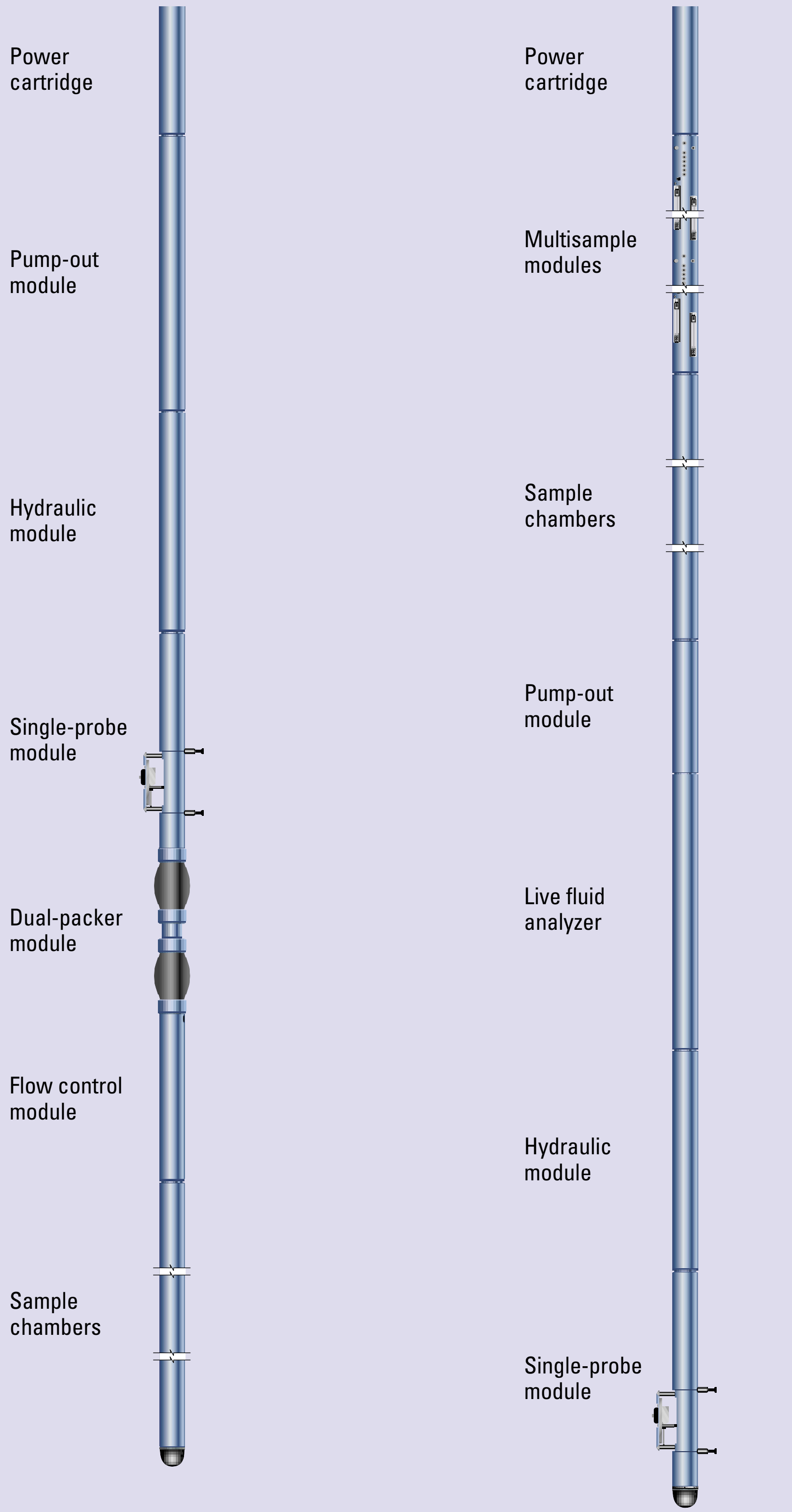
- Modular, custom-design capability
- Multiple samples in one trip
- Multiprobe and inflatable dual packer module options
- Efficient integration with other tools
- Accurate pressure measurements using a CQG* Crystal Quartz Gauge
- Programmable pretest pressure, rate and volume
- Filtrate pumpout prior to sampling
- Fluid resistivity and temperature measurements at the probe
- Quantatative sample contamination measurement with optical spectroscopy techniques
- Low-shock and single-phase sampling
- Field-proven database for accurate pumpout time

The MDT tool can be customized and efficiently assembled on-site to meet exact requirements depending on the needs of a particular well evaluation.



Basic MDT configuration for pressure, permeability and sampling

Multi-probe vertical interference testing



Vertical interference test with probe-packer

Low shock PVT-quality sampling

Real-time measurements

The Schlumberger MDT* Modular Formation Dynamics Tester tool provides fast and accurate pressure measurements and high-quality fluid sampling. It can also measure permeability anisotropy. In a single trip, the MDT tool is able to acquire most of the data requirements needed for accurate and timely decision making.

Flexibility

The key to this remarkable tool is an innovative, modular design that lets you customize the tool for the required applications. MDT modules combine to meet the exact needs and goals of the data acquisition program. This designed flexibility makes the tool compatible with almost all Schlumberger measurement technologies and allows the MDT tool to evolve as new measurement techniques, technologies and options evolve.

Quick, accurate pressure and permeability measurements

Reservoir pressure measurements using a wireline tester require inserting the probe into the reservoir and withdrawing a small amount of fluid. Since the pressure gauge is exposed to many temperature and pressure changes, these measurements require accurate gauges with high resolution that can dependably react to the dynamic conditions.

The MDT tool uses highly accurate gauges with best-in-class resolution, repeatability and dynamic response for pressure measurements. These pressure gauges exhibit excellent response with no compromise in accuracy or resolution. Precise flowline control during testing and sampling ensures monophasic flow. These innovative features provide the most efficient and accurate permeability determination available.

MDT modules

Electronic power module

The power cartridge (MRPC) converts AC power from the surface to provide DC power for all modules in the tool. It is an essential part of any MDT configuration.

Hydraulic power module

The hydraulic power module (MRHY) contains an electric motor and hydraulic pump to provide hydraulic power for setting and retracting the single- and dual-probe modules. The MRHY module features an accumulator that allows the test probes to autoretract and prevent a stuck-tool situation in the event of a power failure.

Single-probe module

The single-probe module (MRPS) contains the probe assembly, (with packer and telescoping backup pistons), the pressure gauges, fluid resistivity and temperature sensors, and a 20-cc pretest chamber. The MRPS also contains a strain gauge and an accurate, high-resolution, quick-response CQG gauge. The volume, rate and drawdown of this chamber can be controlled from the surface to adjust to any test situation, especially in tight formations.

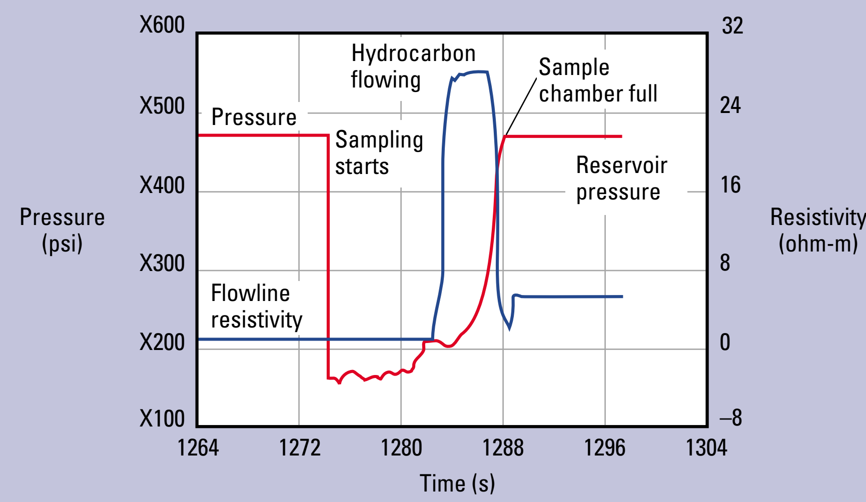
Dual-probe module

The dual-probe module (MRPD) contains two probes mounted back-to-back, 180° apart on the same block. When combined with an MRPS module, it forms a multi-probe system capable of determining horizontal and vertical permeability.

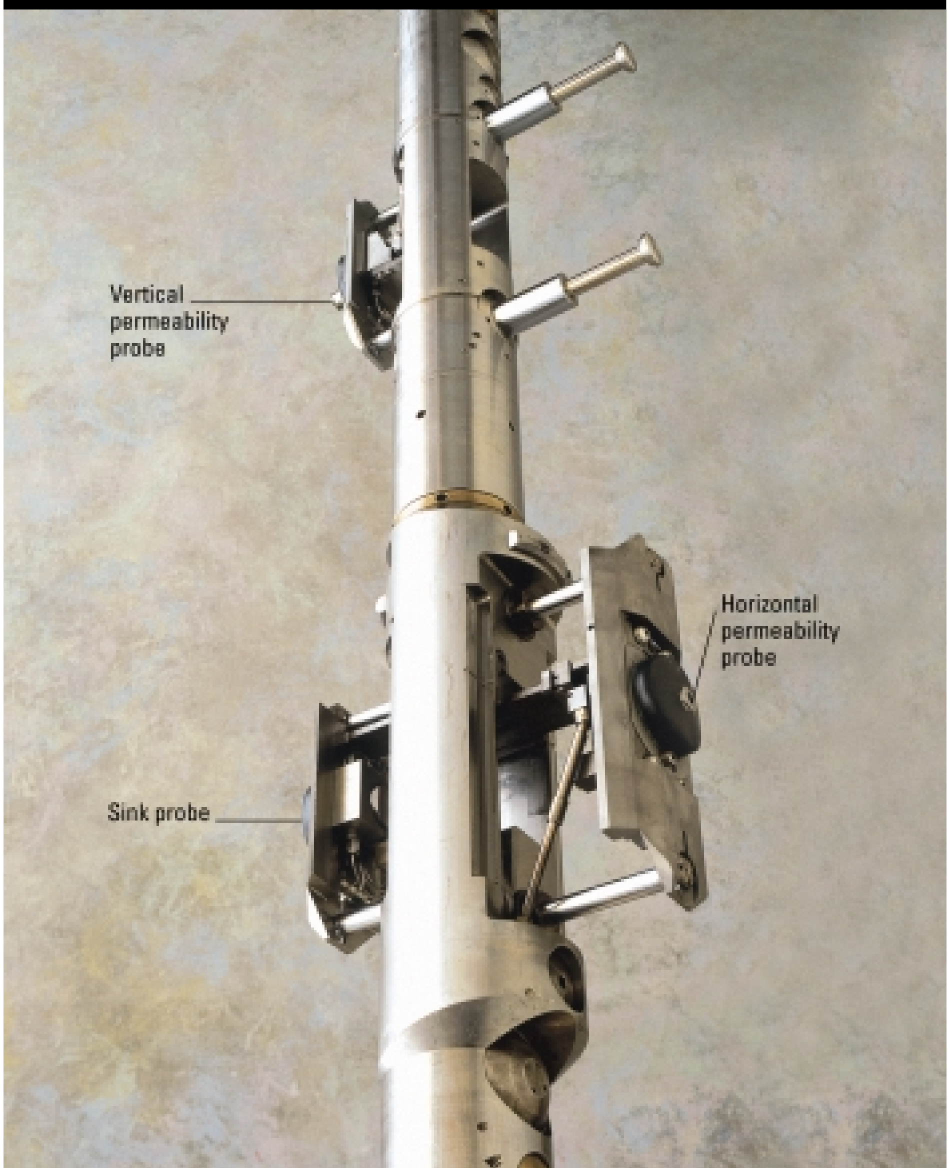
During a typical test with the MRPD module, formation fluid is diverted through the sink probe to a one-liter pretest chamber in the flow control module. The MRPD module, in conjunction with the pressure measured at the vertical probe from the MRPS module, measures the pressure at both probes. These measurements are used to determine near-wellbore permeability anisotropy.

Flexible probe configurations are a unique feature of the MDT tool. By running multiple probe modules, pressure communication between adjacent formations can be monitored during an interference test. The MDT multi-probe configuration also allows in-situ verification of gauge quality and utilization of two different probe assemblies for redundancy in difficult conditions.

In a water-based mud environment, the MDT flowline resistivity measurement helps discriminate between fluid contaminated by mud filtrate and formation oil or fresh water.



The multiprobe configuration of the MDT tool measures the pressure response at two or more locations in addition to the single probe data. Data from the MDT multiprobe configuration provide an evaluation of horizontal and vertical permeabilities and formation heterogeneity.



The MRPA module employs two inflatable packers to isolate a borehole interval for testing. Tests in low-permeability formations are greatly enhanced, because the cross-sectional area of the isolated interval is many times greater than that of the standard MDT probe.

Dual-packer module

The dual-packer module (MRPA) uses two inflatable packers, set against the borehole wall, to isolate a 3 to 11 ft. section of the formation and provide access to the formation over a wall area that is thousands of times larger than the standard probe area. This allows fluids to be withdrawn at a higher rate without dropping below the bubble point, and it provides a permeability estimate with a radius of investigation in the range of tens of feet. The MRPA is useful for making pressure measurements and taking fluid samples in difficult conditions (tight, vuggy, fractured and unconsolidated formations) and has also been used in cased holes after a perforation operation. In addition, the MRPA module can be used for in-situ stress testing and mini-frac testing.

Modular sample chamber

The Modular Sample Chamber (MRSC) is available in three sizes: 1 gal, 2.75 gal and 6 gal. The upper block of each chamber contains a throttle valve that can be operated fully open, fully closed or in throttle mode. The 1-and 2.75-gal chambers exist in both H_2S and non-H_2S versions. The 6-gal chamber can be expanded in 6-gal increments to act as dump chambers by adding more 6-gal cylinders.

Multisample module

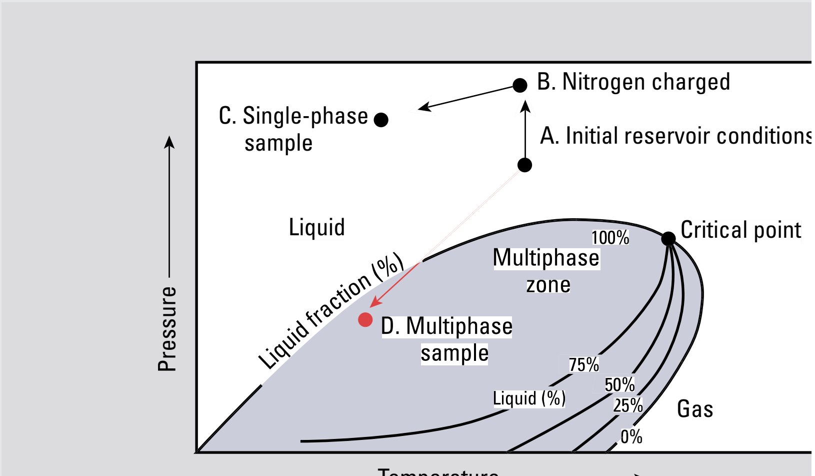
The Multisample Module (MRMS) allows the collection of high-quality samples for PVT analysis. The module is designed to retrieve six formation fluid samples, 450-cc each, during a single trip into the well. Sample bottles detach easily from the tool for transport to a PVT laboratory. The bottles meet transportation regulations for shipping pressurized vessels, so no wellsite transfer is necessary.

Since multiple MRSC and MRMS modules can be combined, the total number of sample modules is limited only by cable strength and well conditions. For longer tool strings, as well as highly deviated and horizontal wells, the MDT tool can be combined with the TLC* Tough Logging Conditions system for efficient sampling operations.

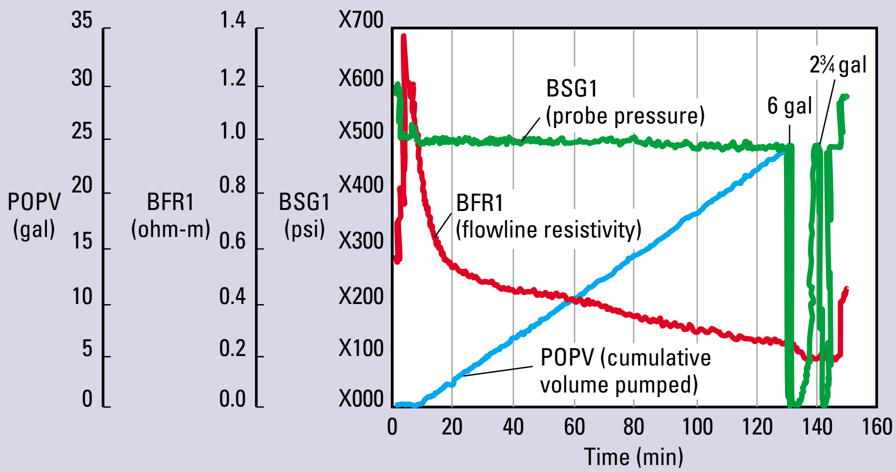
Multiple MRMS modules—each capable of collecting six high-quality PVT samples—can be combined in one run to meet sampling requirements.

Chemical analysis of MDT-acquired samples helps to characterize the reservoir fluid and facilitates optimal completion and surface facilities design.

As they are brought to the surface, samples taken at reservoir temperature and pressure (A) can change phase at lower temperatures and pressures (D). Overpressuring the sample downhole (B) will maintain its initial phase as it is brought to the surface (C) at a lower temperature.



In oil-based mud environments, flowline resistivity may also aid in formation water sampling.



Single-phase multisample chamber

The single-phase multisample chamber ensures collection of monophasic fluid samples by overpressuring samples after they are taken at reservoir conditions. Sample chambers are pressurized with a nitrogen gas chamber across two pistons. This compensates for the temperature-induced pressure drop as the samples are returned to the surface.

Pump-out module

The Pump-Out Module (MRPO) is used to pump unwanted fluid (mud filtrate) from the formation to the borehole, so representative samples can be taken. It is also used to pump fluid from the borehole into the flowline for inflating the packers of the MRPA module. In addition, the module can pump within the tool, for example, from a sample chamber to the inflatable packers.

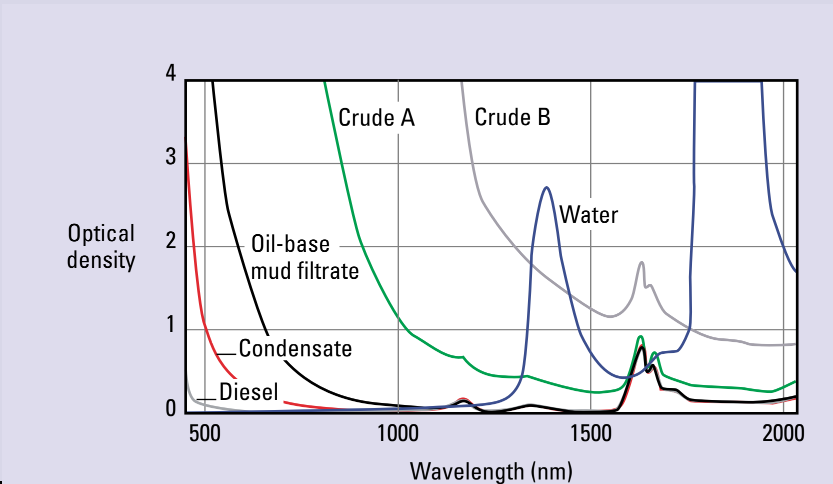
Live fluid analyzer module

Downhole fluid analysis in real time, as provided by the LFA* Live Fluid Analyzer module, enhances the usefulness of new techniques like pumpout and dual inflatable packers. The LFA module measures optical properties of the fluid in the flowline.

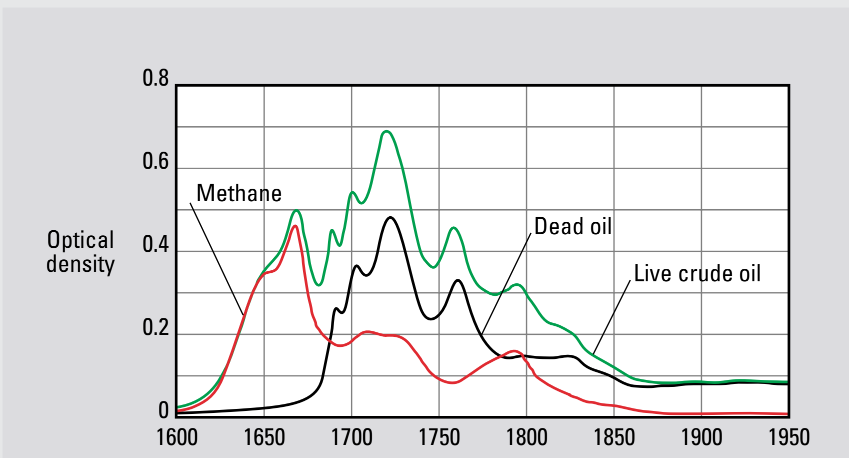
The LFA module employs an absorption spectrometer that utilizes visible and near infrared light to quantify the amount of reservoir and drilling fluids in the flowline. Light is transmitted through the fluid as it flows past the LFA spectrometer. The amount of light absorbed by the fluid depends on the composition of the fluid. Water and oil are reliably detected by their unique absorption spectra. A second sensor in the LFA module is the gas refractometer, which can be used to differentiate between gas and liquid.

Optical absorption in the visible and near infrared region is used for fluid discrimination and quantification; the change in index of refraction is used for free gas detection; and methane presence is used for both contamination monitoring and gas detection.

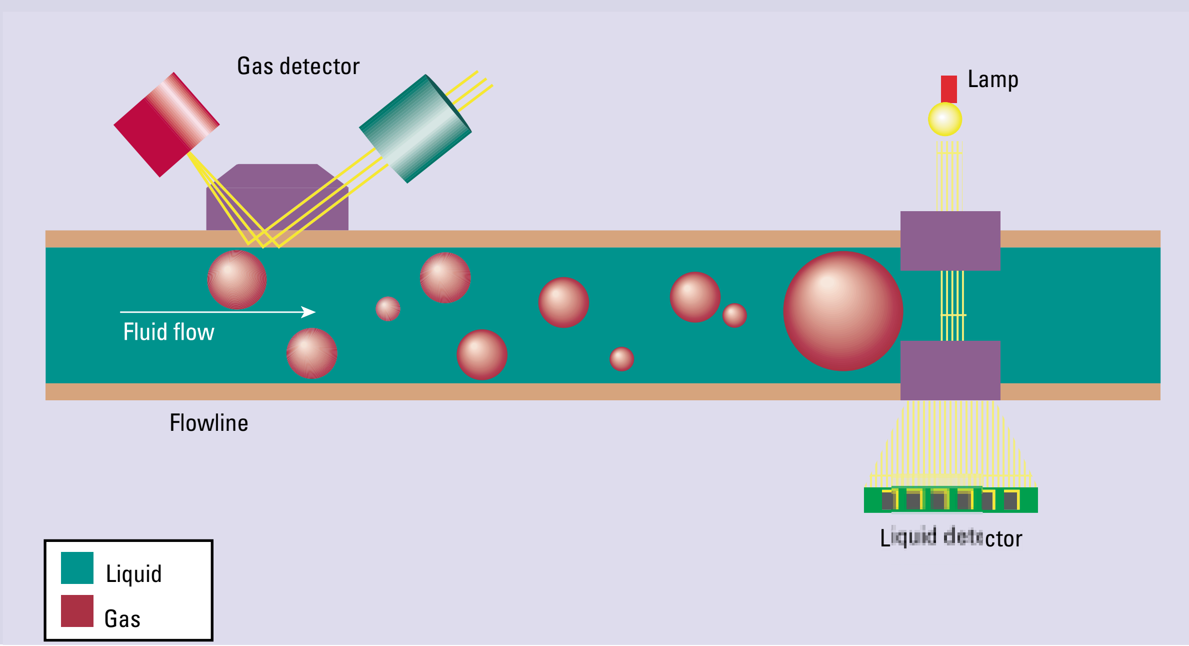
Optical density spectra can be used to uniquely identify different fluids.



The graph below illustrates the optical density (OD) of methane, dead oil and live crude oil. An OD of zero means there is full transmission (no absorption) of light. An OD of 1 means that 10% of the light is transmitted, and 90% is absorbed. Methane and dead oil peaks are prominently shown in the live crude oil spectrum.



The LFA module provides real-time downhole fluid analysis by measuring multiple optical properties of the fluid to quantify the amount of reservoir and drilling fluids in the flowline.



Flow control module

The Flow Control Module (MRCF) is a 1-liter pretest chamber where the flow rate can be accurately measured and controlled. The MRCF can also be used during sampling that requires a controlled flow rate. The volume is limited to 1 liter. The module creates a pressure pulse in the formation large enough for multi-probe measurements.

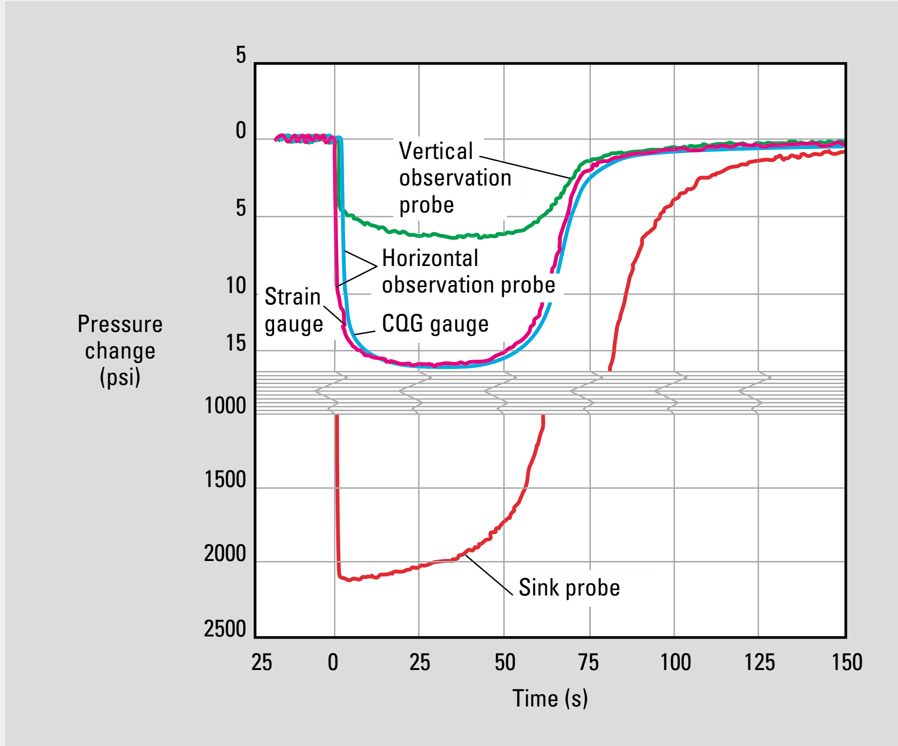
Prejob modeling and real-time answers

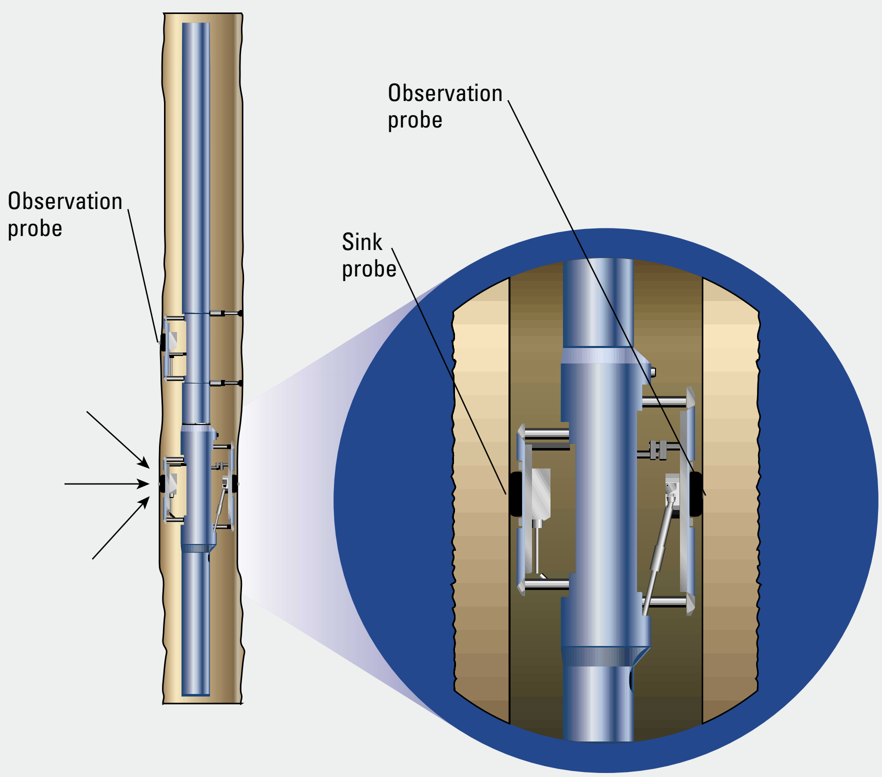
The software capabilities of the MDT tool enhance its hardware capabilities. Drawing on experience based on the vast number of MDT projects that have been completed over the past decade, programs are available to accurately plan and execute new MDT jobs. Highly sophisticated interpretation programs generate accurate pressure gradient, permeability and fluid sampling answers when they are needed.

Planning programs are also available to predict the response of the different gauges under any given environment and for any tool configuration. These programs also predict the duration of required pumping time and the likelihood of sticking in any given situation. These expert systems, based on the huge MDT job database, help optimize the running of the job. In the unlikely event that sticking does occur, the LWF* logging while fishing technique can be used to simultaneously complete the survey on drillpipe and safely retrieve the stuck string.

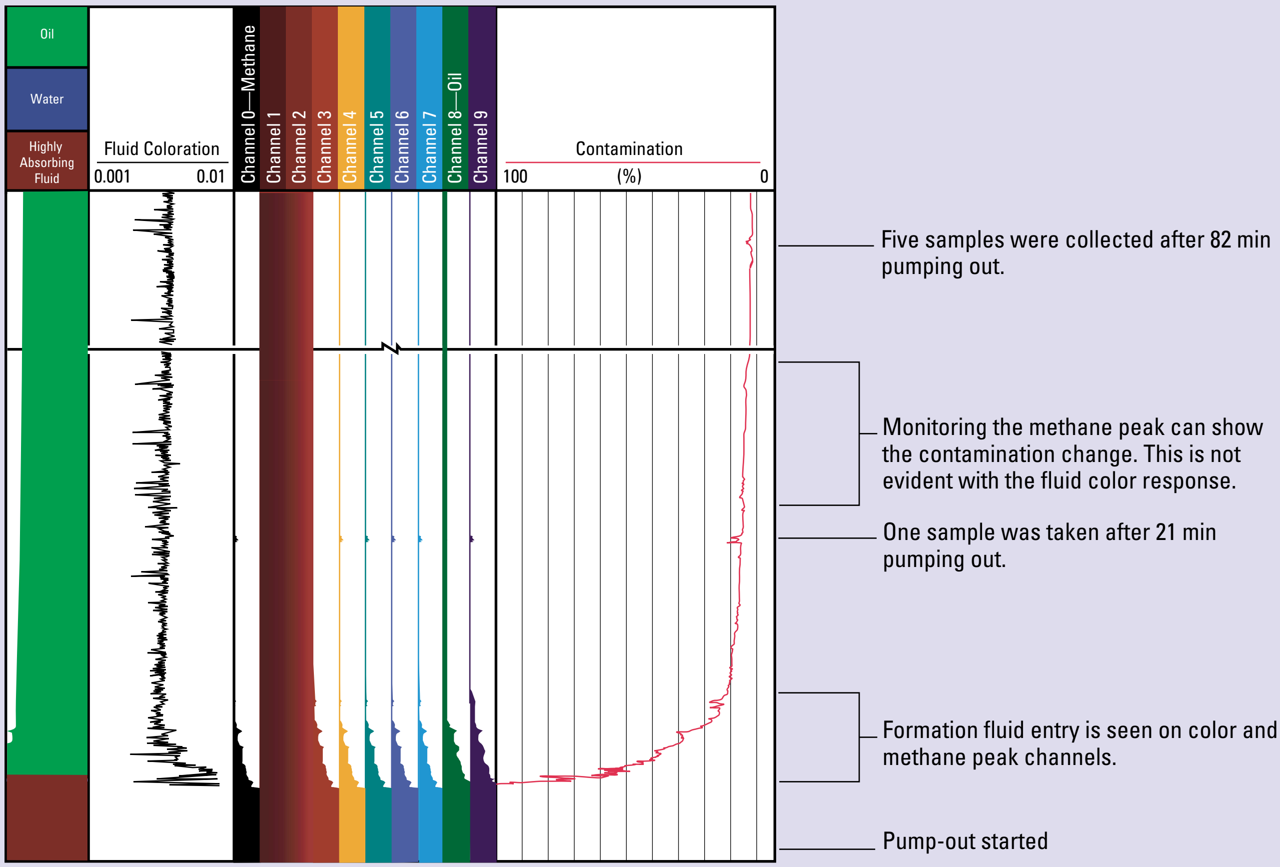
MDT interpretation software provides real-time plotting of pressure, resistivity and optical properties versus time. These plots generate derivatives and perform interpretation at the wellsite. This capability is essential for real-time quality control and ongoing optimization of the job. Using the InterACT* wellsite monitoring and control system for real-time data transfer to remote sites, Schlumberger and customer experts can simultaneously apply more sophisticated and elaborate modeling and interpretation software offsite.

The Flow Control Module contains a one-liter pretest chamber and metering valves capable of producing finely tuned drawdowns.





The LFA module monitors oil-based mud contamination by analyzing fluid color and methane content to ensure quality fluid sampling. Color and methane curves indicate the percentage of fluid contamination.



Fluid identification example

The purpose of fluid sampling is to obtain a representative sample of the virgin reservoir fluid. To obtain the sample, the unwanted fluid must be discarded prior to collecting the formation fluid sample. There also must be a method to analyze and determine the nature of the fluid in real time. The MDT tool with the pump-out module, LFA module and the flow-line resistivity measurement identifies and collects high-quality reservoir fluid samples suitable for further laboratory analysis.

Flowline resistivity measurements taken by the probe module help discriminate between formation fluids and filtrate from water- and oil-base muds. Equipping the MDT tool with a pump-out module makes it possible to sample fluid, while monitoring the flowline resistivity, by pumping filtrate-contaminated fluid into the mud column. Fluid removed from the formation is excluded from the sample chamber until an uncontaminated sample can be recovered.

MDT Specifications	
Single-probe configuration	
OD	4.75 in. [120.6 mm]
Min hole size	5⅞ in. [149. 2 mm]†
Max without kits	14.25 in. [361.5 mm]
Max with kits	24 in. [610 mm]
Pressure rating	25,000 psi [17,235 kPa]‡
Max temperature rating	400°F [205°C]§
Multiprobe tool configuration	
OD	6.00 in. [152.4 mm]
Min hole size	7.62 in. [193.6 mm]
Max without kit	13.75 in. [336.5 mm]
Max with kit	15.00 in. [381.00 mm]
Max pressure rating	25,000 psi [17,235 kPa]
Max temperature rating	400°F [205°C]
Dual-packer configuration	
OD	5.00 to 10.00 in. [127.0 to 254 mm]††
Min hole size	5⅞ in. [149.2 mm]††
Max hole size	14.75 in. [374.6 mm]††
Pressure rating	25,000 psi [17,235 kPa]
Max temperature rating	325°F [163°C]††
LFA module	
OD	4.75 in. [120.6 mm]
Length	5.83 ft [1.7 m]
Weight	161 lbm [73 kg]
Range	0 to 5 optical density
Accuracy	0.01 optical density
Pressure rating	25,000 psi [17,236 kPa]
Temperature rating	350°F [176°C]

Pressure gauge specifications	
Strain gauge	
Range	0 to 25,000 psi [0 to 17,236 kPa]‡‡
Accuracy	0.10% full scale
Repeatability	0.06% full scale
Resolution	0.1 psi [0.689 kPa]
Temperature rating	400°F [205°C]‡‡
CQG gauge	
Range	0 to 25,000 psi‡‡
Accuracy	2.0 psi [13.8 kPa]+ 0.01% of reading
Repeatability	< 1.0 psi
Resolution	0.01 psi
Temperature rating	400°F [205°C]‡‡

† If wellbore conditions are favorable, the tool can be run on TLC in holes with an ID as small as 5½ in. [14 cm].

‡ 25,000 psi [172.5 mPa] for the high pressure MDT and 20,000 psi [138 mPa] for the normal MDT tool

§ 350°F [175°C] with some CQG types

†† Functional rating based on the actual packer installed and type of mud used.

‡‡ Actual pressure/temperature combination will depend on specific type of gauge. For the CQG, HCQG-A is rated 175°C/25,000 psi, HCQG-B/D 200°C/18,000 psi or 180°C/20,000 psi and CQG-C/G 175°C/15,000 psi.

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APPENDIX D-3

SCHLUMBERGER DUAL PACKER MODULE SPECIFICATIONS GUIDELINES

Schlumberger

Dual-Packer Module

Inflatable packers that seal against the borehole wall to isolate the interval for MDT tester operations

APPLICATIONS

Used with the MDT* modular formation dynamics tester for

- Downhole fluid analysis (DFA)
- Formation fluid sampling
- Formation pressure measurement and fluid gradient estimation
- Determination of pretest drawdown mobility (permeability/viscosity)
- Permeability and anisotropy determination away from the well
- In situ stress determination

High-performance packers

The Dual-Packer Module (MRPA) of the MDT modular formation dynamics tester consists of two inflatable packer elements that seal against the borehole wall to isolate an interval, improving the effectiveness of pressure measurement and fluid sampling in low-permeability, laminated, or fractured formations.

High-performance packers are run with the MRPA to expand the MDT tester's operating envelope, with a temperature rating to 410 degF [210 degC] and compatibility with both water- and oil-base mud systems. The superior elasticity and improved durability of the high-performance packers enable performing more stations per run and lessen packer replacement. The asymmetrical packer design reduces sticking and bulging potential.

Operational reliability is further enhanced by the autoretract mechanism (ARM), which applies a longitudinal tensile force to assist in retracting the packers after deflation, in turn minimizing drag. At temperatures below 225 degF [107 degC], the elements retain enough elasticity for operation without the ARM.

The MDT Pumpout Module (MRPO) is used to inflate the packers with fluid.

Reliability in high-H_2S environments

For operations in H_2S environments, the Dual-Packer Module is available in a NACE-compliant version for sampling up to 50% H_2S in hole sizes from 5⅞ to 9⅝ in.

Effective isolation of large areas

The length of the test interval between the packers is 3.2 ft [0.98 m] and can be extended to 5.2, 8.2, or 11.2 ft [1.58, 2.5, or 3.41 m] by using 2- and 3-ft [0.61- and 0.91-m] spacers with large-diameter mandrels. For the 3.2-ft interval, the area of the isolated interval of the borehole is about 3,000 times larger than the area of the borehole wall isolated by the MDT tester's Single-Probe Module (MRPS). For fluid sampling, the large area results in flowing pressures that are only slightly below the reservoir pressure, which avoids phase separation even for pressure-sensitive fluids such as gas condensates or volatile oils. In low-permeability formations, high drawdown usually occurs with the probe, whereas fluid can be withdrawn from the formation using the MRPA with minimum pressure drop through the larger flowing area. In finely laminated formations, the MRPA can be used to straddle permeable streaks that would be difficult to locate with a probe. In fractured formations, the MRPA can usually seal the interval whereas a probe could not.

Dual-Packer Module.

Dual-Packer Module

For pressure transient testing, following a large-volume flow from the formation, the resulting pressure buildup has a radius of investigation of 50 to 80 ft [15 to 24 m]. Depending on the application, an interval pressure transient test (IPTT) provides advantages over a conventional drillstem test (DST). It is environmentally friendly because no fluids flow to the surface, and it is cost effective because many zones can be tested in a short time.

The MRPA can be used to create a micro-hydraulic fracture that can be pressure tested to determine the minimum in situ stress magnitude. The fracture is created by pumping wellbore fluid into the interval between the inflatable packer elements.

Measurement Specifications

	MRPA
Range of measurement	CQG* crystal quartz gauge: 750 to 15,000 psi [5 to 103 MPa]
	Quartzdyne® gauge: 0 to 25,000 psi [0 to 172 MPa]
	Axton* dynamically compensated single quartz gauge: 0 to 30,000 psi [207 MPa] to 374 degF [190 degC] and 0 to 20,000 psi [138 MPa] to 392 degF [200 degC]†
	Temperature: –67 to 400 degF [–55 to 204 degC]
Resolution	CQG gauge: 0.008 psi [55 Pa] at 1.3-s gate time
	Quartzdyne gauge: 0.01 psi/s [69 Pa/s]
	Axton gauge: 0.008-psi [55-Pa] rms at 1-s gate time
	Temperature: 0.01 degF [0.05 degC]
Accuracy	CQG gauge: ±(2 psi [13,789 Pa] + 0.01% of reading)‡
	Quartzdyne gauge: ±(0.02% of full scale + 0.01% of reading)
	Axton gauge: ±2.0 psi [±13,689 Pa] for typical HPHT operational range (>212 degF [>100 degC] and >15,000 psi [>103 MPa]) and ±6.0 psi [±41,368 Pa] for full range‡
	Temperature: ±1.0 degF [±0.5 degC]

† Operating range up to 400 degF and default calibration to 392 degF with calibration to higher temperature on requries.
‡ Includes fitting error, hysteresis, repeatability, and allowance for sensor aging; the corresponding percentages of the pressure reading account for the incertitude of the calibration equipment.

