APPENDIX H – CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

GOLDER
MEMBER OF WSP

PERMIT APPLICATION

Class I (Non-hazardous) Injection Well Permit Application

Milton R. Young Station

Submitted to:

North Dakota Department of Environmental Quality

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1.0 INTRODUCTION

This permit application has been prepared by Golder Associates Inc. (Golder), a member of WSP, on behalf of Minnkota Power Cooperative (MPC) for two proposed Class I underground injection wells at Milton R. Young Station (MRY). Information presented in this application complies with applicable Underground Injection Control (UIC) Program permit application requirements of North Dakota Administrative Code (NDAC), Article 33.1-25 (North Dakota Legislative Council 1978); Title 40 of the Code of Federal Regulations (CFR) § 144 and 146 (USEPA n.d.); and the North Dakota Department of Environmental Quality (NDDEQ) UIC Program permit application form (Appendix A). A checklist of the requirements for a Class I (non-hazardous) injection well permit application in North Dakota, including the locations within this permit application where the requirements are addressed, is provided in Appendix A.

1.1 Background

MRY is a two-unit, lignite coal-based power plant with 705-megawatt generating capacity owned by both MPC (Unit 1) and Square Butte Electric Cooperative (Unit 2) and is operated by MPC. MRY is located adjacent to Nelson Lake, approximately six miles southeast of Center, North Dakota (Figure 1-1). Unit 1 began operations in 1970 and Unit 2 began generation in 1977. Both units have air emission controls, and plant process water is treated and tested prior to discharge to Nelson Lake through a permitted NPDES discharge (Permit No. ND-000370). The Standard Industrial Classification Code for MRY is 4911, Electric Services.

MRY is located in Sections 4 and 5 of Township 141N, Range 83W, in Oliver County. The facility address is:

Minnkota Power Cooperative
Milton R. Young Station
3401 24th St SW
Center, North Dakota 58530
Phone: (701) 794-8711

Correspondence regarding the Class I injection well(s) should be directed to:

Minnkota Power Cooperative
Attention: Daniel Laudal
5301 32nd Avenue South
Grand Forks, North Dakota 58201
Phone: (701) 330-3241

The approximate coordinates for the proposed Class I injection wells, which are positioned 0.5 miles apart, are as follows (NAD 83 State Plane Coordinate System North Dakota South, feet):

- Injection Well #1 – FREEMAN-1: N. 509,872 ft, E. 1,790,841 ft
- Injection Well #2 – RUBEN-1: N. 507,250 ft, E. 1,791,090 ft

The facility is not located on Indian lands, and MPC is unaware of historic or archaeological sites that may be impacted by the proposed Class I injection wells. Land ownership and structures in the vicinity of MRY are shown in Figures 1-2 and 1-3. A site map, including the proposed locations of the injection wells, and adjacent parcel boundaries and owner names are provided in Figure 1-3.

MPC is in the process of permitting and designing a new carbon capture and sequestration (CCS) system for MRY as part of Project Tundra, which would remove 90% of carbon dioxide emissions from Unit 2. The proposed Class I injection wells at MRY will be used to manage non-hazardous process water (primarily cooling water) from the carbon capture process. The proposed Class I injection wells (FREEMAN-1 and RUBEN-1) will be located on MPC property, south of the power block (Figure 1-3).

The proposed Class I injection wells will be operated by MPC staff. The proposed wells will be the first Class I wells that MPC has operated, and the only Class I injection wells located at the MRY site. MPC also plans to permit and construct Class VI injection wells near the plant for geologic sequestration of carbon dioxide as part of Project Tundra. All of the proposed Class VI wells will be completed in the Broom Creek Formation or the Deadwood Formation, which are both deeper than the target injection zone for the Class I injection wells (Inyan Kara Formation), as described further in Section 3.0.

1.2 Proposed Injection Overview

This permit application is for two Class I (non-hazardous) injection wells, proposed for emplacement of non-hazardous wastewater into the subsurface.

1.2.1 Proposed Injectate

MPC plans to discharge excess process water from the Project Tundra CCS system, which includes cooling tower blowdown, reverse osmosis reject, water treatment softening sludge, wet electrostatic precipitator discharge, and polishing scrubber blowdown to their existing flue gas desulfurization (FGD) scrubber blowdown vaults. FGD blowdown from the Unit 1 and Unit 2 scrubber absorber towers is delivered to the scrubber blowdown vaults and then sluiced to Scrubber Pond Cell 4, which is a composite-lined impoundment with a capacity of 307 million gallons below the permitted maximum operating elevation (2,093 feet above mean sea level [ft amsl]). Additional inflow to the FGD scrubber system includes makeup water from Nelson Lake, runoff, leachate from the closed scrubber pond cells (i.e., Cells 1, 2, and 3), and other site process waters. Free water in Scrubber Pond Cell 4 (Cells 5 and 6 will be used in the future) is siphoned back to the scrubbers for use in the scrubbing process and sluicing FGD solids. The proposed injectate will be sourced from the Unit 2 Pond Return Tank, which receives water siphoned from Scrubber Pond Cell 4. Given the known chemistry of water in the FGD scrubber system and the anticipated chemistry of the wastewaters from the CCS system, the proposed injectate is anticipated to be non-hazardous; however, because the CCS system is not operational at this time, the exact chemistry is unknown. A more detailed description of sources contributing flows to the Class I injection wells and potential water chemistry is provided in Section 6.2.

1.2.2 Permitting Strategy

This permit is for two Class I injection wells at MRY. MPC intends to construct the second injection well only if the operational flow capacity of the first well is insufficient to meet MPC's injection needs. Operation of these injection well(s) will be dependent upon whether one or two Class I injection wells are ultimately constructed.

Following approval by the NDDEQ, one injection well (FREEMAN-1) will be constructed on the existing well pad near the plant, adjacent to the proposed Class VI injection wells (Figure 1-3). Following construction and mechanical integrity testing, a step rate test, constant rate test, and falloff test will be conducted on FREEMAN-1 to determine the well's operational injection capacity. If FREEMAN-1 is determined to have sufficient capacity to meet MPC's injection needs, RUBEN-1 will not be constructed. If the capacity is determined to be insufficient, RUBEN-1 will be constructed approximately 0.5 miles south of FREEMAN-1.

The following two injection scenarios are considered as a part of this permit application:

- Scenario 1: One injection well operating at 950 gallons per minute (gpm) (1,368,000 gallons per day)
- Scenario 2: Two injection wells (spaced 0.5 miles apart) each capable of operating at 850 gpm (2,448,000 gallons per day)

1.2.3 Proposed Injection Flow

The proposed permitted injection flow rate is 950 gpm for one well operating or 850 gpm each for two wells operating, dependent upon whether one or two Class I injection wells are ultimately constructed (Section 1.2.2). In the case that two injection wells are constructed, it is unlikely that both wells will be operated at 850 gpm each continuously for 20 years because the disposal demand is not anticipated to be that high. The modeling completed to support this permit application with both injection wells operating continuously for 20 years at 850 gpm each is considered conservative and will allow for flexibility in how the wells are operated. The design life for each injection well is 20 years. The permitted injection flow rate(s) and lifespan were used for injection modeling (Section 4.0). Formation fracture pressure at MRY is estimated in Section 5.0. Upon drilling, testing, and completion of the new injection well(s), formation fracture pressure and formation hydraulic response to injection will be reevaluated. The actual maximum permitted injection flow rate at each well will be determined at the start of well operations based on injecting under pressures such that the sum of the formation hydrostatic pressure and wellhead pressure (measured at the surface) are less than the calculated formation fracture pressure, as specified in NDAC Article 33.1-25 (North Dakota Legislative Council 1978).

1.2.4 Proposed Injection Interval

The proposed injection interval for the Class I injection wells at MRY is composed of the sandstone intervals within the Inyan Kara Formation. To support characterization of the potential underground carbon dioxide storage reservoirs for Project Tundra, three separate stratigraphic test boreholes/wells were drilled to the base of the Inyan Kara Formation or deeper within five miles of MRY. Based on the logging and testing data from these nearby wells and information from other nearby drilling activities, the top of the shallowest sandstone interval of the Inyan Kara Formation at MRY is anticipated to be encountered approximately 3,667 feet below ground surface (ft bgs). Based on combinable magnetic resonance (CMR) logs from the stratigraphic test borehole constructed at MRY (J-ROC1), the Inyan Kara Formation at the Site is approximately 170 feet thick. Of that, the net thickness of permeable zones is approximately 90 feet (Section 4.3.1.1).

The Inyan Kara Formation is used extensively in North Dakota for injection of waters related to oil and gas activity (Class II injection wells). Available literature indicates that the Inyan Kara Formation will be an ideal injection interval for the proposed Class I injection wells at MRY. The injection zone is bounded by upper and lower confining units as summarized in Table 1.

Table 1: Proposed Injection Summary

Interval Name	Formations (listed from oldest to youngest)	Depth Interval (ft bgs)
Upper Confining Unit[(a)]	Cretaceous confining system: Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Shale	1,160 to 3,667
Injection Interval[(b)]	Inyan Kara Formation	3,667 to 3,838
Lower Confining Unit[(a)]	Jurassic confining system: Piper, Rierdon, Swift	3,838 to 4,705

a. Depth intervals for the upper and lower confining units are estimated at MRY using the lithostratigraphic unit top elevation figures (Figures 3-4 to 3-8), the geologic cross section figures (Figures 3-9 and 3-10), and formation top data obtained from the stratigraphic test wells constructed in support of Project Tundra (Section 2.0).

b. Depth interval for the injection interval is estimated at MRY using the CMR logs from the J-ROC1 stratigraphic test well (Section 4.3.1.1).

The concentration of total dissolved solids (TDS) in the Inyan Kara Formation at MRY is anticipated to be between 3,000 and 10,000 milligrams per liter (mg/L) based on measurements of TDS concentration for a formation water sample collected from the J-LOC1 stratigraphic test well (Section 4.3.1.6). Because the TDS concentration in the injection formation is anticipated to be below 10,000 mg/L, MPC is concurrently pursuing an Aquifer Exemption for injection into the Inyan Kara Formation. There is an existing area-based Class II aquifer exemption for the Inyan Kara Formation covering portions of west-central North Dakota, including the western two-thirds of Oliver County (Figure 1-4). The eastern edge of this exemption area covers the Oliver County townships within Range 84W. MPC's proposed Class I injection wells are located approximately two miles east of this boundary. Additionally, there are location exemptions for the Inyan Kara Formation for both Class I and Class II injection wells in neighboring counties (Figure 1-4).

1.3 Area of Review

1.3.1 Area of Review Definition

Per NDAC Article 33.1-25-01-14 (North Dakota Legislative Council 1978) and 40 CFR § 146.6 (USEPA n.d.) requirements, the area of review must be determined by either the zone of endangering influence or a fixed radius around the well not less than one quarter mile. For the purposes of this permit application, a fixed radius of 4.0 miles around each well has been proposed for the area of review. This radius is 16 times larger than the minimum required fixed radius and is a minimum of three times the distance of the radius of fluid displacement (discussed in Section 4.4.3) after 20 years of continuous injection under either injection scenario.

1.3.2 Injection Interval Penetrations

Improperly completed or abandoned wells within the area of review could potentially act as a conduit for injectate fluid or native formation fluid to flow from the injection interval into an underground source of drinking water (USDW). There is only one existing artificial penetration (J-ROC1, North Dakota Industrial Commission [NDIC] File No. 37672) into the proposed injection interval (Inyan Kara Formation) within the area of review (Figure 1-5). After drilling and testing J-ROC1, MPC plugged the borehole. Details for this one existing injection interval penetration within the area of review are provided in Table B-1 (Appendix B). As part of Project Tundra, MPC may convert J-ROC1 to a Class VI injection well and construct additional Class VI injection wells. The future wells will all be located within the area of review and will extend through the Inyan Kara Formation. They will be constructed in accordance with the standard of practice and will be tested for mechanical integrity to ensure they do not act as conduits between the Inyan Kara Formation and the lowermost USDW.

1.3.3 Shallow Groundwater Wells

A total of 158 shallow groundwater wells were identified within the area of review based on wells and driller's logs filed with the North Dakota State Water Commission (NDSWC) (Figure 1-6). An additional eight inactive United States Geological Survey (USGS) shallow wells were identified within the area of review based on groundwater monitoring sites filed in the USGS National Water Information System (USGS n.d.). Details for each of the shallow groundwater wells within the area of review identified from the NDSWC database and the USGS National Water Information System are provided in Table B-2A (Appendix B). MPC's well records contain 78 groundwater wells (73 monitoring wells) within the area of review (Figure 1-6), details of which are provided in Table B-2B (Appendix B). No attempt has been made to remove well records that may be duplicates between the NDSWC database and MPC's well network. There are no wells completed within the Fox Hills Sandstone (the lowermost USDW) within the area of review. MPC plans to construct one monitoring well in the Fox Hills Sandstone within 200 feet of FREEMAN-1 to serve as a monitoring well associated with the proposed Class VI injection wells for Project Tundra. In Oliver County, there are only two wells (one stock well and one observation well) completed in the Fox Hills Sandstone. There are 17 domestic wells located within one mile of MPC's property boundaries (Figure 1-2).

1.3.4 Corrective Action

If applicable, a corrective action plan is to be prepared and submitted to the NDDEQ for any improperly sealed, completed, or abandoned wells within the area of review. Within the 4-mile-radius area of review, there is one existing wellbore (J-ROC1) that penetrates the proposed injection interval. The J-ROC1 surface casing has been properly cemented and the borehole has been properly plugged. As such, no corrective action plan has been developed.

2.0 STRATIGRAPHIC TEST BOREHOLES/WELLS

In support of Project Tundra, three stratigraphic test boreholes/wells were drilled near MRY in Oliver County, North Dakota (Figure 1-5). Publicly available information for each of these test boreholes/wells can be obtained through the NDIC Oil and Gas Division:

- BNI-1 Borehole: NDIC Well File No. W34244 (BNI-1 Well File)
- J-LOC1 Well: NDIC Well File No. W37380 (J-LOC1 Well File)
- J-ROC1 Borehole: NDIC Well File No. W37672 (J-ROC1 Well File) (NDIC n.d.)

The three boreholes/wells were logged and tested to help characterize three geologic reservoirs for potential carbon sequestration and/or wastewater disposal (Inyan Kara Formation, Broom Creek Formation, and Deadwood Formation). The data collected from these test boreholes/wells are used to inform the local geology and hydrogeology (Section 3.0), flow and transport modeling in the Inyan Kara Formation for wastewater injection (Section 4.0), and estimation of formation fracture pressure (Section 5.0).

2.1 BNI-1 Borehole

The BNI-1 stratigraphic test borehole was drilled between January 17 and February 2, 2018. The borehole is located approximately two miles south of Center, North Dakota, in the SE quarter of the SE quarter of Section 27 T142N R84W. Ground elevation and Kelly Bushing (KB) elevation at BNI-1 are 2,067 ft amsl and 2,085 ft amsl, respectively (BNI-1 Well File). BNI-1 was drilled to a total depth of 5,316 ft below KB and terminated in the Amsden Formation (BNI-1 Well File). BNI-1 was drilled to perform geologic and petrophysical logging and conduct in situ testing. After sampling and testing was completed, BNI-1 was plugged and abandoned according to procedures established by the NDIC.

At BNI-1, the Inyan Kara Formation was encountered from a depth of approximately 3,874 to 4,043 ft below KB, for a total thickness of 178 feet (BNI-1 Well File). Formation static pressure and temperature were measured at two depths (3,996 and 4,030 ft below KB) within the Inyan Kara Formation via modular formation dynamics tester (MDT) pressure tests (see Sections 4.3.1.2 and 4.3.1.5, respectively). Additionally, a 6.7-square-mile three-dimensional seismic survey was acquired in the sections surrounding BNI-1. No hazards such as structural features, faults, or discontinuities were observed that would cause a concern about the integrity of the confining units overlying the Inyan Kara Formation.

2.2 J-LOC1 Well

MPC drilled the J-LOC1 stratigraphic test well in the SW quarter of the NW quarter of Section 27 T142 R84W in Oliver County, North Dakota, between May 14, 2020, through June 10, 2020. Ground elevation and KB elevation at J-LOC1 are 2,068 ft amsl and 2,093 ft amsl, respectively (J-LOC1 Well File). The J-LOC1 borehole was drilled to a total depth of 10,470 ft below KB and terminated within Precambrian amphibolite. This borehole was cased to a depth of 10,450 ft below KB to allow for brine injection testing into the coarse grained siliciclastics of the target formations (Inyan Kara Formation, Broom Creek Formation, and the Deadwood Formation) (J-LOC1 Well File). The primary objectives of completing the J-LOC1 well were to extract core samples, collect geologic and petrophysical log data, collect fluid samples, perform injection testing, and conduct in situ testing of the Inyan Kara, Broom Creek, and Deadwood Formations.