Dual-Packer Module Packers Mechanical Specifications

Packer	Outside Diameter, in [cm]	Hole Size—Min., in	Hole Size—Max., in	Temperature Rating, degF [degC]	Pressure Rating, psi [MPa]	Differential Pressure Rating, psi [MPa]	Type	Recommended Number of Settings†
SIP-A3-5in	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	4,500 [31]	Symmetrical	10 settings at 3,000 psi in 6-in hole
SIP-A3A-5in	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	4,500 [31]	Asymmetrical	10 settings at 3,000 psi in 6-in hole
IPCF-H2S-500	5 [12.70]	5.875	7.5	350 [177]	20,000 [138]	TBQ‡	Asymmetrical	TBQ‡
SIP-A3-6.75in	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Symmetrical	10 settings at 3,000 psi in 8.75-in hole
SIP-A3A-6.75in	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.75-in hole
IPCF-PAS-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Symmetrical	10 settings at 3,000 psi in 8.5-in hole
IPCF-PA-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.5-in hole
IPCF-PC-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	4,500 [31]	Asymmetrical	5 settings at 4,500 psi in 8.5-in hole
IPCF-BA-700	7 [17.78]	7.875	9.625	410 [210]	20,000 [138]	3,000 [21]	Asymmetrical	3 settings at 3,000 psi in 8.5-in hole
IPCF-H2S-700	7 [17.78]	7.875	9.625	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 8.5-in hole
SIP-A3A-8.5in	8.5 [21.59]	9.875	14	350 [177]	20,000 [138]	3,000 [21]	Asymmetrical	10 settings at 3,000 psi in 12.25-in hole
SIP-A3A-10in	10 [25.40]	11	17.5	350 [177]	20,000 [138]	2,100 [14]	Asymmetrical	7 settings at 2,100 psi in 14.4-in hole

† At the specified pressure and hole size
‡ To be qualified

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APPENDIX D-4

SCHLUMBERGER SATURN 3D RADIAL PROBE

Schlumberger

Saturn

3D radial probe

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.

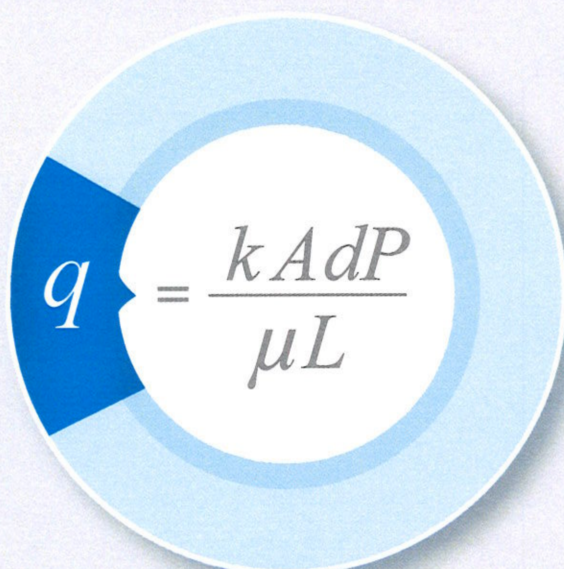
The low storage volume of the Saturn design not only facilitates fluid sampling and DFA but also the efficient performance of complete pressure surveys in extremely low-permeability formations.

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.



$$q = \frac{k A dP}{\mu L}$$

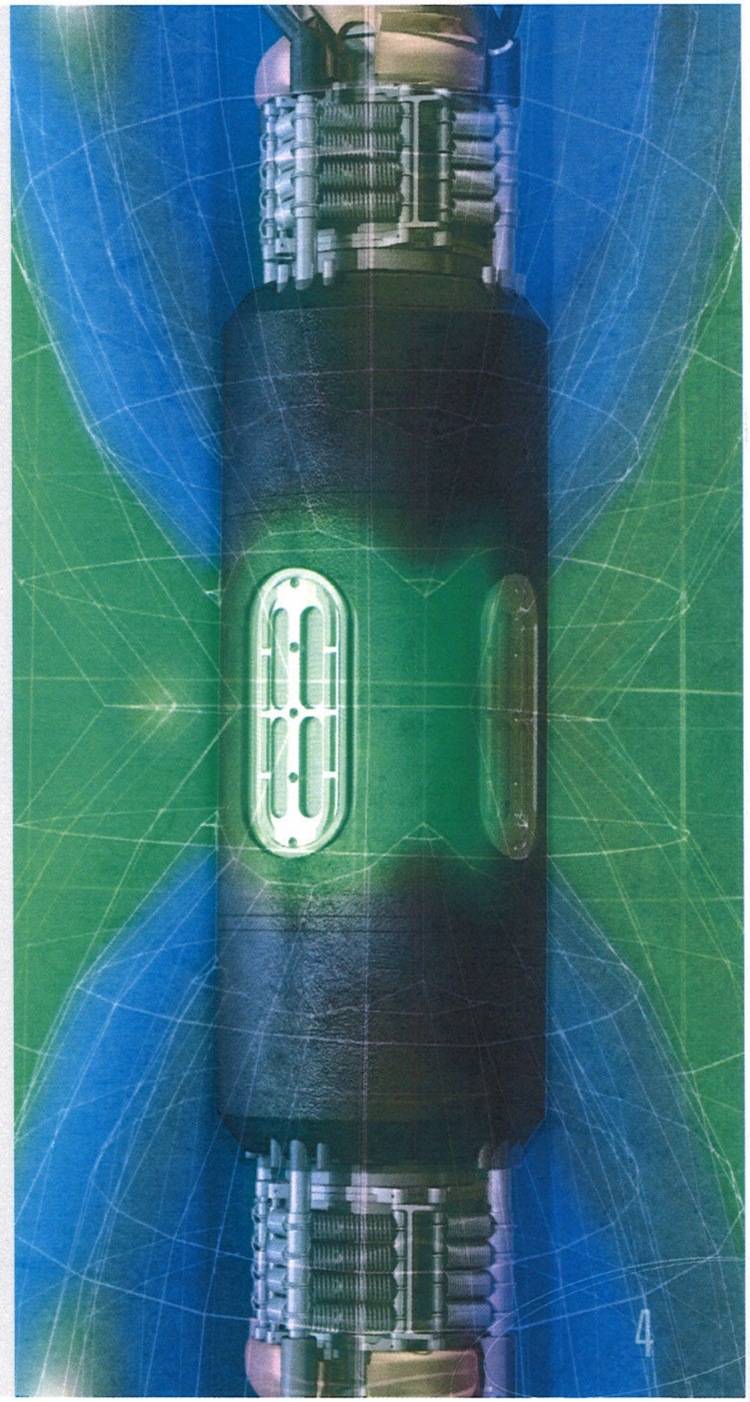
Flow from the formation to a conventional formation tester is narrowed to the intake of the single probe, not from the entire circumference of the borehole wall.

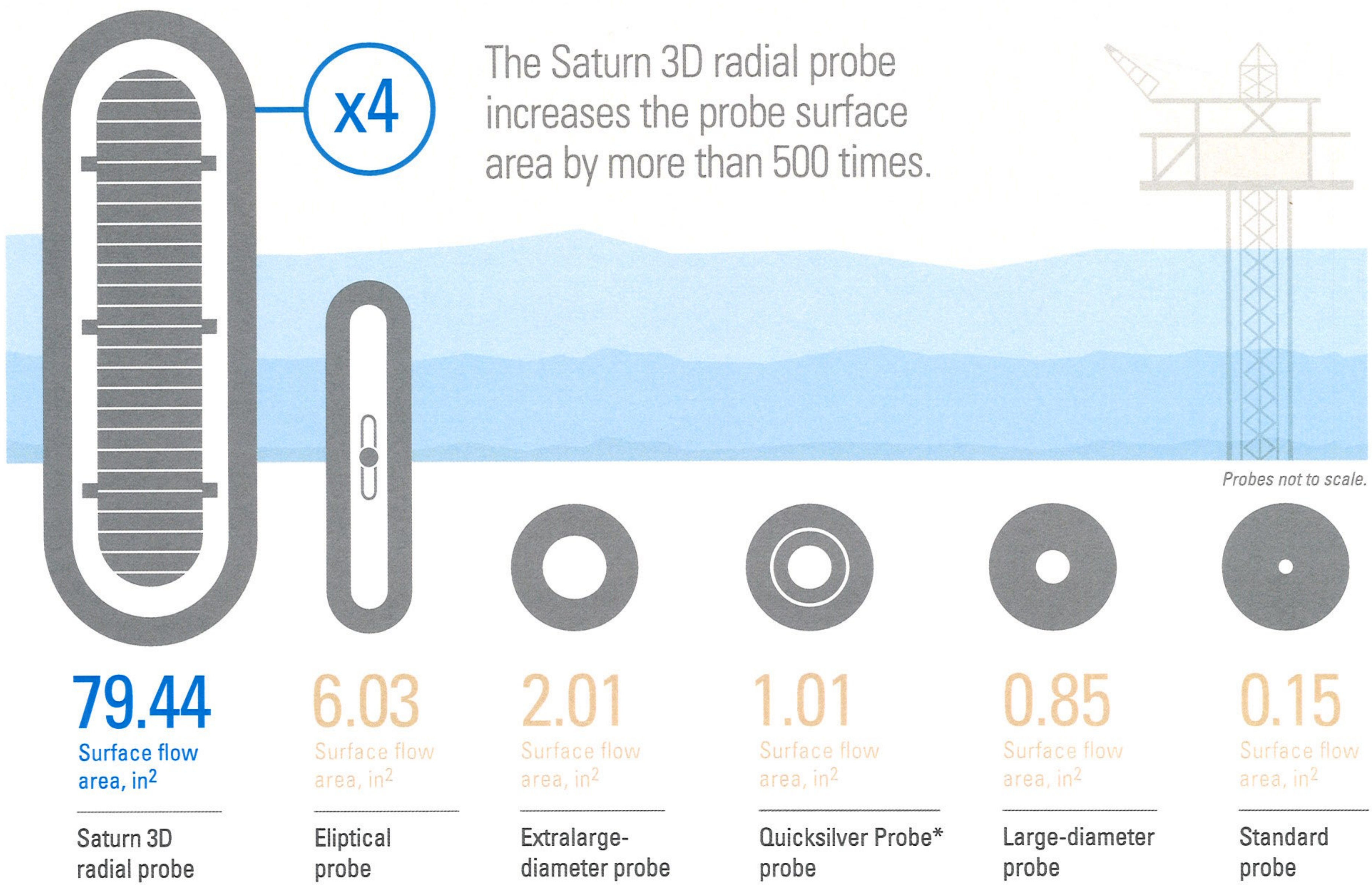
Different probe surface flow areas and the maximum pressure drawdowns that the formation tester can manage are used depending on the formation permeability and fluid viscosity. Typically, the larger the surface area and the higher the maximum drawdown pressure, the higher the flow rate of fluid from 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.

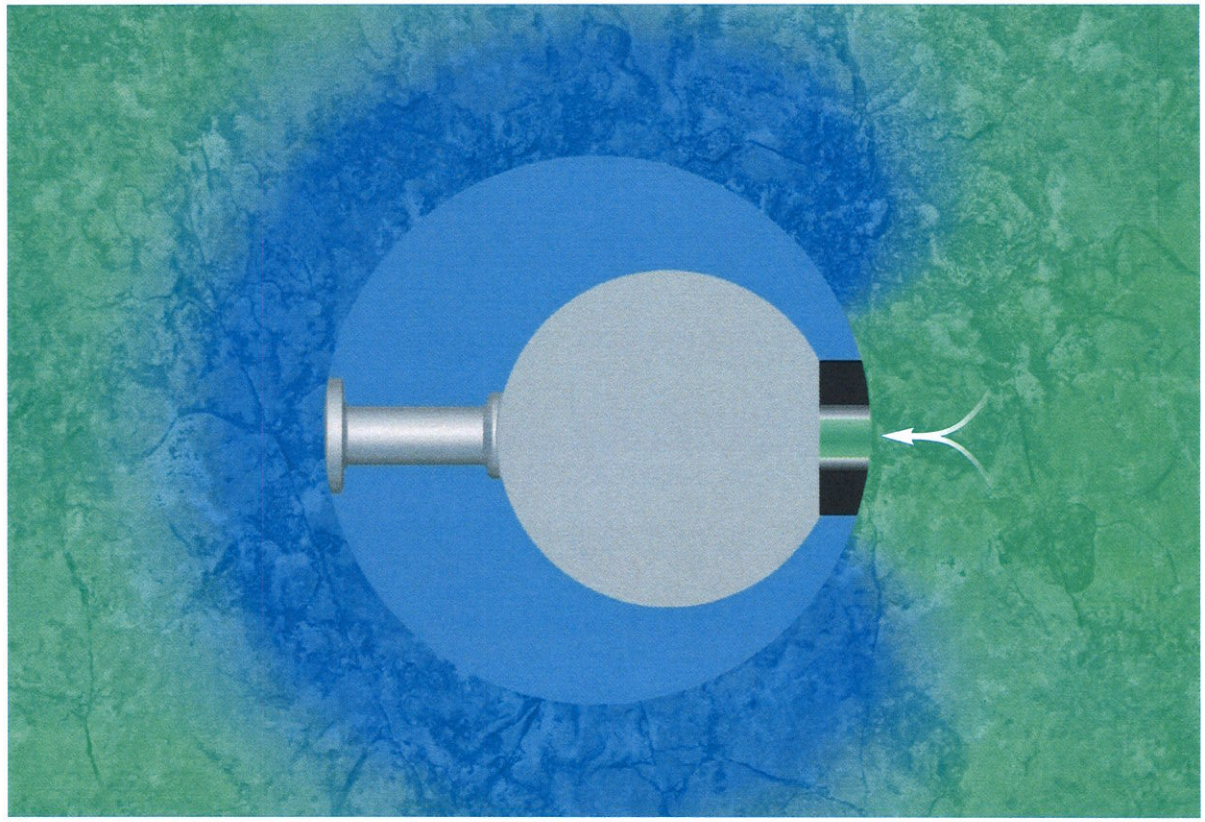
Reliably out of the hole, every time

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.

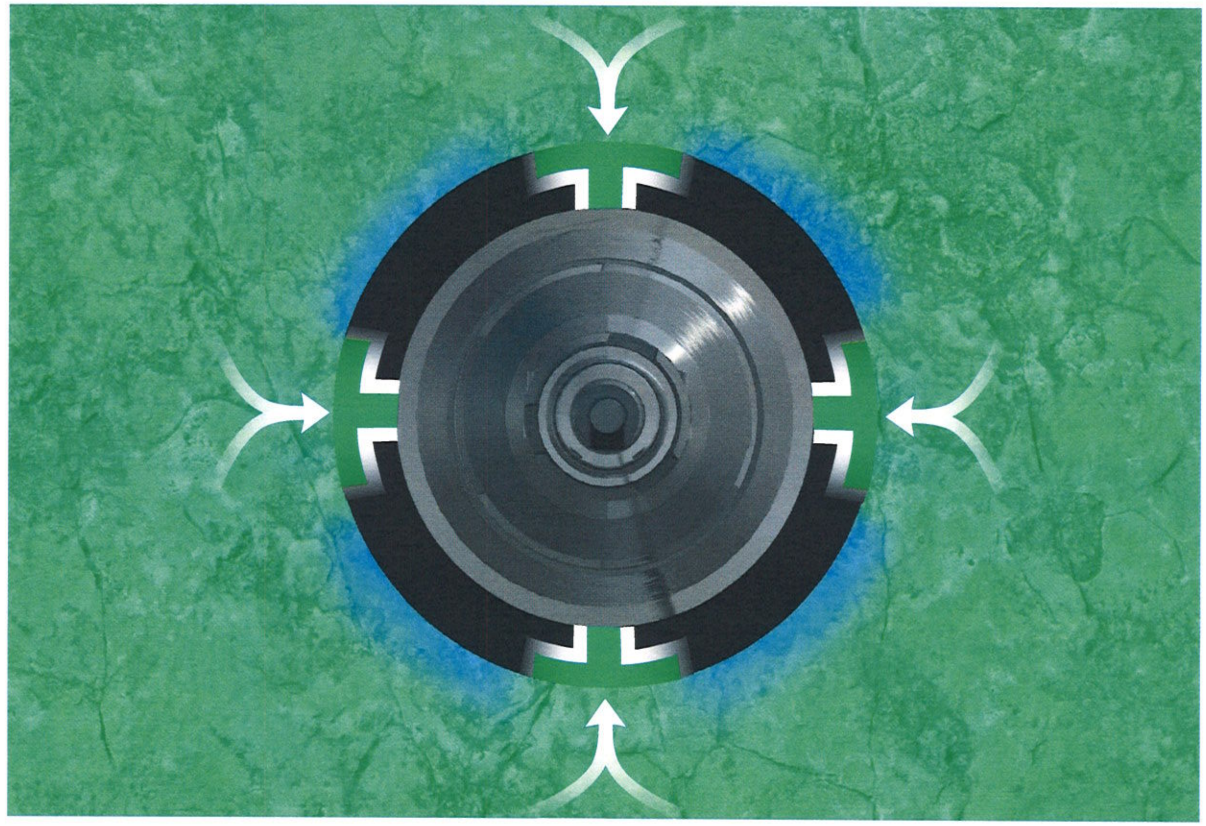
Flow fluid in three dimensions

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.



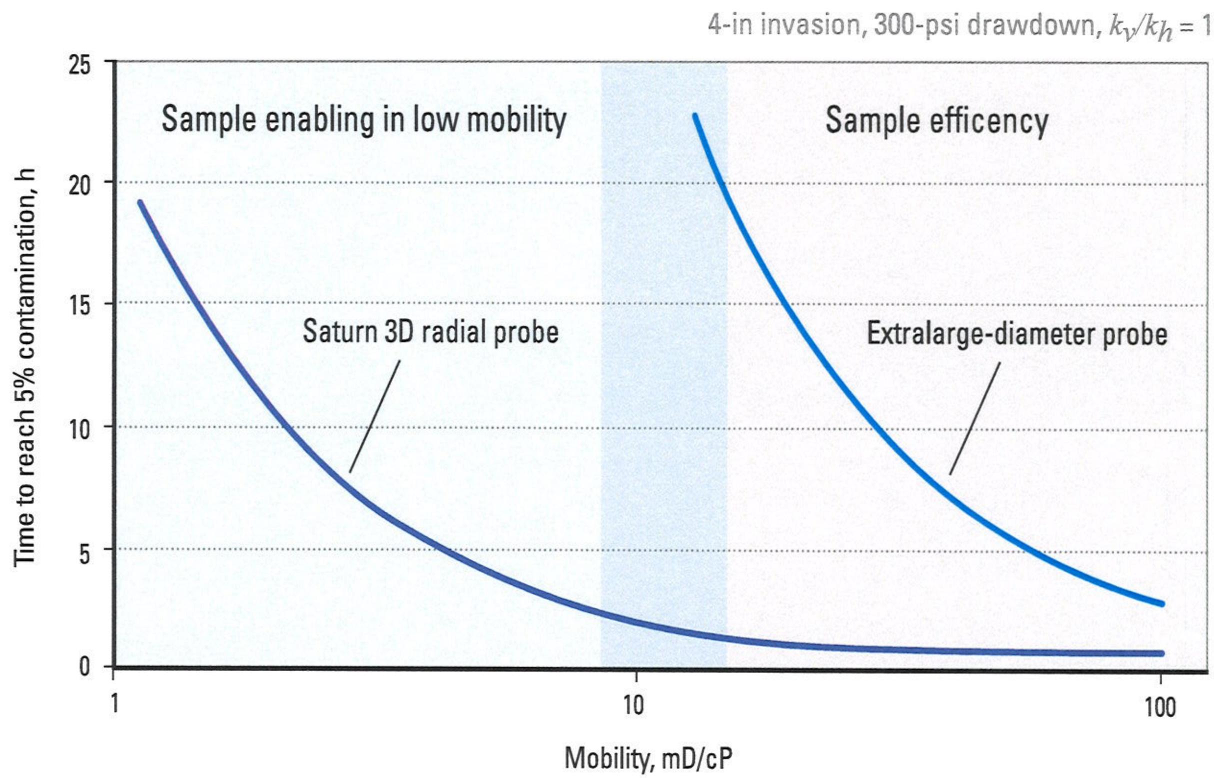
The four Saturn probes efficiently establish circumferential flow from the formation to quickly remove filtrate-contaminated fluid and flow uncontaminated, representative fluid for DFA, sampling, and pressure measurements.

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.

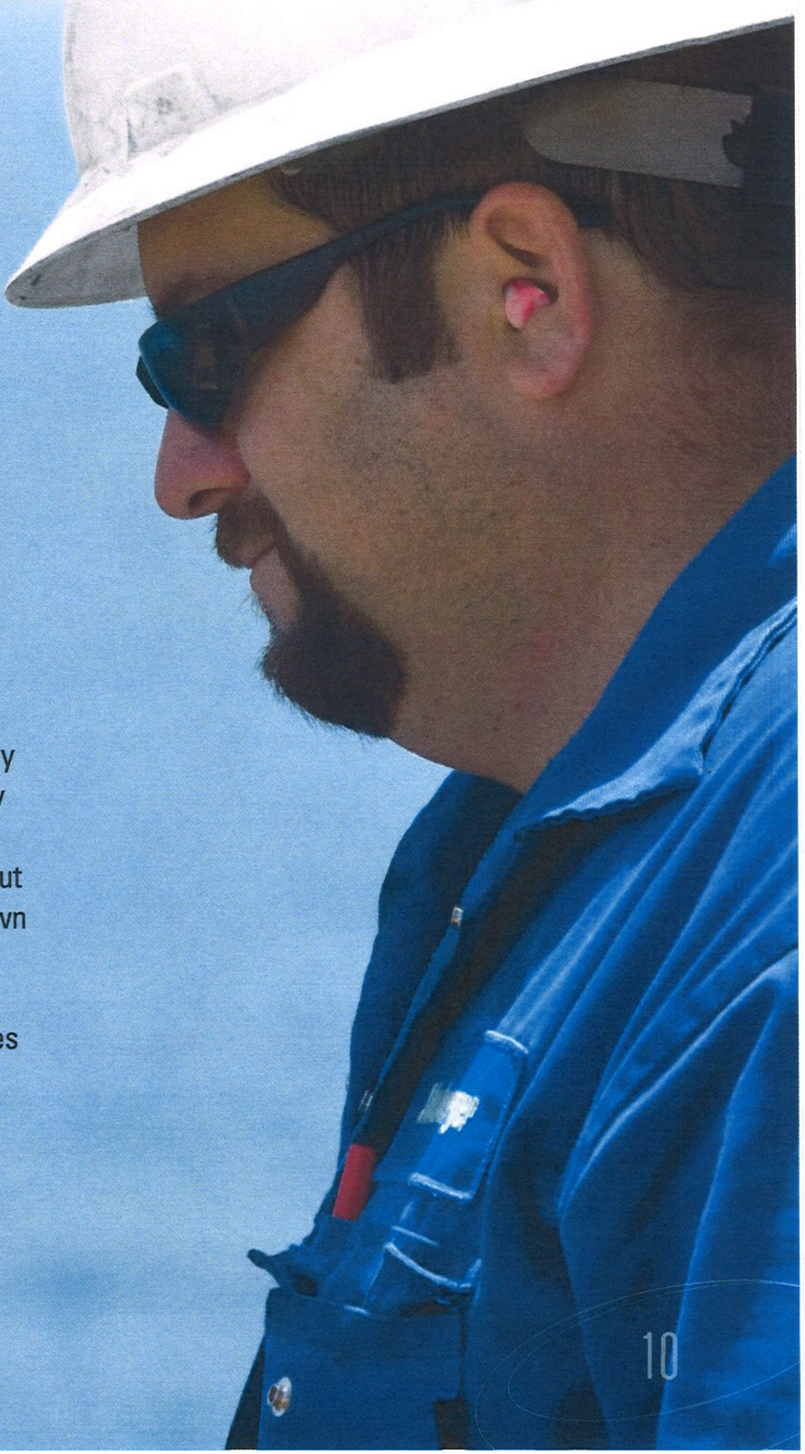
Complete pressure surveys in low-mobility formations

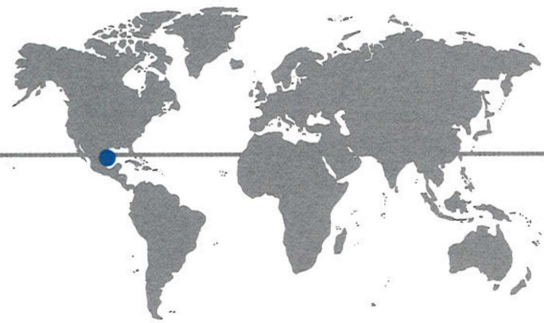
The technology that makes the Saturn 3D radial probe excel at fluid extraction also delivers a step change in formation pressure testing. Conventional formation tester probes with the largest surface flow area currently available are limited to pressure testing formations with mobilities no lower than 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.

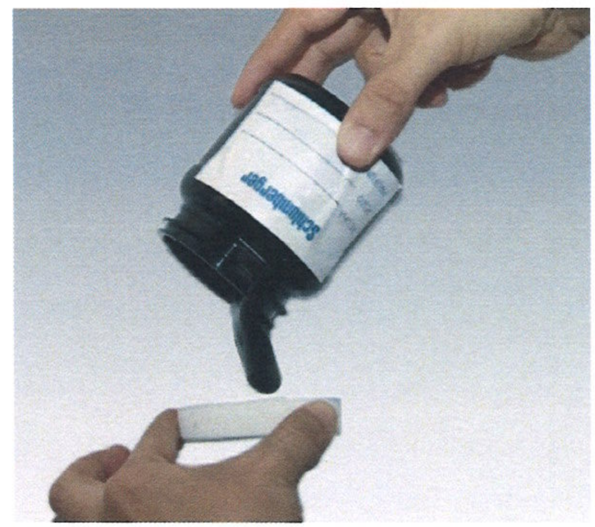
Each self-sealing Saturn probe incorporates a filter to capture any dislodged matrix and prevent plugging.

If sand grains were drawn in with the flowing fluid, the Saturn drain assembly incorporates individual probe filters to prevent flowline plugging.

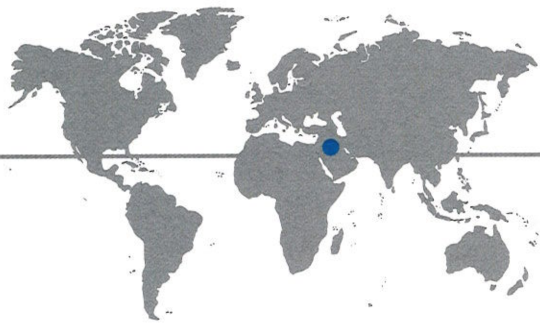
The Saturn 3D radial probe was deployed in the field to test and sample at multiple stations in several wells, which have up to 12% ovalization. Whereas conventional probes commonly experienced lost seals in the rugose holes, the Saturn self-sealing probes maintained seal integrity to support the borehole 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.



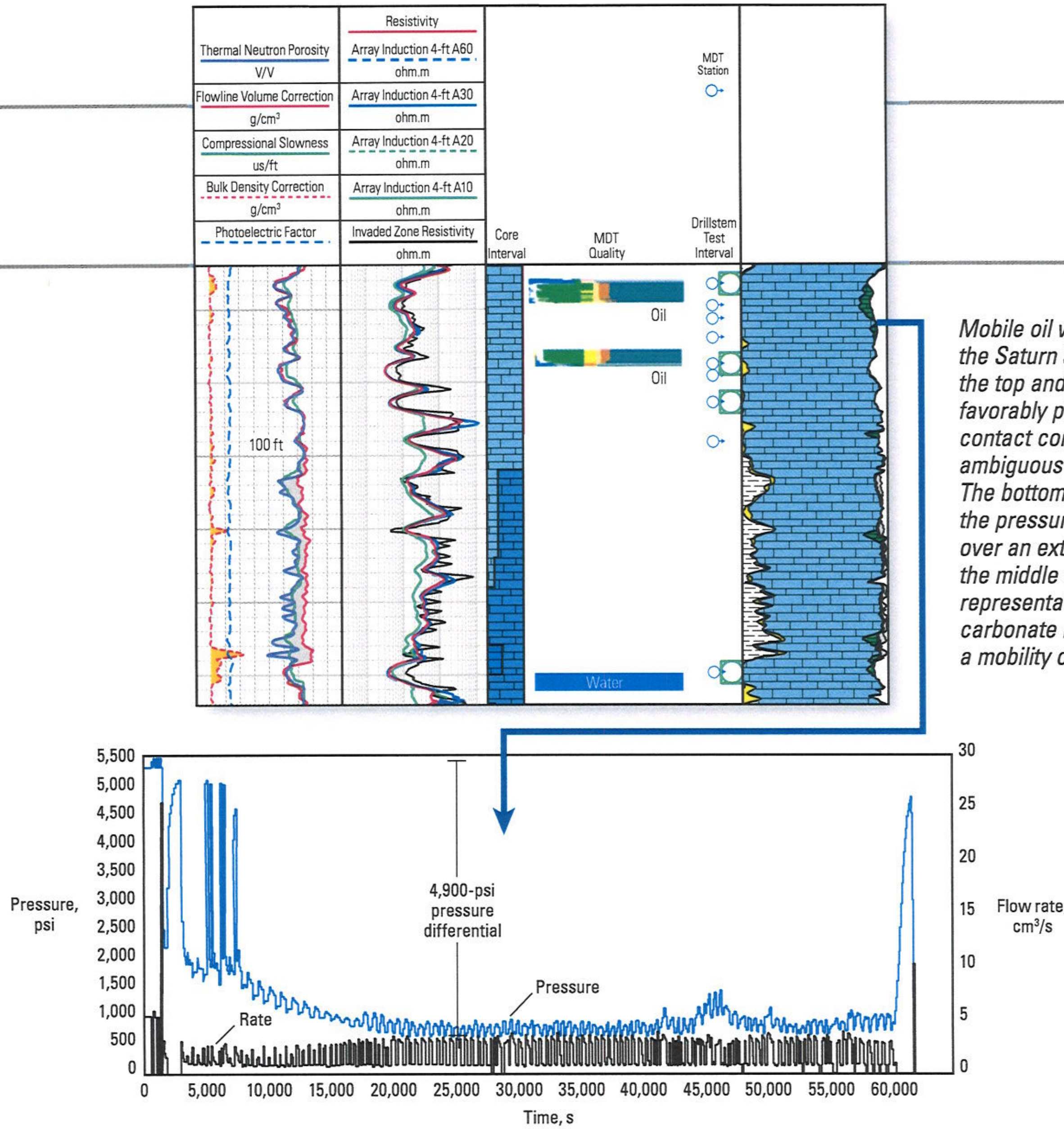
Saturn probe delineates low-mobility oil zone in carbonate reservoir

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.

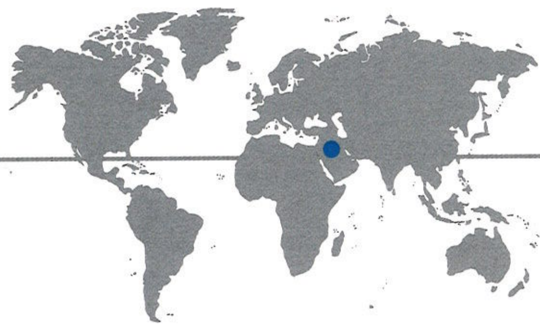
Extensive pumpout by the Saturn probe confirmed light oil in the top zone through DFA. A radial flow regime was established with an estimated horizontal permeability of approximately 1 mD. The station in the bottom zone yielded water and had a similar permeability.

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

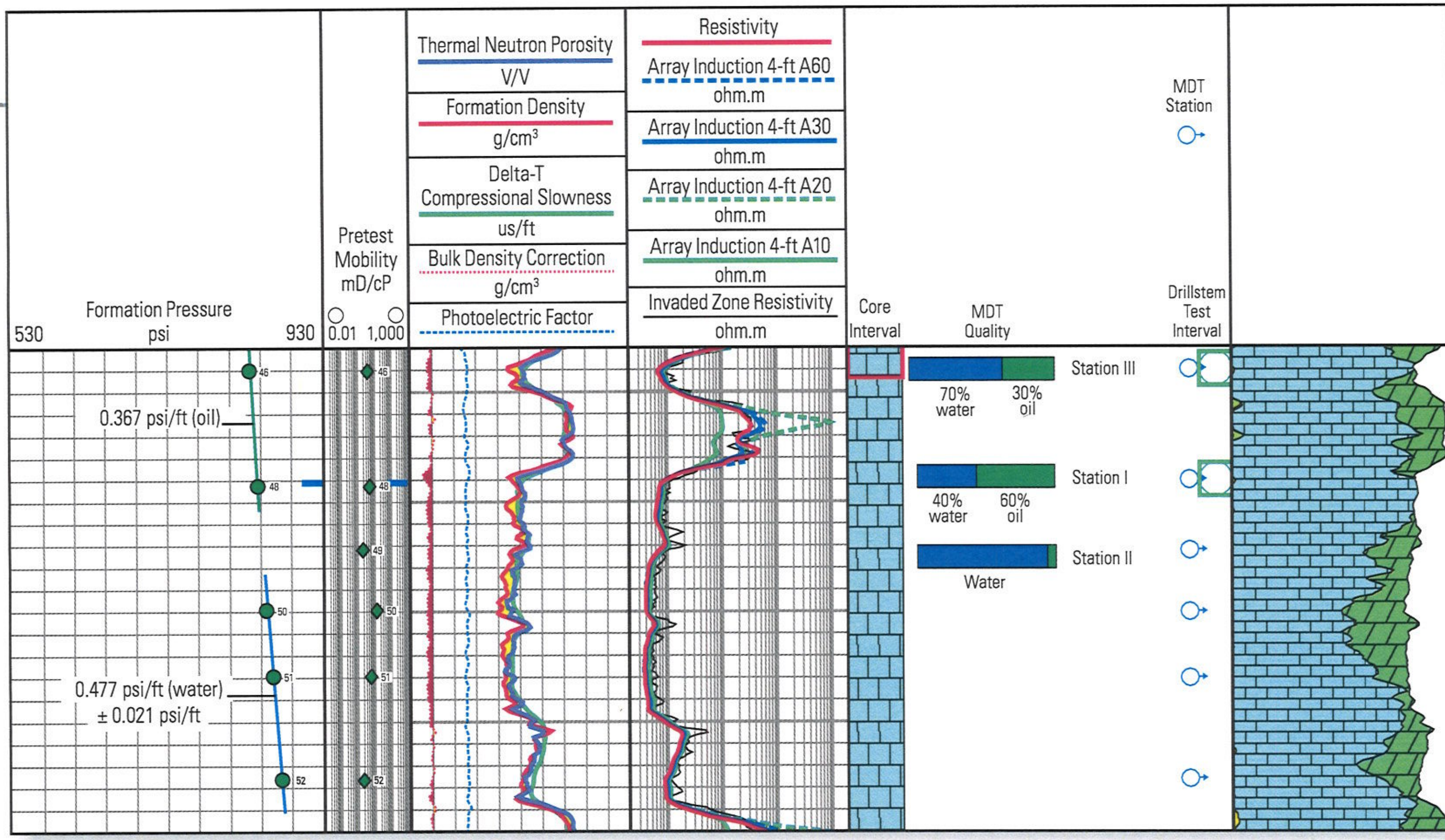


650% faster flow rate efficiently acquires fluids from dolomite

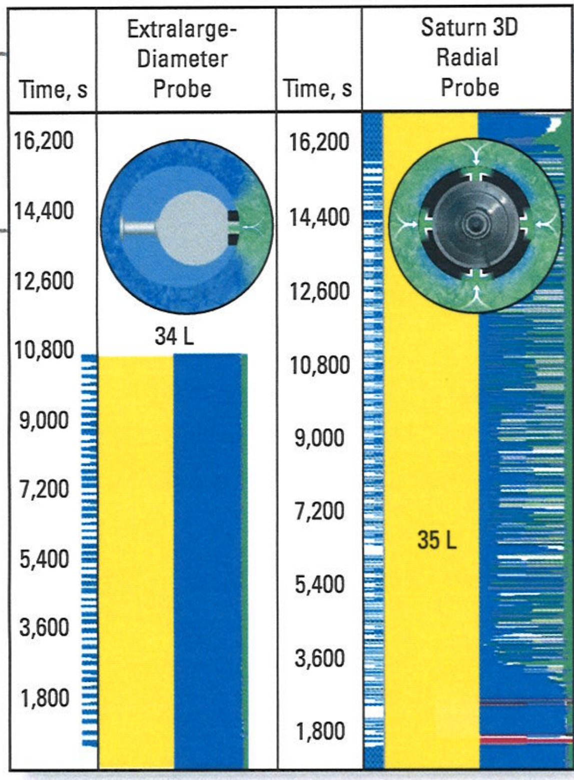
The openhole logs from a dolomitic limestone interval drilled with saline water-base mud in the Middle East did not indicate the presence of hydrocarbon, but the analysis was ambiguous because some zones had resistivity values as low as 0.7 ohm.m. The operator wanted to conduct DFA and collect samples 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.