The Inyan Kara Formation was observed to be approximately 170 feet thick from 3,888 feet to 4,058 ft below KB. The Cretaceous confining system overlying the Inyan Kara Formation, which is composed of the formations listed in Table 1, was observed to be approximately 2,590 feet thick. The Jurassic confining system underlying the Inyan Kara Formation, which is composed of the formations listed in Table 1, was observed to be approximately 850 feet thick (J-LOC1 Well File).

Formation static pressure and temperature were measured at three depths (3,891, 4,018, and 4,019 ft below KB) within the Inyan Kara Formation via MDT pressure tests (see Sections 4.3.1.2 and 4.3.1.5, respectively). One fluid sample from the Inyan Kara Formation was collected (see Section 4.3.1.6 and Table E-1 in Appendix E). The well casing was perforated across a 10-foot interval within the Inyan Kara Formation (4,015 to 4,025 ft below KB) and the following tests were performed: 1) step rate injection test, 2) constant rate injection test, and 3) falloff test. Results of the step rate injection test were used to estimate formation fracture pressure (discussed in Section 5.0). Results of the falloff test were used to estimate formation permeability (discussed in Section 4.3.1.4). Core samples from the Inyan Kara Formation were tested in the laboratory for porosity, permeability (Section 4.3.1.4), and pore volume compressibility (Section 4.3.1.9).

2.3 J-ROC1 Borehole

MPC drilled the J-ROC1 borehole on the well pad south of the power block at MRY in the SW quarter of the NW quarter of Section 4 T141N R83W in Oliver County, North Dakota. J-ROC1 is approximately 100 feet northwest of the proposed FREEMAN-1. Ground elevation and KB elevation at J-ROC1 are 2,004 ft amsl and 2,029 ft amsl, respectively (J-ROC1 Well File). The J-ROC1 borehole was drilled to a total depth of 9,871 ft below KB and terminated within Precambrian basement rock (J-ROC1 Well File). J-ROC1 was drilled to collect additional geologic and petrophysical log data directly underlying MRY.

The Inyan Kara Formation was observed to be approximately 170 feet thick from 3,694 to 3,865 ft below KB. The Cretaceous confining system overlying the Inyan Kara Formation was observed to be approximately 2,520 feet thick. The Jurassic confining system underlying the Inyan Kara Formation was observed to be approximately 870 feet thick (J-ROC1 Well File).

Results of the CMR logs at J-ROC1 indicate the net thickness of permeable and porous sandstone within the Inyan Kara Formation to be approximately 90 feet at MRY (Section 4.3.1.1). The CMR logs at J-ROC1 were also used to estimate effective porosity (Section 4.3.1.3) and permeability (Section 4.3.1.4) of the permeable intervals of the Inyan Kara Formation. Additionally, a 12-square-mile three-dimensional seismic survey was acquired around J-ROC1. No hazards such as structural features, faults, or discontinuities were observed that would cause a concern about the integrity of the confining units overlying the Inyan Kara Formation.

3.0 GEOLOGY AND HYDROGEOLOGY

This section, describing the geology and hydrogeology near MRY, was developed primarily using local and regional literature sources from the North Dakota Geological Survey (NDGS) and the USGS, and supplemented with local information collected from the three recently drilled stratigraphic test boreholes/wells described in Section 2.0.

3.1 Regional Geology

MRY is located in central North Dakota within the southeastern part of the Williston Basin. A geologic map of North Dakota is provided in Figure 3-1. The North Dakota Stratigraphic Column is provided in Figure 3-2. For purposes of this permit application, the term "regional geology" refers to geologic features of the Williston Basin as a whole.

3.1.1 Geologic History

MRY is located in central Oliver County, North Dakota, approximately six miles southeast of Center, North Dakota. The Williston Basin covers approximately 300,000 square miles over parts of North Dakota, South Dakota, Montana, and parts of the adjacent Canadian provinces of Saskatchewan and Manitoba. The basin's deepest point is believed to be near Williston, North Dakota (NDGS 2020), and Oliver County is approximately 135 miles southeast of Williston. Oliver County is located within the southeastern portion of the structural basin (Carlson 1973).

Western North Dakota experienced a major orogeny approximately 1.9 to 1.6 billion years ago resulting in igneous and metamorphism in western North Dakota (Bluemle 2000). One well located in Oliver County penetrated Precambrian amphibolite at 8,850 feet (Carlson 1973). Two of the three stratigraphic test boreholes/wells (J-LOC1 and J-ROC1) drilled in support of Project Tundra encountered the Precambrian amphibolite between 9,725 and 10,280 ft bgs (J-LOC1 Well File and J-ROC1 Well File). The Williston Basin likely initially began to develop during the Late Precambrian or Early Cambrian during crustal uplift of the dense Precambrian rocks. Subsidence then began in the Early Paleozoic, possibly as a result of buoyant adjustment of the dense, uplifted crustal block. Sediments that have accumulated in the Williston Basin since the end of the Precambrian reach a maximum thickness greater than 16,000 feet (Bluemle 2000).

North Dakota subsided relative to the Canadian Shield during the Early Paleozoic, resulting in the development of an interior seaway (Bluemle 2000). Interior seaways developed in the northwest North Dakota portion of the Williston Basin at least four times during the Paleozoic, resulting in deposition of carbonates, sandstones, shales, and evaporites. The area was emergent during the Early to Middle Ordovician, Middle Silurian to Middle Devonian, Late Mississippian to Early Pennsylvanian, and during the Triassic. During these periods of significant erosion, unconformities developed between sedimentary units (Bluemle 1971).

Marine deposition dominated during the Mesozoic from Middle to Late Jurassic until a transition to non-marine deposition that continued until the Early Cretaceous. The Early Cretaceous marked a return to marine deposition as thick sequences of fine-grained clastics accumulated. The Late Cretaceous into the Paleocene was characterized by non-marine deposition with a period of marine deposition in the Paleocene followed by a return to non-marine deposition (Bluemle 1971).

Since the mid-Pliocene and continuing through the Pleistocene, North Dakota experienced a continental climate with a succession of ice sheets advancing south from Canada (Bluemle 2000).

3.1.2 Regional Physiography

The landscape of North Dakota can be split into two physiographic provinces: 1) the Great Plains, which covers much of southwestern North Dakota, and 2) the Central Lowlands, covering the north and eastern parts of the state. The effect of glacial activity on the modern landscape is the primary difference between the two provinces. The Central Lowlands have been shaped completely by glacial deposition, but little evidence of glacial activity is visible in the Great Plains, which extend westward to the Rocky Mountains (Bluemle 2000). The Central Lowlands are characterized by an intricate but low relief hill and valley topography. Drainage in the glaciated Central Lowlands ranges from non-existent to well-developed. Local relief (i.e., maximum difference in elevation within a township-sized area) in the Central Lowlands ranges from less than 100 feet to 300 feet, except in the hummocky Turtle Mountains and Prairie Coteau. The Great Plains were shaped primarily by bedrock erosion via fluvial and eolian processes, resulting in irregular surface structure that ranges from gently sloping to rugged hills. Local relief of the Great Plains province generally ranges from 300 feet to 500 feet, except for the Little Missouri Badlands, where local relief regularly exceeds 500 feet (Bluemle 2000).

The Williston Basin, which extends through all of western and approximately half of eastern North Dakota, is overlain by both the Central Lowlands and Great Plains provinces in North Dakota. The proposed injection site is in the southeastern portion of the Williston Basin and falls within the Central Lowlands province of North Dakota. Both the Great Plains and the Central Lowlands provinces can be subdivided into several distinct sub-physiographic regions (Bluemle 2000); those present in Oliver County are described in Section 3.2.1.

3.1.3 Structural Geology

The Williston Basin is generally characterized as a sag or depression and as tectonically benign; its configuration was most likely formed by structural deformation and down-to-the-basin block faulting in Precambrian-rooted structures. Additionally, deformation related to the Trans-Hudson orogenic belt played a role in the development of the basin (Anna et al. 2013). The Trans-Hudson orogenic belt sutured the Archean Superior craton to the Archean Wyoming craton and the resulting collision created a north–south trending strike-slip fault and shear belt. The basin center was created and impacted by later folding of the Trans-Hudson belt and possible rifting. Multiple Precambrian fault zones within the Williston Basin were reactivated during the Neoproterozoic to create new north–south and northwest–southeast-oriented structures. These reactivated fault zones acted as precursors to structures and zones of weakness that formed the Nesson, Cedar Creek, Little Knife, and Billings anticlines; the

Bismarck-Williston lineament; and Goose Lake trend along with many small-scale structures that are pervasive throughout the Williston Basin (Figure 3-3) (Anna et al. 2013).