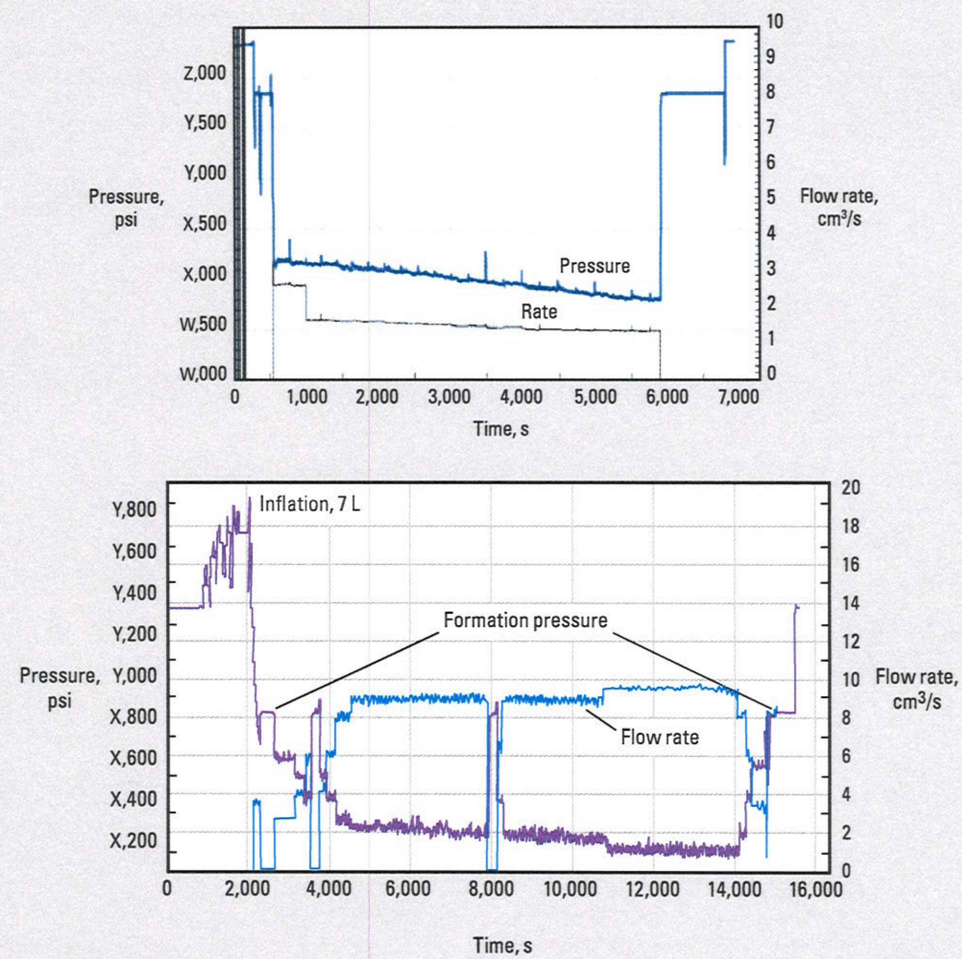
After DFA at Station I clearly identified 60%–70% oil, Station II was selected for determining the lowest mobile oil. The initial sampling attempt with the extralarge-diameter probe experienced a significant pressure drop, with 2,000-psi drawdown and a low flow rate of 5.2 L/h. The resulting pretest 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

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APPENDIX E

RISK ASSESSMENT EMERGENCY REMEDIAL AND RESPONSE

Stage	Risk	Description	Severity	Likelihood	Monitoring	Control in Place	Potential Response Actions	Response Personnel
Construction Period	Well control event while drilling or completing the well with loss of containment.	This event could occur during drilling and completion operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well suddenly.	Serious	Unlikely	* Flow sensor. * Pressure sensor. * Tank level indicator. * Tripping displacement practices. * Mud weight control.	* Blowout prevention (BOP) equipment. * Kill fluid. * Well control training. * BOP testing protocol. * Kick drill. * Lubricators for wireline operations.	Drilling: * Stop operation. * Close BOP. * Clear floor and secure area. * Execute well control procedure. * Evaluate drilling parameters to identify root cause. * Continue operations. Completion: * Stop operations. * Close BOP. * Clear floor and secure area. * Execute well control procedure. * Continue operations.	* Rig crew * Rig manager * Field superintendent * Project manager
Construction Period	Movement of brine between formations during drilling.	This event could occur if, while drilling the injection target, there is cross flow, with losses into the USDW.	Minor	Unlikely	* Tank level sensor. * Mud lab test. * Pressure sensors. * Flow sensors. * Tripping sheets.	* USDW will be covered with the surface casing and set in Pierre Formation. * Casing test after cementing surface casing to check integrity. * FIT test to verify shoe integrity. * Mud used in surface casing are based on fresh water and clays. * CBL to check cement bonding.	* Stop drilling. * Check well level to detect a lost circulation or influx. * In case of losses, treat the well with lost circulation material, and evaluate mud weight and drilling parameters. * In case of influx, control the well, without compromising the shoe integrity. * In case shoe is identified as leaking, squeeze to regain integrity. * In case surface casing shows a leak, squeeze or install a casing patch.	* Rig crew * Rig manager * Field superintendent
Injection Period	Loss of mechanical integrity injection wells – tubing/packer leak	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause communication of formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario.	Serious	Likely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * Annular pressure test * CO_2 leak sensors on the wellhead	* Coated tubing. * Inhibited packer fluid in annular. * Corrosion monitoring plan. * Dry CO_2 injected. * Nickel-plated packers. * FF trim tubing hanger and tree. * CR tubing tailpipes below packers. * CR or Inconel carrier for the sensors. * New tubing.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * If tubing leak is detected, discuss with regulator the action plan based on the finding. * Schedule well service to repair tubing.	* Operation engineer * Field superintendent * Project manager
Injection Period Postinjection	Loss of mechanical integrity monitoring wells – tubing/packer leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause a communication of the formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario. Monitoring wells are designed to be outside of the projected plume for the majority of the project which reduces the risk of contact with CO_2.	Minor	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * Annular pressure test. * CO_2 leak sensors on the wellhead.	* Coated tubing. * Inhibited packer fluid in annular. * Corrosion monitoring plan. * Nickel-plated packers * CR tubing below/between packers. * CR or Inconel carrier for the sensors. * New tubing.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * If tubing leak is detected, discuss with regulator the action plan for well service. * Schedule well service to repair tubing or abandon the well.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors

Injection Period	Loss of mechanical integrity injection wells – casing leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, or others. This event could cause a migration of CO2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	Serious	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * CO_2 leak sensors on the wellhead. * DTS fiber real time alongside the casing. * Flow rate monitoring. * Soil gas probes. * Neutron activated logs. * USDW water monitoring.	* CO_2-resistant cement and metallurgic across injection zone. * Injection through tubing and packer. * Nickel-plated packers. * CR or Inconel carrier sensors. * Inhibited packer fluid in the annular. * Cement to surface. * Corrosion monitoring plan. * CBL/USIT after installation. * New casing and tubing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * If casing leak is detected, discuss with regulator the action plan based on the finding and location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	Loss of mechanical integrity monitoring wells – casing leak.	This event could occur because of corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others. This event could cause a migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW. Monitoring wells are designed to be outside of the projected plume for the majority of the project which minimizes the risk of contact with CO_2.	Serious	Unlikely	* Pressure and temperature gauges on surface and downhole real time. * Electromagnetic casing inspection log. * CO_2 leak sensors on the wellhead. * Soil gas probes. * Neutron activated logs. * USDW water monitoring.	* CO_2-resistant cement across injection zone. * Nickel-plated packers. * CR or Inconel carrier sensors. * Inhibited packer fluid in the annular. * Cement to surface. * Corrosion monitoring plan. * CBL/USIT after installation. * New casing and tubing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * If casing leak is detected, discuss with regulator the action plan based on the findings and the location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period	LOC: vertical migration via injection wells.	During the life of the injector wells, there are induced stresses and chemical reactions on the tubulars and cement exposed to the CO_2 pressure and plume. Changes in temperature and injection pressure create stresses in the tubulars trying to expand or contract, and it can lead to microannulus effects. The combination of the dry CO_2 injected and the formation brines creates carbonic acid that reacts with the components of the cement to degrade properties such as permeability, strength, porosity, etc., weakening the matrix. These mechanics could lead to cracks, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * DTS fiber real time alongside the casing. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI. * Pressure gauges at surface. * Flow rate monitoring.	* CO_2-resistant cement and metallurgic across injection zone. * Injection through tubing and packer. * Cement to surface. * CBL/USIT after installation. * USDW covered as second barrier with surface casing and surface cement sheet. * New casing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator the action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors

Injection Period Postinjection	LOC: vertical migration via monitoring wells.	During the life of the monitoring wells, there are induced stresses and chemical reactions on the tubulars and cement-exposed brines, pressure plume and, eventually, CO_2. These mechanics could lead to cracks, cement deterioration, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2. Monitoring wells are designed to be outside of the plume for the majority of the injection period.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI. * Pressure gauges at surface.	* CO_2-resistant cement across injection zone. * Cement to surface. * CBL/USIT after installation. * USDW covered as second barrier with surface casing and surface cement sheet. * New casing installed.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	LOC: vertical migration via water disposal well in Inyan Kara.	This scenario could occur if there is a LOC in the CO_2 injector well through poor cement or cracks that could allow movement of carbonic acid into the Inyan Kara Formation. Inyan Kara is the main target for water disposal in the area. If carbonic acid gets in contact with the cement and casing for the water disposal well, corrosion and cement degradation could happen, with a potential path to USDW.	Serious	Unlikely	* CO_2 leak sensors on the wellhead. * Soil gas probes. * USDW water monitoring. * Neutron activated logs to be run for external MI or tracers. * Pressure gauges at surface.	* Evaluate CO_2-resistant cement through Inyan Kara in the water disposal well. * Validate Class I well will cover USDW to Pierre as well. * Recommended to include water disposal well in corrosion monitoring plan.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop injection. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW and the source of the leak. * If the injector is the source of the leak, follow protocol for LOC in injectors. * In the remote event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Discuss with regulator action plan to repair the well or P&A based on the findings of the assessment.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period Postinjection	LOC: vertical migration via legacy wells and P&A wells.	Brines and CO_2 could migrate through poor cement bonding, cement degradation, or cracking in the cement in P&A wells.	Serious	Unlikely	* Soil gas probes. * CO_2 leak sensors. * 4D seismic survey (AOR review periods).	* Legacy wells are properly abandoned for brine movement because of pressurization of injection zone. * Injectors will be abandoned as soon as CO_2 injection in the HUB ends, except if they are left as monitoring wells.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Evaluate if it's a positive CO_2 release because of a leak in the legacy/P&A well. * Discuss plan with regulator to repair the well, delineate the area, and identify potential resources affected. * Discuss specific remediation actions and monitoring plans. * Execute program, monitor, and evaluate efficacy.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors
Injection Period	LOC: vertical migration due to failure of confining rock, faults, or fractures.	This event can occur if, during injection, the pressurization of the injection zone exceeds the sealing capacity of the cap rock/seal above or if there are features such as fault or fractures that are reactivated. CO_2 and brine could find a leak path to a shallower formation, including USDW.	Serious	Unlikely	* USDW water sampling. * 4D seismic survey. * Neutron activated log in injector and monitoring wells. * Gas soil monitoring.	* Seismic survey in the area shows no faults crossing the storage formation or the seal. * Injection is limited to 90% of frac gradient. * Extensive characterization of the rocks show good sealing capacity. * In case cap rock above Broom Creek fails, Inyan Karan underpressure zone will act as a buffer formation before CO_2 or brines reaching USDW.	* Trigger alarm by the system, monitoring personnel, or operations engineer. * Follow protocol to stop injection. * Assess root cause by reviewing monitoring data. * If required, conduct geophysical survey to delineate potential leak path. * Evaluate if there is a movement of CO_2 or brines to USDW. In the event that USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with regulator.	* Monitoring staff * Geologist * Reservoir engineer * Project manager * Remediation contractors

Injection Period Postinjection	LOC: lateral migration of CO_2 outside defined AoR.	This event could occur if the CO_2 plume moves faster or in an unexpected pattern and expands beyond the secured pore space for the project and the AoR.	Serious	Unlikely	* 4D seismic. * Neutron activated logs in monitoring wells. * Pressure and temperature gauges real time in monitoring wells.	* Detailed geologic model with stratigraphic wells as calibration. * Seismic survey integrated in the model. * Extensive characterization of the rocks and formation. * AoR review and calibration at least every 5 years. * Monitor the plume until stabilization (min 10 years).	Injection period: * Trigger alarm by monitoring staff. * Review monitoring data and trends, and compare with the simulation. * Discuss with regulatory agency the findings, and request to keep injection process while AoR is reviewed, if the data show that CO_2 will stay in the secured pore space. * Perform logging in monitoring wells. * Conduct geophysical survey as required to evaluate AoR. * Recalibrate model, and simulate new AoR. * Assess if additional corrective actions are needed and if it's required to secure additional pore space. * Assess if any remediation is needed, and discuss action plan with regulatory agency. * Present AoR review to regulatory agency for approval and adjust monitoring plan. Postinjection period: * Trigger alarm by monitoring staff. * Review monitoring data and trends, compare with the simulation. * Discuss findings with regulatory agency. * Conduct geophysical survey as required to evaluate AoR. * Recalibrate model, and simulate new AoR. * Assess if additional corrective actions are needed and if it's required to secure additional pore space. * Assess if any remediation is needed, and discuss action plan with regulatory agency.	* Monitoring staff * Geologist * Reservoir engineers * Project manager
Injection Period	External impact – injector well.	This event could occur if, during injection, the wellhead is hit by a massive object that causes major damages to the equipment. The well gets disconnected from the pipeline and from the shutoff system and leads to a loss of containment of CO_2 and brine.	Major	Unlikely	* Pressure, temperature, and flow sensors in real time. * Field inspections. * OGI cameras.	* Fence location and block direct access to the wellhead. * No populated area. * Doubled lined pads. * Location is able to contain 70.000 bbl, and additional transfer pump and lines are designed to move fluid to the settling ponds southwest of the location.	* Trigger alarm by the system or operations staff. * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional. * If there is injured personnel, call emergency team, and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include but is not limited to capping the well, secure location, drill relief well to kill injector, properly repair or abandon injection well. This plan would be discussed with the regulatory agency. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist

Injection Period Postinjection	External impact – monitoring well.	This event could occur if the wellhead of the deep monitoring well is hit by a massive object that causes major damages leading to a LOC. Since the well is open to the formation pressure at the injection zone, formation fluids have the potential to flow and spill on the location.	Major	Unlikely	* Pressure, temperature, and flow sensors in real time. * Field inspections. * OGI cameras.	* Fence location, and block direct access to the wellhead. * No populated area. * Lined pads. * Reduced pressure in the monitoring well compared with the injector well on bottom.	* Trigger alarm by the system or operations staff. * If there is injured personnel, call emergency team and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include, but is not limited to, capping the well, securing the location, drilling relief well to kill the injector, properly repairing, or abandoning the injection well. This plan would be discussed with the regulatory agency. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Project manager * Rig crew and DH contractors * Remediation contractors * Well control specialist
Injection Period	External impact – pipeline.	This event could occur if, during injection, the CO_2 pipeline is hit, causing major damages and LOC of the CO_2.	Major	Unlikely	* Pressure, temperature, and flowmeter sensors in real time. * Field inspections. * OGI cameras?	* Buried pipe. * Bollards and/or concrete barriers installed to protect aboveground piping at valve stations. * Painting for visibility in varied weather conditions. * Signage along right of way as needed. * One-call 811 program.	* Trigger alarm by the system or operations staff. * If there is injured personnel, call emergency team, and execute evacuation protocol. * Verify CO_2 flow was shut off by the system, or start protocol to stop flow. * Contact the field superintendent to activate emergency plan. * Clear the location, and secure the perimeter. If possible, install containment devices around the location. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Remediation contractors * Emergency teams * Plant manager/contact
Injection Period	Monitoring equipment failure or malfunction.	If there is a failure on the monitoring system/ alarm devices, it could lead to overpressurization of the system or reservoir beyond the design limits, causing potential fracturing of the reservoir, leaks or failure on equipment and tubulars, and damage of the facilities.	Serious	Unlikely	* Real-time monitoring system and redundancy. * Field inspections.	* Preventive maintenance. * Periodic inspections.	* Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Assess mechanical integrity of the system, and propose repair actions if needed. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * If the assessment allows resuming injection safely, discuss plan with the Commission, and get approval. * Repair or replace instrumentation. Calibrate equipment. * Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

Injection Period	Induced seismicity.	This event could occur if pressurization of the reservoir, during injection of CO_2, activates preexisting fault planes and creates a displacement that causes a seismic event. If it's a major event (>2.7 Richter), it could compromise the integrity of the wells, facilities, or pipeline.	Major	Unlikely	* Geophones array in surface to monitor induced seismicity. * Geophones/DAS fiber.	* Seismic survey of the storage complex shows no faults that could be reactivated. * A detailed geomechanical model was created to evaluate the storage complex. * The region is seismically stable.	Event < 2.7 Richter: * Trigger alarm by monitoring personnel. * Review monitoring parameters to validate normal operations. If parameters indicate a potential mechanical integrity failure, follow procedure for Event > 2.7 Richter. * Compare storage behavior with the model, and if needed, propose adjustment in operating conditions. Event > 2.7 Richter *Trigger alarm by the system or operations staff. * If there is injured personnel or property damages, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection. * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * Review regional information as well as monitoring records to determine the origin of the event (natural or induced). * If it's an induced event, reevaluate model, define new injection parameters, and get approval from the Commission. * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff
Injection Period Postinjection	Major seismic event.	Major natural seismic event.	Major	Unlikely	* Geophones array in surface to monitor induced seismicity. * Geophones/DAS fiber.	* The region is seismically stable.	Event < 2.7 Richter: * Trigger alarm by monitoring personnel. * Review monitoring parameters to validate normal operations. If parameters indicate a potential mechanical integrity failure, follow procedure for Event > 2.7 Richter. Event > 2.7 Richter *Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection (injection period). * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * Review regional information as well as monitoring records to determine the origin of the event (natural or induced). * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period).	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

Injection Period Postinjection	Other major natural disaster.	This scenario could occur in the event of a natural disaster that limits or endangers the normal operation of the Hub.			n/a	n/a	*Trigger alarm by the system or operations staff. * If there is injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. * Follow protocol to stop injection. * Assess mechanical integrity of the system, and propose repair actions based on the findings. * Assess any potential environmental impact, and discuss remedial action with the Commission if needed. * If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	* Operation engineer * Field superintendent * Project manager * Remediation contractors * Emergency teams * Geologist * Reservoir engineers * Monitoring staff

APPENDIX F

CORROSION CONTROL MATRIX

System	Category	Component	Material	Additional Specs	Temperature		Pressure		Flow Rate (MMscfd)		Fluid Composition	
					Surface	Downhole	Surface	Downhole	Min	Max	External	Internal
Downhole Equipment	Injection well Broom Creek.	Tubing, nipples, XO.	* L80, coated TK-805 or equiv. * 13CR any tail pipe or tubular potentially exposed to carbonic acid.	Internal connection flush, "corrosion barrier-type."	Ambient 6° to 120°F	Max: 140°F	Max: 1,700 psi.	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Broom Creek.	Casing.	* L80 from surface to min 200 ft above first injection zone. * CR13 across all injection zones.	Premium connection gas sealed.	Ambient 6° to 120°F	Max: 140°F	Max: 1,700 psi.	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* CO_2-resistant cement across injection zone and min 200 ft above the seal formation. * Conventional cement above seal formation to surface.	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * CO_2 Tundra spec. from injection packer to perforations. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Broom Creek.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event
Downhole Equipment	Injection well Broom Creek.	Electric cable for the gauges.	* Inconel.	n/a	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut in event in tail pipes during shut in event	n/a
Downhole Equipment	Injection well Broom Creek.	Packers.	* Nickel-plated. * Hydrogenated nitrile rubber (HNBR), rapid gas decompression (RGD) with 90 D hardness.	Validate with provider.	n/a	Max: 140°F	n/a	Max: 3,550 psi. Assuming 0.71 psi/ft frac.	50	150	* Packer fluid (corrosion inhibitor additive), above packer. * CO_2 Tundra spec. below packer. * Potential CO_2 mixed with formation brine below packer.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine when shut in.
Downhole Equipment	Injection well Broom Creek.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	1,700 psi.	n/a	50	150	Ambient air.	n/a
Downhole Equipment	Injection well Broom Creek.	Tree and tubing hanger.	* CC or FF trim.	n/a	Min: 6°F Max: 120°F	n/a	1,700 psi.	n/a	50	150	Ambient air.	* CO_2 Tundra spec.
Downhole Equipment	Injection well Deadwood.	Tubing, nipples, XO.	* L80, coated TK-805 or equiv.	Internal connection flush, corrosion barrier-type.	Min: 6°F Max: 120°F	Max: 190°F	Max: 2,800 psi.	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	Casing.	* L80 from surface min to 200 ft above first injection zone. * CR13 across all injection zones. * L80 between injection zones.	Premium connection gas sealed.	Min: 6°F Max: 120°F	Max: 190°F	Max: 2,800 psi.	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* CO_2-resistant cement across all injection zone and min 200 ft above the seal. * Conventional cement above seal formation to surface.	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * CO_2 Tundra spec. from injection packer to perforations. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in shut-in event in tail pipes during shut-in event.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine in shut-in event.
Downhole Equipment	Injection well Deadwood.	Electric cable.	* Inconel.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive). * Potential CO_2 mixed with formation brine in tail pipes during shut-in event.	n/a
Downhole Equipment	Injection well Deadwood.	Packers.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	50	100	* Packer fluid (corrosion inhibitor additive), above packer. * CO_2 Tundra spec. below packer. * Potential CO_2 mixed with formation brine below packer.	* CO_2 Tundra spec. * Potential CO_2 mixed with formation brine when shut in.
Downhole Equipment	Injection well Deadwood.	Tapered long string hanger.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	Validate with provider.	n/a	Max: 190°F	n/a	Max: 5800 psi. Assuming 0.3 psi/ft fluid and 2800 psi max on surface.	n/a	n/a	* CO_2-resistant cement	* Packer fluid (corrosion inhibitor additive).
Downhole Equipment	Injection well Deadwood.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	2800 psi	n/a	50	100	Ambient air.	n/a
Downhole Equipment	Injection well Deadwood.	Tree and tubing hanger.	* CC or FF trim.	n/a	Min: 6°F Max: 120°F	n/a	2800 psi	n/a	50	100	Ambient air.	* CO_2 Tundra spec.
Downhole Equipment	In-zone monitoring well.	Tubing.	* L80. * 13CR between packers in open zones.	Premium connection gas-sealed.	Min: 6°F Max: 120°F	Max: 190°F	n/a	Max: 5800 psi. Assuming 0.3 psi/ft fluid and 2800 psi max on surface.	n/a	n/a	* Packer fluid (corrosion inhibitor additive) from surface to injection packer. * Formation brine between packers in monitoring zone. Once CO_2 breakthrough, CO_2 + formation brines.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Casing.	* L80 from surface to 200 ft from injection zones. * CR injection zones.	Premium connection gas-sealed.	Min: 6°F Max: 120°F	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* CO_2-resistant cement across all injection zone and min 200 ft above the seal. * Conventional cement above seal formation to surface.	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.
Downhole Equipment	In-zone monitoring well.	P/T gauges and carriers.	* Inconel carriers. * Quartz gauges.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Electric cable.	* Inconel.	n/a	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	n/a
Downhole Equipment	In-zone monitoring well.	Packers.	* Nickel-plated. * HNBR, RGD with 90 D hardness.	Validate with provider.	n/a	Max: 190°F	n/a	Max: 5,800 psi. Assuming 0.3 psi/ft fluid and 2,800 psi max on surface.	n/a	n/a	* Packer fluid. * Formation brines. * Formation brines and CO_2 after breakthrough.	* Packer fluid. * Formation brines in lower joints.
Downhole Equipment	In-zone monitoring well.	Wellhead.	* Carbon or low-alloy steel.	n/a	Min: 6°F Max: 120°F	n/a	2,800 psi.	n/a	n/a	n/a	Ambient air.	n/a
Downhole Equipment	In-zone monitoring well.	Tree and tubing hanger.	* Carbon or low-alloy steel	n/a	Min: 6°F Max: 120°F	n/a	2,800 psi.	n/a	n/a	n/a	Ambient air.	n/a

System	Category	Component	Material	Additional Specs	Temperature		Pressure		Flow Rate (MMscfd)		Fluid Composition	
CO_2 Pipeline – Minimum Burial Depth 48"	Pipeline.	Pipeline.	API 5L	14–16 mil fusion. Bond epoxy external coating.	Min: 0°F; Max: 120°F		1,800 psig.		224		Ground.	*CO_2 Tundra spec.
CO_2 Pipeline – Surface	Pipeline.	Pipeline.	API 5L	Painted.	Min: −50°F; Max: 120°F		1,800 psig.		224		Ambient air.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Surface piping.	API 5L	Painted.	Min: −50°F; Max: 120°F		1,800 psig.		224		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Valves.	Carbon steel body x stainless steel or ENP carbon steel internals.	Soft seats; CO_2-compatible materials.	Min: −50°F; Max: 120°F		1,800 psig.		156 (each well total flow)		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Instrumentation.	Stainless steel x stainless steel 2" isolating valving (WOG3000); in-line instrumentation per piping specification.		Varied.	Varied.	1,800 psig.		Varied		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection pressure gauge.			Min: 6°F; Max: 120°F		Design pressure: 1,800 psig. Analog gauge operating range: 1,500–3,000 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection rate meter.	Carbon steel body x stainless steel internals.	Senior orifice meter.	Min: 6°F; Max: 120°F		1,800 psig.		50–160 (each well flow range)		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Injection temperature gauge.			Operating range: −40°–200°F.				n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra Spec
Surface Piping, Instrumentation, and Pressure Control	Surface scope Broom Creek well.	Emergency shutdown valve.	Carbon steel body x stainless steel internals.	Soft seats; CO_2-compatible materials.	Min: 6°F; Max: 120°F		1,800 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Surface piping.	API 5L	Painted.	Min: −50°F; Max: 120°F		3,500 psig.		68		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Valves.	Carbon steel body x stainless steel or ENP carbon steel internals.	Soft seats; CO_2-compatible materials.	Min: −50°F; Max: 120°F		3,500 psig.		68		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Instrumentation.	Stainless steel x stainless steel 2" isolating valving (WOG3000); in-line instrumentation per piping specification.		Varied.	Varied.	3,500 psig.		Varied.		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection pressure gauge.			Min: 6°F; Max: 120°F		Design pressure: 3,500 psig. Analog gauge operating range: 2,000–4,000 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection rate meter.	Carbon steel body x stainless steel internals.	Senior orifice meter.	Min: 6°F; Max: 120°F		3,500 psig.		30–70		Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Injection temperature gauge.			Operating Range: −40°–200°F				n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.
Surface Piping, Instrumentation, and Pressure Control	Surface scope Deadwood well.	Emergency shutdown valve.	Carbon steel body x stainless steel internals.	Soft seats; CO_2-compatible materials.	Min: 6°F Max: 120°F		3,500 psig.		n/a	n/a	Ambient air; heat tracing.	*CO_2 Tundra spec.

Corrosion Threat Assessment – Damage Mechanism

Corrosion Damage Mechanism Category

		Internal Corrosion Mechanism				External Corrosion				Enviromental Induced Cracking		Mechanical and Metallurgical		
System	Component/ Equipment	CO_2 Corrosion	Deadleg Corrosion	Wet H_2S Corrosion	Microbiological Corrosion	Atmospheric Corrosion	Corrosion under Insulation (CUI)	Soil Corrosion	CO_2 Corrosion	Chloride SCC	Wet H_2S Damage	Erosion	Fatigue	Brittle Fracture
Downhole Equipment	Tubing, nipples, X/O	x							x					
Downhole Equipment	Casing	x							x					
Downhole Equipment	P/T gauges and carriers	x												
Downhole Equipment	Electric cable	x												
Downhole Equipment	Packers	x							x					
Downhole Equipment	Injection well wellhead	x				x								
Downhole Equipment	Injection well tree	x				x								
Downhole Equipment	Injection well tubing hanger	x												
Downhole Equipment	Monitoring well wellhead	x				x								
Downhole Equipment	Monitoring well tree	x				x								
Downhole Equipment	Monitoring well tubing hanger	x												
Downhole Equipment	Tapered long string hanger	x							x					
Surface Piping, Instrumentation, and Pressure Control	Surface piping	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Valves	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Instrumentation	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection pressure gauge	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection rate meter	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Injection temperature gauge	x					x							x
Surface Piping, Instrumentation, and Pressure Control	Emergency shutdown valve	x					x							x
CO_2 Pipeline – Buried	API-5L line pipe	x						x						
CO_2 Pipeline – Surface	API-5L line Pipe	x				x								

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Corrosion Control Program – Corrosion Control Matrix

System	Category	Equipment or Component	Damage Mechanism	Mitigation	Monitoring Activity	Location	Frequency	Limits	Consequences	Remedial Action	Remedial Action Responsible Person	Remedial Action Time Limit
Downhole Equipment	Injection Wells	Tubing , Nipples, X/O	CO_2 Corrosion	* Dehydrated CO_2 to 630 ppm of H_2O Injected. * Internal coating applied to the tubing. * CR13 specification for tail pipe below packers. * Inhibited packer fluid.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Surface.	1. Every 5 years. 2. Quarterly. 3. Real time. 4. Every 5 years.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr and discuss with action plan. 5. Pull tubing and packer scanning . 6. Run casing inspection log. 7. If well has casing integrity , run back completion hydrostesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Casing	CO_2 Corrosion	* CR13 material selected across CO_2 injection zones. * CO_2-resistant cement covering injection zone interval. * Injection though packer and tubing. * Casing cemented to surface. * Continous injection.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. DTS fiber technology. 5. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Casing exterior. 5. Surface.	1. Every 5 years. 2. Quarterly. 3. Real time. 4. Real time. 5. Every 5 years.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If required, propose casing repair program or P&A and discuss with Commission, based on the findings. 8. Once the casing is repaired, run back completion hydrotesting. 9. Perform annular pressure test. 10. Run CIL log through tubing. 11. Perform falloff test. 12. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	P/T Gauges & Carriers	CO_2 Corrosion	* Inconel carriers and quartz gauges. * Packer inhibited fluid in the annular in contact with the tools.	1. Real-time data transfer. 2. Electromagnetic logging. 3. Annular pressure test.	1. n/a 2. Log run through tubing. 3. Surface test.	1. Real time. 2. Annually. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Replace or repair tool.	1. Stop injection. 2. Perform annular pressure test to identify any loss of mechanical integrity in tubing or casing above injection zone. 3. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or aquire the date. 4. If the Commission approves, continue injection while the remedial action is taken. 5. During well service to repair or replace the gauges and carriers, run casing integrity log and pressure test well, inspect tubing, and change any defective equipment on the completion. 6. Identify root cause of failure to take remedial actions, and record the findings in the corrosion management database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.

Downhole Equipment	Injection Wells	Electric Cable	CO_2 Corrosion	* Inconel material * Packer inhibited fluid in the annular in contact with the tools.	* Real-time data transfer.	n/a	* Real time.	* Failure detected.	Replace or repair tool.	1. Troubleshoot the system. 2. Review monitoring data. 3. If the well has integrity , inform Commission within 24 hr, and discuss WO or alternative to replace cable or acquire data. 4. Prepare plan for replacement or repair of the equipment. 5. Upon Commission approval, continue injection and monitor pressure with surface gauges.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.
Downhole Equipment	Injection Wells	Packers	CO_2 Corrosion	* Nickel-plated packers. * Elastomers HNBR (RGD).	1. Pressure and temperature gauges surface and downhole. 2. DST fiber alongside the casing. 3. Annular pressure test.	1. Wellhead and downhole. 2. Casing. 3. Surface test.	1. Real time. 2. Real time. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrostesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Wellhead	CO_2 Corrosion Atmospheric Corrosion	* Wellhead sections are not in contact with CO_2 or formation fluids.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	1. Surface. 2. Surface.	1. Quarterly. 2. Weekly.	* Damage detected.	Replace or repair equipment (potentially the valves).	1. Perfom inspection with wellhead provider. 2. Define replacement or repair procedure.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	n/a
Downhole Equipment	Injection Wells	Tree	CO_2 Corrosion Atmospheric Corrosion	* FF trim selected in the wellhead. * Dry CO_2 injected , no H_2S in the system.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	Surface.	1. Quarterly. 2. Weekly. 3. By manufacturer recommendation.	* Damage or malfunction detected.	Stop injection to replace equipment.	1. Stop injection. 2. Perform inpection by wellhead specialist. 3. Define action plan based on findings.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	To be defined by the procedure and findings.
Downhole Equipment	Injection Wells	Tubing Hanger	CO_2 Corrosion	* FF trim selected in the wellhead. * Dry CO_2 injected, no H_2S in the system.	1. Surface pressure gauges.	1. Surface. 2. Surface.	1. Real time.	* Damage or malfunction detected.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. Actions will depend on the assessment and troubleshooting. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Execute repair. 6. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Surface maintenance team. 4. Downhole maintenance team.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.
Downhole Equipment	Injection Wells	Tapered Long String Hanger	CO_2 Corrosion	* CO_2-resistant cement. * Inhibited packer fluids above tapered long string. * Top packer seal. * Continuous injection. * Elastomers HNBR (RGD).	1. Corrosion coupons. 2. Pressure and temperature gauges. 3. DTS fiber technology.	1.Installed upstream injection wellhead. 2. Wellhead and on top of the packer. 3. Casing exterior.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Stop of injection is required by permit once the failure is detected.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If needed, pressure-test the casing with straddle packers. 8. If damage in the tapered long string hanger is detected, prepare workover proposal, and discuss it with the Commission. 9. Once the tapered long string hanger is repaired, run back upper completion hydrotesting. 10. Perform annular pressure test. 11. Run CIL log through tubing. 12. Perform falloff test. 13. Perform root cause analysis, and report	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 90 days; request an extension or P&A.

Downhole Equipment	Monitoring Wells	Tubing , Nipples, X/O	CO_2 Corrosion	* CR13 metallurgic for tail pipe below/between packers. * Inhibited packer fluid.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Log run through tubing. 2.Installed upstream injection wellhead. 3. Wellhead and on top of the packer. 4. Surface.	1. Annually . 2. Quarterly. 3. Real time. 4. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Trigger alarm from monitoring system/operator. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrotesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back within a year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	Casing	CO_2 Corrosion	* CR13 metallurgic across injection zones. * Inhibited packer fluid in annular above injection zones. * Casing cemented to surface. * Isolated monitoring zone with packer across injection targets.	1. Electromagnetic logging. 2. Corrosion coupons. 3. Pressure and temperature gauges. 4. Annular pressure test.	1. Run through tubing. 2. Installed upstream injection wellhead. 3. Surface and downhole. 4. Surface.	1. Annually . 2. Quarterly. 3. Real time. 4. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Trigger alarm from monitoring system/ operator. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. Inform Commission within 24 hr, and discuss with action plan. 5. Pull tubing and packer. 6. Run casing inspection log. 7. If required, propose casing repair program or P&A, and discuss with director, based on the findings. 8. Once the casing is repaired, run back completion hydrotesting. 9. Perform annular pressure test. 10. Run CIL log through tubing. 11. Perform root cause analysis and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back within a year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	P/T Gauges & Carriers	CO_2 Corrosion	* Inconel carriers and quartz gauges.	1. Real-time data transfer. 2. Electromagnetic logging. 3. Annular pressure test.	1.n/a 2. Log run through tubing. 3. Surface test.	1. Real time. 2. Annually. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	Replace or repair tool.	1. Trigger alarm from monitoring system/ operator. 2. Troubleshoot the well. 3. Perform annular pressure test to identify any loss of mechanical integrity in tubing or casing above packers. 4. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or acquire the date. 6. During well service to repair or replace the gauges and carriers, run electromagnetic integrity log to verify condition of the casing, replace any packer or equipment damaged, and hydrotest tubing. 7. Identify root cause of failure to take preventive actions, and record findings in the corrosion management database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the remediation with the Commission.
Downhole Equipment	Monitoring Wells	Electric Cable	CO_2 Corrosion	* Inconel material. * Packer inhibited fluid in the annular in contact with the tools.	* Real-time data transfer.	n/a	* Real time.	* Failure detected.	Replace or repair tool.	1. Troubleshoot the system. 2. Review monitoring data. 3. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace cable or acquire data. 4. Prepare plan for replacement or repair of the equipment. 5. Upon Commission approval, continue injection and monitor pressure with surface gauges.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. If the well proves mechanical integrity, discuss time of the repair with the Commission.

Downhole Equipment	Monitoring Wells	Packers	CO_2 Corrosion	* Nickel-plated packers. * Elastomers HNBR (RGD).	1. Pressure and temperature gauges surface and downhole. 2. DST fiber alongside the casing. 3. Annular pressure test.	1. Wellhead and downhole. 2. Casing. 3. Surface test.	1. Real time. 2. Real time. 3. Annually.	* Failure detected. * High risk assessed by the monitoring technique.	* Lost of information for plume monitoring. * Corrosion from formation brines if it's not repaired.	1. Stop injection. 2. Troubleshoot the well. 3. If loss of mechanical integrity is validated, prepare workover proposal. 4. If the well has integrity, inform Commission within 24 hr, and discuss WO or alternative to replace the gauge or acquire the data. 5. Pull tubing and packer scanning. 6. Run casing inspection log. 7. If well has casing integrity, run back completion hydrotesting. 8. Perform annular pressure test. 9. Run CIL log through tubing. 10. Perform falloff test. 11. Perform root cause analysis, and report finding to corrosion database.	1. Field Manager. 2. Project Manager. 3. Downhole maintenance crew.	1. The well needs to be repaired and put back on injection within 1 year; request an extension or P&A.
Downhole Equipment	Monitoring Wells	Wellhead / Tree	CO_2 Corrosion Atmospheric Corrosion	* Wellhead and tree section are not in contact with CO_2 or formation fluids.	1. Preventive maintenance. 2. Visual inspection. 3. Function test.	1. Surface. 2. Surface. 3. Surface.	1. Quarterly. 2. Weekly. 3. By manufacturer recommendatio.n	* Damage detected.	Replace or repair equipment (potentially the valves).	1. Preform inspection with wellhead provider. 2. Define replacement or repair procedure based on the findings.	1. Field Superintendent. 2. Project Manager. 3. Surface maintenance team.	n/a
CO_2 Pipeline	CO_2 Pipeline	API-5L Line Pipe	CO_2 in the Presence of H_2O	Dehydrate the CO_2 to 630 ppm of H_2O (30 #/MMscf).	1. ILI smart pig the pipeline every 5 years. 2. Annual cathodic protection potential survey. 3. Monitor cathodic protection rectifier monthly. 4.DCVG survey every 5 years (DOT pipeline). 5. Analyze product for H_2O levels above 30 lb/MMscf with shut-off capabilities prior to entering pipelines. 6. Coupon test station near pipeline inlet.	n/a	1. Every 5 years. 2. Annually. 3. Monthly 4. Every 5 years. 5. Continuously. 6. Monthly.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination.	TBD by the severity of the finding on the examination.	Mechanical Integrity (MI) personnel in charge of the pipeline.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility.	1. Surface. 2. Capture facility.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of piping segment, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility.	1. Surface. 2. Capture facility.	1. Quarterly. 2. Real time. 3. Real time.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of valve, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; noncritical instrumentation may be isolated and replaced online; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of the instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2. composition from capture facility. 3. Visual inspection of orifice plate using senior fittings.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Quarterly.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Visual inspection.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. Weekly site visits.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of instrumentation, depending on severity of examination.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.

Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	CO_2 Corrosion	*CO_2 dehydrated to 630 ppm H_2O injected (30 lb/ MMscf). *Selection of materials for CO_2 service.	1. Corrosion coupons. 2. Monitoring of CO_2 composition from capture facility. 3. Testing of valve integrity.	1. Surface. 2. Capture facility. 3. Surface.	1. Quarterly. 2. Real time. 3. By manufacturer recommendation.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; critical instruments and valves will require shutdown.	Replacement of valve, depending on severity of examination.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	Corrosion under Insulation (CUI)	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	CUI	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	CUI	*Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	CUI	*Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	CUI	*External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	CUI	* Stainless steel materials.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	CUI	* External painting.	1. Visual inspection.	1. Surface.	1. Site visits/expected weekly activity.	* Failure detected.	n/a	Repainting and replacement of insulation.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Surface Piping	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of piping depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Valves	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of valve(s) depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of valve.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Instrumentation	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface 2. Surface	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	TBD by the severity of the finding on the examination and criticality of instrument.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Pressure Gauge	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Pressure must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Rate Meter	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Rate must be monitored during injection.

Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Injection Temperature Gauge	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.	1. Surface. 2. Surface.	1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of instrumentation depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Temperature must be monitored during injection.
Surface Piping, Instrumentation, and Pressure Control	Surface Piping, Instrumentation, and Pressure Control	Emergency Shutdown Valve	Brittle Fracture	*Insulation/heat tracing to provide cold-weather protection. *Building/structure.	1. Visual inspection. 2. Monitoring heat tracing and maintenance per vendor requirements.		1. Site visits/expected weekly activity. 2. Per vendor requirements.	* Failure detected. * High risk assessed by the monitoring technique.	Depends on the severity of the finding during examination; shutdown may be required.	Replacement or repair of insulation/heat tracing. Potential replacement of valve depending on results of inspection.	MI personnel in charge of the surface facility.	Immediate action required to maintain compliance. Shutoff capability must be maintained during injection.

Fluid Specifications

1. CO_2 Spec

Stream Description	Compressed CO_2 Product to Battery Limits
Stream Number	606
Temperature, °F	120
Pressure, psia	1688.7
Components	
Component Flows	Limits
H_2O	632 ppmv
CO_2	99.90%
N_2	163 ppmv
Ar	4 ppmv
O_2	6 ppmv
H_2	0%
SO_2	<1 ppmv
NO_2	< 1ppmv
NO	30 ppmv

APPENDIX G

FINANCIAL ASSURANCE DEMONSTRATION PLAN

Tundra Secure Geologic Storage Site
Financial Assurance Plan
Details of Financial Instruments Provided in Conjunction with Application

SPECIAL-PURPOSE TRUST

This section describes the selection of a trustee for the Tundra SGS Trust Fund, the Trust Agreement, and the financial strength of the trustee. The trust fund will be established prior to first injection and will be designed to meet the requirements of NDAC § 43-05-01-09.1.

The trust fund will be available for emergency and remedial response upon approval of the Class VI permits and, after injection ceases, for injection well plugging, postinjection site care, and site closure. The trust funds will be available to the Applicant or to a third party if the Applicant were no longer involved with Tundra SGS site operation.

Applicant sent request to three local, regional, and national banks seeking a statement of qualifications for the management of an irrevocable trust to meet Tundra SGS obligations for injection well plugging and postinjection site care and site closure. The Applicant provided the trustee requirements and specifications that prospective trustees must meet and provided the draft Trust Agreement attached hereto as Appendix G-1. Expressions of interest were due to Applicant February 15, 2021.

On March 8, 2021, the Applicant sent a formal Request for Proposal to two banks that had expressed interest in serving as the trustee for the Tundra SGS Trust Fund. Applicant selected Bank of North Dakota (BND) based upon its experience, expertise, and overall approach and responsiveness.

BND provides corporate trust services for the state of North Dakota and its political subdivisions. Services include trustee, escrow agent, paying agent, bond registrar, and transfer agent. BND monitors compliance with financing documents, oversees reporting requirements, invests fund balance, receives and disburses funds, reconciles accounts, and maintains proper records. BND will provide monthly transaction and balance sheet reports, and annual valuations of the account will be completed.

BND has a Compliance Officer who monitors regulations and assists with implementation of new requirements. In addition, Internal Audit staff provide periodic reviews of the Trust Services to ensure adherence to policies and procedures.