Lithofacies distribution and thickness patterns reflect the influence of paleostructure on sedimentation in the Williston Basin. Recurrent movement of basement grabens, half-grabens, and horsts is expressed by patterns of faults, fractures, and folds. Drape folds were commonly created in overlying sedimentary rocks. Wrench or strike-slip faults occur as simple shears and are typically associated with folds, thrust faults, and reverse faults, while scissor-type faults are also common. Folds, thrust faults, and reverse faults are associated with Laramide features. Basement faults have less effect on sedimentation distribution as the rock section thickens, and the observed distribution and thickness of sediments stems from recurrent movement of Precambrian blocks, eustatic changes in sea level, and from quantity and quality of available sediments (Anna et al. 2013).

The present structural configuration of the basin was shaped in the Late Cretaceous (Bluemle 2000), and the regional dip of Cenozoic deposits is to the north and west (Carlson 1973).

3.1.4 Regional Stratigraphy

The Williston Basin represents a portion of the North American craton where the sedimentation history can be generally characterized as carbonate deposition during the Paleozoic and clastic deposition during the Mesozoic and Cenozoic, and where thickness of Phanerozoic strata is more than 16,000 feet in the basin center (Anna et al. 2013). Six major depositional sequences, each bound by major unconformities, are distinguished within Phanerozoic rocks of North America. As presented in the North Dakota Stratigraphic Column (Figure 3-2), from oldest to youngest, these sequences are the Sauk, Tippecanoe, Kaskaskia, Absaroka, Zuni, and Tejas (Anna et al. 2013). Within these major depositional sequences are allocyclic successions that are caused by variations external to the basin such as climate change and tectonic movements. First order cycles are likely caused by major eustatic cycles driven by the formation and breakup of supercontinents with durations of approximately 200 to 400 million years (m.y.). Second order cycles are caused by eustatic cycles induced by volume changes in global midocean spreading ridge systems with a duration of approximately 10 to 100 m.y. Third order cycles are possibly produced by spreading ridge changes and continental ice growth and decay that last for approximately 1 to 10 m.y. Fourth and fifth order cycles each are attributed to Milankovitch glacioeustatic cycles, while the duration of fourth order cycles is approximately 0.2 to 0.5 m.y. and the duration of fifth order cycles is approximately 0.01 to 0.2 m.y. (Boggs 2012).The major sequences that consist of first order and second order cycles within the Williston Basin are likely the result of eustatic sea level change, while third and fourth order cycles are possibly the result of tectonic activity or a combination of tectonic activity and eustacy. Substantial depositional environment and sedimentation changes were possible in response to changes in water depth because water depths during the Phanerozoic were relatively shallow (Anna et al. 2013). Paleozoic rocks range in thickness from 4,500 feet in southeastern Oliver County to approximately 7,500 feet in northwestern Mercer County. The Paleozoic stratigraphy is represented by the Sauk, Tippecanoe, Kaskaskia, and Absaroka Sequences. The Absaroka Sequence extends into the Triassic rocks of the Mesozoic. Mesozoic rocks range in thickness from approximately 3,900 feet in southeastern Oliver County to approximately 4,600 feet in northwestern Mercer County. The Mesozoic rocks fall within the Zuni Sequence. The Cenozoic rocks are represented by the Zuni and Tejas Sequences, and range in thickness from approximately 250 feet in southeastern Oliver County to approximately 1,350 feet in northwestern Mercer County (Carlson 1973).

3.1.4.1 Basement Rock

The Precambrian rocks, which are the deepest rock layers in the earth's crust, are metamorphic, having transformed over geologic time from sediments that settled in a marine environment. As a result of intense heat and pressure, these sediments were transformed into gneiss and marble alongside intrusive granite (Anna et al. 2013). The geology of the Precambrian rocks underlying the Williston Basin is complex, consisting of many juxtaposed, fault-bounded lithostructural domains (Peterman and Goldich 1982). Little is known with certainty about the Precambrian basement rock due to the depth and very few wells drilled into this sequence. The Precambrian basement rock is encountered at approximately 9,725 ft bgs at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.2 Sauk Sequence

The Deadwood Formation represents the Sauk Sequence in Oliver County, and consists of approximately 295 feet of limestone, shale, and sandstone. The formation thickens to approximately 500 feet to the west in Mercer County (Carlson 1973). The Deadwood Formation represents the first order transgression over a low-relief Precambrian surface, while some major structural features impacted thickness patterns, such as the Nesson anticline. Weathered Precambrian rocks served as the sediment source for the Deadwood Formation, and the sediment was eroded from highlands to the east or from the Transcontinental arch to the southeast (Anna et al. 2013). Sandstones and shales are the dominant lithologies in North Dakota, resulting from siliciclastic sedimentation (NDGS 2000). The Sauk Sequence is anticipated to be encountered at approximately 9,285 ft bgs (top of Deadwood Formation) at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.3 Tippecanoe Sequence

The thickness of Tippecanoe Sequence rocks ranges from approximately 1,360 feet in eastern Oliver County to approximately 1,820 feet in Mercer County (Carlson 1973). The early Tippecanoe Sequence is represented by the Winnipeg Group, and this package consists of the Black Island, Icebox, and Roughlock Formations (NDGS 2020). The Bighorn Group conformably overlies the Winnipeg Group. The Red River Formation is the basal unit of the Bighorn Group, and the Red River Formation is overlain by the Stony Mountain and Stonewall Formations. The Winnipeg Group unconformably overlies the Deadwood Formation except in the eastern portion of the basin where it overlies Precambrian basement. The latest deposition of the Tippecanoe Sequence resulted in the Interlake Formation, which conformably overlies the Stonewall Formation (NDGS 2020). The Red River, Stony Mountain, and Interlake Formations represent conformable sedimentation, but Tippecanoe deposition ended at the end of the Silurian by a major regression leading to significant erosion. Especially around the basin margin, parts of the Interlake Group, Stony Mountain, Stonewall, and Red River Formations were removed via erosion (Anna et al. 2013). The Tippecanoe Sequence is situated approximately 7,885 ft bgs (top of Interlake Formation) at MRY, using logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.4 Kaskaskia Sequence

The Kaskaskia Sequence rocks are approximately 2,250 feet thick in eastern Oliver County and approximately 3,400 feet thick to the west in Mercer County (Carlson 1973). The sequence began with a transgressive event in the Early Devonian and concluded with a major regression at the end of the Mississippian, and uplift of the Transcontinental arch resulted in the basin configuration shifting from circular in northwestern North Dakota to a northwest–southeast-trending elongated shelf basin. The Williston Basin became the southeastern corner of the newly formed Devonian Elk Point Basin (Anna et al. 2013). Within the greater Elk Point Basin, numerous cycles of sea level change resulted in diverse lithologies being deposited as part of the Elk Point Group, and the first transgression deposited the Ashern and Winnipegosis Formations followed by the regression-related Prairie Formation. The next transgression deposited the Manitoba Group consisting of the Dawson Bay Formation and overlying Souris River Formation (Anna et al. 2013; NDGS 2020). The Jefferson Group conformably overlies the

Souris River Formation, and is composed of the Duperow, Birdbear, and Three Forks Formations that were deposited as sea level regressed. A third major transgression in the Late Devonian resulted in the deposition of the Bakken Formation, which conformably overlies the Three Forks Formation in the basin center and unconformably overlies it elsewhere (Anna et al. 2013; NDGS 2020). During the Early Mississippian there was a shift from the northwest–southeast elongated Elk Point Basin back to a circular basin configuration, and the depocenter was reestablished in northwestern North Dakota. Following this structural change, the Madison Group was deposited within a renewed cycle of transgressions and regressions (Anna et al. 2013). Regressing sea levels led to the deposition of the Madison Group, which consists of the Lodgepole, Mission Canyon, and Charles Formations. The Madison Group formations are conformable in the basin center but exhibit complex intertonguing relationships along the basin margins (NDGS 2020). The Big Snowy Group, recorded by the Kibbey and Otter Formations, overlies the Madison Group and records influences of the Ancestral Rocky Mountain orogeny. The top of the Big Snowy Group represents a major regression (Anna et al. 2013; NDGS 2020). Based on logging of drill cuttings and electric logs collected from J-ROC1, the Kaskaskia Sequence is approximately 5,315 ft bgs (top of the Big Snowy Group) at MRY (J-ROC1 Well File).