Strength of the Trustee

BND maintains a Standard & Poor's long-term A+ and short-term A-1 credit rating. The Trust department currently has over $2 billion under management.

Trust Agreement

The trust fund will be funded in a phased approach to account for the fact that certain covered activities will not be incurred until shortly before authorization of operation is received. For example, resources to cover the cost of activities like emergency remedial response and postinjection site care will not need to be covered until closer to when injection begins. The Applicant is providing financial responsibility for the cost of plugging injection wells, postinjection site care, site closure, and emergency and remedial response via a trust fund valued at $19,824,000.00 and established through the attached Trust Agreement which BND has expressed willingness to accept all recommended terms.

Payment Schedule
The payment schedule for Trust funds commences upon approval of the Class VI permit to operate. Commercial insurance will be bound upon approval of drilling contractor for injection wellbores and is not included in this section.

Initial funding for Trust, in the amount of $2.12 million, representing potential exposure for emergency and remedial response actions, shall be placed into the Trust upon approval of the Class VI permit to operate.

Subsequent funding of the Trust, in the amount of $17.704 million, representing obligations for injection well plugging and postinjection site care and site closure, shall be placed into the Trust in equal installments over a period of seven (7) years commencing on the anniversary of the date of first injection.

Pay-In Periods
The following table provides the pay-in periods for the funding of the Trust. Amounts after initial pay-in are subject to annual review and reporting for continuing validation of estimated costs and underlying assumptions.

Funding	Activities	Costs ($000)	Amount to Be Added Before End of Phase ($000)
Preinjection (within 7 days of operating permit issuance)	Emergency and Remedial Response	$5,960	$2,120
	AOR and Corrective Action	$0	
Injection (seven (7) equal installments at least 7 days prior to successive anniversaries of operating permit issuance)	Plugging Injection and Monitoring Wells	$2,025	$17,704
	Emergency and Remedial Response	$3,840	
	Postinjection Site Care (includes monitoring)	$10,285	
	Closure	$1,554	
		Total Fund	**$19,824**

COMMERCIAL INSURANCE

This section describes the manner in which the Applicant will select a third-party insurer, develop an insurance estimate, obtain proof of insurance, and confirm the financial strength of the insurer.

The Applicant has procured the services of Marsh McLennan Companies.

The Applicant intends to secure third-party insurance to cover the potential need to undertake emergency and remedial response actions to protect USDWs in the AOR. Although the Applicant has been able to obtain information about the possible terms, conditions, and cost of such a policy, the Applicant has not yet applied for such a policy. This section and accompanying market assessment describe the type of coverage that the Applicant expects to obtain from a third-party insurer, including protective conditions of coverage (cancellation, renewal, and continuation provisions). Additional information about deductions, exceptions, and the premium to be paid is also provided in the attached Appendix G-2 Market Assessment.

Coverage Limits

The greatest exposure would be an acute upward migration through the CO_2 injection well, which would have an estimated cost of $16,560,000.00 for emergency and remedial response actions, and such coverage would be an amount sufficient to cover the amounts identified in the endangerment of USDWs. The coverage limit will not be lower than the estimated amount to be covered by Commercial Insurance, $10,600,000.00, as found in Section 4.0, Table 4-14, and may be acquired at a higher limit based upon assessment of available insurance products and market capacity.

Premium

These are only estimates; the premium will be determined based on information provided to the underwriter prior to a cost quotation.

Proof of Insurance

Proof of insurance will be provided when the insurance policy is obtained, prior to first injection.

Financial Strength of Insurer

The financial strength of the insurer will be an important component of the Applicant's selection of an insurer. Information regarding the insurer's financial strength will be provided to the Commission when the insurer is selected.

APPENDIX G-1

STANDBY TRUST AGREEMENT

APPENDIX G-1
STANDBY TRUST AGREEMENT

THIS TRUST AGREEMENT (the "Agreement") is entered into as of _______________ by and between Minnkota Power Cooperative, Inc. (MPC), owner or operator, a corporation (the "Grantor"), and Bank of North Dakota (the "Trustee"), a bank duly organized and existing under the laws of the State of North Dakota.

WHEREAS, the North Dakota Industrial Commission (Commission), an agency of the State of North Dakota, has established authority to administer certain regulations pursuant to the US Environmental Protection Agency's Class VI Underground Injection Control Program (UIC). The Commission's regulations, applicable to the Grantor, require that an owner or operator of an injection well shall provide assurance that funds will be available when needed for corrective actions, injection well plugging, post-injection site care and site closure, and emergency and remedial response during the operation of carbon dioxide (CO_2) geologic sequestration injection wells;

WHEREAS, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facility or facilities identified herein, and;

WHEREAS, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this Agreement, and the Trustee is willing to act as trustee.

NOW THEREFORE, the Grantor and the Trustee agree as follows:

Section 1. Definitions. As used in this Agreement:

A. The term "Grantor" means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor.
B. The term "Trustee" means the Trustee who enters into this Agreement and any successor Trustee.
C. Facility or activity means any "underground injection well" or any other facility or activity that is subject to regulation under the Underground Injection Control Program.
D. "Commission" means the North Dakota Industrial Commission or an authorized representative.
E. "ERR" means emergency and remedial response plan, associated cost estimate and the funded trust property and income apportioned to cover these costs.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a CO_2 Storage Trust Fund (the "Fund") to satisfy the financial responsibility demonstration and storage facility fees under the Class VI Underground Injection Control ("UIC") regulations (N.D.A.C. § 43-05-01-09.1 and N.D.A.C. § 43-05-01-17). This Fund shall remain dormant until funded with the proceeds listed on Schedule C. The Trustee shall have no duties or responsibilities beyond safekeeping this Agreement. Upon funding, this Fund shall become active and be administered pursuant to the terms of this instrument. The Grantor and the Trustee acknowledge that the purpose of the Fund is to fulfill the Grantor's corrective action, injection well plugging, post-injection site care, site closure, emergency and remedial response, and storage facility fee obligations described at N.D.A.C. § 43-05-01-05.1 (Area of review and corrective action), N.D.A.C. § 43-05-01-11.5 (Injection well plugging), N.D.A.C. § 43-05-01-19 (Post-injection site care and site closure), N.D.A.C. § 43-05-01-13 (Emergency and remedial response), and N.D.A.C. § 43-05-01-17 (Storage Facility Fees) respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission or any other state agency. The Grantor and the Trustee intend that no third party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN TRUST, as hereinafter provided. The Trustee shall not be responsible, nor shall it undertake any responsibility, for the amount or adequacy of any additional payments necessary to discharge any liabilities of the Grantor established by the Commission.

Section 4. Payment for Corrective Action, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response. The Trustee shall make payments from the Fund only as the Commission shall direct, in writing, to provide for the payment of the costs of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response of the injection wells covered by this Agreement. The Trustee shall use the Fund to direct-pay or reimburse the Grantor, other persons selected by the Grantor to perform work, or as otherwise directed by the Commission when the Commission advises in writing that the work will be or was necessary for the fulfillment of the Grantor's corrective action, injection well plugging, post-injection site care and site closure, or emergency and remedial response obligations described in N.D.A.C. §§ 43-05-01-05.1, 43-05-01-11.5, 43-05-01-19 and 43-05-01-13, respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission, as the Commission is not a beneficiary of the Trust. The Commission may advise the Trustee that amounts in the Fund are no longer necessary to fulfill the Grantor's obligations under N.D.A.C. § 43-05-01-09.1 and that the Trustee may refund all or a portion of the remaining funds to the Grantor. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

Section 5. Payments Comprising the Fund. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee. Schedule C provides the amounts and timing of the seven (7) payments (i.e., the pay-in schedule).

Section 6. Trustee Management and Investment. Trustee shall manage, invest, and reinvest all of the Trust assets, made up of the principal and income of the Fund, in accordance with the North Dakota Prudent Investor Standards, Chapter 59-17, *et seq.* of the North Dakota Century Code, as amended ("Act"). The Trustee shall invest and reinvest the principal and income, without distinction, according to the investment instructions included within the attached Exhibit B (referred to as "Permitted Investments"), *provided* the Permitted Investments may be revised at any time upon notice from the Grantor. To the extent not inconsistent with the Act and Permitted

Investments, Trustee shall hold the Fund assets thereon subject to the terms and conditions of this Agreement and is empowered and directed to invest and reinvest the Fund assets and any accumulated income in such certificates of deposit, obligations to the United States of America, demand deposits, commercial paper or other securities or accounts as the Grantor shall direct. In the absence of instructions from the Grantor, Trustee shall invest and reinvest the Fund assets in money market funds available upon demand or short notice. All interest earned on the Fund principal shall become part of the Fund assets. Notwithstanding the foregoing, none of the Fund assets may be held in any investment that cannot be sold, redeemed or otherwise liquidated at the holders' option in ninety (90) days or less without loss of interest or discount. All amounts and investments (other than bearer instruments) comprising the Fund assets shall be registered and held in the name of the Trustee.

Section 7. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

A. To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;
B. To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;
C. To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund;
D. To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the Federal or State government; and,
E. To compromise or otherwise adjust all claims in favor of or against the Fund, including claims in favor of the Trust as a loss payee under applicable insurance policies.

Section 8. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other charges and disbursements of the Trustee permitted under this Agreement shall be paid from the Fund.

Section 9. Annual Valuation. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the Commission a statement confirming the value of the Fund. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund.

Section 10. Advice of Counsel. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement or any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

Section 11. Trustee Compensation. Trustee shall be entitled to reasonable compensation for its services provided hereunder in accordance with the Trustee's fee schedule as in effect during the course of this Agreement, *provided* that any change or revision to the fee schedule shall be effective only upon Trustee providing Grantor with thirty (30) days written notice, or another mutually agreed to period of time, which notice shall include effective date(s) of any change or revision. Trustee's current fee schedule is attached as Exhibit C, with such fees identified therein being each and together "Trustee Fees." Additionally, Trustee shall be reimbursed for all expenses reasonably incurred by Trustee in connection with the performance of its duties and enforcement of its rights hereunder and otherwise in connection with the preparation, operation, administration and enforcement of this Agreement, including, without limitation, attorneys' fees, brokerage costs and related expenses incurred by Trustee ("Trustee Expenses"). Grantor shall pay the Trustee Fees and Trust Expenses within thirty (30) days following receipt of an invoice from Trustee.

Section 12. Successor Trustee. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment, and the Commission consents to the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance and receipt of Commission consent of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the Commission, and the present Trustee by certified mail ten (10) days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

Section 13. Instructions to the Trustee. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the Commission to the Trustee shall be in writing, signed by the Commission or its duly constituted delegate(s), and the Trustee may rely on these instructions to the extent permissible by law. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or Commission hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or the Commission, except as provided for herein.

Section 14. Notice of Nonpayment. The Trustee shall notify the Grantor and the Commission, by certified mail within ten (10) days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period.

Section 15. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Provided, however, that the Commission may not be named as a beneficiary of the Trust, receive funds from the Trust, or direct that Trust funds be paid to a particular entity selected by the Commission.

Section 16. Cancellation, Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Upon termination of the Trust, all remaining Fund property, less final trust administration expenses, and excluding the principal and income contained in the ERR fund account, shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission. At termination of the Trust or upon early written direction by the Grantor, with concurrence of the Commission, Trustee must distribute ERR principal in an amount calculated in accordance with N.D.A.C. § 43-05-01-17 plus a pro rata portion of the income accrued. Following the distribution of the ERR principal and income in accordance with the foregoing clause, any remaining Fund property shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission.

Section 17. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense. The Commission does not indemnify either the Grantor or the Trustee. Rather, any claims against the Commission are subject to Chapter 32-12.2, *et seq*.

Section 18. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of North Dakota with regard to claims by the Grantor or Trustee. Claims involving the Commission are subject to North Dakota State law.

Section 19. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

{*Signature Page to Follow*}

IN WITNESS WHEREOF the parties below have caused this Agreement to be executed by their respective representatives duly authorized and their seals to be hereunto affixed and attested as of the date first above written.

Signature of Grantor's Authorized Representative: ________________________________
Name of Grantor's Authorized Representative: _______________________
Title: ____________________

Attest:

Signature: ___________________________________
Name of Attester: ______________________
Title of Attester: _______________________

Certification of Acknowledgement of Notary:

Signature of Trustee's Authorized Representative: _________________________________
Name of Trustee's Authorized Representative: _______________________
Title: ____________________

Attest:

Signature: ___________________________________
Name of Attester: ______________________
Title of Attester: _______________________

Certification of Acknowledgement of Notary:

Schedule A: Facilities and Cost Estimates to which the Trust Agreement Applies

Because the three injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the three wells will form one co-mingled and overlapping, stacked CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to all three injection wells as one integrated facility.

<table>
<tr><th>Facility</th><th>Corrective Action ($)</th><th>Injection Well Plugging ($)</th><th>Post-injection Site Care ($)</th><th>Site Closure ($)</th><th>Emergency and Remedial Response ($)</th></tr>
<tr><td>Unity-2 (BC-2)</td><td rowspan="4">$0.00</td><td rowspan="4">$2,025,000.00</td><td rowspan="4">$10,285,000.00</td><td rowspan="4">$1,554,000.00</td><td rowspan="4">$5,960,000.00</td></tr>
<tr><td>Liberty-1 (BC-1)</td></tr>
<tr><td>McCall-3 (DW-1)</td></tr>
<tr><td>NRDT(Monitoring Well)</td></tr>
</table>

Schedule B: Trust Fund Property

Because the <u>three</u> injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the three wells will form one co-mingled and overlapping, stacked CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to all <u>three</u> injection wells as one integrated facility.

Facility	Funding Value for Activities
Unity-2 (BC-2)	$19,824,000.00
Liberty-1 (BC-1)	
McCall-3 (DW-1)	
NRDT(Monitoring Well)	

Schedule C: Pay-in Periods/Schedule

The Fund will be funded according to when the financial risks are incurred in three (3) distinct Periods of activity.

- **Pre-Injection**: Upon authorization from the Commission to begin injecting CO_2 under the Class VI well permit(s), Grantor must be prepared to undertake any emergency or remedial response (ERR) actions, although such actions are unlikely to be needed. Further, in accordance with N.D.C.C. § 43-05-01-17 Grantor must account for a one cent fee on each metric ton of carbon dioxide for administration of a storage facility fund and a fee of seven cents on each ton of carbon dioxide injected for a storage facility fund which can be utilized for post closure period activities (together referred to as "Commission Fee"). The average projected amount of carbon dioxide injected will be 4MM metric tons annually. The Grantor estimates a minimum of 12 years of operation and is permitting operation of the storage facility for 20 years of injection. Grantor's estimated total cost of ERR activities is $16,560,000.00 assuming conditions allowing a conservative outer-limit cost estimate (at least 10 years of operation) with $5,960,000.00 of the estimate funded by the trust. Grantor shall initially fund an amount equal to the net of the cost estimate for ERR activities less the calculated 12 year Commission Fee based upon the projected annual average injection rate of 4MM metric tons, $2,120,000.00. The initial funding payment in the amount of $2,120,000.00 will fund the Fund account in the Pre-Injection Period with the remaining equal installments made in the Injection Period, as further discussed below.

- **Injection**:

  - Once an injection or monitoring well is drilled, plugging costs will need to be incurred prior to cessation of injection operations. Therefore, the trust account will need to account for the cost of plugging injection and monitoring wells prior to the Post-Injection period. Grantor's estimated cost of this plugging activity is $2,025,000.00. The total plugging cost will be paid across the seven (7) equal annual funding installments made in the Injection Period, each installment consisting of $289,285.71 for plugging expenses with the first installment prior to the one-year anniversary of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $2,025,000.00.

  - Also, Grantor will fully fund the ERR Fund account making seven (7) equal annual installments of $548,572.00 made in the Injection Period, with the first installment prior to the one-year anniversary Commission's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $5,960,000.00. However, if at any time the Commission determines the actual amount of the Commission Fee as calculated under N.D.C.C. 43-05-01-17 exceeds the principal amount then contained in the ERR account, then upon written direction from the Commission, Grantor shall fund amounts to bring the principal and income to an amount sufficient cover the Commission Fee.

- Grantor will fund the Fund account for post-injection site care, monitoring and site closure making seven (7) equal annual installments of $1,691,286.00. Grantor's estimated cost of post-injection site care and monitoring is $10,285,00.00 and site closure activities is $1,554,000.00. The first installment to be made in the Injection period prior to the one-year anniversary of the Commission's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $11,839,000.00.

- The seven (7) installments are to be made individually prior to the successive anniversary of the Commission's issuance of authorization to operate a Class VI injection well until fully funding the principal amount of $19,824,000.00.

- **Post-Injection and Closure**: All costs associated with post-injection and closure activities must be funded before or at the start of the post-injection phase. However, the Fund may phase out these costs as associated Pre-Injection and Injection Period activities are completed (with approval from the Commission). For example, once wells have been plugged, their corresponding plugging costs may be subtracted from the total value of the Fund account.

Pay-in Schedule
Within seven (7) calendar days after the issuance of final Class VI authorization to operate for the three injection wells, Grantor will ensure that $2,120,000.00 is in the Fund to cover the cost of Injection Period activities (Emergency and Remedial Response Plan). The total value of the trust at the beginning of the Injection Period will be $2,120,000.00.

On or before the seven-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells, Grantor will ensure that an additional $17,704,000.00 is in the Fund to cover the remaining costs of the Pre-Injection, Injection, Post-Injection, and Closure Periods. An additional $2,529,143.00 will be added on or before the one-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the two-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the three-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the four-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the five-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. An additional $2,529,143.00 will be added on or before the six-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells. A final installment of $2,529,142.00 will be added on or before the seven-year anniversary for the permit to operate for the three injection wells, completing the phase-in of financial responsibility payments for the Pre-Injection, Post-Injection, and Closure Periods. Grantor may also elect to substitute another mechanism to demonstrate financial responsibility for emergency and remedial response for the injection and post-injection phases. If Commission approves such a substitution, this Agreement will be amended accordingly.

These amounts are based on the third-party cost estimate submitted by Grantor in its *Supporting Documentation: Underground Injection Control Class VI Injection Well Permit Applications for Tundra SGS _______________ Wells _,_,_ and _*, dated ____________ (Appendix _) and on the

Commission's independent evaluation of the cost estimates. These costs are subject to review and approval by the Commission and may be adjusted for inflation or any change to the cost estimate in accordance with N.D.C.C. § 43-05-01-09.1.

Table 1 shows the activities and estimated costs according to when the payments would be required (i.e., at the start of the "Pre-Injection") phase or at the start of the "Injection and Post-Injection Phase").

Table 1: Trust Funding Schedule

Funding Phase	**Activities**	**Total Activities' Costs Prior to Funding Phase ($000)**	**Amount to be Added Before End of Phase ($000)**
Pre-Injection (within 7 days of operating permit issuance)	Emergency and Remedial Response	$5,960	$2,120
	AoR and Corrective Action	$0	
Injection (seven (7) equal installments prior to successive anniversaries of operating permit issuance)	Plugging Injection and Monitoring Wells	$2,025	$17,704
	Emergency and Remedial Response	$3,840	
	Post-Injection Site Care (Includes Monitoring)	$10,285	
	Closure	$1,554	
		Total Fund	$19,824

Exhibit A: [Grantor] Designee Authorized to Instruct Trustee

[Name]
[Title]
[Grantor name or company if different]
[Address 1]
[Address 2]
[Phone]

[Grantor], as Grantor, may designate other designees by amendment to this Exhibit.

Exhibit B

Permitted Investments

(i) Direct obligations of the United States of America or any agency or instrumentality thereof or obligations backed by the full faith and credit of the United States of America maturing in twelve (12) months or less from the date of acquisition:

(ii) Commercial paper maturing in 180 days of less rated not lower than A-1, by Standard & Poor's or P-1 by Moody's Investors Service, Inc. on the date of acquisition.

(iii) Demand deposits, time deposits or certificates of deposit maturing within one year in commercial banks whose obligations are rated A-1, A or the equivalent or better by Standard & Poor's on the date of acquisition;

(iv) Money market or mutual funds whose investments are limited to those types of investments described in clauses (i) and (iii) above; and

(v) Deposits of the Bank of North Dakota, to the extent guaranteed by the State of North Dakota under North Dakota Century Code Section 6-09-10, or a successor statute.

Exhibit C

Compensation and Reimbursement of Expenses
Trustees Fee Schedule

Outlined below are the initial and ongoing fees for the Bank of North Dakota to provide Trustee services:

One Time Initial Fee:	$1,250.00
Annual fee for Administration:	$1,250.00
Legal Review of Documents:	$400 - $600 estimated
Contact:	Carrie Willits (701) 328-5612 cwillits@nd.gov

The Annual Fee for Administration is subject to change upon a 30 day notification.

APPENDIX G-2

MARKET ASSESSMENT

Marsh

Project Tundra

Use of Insurance in the FADP

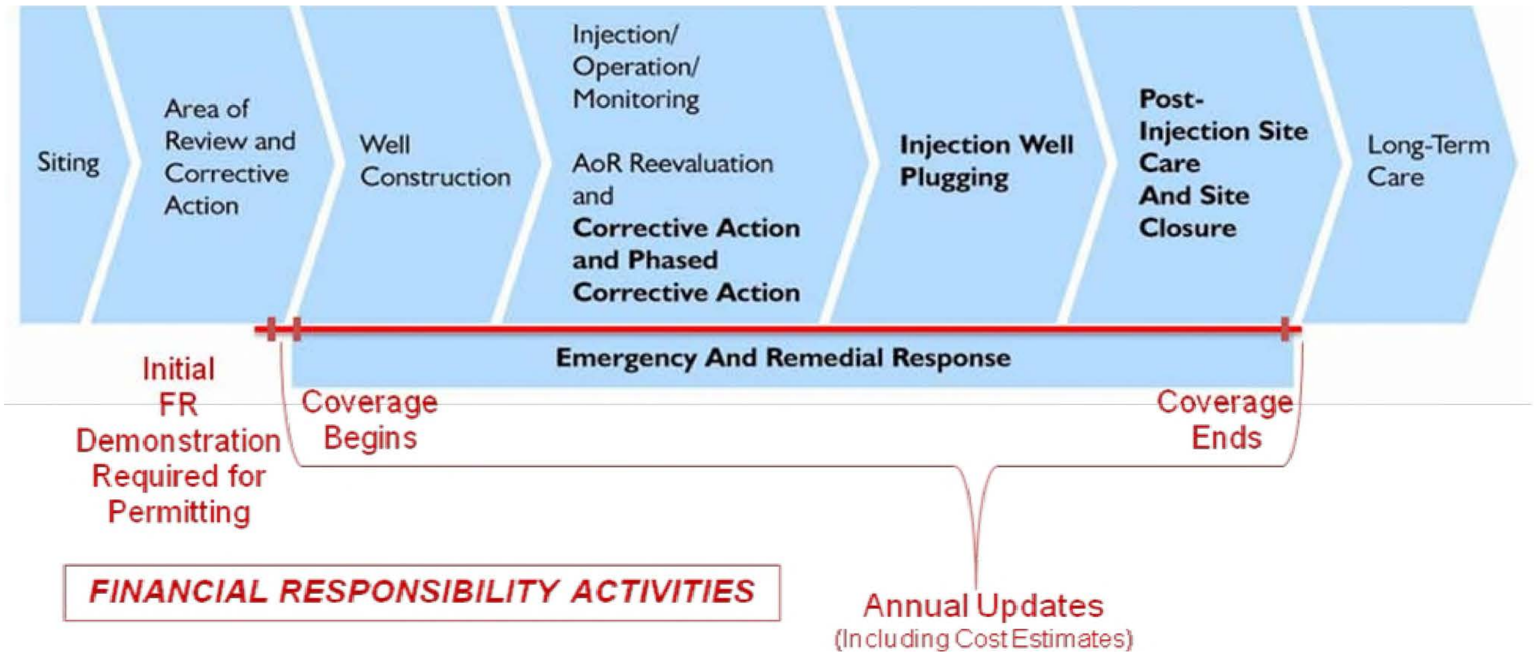
May 26, 2021

Contents

Section One

Executive Summary

This document will examine pollution liability insurance options over the course of the operating lifetime of the CO_2 sequestration company, "Tundra SGS", including the 10 year, post-injection site care period prior to transfer of liability to the State of North Dakota. The following graphic is a helpful summary.



The market review was requested to outline the applicable environmental insurance products, expected policy terms and conditions, exclusions, costs and deductibles to support applicant to the North Dakota Industrial Commission for necessary UIC Class VI well injection permit financial responsibility requirements. The examination extends only to Contractors Pollution Liability, Pollution Liability and Operators Extra Expense/Control of Well insurances based on the Emergency and Remedial Response activities for the Tundra SGS geologic sequestration project, which could respond following a liability claim arising from contamination of an Underground Source of Drinking Water (USDW). First party/property insurances as well as the extended family of 3rd party liability insurance such as (but not limited to): general liability, auto liability, employer's liability, cyber liability, professional liability and all measure of executive liability coverages, while generally critical to the greater project and highly recommended, are not under consideration in this analysis. All coverage descriptions, options and estimates provided herein are non-binding estimates based on whatever project data has been provided at this point. Over the 20+ year of life of the project (not to mention the next few months) these estimates will change, as such no guarantee is possible as to the future fitness of the program details provided in this report.

Marsh & McLennan Companies Introduction

Marsh & McLennan Companies (MMC) is the leading global professional services firm in the areas of risk, strategy and people. With annual revenue approaching USD17 billion and 76,000 colleagues worldwide, MMC helps clients navigate an increasingly dynamic and complex environment through four market-leading businesses: Marsh, Guy Carpenter, Mercer, and Oliver Wyman.

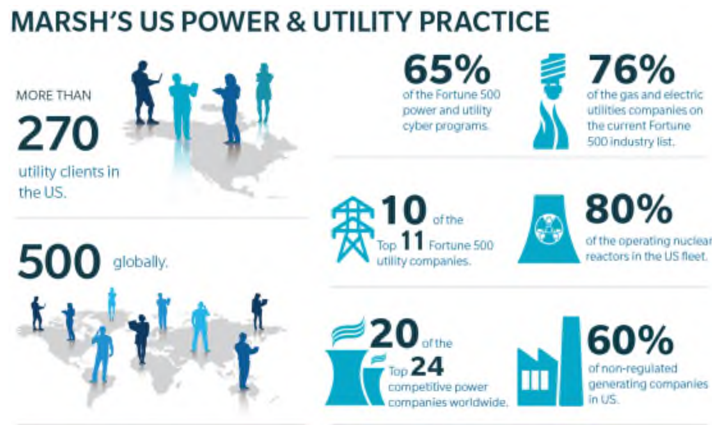
We are four companies, with one purpose: helping our clients to meet the challenges of our time.

About Marsh

Marsh is the world's leading insurance broker and risk adviser. With over 35,000 colleagues operating in more than 130 countries, Marsh serves commercial and individual clients with data driven risk solutions and advisory services.

Power Industry Expertise

With more than 270 utility clients in the United States, the Marsh Power and Utilities team remains at the forefront of helping utilities manage the many risks they face. We placed over $1 billion of insurance premium on behalf of our utility clients into the global insurance market. We are recognized as the leading broker in the power and utility industry sector, and have deep relationships with all the major insurers actively underwriting power and utilities business, including AEGIS, EIM, AIG, ANI, Everest, Liberty International, and FM Global. We have extensive knowledge and deliver results for clients owning all forms of power generation, including natural gas, coal, nuclear, hydro, biomass, geothermal, wind, solar, and energy storage.



Contact

Gavin Hurd, Managing Director, Energy & Power

Marsh Specialty, a business of Marsh McLennan

T +1 713-346-1090; M +1 832-454-8136

Gavin.hurd@marsh.com

Section Two

Coverage Assessment by Project Phase

This section outlines the certain types of insurance which may respond to a pollution event during certain phases of the project life.

Project Phase	General Risks Associated	Types of Insurance	Assumptions/Questions
Construction phase pollution event	1. Pollution event during construction 2. Well control event during drilling or completion	1. Contractors Pollution Liability (CPL) for Contractor. Separate CPL policy for Owner interest. 2. Operators Extra Expense (OEE) for either owner or contractor as assigned in the drilling contract	1. CPL required by contract with contractor. Owners CPL operates as a difference in limits/difference in conditions to contractors policy 2. Party responsible to provide OEE is established by contract
Operations phase pollution event	1. Pollution during operations 2. Well control event during operations	1. Pollution Liability (PL) Coverage for owner 2. Operators Extra Expense (OEE) for owner or operator	1. Multi-year policy could be desirable. Combined GL/PL may also be available 2. Responsibility to carry OEE can be transferred to the contract operator and can include operator of record via Contract Operator Endorsement.
Injection Well Plugging phase pollution event	Well control event during plugging	OEE for either owner or contractor as per contract	Party responsible to provide OEE is established by contract. Owner's operating pollution liability coverage remains in force until Tundra SGS operations are discontinued
Post Injection Site Care pollution event	Gradual migration of CO_2 into USDWs	Pollution Liability	Following injection well plugging, pollution policies adjusted to maximum terms and renewed as necessary until liabilities assumed by State of North Dakota

Section Three

Contractors Pollution Liability Coverage Details

Summary

Contractors Pollution Liability (CPL) covers third party damages for bodily, injury property damage or cleanup related to pollution events which occur during construction operations. Unlike other pollution coverage, CPL does not have reporting windows for discovery or reporting of an occurrence. The following coverage sections can be included in a CPL policy:

Coverage A: Contractors Pollution Liability
Coverage B: Pollution Liability during Transportation
Coverage C: Non-Owned Site Pollution Liability
Coverage D: Time-Element Pollution Liability
Coverage E: Image Restoration Expenses
Coverage F: Disinfection Event Expenses
Coverage G: Pre-Claim Event Expenses

Refer to Specimen Policy Form in Appendix A

Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate and are elected at time of binding.

Pollution Liability (PL) policies (discussed in the following section) prefer not to extend coverage to construction operations, including those events occurring during the operations period but arising directly from construction. Accordingly, in order to keep PL market selection as broad as possible, we recommend a separate CPL to cover construction operations.

Status of Market

The market for CPL is stable and very competitive. Viable markets include Ironshore, Aspen, Ascot, Enviant, Hamilton, and Markel.

Review of Coverage

Coverage Limits

Benchmarking reveals an average Contractors Pollution Liability purchase of $20M for multi-year policies. Drilling contractors often carry lower than average CPL limits due to the historical experience of pollution events at contractor risk which occur during drilling operations, the rural location of their work and general reliance on the pollution coverage grants within other policies which can cover sudden and accidental pollution events. Selection of CPL limits is often driven by broader contract negotiations as well as the aggregate nature of the limit provided over the term of the construction period and completed operations period.

CPL coverage can be structured in many ways, as owner or contractor controlled for the project, owner's or contractor's interest separately or in a combination. The owner's basic objective should be to cover a target limit for pollution events arising from construction activities both during the actual construction and completed operations coverage for 10-years following construction. The simplest approach would be to require the contractor via the construction contact to carry the entire desired limit. While most contractors already carry CPL, the limit may not be large enough and is usually shared across the contractor's entire portfolio of projects. Given smaller usual limits and the shared aggregate, requiring the contractor to cover the entire desired limit can restrict contractor selection and distort available bids.

For this project we recommend that part of the desired CPL limit be stipulated by contract as a Contractor required insurance, along with others such as General Liability, Auto Liability, Excess, etc. All contractors and subcontractors engaged to perform work at the site should carry the required CPL. We further recommend the owner carry the balance of the desired limit in a CPL Owner's Interest policy to protect against contractor CPL policy deficiencies and termination of coverage or exhaustion of limit over the completed operations period. The owner's CPL policy would operate as Difference in Conditions/Difference in Limit to the Contractors so would only be accessed in the event the limit was exhausted or not maintained in accordance with the contract requirements. We recommend that both CPL and CPL Owner's interest policies be purchased during the construction period. For the contractor's CPL, a project specific policy is recommended, but not required in this case as the Owner's CPL can supplement. If contractor needs more flexible terms (such as lower limit and not project specific), the owner's CPL can be adjusted to make up the balance of the target pollution policy limit.

Market capacity for CPL is estimated at $500M.

Deductible

Standard deductibles vary from $25,000 to $100,000 for Owner's Interest CPL policies

Exclusions

Exclusions – Refer to Specimen Policy Form in Appendix A

Some of the basic exclusions in a pollution legal liability policy are outlined below, however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in agreement
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Identified Underground Storage Tank (unless scheduled)
- Closure/Post Closure and Reclamation Costs
- Drilling and Specialty Equipment
- Divested Property
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds

Renewal

The policies would not renew. The recommended Contractor's CPL and owner's interest CPL would both run the course of construction and carry a 10 year completed operations extension.

Cancellation

Policy cancellation as per Section IV. Conditions clause 3. Cancellation on page 11 of the sample wording in Appendix A

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

CPL Limit: Contractor premiums are difficult to estimate without detailed knowledge of contractor revenues, operations and loss history.

CPL Owner's interest Limit Option: Construction Period plus 10 Years Completed Operations, Limit of $10M – at $50,000 Deductible = $25,000 to $35,000 annually ($250,000 to $350,000 for a 10-year term), not including applicable taxes and fees.

Pollution Liability Coverage Details

Summary

Pollution Liability is an insurance policy which protects business organizations against liability claims for bodily injury (BI), property damage (PD) and Cleanup (CU) arising out of premises and operations at scheduled locations. Coverage may include various extensions, including first party discovery, non-owned disposal sites, contingent transportation, emergency response, image restoration, and Natural Resource Damages. Additionally, as this coverage does not have reporting windows for events, it can be coordinated with other liability policies that may offer sudden & accidental pollution coverage, such as General Liability and Excess and Operators Extra Expense.

Pollution Liability (PL) coverage can be provided on an annual or multi-year policy term covering property, assets. Coverage is offered on a claims-made policy form for specifically scheduled assets. Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate. *Most often those limits are the same; however, some Insured's choose a split aggregate limit. A split aggregate makes it challenging to build a significant tower of* limits.

Coverage A: Third party claims for Bodily Injury, Property Damage or Remediation expenses
Coverage B: First party Remediation Expenses
Coverage C: Emergency Response Expenses
Coverage D: Evacuation Expenses
Coverage E: Image Restoration Expenses

Status of Market

The pollution market is hardening, fueled by claims and the exit of a major carrier. This has led to increased retentions, increased premiums, and lower limits. This has primarily applied to operators and facility owners. On the other hand, CO_2 sequestration has caught the attention of many insurers who want to be involved in the next trend, especially a green initiative. However, since CO_2 sequestration unrelated to enhanced oil recovery projects are rare, there is limited appetite at this moment. We anticipate that as more projects are developed and come to market, the coverage will be easier to obtain.

Many insurers offer coverage on an annual basis. However, some can offer on a multi-year basis. Therefore, it is important to remember the limits do not reinstate annually. However, this type of structure is advantageous as discounts are built into multi-year options. Pollution Liability is driven by severity, not frequency. Viable markets include Ironshore, Aspen, Ascot, Enviant, Hamilton, and Markel.

Review of Coverage

Coverage Limits

Benchmarking reveals an average Pollution Liability (PL) purchase of $10M for annual and 2-3 year policies. Longer-term policies (such as 10 years) have larger limits to accommodate the possibility of erosion of the aggregate limit. At first glance, the average PL limit purchase of $10M would appear lower than necessary to respond to recent pollution events. Pollution Liability is often purchased as an excess and difference in conditions coverage to sudden and accidental pollution coverage grants within the main liability program. Operational liability programs normally have much larger limits and serve as a natural downward influence on PL limits purchased. It is almost impossible to say how insurance programs covering CO_2 sequestration compare to the benchmark as there are so few working examples with pollution policies. Considering the nature of sequestration operations, contamination of an underground source of drinking water is likely to occur gradually and not be discovered until well after the event which caused it. Typical sudden & accidental pollution liability with discovery and reporting windows generally around 21 and 45-days respectively (and shorter) may not reasonably be expected to provide much coverage. Due to the novel nature of CO_2 sequestration operations and lack of an ability to rely on the sudden and accidental pollution grants within the operational liability, it is likely that selection of Pollution Liability limits by CO_2 sequestration operations will trend well above benchmarked limits.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the PL policy such as Coverages A, C and E and potentially D. Generally, the policy would respond to efforts to measure the extent of the contamination and compensate any users of the drinking water for property damage and/or bodily injury arising from the contamination. Costs to control the breach and restore the well to production would be covered under the OEE policy discussed in the following section.

Market capacity for PL for this risk is estimated at $150M. A combined General Liability and Pollution Liability product is often preferred by other waste disposal operations as it tends to be more cost efficient than standalone liability and pollution towers. Given the novel nature of standalone CO_2 sequestration, this is certainly the desired option but may not be available until the market gains more comfort with sequestration operations.

Deductible

The minimum deductible for this risk will likely be $250,000. Small credits are available for incremental increases in deductible but are generally not efficient. Deductible is usually established by market preference and premium for the overall account and limit. The preferred maximum deductible would be $1,000,000, as very small discounts are provided above that amount. The deductible will be a self-insured retention versus a true deductible. Environmental markets do not typically analyze individual financial performance or require collateral for support.

Exclusions

Refer to Specimen Policy Form in Appendix B

Some of the basic exclusions in a PL policy are outlined below, however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in JOAs
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Identified Underground Storage Tank (unless scheduled)
- Closure/Post Closure and Reclamation Costs
- Drilling and Specialty Equipment
- Divested Property
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds

Renewal

Operations: If PL is purchased on a standalone basis, then we recommend a multi-year period for premium efficiency. The longest available multi-year period for operating assets is usually three years. A combined GL/PL form may be available in the near future as Insurers become more comfortable with risk, technology and appetite. A combined form renews annually.
Post Injection Site Closure: After plugging of the injection well, it would be desirable (if possible) to purchase a 10-year policy to match the post injection site closure period.

Cancellation

Policy cancellation as per Section VII. Conditions clause E. on page 9 of the sample wording in Appendix B

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

Pollution Legal Limit Options

PL Limit Option 1: Annual Limit of $15M = $125,000

PL Limit Option 2: Three-year Limit of $25M = $400,000

PL Limit Option 3: Three-year Limit of $50M = $700,000

All premiums are non-adjustable

Section Four

Operators Extra Expense Coverage Details

Operators Extra Expense (OEE), also known as Control of Well (COW), indemnifies owners against costs associated with a well out of control. The base coverage is divided into 3 coverage grants:

A. Cost to control,
B. Cost of re-drill or restoration of the well, and
C. Cost of pollution clean-up

Coverage C. grant is of interest to this analysis but can only be triggered by a well out of control event per policy definition. Limits are also supplemented by various extensions (see below).

Review of Coverage

Coverage Limits

OEE policy limits are combined single limits of liability across all coverage sections and extensions for any one occurrence (including defense costs). Therefore, it is prudent to be conservative with limit selection. Conventional wisdom for OEE limit selection for exploration and production accounts holds that the OEE limit should be 3-5 times the dry hole cost of the well insured. While this approach tends to breakdown for uncommon well types and operations, it is considered the general benchmark in selecting limits. A comparison of five times the projected dry hole cost ($5.8MM * 5 = $29MM) and the sum of estimated Emergency and Remedial Response expenses from the FADP report ($16.6MM) reveals that a limit of either $25,000,000(100%) or $30,000,000(100%) any one occurrence appears reasonable for both drilling and producing wells.

OEE and PL limits can be coordinated by the insured but the OEE limit is generally not viewed as substitute for PL coverage for the following reasons:

- The priority of payments clause on the OEE policy allows the Insured to direct the limit to whichever sections he chooses
- Operators prefer to reserve OEE limits for Cost to Control or Re-drill. These activities have been known to be very expensive in large or difficult claims and could leave little for pollution clean-up.
- Given the broader nature of PL coverage, insureds prefer to reserve PL limits for claims arising from an occurrence which would not be covered by either the OEE or Operational Liability program.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the OEE policy such as Coverages A, B and C. We recommend that Tundra SGS direct costs to control and restore the well to production first to the OEE policy and deploy any remaining limit to clean-up pollution. The PL policy referenced above should be used to respond to all other remaining clean-up costs that are covered by the policy.

Coverage form should be as broad as possible and include such coverage extensions as: Making Wells Safe, Underground Control of Well, Care Custody and Control, Unlimited Re-Drill, Extended Re-Drill, Extended Pollution, and Removal of Wreck.

The load or credit associated with increased or diminished limits is discussed in the premium section.

Deductible

Often referred to as a retention or excess, the OEE policy carries a single deductible over all coverage sections. The Project should expect a deductible of between $250,000(100%) and $500,000(100%) any one occurrence for drilling and producing wells. Due to the small schedule and Minnkota's minimal well operating record, Insurers may be reluctant to offer lower deductibles.

The credit associated with increased deductibles is discussed in the premium section

Exclusions

A sample copy of the wording is provided in the Appendix C. Exclusions of note are:

- Fines or Penalties
- Breach of Warranties Clause and breach of Due Diligence Clause
- Delay or loss of use (adding Loss of Production Insurance would serve to add back coverage)
- Costs arising out of a well which flow can be promptly controlled by use of onsite equipment or by increasing the weight of drilling fluid
- Exclusion for claim recoverable under the policy solely by reason of the addition or attachment to Section A of the Underground Control of Well Endorsement. This exclusion should be amended or removed to better fit CO_2 Sequestration operations.

Renewal

Most OEE policies renew annually.

Cancellation

As per clause 13. Cancellation on page 9 of the sample policy wording in Appendix C

Premium

All premiums are annual minimum and deposit premiums which are adjustable for drilling wells and flat at inception for producing wells. Based on current market feedback, the $100,000 minimum premium drives the premium during the operating phase due to the small schedule of wells and Minnkota's minimal well operating record. A contract operator could possibly leverage their experience and existing premium base to provide lower OEE premiums. Additionally, we may be able to negotiate lower premiums for the operating period once injection operations are established and the market is more comfortable with the risk.

Type of Well	Combined Single Limit	Est. Annual Premium
2 Broom Creek Wells (drilling phase)	$25,000,000	Rate of 1.5% times Completed Well Cost (CWC), minimum annual premium $100,000. Eg. CWC est. $5.8M for each then Est. Annual Premium for 2 wells is $174,000
	$30,000,000 (option)	Rate of 1.7% on CWC, minimum annual premium of $100,000. Eg. CWC est. $5.8M for each then Est. Annual Premium for 2 wells is $197,200
2 Broom Creek Wells (operating phase)	$25,000,000	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000
	$30,000,000 (option)	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000

Type of Well	Combined Single Limit	Est. Annual Premium
2 Broom Creek wells & 1 Deadwood Well (drilling phase)	$25,000,000	Rate of 1.5% times Completed Well Cost (CWC), minimum annual premium $100,000. Eg. CWC est. $5.8M for each Broom Creek well and $8.2M for the Deadwood well then Est. Annual Premium for 3 wells is $297,000
	$30,000,000 (option)	Rate of 1.7% on CWC, minimum annual premium of $100,000. Eg. CWC est. $5.8M for each Broom Creek well and $8.2M for the Deadwood well then Est. Annual Premium for 3 wells is $336,600
2 Broom Creek wells & 1 Deadwood well (operating phase)	$25,000,000	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000
	$30,000,000 (option)	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000

Appendix A

Contractors Pollution Wording

Ironshore sample CPL wording.pdf

Appendix B

Pollution Liability Policy Wording

IE.COV.SPILLS.OG.001
_1212_ Oil and Gas Cc

Appendix C

OEE Draft Policy Wording

EED FORM.pdf

APPENDIX H

SURFACE USE AND PORE SPACE LEASE

STORAGE AGREEMENT
TUNDRA DEADWOOD – SECURE GEOLOGIC STORAGE
OLIVER COUNTY, NORTH DAKOTA

THIS AGREEMENT ("Agreement") is entered into as of the 1st day of November 1, 2021, 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.

RECITALS:

A. 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 coal and power industries, to the economic benefit of North Dakota and its citizens;

B. 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

C. 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.

AGREEMENT:

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 18903.211 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 Opeche-Picard (Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at two stratigraphic wells, the J-LOC1 well (File No. 37380) and the J-ROC1 1 well (File No. 37672). The log suites included caliper, gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, spectral GR, a combinable magnetic resonance (CMR), and fracture finder log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from two 3D seismic surveys covering an area totaling 18.5 miles in and around the J-ROC1 1 (located in Section 4, Township 141 North, Range 83 West) and the J-LOC 1 (located in Section 27, Township 142 North, Range 84 West) stratigraphic wells located in Oliver County, North Dakota. Formation top depths were picked from the top of the Pierre Formation to the top of the Precambrian. These logs and data which encompass the stratigraphic interval from an average depth of 4,650 feet to an average depth of 5,450 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, fluids, and minerals.

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 Tundra Deadwood Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Tundra Deadwood 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 a 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 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 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.** Minnkota Power Cooperative, Inc. 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.** As permitted by the Commission 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 April 1, 2022 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 § 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 with the approval of the Commission.

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 **<u>Successors and Assigns</u>.** 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: ___________, 2021

STORAGE OPERATOR

MINNKOTA POWER COOPERATIVE, INC.

By:_________________________________

Its:_________________________________

71751370.1

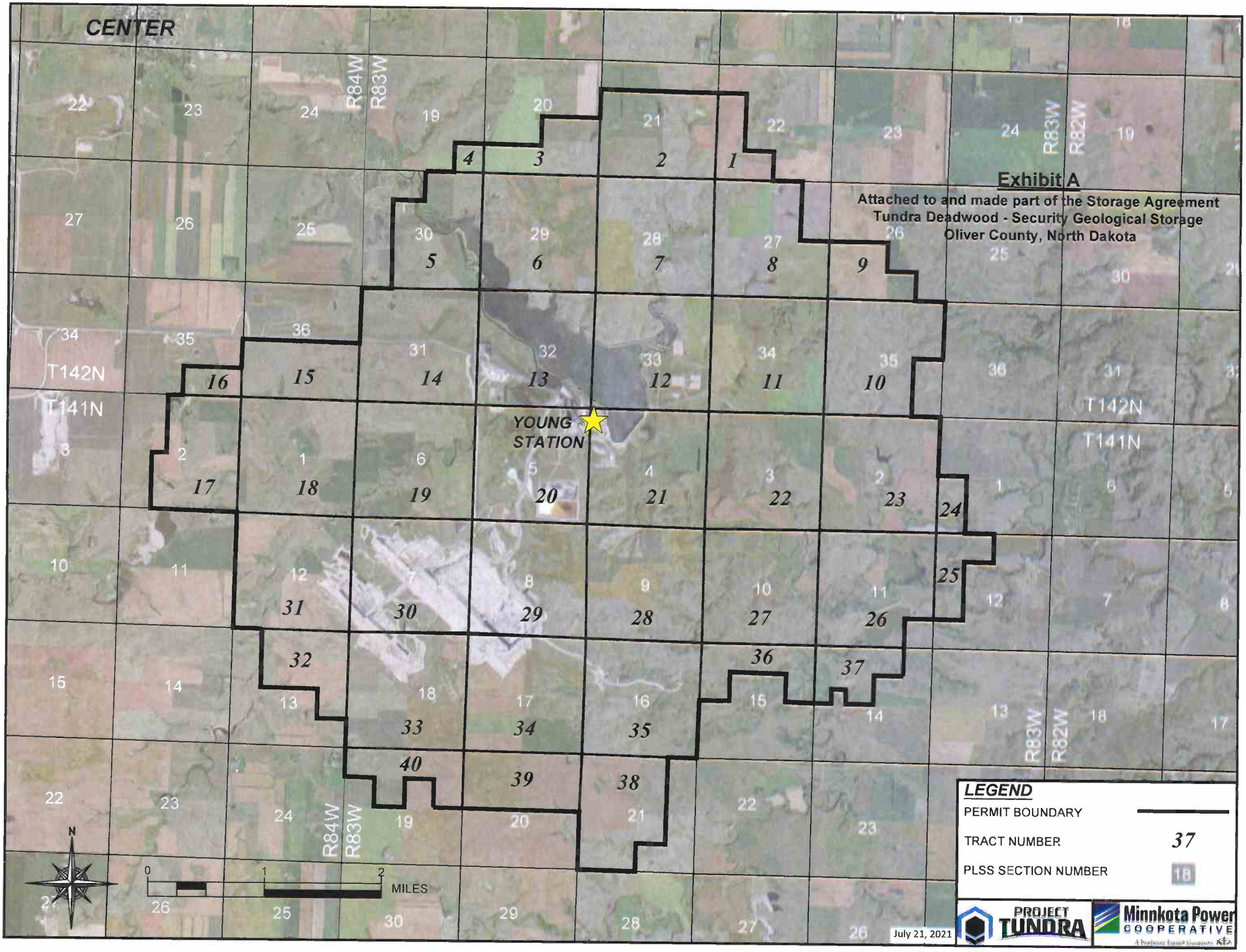

CENTER
Exhibit A
Attached to and made part of the Storage Agreement
Tundra Deadwood - Security Geological Storage
Oliver County, North Dakota
YOUNG STATION
T142N
T141N
R84W
R83W
R82W
LEGEND
PERMIT BOUNDARY
TRACT NUMBER 37
PLSS SECTION NUMBER 18
MILES
0
1
2
July 21, 2021
PROJECT TUNDRA
Minnkota Power COOPERATIVE

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Tundra Deadwood - Secure Geological Storage
Oliver County, North Dakota

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 22-T142N-R83W	Melvin Schoepp	20.000	12.50000000%	0.10580213%
		Caroline K. Schoepp	20.000	12.50000000%	0.10580213%
		Marie Mosbrucker	30.000	18.75000000%	0.15870320%
		Raymond Friedig	30.000	18.75000000%	0.15870320%
		Duane Friedig	30.000	18.75000000%	0.15870320%
		Shirley Hilzendeger	30.000	18.75000000%	0.15870320%
		Tract Total:	**160.000**	**100.00000000%**	
2	Section 21-T142N-R83W	Jeff Erhardt and Mary Erhardt	120.000	25.00000000%	0.63481278%
		Keith Erhardt	35.000	7.29166667%	0.18515373%
		Keith Erhardt and Kelly Jo Erhardt	5.000	1.04166667%	0.02645053%
		Melvin Schoepp and Caroline Schoepp	320.000	66.66666667%	1.69283409%
		Tract Total:	**480.000**	**100.00000000%**	
3	Section 20-T142N-R83W	Jeff Erhardt and Mary Erhardt	160.000	66.66666667%	0.84641705%
		Matthias A. Erhardt, as trustee of the Matthias A. Erhardt Trust dated December 27, 1994	40.000	16.66666667%	0.21160426%
		Josephine Erhardt, as trustee of the Josephine Erhardt Trust dated December 27, 1994	40.000	16.66666667%	0.21160426%
		Tract Total:	**240.000**	**100.00000000%**	
4	Section 19-T142N-R83W	Matthias A. Erhardt, trustee, or successor trustee(s), of the Matthias A. Erhardt Trust dated December 27, 1994	20.000	50.00000000%	0.10580213%
		Josephine Erhardt, trustee, or successor trustee(s), of the Josephine Erhardt Trust dated December 27, 1994	20.000	50.00000000%	0.10580213%
		Tract Total:	**40.000**	**100.00000000%**	
5	Section 30-T142N-R83W	Minnkota Power Cooperative, Inc.	322.170	73.22045455%	1.70431362%
		Ryan J. Weber	40.000	9.09090909%	0.21160426%

		Darlene Voegele	77.830	17.68863636%	0.41172899%
		Tract Total:	**440.000**	**100.00000000%**	
6	Section 29-T142N-R83W	Minnkota Power Cooperative, Inc.	92.360	14.43125000%	0.48859424%
		Darlene Voegele	227.640	35.56875000%	1.20423985%
		Charles Kuether	150.000	23.43750000%	0.79351598%
		Doris Kuether	150.000	23.43750000%	0.79351598%
		Terrie Nehring	20.000	3.12500000%	0.10580213%
		Tract Total:	**640.000**	**100.00000000%**	
7	Section 28-T142N-R83W	Minnkota Power Cooperative, Inc.	160.000	25.00000000%	0.84641705%
		Dale Barth	476.320	74.42500000%	2.51978354%
		Dusty Backer	3.680	0.57500000%	0.01946759%
		Tract Total:	**640.000**	**100.00000000%**	
8	Section 27-T142N-R83W	Dale Barth	560.000	100.00000000%	2.96245966%
		Tract Total:	**560.000**	**100.00000000%**	
9	Section 26-T142N-R83W	Raymond Friedig, as personal representative of the Estate of Magdalen F. Friedig, deceased	154.460	77.23000000%	0.81710986%
		Carl Schwalbe	13.333	6.66666567%	0.07053475%
		Heirs or Devisees of the Estate of Loren Schwalbe, deceased	13.333	6.66666567%	0.07053475%
		Rolland Schwalbe	13.333	6.66666567%	0.07053475%
		Randolph Middleton and Mary Middleton	5.540	2.77000000%	0.02930719%
		Tract Total:	**200.000**	**100.00000000%**	
10	Section 35-T142N-R83W	Brennan Price	560.000	100.00000000%	2.96245966%
		Tract Total:	**560.000**	**100.00000000%**	
11	Section 34-T142N-R83W	Minnkota Power Cooperative, Inc.	477.990	74.68593750%	2.52861802%
		State of North Dakota	160.000	25.00000000%	0.84641705%
		County of Oliver	2.010	0.31406250%	0.01063311%
		Tract Total:	**640.000**	**100.00000000%**	
12	Section 33-T142N-R83W	Square Butte Electric Cooperative	3.900	0.60937500%	0.02063142%
		Minnkota Power Cooperative, Inc.	625.040	97.66250000%	3.30652819%
		ALLETE, INC.	11.060	1.72812500%	0.05850858%
		Tract Total:	**640.000**	**100.00000000%**	
13	Section 32-T142N-R83W	Minnkota Power Cooperative, Inc.	465.830	72.78593750%	2.46429033%
		Heirs or Devisees of Alex Sorge, deceased	80.000	12.50000000%	0.42320852%

		Darlene Voegele	37.470	5.85468750%	0.19822029%
		BNI Coal, Ltd.	56.700	8.85937500%	0.29994904%
		Tract Total:	**640.000**	**100.00000000%**	
14	Section 31-T142N-R83W	Robert Reinke	456.910	70.56743065%	2.41710258%
		Darlene Voegele	149.640	23.11113857%	0.79161154%
		BNI Coal, Ltd.	40.930	6.32143078%	0.21652406%
		Tract Total:	**647.480**	**100.00000000%**	
15	Section 36-T142N-R84W	State of North Dakota Board of University and School Lands	320.000	100.00000000%	1.69283409%
		Tract Total:	**320.000**	**100.00000000%**	
16	Section 35-T142N-R84W	Michael P. Dresser	80.000	100.00000000%	0.42320852%
		Tract Total:	**80.000**	**100.00000000%**	
17	Section 2-T141N-R84W	City of Center Park District	46.050	10.68544645%	0.24360941%
		Barry A. Berger and Carrie Berger	286.460	66.47020605%	1.51540392%
		Dwight Wrangham and Linda Wrangham	3.000	0.69612029%	0.01587032%
		BNI Coal, Ltd.	95.450	22.14822721%	0.50494067%
		Tract Total:	**430.960**	**100.00000000%**	
18	Section 1-T141N-R84W	Jolene Berger	627.320	97.93917442%	3.31858963%
		Travis Klatt and Jessica Klatt	8.310	1.29738338%	0.04396079%
		Gary Leinius	4.890	0.76344220%	0.02586862%
		Tract Total:	**640.520**	**100.00000000%**	
19	Section 6-T141N-R83W	Brian Reinke	19.577	3.02274377%	0.10356336%
		Benjamin Reinke	30.997	4.78601096%	0.16397532%
		Elizabeth Wagendorf	30.997	4.78601096%	0.16397532%
		Jolene Berger	245.840	37.95877403%	1.30051979%
		Gary Leinius	320.240	49.44646028%	1.69410372%
		Tract Total:	**647.650**	**100.00000000%**	
20	Section 5-T141N-R83W	Minnkota Power Cooperative, Inc.	641.12000000	99.92518703%	3.39159310%
		Square Butte Electric Cooperative	0.48000000	0.07481297%	0.00253925%
		Tract Total:	**641.600**	**100.00000000%**	
21	Section 4-T141N-R83W	Square Butte Electric Cooperative	3.820	0.59499704%	0.02020821%
		Minnkota Power Cooperative, Inc.	638.200	99.40500296%	3.37614599%
		Tract Total:	**642.020**	**100.00000000%**	

22	Section 3-T141N-R83W	Minnkota Power Cooperative, Inc.	7.720	1.20256714%	0.04083962%
		Alan Schwalbe	634.240	98.79743286%	3.35519717%
		Tract Total:	**641.960**	**100.00000000%**	
23	Section 2-T141N-R83W	Carl Schwalbe	214.347	33.33333333%	1.13391846%
		Rolland Schwalbe	214.347	33.33333333%	1.13391846%
		Loren Schwalbe	214.347	33.33333333%	1.13391846%
		Tract Total:	**643.041**	**100.00000000%**	
24	Section 1-T141N-R83W	Carl Schwalbe	26.667	33.33333333%	0.14106951%
		Rolland Schwalbe	26.667	33.33333333%	0.14106951%
		Loren Schwalbe	26.667	33.33333334%	0.14106951%
		Tract Total:	**80.000**	**100.00000000%**	
25	Section 12-T141N-R83W	Richard A. Schwalbe and Lila M. Schwalbe	160.000	100.00000000%	0.84641705%
		Tract Total:	**160.000**	**100.00000000%**	
26	Section 11-T141N-R83W	Alan Schwalbe	480.000	80.00000000%	2.53925114%
		Julie Hatzenbihler	15.000	2.50000000%	0.07935160%
		Rodney J. Hatzenbihler	15.000	2.50000000%	0.07935160%
		Nancy Henke	15.000	2.50000000%	0.07935160%
		Bonnie Schwab	15.000	2.50000000%	0.07935160%
		Peggy Gobar	15.000	2.50000000%	0.07935160%
		Annette Hatzenbihler	15.000	2.50000000%	0.07935160%
		Brent Hatzenbihler	15.000	2.50000000%	0.07935160%
		Randy Hatzenbihler	15.000	2.50000000%	0.07935160%
		Tract Total:	**600.000**	**100.00000000%**	
27	Section 10-T141N-R83W	Alan Schwalbe	237.840	37.16250000%	1.25819894%
		Minnkota Power Cooperative, Inc.	2.160	0.33750000%	0.01142663%
		Delmar Hagerott	400.000	62.50000000%	2.11604261%
		Tract Total:	**640.000**	**100.00000000%**	
28	Section 9-T141N-R83W	Minnkota Power Cooperative, Inc.	640.000	100.00000000%	3.38566818%
		Tract Total:	**640.000**	**100.00000000%**	
29	Section 8-T141N-R83W	BNI Coal, Ltd.	161.000	25.15625000%	0.85170715%
		Minnkota Power Cooperative, Inc.	160.000	25.00000000%	0.84641705%
		Five D's, LLP	319.000	49.84375000%	1.68754398%
		Tract Total:	**640.000**	**100.00000000%**	

30	Section 7-T141N-R83W	Janet K. Dohrmann and L. J. Dohrmann, Trustees of the Janet and L. J. Dohrmann Revocable Trust	328.460	50.65231471%	1.73758839%
		Gary Leinius	320.000	49.34768529%	1.69283409%
		Tract Total:	**648.460**	**100.00000000%**	
31	Section 12-T141N-R84W	Jolene Berger	160.00000000	25.00000000%	0.84641705%
		Brian Dresser	320.00000000	50.00000000%	1.69283409%
		Frances Fuchs	160.00000000	25.00000000%	0.84641705%
		Tract Total:	**640.000**	**100.00000000%**	
32	Section 13-T141N-R84W	Mark Leischner and Susan Leischner	280.000	100.00000000%	1.48122983%
		Tract Total:	**280.000**	**100.00000000%**	
33	Section 18-T141N-R83W	Janet K. Dohrmann and L.J. Dohrmann, as Trustees of The Janet and L.J. Fast Revocable Trust	123.820	19.12100809%	0.65502099%
		Wayne Reuther	33.957	5.24378693%	0.17963438%
		Kent Reuther	33.957	5.24378693%	0.17963438%
		Keith Reuther	33.957	5.24378693%	0.17963438%
		Karen Shulz	33.957	5.24378693%	0.17963438%
		Jerald Reuther	33.957	5.24378693%	0.17963438%
		Martha Reuther	33.957	5.24378693%	0.17963438%
		Larry F. Schmidt and Virginia Schmidt	320.000	49.41627031%	1.69283409%
		Tract Total:	**647.560**	**100.00000000%**	
34	Section 17-T141N-R83W	Five D's LLP	320.000	50.00000000%	1.69283409%
		Jerald O. Reuther	79.698	12.45286458%	0.42161267%
		Wayne A. Reuther	53.333	8.33333333%	0.28213902%
		Karen L. Reuther	26.667	4.16666667%	0.14106951%
		Jeanette M. Reuther	0.302	0.04713542%	0.00159585%
		Larry F. Schmidt and Virginia Schmidt	160.000	25.00000000%	0.84641705%
		Tract Total:	**640.000**	**100.00000000%**	
35	Section 16-T141N-R83W	Larry F. Schmidt and Virginia Schmidt	160.000	25.00000000%	0.84641705%
		BNI Coal, Ltd.	160.000	25.00000000%	0.84641705%
		Oliver County	2.510	0.39218750%	0.01327817%
		State of North Dakota - Dept. of Trust Lands Attn: Commissioner of University and School Lands	317.490	49.60781250%	1.67955592%
		Tract Total:	**640.000**	**100.00000000%**	
36	Section 15-T141N-R83W	Delmar Hagerott	240.000	100.00000000%	1.26962557%
		Tract Total:	**240.000**	**100.00000000%**	

37	Section 14-T141N-R83W	Alan Schwalbe	190.000	100.00000000%	1.00512024%
		Tract Total:	**190.000**	**100.00000000%**	
38	Section 21-T141N-R83W	Douglas D. Doll and Deberra K. Doll	100.000	22.72727273%	0.52901065%
		James D. Pazdernik and Bonita Pazdernik	100.000	22.72727273%	0.52901065%
		Anton Pfleger and Helen Pfleger	160.000	36.36363636%	0.84641705%
		Delmar Hagerott	80.000	18.18181818%	0.42320852%
		Tract Total:	**440.000**	**100.00000000%**	
39	Section 20-T141N-R83W	Douglas D. Doll and Deberra K. Doll	80.000	25.00000000%	0.42320852%
		James D. Pazdernik and Bonita Pazdernik	80.000	25.00000000%	0.42320852%
		Dale P. Pfliger and Judy Pfliger	80.000	25.00000000%	0.42320852%
		Thomas Pfliger	80.000	25.00000000%	0.42320852%
		Tract Total:	**320.000**	**100.00000000%**	
40	Section 19-T141N-R83W	Winfrid Keller	120.000	49.59497438%	0.63481278%
		Jerald Reuther	23.684	9.78839478%	0.12529088%
		Wayne Reuther	23.684	9.78839478%	0.12529088%
		Kent Reuther	23.684	9.78839478%	0.12529088%
		Keith Reuther	27.224	11.25144652%	0.14401786%
		Karen Shulz	23.684	9.78839478%	0.12529088%
		Tract Total:	**241.960**	**100.00000000%**	
		Total Acres:	**18903.211**	**Total Participation:**	**100.00000000%**

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Storage Agreement
Tundra Deadwood - Secure Geological Storage
Oliver County, North Dakota

Tract No.	Acres	Tract Participation Factor
1	160.000	0.84641705%
2	480.000	2.53925114%
3	240.000	1.26962557%
4	40.000	0.21160426%
5	440.000	2.32764687%
6	640.000	3.38566818%
7	640.000	3.38566818%
8	560.000	2.96245966%
9	200.000	1.05802131%
10	560.000	2.96245966%
11	640.000	3.38566818%
12	640.000	3.38566818%
13	640.000	3.38566818%
14	647.480	3.42523818%
15	320.000	1.69283409%
16	80.000	0.42320852%
17	430.960	2.27982431%
18	640.520	3.38841904%
19	647.650	3.42613750%
20	641.600	3.39413235%
21	642.020	3.39635420%
22	641.960	3.39603679%
23	643.041	3.40175539%
24	80.000	0.42320852%
25	160.000	0.84641705%
26	600.000	3.17406392%
27	640.000	3.38566818%
28	640.000	3.38566818%
29	640.000	3.38566818%
30	648.460	3.43042248%
31	640.000	3.38566818%
32	280.000	1.48122983%
33	647.560	3.42566139%
34	640.000	3.38566818%
35	640.000	3.38566818%
36	240.000	1.26962557%
37	190.000	1.00512024%
38	440.000	2.32764687%
39	320.000	1.69283409%
40	241.960	1.27999418%
Total:	**18903.211**	**100.00000000%**

EXHIBIT D

Surface Use And Pore Space Lease
Attached to and made part of the Storage Agreement
Tundra Deadwood
Oliver County, North Dakota

SURFACE USE AND PORE SPACE LEASE

THIS SURFACE USE AND PORE SPACE LEASE **("Lease")** is made, entered into, and effective as of the _______day of ___________________, 2020 **("Effective Date")** by and between ________________, whose address is ______________________ (whether one or more, **"Lessor")**, and Minnkota Power Cooperative, Inc., a Minnesota cooperative association, whose address is _________________________ (whether one or more, **"Lessee")**. Lessor and Lessee are sometimes referred to in this Lease individually as a **"Party"** and collectively as the **"Parties."**

1. **DEFINITIONS.** The following terms shall have the following meanings in this Lease:

"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.

"Commencement of Operations" means the date on which Carbon Dioxide is first injected into a Reservoir for commercial operations under this Lease, provided that the performance of test injections and related activities shall not be deemed Commencement of Operations.

"Commission" means the North Dakota Industrial Commission.

"Completion Notice" means a certificate of project completion issued to Lessee by the Commission pursuant to Chapter 38-22 of the North Dakota Century Code.

"Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the Operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits.

"Environmental Incentives" means any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into the Operations, environmental benefits of Operations, or other similar programs available from any regulated entity or any Governmental Authority.

"Facilities" means all facilities, structures, improvements, fixtures, equipment, and any other personal property at any time acquired or constructed by or for Lessee that are necessary or desirable in connection with any use of Reservoirs and their Formations or Operations, including without limitation wells, pipelines, roads, utilities, metering or monitoring equipment, and buildings.

"Financing Parties" means person or persons providing construction or permanent financing to Lessee in connection with construction, ownership, operation and maintenance of Facilities or Operations, including financial institutions, leasing companies, institutions, tax equity partners, joint venture partners and/or private lenders.

"Formation" means the geological formation of which any Reservoir is a part.

"Hazardous Substance" means any chemical, waste or other substances, expressly excluding Carbon Dioxide and Non-Native Carbon Dioxide, (a) which now or hereafter becomes defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollutions," "pollutants," "regulated substances," or words of similar import under any law pertaining to environment, health, safety or welfare, (b) which is declared to be hazardous, toxic or polluting by any Governmental Authority, (c) exposure to which now or hereafter prohibited, limited or regulated by any Governmental Authority, (d) the storage, use, handling, disposal or release of which is restricted or regulated by any Governmental Authority, or (e) for which remediation or cleanup is required by any Governmental Authority.

"Leased Premises" means the surface and subsurface of the land, excluding mineral rights, described in **Exhibit A** of this Lease.

"Native Oil and Gas" means all oil, natural gas, and other hydrocarbons present in and under the Leased Premises and not injected by Lessor, Lessee or any third party.

"Non-Native Carbon Dioxide" means Carbon Dioxide that is not naturally occurring in the Reservoir together with incidental associated substances, fluids, minerals, oil, and gas, excluding that which, independent of Operations, originates from an accumulation meeting the definition of a Pool. All Non-Native Carbon Dioxide will be considered personal property of the Lessee and its successor and assigns under this Agreement.

"Operating Year" means the calendar year or portion of the calendar year following Commencement of Operations during which Operations occur.

"Operations" means the transportation and injection of Carbon Dioxide into a Reservoir after Commencement of Operations, and any withdrawal of this Carbon Dioxide, as well as the withdrawal of Non-Native Carbon Dioxide, for sale or disposal in accordance with applicable law.

"Option Money" means 20 percent of the Initial Term Payment (as such term is defined in that certain Option to Lease between Lessor and Lessee with respect to the Leased Premises).

"Pool" means an underground Reservoir containing a common accumulation of Native Oil and Gas that is economically recoverable. A zone of a structure that is completely separated from any other zone in the same structure is a Pool.

"Pore Space" means a cavity or void, whether natural or artificially created, in a Reservoir.

"Related Person" means any member, partner, principal, officer, director, shareholder, predecessor-in-interest, successor-in-interest, employee, agent, heir, representative, contractor, lessee, sublessee, licensee, invitee, permittee of a Party, Financing Parties or any other person or entity that has obtained or in future obtains rights or interests from, under or through a Party (excluding the other Party itself).

"Reservoir" means any subsurface stratum, sand, formation, aquifer, cavity or void, whether natural or artificially created, wholly or partially within the Leased Premises, suitable for the storage or sequestration of carbon dioxide or other gaseous substances.

"Storage Fee" means Lessor's proportionate share of sixteen cents ($0.16) per metric ton of Carbon Dioxide ("Storage Rate") as determined by the Lessee's last meter before injection as part of Operations. For injection periods after 2026, the Storage Rate shall be adjusted to an amount equal to the product of sixteen cents ($0.16) and the inflation adjustment factor for such calendar year. The inflation adjustment factor shall be determined in the same manner as provided in 26 U.S.C. §45Q(f)(7)(B), substituting "2026" for "2008". The Storage Fee shall be: (i) calculated separately for each amalgamated area as created and established by the Commission that includes any portion of the Leased Premises; (ii) limited to the Carbon Dioxide injected in said amalgamated area in the immediately preceding Operating Year; and (iii) based on the Lessor's proportionate per net acre share of said unit. For avoidance of doubt, the Lessor shall receive a separate Storage Fee for each amalgamated area created and established by the Commission that includes any portion of the Leased Premises on a net acre basis within the Lessor's interest being the numerator and the acres in the amalgamated area being the denominator.

"Tax Credits" means any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. §45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to construction, ownership or Operations

2. LEASE RIGHTS. In consideration of the compensation, covenants, agreements, and conditions set forth in this Lease, Lessor grants, demises, leases and lets to Lessee the exclusive right to use all Pore Space, Reservoirs and their Formations in the Leased Premises for any purpose not previously granted or reserved by an instrument of record related to the capture, injection, storage, sequestration, sale, withdrawal or disposal of Carbon Dioxide, Non-Native Carbon Dioxide and incidental associated substances, fluids, and minerals, provided that Lessee shall have no right to use potable water from within the Leased Premises in Operations; together with the following exclusive rights:

(a) to use the Leased Premises for developing, constructing, installing, improving, maintaining, replacing, repowering, relocating, removing, abandoning in place, expanding, and operating Facilities;

(b) to lay, maintain, replace, repair, and remove roads on the Leased Premises to allow Lessee, in its sole discretion, to exercise its rights under this Lease; and

(c) to enter upon and use the Leased Premises for the purposes of conducting:

(i) any investigations, studies, surveys, and tests, including without limitation drilling and installing test wells and monitoring wells, seismic testing, and other activities as Lessee deems necessary or desirable to determine the suitability of the Leased Premises for Operations,

(ii) any inspections and monitoring of Reservoirs and Carbon Dioxide as Lessee or any governmental authority deems necessary or desirable during the term of this Lease, and

(iii) any maintenance to the Facilities that Lessee or any governmental authority deems necessary or as required by applicable law.

Lessor also hereby grants and conveys unto Lessee all other and further easements across, over, under and above the Leased Premises as reasonably necessary to provide access to and services reasonably required for Lessee's performance under the Lease. The easements granted hereunder shall run with and burden the Leased Premises for the term of this Lease. Notwithstanding the surface easements granted herein, Lessee shall provide notice to Lessor prior to accessing the surface of the Property, and if such activity requires permit then prior notice shall be in form and not be less than that required by law or rule.

Lessee may exercise its rights under this Lease in conjunction with related operations on other properties near the Leased Premises. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or to 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.

3. INITIAL TERM. This Lease shall commence on the Effective Date and shall continue for an initial term of twenty (20) years ("Initial Term") unless sooner terminated in accordance with the terms of this Lease. Lessee may, but is not obligated to, extend the Initial Term for up to four successive five-year periods by paying Lessor $25.00 per net acre in the Leased Premises per five-year extension on or prior to the last day of the Initial Term or expiring five-year extension period. The Initial Term together with any extensions are referred to as the "Primary Term."

4. OPERATIONAL TERM. Upon Commencement of Operations at any time during the Primary Term, this Lease shall continue for so long as any portion of the Leased Premises or

Lessee's Facilities are subject to a permit issued by the Commission or under the ownership or control of the State of North Dakota ("Operational Term"); *provided, however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a Completion Notice, except for payment of the Final Royalty Payment (as applicable), and Final Occupancy Fee (as applicable). If Commencement of Operations does not occur during the Primary Term, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county in which the Leased Premises is located.

5. COMPENSATION.

(a) **Initial Term Payment.** Lessee shall pay to Lessor the greater of $50.00 per net acre in the Leased Premises ("Initial Term Payment") or a one-time flat $500.00 payment, the receipt and sufficiency of which are hereby acknowledged.

(b) **Royalty.** During the Operational Term, Lessee shall annually on or before May 31st pay to Lessor a royalty equal to the greater of a flat $100.00 payment or the Storage Fee(s) for the immediately preceding Operating Year. For the Operating Year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay a pro rata share of the Storage Fee(s) ("Final Royalty Payment"), as applicable, and said payment shall be made within sixty days after the date the Completion Notice was issued.

(c) **Occupancy Fee.** Within sixty days of the anniversary of the Effective Date after which any Facilities are installed or used, Lessee shall pay Lessor, as applicable, a one-time fee of (i) $3,000.00 per net surface acre of the Leased Premises occupied by Facilities (excluding pipelines), and (ii) $1.50 for each linear foot of pipeline in place on the Leased Premises. For the year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay any fees owed pursuant to this provision ("Final Occupancy Fee") within sixty days after the date the Completion Notice was issued.

Lessor and Lessee agree that the Lease shall continue as specified herein even in the absence of Operations and the payment of royalties.

6. AMALGAMATION. (a) Lessee, in its sole discretion, shall have the right and power, at any time (including both before and after Commencement of Operations), to pool, unitize, or amalgamate any Reservoir or portion of a Reservoir with any other lands or interests into which that Reservoir extends and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county in which the amalgamated unit. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit agreements and operating agreements with respect to the operation of any amalgamated areas formed under this Lease.
(b) The injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide into a Reservoir from any property within a amalgamated area that includes the Leased Premises shall be treated as if Operations were occurring on the Leased Premises, except that the royalty payable to Lessor under Section 5(b) of this Lease shall be Lessor's per net acre proportionate share of the total Storage Fee for the preceding Operating year's injection of Carbon Dioxide into the amalgamated area.

7. ENVIRONMENTAL INCENTIVES. Unless otherwise specified, Lessee is the owner of all

Environmental Attributes and Environmental Incentives and is entitled to the benefit of all Tax Credits or any other attributes of ownership of the Facilities and Operations. Lessor shall cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

8. SURRENDER OF LEASED PREMISES. Lessee shall have the unilateral right at any time and from time to time to execute and deliver to Lessor a written notice of surrender and/or release covering all or any part of the Leased Premises for which the subsurface pore space 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.

9. FACILITIES.

(a) Lessee shall in good faith consult with Lessor regarding the location of the Facilities, selection of the Facilities location shall be within the discretion of the Lessee with consent of the Lessor, not to be unreasonably withheld. The withholding of such consent by the Lessor regarding the location of the Facilities shall be deemed "unreasonable" if the proposed location of the Facility is located more than 500 feet from any occupied dwellings or currently used buildings existing on the Leased Premises as of the Effective Date. Notwithstanding the foregoing, in no event shall Facilities be located within 500 feet of any currently occupied dwelling or currently used building existing on the Leased Premises as of the Effective Date without Lessor's express consent. Lessee may erect fences around all or part of any aboveground Facilities (excluding roads) to separate Facilities from adjacent Lessor-controlled lands, and shall do so if Lessor so requests. Lessee shall maintain and repair at its expense any roads it constructs on the Leased Premises in reasonably safe and usable condition.

(b) Lessor and Lessee agree that all Facilities and property of whatever kind and nature constructed, placed or affixed on the rights-of-way, easements, patented or leased lands as part of Lessee's Operations, as against all parties and persons whomsoever (including without limitation any party acquiring interest in the rights-of-way, easements, patented or leased lands or any interest in or lien, claim or encumbrance against any of such Facilities), shall be deemed to be and remain the property of the Lessee, and shall not be considered to be fixtures or a part of the Leased Premises. Lessor waives, to the fullest extent permitted by applicable law, any and all rights it may have under the laws of the State of North Dakota, arising under this Lease, by statute or otherwise to any lien upon, or any right to distress or attachment upon, or any other interest in, any item constituting the Facilities or any other equipment or improvements constructed or acquired by or for Lessee and located on the leased Premises or within any easement area. Each Lessor and Lessee agree that the Lessee (or the designated assignee of Lessee or Financing Parties) is the tax owner of any such Facilities, structures, improvements, equipment and property of whatever kind and nature and all tax filings and reports will be filed in a manner consistent with this Lease. Facilities shall at all times retain the legal status of personal property as defined under Article 9 of the Uniform Commercial Code. If there is any mortgage or fixture filing against the Premises which could reasonably be construed as prospectively attaching to the Facilities as a fixture of the Premises, Lessor shall provide a disclaimer or release from such lienholder. Lessor, as fee owner, consents to the filing of a disclaimer of the Facilities as a fixture of the Premises in the Oliver County Recorder's Office, or where real estate records of Oliver County are customarily filed.

10. SURFACE DAMAGE COMPENSATION ACT. The 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 (to the extent applicable).

11. MINERALS, OIL AND GAS. This Lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for Lessee to explore for or produce minerals, including Native Oil and Gas, that may exist on the Leased Premises. Lessee shall not engage in any activity or permit its Related Persons to engage in any activity that unreasonably interferes with the Lessor's or third party's (or parties') rights to the granted, leased, or reserved mineral interests. If Lessor owns hydrocarbon mineral interests in the Leased Premises and Lessee should inadvertently discover a Pool in conjunction with its efforts to explore for and develop a Reservoir for Operations, Lessee shall inform Lessor within 60 days of discovery. If Lessee determines that it will not use in conjunction with Operations a well that has encountered a Pool within the Leased Premises, Lessor shall have the option but not the obligation to buy such well at cost, provided Lessor has the ability and assumes all permits and risks and liabilities which are associated with the ownership and operation of an oil, gas or mineral well.

12. FORCE MAJEURE. Should Lessee be prevented from complying with any express or implied covenant of this Lease, from utilizing the Leased Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material failure or breakdown of equipment, or by operation of force majeure (including, but not limited to, riot, insurrection, war (declared or not), mobilization, explosion, labor dispute, fire, flood, earthquake, storm, lightning, tsunami, backwater caused by flood, vandalism, act of the public enemy, terrorism, epidemic, pandemic (including COVID-19), civil disturbances, strike, labor disturbances, work slowdown or stoppage, blockades, sabotage, labor or material shortage, national emergency, and the amendment, adoption or repeal of or other change in, or the interpretation or application of, any applicable laws, orders, rules or regulations 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.

13. DEFAULT/TERMINATION. Lessor may not terminate the Lease for any reason whatsoever unless a Default Event has occurred and is continuing consistent with the terms of this Section 13. Any Party that fails to perform its responsibilities as listed below shall be deemed to be the "Defaulting Party," the other Party shall be deemed to be the "Non-Defaulting Party," and each event of default shall be a "Default Event." A Default Event is: (a) failure of a Party to pay any amount due and payable under this Lease, other than an amount that is subject to a good faith dispute, within thirty (30) days following receipt of written notice from Non-Defaulting Party of such failure to pay; or (b) a material violation or default of any terms of this Lease by a Party, provided the Non-Defaulting Party provides written notice of violation or default and Defaulting Party fails to substantially cure the violation or default within sixty (60) days after receipt of said notice to cure such violations or defaults. Parties acknowledge that in connection with any construction or long-term financing or other credit support provided to Lessee or its affiliates by Financing Parties, that such Financing Parties may act to cure a continuing Default Event and Lessor agrees to accept performance from any such Financing Parties so long as such Financing Parties perform in accordance with the terms of this Lease. If Lessee, its affiliates or Financing Parties, fail to substantially cure such Default Event within the applicable 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, plug, and/or abandon in place all Facilities of Lessee located on the Leased Premises in accordance with applicable permit requirements or other applicable statutes, rules or regulations.

14. ASSIGNMENT. (a) Lessor shall not sell, transfer, assign or encumber the Facilities or any part of Operations, Lessee's title or Lessee's rights under this Lease. (b) Lessee has the right to sell, assign, mortgage, pledge, transfer, use as collateral, or otherwise collaterally assign or convey all or any of its rights under this Lease, including, without limitation, an assignment by Lessee to Financing Parties. (c) In the event Lessee assigns its rights under this Lease, Lessee shall be relieved of all obligations with respect to the assigned portion arising after the date of assignment so long as notice of such assignment is provided to Lessor, and provided that Lessee shall not be relieved from any obligation in respect of any payment or other obligations that have not been satisfied or performed prior to such date of assignment. (d) This Lease shall be binding on and inure to the benefit of the successors and assignees. 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. Further, no change or division in Lessor's ownership of or interest in the Leased Premises or royalties shall enlarge the obligations or diminish the rights of Lessee or be binding on Lessee until after Lessee has been furnished with a written assignment or a true copy of the assignment with evidence that same has been recorded with the Oliver County Recorder's Office.