3.1.4.5 Absaroka Sequence

The Absaroka Sequence rocks are approximately 550 feet thick in eastern Oliver County and approximately 1,130 feet thick in Mercer County (Carlson 1973). The sequence represents the upper part of a first order regression and includes several secondary transgressive and regressive cycles within a relatively shallow sea. The initial second order transgression was brought on by uplift of areas to the east, west, and south that became major sources of clastic sediment deposited into the Williston Basin. This transgressive sequence includes interbedded sandstone, siltstone, shale, and limestone of the Pennsylvanian Tyler Formation and equivalents (Anna et al. 2013). The Minnelusa Formation overlies the Tyler Formation and records sedimentation from the Ancestral Rocky Mountains and Transcontinental arch. Regression continued and major unconformities occur near the end of the Pennsylvanian, and the end of the Permian and Triassic. The Minnekahta Formation overlies the Minnelusa Formation (Anna et al. 2013). The Spearfish Formation overlies the Minnekahta Formation and unconformably overlies the Madison Group across much of eastern North Dakota (NDGS 2020). The Absaroka Sequence is located approximately 4,660 ft bgs (top of Spearfish Formation) at MRY, based on logging of drill cuttings and electric logs collected from J-ROC1 (J-ROC1 Well File).

3.1.4.6 Zuni Sequence

The Zuni Sequence rocks range in thickness from approximately 3,270 feet in eastern Oliver County to approximately 4,300 feet in Mercer County (Carlson 1973). The lithologic package contains three major chronostratigraphic units bounded by unconformities: Middle and Upper Jurassic, Lower Cretaceous, and Upper Cretaceous and Tertiary through Paleocene (Anna et al. 2013). Cretaceous rocks include well-developed sandstones in the Fall River-Lakota, also called the Inyan Kara interval, and poorly developed sandstone in the Newcastle Formation. The Cretaceous rocks below the Fox Hills Formation consist of gray and calcareous shales with thin bentonites; they include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations. The Fox Hills Formation conformably overlies the Pierre Formation (Bluemle 1973).

3.1.4.7 Tejas Sequence

The Tejas Sequence consists of silt, clay, sand, sandy loam, and gravel in Oliver County (Carlson 1973). The Tejas Sequence represents the final first order regression in the sedimentary record of the Williston Basin, and the system is composed of three regional transgression–regression cycles with strata ranging in age from mid-Paleocene through the Quaternary (Anna et al. 2013).

3.2 Local Geology

Within Section 3.2.1, the term "local" refers to Oliver County. The definition of "local" changes after Section 3.2.1 to describe the area within an approximately 40-mile radius of the proposed injection site.

3.2.1 Local Physiography

Oliver County is located within the Missouri Slope District of the Glaciated Missouri Plateau Section of the Central Lowland Province. Pleistocene and Recent deposits are found north of Square Butte Creek in Oliver County. South of this area, glacial deposits are patchy or absent on the uplands but are relatively thick in the Knife River valley. Since the glaciers retreated, Late Pleistocene to Recent slopewash from the valley walls has accumulated in lowland areas (Croft 1973).

3.2.2 Structural Geology

The structural geology within a 40-mile radius of the proposed injection site is generally shaped by the structure of the Williston Basin. Formation top data from the NDIC Oil and Gas Division were used to develop lithostratigraphic unit top elevation figures for the formations of interest, which includes the tops of the Pierre Shale (Figure 3-4), Mowry Formation (Figure 3-5), Inyan Kara Formation (Figure 3-6), Swift Formation (Figure 3-7), and Rierdon Formation (Figure 3-8). For simplicity, lithostratigraphic unit top elevation figures were not created for the shale formations of the Colorado Group (Niobrara, Carlile, Greenhorn, and Belle Fourche) or the Newcastle and Skull Creek Formations. Using the formation top data, these contours were developed by averaging the results of the inverse distances weighted interpolation and the Kriging method (linear semivariogram method).

Two geologic cross sections were created using the lithostratigraphic unit top elevation figures (Figures 3-4 to 3-8) to evaluate the general stratigraphic framework in the vicinity of MRY. Cross section A-A' has a northwest–southeast alignment (Figure 3-9) and cross section B-B' has a southwest–northeast alignment (Figure 3-10). The Inyan Kara Formation is approximately 170 to 200 feet thick in the vicinity of MRY. The structural tops depicted in these figures generally parallel each other, maintaining relatively consistent thicknesses within the 40-mile radius.

Cross section A-A' (Figure 3-9) depicts an irregular ground surface with small local variations in elevations (less than 500 feet) that generally slopes gently to the east and a relatively flat Missouri River valley. The tops of the Pierre Shale, Mowry Formation, Inyan Kara Formation, Swift Formation, and Rierdon Formation generally dip to the northwest, with deeper strata dipping the most steeply, most notably for the Swift and Rierdon Formations.

Cross section B-B' (Figure 3-10) depicts the Missouri River valley north of MRY and more irregular ground surface with relief of up to approximately 300 feet south of the Missouri River valley. North of MRY, ground topography is less variable with gentle slopes toward the Missouri River. The structural dips at MRY are generally sub-horizontal with a low-degree southern dip emerging below the top of the Mowry Formation approximately 10 miles north of MRY.

3.2.3 Injection Interval Stratigraphy

The following sections describe the proposed injection interval and surrounding units as present in Oliver County. Emphasis is placed on the bounding confining units.

3.2.3.1 Injection Interval – Inyan Kara Formation of the Lower Dakota Group

Within the Cretaceous System, the Dakota Group consists of, in ascending order, the Inyan Kara (also called the Fall River-Lakota), Skull Creek, Newcastle, and Mowry Formations (Butler 1984). Another definition of the Inyan Kara Group includes the locally recognized Fuson Shale Formation between the older Lakota Sandstone and the younger Fall River Sandstone (Buursink et al. 2014). The Inyan Kara Formation is primarily sandstone in the south-central, southeast, north-central, and northeast portions of North Dakota. In North Dakota, the water-bearing sandstones of the Inyan Kara Group, including other sandstones of the Dakota Group, form the Dakota aquifer. The Dakota aquifer is the shallowest aquifer with state-wide extent (Wartman 1984). The J-ROC1 well drilled at MRY encountered the Inyan Kara Formation at approximately 3,669 ft bgs. The transition from the overlying Skull Creek Formation to the Inyan Kara Formation at J-ROC1, J-LOC1, and BNI-1 were similar, with mud-dominated flaser bedding giving way to sand-dominated lenticular bedding with very fine grained, quartzose sandstone interbeds (J-ROC1, J-LOC1, and BNI-1 Well Files). The main sandstone interval of the Inyan Kara Formation is described as exhibiting large intervals of apparently moderate to good permeability, fine grained, well rounded, quartzose sandstone. The lower portions of the Inyan Kara Formation show increasing interbedding of sand-rich dark gray shale with increasingly significant portions of pyrite and organic rich clasts. Intervals of light to medium gray-green siltstones and very fine-grained sandstones with large zones of oxidation and reduction with chlorite cement constitute the lowermost Inyan Kara Formation (J-ROC1, J-LOC1, and BNI-1 Well Files).

The Inyan Kara Formation is the target interval for injection of non-hazardous wastewater at MRY. Northwest–southeast and northeast–southwest cross sections through MRY show the Inyan Kara is approximately 170 to 200 feet thick beneath MRY (Figures 3-9 and 3-10).

The Inyan Kara Formation is a favorable injection interval for the following reasons:

- The sandstone lenses in the Inyan Kara Formation have high permeability and porosity and do not typically require stimulation prior to injection.
- The Inyan Kara Formation is confined by thick and impermeable shales above by the Cretaceous confining units and below by the Jurassic confining units.

Because of these excellent properties, the Inyan Kara Formation is commonly used for wastewater injection in North Dakota. As described in Section 1.2.4, the proposed injection interval in the Inyan Kara Formation at MRY is anticipated between 3,667 and 3,838 ft bgs and is subject to change based on observed conditions during drilling of the Class I injection well(s).

3.2.3.2 Underlying and Overlying Confining Units

Underlying the target injection interval (Inyan Kara Group) in order of oldest to youngest, are the Piper, Rierdon, and Swift Formations. The Piper Formation is characterized by limestone, anhydrite, salt, and red shale. The Rierdon and Swift Formations are dominated by shale and sandstone (Carlson 1973). The upper units of the Dakota Group overlie the Inyan Kara Group, and in order of oldest to youngest are the Skull Creek, Newcastle, and Mowry Formations. The Skull Creek and Mowry Formations are dominated by shale, while the Newcastle Formation consists of sandstone. Overlying the Mowry Formation are thick shale units of the Colorado and Montana Groups, including the Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Carlson 1973). The Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations are considered the upper seal on the Inyan Kara Formation, isolating the proposed injection interval from the lowest USDW, the Fox Hills Sandstone. The Rierdon and Swift Formations serve as the lower seal, isolating the proposed injection interval from the underlying Pennsylvanian aquifer (Minnelusa Group) (Buursink et al. 2014). These units underlying and overlying the Inyan Kara Group serve as confining layers that can vertically contain injected fluids within the Inyan Kara Formation (Nesheim et al. 2016).