15. FINANCING. (a) Lessor acknowledges that Lessee may obtain tax equity, construction, long-term financing and other credit support from one or more Financing Parties and that Lessee intends to enter into various agreements and execute various documents relating to such financing, which documents may, among other things, assign this Lease and any related easements to a Financing Party, grant a sublease in the Leased Premises and a lease of the Facilities from such Financing Party to Lessee, grant the Financing Parties a sublease or other real property interest in Lessee's interests in and to the Leased Premises, grant a first priority security interest in Lessee's interest in the Facilities and/or this Lease and Lessee's other interests in and to the Leased Premises, including, but not limited to, any easements, rights of way or similar interests (such documents, "Financing Documents"). Lessor acknowledges notice of the foregoing and consents to the foregoing actions and Financing Documents described above.

(b) Lessor agrees, to execute, and agrees to cause any and all of Lessor's lenders to execute, such commercially reasonable subordination agreements, non-disturbance agreements, forbearance agreements, consents, estoppels, modifications of this Lease and other acknowledgements of the foregoing as Lessee or the Financing Parties may reasonably request (collectively, "Lessor Financing Consent Instruments"). Lessor acknowledges and agrees that (i) Lessee's ability to obtain financing for the construction and operation of the Facilities is dependent upon the prompt cooperation of Lessor and its lenders as contemplated by this Section 15; (ii) if Lessee is unable to close on the financing for the Facilities, the construction of the Facilities and the Commencement of Operations will not likely occur; and (iii) it is in the best interest of both Lessee and Lessor for Lessee to obtain financing from the Financing Parties as contemplated by this Section 15. Therefore, Lessor agrees to act promptly, reasonably and in good faith in connection with any request for approval and execution of all Lessor Financing Consent Instruments. The Lessor shall also reasonably cooperate with the Lessee or the Financing Party in the making of any filings required by such requesting party for regulatory compliance or in accordance with applicable laws and in the operation and maintenance of the Facilities, all solely at the expense of the Lessee.

(c) As a precondition to exercising any rights or remedies as a result of any default or alleged default by Lessee under this Lease, Lessor shall deliver a duplicate copy of the applicable notice of default to each Financing Parties concurrently with delivery of such notice to Lessee, specifying in detail the alleged default and the required remedy, provided Lessor was given notice of such Financing Parties and if no such notice of default is required to be delivered to Lessee under this Lease, Lessor may not terminate this Lease unless Lessor has delivered a notice of default to each Financing Party specifying in detail the alleged default or breach and permitting each Financing Party the opportunity to cure as provided in this Section 15(c). Each Financing Party shall have the same period after receipt of a notice of default to remedy default, or cause the same to be remedied, as is given to Lessee after Lessee's receipt of a notice of default under this Lease, plus, in each instance, the following additional time periods: (i) ten (10) Business Days in the event of any monetary default; and (ii) sixty (60) days in the event of any non-monetary default; provided, however, that (A) such sixty (60)-day period shall be extended for an additional sixty 60 days to enable such Financing Party to complete such cure, including the time required for such Financing Party to obtain possession of the Facilities (including possession by a receiver), institute foreclosure proceedings or otherwise perfect its right to effect such cure and (B) such Financing Party shall not be required to cure those defaults which are not reasonably susceptible of being cured or performed. Lessor shall accept such performance by or at the instance of a Financing Party as if the performance had been made by Lessee.

(d) If any Lessee Default Event cannot be cured without obtaining possession of all or part of the Facilities and/or the leasehold interest created by the Lease (the "Leasehold Estate"), then any such Lessee Default Event shall nonetheless be deemed remedied if: (i) within sixty (60) days after receiving the notice of default, a Financing Party acquires possession thereof, or commences appropriate judicial or non-judicial proceedings to obtain the same; (ii) such Financing Party is prosecuting any such proceedings to completion with commercially reasonable diligence; and (iii) after gaining possession thereof, such Financing Party performs all other obligations as and when the same are due in accordance with the terms of the Lease. If a Financing Party is prohibited by any process or injunction issued by any court or by reason of any action of any court having jurisdiction over any bankruptcy or insolvency proceeding involving Lessee from commencing or prosecuting the proceedings described above, then the sixty (60)-day period specified above for commencing such proceedings shall be extended for the period of such prohibition.

(e) Financing Parties shall have no obligation or liability to the Lessor for performance of the Lessee's obligations under the Lease prior to the time the Financing Party acquires title to the Leasehold Estate. A Financing Party shall be required to perform the obligations of the Lessee under this Lease only for and during the period the Financing Party directly holds such Leasehold Estate. Any assignment pursuant to this Section 15 shall release the assignor from obligations accruing under this Lease after the date the liability is assumed by the assignee.

(f) Each Financing Party shall have the absolute right to do one, some or all of the following things: (i) assign the rights, mortgage or pledge held by Financing Party (the "Financing Party's Lien"); (ii) enforce the Financing Party's Lien; (iii) acquire title (whether by foreclosure, assignment in lieu of foreclosure or other means) to the Leasehold Estate; (iv) take possession of and operate the Facilities or any portion thereof and perform any obligations to be performed by Lessee under the Lease, or cause a receiver to be appointed to do so; (v) assign or transfer the Leasehold Estate to a third party; or (vi) exercise any rights of Lessee under this Lease. Lessor's consent shall not be required for any of the foregoing; and, upon acquisition of the Leasehold Estate by a Financing Party or any other third party who acquires the same from or on behalf of the Financing Party or any purchaser who purchases at a foreclosure sale, Lessor shall recognize the Financing Party or such other party (as the case may be) as Lessee's proper successor, and this Lease shall remain in full force and effect.

(g) If this Lease is terminated for any reason whatsoever, including a termination by Lessor on account of a Lessee Default Event, or if this Lease is rejected by a trustee of Lessee in a bankruptcy or reorganization proceeding or by Lessee as a debtor-in-possession (whether or not such rejection shall be deemed to terminate this Lease), if requested by Financing Party, Lessor shall execute a new lease (the "New Lease") for the Leased Premises with the Financing Parties (or their designee(s), if applicable) as Lessee, within thirty (30) days following the date of such request. The New Lease shall be on substantially the same terms and conditions as are in this Lease (except for any requirements or conditions satisfied by Lessee prior to the termination or rejection). Upon execution of the New Lease by Lessor, Financing Parties (or their designee, if applicable) shall pay to Lessor any and all sums owing by Lessee under this Lease that are unpaid and that would, at the time of the execution of the New Lease, be due and payable under this Lease if this Lease had not been terminated or rejected. The provisions of this Section 15(g) shall survive any termination of this Lease prior to the expiration of the Term, and any rejection of this Lease in any bankruptcy or reorganization proceeding.

(h) Lessor consents to each Financing Party's security interest, if any, in the Facilities and waives all right of levy for rent and all claims and demands of every kind against the Facilities, such waiver to continue so long as any sum remains owing from Lessee to any Financing Parties. Lessor agrees that the Facilities shall not be subject to distraint or execution by, or to any claim of, Lessor.

16. INDEMNIFICATION; WAIVER. (a) Each Party shall indemnify, defend, and hold harmless the other Party and its Related Persons from and against any and all third-party suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of physical damage to property and physical injuries to any person, including death, caused by the indemnifying Party or its Related Persons except to the extent such claims arise out of the negligence or willful misconduct of the indemnified Party or its Related Persons. (b) Each Party shall indemnify, defend and hold harmless the other Party and its Related Persons from and against all suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of or relating to the existence at, on, above, below or near the Leased Premises of any Hazardous Substance, except to the extent deposited, spilled or otherwise caused by the indemnified Party or any of its contractors or agents, provided that Lessee shall not be obligated to indemnify Lessor with respect to any Hazardous Substance on the Leased Premises prior to the Effective Date.

17. INSURANCE. Lessee shall, at its sole cost and expense, keep and maintain in force commercial general liability insurance including broad form property damage liability, personal injury liability, and contractual liability coverage, on an "occurrence" basis, with a combined single limit, which may be effected by primary and excess coverage, of not less than Five Million Dollars ($5,000,000.00) during the primary term, except that such limit in the Primary Term shall be instead not less than One Million Dollars ($1,000,000.00) until such time as Lessee commences physical testing of any injection wells or other similar commercial activities, with such commercially reasonable deductibles as Lessee, in its discretion, may deem appropriate. Lessor shall be named as an additional insured in such policy but only to the extent of the liabilities specifically assumed by the Lessee under this Lease. The policy shall contain provisions by which the insurer waives any right of subrogation it may have against Lessor and shall be endorsed to provide that the insurer shall give Lessor thirty days written notice before any material modification or termination of coverage. Upon Lessor's request, Lessee shall promptly deliver certificates of such insurance to Lessor.

18. MISCELLANEOUS.

(a) **Confidentiality.** Lessor shall maintain in the strictest confidence, and shall require each of Lessor's Related Persons to hold and maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business, operations on the Leased Premises or on any other lands, the capacity and suitability of the Reservoir, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

(b) **Liens.** (i) Lessee shall protect the Leased Premises from liens of every character arising from its activities on the Leased Premises, provided that Lessee may, at any time and without the consent of Lessor, encumber, hypothecate, mortgage, pledge, or collaterally assign (including by mortgage, deed of trust or personal property security instrument) all or any portion of Lessee's right, title or interest under this Lease (but not Lessor's right, title or interest in the Leased Premises), as security for the repayment of any indebtedness and/or the performance of any obligation. (ii) Lessor shall not directly or indirectly cause, create, incur, assume or allow to exist any mortgage, pledge, lien, charge, security interest, encumbrance or other claim of any nature on or with respect to the Facilities, Operations or any interest therein. Lessor shall immediately notify Lessee in writing of the existence of any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim, shall promptly cause the same to be discharged and released of record without cost to Lessee, and shall indemnify the Lessee against all costs and expenses (including reasonable attorneys' fees) incurred in discharging and releasing any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim.

(c) **Warranty of Title.** Lessor represents and warrants to Lessee that Lessor is the owner in fee of the surface and subsurface pore space 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. At any time on or after the Effective Date, Lessee may obtain for itself and/or any Financing Party, at Lessee's expense, a policy of title insurance in a form and with exceptions acceptable to Lessee and/or such Financing Party in its sole discretion (the "Title Policies"). Lessor agrees to cooperate fully and promptly with Lessee in its efforts to obtain the Title Policies, and Lessor shall take such actions as Lessee or any Financing Party may reasonably request in connection therewith.

(d) **Conduct of Operations.** Each Party shall, at its expense, use best efforts to comply (and cause its Related Persons to comply) in all material respects with all laws applicable to its (or their) activities on the Leased Premises, provided that each Party shall have the right, in its sole discretion, to contest, by appropriate legal proceedings, the validity or applicability of any law, and the other Party shall cooperate in every reasonable way in such contest, at no out-of-pocket expense to the cooperating Party. During the Primary Term, Lessee, its agents, affiliates, servants, employees, nominees and licensees shall be entitled to: (i) apply for and obtain any necessary permits, approvals and other governmental authorizations (collectively called "Governmental Authorizations") required for the development, construction, operation and maintenance of the Project and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to the Governmental Authorizations upon Lessee's written request and at Lessee's direction, cost and expense; and (ii) apply for any approvals and permits and any zoning amendment of any area of the Leased Premises required in connection with the Project, and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to such approvals, permits and zoning amendments upon Lessee's written request and at Lessee's direction, cost and expense.

(e) **Title to Carbon Dioxide.** As between Lessor and Lessee, all right, title, interest and ownership to all Carbon Dioxide injected into any Reservoir shall belong to Lessee, as measured by corresponding Storage Fee payment to Lessor.

(f) **Hazardous Substances.** Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or within the Leased Premises by Lessor or any of its Related Persons on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances.

(g) **Interference.** Lessee shall peaceably and quietly have, hold and enjoy the Leased Premises against any person claiming by, through or under the Lessor and without disturbance by the Lessor, unless Lessee is found in default of the terms of this Lease and such default is continuing. Lessor shall not unreasonably interfere with Lessee's access to or maintenance of the Facilities or associated use of Leased Premises under this Lease; endanger the safety of Lessor, Lessee, the general public, private or personal property, or the Facilities; or install or maintain or permit to be installed or maintained vegetation, undergrowth, trees (including overhanging limbs and foliage and any trees standing which are substantially likely to fall), buildings, structures, installations, and any other obstructions which unreasonably interfere to Lessee access or use of the Facilities, Formations or Lessee's use of the Leased Premises under this Lease. Lessor shall not engage in any activity or permit its Related Persons to engage in any activity that might damage or undermine the physical integrity of any Formation or interfere with Lessee's use of the Leased Premises under this Lease, provided however that it is understood by Lessee that Lessor has no right to permit or to prohibit the exercise of any mineral rights not owned by Lessor at the time of entering into the Option to Lease between Lessor and Lessee with respect to the Leased Premises. Neither Lessee nor its agents will engage in any activity that damages existing oil, gas and other mineral exploration and development activities occurring on the Leased Premises without first obtaining permission from the relevant mineral rights holder.

(h) **Reservations.** Lessor reserves the right to sell, lease, or otherwise dispose of any interest in the Leased Premises subject to the rights granted in this Lease and agrees that sales, leases, or other dispositions of any interest or estate in the Leased Premises shall be expressly made subject to the terms of this Lease and shall not unreasonably interfere with Lessee's rights under this Lease.

(i) **Taxes.** Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall pay any taxes, assessments, fines, fees, and other charges levied by any governmental authority against its Facilities on the Leased Premises. The Parties agree to cooperate fully to obtain any available tax refunds or abatements with respect to 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.

(j) **Amendments.** Lessee reserves the right to revise this Lease to remedy any mistakes, including correcting the names of the Parties, the legal description of the Leased Premises, or otherwise. In the event that any amendment alters the bonus and royalty payable under Section 5(a)-(b) of this Lease, the Lessee shall pay the Lessor the amount owed under the Lease as amended. Any amendments must be in writing and signed by both parties.

(k) **Remedies.** Notwithstanding anything to the contrary in this Lease, neither Party shall be liable to the other for any indirect, special, punitive, incidental or exemplary damages, whether foreseeable or not and whether arising out of or in connection with this Lease, by statute, in contract, tort, including negligence, strict liability or otherwise, and all such damages are expressly disclaimed.. This provision does not limit Lessee's obligation to indemnify Lessor for third-party suits, claims, or damages under Section 16 of this Lease.

(l) **Financial Responsibility.** Lessee will comply with all applicable law regarding financial responsibility for Carbon Dioxide storage, and will post bonds or other financial guarantees as required by the government entities.

(m) **Attorneys' Fees.** If any suit or action is filed or arbitration commenced by either Party against the other Party to enforce this Lease or otherwise with respect to the subject matter of this Lease, the prevailing party shall be entitled to recover reasonable costs and attorneys' fees incurred in investigation of related matters and in preparation for and prosecution of such suit, action, or arbitration as fixed by the arbitrator or court, and if any appeal or other form of review is taken from the decision of the arbitrator or any court, reasonable costs and attorneys' fees as fixed by the court.

(n) **Representations and Warranties.** Lessor represents and warrants to Lessee the following as of the Effective Date and covenants that throughout the Term: (i) Lessor has the full right, power and authority to grant rights, interests and license as contained in this Lease. Such grant of the right, interests and license does not violate any law, ordinance, rule or other governmental restriction applicable to the Lessor or the Leased Premises and is not inconsistent with and will not result in a breach or default under any agreement by which the Lessor is bound or that affects the Leased Premises. (ii) Neither the execution and delivery of this Lease by Lessor nor the performance by Lessor of any of its obligations under this Lease conflicts with or will result in a breach or default under any agreement or obligation to which Lessor is a party or by which Lessor or the Leased Premises is bound. (iii) All information provided by Lessor to Lessee, as it pertains to the Leased Premises' physical condition, along with Lessor's rights, interests and use of the Leased Premises, is accurate in all material respects. (iv) Lessor has no actual or constructive notice or knowledge of Hazardous Substances at, on, above, below or near the Leased Premises. (v) Each of the undersigned represents and warrants that they have the authority to execute this Lease on behalf of the Party for which they are signing.

(o) **Severability.** Should any provision of this Lease be held, in a final and unappealable decision by a court of competent jurisdiction, to be either invalid, void or unenforceable, the remaining provisions of this Lease shall remain in full force and effect, unimpaired by the holding. If the easements or other rights under this Lease are found to be in excess of the longest duration permitted by applicable law, the term of such easements or other rights shall instead expire on the latest date permitted by applicable law.

(p) **Memorandum 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 is situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

(q) **Notices.** All notices required to be given under this Lease shall be in writing, and shall be deemed to have been given upon (a) personal delivery, (b) one (1) Business Day after being deposited with FedEx or another reliable overnight courier service, with receipt acknowledgment requested, or (c) upon receipt or refused delivery deposited in the United States mail, registered or certified mail, postage prepaid, return receipt required, and addressed to the respective Party at the addresses set forth at the beginning of this Lease, or to such other address as either Party shall from time to time designate in writing to the other Party.

(r) **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.

(s) **Estoppels.** Either party hereto (the "Receiving Party"), without charge, at any time and from time to time, within ten (10) Business Days after receipt of a written request by the other party hereto (the "Requesting Party"), shall deliver a written statement, duly executed, certifying to such Requesting Party, or any other person, firm or entity specified by such Requesting Party: (i) that this Lease is unmodified and in full force and effect, or if there has been any modification, that the same is in full force and effect as so modified and identifying the particulars of such modification; (ii) whether or not, to the knowledge of the Receiving Party, there are then existing any offsets or defenses in favor of such Receiving Party against enforcement of any of the terms, covenants and conditions of this Lease and, if so, specifying the particulars of same and also whether or not, to the knowledge of such Receiving Party, the Requesting Party has observed and performed all of the terms, covenants and conditions on its part to be observed and performed, and if not, specifying the particulars of same; and (iii) such other information as may be reasonably requested by the Requesting Party. Any written instrument given hereunder may be relied upon by the recipient.

(t) **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.

(u) **Governing Law.** This Lease shall be governed, interpreted, and enforced in accordance with the laws of the state of North Dakota.

(v) **Further Action.** Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of easement and all documents required to obtain any necessary government approvals.

(w) **Entire Agreement.** This Lease, into which the attached **Exhibit A** is incorporated by reference, contains the entire agreement of the Parties. There are no other conditions, agreements, representations, warranties, or understandings, express or implied.

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

IN WITNESS OF THE ABOVE, Lessor and Lessee have caused this Lease to be executed and delivered by their duly authorized representatives as of the Effective Date.

LESSOR:

By:____________________________________
Print:__________________________________

By:____________________________________
Print:__________________________________

LESSEE:

MINNKOTA POWER COOPERATIVE, INC.

By:____________________________________
Print:__________________________________
Its:____________________________________

Exhibit A

LEGAL DESCRIPTION OF THE PROPERTY

The Leased Premises consists of the lands located in Oliver County, North Dakota that are owned by the Lessor and generally described as follows:

For purposes of calculating the royalty payable under Section 5(b) of this Lease, the Parties stipulate that the Leased Premises consists of ____________ acres.

73933018.1

APPENDIX I

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

<table>
<tr><th>Permit Item</th><th>NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description</th></tr>
<tr><td rowspan="7">Pore Space Amalgamation</td><td rowspan="7">NDCC
38-22-06
§3 & 4

NDAC
43-05-01-08
§1 & 2</td><td rowspan="7">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 [0.80 kilometer] of its outside boundary;

b. Each mineral lessee of record within the facility area and within one-half mile [0.80 kilometer] of its outside boundary;</td><td>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;</td><td>Minnkota Power Cooperative, Inc. (Minnkota) 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. Minnkota 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.</td><td></td></tr>
<tr><td>b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;</td><td rowspan="6">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 required by North Dakota statute for geologic storage of carbon dioxide (CO2) to make a good faith attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith attempt, it was able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of the pore space. 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, Minnkota submits the form of storage agreement attached hereto as Appendix H 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.

1.1 Storage Reservoir Pore Space
Minnkota Power Cooperative, Inc. (Minnkota) defines the proposed storage reservoir boundaries as the projected vertical and horizontal migration of the CO2 plume from the start until the end of injection. The storage reservoir vertical and horizontal boundaries are identified based on the computational model output of the areal extent of the CO2 plume volume at the end of the injection period (20 years), in which a CO2 saturation is predicted to be greater than or equal to 5%. The model utilizes applicable geologic and reservoir engineering information and analysis as detailed in Section 2.0 and Appendix A.

The operation inputs for the simulation scenarios assumes storage at the average designed injection rates, approximately 4.0 MMt/year injected into the Broom Creek storage reservoir for the first 15 years of operation and 3.5MMt/year for year 15 through year 20 of operation. The operation input for the Black Island–Deadwood simulation scenario assumes storage at the maximum designed injection rate of approximately 1.17 MMt/year for 20 years. These maximum rates were based on Minnkota's consideration of the planned maintenance, outage, and operating capacity of the Milton R. Young Station (MRYS) and carbon capture equipment along with the planned maintenance requirements and testing requirements of the Tundra SGS (secure geologic storage) site equipment. During Phase 1 operation of the Broom Creek storage facility, Minnkota will conduct ongoing validation and assessment of need for construction and operation of the Black Island–Deadwood.

1.1.1 Horizontal Boundaries
The proposed horizontal boundaries of the storage reservoirs, including an adequate buffer area, are defined by the simulated migration of the CO2 plume, using the actual rate of injection from the start until the end of injection. In establishing the definite boundaries of the storage facility area, Minnkota considered the characteristics and external factors influencing the operating life of the project, the opportunity for phased development of stacked storage facilities, and the coordinated operation of Broom Creek and Deadwood storage facilities if needed. The horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off the maximum design life of the carbon capture equipment. The reservoir models will be updated regularly with operating data and the operator will provide evidence of the CO2 plume migration as part of the reevaluations required under NDAC §§ 43-05-01-05.1 and 43-05-01-</td><td>Figure 1-1. Deadwood storage facility area map.</td></tr>
<tr><td>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;</td><td>Figure 1-1. Deadwood storage facility area map.</td></tr>
<tr><td>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;</td><td>Figure 1-1. Deadwood storage facility area map.</td></tr>
<tr><td>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;</td><td></td></tr>
<tr><td>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;</td><td>Table 1-1. Owners, Lessees, and Operators Requiring Pore Space Hearing Notification</td></tr>
<tr><td>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.</td><td>Table 1-2. Mineral Owners, Mineral Lessees and Operators Requiring Hearing Notification</td></tr>
</table>

		c. Each owner of record of the surface within the facility area and one-half mile [0.80 kilometer] of its outside boundary; d. Each owner of record of minerals within the facility area and within one-half mile [0.80 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 [0.80 kilometer] of the reservoir's boundary; and 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.		11.4. These reevaluations are to occur no later than every 5 years, thus the simulation output at 5 years of operation is indicated in Figure 1-1 to exemplify the buffer existing within the proposed storage facility area, allowing safe operation as proposed and contemplated. The stacked storage operations scenario option allows for coordination of the capacity of the Black–Island Deadwood with the Broom Creek capacity and provides further assurance of the contemplated operation within the defined storage reservoir boundary. The simulated horizontal storage reservoir boundary results proposed for the Deadwood Formation are depicted in Figure 1-1. ***1.1.2 Vertical Boundaries*** The Tundra SGS site was designed using a stacked storage concept, where two storage reservoirs identified with varying vertical depths could be accessed by a common well site. A key benefit of this development approach is to minimize the surface land use impact by reducing the amount of surface facilities required for operation. Despite the significant overlap of pore space area between the Broom Creek and Deadwood reservoirs, two distinct SFPs are being requested, with the distinct vertical boundaries based upon geologic analysis and simulations which are further detailed and described in Section 2.0 of the respective SFP application supporting information. The applicant requests amalgamation of the injection zone pore space within the Black Island, Deadwood E-member, and Deadwood C-member Sand intervals, as identified in Section 2.0, Figure 2-3. In addition to the injection zone, the applicant requests the permitted storage facility consist of the Icebox Formation as the upper confining zone and Deadwood B member shale as the lower confining zone (Section 2.0, Figure 2-3). **1.2 Persons Notified** Minnkota will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 mi of its outside boundary. Minnkota will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to 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 in accordance with North Dakota law (NDCC Chapter 47-31): • A map showing the extent of the pore space that will be occupied by the CO2 plume over the injection period, including the storage reservoir boundary and 0.5 mi (0.8 km) outside of the storage reservoir boundary with a description of the pore space ownership, surface owner, and pore space lessees of record (Figure 1-1). • A table identifying all pore space (surface) owners, and lessees of pore space of record, their mailing addresses, and legal descriptions of their pore space landownership (Table 1-1). • A table identifying each owner of record of minerals, mineral lessees and operators of record (Table 1-2).	
Geologic Exhibits	NDAC 43-05-01-05 §1b(1) and §1b(2)(k)	**NDAC 43-05-01-05 §1b(1) and §1b(2)(k)** (1) The name, description, and	a. Geologic description of the storage reservoir: Name Lithology	**2.3 Storage Reservoir (injection zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment	Figure 2-8. Areal extent of the Deadwood Formation in North Dakota (modified from Nesheim, 2012b).

		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;	Average depth Average thickness	(Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base. • The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic. • The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area. • The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). <u>For additional information, go to Section 2.3 of the Tundra SGS SFP.</u>	Figure 2-9. Type log showing the interpreted Deadwood members within the Williston Basin (Lefever and others, 1987). Figure 2-10. Isopach map of the Black Island and Deadwood Formations in the simulation model extent. Figure 2-11. Well log display of the interpreted lithologies of the Roughlock, Icebox, Black Island, Deadwood, and Precambrian in J-ROC1. Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue). Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent. Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level. Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex. Table 2-6. Deadwood Microfracture Results from J-LOC1

Table 2-1. Formations Comprising the Tundra SGS CO_2 Storage Complex

	Formation	Purpose	Average Thickness at Tundra SGS Site, ft	Average Depth Tundra SGS Site, ft TVD	Lithology
Storage Complex	Icebox	Upper confining zone	118 (58 to 176)	9,308	Shale
	Black Island and Deadwood E member	Storage reservoir (i.e., injection zone)	118 (35 to 202)	9,427	Sandstone, shale, dolostone, limestone
	Deadwood C member sand	Storage reservoir (i.e., injection zone)	64 (40 to 88)	9,773	Sandstone
	Deadwood B member shale	Lower confining zone	34 (20 to 49)	9,791	Shale

NDAC 43-05-01-05 §1b(2)(k)

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;

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
   - Facies changes

2.3 Storage Reservoir (injection zone)
Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3).

At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10).

The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11):

- The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area.
- The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections.
- The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area.
- The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base.
- The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic.
- The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic.

Figure 2-8. Areal extent of the Deadwood Formation in North Dakota (modified from Nesheim, 2012b).

Figure 2-9. Type log showing the interpreted Deadwood members within the Williston Basin (Lefever and others, 1987).

Figure 2-10. Isopach map of the Black Island and Deadwood Formations in the simulation model extent.

Figure 2-11. Well log display of the interpreted lithologies of the Roughlock, Icebox, Black Island, Deadwood, and Precambrian in J-ROC1.

Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log.

Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue).

Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent.

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

- The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area.
- The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13).

For additional information, go to section 2.3 of the Tundra SGS SFP.

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	Black Island, Deadwood E member, and Deadwood C-sand member		
Lithology	Sandstone, dolostone, limestone		
Formation Top Depth, ft	9782.2, 9820.9, and 10,077.4		
Thickness, ft	38.9, 92.3, and 60.9		
Capillary Entry Pressure (CO_2/brine), psi	0.16		
Geologic Properties			
Formation	**Property**	**Laboratory Analysis**	**Model Property Distribution**
Black Island (sandstone)	Porosity, %*	8.0 (3.4–10.3)	5.6 (1.1–14.8)
	Permeability, mD**	3.7 (0.0019–157)	0.805 (<0.0001–96.0)
Deadwood E Member (sandstone)	Porosity, %	10 (6.85–14.43)	7.0 (0–17.7)
	Permeability, mD	5.63 (0.0325–2,060)	3.88 (<0.0001–4549.2)
Deadwood C-Sand Member	Porosity, %	7.6 (1.01–14.69)	7.6 (0.3–17.2)
	Permeability, mD	11 (0.0018–1140)	7.03 (<0.0001–830.3)

Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level.

Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex.

Table 2-6. Deadwood Microfracture Results from J-LOC1

Figure 2-16. J-LOC1 Deadwood Formation MDT microfracture in situ stress pump cycle graph at 9,885.1 ft.

Figure 2-17. Step rate test data from the Deadwood Formation with no fracture opening pressure observed (courtesy of GeothermEx, a Schlumberger Company). The x-axis is injection rate in bpm while the y-axis is bottomhole injection pressure in psi.

Figure 2-18. GeothermEx interpretation of the Deadwood Formation pressure fall-off test using Saphir – Kappa (courtesy of GeothermEx, a Schlumberger Company).

Figure 2-19. Deadwood well test summary of J-LOC1 well (modified from Schlumberger's presentation).

Table 2-7. J-LOC1 Deadwood Formation Test Summary

Figure 2-20. Laboratory-derived mineralogic characteristics of the Black Island and Deadwood Formations.

Figure 2-21a. XRF data from the Black Island Formation from J-LOC1.

Figure 2-21b. XRF data from the Upper Deadwood Formation, including the C, D, and E members from J-LOC1.

Table 2-8. XRD Results for JLOC-1 Deadwood Formation Core Samples

Table 2-9. Deadwood Formation Water Ionic Composition, expressed as molality

Figure 2-22. The upper graph shows cumulative injection vs. time. There is an increase in injection due to geochemical

2.3.1 J-LOC1 Injectivity Tests

The J-LOC1 formation well testing was performed specifically to characterize the injectivity and obtain the breakdown pressure of the Deadwood Formation in December 2020. The well testing consisted of step rate test, extended injection test, and pressure fall-off test. The well was perforated from 9,880 to 9,890 ft with 4 shots per foot (spf) and 90° phasing. To record the bottomhole pressure, a downhole memory gauge was installed at a depth of 9,855 ft. The well test data were interpreted by GeothermEx, a Schlumberger Company.

The step rate test was performed with a total of ten injection rates. The initial injection rate was 2.00 barrels per minute (bpm), and the final injection rate was 10.5 bpm. From the step rate test evaluation, no definitive analysis can be concluded from this test, but injection at the higher rate was below fracture opening pressure. Figure 2-17 provides the step rate test data of the Deadwood Formation.

A 12-hour extended injection rate was performed at a constant rate of 4.5 bpm followed by a 24-hour pressure fall-off test. The pressure fall-off data interpretation showed a permeability of 1,621 mD, with reservoir pressure of 4,521 psi. There was no lateral boundary observed from the pressure fall-off test within the radius of investigation of 9,183 ft, as shown in Figures 2-18 and 2-19. The Deadwood Formation well testing is summarized in Table 2-7.

2.3.2 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Deadwood Formation is composed of fine- to medium-grained sandstone and several interbeds of carbonates (dolostone and limestone). Seventy-eight depth intervals representing nearly 274 ft of the Deadwood Formation were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. For the assessment below, thin sections and XRD provided an independent confirmation of the mineralogical constituents of the Deadwood Formation.

Thin-section analysis of the sandstone intervals shows that quartz (85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (5%), dolomite (5%), and calcite as cements (5%). Where present, calcite and dolomite are crystallized between quartz grains and obstruct the intercrystalline porosity. The contact between grains is long (straight) to tangential. The porosity due to quartz and feldspar dissolution ranges from 5% to 14%.

Four distinct carbonate intervals are notable. The first is the presence of a fine- to medium-grained dolostone (80%), with quartz of variable size and shape (10%) and calcite (10%) present. The porosity is not well-developed, averaging 5%. Diagenesis is expressed by dolomitization of the original calcite grains and dissolution of quartz 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 limestone (80%), dolomite 10%, and quartz (10%). Diagenesis is expressed by dolomitization of the original calcite grains. The porosity is mainly fracture-related and averages 2%.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Deadwood Formation core primarily comprises quartz, feldspar, dolomite, calcite, anhydrite, clay, and iron oxides (Figure 2-20).

XRF data are shown in Figure 2-21a and 2-21b for the Black Island and Upper Deadwood Formations. As shown, the majority of the Upper Deadwood sandstone, calcite, and dolomite intervals are confirmed through the high percentages of SiO_2, CaO, and MgO. The presence of certain percentages of CaO and SO_3 at 10,077 ft indicates a presence of anhydrite as cement. The formation shows very little clay, with a range of 0.5% to 10% being the highest detected.

2.3.3 Mechanism of Geologic Confinement

For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Deadwood Formation will be the cap rock (Icebox interval), 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), confining the CO_2 within the proposed storage reservoir, as identified in Figure 2-3. 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 (>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; therefore, this process 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.

reactions. The lower graph shows wellhead injection pressure for the geochemistry case is slightly lower than for the injection case without geochemistry.

Figure 2-23. Geochemistry case simulation results after 20 years of injection showing the distribution of CO_2 molality. Upper images are west–east and north–south cross sections. Lower image is a planar view of Simulation Layer 8.

Figure 2-24. Geochemistry case simulation results after 20 years of injection showing the pH of formation brine.

Figure 2-25. Dissolution and precipitation quantities of reservoir minerals due to CO_2 injection. Dissolution of illite and anhydrite with precipitation of calcite, quartz, and dolomite was observed. K-feldspar dissolves during the injection period but slowly begins to reprecipitate after injection.

Figure 2-26. Molar distribution of illite, the most prominent dissolved mineral at the end of the injection period, shown in green. Compare to the molar CO_2 distribution in Figure 2-23.

Figure 2-27. Molar distribution of calcite, the most prominent precipitated mineral at the end of the injection period. Compare to the molar CO_2 distribution in Figure 2-23.

Figure 2-28. Change in porosity due to net geochemical dissolution after the 20-year injection period. Maximum porosity change is less than 0.1%. Compare to the molar CO_2 distribution in Figure 2-22.

2.3.4 Geochemical Information of Injection Zone
Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream into the injection zone. The effects have been found to be minor and not threatening to the geologic integrity of the storage system.

The injection zone, the Upper Deadwood sands and Black Island 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 injection scenario was rerun with the geochemical analysis option included, and the differences were compared to the scenario that was run without the geochemical option included. Geochemical alteration effects were seen in the geochemistry case, as described below. However, these effects were not significant enough to cause meaningful change to storage reservoir performance or mechanical properties of the storage formation.

The geochemistry case was constructed using the injection case simulation inputs and assumptions as well as honoring the average mineralogical composition of the Deadwood Formation rock materials (94% of bulk reservoir volume) and average formation brine composition (6% of bulk reservoir volume). XRD data from the JLOC-1 well core samples were used to inform the mineralogical composition of the Deadwood Formation used in the geochemical modeling (Table 2-8). The ionic composition of the formation water is listed in Table 2-9. The injection stream composition remained the same as the injection case simulation, assumed as 100% CO_2. The injection stream is expected to be 99.9% CO_2. The other constituents represent 0.1% in the stream and likely include nitrogen (N_2) and water vapor (H_2O). However, 100% CO_2 was assumed for computational efficiency in the geochemical simulation to investigate rock and fluid interaction in the saline storage formation. N_2 is known to be an inert gas, and water is already in the saline storage formation and will have little to no impact on the geochemical reactions. In the injection stream, argon (Ar) and oxygen vapor (O_2) may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation. The geochemistry case was run for the 20-year injection period followed by 94 years of postinjection shutdown and monitoring.

Figure 2-22 shows that reservoir performance results for the two cases are slightly different. As a result of geochemical reactions in the reservoir, there is an approximately 8% increase in cumulative injection potential. Wellhead injection pressure is slightly lower for the geochemistry case. Figure 2-23 shows the concentration of CO_2, in molality, in the reservoir after 20 years of injection. The pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-24. The pH of the Deadwood native brine is 5.7 whereas the fluid pH declines to approximately 4.0 in the CO_2-flooded areas.

Figure 2-25 shows the mass of mineral dissolution and precipitation due to geochemical reactions in the model. Illite is the most prominent dissolution mineral, followed by anhydrite. Illite and anhydrite dissolution slows after Year 2042, the year in which injection ends. K-feldspar dissolves during the injection period but slowly begins to reprecipitate in the near-wellbore areas after injection. Calcite, quartz, and dolomite are the primary precipitation minerals. There is a small amount of net dissolution during the simulation period as somewhat larger quantities of minerals are dissolved rather than precipitated. Slow net dissolution continues after the injection period. Figures 2-26 and 2-27 provide an indication of the change in distribution of the mineral that has experienced the most dissolution (illite) and the mineral that has experienced the most precipitation (calcite), respectively. Considering the apparent net dissolution of minerals in the system, as indicated in Figure 2-25, there is an associated net increase in porosity of the affected area, as shown in Figure 2-28. However, the porosity change is small, less than 0.1% porosity units, equating to a maximum increase in average porosity from 6% to 6.1% after the 20-year injection period.

Results of the simulation show that geochemical processes will be at work in the Deadwood Formation during and after CO_2 injection. Mineral dissolution and some reprecipitation are expected to occur during the simulated time span of 114 years. Fluid pH will decrease in the area of the CO_2 accumulation from 5.7 to approximately 4.0, and there will be a slight net increase in system porosity. However, these changes create relatively small changes in reservoir performance parameters such as injection rate or wellhead injection pressure.

Table 2-8. XRD Results for JLOC-1 Deadwood Formation Core Samples

Mineral Data	Average %
Calcite	25.85
Dolomite	12.78
Quartz	32.94
Illite	4.7
K-Feldspar	8.54
Anhydrite	5.18
Ankerite	3.97
Other	6.04

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 Deadwood and Black Island Formations are the overlying Icebox Formation and underlying Deadwood B member shale (Figure 2-3, Table 2-10). All three units, the Icebox Formation, Deadwood B member shale, and Precambrian basement, consist of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones at the J-LOC1 Well

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Icebox	Deadwood B member shale
Lithology	Shale	Shale
Formation Top Depth, ft	9,308	9,791
Thickness, ft	118	34
Porosity, % (core data)*	3.6***	2.0
Permeability, mD (core data)**	0.00002***	0.0103
Capillary Entry Pressure (CO_2/brine), psi	845	176****
Depth Below Lowest Identified USDW, ft	8,097	8,580

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Icebox consists of shale. This upper confining zone is laterally extensive across the project area (Figures 2-29 and 2-30) 9,308 ft below the land surface and 118 ft thick at the Tundra SGS site (Table 2-10 and Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The contact between the underlying sandstone of the Black Island Formation is conformable and can be correlated across the project area. The transition from the Icebox to the Black Island is indicated by a relatively low GR, low neutron, high density, and low compressional sonic across the contact (Figure 2-32).

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 wellbore. Microfracture stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

For the J-LOC1 well, in the Icebox Formation at 9,749.5 and 9,751.2 ft, the MDT tool was unable to cause a breakdown in the formation with an applied maximum injection pressure of 10,984.9 and 10,867.24 psi, respectively

Table 2-10. Properties of Upper and Lower Confining Zones at the J-LOC1 Well

Figure 2-29. Areal extent of the Icebox Formation in western North Dakota (modified from Nesheim, 2012a).

Figure 2-30. Structure map of the upper confining zone across the simulation model extent.

Figure 2-31. Isopach map of the upper confining zone across the simulation model extent.

Figure 2-32. Well log display of the upper confining zone at the J-ROC1 well.

Figure 2-33. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,749.5 ft.

Figure 2-34. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,751.2 ft.