3.2.3.2.1 Underlying Confining Unit

The Jurassic confining unit, which underlies the Inyan Kara Formation, is composed of the Swift Formation and the Rierdon Formation. In North Dakota, the Swift Formation consists of varicolored shales; geophysical logs indicate that the Swift Formation is more shale-prone than in other regions. Near MRY, the Swift Formation is composed of approximately 400 to 500 feet (Figure 3-9 and 3-10) of shale with few sandstone interbeds. The Rierdon Formation consists of shale, anhydrite, limestone, salt, and sandstone. The Jurassic confining unit serves as an effective lower seal for the proposed injection interval (Buursink et al. 2014).

3.2.3.2.2 Overlying Confining Unit

The Cretaceous confining units, composed of a thick, impermeable group of shales, overlies the Inyan Kara Formation and effectively isolates it from the lowermost USDW, the Fox Hills Sandstone. The Cretaceous confining unit is composed of the Pierre Shale, Niobrara Formation, Carlile Formation, Greenhorn Formation, Belle Fourche Formation, and Mowry Formation (listed in descending order).

The Pierre Shale is a regionally extensive, thick unit of late-Cretaceous-aged marine shales that can exceed 3,000 feet of thickness in some areas of the northern Great Plains. Shale units underlying the Pierre Shale Formation also act as effective confining units, particularly as part of the larger group of formations composing the Cretaceous confining unit (Downey and Dinwiddie 1988). Underlying the Pierre Shale are the Niobrara (gray marine, calcareous shale), Carlile (gray marine shale with interbeds of thin sandstone), Greenhorn, Belle Fourche, and Mowry Formations. The Greenhorn Formation is a sandstone sequence with interbedded chalky shale, grey to black marine shale, and numerous bentonite beds. The Mowry Formation consists of a medium to dark gray shale with traces of bluish gray bentonitic claystone. Previous aquifer studies, most notably the USGS Regional Aquifer Systems Analysis (RASA) and the USGS Hydrologic Investigations Atlas, have grouped these units together as the uppermost bedrock confining unit in the Williston Basin region (Downey and Dinwiddie 1988; Whitehead 1996). The Cretaceous confining unit has an estimated thickness of 2,500 feet at MRY (Figures 3-9 and 3-10, J-ROC1 Well File) and serves as an effective upper seal for the proposed injection interval.

3.3 Groundwater

3.3.1 Regional Groundwater

North Dakota's groundwater resources are supplied by the Northern Great Plains regional aquifer system and various shallower local aquifers. The five bedrock aquifers present in North Dakota are described in the following sections. A conceptual depiction of the lateral and vertical extents of the bedrock aquifers in North Dakota is shown in Figure 3-11. A cross section depicting regional groundwater flow in North Dakota is provided in Figure 3-12.

3.3.1.1 Lower Tertiary Aquifer

Most of the water in the Lower Tertiary aquifer is stored in and transported through semi-consolidated to consolidated sandstone beds of the Fort Union Group. The thickness of the Fort Union Group is highly variable, ranging from 300 feet in northeastern Montana and northwestern North Dakota to 3,600 feet in the Powder River Basin. However, the thickness of the permeable layers within the Fort Union Group is much less than the total thickness of the unit. On a regional scale, groundwater in the Lower Tertiary aquifer generally flows northeastward from recharge areas at higher altitudes in eastern Montana, northeastern Wyoming, and southwestern North Dakota through the Williston Basin. The potentiometric surface of this aquifer generally parallels the surface topography due to its regionally unconfined condition. Large rivers in the region are discharge areas for the Lower Tertiary aquifer, resulting in potentiometric low points that follow the course of the rivers (Whitehead 1996). The potentiometric surface of the Lower Tertiary aquifer is shown in Figure 3-13.

3.3.1.2 Upper Cretaceous Aquifer

In the Williston Basin, the most significant water-yielding layers of the Upper Cretaceous aquifer are the sandstone beds of the Hell Creek Formation and the Fox Hills Sandstone Formation. Composed of interbedded sandstone, siltstone, claystone, and thin, localized beds of lignite, the Hell Creek Formation varies from 350 to 3,400 feet in thickness within the basin. The Fox Hills Sandstone is one of the most continuous water yielding formations within the aquifer system and is 300 to 450 feet thick. Regional groundwater flow patterns in the Upper Cretaceous aquifer closely resemble that of the overlying Lower Tertiary aquifer, with flow northeastward from high altitude recharge areas in eastern Montana and northeastern Wyoming and discharging into major rivers of the region (Figure 3-14). The Upper Cretaceous aquifer is confined in Wyoming and central Montana and unconfined in most of the Williston Basin (western North Dakota and northwestern South Dakota). Because of their connection with surface water resources, the Lower Tertiary and Upper Cretaceous aquifers are characterized by local flow systems with short flow paths. The Upper Cretaceous aquifer generally contains water with TDS concentrations less than 3,000 mg/L, with areas of less than 1,000 mg/L near the Black Hills Uplift and at the boundaries of the aquifer. Small, localized areas in North Dakota and South Dakota have dissolved solids concentrations as high as 10,000 mg/L. The dominant ions dissolved in water of the Upper Cretaceous aquifer are sodium, sulfate, and bicarbonate, and generally high sodium concentrations make the water unsuitable for irrigation. The Upper Cretaceous aquifer is a domestic and livestock watering supply for much of the region (Whitehead 1996).

3.3.1.3 Lower Cretaceous Aquifer

Several thick shale layers overlying the Lower Cretaceous aquifer separate it from the Upper Cretaceous aquifer and act as a confining unit. The Lower Cretaceous aquifer is composed of the following principal water-yielding units within the Williston Basin: The Fall River Sandstone and the Lakota Formation, collectively referred to as the Inyan Kara Formation, in addition to the Newcastle Sandstone. While the Newcastle Sandstone is more than 400 feet thick in southeastern South Dakota, it is mostly absent throughout North Dakota. The Inyan Kara Group is 700 feet thick in central Montana but thins eastward into the Dakotas. On a regional scale, groundwater flows northeastward from high altitude and structural uplift recharge areas in central Montana and northeast Wyoming to discharge areas in eastern North Dakota and South Dakota (Figure 3-15). Most of the aquifer is overlain by a thick confining unit that tends to isolate the aquifer from other systems, except in localized zones of recharge (central Montana and northeast Wyoming) and discharge (eastern North Dakota and South Dakota). In the Lower Cretaceous aquifer, freshwater (TDS concentrations less than 1,000 mg/L) is only present near the Bighorn Mountains and the Black Hills Uplift recharge areas. Throughout most of the remainder of the aquifer, the TDS concentrations are greater than 3,000 mg/L; much of the slightly saline water is hypothesized to result from upward leakage of highly mineralized water from underlying Paleozoic aquifers. The Lower Cretaceous aquifer is the primary source for livestock watering and domestic supply in eastern North Dakota because it is the shallowest bedrock aquifer in that area. In the deep parts of the Williston Basin, the water in this aquifer is classified as very saline or brine (Whitehead 1996).

Wells completed in the Inyan Kara Formation could be considered possible receptors of injectate from the proposed injection site. Based on the NDSWC database, the nearest downgradient water supply well extracting water from the Dakota Group (Inyan Kara Formation) is located approximately 75 miles northeast of MRY in the northwest corner of Wells County (NDSWC Well Index 11697). This well is classified as a domestic water well. Additional downgradient water supply wells completed in the Dakota Group are more than 100 miles from MRY.