Table 2-11. Icebox Core Sample Porosity and Permeability from J-LOC1

Table 2-12. XRF Data for the Icebox Formation from the J-LOC1 Well

Table 2-13. Mineral Composition of the Icebox Formation Derived from XRD Analysis of JLOC-1 Core Samples (9773 ft MD)

Table 2-14. Formation Water Chemistry from Deadwood Formation Fluid Samples from JLOC-1

				(Figures 2-33 and 2-34). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent and exhibits sufficient geologic integrity to contain the injected CO_2 stream. The Icebox Formation was not suitable to collect competent core samples from the J-LOC1 well core for the purposes of porosity and permeability laboratory tests; the samples would crush in the equipment. The formation was found to be tight, and porosity and permeability estimates were derived from HPMI testing for one sample (Table 2-11). The lithology of the cored sections of the Icebox Formation is primarily shale, with minor pyrite. *2.4.1.1 Mineralogy* Thin-section investigation shows that the Icebox Formation is primarily shale. Thin sections were created from the base of the Icebox and the shales present in the Black Island Formation. The shales present in the Black Island Formation have characteristics similar to the shales of the Icebox Formation. The mineral components present are clay, quartz, feldspar, and iron oxides. The quartz grains are always surrounded by a clay matrix. The porosity and permeability measurements could not be performed because of the fissility of the rock. The porosity was estimated from HPMI analysis and equaled 3.6%. Log interpretations (Figure 2-31) and visual inspection of the collected core validate consistent mineral assemblage within the Icebox and Black Island Formations. XRD data from the J-LOC1 well core supported facies interpretations from core descriptions and thin-section analysis. The Icebox Formation comprises clay, quartz, feldspar, and iron oxides. XRF analysis of the Icebox Formation identified the major chemical constituents to be dominated by SiO_2 (53%), SO_3 (1.6%), CaO (0.26%), Al_2O_3 (24%), and MgO (1.9%), correlating well with the silicate- and aluminum-rich mineralogy determined by XRD (Table 2-12). This correlates with XRD, core description, and thin-section analysis. *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 Icebox Formation, the primary confining zone for the Deadwood Formation. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. The results were calculated at grid cell centers located at 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Icebox was honored (Table 2-13). The formation brine composition was assumed to be the same as the known composition from the Deadwood injection zone below (Table 2-14). The injection stream composition was as described by Minnkota Power Cooperative (Minnkota) (Table 2-15). Three different exposure levels, expressed in moles per year, 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 expected actual exposure levels. This overestimate 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. The results showed relatively minor geochemical processes at work. Figures 2-35, 2-36, and 2-37 show results from the most extreme exposure case. Figure 2-35 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 and stabilizes at a level of 4.9. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 8. The pH is unaffected in Cell C3. Figure 2-36 shows change in mineral dissolution and precipitation in grams per cubic meter of rock. Dashed lines are for Cell C1, solid lines that are seen in the figure are from Cell C2, 1.0 to 2.0 meters into the cap rock. Any effects in Cell C3 are too small to represent at this scale. In Cell C1, K-feldspar is the primary dissolution mineral, which is primarily replaced by precipitation of illite, quartz, and montmorillonite. Similar, but lesser, effects are seen in Cell C2. Figure 2-37 shows change in porosity of the Icebox cap rock. During an initial model stabilization period, Cell C1 experiences an increase in porosity due to K-feldspar dissolution. However, the porosity gradually returns to its initial condition by Year 10. As the porosity scale shows, these changes are small, less than 0.0013 porosity units. Cells C2 and C3 experience no significant change in porosity during the 45 years of the simulation. The small net porosity changes from dissolution and precipitation in Cells C1 and C2, with essentially zero observed effect on Cell C3, suggest that geochemical change from exposure to CO2 is very minor and will not cause substantive deterioration of the Icebox cap rock.	Table 2-15. Injection Stream Composition Figure 2-35. Change in fluid pH vs. time. Red line shows pH for the center of Cell C1 at 0.5 meters above the base of the Icebox cap rock. Yellow line shows Cell C2 at 1.5 meters above the cap rock base. Green line shows Cell C3 at 2.5 meters above the cap rock base. Figure 2-36. Dissolution and precipitation of minerals in the Icebox cap rock. Dashed lines show results calculated for Cell C1 at 0.5 meters above the cap rock base. Solid lines show results for Cell C2 at 1.5 meters above the cap rock base. Results from Cell C3 at 2.5 meters above the caprock base are not shown as they are too small to be seen at this scale. Figure 2-37. Change in percent porosity of the Icebox cap rock. Red line shows porosity change calculated for Cell C1at 0.5 meters above the cap rock base. Yellow line shows Cell C2 at 1.5 meters above the cap rock base. Green line shows Cell C3 at 2.5 meters above the cap rock base. Long-term change in porosity is minimal. Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well) Figure 2-38. Isopach map of the interval between the top of the Black Island Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. Figure 2-39. 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 2-40. Structure map of the Deadwood B member shale across the greater Tundra SGS area. Figure 2-41. Isopach map of the Deadwood B member shale across the Tundra SGS area. Table 2-17. Deadwood B Member Shale Core Sample Porosity and Permeability from J-LOC1

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Icebox. Impermeable rocks above the primary seal include the Roughlock Formation and the Red River D member, which make up the first additional group of confining formations (Table 2-16). Together with the Icebox, these formations are 612 ft thick and will isolate the Deadwood/Black Island Formations fluids from migrating upward into the next permeable interval, the Red River A, B, and C members (see Figure 2-38). Above the Red River Formation, >1,000 ft of impermeable rocks act as an additional seal between the Red River and Broom Creek, the next proposed storage complex, 876 ft of impermeable rocks separate the Broom Creek from the Inyan Kara and an additional 2,545 ft of impermeable rocks separates the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-39). Confining layers above the Inyan Kara include the Skull Creek, Newcastle, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

No known transmissible faults are within these confining systems in the project area. These formations between the Deadwood, 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 (Downey, 1986; Downey and Dinwiddie,1988).

Carbonates of the Red River A, B, and C members comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Red River represents the most likely candidate to act as an overlying pressure dissipation zone. The depth to the Red River Formation in the project area is approximately 8,438 ft, and the formation itself is about 450 ft thick. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Red River Formation. Monitoring DTS (distributed temperature sensor) data for the Red River Formation using the downhole fiber optic cable in the proposed monitor well provides an additional opportunity for mitigation and remediation (Section 4.0).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444
Opeche	Shale/mudstone	4,685	55	3,535
Amsden	Dolostone/anhydrite	4,974	247	3,824
Kibbey Lime	Limestone	5,384	31	4,234
Charles	Limestone/anhydrite	5,526	147	4,376
Bakken	Shale	6,926	10	5,776
Birdbear	Limestone	7,075	74	5,925
Duperow	Limestone/dolostone	7,149	272	5,999

Table 2-18. XRF Data for the Deadwood B Shale from the J-LOC1 Well

Table 2-19. Mineral Composition of the Deadwood B Shale, derived from XRD analysis of JLOC-1 core samples Deadwood B Shale (10, 144 ft)

Figure 2-42. Change in fluid pH in the Deadwood B shale underlying confining layer. The red line shows the pH calculated at the center of Cell C1 at 0.5 meters below the Deadwood B top. The green line shows Cell C5 at 4.5 meters below the Deadwood B top.

Figure 43. CO_2 concentration (molality) in the Deadwood B shale underlying confining layer for Cells C1–C19.

Figure 2-44. Dissolution and precipitation of minerals in the Deadwood B underlying confining layer. Dashed lines show results for Cell C1 at 0 to 1 meter below the Deadwood B top. Solid lines show results for Cell C2 at 1 to 2 meters below the Deadwood B.

Figure 2-45. Change in percent porosity in the Deadwood B underlying confining layer. The red line shows porosity change for Cell C1 at 0 to 1 meter below the Deadwood B top. The yellow line shows Cell C2 at 1 to 2 meters below the Deadwood B top. The green line shows Cell C3 at 2 to 3 meters below the Deadwood B top. Long-term change in porosity is minimal and stabilized. Cells C4–C19 showed similar results, with net porosity change being less than 0.3%.

Souris River	Dolostone/limestone	7,421	175	6,271
Dawson Bay	Dolostone	7,596	729	6,446
Gunton	Dolostone/limestone	8,325	39	7,175
Stoughton	Shale/limestone	8,364	91	7,214
Lower Red River	Limestone	8,645	488	7,495
Roughlock	Shale/limestone	9,133	25	7,983

2.4.3 Lower Confining Zones

The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member shale consists predominantly of shale with a consistent and correlative package of higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic across the project area. The shale within the Deadwood B member is 9,791 ft below the surface and 34 ft thick at the Tundra SGS site (Figures 2-40 and 2-41, Table 2-10).

At 144 ft below the top of the Deadwood C-sand is an 80-ft-thick shaly layer of the Deadwood B member. Data acquired from the core plug samples taken from the Deadwood B member show porosity values ranging from 1.55% to 2.63% and permeability values from 0.0083 to 0.0177 mD (Table 2-17).

2.4.3.1 Mineralogy

Thin-section analysis and well logs show that the Deadwood B interval comprises carbonates and shale facies. The carbonates are composed mainly of calcite minerals and fossils and then by feldspar and quartz. The Deadwood B shows a tight formation characteristic where the permeability ranges from 0.0094 and 3.18 mD and porosity ranges from 1% to 8%.

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

XRF data show the Deadwood B shale mainly comprises CaO (35%), SiO_2 (30%), and Al_2O_3 (4%) (Table 2-18).

2.4.3.2 Geochemical Interaction

The Deadwood C-sand's underlying confining layer, the Deadwood B, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of five cells, each cell 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation and allowed to enter the system by advection and dispersion processes. The results were calculated at the center of each cell below the confining layer–CO_2 exposure boundary. The mineralogical composition of the Deadwood B was honored (Table 2-19). Formation brine composition was assumed the same as the known composition from the Deadwood sand injection zone above (previously shown in Table 2-14). The injection stream composition was as described by Minnkota (Table 2-15). The Deadwood B Formation temperature and pressure were adjusted from the Deadwood sand reservoir temperature and pressure conditions, 188°F and 4,357 psi, respectively. Two different pressure levels, 4,357 and 4,652 psi, were applied to the CO_2-saturated brine at the base of the Deadwood sand. These values represent the initial and potential pore pressure levels. The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. These simulations were run for 45 years to represent 20 years of injection plus 25 years postinjection.

The results showed geochemical processes at work. Figures 2-42, 2-43, 2-44, and 2-45 show findings from the high-pressure, more extreme exposure case. Figure 2-42 shows change in fluid pH over 45 years of simulation time as CO_2 enters the system. Initial change in pH in all the cells from 6 to 5.8 is related to initial equilibration of the model. For the cell at the CO_2 interface, C1, the pH declines from its initial level of 6.0 to 5.3 after 4 years of injection and slowly declines further to 4.4 after the 25-year postinjection period. Similar, but progressively slower, pH change occurs for each cell that is more distant from the CO_2 interface. The pH for Cells 10–19 did not decline over the 45 years of simulation time. Figure 2-43 shows that CO_2 does not penetrate more than 9 meters (represented by Cell C9) within the 45 years simulated.

Figure 2-44 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For Cell C1, K-feldspar is the primary dissolution mineral, with minor chlorite. Illite and quartz precipitation largely replace that dissolution. The reaction rate in the C1 cell dramatically slows after approximately 9 years, and cell geochemistry

				stabilizes. As Cell C1 stabilizes, dissolution and precipitation begin in Cell C2, with minor amounts of chlorite dissolving and modest precipitation of dolomite. Change in porosity (% units) of the Deadwood B underlying confining layer is displayed in Figure 2-45. The overall net porosity changes from dissolution and precipitation are minimal, less than a 0.2% change during the life of the simulation. Cell C1 shows an initial porosity increase of 0.1%, but this change is temporary, and the cell returns to its near- end of the simulation, no significant net porosity changes were observed for these cells. These results suggest that the Deadwood B will not undergo significant geochemical change in the presence of CO_2 injection.	
	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 pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of		For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Deadwood Formation will be the cap rock (Icebox interval), which will contain the initially buoyant CO_2 under the effects of relative permeability and and solubility trapping (dissolution of the CO_2 into the native formation brine), confining the CO_2 within the proposed	Figure 2-20. Laboratory-derived mineralogic Figure 2-21a. XRF data from the Black Island Figure 2-21b. XRF data from the Upper Deadwood Formation, including the C, D, and

		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 one 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	***2.3.3 Mechanism of Geologic Confinement*** For Tundra SGS, the initial mechanism for geologic confinement of CO_2 injected into the Deadwood Formation will be the cap rock (Icebox interval), 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), confining the CO_2 within the proposed storage reservoir, as identified in Figure 2-3. 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 (>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; therefore, this process 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 5-mi-long seismic source test and 6.5-mi2 3D seismic survey were acquired in 2019, and a 12-mi2 3D seismic survey and 21 mi of 2D seismic lines were acquired in 2020 (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 2D seismic data provided a means to connect the two 3D seismic data sets and ensure consistent interpretation across the entire Tundra SGS area. The seismic data were used for an assessment of the geologic structure, interpretation of interwell heterogeneity, and well placement. Data products generated from the interpretation and inversion of the 3D seismic data were used as inputs into the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 4.0). The 3D seismic data and J-LOC1 and J-ROC1 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 J-LOC1 and J-ROC1 sonic logs. 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 Black Island/Deadwood storage complex in the Tundra SGS area. There were also no structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Black Island Formation observed in the seismic data. In addition, the 3D seismic data were used to gain a better understanding of interwell heterogeneity across the Tundra SGS area for petrophysical property distributions. Acoustic impedance volumes were created using the 3D seismic and petrophysical data from the J-LOC1 and J-ROC1 wells (e.g., dipole sonic and density logs) (Figure 2-7). The acoustic	Figure 2-20. Laboratory-derived mineralogic characteristics of the Black Island and Deadwood Formations. Figure 2-21a. XRF data from the Black Island Formation from J-LOC1. Figure 2-21b. XRF data from the Upper Deadwood Formation, including the C, D, and E members from J-LOC1. Figure 2-6. Map showing the 2D and 3D seismic surveys in the Tundra SGS area. Figure 2-7. Left: cross section of the inverted acoustic impedance volume for the western seismic 3D survey that transects the J-LOC1 well. The acoustic impedance log calculated from the J-LOC1 sonic and density logs is shown on the inset panel. Right: cross section of the inverted acoustic impedance volume for the eastern 3D survey.

				impedance volumes were used to classify lithofacies of the Deadwood Formation and distribute lithofacies through the geologic model as well as inform petrophysical property distribution in the geologic model.	
	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 Tundra SGS 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. Features interpreted from the 3D seismic data, including paleochannels, a flexure, and a suspected fault in the Precambrian basement, are discussed in this section as well as the data that support the low probability that these features will interfere with containment. The following section also discusses the seismic history the top of the Precambrian and the lower portion of the Deadwood (Figure 2-56 and 2-57). The isopach values depicted in Figure 2-58 suggest erosional relief on the Precambrian surface of nearly 460 ft. The absence of thickness changes in the Winnipeg or other formations overlying the Deadwood associated with these features suggest these features were filled in during the deposition of the Deadwood. In the western 3D seismic survey data, there is no indication that the identified features impact the intervals above the lower Deadwood. Additionally, there is no indication of offset reflections above or below these features in the western 3D seismic survey data that would suggest any deformation or movement associated with these features. There is no evidence to suggest that these interpreted paleochannel features have sufficient permeability or vertical extent to interfere with There is a flexure in the eastern 3D seismic data where the seismic reflections above the interpreted Precambrian–Deadwood boundary through the Red River Formation appear to dip or sag down (Figure 2-59). These depressions are interpreted to be draped over one of the interpreted paleochannels located at the Precambrian–Deadwood boundary (Figure 2-57). A deep structure was interpreted in the Precambrian basement below this paleochannel and flexure. This structure appears to be a low-dipping thrust fault that terminates at the top of the Precambrian basement (Figure 2-60). The location of this Precambrian fault provides evidence that there was likely preferential erosion along the exposed Precambrian fault trace during the deposition of the Deadwood Formation. The dip of the Precambrian fault is low-angle whereas the flexure above the paleochannel feature is near-vertical, supporting the interpretation of the fault terminating at the top of the Precambrian basement. The seismic interpretation indicates that the interpreted fault in the Precambrian basement is dipping at ~25 degrees relative to horizontal being 0 degrees. The flexure observed in the overlying sediments is likely associated with postdepositional differential compaction above the paleochannel or slump due to movement along this low-angle basement fault. There is no evidence to suggest that this flexural feature has sufficient permeability to	Figure 2-55. Map showing the time structure of the seismic reflection event interpreted to be Figure 2-56. Cross-sectional view of the 3D seismic data through one of the linear trends in the West 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). The red box indicates the area that corresponds to the linear feature. Figure 2-55 shows the Figure 2-57. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). Depressions along the top of the Precambrian suggest the presence of paleochannels. Figure 2-55 shows the location of this cross Figure 2-58. Map showing the thickness of the up through the top of the Deadwood Formation calculated using the seismic data. The linear trends correspond to areas of increased Figure 2-59. Map showing the time structure of the seismic reflection event interpreted to be the top of the Red River Formation. The line shows the location of the interpreted paleochannel that underlies the flexure. Figure 2-60. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Deadwood (blue) and Precambrian (yellow). The location of the interpreted low-angle thrust fault is shown by the green dashed line. Cross Section C-C' runs parallel to Cross Section B-B' shown in Figure
	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	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 Interpreted Features*** The analysis of 3D seismic data acquired specifically for Tundra SGS in 2019 and 2020 (Figure 2-6) revealed evidence for Precambrian and the lower portion of the Deadwood (Figure 2-56 and 2-57). The isopach values depicted in Figure 2-58	Figure 2-55. Map showing the time structure of the seismic reflection event interpreted to be Figure 2-56. Cross-sectional view of the 3D seismic data through one of the linear trends in the West 3D seismic survey. Identified

		zone in the area of review, and a determination that they would not interfere with containment;		other formations overlying the Deadwood associated with these features suggest these features were filled in during the deposition of the Deadwood. In the western 3D seismic survey data, there is no indication that the identified features impact the intervals above the lower Deadwood. Additionally, there is no indication of offset reflections above or below these features in the western 3D seismic survey data that would suggest any deformation or movement associated with these features. There is no evidence to suggest that these interpreted paleochannel features have sufficient permeability or vertical extent to interfere with containment. There is a flexure in the eastern 3D seismic data where the seismic reflections above the interpreted Precambrian–Deadwood boundary through the Red River Formation appear to dip or sag down (Figure 2-59). These depressions are interpreted to be draped over one of the interpreted paleochannels located at the Precambrian–Deadwood boundary (Figure 2-57). A deep structure was interpreted in the Precambrian basement below this paleochannel and flexure. This structure appears to be a low-dipping thrust fault that terminates at the top of the Precambrian basement (Figure 2-60). The location of this Precambrian fault provides evidence that there was likely preferential erosion along the exposed Precambrian fault trace during the deposition of the Deadwood Formation. The dip of the Precambrian fault is low-angle whereas the flexure above the paleochannel feature is near-vertical, supporting the interpretation of the fault terminating at the top of the Precambrian basement. The seismic interpretation indicates that the interpreted fault in the Precambrian basement is dipping at ~25 degrees relative to horizontal being 0 degrees. The flexure observed in the overlying sediments is likely associated with postdepositional differential compaction above the paleochannel or slump due to movement along this low-angle basement fault. There is no evidence to suggest that this flexural feature has sufficient permeability to interfere with containment.	Deadwood (blue), and Precambrian (yellow). The red box indicates the area that corresponds to the linear feature. Figure 2-55 shows the location of this cross section. Figure 2-57. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). Depressions along the top of the Precambrian suggest the presence of paleochannels. Figure 2-55 shows the location of this cross section. Figure 2-58. Map showing the thickness of the interval from the Precambrian erosional surface up through the top of the Deadwood Formation calculated using the seismic data. The linear trends correspond to areas of increased thickness. Figure 2-59. Map showing the time structure of the seismic reflection event interpreted to be the top of the Red River Formation. The line shows the location of the interpreted paleochannel that underlies the flexure. Figure 2-60. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Deadwood (blue) and Precambrian (yellow). The location of the interpreted low-angle thrust fault is shown by the green dashed line. Cross Section C-C' runs parallel to Cross Section B-B' shown in Figure 2-55 and is located 160 ft to the west of Cross Section B-B'.
	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 subsurface zones to be used for monitoring. The evaluation must	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 Tundra SGS 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. Features interpreted from the 3D seismic data, including paleochannels, a flexure, and a suspected fault in the Precambrian basement, are discussed in this section as well as the data that support the low probability that these features will interfere with containment. The following section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment. ***2.5.1 Interpreted Features*** The analysis of 3D seismic data acquired specifically for Tundra SGS in 2019 and 2020 (Figure 2-6) revealed evidence for suspected paleochannels or preferential erosional zones at the top of the Precambrian basement. Maps of the seismic reflection event interpreted to be the Precambrian–Deadwood contact suggest these features are fairly linear in nature (Figure 2-55). In cross-sectional view of the seismic data, these features appear as depressions in the top of the Precambrian and the lower portion of the Deadwood (Figure 2-56 and 2-57). The isopach values depicted in Figure 2-58 suggest erosional relief on the Precambrian surface of nearly 460 ft. The absence of thickness changes in the Winnipeg or other formations overlying the Deadwood associated with these features suggest these features were filled in during the deposition of the Deadwood.	Figure 2-55. Map showing the time structure of the seismic reflection event interpreted to be the Precambrian–Deadwood contact. Figure 2-56. Cross-sectional view of the 3D seismic data through one of the linear trends in the West 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow). The red box indicates the area that corresponds to the linear feature. Figure 2-55 shows the location of this cross section. Figure 2-57. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Roughlock (green), Deadwood (blue), and Precambrian (yellow).

		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 one 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)(m)** (m) Information on the seismic history, including the presence and depth of seismic sources and a		In the western 3D seismic survey data, there is no indication that the identified features impact the intervals above the lower Deadwood. Additionally, there is no indication of offset reflections above or below these features in the western 3D seismic survey data that would suggest any deformation or movement associated with these features. There is no evidence to suggest that these interpreted paleochannel features have sufficient permeability or vertical extent to interfere with containment. There is a flexure in the eastern 3D seismic data where the seismic reflections above the interpreted Precambrian–Deadwood boundary through the Red River Formation appear to dip or sag down (Figure 2-59). These depressions are interpreted to be draped over one of the interpreted paleochannels located at the Precambrian–Deadwood boundary (Figure 2-57). A deep structure was interpreted in the Precambrian basement below this paleochannel and flexure. This structure appears to be a low-dipping thrust fault that terminates at the top of the Precambrian basement (Figure 2-60). The location of this Precambrian fault provides evidence that there was likely preferential erosion along the exposed Precambrian fault trace during the deposition of the Deadwood Formation. The dip of the Precambrian fault is low-angle whereas the flexure above the paleochannel feature is near-vertical, supporting the interpretation of the fault terminating at the top of the Precambrian basement. The seismic interpretation indicates that the interpreted fault in the Precambrian basement is dipping at ~25 degrees relative to horizontal being 0 degrees. The flexure observed in the overlying sediments is likely associated with postdepositional differential compaction above the paleochannel or slump due to movement along this low-angle basement fault. There is no evidence to suggest that this flexural feature has sufficient permeability to interfere with containment. *2.5.5.1 Precambrian Fault Geomechanics Study* Geomechanical modeling was done to determine the potential risk of induced seismicity associated with the interpreted Precambrian fault and planned injection activities. The 3D seismic data were used to estimate the dip and strike of the interpreted fault, including uncertainty ranges on both for input into this modeling. A 1D stress model was built from the J-LOC1 well data using the density, compressional sonic, and shear sonic well logs. The pore pressure is assumed equivalent to hydrostatic pressure, with a slight overpressure in the Broom Creek Formation. Overburden stress was estimated by integrating the density data and projecting the density trend to surface. The principal horizontal stresses Shmin and SHmax were estimated using the modified Eaton poroelastic model from Theircelin and Plumb (1994) and calibrated to closure pressure measurements in the Deadwood, Broom Creek, and Inyan Kara Formations. Static elastic rock property inputs were calibrated to core measurements. The most conservative approach was taken by choosing the largest differential stress model to conduct the analysis, as it represented the highest risk scenario. A stress trend was developed to represent a consistent stress trend through the Deadwood Formation that was an equivalent trend through the highest-magnitude stresses. For the purposes of failure analysis on the existing feature in the seismic interpretation, that stress trend was projected down into the Precambrian basement. To understand the highest possible risk scenario, the scenario where the interpreted Precambrian fault extends into the Deadwood Formation was considered even though the seismic data do not suggest that it does. Conservative estimates for friction coefficient (30) and cohesion (0) were used in this analysis. Given those conditions and the state of stress modeled in the Deadwood, the failure analysis indicated that a pressure increase of 3,600–4,800 psi would be required to induce shear failure on that feature (Figure 2-61). The maximum expected pressure change in the Deadwood due to planned injection activities does not exceed 1,800 psi, which is well below the 3,600–4,800-psi pressure threshold for failure (Figure 2-62). Additionally, the injection interval is approximately 120 ft above the Precambrian–Deadwood boundary and the expected pressure change due to planned injection activities at the Precambrian–Deadwood boundary does not exceed 60 psi. Analysis of the geomechanics study results as applied to the characteristics of the interpreted Precambrian fault and site-specific geomechanical data suggests planned injection activities will not cause induced seismicity. Additionally, sensitivity analysis was run using the publicly available Fault Slip Potential tool using the inputs of friction coefficient, SHmax azimuth, fault dip, fault strike, pore pressure, SHmax magnitude, SHmin magnitude, and overburden magnitude. The results proved insensitive to all inputs except the dip of the fault. At the low-angle dip of the fault, there is very low risk of failure given the interpretation of the state of stress. ***2.5.2 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	Depressions along the top of the Precambrian suggest the presence of paleochannels. Figure 2-55 shows the location of this cross section. Figure 2-58. Map showing the thickness of the interval from the Precambrian erosional surface up through the top of the Deadwood Formation calculated using the seismic data. The linear trends correspond to areas of increased thickness. Figure 2-59. Map showing the time structure of the seismic reflection event interpreted to be the top of the Red River Formation. The line shows the location of the interpreted paleochannel that underlies the flexure. Figure 2-60. Cross-sectional view of the 3D seismic data through one of the linear trends in the east 3D seismic survey. Identified formations include Deadwood (blue) and Precambrian (yellow). The location of the interpreted low-angle thrust fault is shown by the green dashed line. Cross Section C-C' runs parallel to Cross Section B-B' shown in Figure 2-55 and is located 160 ft to the west of Cross Section B-B'. Figure 2-61. Mohr circle depiction of the stress state at the depth of the Deadwood Formation indicates a pressure window of 3,600 to 4,800 psi to create failure on the fault represented by the pink dots. Pink dots represent the strike and dip values for the fault interpreted from the seismic data relative to in situ stress orientations. Figure 2-62. Map showing the maximum pressure change expected within the injection zone from the proposed injection activities. The location of the interpreted paleochannel and flexure is indicated by the red line. Table 2-25. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016) Figure 2-63. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations listed in Table 2-24. Figure 2-64. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S.

		determination that the seismicity would not interfere with containment;		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 seismic events were detected within the North Dakota portion of the Williston Basin (Table 2-25) (Anderson, 2016). Of these 13 seismic events, only three occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-63). The seismic event recorded closest to the Tundra SGS storage facility area occurred 39.6 mi from the J-ROC1 well near Huff, North Dakota (Table 2-25). The magnitude of this seismic event is estimated to have been 4.4. 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 damaging seismic events predicted to occur over a 10,000-year time period (Figure 2-64) (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 the injection wells in the Williston Basin. They noted only two historic seismic events in North Dakota that could be associated with nearby oil and gas activities. These results indicate relatively stable geologic conditions in the region surrounding the potential injection site. Based on the review and assessment of 1) the USGS studies, 2) the characteristics of the Black Island and Deadwood injection zone and upper and lower confining zones, 3) the low risk of induced seismicity due to the basin stress regime, and 4) the history of recorded seismic events, seismic activity is not expected to interfere with containment of the maximum volume of CO_2 proposed to be injected annually over the life of this project.	Geological Survey, 2019).The map shows there is a low probability of damaging seismic events occurring in North Dakota.
	NDAC 43-05-01-05 §1b(2) ¶ NDAC 43-05-01-05 §1b(2)(n)	**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,	i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area: Geologic maps Topographic maps Cross sections	**2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base.	Figure 2-8. Areal extent of the Deadwood Formation in North Dakota (modified from Nesheim, 2012b). Figure 2-9. Type log showing the interpreted Deadwood members within the Williston Basin (Lefever and others, 1987). Figure 2-10. Isopach map of the Black Island and Deadwood Formations in the simulation model extent. Figure 2-11. Well log display of the interpreted lithologies of the Roughlock, Icebox, Black Island, Deadwood, and Precambrian in J-ROC1. Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue).

		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 one 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; and		• The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic. • The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area. • The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). <u>For additional information, go to Section 2.3 of the Tundra SGS SFP.</u>	Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent. Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level. Figure 2-15. Vertical distribution of core-derived porosity and permeability values in the Tundra SGS CO_2 storage complex. Table 2-6. Deadwood Microfracture Results from J-LOC1 Table 2-10. Properties of Upper and Lower Confining Zones at the J-LOC1 Well Figure 2-29. Areal extent of the Icebox Formation in western North Dakota (modified from Nesheim, 2012a). Figure 2-30. Structure map of the upper confining zone across the simulation model extent. Figure 2-31. Isopach map of the upper confining zone across the simulation model extent. Figure 2-32. Well log display of the upper confining zone at the J-ROC1 well. Figure 2-33. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,749.5 ft. Figure 2-34. J-LOC1 Icebox Formation MDT microfracture in situ stress test pump cycle graph at 9,751.2 ft. Table 2-11. Icebox Core Sample Porosity and Permeability from J-LOC1 Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well) Figure 2-38. Isopach map of the interval between the top of the Black Island Formation

Table 2-1. Formations Comprising the Tundra SGS CO_2 Storage Complex

	Formation	Purpose	Average Thickness at Tundra SGS Site, ft	Average Depth Tundra SGS Site, ft TVD	Lithology
Storage Complex	Icebox	Upper confining zone	118 (58 to 176)	9,308	Shale
	Black Island and Deadwood E member	Storage reservoir (i.e., injection zone)	118 (35 to 202)	9,427	Sandstone, shale, dolostone, limestone
	Deadwood C member sand	Storage reservoir (i.e., injection zone)	64 (40 to 88)	9,773	Sandstone
	Deadwood B member shale	Lower confining zone	34 (20 to 49)	9,791	Shale

Table 2-5. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC1 Well

Injection Zone Properties	
Property	**Description**
Formation Name	Black Island, Deadwood E member, and Deadwood C-sand member
Lithology	Sandstone, dolostone, limestone
Formation Top Depth, ft	9782.2, 9820.9, and 10,077.4
Thickness, ft	38.9, 92.3, and 60.9
Capillary Entry Pressure (CO_2/Brine), psi	0.16
Geologic Properties	

Formation	Property	Laboratory Analysis	Model Property Distribution

Black Island (sandstone)	Porosity, %*	8.0 (3.4–10.3)	5.6 (1.1–14.8)
	Permeability, mD**	3.7 (0.0019–157)	0.805 (<0.0001–96.0)
Deadwood E Member (sandstone)	Porosity, %	10 (6.85–14.43)	7.0 (0–17.7)
	Permeability, mD	5.63 (0.0325–2,060)	3.88 (<0.0001–4549.2)
Deadwood C-Sand Member	Porosity, %	7.6 (1.01–14.69)	7.6 (0.3–17.2)
	Permeability, mD	11 (0.0018–1140)	7.03 (<0.0001–830.3)

2.4 Confining Zones

The confining zones for the Deadwood and Black Island Formations are the overlying Icebox Formation and underlying Deadwood B member shale (Figure 2-3, Table 2-10). All three units, the Icebox Formation, Deadwood B member shale, and Precambrian basement, consist of impermeable rock layers.

Table 2-10. Properties of Upper and Lower Confining Zones at the J-LOC1 Well

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Formation Name	Icebox	Deadwood B member shale
Lithology	Shale	Shale
Formation Top Depth, ft	9,308	9,791
Thickness, ft	118	34
Porosity, % (core data)*	3.6***	2.0
Permeability, mD (core data)**	0.00002***	0.0103
Capillary Entry Pressure (CO_2/brine), psi	845	176****
Depth below Lowest Identified USDW, ft	8,097	8,580

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Icebox consists of shale. This upper confining zone is laterally extensive across the project area (Figures 2-29 and 2-30) 9,308 ft below the land surface and 118 ft thick at the Tundra SGS site (Table 2-10 and Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The contact between the underlying sandstone of the Black Island Formation is conformable and can be correlated across the project area. The transition from the Icebox to the Black Island is indicated by a relatively low GR, low neutron, high density, and low compressional sonic across the contact (Figure 2-32).

and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

Figure 2-39. 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 2-40. Structure map of the Deadwood B member shale across the greater Tundra SGS area.

Figure 2-41. Isopach map of the Deadwood B member shale across the Tundra SGS area.

Table 2-17. Deadwood B Member Shale Core Sample Porosity and Permeability from J-LOC1

Table 3-6. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Figure 3-9. Major aquifer systems of the Williston Basin.

Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

Figure 3-12. 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 Oliver County (modified from Fischer, 2013).

Figure 3-13. Map of water wells in the AOR in relation to the McCall-1 planned injection well, the NRDT-1 proposed monitoring well, storage facility area, AOR, and legacy oil and gas wells.

Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 wellbore. Microfracture stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

For the J-LOC1 well, in the Icebox Formation at 9,749.5 and 9,751.2 ft, the MDT tool was unable to cause a breakdown in the formation with an applied maximum injection pressure of 10,984.9 and 10,867.24 psi, respectively (Figures 2-33 and 2-34). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module." The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent and exhibits sufficient geologic integrity to contain the injected CO_2 stream.

The Icebox Formation was not suitable to collect competent core samples from the J-LOC1 well core for the purposes of porosity and permeability laboratory tests; the samples would crush in the equipment. The formation was found to be tight, and porosity and permeability estimates were derived from HPMI testing for one sample (Table 2-11). The lithology of the cored sections of the Icebox Formation is primarily shale, with minor pyrite.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Icebox. Impermeable rocks above the primary seal include the Roughlock Formation and the Red River D member, which make up the first additional group of confining formations (Table 2-16). Together with the Icebox, these formations are 612 ft thick and will isolate the Deadwood/Black Island Formations fluids from migrating upward into the next permeable interval, the Red River A, B, and C members (see Figure 2-38). Above the Red River Formation, >1,000 ft of impermeable rocks act as an additional seal between the Red River and Broom Creek, the next proposed storage complex, 876 ft of impermeable rocks separate the Broom Creek from the Inyan Kara and an additional 2,545 ft of impermeable rocks separates the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-39). Confining layers above the Inyan Kara include the Skull Creek, Newcastle, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

No known transmissible faults are within these confining systems in the project area. These formations between the Deadwood, 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 (Downey, 1986; Downey and Dinwiddie,1988).

Carbonates of the Red River A, B, and C members comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Red River represents the most likely candidate to act as an overlying pressure dissipation zone. The depth to the Red River Formation in the project area is approximately 8,438 ft, and the formation itself is about 450 ft thick. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Red River Formation. Monitoring DTS (distributed temperature sensor) data for the Red River Formation using the downhole fiber optic cable in the proposed monitor well provides an additional opportunity for mitigation and remediation (Section 4.0).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714

black dots on the inset map represent the locations of the water wells illustrated on the cross section.

Rierdon	Shale	4,337	147	3,187
Piper (Kline member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444
Opeche	Shale/mudstone	4,685	55	3,535
Amsden	Dolostone/anhydrite	4,974	247	3,824
Kibbey Lime	Limestone	5,384	31	4,234
Charles	Limestone/anhydrite	5,526	147	4,376
Bakken	Shale	6,926	10	5,776
Birdbear	Limestone	7,075	74	5,925
Duperow	Limestone/dolostone	7,149	272	5,999
Souris River	Dolostone/limestone	7,421	175	6,271
Dawson Bay	Dolostone	7,596	729	6,446
Gunton	Dolostone/limestone	8,325	39	7,175
Stoughton	Shale/limestone	8,364	91	7,214
Lower Red River	Limestone	8,645	488	7,495
Roughlock	Shale/limestone	9,133	25	7,983

2.4.3 Lower Confining Zones
The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member shale consists predominantly of shale with a consistent and correlative package of higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic across the project area. The shale within the Deadwood B member is 9,791 ft below the surface and 34 ft thick at the Tundra SGS site (Figures 2-40 and 2-41, Table 2-10).

At 144 ft below the top of the Deadwood C-sand is an 80-ft-thick shaly layer of the Deadwood B member. Data acquired from the core plug samples taken from the Deadwood B member show porosity values ranging from 1.55% to 2.63% and permeability values from 0.0083 to 0.0177 mD (Table 2-17).

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 deepest USDW in the AOR. The Icebox Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6).

3.4.2 Geology of USDW Formations
The hydrogeology of western North Dakota comprises 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 3-9). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 3-

				10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973). 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 700 to 900 ft deep and 200 to 350 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 3-11). 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 1000 ft thick in the AOR (Thamke and others, 2014). ***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, which isolates 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 east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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. Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the McCall-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown. Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973). The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973). ***3.4.4 Protection for USDWs*** The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Deadwood Formation) and lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and carbonate formations of Ordovician, Silurian, Devonian, Carboniferous, Permian, Jurassic, and Cretaceous ages (Figure 3-9). The primary seal of the injection zone is the Ordovician-aged Icebox	

				Formation with shales of the Ordovician-aged Roughlock and Stoughton, Mississippian–Devonian-aged Bakken, Permian-aged Opeche, Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Icebox 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection well, McCall-1 and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, 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 consist 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.	
	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 2-10** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base. • The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic. • The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area.	Figure 2-10. Isopach map of the Black Island and Deadwood Formations in the simulation model extent.

				• The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). For additional information, go to section 2.3 of the Tundra SGS SFP.	
	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 2-31 and Figure 2-41** **2.4 Confining Zones** The confining zones for the Deadwood and Black Island Formations are the overlying Icebox Formation and underlying Deadwood B member shale (Figure 2-3, Table 2-10). All three units, the Icebox Formation, Deadwood B member shale, and Precambrian basement, consist of impermeable rock layers. ***2.4.1 Upper Confining Zone*** In the Tundra SGS area, the Icebox consists of shale. This upper confining zone is laterally extensive across the project area (Figures 2-29 and 2-30) 9,308 ft below the land surface and 118 ft thick at the Tundra SGS site (Table 2-10 and Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The contact between the underlying sandstone of the Black Island Formation is conformable and can be correlated across the project area. The transition from the Icebox to the Black Island is indicated by a relatively low GR, low neutron, high density, and low compressional sonic across the contact (Figure 2-32). Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 wellbore. Microfracture stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore. For the J-LOC1 well, in the Icebox Formation at 9,749.5 and 9,751.2 ft, the MDT tool was unable to cause a breakdown in the formation with an applied maximum injection pressure of 10,984.9 and 10,867.24 psi, respectively (Figures 2-33 and 2-34). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, “Schlumberger Dual-Packer Module.” The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent and exhibits sufficient geologic integrity to contain the injected CO_2 stream. The Icebox Formation was not suitable to collect competent core samples from the J-LOC1 well core for the purposes of porosity and permeability laboratory tests; the samples would crush in the equipment. The formation was found to be tight, and porosity and permeability estimates were derived from HPMI testing for one sample (Table 2-11). The lithology of the cored sections of the Icebox Formation is primarily shale, with minor pyrite. *2.4.3 Lower Confining Zones* The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member shale consists predominantly of shale with a consistent and correlative package of higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic across the project area. The shale within the Deadwood B member is 9,791 ft below the surface and 34 ft thick at the Tundra SGS site (Figures 2-40 and 2-41, Table 2-10). At 144 ft below the top of the Deadwood C-sand is an 80-ft-thick shaly layer of the Deadwood B member. Data acquired from the core plug samples taken from the Deadwood B member show porosity values ranging from 1.55% to 2.63% and permeability values from 0.0083 to 0.0177 mD (Table 2-17).	Figure 2-31. Isopach map of the upper confining zone across the simulation model extent. Figure 2-41. Isopach map of the Deadwood B member shale across the Tundra SGS area.

			l. An isopach map of the secondary containment barrier for the storage reservoir;	**Figure 2-38 and Figure 2-39** ***2.4.2 Additional Overlying Confining Zones*** Several other formations provide additional confinement above the Icebox. Impermeable rocks above the primary seal include the Roughlock Formation and the Red River D member, which make up the first additional group of confining formations (Table 2-16). Together with the Icebox, these formations are 612 ft thick and will isolate the Deadwood/Black Island Formations fluids from migrating upward into the next permeable interval, the Red River A, B, and C members (see Figure 2-38). Above the Red River Formation, >1,000 ft of impermeable rocks act as an additional seal between the Red River and Broom Creek, the next proposed storage complex, 876 ft of impermeable rocks separate the Broom Creek from the Inyan Kara and an additional 2,545 ft of impermeable rocks separates the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-39). Confining layers above the Inyan Kara include the Skull Creek, Newcastle, Mowry, Greenhorn, and Pierre Formations (Table 2-16). No known transmissible faults are within these confining systems in the project area. These formations between the Deadwood, 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 (Downey, 1986; Downey and Dinwiddie,1988). Carbonates of the Red River A, B, and C members comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Red River represents the most likely candidate to act as an overlying pressure dissipation zone. The depth to the Red River Formation in the project area is approximately 8,438 ft, and the formation itself is about 450 ft thick. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Red River Formation. Monitoring DTS (distributed temperature sensor) data for the Red River Formation using the downhole fiber optic cable in the proposed monitor well provides an additional opportunity for mitigation and remediation (Section 4.0).	Figure 2-38. Isopach map of the interval between the top of the Black Island Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. Figure 2-39. 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 2-13 and Figure 2-30** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections.	Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent. Figure 2-30. Structure map of the upper confining zone across the simulation model extent.

- The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area.
- The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base.
- The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic.
- The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic.
- The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area.
- The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13).

For additional information, go to section 2.3 of the Tundra SGS SFP.

2.4.1 Upper Confining Zone

In the Tundra SGS area, the Icebox consists of shale. This upper confining zone is laterally extensive across the project area (Figures 2-29 and 2-30) 9,308 ft below the land surface and 118 ft thick at the Tundra SGS site (Table 2-10 and Figure 2-31). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The contact between the underlying sandstone of the Black Island Formation is conformable and can be correlated across the project area. The transition from the Icebox to the Black Island is indicated by a relatively low GR, low neutron, high density, and low compressional sonic across the contact (Figure 2-32).

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC1 wellbore. Microfracture stress tests were attempted in the J-ROC1 well; however, because of extremely unstable wellbore conditions, the MDT stress tool run was not performed after a near loss of the tool in the wellbore.

For the J-LOC1 well, in the Icebox Formation at 9,749.5 and 9,751.2 ft, the MDT tool was unable to cause a breakdown in the formation with an applied maximum injection pressure of 10,984.9 and 10,867.24 psi, respectively (Figures 2-33 and 2-34). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, “Schlumberger Dual-Packer Module.” The inability to break down the Icebox Formation at the two depths indicated that the formation is very tight competent and exhibits sufficient geologic integrity to contain the injected CO_2 stream.

The Icebox Formation was not suitable to collect competent core samples from the J-LOC1 well core for the purposes of porosity and permeability laboratory tests; the samples would crush in the equipment. The formation was found to be tight, and porosity and permeability estimates were derived from HPMI testing for one sample (Table 2-11). The lithology of the cored sections of the Icebox Formation is primarily shale, with minor pyrite.

			n. A structure map of the base of the storage formation;	**Figure 2-13 and Figure 2-40** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base. • The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic. • The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area. • The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). For additional information, go to section 2.3 of the Tundra SGS SFP.	Figure 2-13. Structure map of the Black Island and Deadwood Formations across the simulation model extent. Figure 2-40. Structure map of the Deadwood B member shale across the greater Tundra SGS area

				2.4.3 Lower Confining Zones The lower confining zone of the storage complex is the Deadwood B member shale. The Deadwood B member shale consists predominantly of shale with a consistent and correlative package of higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic across the project area. The shale within the Deadwood B member is 9,791 ft below the surface and 34 ft thick at the Tundra SGS site (Figures 2-40 and 2-41, Table 2-10). At 144 ft below the top of the Deadwood C-sand is an 80-ft-thick shaly layer of the Deadwood B member. Data acquired from the core plug samples taken from the Deadwood B member show porosity values ranging from 1.55% to 2.63% and permeability values from 0.0083 to 0.0177 mD (Table 2-17).	
	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 2-12a and 2-12b; and 2-14** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base. • The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic. • The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area.	Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue). Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level.

				• The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). For additional information, go to section 2.3 of the Tundra SGS SFP.	
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	**Figures 2-12a and 2-12b; and 2-14** **2.3 Storage Reservoir (Injection Zone)** Regionally, the Black Island and Deadwood Formations are laterally extensive (Figure 2-8). The Black Island comprises high-energy shallow marine sandstone (permeable storage intervals) and shale (impermeable layers). The sandy members (C-sand and E member) of the Deadwood Formation comprise reworked quartz arenites of marginal marine environment (Figure 2-9). The Deadwood Formation unconformably overlies the Precambrian basement and is unconformably overlain by the sands of the Black Island Formation followed by the conformable Icebox Formation (Figure 2-3). At J-ROC1, the Deadwood C-sand member is made up of 50 ft of sandstone and is located at a depth of 9,548 ft. Across the model area, the Deadwood C-sand member varies in thickness from 40 to 88 ft, with an average thickness of 64 ft. Based on offset well data and geologic model characteristics, the Deadwood C-sand member is 100% sandstone. The Deadwood E member and Black Island Formations are made up of 69 ft of sandstone and 19 ft of dolostone and limestone at J-ROC1 and are located at a depth of 9,283 ft. Across the project area, the Deadwood E member varies in thickness from 0 to 139 ft, with an average thickness of 81 ft. The Black Island Formation varies in thickness from 14 to 77 ft, with an average of 36 ft. Based on offset well data and geologic model characteristics, the net reservoir thickness within the project area ranges from 63 to 287 ft, with an average of 165 ft (Figure 2-10). The well log signatures for the Black Island and Deadwood storage complex are consistent and predictable across the project area. The following are the correlation definitions used to indicate the reservoir and confining zones (Figure 2-11): • The Icebox Formation is indicated at the transitions between a moderate GR, higher resistivity, low neutron, high density, and moderate compressional sonic for the base of the Roughlock Formation to the high GR, low resistivity, high neutron, high density, and high compressional sonic. The Icebox Formation is correlative across the project area. • The Black Island Formation is indicated by the transition from the Icebox Formation to a relatively low GR, low neutron, high density, and low compressional sonic. The Black Island has interbedded high-GR and moderate-resistivity sections. • The Deadwood Formation (Deadwood E member) is indicated by a transition from the base high GR signature of the Black Island Formation to a low GR signature, lower neutron, higher density, and lower compressional sonic. The Deadwood E thins from west to east across the project area. • The Deadwood D member (base of Deadwood E member) is indicated by a transition to moderate to higher GR from top to base, higher resistivity, low neutron, high density, and low to higher compressional sonic from top to base. • The Deadwood C member is the transition between the high GR of the Deadwood D member and moderate GR, higher resistivity, low neutron, high density, and low compressional sonic. The Deadwood C-sand member at the base of the Deadwood C member is indicated by a section of low GR (10 API), low resistivity, moderate neutron, moderate density, and moderate compressional sonic. • The Deadwood B member (base of Deadwood C-sand member) is indicated by the transition from a low GR signature of the Deadwood C-sand member to a high GR, higher resistivity, low neutron, high density, and higher compressional sonic.	Figure 2-12a. Regional well log stratigraphic cross sections of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement flattened on the top of the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red), 2) delta time (blue), and 3) interpreted lithology log. Figure 2-12b. Regional well log cross sections showing the structure of the Roughlock, Icebox, Black Island, and Deadwood Formations and the Precambrian basement. Logs displayed in tracks from left to right are 1) GR (green) and caliper (red) and 2) delta time (blue). Figure 2-14. Cross section of the Tundra SGS CO_2 storage complex from the geologic model showing lithofacies distribution in the Deadwood Formation. Depths are referenced to mean sea level.

				• The Deadwood B member shale unit is indicated by a higher GR, moderate resistivity, higher neutron, moderate density, and high compressional sonic. This unit is contained within the Deadwood B member and can be correlated across the project area. • The Precambrian basement is indicated by a change from low to relatively high GR, low-to-moderate resistivity, and a lower compressional sonic character that can 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 J-LOC1 and J-ROC1 (Figures 2-12a and 2-12b). The Deadwood E member pinches out 12.5 mi to the east of the J-ROC1 site. A structure map of the Deadwood and Black Island Formations shows no detectable features (e.g., folds, domes, or fault traps) with associated spill points in the project area (Figure 2-13). <u>For additional information, go to section 2.3 of the Tundra SGS SFP.</u>	
	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 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[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 (Figure 3-1) 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 resultant pressure as the “critical threshold pressure.” Application of the U.S. Environmental Protection Agency (EPA) method shows the critical threshold pressure increase at the top of the Deadwood Formation using site-specific data from J-ROC1 was determined to be 127 psi (Appendix A, Table A-4). Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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.	Table A-5. EPA Method 1 Critical Threshold Pressure Increase Calculated at the J-ROC1 Wellbore Location Figure A-20. Final AOR estimations of the Tundra SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), area of review (gray boundary and shaded area), and Center city limits (dotted yellow boundary). Orange circles represent legacy wells near the storage facility area. Figure A-21. Land use in and around the AOR of the Tundra SGS storage facility.

				This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were identified in Table 3-1. **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 (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. EPA (2013) Method 1 (pressure front based on bringing injection zone and USDW to equivalent hydraulic heads) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (Thornhill and others, 1982). Under Method 1, the increase in pressure (ΔP) that may be sustained in the injection zone (critical pressure threshold) is given by: $\Delta Pi,f = P\text{u} + \rho ig \cdot (zu - zi) - Pi$ [Eq. 1] where Pu is the initial fluid pressure in the USDW, ρi is the storage reservoir fluid density (mg/m^3), g is the acceleration due to gravity (m/s^2), zu is the representative elevation of the USDW (m amsl), zi is the representative elevation of the injection zone (m amsl), Pi is the initial pressure in the injection zone (Pa), and ΔPi,f is the critical pressure threshold. Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta Pi,f = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta Pi,f > 0$, then the reservoir is underpressurized relative to the USDW, and if $\Delta Pi,f < 0$, then the reservoir is overpressurized relative to the USDW. In the case of $\Delta Pi,f > 0$, the value of $\Delta Pi,f$ represents the amount of pressure increase that can be accommodated in the storage reservoir before brine would flow into the lowest USDW. **Critical Threshold Pressure Increase Estimation at J-ROC1**For the purposes of delineating the $\Delta Pi,f$ for the Tundra SGS study area, constant fluid densities for the lowermost USDW (the Fox Hills Formation) and the injection zone (the Deadwood Formation) were used. A density of 1,001 kg/m3 was used to represent the USDW fluids, and a density of 1,177 kg/m3, 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 Equation 1, formation depths and thicknesses from J-ROC1, and fluid density values from the nearby J-LOC1 stratigraphic test well (Table A-5). Using this method, the critical threshold pressure increase ($\Delta Pi,f$) at the top of the Deadwood Formation at the J-ROC1 well was determined to be 127 psi. Because $\Delta Pi,f > 0$, the value of $\Delta Pi,f$ represents the amount of pressure increase that can be accommodated in the storage reservoir before brine would flow into the lowest USDW. Calculations 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-5 provides estimates of $\Delta Pi,f$ for various depths within the Deadwood Formation at J-	

				ROC1. The same calculations were applied to the geologic model to determine $\Delta Pi,f$ for each cell, values from which were then compared against the difference in pressure predicted for each cell in the simulation model at the end of injection (time of greatest increase in pressure since the beginning of simulated injection). A defined area of the simulation model around the injection well displays a 20-year pressure increase (ΔP) that is greater than the calculated $\Delta Pi,f$ for the cells in that area. The boundary between where $\Delta PI,f > \Delta P$ and where $\Delta PI,f < \Delta P$ delineates the line of critical threshold pressure increase and must be accounted for—in conjunction with the CO_2 areal extent—when determining AOR. The storage reservoir is the maximum extent of the injected CO_2 or the maximum extent of the critical pressure, whichever is greater. At Tundra SGS, the line of critical threshold pressure increase plus 1 mile is the AOR, because the maximum extent of critical pressure is larger than the maximum extent of the injected CO_2. As shown in Figure A-20, the AOR is depicted by the gray shaded area, which includes the storage facility area (purple shaded area). Figure A-21 illustrates the land use within the AOR.	
	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 Icebox Formation, the overlying confining zone, and Deadwood B Formation, the underlying confining zone, have been assessed during the description of the J-LOC1 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 Schlumberger's Quanta Geo log acquired during the drilling of the J-LOC1 well. *2.4.4.2 Fracture Analysis Core Description* Features within the Icebox Formation are primarily related to the compaction. There is no presence of natural fractures. Only the stylolites which are compaction-related exist; they vary in orientation and exhibit mainly horizontal and rare oblique trends. In the Deadwood B Formation, rare closed-tension fractures were observed in the core interval and are commonly coincident with the observed horizontal compaction features (stylolite). Quartz is the dominant mineral found to fill observable fractures. The stylolites are well-represented, vary in orientation, and exhibit mainly a horizontal trend. *2.4.4.3 Borehole Image Fracture Analysis (FMI)* Schlumberger's Quanta Geo 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 2-46 and 2-47 show two sections of the interpreted borehole imagery and primary features observed. The far-right track on Figure 2-46 demonstrates that the tool provides information on surface boundaries and bedding features and notes the presence of electrically conductive features that characterize the Icebox Formation. These are interpreted as stylolites. Figure 2-47 reveals the features that are clay-filled because of their electrically conductive signal. The logged interval of the Deadwood B shows that the main features present are stylolites, which are an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. The diagrams shown in Figures 2-48 and 2-49 provide the orientation of the electrically conductive features in the Icebox and Deadwood B Formations, respectively. As shown, the electrically conductive features are stylolites and have no preferred orientation. Drilling-induced fractures were not identified either in the Icebox or Deadwood B Formations. However, breakouts were highlighted in the Precambrian basement and are oriented northwest–southeast (Figure 2-50), which is perpendicular to the maximum horizontal stress (SHmax). *2.4.4.4 Stress* During drilling of the J-LOC1 well, an openhole MDT microfracture in situ stress test was completed to determine a formation breakdown pressure and minimum horizontal stress. The microfracture in situ stress test operation was performed using the MDT dual-packer module to obtain the formation breakdown pressure followed by multiple injection–falloff cycles to determine formation geomechanics properties. Within the Icebox Formation confining zone, two attempts were made at a depth of 9,749.51 and 9,751.19 ft to determine the formation breakdown pressure and closure pressure, which corresponds to the minimum horizontal stress. Unfortunately, these attempts were unsuccessful to achieve the	Figure 2-46. Examples of the interpreted Quanta Geo log for the J-LOC1 well. This example shows the common feature types seen in the Icebox Quanta Geo borehole image analysis. Figure 2-47. Examples of the interpreted Quanta Geo log for the J-LOC1 well. This example shows the common feature types seen in the Deadwood B Quanta Geo borehole image analysis. Figure 2-48. This example shows stylolites seen in the Icebox Formation. Figure 2-49. This example shows stylolites seen in the Deadwood B Formation. Figure 2-50. Breakout dip orientation in the Precambrian basement. Figure 2-51. J-LOC1 Icebox MDT microfracture in situ stress test (first attempt) at 9,749.51 ft. Figure 2-52. J-LOC1 Icebox MDT microfracture in situ stress test (second attempt) at 9,751.19 ft. Table 2-21. Summary of Stresses in Icebox Formation Figure 2-53. 1D MEM of the Icebox Formation. Figure 2-54. 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 121.8 MPa. Table 2-22. Sample Parameters

formation breakdown pressure with an applied maximum injection pressure of 10984.9 and 10867.24 psi (Figure 2-51 and Figure 2-52). The maximum injection pressure was limited by the dual-packer mechanical specifications having a set maximum differential pressure rating between the upper packer and hydrostatic pressure of 5,500 psi; see Appendix D, "Schlumberger Dual-Packer Module."

J-LOC1 openhole logging data were used to construct a 1D mechanical earth model (MEM) for different formations, including the Icebox Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties such as Young's modulus, Poisson's ratio, Shear modulus, and Bulk modulus were calculated based on the available well logs. The formation strength properties like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion were also estimated from the available data (Figure 2-53). Table 2-21 provides the summary of stresses in the Icebox Formation generated using the 1D MEM.

2.4.4.5 Ductility and Rock Strength

Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Icebox and Deadwood B Formation cores in the J-LOC1. Icebox Formation samples were not testable. Plugs failed under minor stress because of the fissility of the rock. On the other hand, one sample from the Deadwood B Formation was tested and characterized by a porosity equal to 1.4% and a permeability of 0.001 mD. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5801.51 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material (Figure 2-54). Table 2-22 shows the sample parameters, while Tables 2-23 and 2-24 show the elastic, dynamic, and velocity parameters obtained at different confining pressures.

Appendix A - DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS

Table A-2. MDT Pressure Measurements Recorded from the J-LOC1 Well and Derived Formation Pressure Gradients

Test Depth, ft MD*	Formation Pressure, psi	Formation Pressure Gradient, psi/ft
9,800	4,507	0.46
9,885	4,548	0.46
9,885	4,548	0.46
10,087	4,651	0.46
10,254	4,734	0.46

Table A-3. Summary of Reservoir Properties in the Simulation Model

Average Permeability, mD	Average Porosity, %	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Icebox: 7.25×10^{-7} Black Island: 9.81 Deadwood: 31.65 Precambrian: 7.88×10^{-7}	Icebox: ~0.12 Black Island: ~5.48 Deadwood: ~3.81 Precambrian: ~0.74	~4,548.42	256,000	Open (infinite-acting)

Table 2-23. Elastic Properties Obtained Through Experimentation: E = Young's Modulus, n = Poisson's Ratio, K = Bulk Modulus, G = Shear Modulus, P = Uniaxial Strain Modulus

Table 2-24. Velocity and Dynamic Properties Obtained Through Experimentation: Vp = P-Wave Velocity, Vs = Shear Wave Velocity, E = Young's Modulus, n = Poisson's Ratio

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

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 other formations provide additional confinement above the Icebox. Impermeable rocks above the primary seal include the Roughlock Formation and the Red River D member, which make up the first additional group of confining formations (Table 2-16). Together with the Icebox, these formations are 612 ft thick and will isolate the Deadwood/Black Island Formations fluids from migrating upward into the next permeable interval, the Red River A, B, and C members (see Figure 2-38). Above the Red River Formation, >1,000 ft of impermeable rocks act as an additional seal between the Red River and Broom Creek, the next proposed storage complex, 876 ft of impermeable rocks separate the Broom Creek from the Inyan Kara and an additional 2,545 ft of impermeable rocks separates the Inyan Kara and the lowermost USDW, the Fox Hills Formation (see Figure 2-39). Confining layers above the Inyan Kara include the Skull Creek, Newcastle, Mowry, Greenhorn, and Pierre Formations (Table 2-16).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Figure 2-38. Isopach map of the interval between the top of the Black Island Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones.

provide additional opportunities for monitoring, mitigation, and remediation.

No known transmissible faults are within these confining systems in the project area. These formations between the Deadwood, 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 (Downey, 1986; Downey and Dinwiddie,1988).

Carbonates of the Red River A, B, and C members comprise the first unit with relatively high porosity and permeability above the injection zone and primary sealing formation. The Red River represents the most likely candidate to act as an overlying pressure dissipation zone. The depth to the Red River Formation in the project area is approximately 8,438 ft, and the formation itself is about 450 ft thick. In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO_2 would become trapped in the Red River Formation. Monitoring DTS (distributed temperature sensor) data for the Red River Formation using the downhole fiber optic cable in the proposed monitor well provides an additional opportunity for mitigation and remediation (Section 4.0).

Table 2-16. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1,150	1862	0
Greenhorn	Shale	3,012	391	1,862
Mowry	Shale	3,403	56	2,253
Skull Creek	Shale	3,458	235	2,308
Swift	Shale	3,864	473	2,714
Rierdon	Shale	4,337	147	3,187
Piper (Kline member)	Limestone	4,484	110	3,334
Piper (Picard)	Shale	4,594	91	3,444
Opeche	Shale/mudstone	4,685	55	3,535
Amsden	Dolostone/anhydrite	4,974	247	3,824
Kibbey Lime	Limestone	5,384	31	4,234
Charles	Limestone/anhydrite	5,526	147	4,376
Bakken	Shale	6,926	10	5,776
Birdbear	Limestone	7,075	74	5,925
Duperow	Limestone/dolostone	7,149	272	5,999
Souris River	Dolostone/limestone	7,421	175	6,271
Dawson Bay	Dolostone	7,596	729	6,446
Gunton	Dolostone/limestone	8,325	39	7,175
Stoughton	Shale/limestone	8,364	91	7,214
Lower Red River	Limestone	8,645	488	7,495
Roughlock	Shale/limestone	9,133	25	7,983

Figure 2-39. 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.

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 one 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 one 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 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[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 (Figure 3-1) 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 resultant pressure as the "critical threshold pressure." Application of the U.S. Environmental Protection Agency (EPA) method shows the critical threshold pressure increase at the top of the Deadwood Formation using site-specific data from J-ROC1 was determined to be 127 psi (Appendix A, Table A-4). Appendix A includes a detailed discussion on the computational modeling and simulations (e.g., CO_2 plume extent, pressure front, AOR boundary, etc.), assumptions, and justification used to delineate the AOR and method for delineation of the AOR. NDAC § 43-05-01-05 subsection 1(b)(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 computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 3-1), the resulting AOR for Tundra SGS is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 3-2 through 3-5) by a professional engineer pursuant to NDAC § 43-05-01-05 subsection 1(b)(3). The evaluation was performed to determine if corrective action is required and included a review of all available well records (Table 3-1). The evaluation determined that all abandoned wells 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 (Tables 3-2 through 3-5 and Figures 3-6 through 3-8). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed 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. This section of the storage facility permit application is accompanied by maps and tables that include information required and in accordance with NDAC §§ 43-05-01-05 subsections 1(a) and 1(b) and 43-05-01-05.1 subsection 2, such as the storage facility area, location of any proposed injection wells or monitoring wells, presence of significant surface structures or land disturbances, and location of water wells and any other wells within the AOR. Table 3-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC §§ 43-05-01-05 subsections 1(a) and 1(b)(3) and 43-05-01-05.1 subsection 2. Surface features that were investigated but not found within the AOR boundary were 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	**§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 within the facility area [1.61 kilometers], or any necessary by the facility area boundary. the following: **NDAC 43-05-01-05 §1a** a. A site map showing storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and	a. A map showing the following within i. Boundaries of the storage 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 storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow boundaries represent buildings.
	NDAC 43-05-01-05 §1b(2)(a)	**§1b(2)(a)** (a) All wells, including gas exploration and development wells, including coal mines, within the facility mile [1.61 kilometers] boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells structures and activities, including	**3.1.2 Supporting Maps**	
	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 by utilizing all appropriate geologic and reservoir	c. A description of the method used for delineating the area of review, including: i. The computational model to be ii. The assumptions that will be	**Appendix A – DATA, PROCESSING, AND OUTCOMES OF CO_2 STORAGE GEOMODELING AND SIMULATIONS**	

		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;	iii. The site characterization data on which the model will be based;		
	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; (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; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection	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 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;	**3.3 Reevaluation of AOR and Corrective Action Plan** Minnkota will periodically reevaluate the AOR and corrective action plan in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each being a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified. • The protocol to conduct 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.	

		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.			
	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 one 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 one mile outside of its boundary;	**3.1.2 Supporting Maps**	Figure 3-2. Final AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings, and yellow 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	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones** There has been no historic hydrocarbon exploration in, or production from, formations above the Deadwood Formation in the storage facility area. The only hydrocarbon exploration well near the storage facility area, the Herbert Dresser 1-34 (NDIC File No. 4937), was drilled in 1970 to explore potential hydrocarbons in the Charles Formation. The well was dry and did not suggest the presence of hydrocarbons. There are no known producible accumulations of hydrocarbons in the storage facility area. Shallow gas resources can be found in many areas of North Dakota. North Dakota regulations define shallow gas resources as “gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of five thousand feet (1,524 meters) below the surface, or located more than five thousand feet (1,524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced.” Lignite coal currently is mined in the area of the Center coal mine, operated by BNI Coal. The Center Mine currently mines the Hagel coal seam for use as fuel at Minnkota’s MRYS. The Hagel coal seam is the lowermost major lignite present in the area in the Sentinel Butte Formation. Thickness of the Hagel coal seam averages 7.8 ft in the area permitted to be mined but varies, with some areas exceeding 10 ft in thickness (Figure 2-65) (Ellis and others, 1999). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam, but currently the Hagel is the only economically minable seam with its thickness and overburden of 100 ft or less (Figure 2-66). The thickness of the Hagel and other coal seams in the Fort Union Group thicken and deepen to the west. The overlying Beulah–Zap coal seam pinches out farther to the west but is economically minable in the central part of Mercer County at North American Coal’s Coteau Mine. The Hagel seam pinches out to the east, and there are no other coal seams mined farther east than the Hagel.	Figure 2-65. Hagel net coal isopach map (modified from Ellis and others, 1999). Figure 2-66. Hagel overburden isopach map (modified from Ellis and others, 1999).

		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 one 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 one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary.	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	**3.1.2 Supporting Maps**	Figure 3-4. The AOR map in relation to nearby legacy wells. Shown are the storage facility area (purple boundary), Center city limits (yellow dotted boundary), and AOR (gray boundary). Orange circles represent nearby legacy wells near the project area, including within the AOR.

		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. 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; and			
	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)(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;	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:	**3.2 Corrective Action Evaluation** **Table 3-2. Wells in AOR Evaluated for Corrective Action** **Table 3-3. Little Boot 15-44 (NDIC File No. 8144) Well Evaluation** **Table 3-4. J-ROC1 (NDIC File No. 37672) Well Evaluation** **Table 3-5. J-LOC1 (NDIC File No. 37380) Well Evaluation** **Table 3-1. Investigated and Identified Surface and Subsurface Features (Figures 3-1 through 3-5)**	Figure 3-6. Little Boot 15-44 (NDIC File No. 8144) well schematic showing the location and thickness of cement plugs. Figure 3-7. J-ROC1 (NDIC File No. 37672) well schematic showing the location and thickness of cement plugs. Figure 3-8. J-LOC1 (NDIC File No. 37380) as-constructed well schematic showing the final installation equipment used inside the wellbore to isolate perforations.

	NDAC 43-05-01-05 §1b(3)(d) NDAC 43-05-01-05 §1b(3)(e) NDAC 43-05-01-05 §1b(3)(b)(f)	**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 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),	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: 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		

		quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads; **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; and	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 deepest USDW in the AOR. The Icebox Formation is the primary confining zone with additional confining layers above, which geologically isolates all USDWs from the injection zone (Table 3-6). ***3.4.2 Geology of USDW Formations*** The hydrogeology of western North Dakota comprises 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 3-9). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014). The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 3-10). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973). 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 700 to 900 ft deep and 200 to 350 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 3-11). 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 1000 ft thick in the AOR (Thamke and others, 2014). ***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, which isolates 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	Table 3-6. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-ROC1 well) Figure 3-9. Major aquifer systems of the Williston Basin. Figure 3-10. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973). Figure 3-11. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). Figure 3-12. 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 Oliver County (modified from Fischer, 2013). Figure 3-13. Map of water wells in the AOR in relation to the McCall-1 planned injection well, the NRDT-1 proposed monitoring well, storage facility area, AOR, and legacy oil and gas wells. Figure 3-14. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the

				strata under central and eastern North Dakota (Fischer, 2013). Flow through the AOR is to the east (Figure 3-12). Water sampled from the Fox Hills Formation is a 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. Based on the North Dakota State Water Commission (SWC) database, eight water wells penetrate the Fox Hills Formation in the AOR (Figure 3-13). One observation well monitored by the U.S. Geological Survey is located 1 mi east of Center, North Dakota, nearly 5 mi northwest of the McCall-1 injection site. One well is 5 mi northeast of the injection site along North Dakota Highway 25 and is used for stock. The status of the remaining six wells is under investigation. One well is about 9 mi southeast of the injection site near a legacy oil exploratory well and is permitted as an industrial well. Five wells lie to the southwest. Three wells are about 3, 11, and 12 mi from the injection site and are permitted as domestic water supply. The last two wells are located on adjacent sections 11 mi from the injection site; one is permitted for stock, and the other's purpose is unknown. Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR (Figure 3-14). 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. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the area of investigation. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1,000 ppm (Croft, 1973). The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in the extreme western portion of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400–1,000 ppm (Croft, 1973). ***3.4.4 Protection for USDWs*** The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Deadwood Formation) and lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and carbonate formations of Ordovician, Silurian, Devonian, Carboniferous, Permian, Jurassic, and Cretaceous ages (Figure 3-9). The primary seal of the injection zone is the Ordovician-aged Icebox Formation with shales of the Ordovician-aged Roughlock and Stoughton, Mississippian–Devonian-aged Bakken, Permian-aged Opeche, Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overly the Icebox 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 Formation will be monitored for temperature and pressure changes via fiber optic lines installed in the injection well, McCall-1 and the NRDT-1 monitoring well. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, 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 consist 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.	
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 pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**4.3 Financial Assurance Demonstration Plan;** See Appendix G ***4.3.1 Approach to Meeting Financial Responsibility Requirements*** *4.3.1.1 Corrective Action* *4.3.1.2 Injection Well-Plugging Program* *4.3.1.3 Postinjection Site Care and Facility Closure*	

4.3.1.4 Emergency and Remedial Response

4.3.1.5 Endangerment of Drinking Water Sources

4.3.2 Approach to Financial Risk

4.3.3 Selected Elements of Applicant's Analysis of Inherent Risks

4.3.4 Costs Estimates

Table 4-14. Potential Future Costs Covered by Financial Assurance in $K

Activity	**Total Cost**	**Covered by Special-Purpose Trust**	**Covered by Commercial Insurance**	**Details in Supporting Table**
Corrective Action on Wells in AOR	$0	$0	$0	NA
Plugging Injection Wells	$2,025	$2,025	$0	Table 4-14-1
Postinjection Site Care	$10,285	$10,285	$0	Table 4-14-2
Site Closure	$1,554	$1,554	$0	Table 4-14-3
Emergency and Remedial Response	$16,560	$5,960	$10,600	Table 4-14-4
Endangerment of USDWs	$2,240	$0	$2,240	Table 4-14-5
Total	**$32,664**	**$19,824**	**$12,840**	

	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;	**4.2 Emergency and Remedial Response Plan;** See Appendix E ***4.2.1 Description of Project Area*** ***4.2.2 Risk Identification and Severity*** ***4.2.3 Response Protocols*** ***4.2.4 Emergency Contacts*** ***4.2.5 Emergency Communications Plan*** ***4.2.6 ERRP Review***	
	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;	**4.4 Worker Safety Plan (NDAC 43-05-01-05 §1e; NDAC 43-05-01-13)** ***4.4.1 Definitions*** ***4.4.2 Stop Work Authority*** ***4.4.3 Incident Notification and Response*** ***4.4.4 Incident Report and Investigation***	

				4.4.5 Training ***4.4.6 Contractor Qualification and Bridging Documents*** ***4.4.7 General Health, Safety, and Welfare*** ***4.4.8 Personal Protective Equipment*** ***4.4.9 Hand Safety*** ***4.4.10 Permitted Work Activities*** ***4.4.11 Chemical, Hazardous, or Flammable Materials*** ***4.4.12 Compressed Gas and Air Cylinders*** ***4.4.13 Overhead/Outside Guarded Area*** ***4.4.14 Work Site Conduct***	
	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;	***4.1.2 Corrosion Monitoring and Prevention Plan*** *4.1.2.1 Corrosion Threat Assessment* *4.1.2.2 Identification of Critical Components and Operating Conditions;* See Appendix F *4.1.2.3 Damage Mechanism* *4.1.2.4 Corrosion Control Program (CCP)* *4.1.2.5 Annual Review* *4.1.2.6 Data Management*	
	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 sources of	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;	***4.1.3 Surface Leak Detection and Monitoring Plan***	

		drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.			
	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 one 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; and	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 one mile of the facility area's outside boundary;	***4.1.4 Subsurface Leak Detection and Monitoring Program*** ***4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring*** ***4.1.6 Baseline Sampling Program*** *4.1.6.1 Groundwater Baseline Sampling* *4.1.6.2 Soil Gas Baseline Sampling*	

		(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.			
	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;	**4.1 Testing and Monitoring Plan** ***4.1.1 Analysis of Injected CO_2 and Injection Well Testing*** *4.1.1.1 CO_2 Analysis* *4.1.1.2 Injection Well Integrity Tests* ***4.1.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring*** ***4.1.6 Baseline Sampling Program;*** See Appendix C *4.1.6.1 Groundwater Baseline Sampling* *4.1.6.2 Soil Gas Baseline Sampling* ***4.1.7 Near-Surface Monitoring Plan*** ***4.1.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front*** *4.1.8.1 Direct Monitoring Methods* *4.1.8.2 Indirect Monitoring Methods* ***4.1.9 Quality Control and Surveillance Plan;*** See Appendix D	
	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 McCall-1 – Proposed Deadwood CO_2 Injection Well Casing and Cementing Programs*** ***4.5.2 NRDT-1 – Proposed Deadwood CO_2-Monitoring Well Casing and Cementing Programs***	
	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 Well P&A Program** ***4.6.1 McCall-1 Deadwood CO_2 Injection Well Plugging and Abandonment*** *4.6.1.1 McCall-1 Injection Well-Plugging Schematic* *4.6.1.2 Tentative Plugging Procedures* ***4.6.2 NRDT-1 Deadwood Monitor Well Plugging and Abandonment*** *4.6.2.1 NRDT-1 Monitor Well-Plugging Schematic* *4.6.2.2 Tentative Plugging Procedures*	

	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; and	j. A postinjection 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*	
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;	**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 below)	
	NDAC 43-05-01-05 §1b(5)	**NDAC 43-05-01-05 §1b(5)** (5) The proposed average and maximum bottomhole 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	d. The proposed average and maximum bottomhole injection pressure to be utilized;		

Table 5-1. McCall-1 Proposed Deadwood Injection Well Operating Parameters

Predicted Metric	McCall-1	Description/Comments
Injection Volume		
Total Injected Volume, MMt	23.4	Based on 20 years of injection.
Injection Rate		
Predicted Average Injection Rate, tonnes per day	3,250	Based on total injected volumes for 20 years and using 365 operating days a year.
Maximum Predicted Daily Injection Rate, tonnes per day	3,865	Based on 20 years of injection.
Pressure		
Formation Fracture Pressure at Top Perforation, psi	6,866	The injectivity test results fracture closure gradient of 0.75 psi/ft.
Average Predicted Operating Surface Injection Pressure, psi	2,794	Based on 20 years of injection.

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<td>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;</td>
<td>e. The proposed average and maximum surface injection pressures to be utilized;</td>
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<table>
<tr><td>Maximum Wellhead Injection Pressure, psi</td><td>3,445</td><td>Maximum wellhead injection pressure is limited based on surface facility constraints and 90% of formation fracture pressure.</td></tr>
<tr><td>Average Predicted Operating Bottomhole Pressure (BHP), psi</td><td>6,139</td><td>Based on 20 years of injection.</td></tr>
<tr><td>Maximum BHP psi</td><td>6,179</td><td>Calculated maximum BHP using 90% of the closure pressure from the injectivity test at the top of the perforation. Maximum BHP is limited based on surface facility constraints.</td></tr>
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<td>NDAC 43-05-01-05 §1b(6)</td>
<td>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;</td>
<td>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;</td>
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Table 4-8a. Logging Program for Deadwood Injector Well (McCall-1 [proposed])
<table>
<tr><th>Log</th><th>Justification</th><th>NDAC Section</th></tr>
<tr><td>Cased Hole Logs: ultrasonic CBL (cement bond log), VDL (variable-density log), GR (gamma ray), Temperature Log</td><td>Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Triple Combo (resistivity, density,* neutron,* GR, caliper) and SP (spontaneous potential)

*No density or neutron in surface section.</td><td>Quantify variability in reservoir properties such as resistivity and lithology. Identify the wellbore volume to calculate the required cement volume. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>Temperature Log</td><td>Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Spectral GR</td><td>Identify clays and lithology that could affect injectivity.</td><td>43-05-01-11.2(2)</td></tr>
<tr><td>Dipole Sonic and 4-Arm Caliper</td><td>Identify mechanical properties including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>Fracture Finder Log</td><td>Quantify fractures in the Broom Creek and Black Island/Deadwood Formations and confining layers to ensure safe, long-term storage of CO_2.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>MDT (modular dynamics testing) Fluid Sampling</td><td>Collect fluid samples from the Broom Creek and Deadwood Formations for geochemical testing and TDS quantification.</td><td>43-05-01-11.2(2)</td></tr>
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<tr><td>MDT Formation Pressure Testing</td><td>Collect reservoir pressure tests to establish a pressure profile and mobility.</td><td>43-05-01-11.2(2)</td></tr>
<tr><td>MDT Stress Testing</td><td>Collect breakdown pressure, fracture propagation pressure, fracture closure pressure (minimum in situ stress) to establish injection pressure limits.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>Sidewall Cores</td><td>Sidewall cores will be collected from the injection zones and associated confining zones.</td><td>43-05-01-11.2(2)</td></tr>
</table>
Table 4-8b. Logging Program for Deadwood Monitor Well (NRDT-1 proposed monitoring well)
<table>
<tr><th>Log</th><th>Justification</th><th>NDAC Section</th></tr>
<tr><td>Cased_Hole Logs: Ultrasonic CBL, VDL, GR, Temperature Log</td><td>Identify cement bond quality radially. Detect cement channels. Evaluate the cement top and zonal isolation.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Triple Combo and SP</td><td>Quantify variability in reservoir properties such as resistivity and lithology. Identify the wellbore volume to calculate the required cement volume. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve test design and interpretations.</td><td>43-05-01-11.2(1c[1])</td></tr>
<tr><td>Temperature Log</td><td>Monitor wellbore temperature in the openhole. A temperature log will also be run in cased hole for temperature to DTS calibration.</td><td>43-05-01-11.2(1c[2])</td></tr>
<tr><td>Dipole Sonic and 4-Arm Caliper</td><td>Identify mechanical properties including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.</td><td>43-05-01-11.2(1c[1])</td></tr>
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Appendix B - WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS
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<td>NDAC 43-05-01-05 §1b(7)</td>
<td>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; and</td>
<td>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;</td>
<td>5.1 Proposed Completion Procedure to Conduct Injection Operations in the Deadwood Injection Well
Minnkota Power Cooperative (Minnkota) plans to construct one carbon dioxide (CO2) injection well (McCall-1) designed by Oxy Low Carbon Ventures in compliance with Class VI UIC (underground injection control) injection well construction requirements, as discussed in previous sections and drilled according to the proposed program in the permit to drill. The following proposed completion procedure outlines the steps necessary to complete a Deadwood well for injection purposes (Figure 5-1, Table 5-2).</td>
<td>Table 5-2. McCall-1_Deadwood Injection Well Proposed Casing Properties

Table 5-3. McCall-1_Deadwood CO_2 Injection Well Proposed Tubing Design</td>
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	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	see below	

5.1 Proposed Completion Procedure to Conduct Injection Operations in the Deadwood Injection Well

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		Injection Rate
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		Pressure
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5.2 WELL – Proposed Procedure for Monitoring Well Operations

1. Pick up work string with 8½" bit to clean cement on top of the liner. Clean cement, circulate, and pull out of the hole.
2. Pick up work string with 6¾" and rotating scrapper to clean cement inside of the liner. Clean cement to the top of the landing collar.
3. Circulate with brine 10 ppg.
4. Test casing for 30 minutes with 1,500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the Operator may require assessing the root cause and correcting it.
5. Pull bottomhole assembly (BHA) out of the hole.
6. Perform safety meeting to discuss logging and perforating operations.
7. Rig up logging truck.
8. Run cased hole logs by program. Note: run CBL/VDL (cement bond log/carriable-density log) and USIT (ultrasonic imaging tool) without pressure as a first pass and run it with 1,000 psi pressure as a second pass, if needed.

Note: In case the cementing logs show poor bonding in the cementing job, the results will be communicated to the North Dakota Industrial Commission (NDIC), and an action plan will be prepared.

9. Run perforating guns to the injection target.
10. Perforate the Black Island and Deadwood Formation, minimum 4 spf (shots per foot). Depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation.
11. Pull guns out of the hole.
12. Rig down logging truck.
13. Pick up straddle packer and run in the hole with working string.
14. Circulate with brine 10 ppg.
15. Set packer in the Deadwood Formation to isolate the perforations.
16. Rig up acid trucks and equipment.
17. Perform cleaning of the perforations with acid. Adjust acid formulation and volumes with water samples and compatibility test.
18. Rig down acid trucks and equipment.
19. Perform an injectivity test/step rate test.
20. Unset packer and circulate hole.
21. Set packer in the Black Island Formation to isolate the perforations.
22. Rig up acid trucks and equipment.
23. Perform cleaning of the perforations with acid. Adjust acid formulation and volumes with water samples and compatibility test.
24. Rig down acid trucks and equipment.
25. Perform an injectivity test/step rate test.
26. Unset packer and circulate hole.
27. Pull packer and work string out of the hole.
28. Rig up spooler and prepare rig floor to run upper completion.
29. Run completion assembly per program.
30. Circulate well with inhibited packer fluid.
31. Set packer 50 ft above the top perforations.
32. Install tubing sections, cable connector, and tubing hanger.
33. Rig up logging truck.
34. Run cased hole logs through tubing by program.
35. Rig down logging truck.
36. Nipple down BOP (blowout preventer).
37. Install injection tree.

Note: Figure 5-2 illustrates the proposed wellhead schematic

38. Rig down equipment.

Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber optic will be run and attached to the exterior of the intermediate casing. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

				Note: Liner hanger should include top packer seal. The McCall-1_Deadwood CO_2 Injection Well Proposed Tubing Design is detailed in the following section (Table 5-3). 1. Packer depth will be adjusted with the final perforation depth interval. 2. Packer will be set 50 ft above top perforations. 3. Packer is required to be nickel-plated with HNBR elastomers. 4. Inconel cable along with quartz pressure and temperature gauges will be run in upper completion.	