3.3.1.4 Pennsylvanian Aquifer

Underlying the Lower Cretaceous aquifer are confining units composed of shales, limestones, and siltstones of Jurassic, Triassic, and Permian ages. Below that, the interbedded shale, sandstone, and carbonate of Pennsylvanian age makes up the Pennsylvanian aquifer. Water-bearing sandstone units are found in the Tensleep Formation in central to north-central Wyoming and in south-central Montana. In western North Dakota and along the eastern edge of the Williston Basin, analogous units are found in the middle of the Minnelusa Formation. Additionally, interbedded sandstone layers are prevalent in the upper part of the Minnelusa Formation in the Powder River Basin, the Williston Basin, and in western North Dakota. Regionally, groundwater flows northeastward from recharge zones in Wyoming, Montana, and South Dakota, before flowing southeastward in western North Dakota, and finally discharging by upward leakage to the Lower Cretaceous aquifers in central North and South Dakota (Figure 3-16). Freshwater is found in the Pennsylvanian aquifer only near the Bighorn Mountains, Little Belt Mountains, and Black Hills Uplift recharge areas. Downgradient of recharge zones, water progresses from brackish to briny, with TDS concentrations upward of 100,000 mg/L in parts of the Williston Basin and the Powder River Basin (Downey 1986). The Minnelusa Formation is not used as a water supply source in North Dakota due to its water quality and depth. Although the Pennsylvanian system falls within the Paleozoic era, and should therefore be considered an Upper Paleozoic aquifer, it is classified as a confining unit in the Groundwater Atlas (Whitehead 1996). The 1986 RASA study considered the Pennsylvanian aquifer an important source of water in the Northern Great Plains; therefore, in this permit application, it is considered as a regional aquifer. However, as Whitehead (1996) does not include the Pennsylvanian aquifer in his Upper Paleozoic aquifer system, it is considered distinct from the Upper Paleozoic aquifer.

3.3.1.5 Upper Paleozoic Aquifer

The next principal aquifer is the Upper Paleozoic aquifer, which is isolated from the Pennsylvanian aquifer by the interbedded shales, sandstones, and limestones of the Big Snowy Group. The Upper Paleozoic aquifer, as defined by Whitehead (1996), consists primarily of the Madison Group. From youngest to oldest, the Madison Group is composed of the Charles Formation, the Mission Canyon Limestone, and the Lodgepole Limestone. The Charles Formation, consisting mostly of evaporite deposits, is a confining unit, while the Mission Canyon and Lodgepole consist of limestone and dolomite beds. The Madison Group ranges in thickness from greater than 2,800 feet in western North Dakota to almost non-existent at its eastern limits. Karst topography has been observed in areas where the Madison Group outcrops. Karst topography occurs where circulating groundwater has dissolved minerals from the carbonate rocks, potentially producing large openings in the rock that can become interconnected to form cave systems. As with the other principal aquifers in the region, water in the Upper Paleozoic aquifer moves regionally northeastward from areas of recharge near the western and southern extents of the aquifer system (Figure 3-17). Water discharges from the aquifer by upward leakage to the Pennsylvanian and Lower Cretaceous aquifers in eastern North Dakota and central South Dakota. Freshwater is present in the Upper Paleozoic aquifer only in areas of recharge near the Bighorn Mountains and Black Hills outcrops. Downgradient of the recharge areas, the water quickly becomes saline and then briny, with TDS concentrations greater than 300,000 mg/L in the deep parts of the Williston Basin in western North Dakota (Whitehead 1996).

3.3.2 Local Groundwater

Important aquifers within Oliver County occur in the Fox Hills, Hell Creek, and Tongue River Formations. Wells that access these aquifers typically yield less than 150 gpm, and the water is likely not suitable for irrigation due to high sodium content. The largest yield and best quality water are obtained from the relatively undeveloped glacial drift and alluvial aquifers. The glacial drift and alluvial aquifers are generally one to five miles wide with maximum thicknesses of approximately 250 feet (Croft 1973).

3.3.2.1 Quaternary Glacial Drift and Alluvial Aquifers

Glacial drift and alluvial aquifers in Oliver County include the Missouri River aquifer and Square Butte Creek aquifer. The Missouri River aquifer underlies the terraces and floodplains of the Missouri River valley across eastern Oliver County, and it consists of coarse glaciofluvial and alluvial deposits. The majority of permitted wells screened in the Missouri River aquifer within Oliver County are intended for irrigation, while one permitted well is intended for stock. Water quality samples collected from observation wells screened in the Missouri River aquifer show TDS concentrations ranging from approximately 610 to 1,520 mg/L, conductivity ranging from approximately 980 microsiemens per centimeter (µS/cm) to 2,410 µS/cm, and pH measurements between 7.3 and 8.2 standard units (s.u.). The Square Butte Creek aquifer extends from Mercer County to the southeast corner of Oliver County. This aquifer is as much as 130 feet thick and consists of glaciofluvial and alluvial deposits (Croft 1973). There are no permitted water wells within the Square Butte Creek aquifer according to the North Dakota State Water Commission Ground/Surface Water Database.

3.3.2.2 Undifferentiated Lignite Aquifers in the Tongue River and Sentinel Butte Formations

Livestock and domestic wells in rural areas often screen fractures and joints in the undifferentiated beds of lignite for water supplies. The water quality of these aquifers is highly variable and typically contain 1,050 to 1,810 mg/L TDS based on water samples collected (Croft 1973).

3.3.2.3 Lower Tongue River Aquifer

The lower Tongue River aquifer is found in the lower part of the Tongue River Formation that underlies most of Oliver County. The lower Tongue River Formation is a fine- to medium-grained sandstone, and the aquifer is less than 150 feet thick. Siltstone and claystone separate the lower Tongue River aquifer from the upper Hell Creek and lower Cannonball-Ludlow aquifer. The sandstone of the lower Tongue River aquifer has a low hydraulic conductivity and is interbedded with siltstone and claystone (Croft 1973). Groundwater flows to the north-northeast with a hydraulic gradient of about 10 feet per mile. Differences in head indicate that groundwater is flowing vertically downward from the lower Tongue River aquifer into the upper Hell Creek and lower Cannonball-Ludlow aquifer. The groundwater is a sodium bicarbonate type with 1,440 to 1,700 mg/L TDS beneath Oliver County. The groundwater is suitable for livestock and domestic use but would not be suitable for irrigation due to a high sodium adsorption ratio (Croft 1973).

3.3.2.4 Upper Hell Creek and Lower Cannonball-Ludlow Aquifer

The upper Hell Creek and lower Cannonball-Ludlow aquifer is approximately 70 to 150 feet thick and underlies all of Oliver County. This aquifer is composed of fine- to medium-grained sandstone in the upper part of the Hell Creek Formation with fine-grained sandstone at the base of the Cannonball and Ludlow Formations, and contains some interbedded siltstone and claystone. Siltstone and claystone beds separate the aquifer from the Fox Hills and basal Hell Creek aquifer. Transmissivity ranges from 180 to 4,200 gallons per day per foot. Wells that screen this aquifer typically yield flows of approximately 5 to 100 gpm (Croft 1973). Groundwater generally flows from west to east, and head differences indicate that water is moving vertically upward from the Fox Hills and basal Hell Creek aquifer to the upper Hell Creek and lower Cannonball-Ludlow aquifer. The groundwater is a sodium bicarbonate type and contains approximately 1,510 to 1,890 mg/L TDS. The groundwater is suitable for livestock and domestic purposes, but likely not suitable for irrigation because it has a high sodium adsorption ratio (Croft 1973).

3.3.2.5 Fox Hills and Basal Hell Creek Aquifer

Extensive sandstone beds in the upper part of the Fox Hills and the lower part of the Hell Creek Formations form a major aquifer that underlies all of Oliver County. The sandstone is fine- to medium-grained with interbedded siltstone and has a low hydraulic conductivity. The aquifer is approximately 150 to 370 feet thick. Hundreds of wells in North Dakota are drilled as deep as 1,515 feet in this aquifer and supply municipal, domestic, and livestock water needs. Within Oliver County, one stock well and one observation well are completed in the Fox Hills (NDSWC n.d.). Groundwater within this aquifer generally flows from west to east, and the hydraulic gradient is approximately 3.5 feet per mile (Croft 1973). The groundwater is a sodium bicarbonate type and generally contains 1,230 to 1,990 mg/L TDS. The water is suited for livestock and most domestic needs but is not suitable for irrigation due to a high sodium adsorption ratio (Croft 1973). The Fox Hills and Basal Hell Creek aquifer represents the deepest source of drinking water in Oliver County.

3.3.3 Lowermost Underground Source of Drinking Water

As outlined in the Code of Federal Regulations 40 CFR § 144.3 (USEPA n.d.), a USDW is defined as an aquifer or its portion that supplies a public water system or contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 mg/L of TDS.

As described previously, the Fox Hills Formation, within the Upper Cretaceous Aquifer, contains the lowest potential USDW in Williams County, based on its estimated water quality and relatively shallow depth. The base of the Fox Hills Formation is estimated to be approximately 1,160 ft bgs at MRY based on geologic logs from J-ROC1, while the top is estimated to be approximately 900 ft bgs. The bottom of the Fox Hills Formation and the top of the Inyan Kara Formation are separated by approximately 2,500 feet of strata consisting of significant shale-dominated formations. North Dakota State Water Commission Well Index 9442 records a TDS concentration of 1,670 mg/L, conductivity of approximately 2,800 µS/cm, and a pH of 8.6 s.u. The TDS concentrations of water within the deeper aquifers in the area are too high to be considered USDWs.

4.0 FLOW AND TRANSPORT MODELING

4.1 Overview

Injection of wastewater into the Inyan Kara Formation requires forcing fluids through the wellbore at a pressure that exceeds the injection interval pore pressure to allow fluids to flow radially away from the wellbore without propagating fractures in the injection interval or confining formations. The expected changes in pressure within the formation as a result of injection is evaluated to understand the necessary wellbore pressure required to force injected wastewater radially away from the wellbore at the desired flow rate. The pressure increase within the formation decreases in magnitude with radial distance from the wellbore. If not properly evaluated and controlled, pressure increases within the injection interval can result in failure of nearby plugged and abandoned wells, fracture of the injection interval or adjacent confining units, or vertical migration of injected fluids through adjacent confining units, all of which can put the lowest USDW at risk. Analytical calculations and groundwater flow models are useful tools for estimating the pressure effects of injection into aquifers with specific hydrological properties.

The direction and movement of injected fluid within a confined aquifer must be understood in order to predict the potential impact to downgradient receptors. To assess the extent of potential impacts, it is important to understand how far and how quickly constituents will travel within the aquifer. A conservative estimate assumes that potential constituents of concern will travel at the same velocity as water particles; this allows particle tracking to serve as an effective tool to assess injection fluid movement. Transient particle tracking codes consider the formation porosity and the head distribution at a given time step to calculate water particle velocity and, therefore, particle travel distance during that time step and for the duration of the simulation.

At the proposed injection site at MRY, the total thickness of the sandstone intervals of the Inyan Kara Formation is approximately 90 feet (Section 4.3.1.1). The upper portion of the Inyan Kara Formation is composed of large intervals of moderate to good permeability, light gray, quartzose, fine-grained to coarse-grained sandstone interbedded with gray, silty, and lumpy shale. The lower portion is characterized by increased interbedding of sand-rich dark gray shale with intervals of light to medium gray-green siltstones and very fine-grained sandstones (J-LOC1 Well File).

4.2 Modeling Approaches

The formation pressure response to wastewater injection with respect to time and radial distance from the wellbore was calculated using the line source solution of the diffusivity equation for the flow of a single-phase fluid in a porous medium (Matthews and Russel 1967). The results of this evaluation were then compared to results from a subsequent evaluation using the software AquiferWin32 (by Environmental Simulations Inc.) to confirm agreement between the two modeling approaches in representing the impacts of injection into the Inyan Kara Formation.

As discussed in Section 1.2, two injection scenarios are evaluated: 1) one injection well operating at 950 gpm, and 2) two injection wells spaced 0.5 miles apart, each operating at 850 gpm. Both scenarios are evaluated assuming a 20-year lifespan with continuous injection.

4.2.1 Line Source Solution of Diffusivity Equation (Primary Modeling)

The line source solution of the diffusivity equation for the flow of a single-phase fluid in a porous medium is presented in Equation 1 (Matthews and Russel 1967).

$$P_{wf} = P_o - \frac{162.6\,q\mu B}{\kappa h}\left(\log\frac{\kappa t}{\phi_e \mu c_t {r_w}^2} - 3.23 + 0.869s\right) \tag{Eq.1}$$

Where:

P_o = initial static pressure at top of injection interval (psi)
P_{wf} = pressure while flowing at top of injection interval (psi)
q = flow rate (bbl/day), positive when withdrawing, negative when injecting
μ = viscosity (cP)
B = formation volume factor (bbl/bbl)
κ = formation permeability (mD)
h = net sandstone thickness (ft)
t = injection duration (hours)
ϕ_e = effective porosity (-)
c_t = total compressibility (1/psi)
r_w = radial distance from well center (ft)
s = skin factor (-)

4.2.2 AquiferWin32 (Confirmatory Modeling)

AquiferWin32 is an interactive, analytic element modeling tool that simulates two-dimensional (in the horizontal plane) steady-state and transient groundwater flow using analytical functions developed for different types of aquifers (unconfined, confined, and leaky confined).The principle of superposition is used to evaluate the effects of multiple closed-form analytical functions, each representing a hydrological feature (e.g., point sinks for wells, line sinks for rivers, and area elements for zones of effective recharge), in a uniform regional flow field. The model depicts the flow field using streamlines, particle traces, and contours of hydraulic head. Streamlines are computed semi-analytically to illustrate groundwater flow directions, while particle-tracking techniques are implemented numerically to compute travel times and flow directions.

To understand the effects of injection into the Inyan Kara Formation, the transient solution for leaky aquifers (Hantush and Jacob 1955) was implemented within the AquiferWin32 framework. AquiferWin32 requires inputs such as aquifer properties, confining unit properties, and well sizing and capacity. Assumptions for the Hantush and Jacob transient solution for leaky aquifers are as follows:

- The aquifer and aquitard have infinite areal extents and are homogenous, isotropic, and of uniform thickness over the area of influence.
- Injection into the aquifer occurs at a constant rate.
- Flow in the aquitard is vertical, and drawdown in the aquitard is negligible.
- Water removed from storage in the aquifer and water supplied by leakage from the aquitard is discharged instantaneously with decline of head.
- The diameter of the well is small (i.e., well storage can be neglected).
- The aquitard is incompressible (i.e., changes in aquitard storage are negligible).

The simulated drawdown due to injection is used to understand the pressure increase effects on the formation and nearby abandoned well penetrations. The simulated particle traces help determine the extent to which the injectate will migrate through the formation in a given time period. Results of the AquiferWin32 modeling are compared to modeling results using the diffusivity equation (Equation 1).

4.3 Modeling Inputs

The following subsections describe the input variables estimated or developed for use in the groundwater flow and transport modeling and fracture pressure estimation. Input variables for use in the diffusivity equation are tabulated in Table C-1 (Appendix C). Input variables for use in the AquiferWin32 confirmatory modeling are tabulated in Table C-2 (Appendix C). Results of MDT pressure tests performed at BNI-1, J-LOC1, and J-ROC1 are summarized in Table C-3 (Appendix C).

Generally, modeling inputs were estimated from information gathered at the J-ROC1 well, which is nearest to the locations of the proposed Class I injection well(s). Occasionally, testing at J-LOC1 provided more direct measurements of certain modeling inputs compared to testing at J-ROC1. For those inputs, measurements from J-LOC1 were used.

4.3.1 Formation and Formation Fluid Properties

4.3.1.1 Net Sandstone Thickness

The net sandstone thickness (h) represents the total thickness of porous and permeable sandstone material within the injection interval that is anticipated to receive injected fluids. The top and bottom elevations of the sandstone beds in the Inyan Kara Formation are identified by evaluating the CMR log obtained during drilling of J-ROC1 (Figure 4-1) and the formation tops identified in the J-ROC1 Well File. At J-ROC1, the top and bottom of the sandstone intervals in the Inyan Kara Formation are located at 1,663 ft below msl and 1,834 ft below msl, respectively. It is assumed that the top and bottom elevations of the sandstone beds of the Inyan Kara Formation at the proposed locations for the Class I injection well(s) will be the same as at J-ROC1. This means that the depth to the top and bottom of the injection interval are approximately 3,667 ft bgs and 3,838 ft bgs, respectively, based on the ground surface elevation of 2,004 ft amsl at J-ROC1 (J-ROC1 Well File). Because the Inyan Kara Formation is composed of sandstones interbedded with shales and siltstones, the CMR log from J-ROC1 was used to estimate the net sandstone thickness by identifying zones within the formation where the CMR log-derived permeability values are generally greater than 10 millidarcies (mD). The net sandstone thickness was estimated to be approximately 90 feet (Figure 4-1).

Based on the Inyan Kara Sandstone Isopach Map in the area of MRY (Hazen 100K Sheet, North Dakota), the net sandstone thickness at MRY may be greater than 100 feet (Stolldorf 2021).

4.3.1.2 Formation Static Pore Pressure

Pore pressure (P_o) is the pressure of groundwater within the pore spaces of a rock or soil matrix at a known elevation and represents the static formation pressure that must be overcome by an injection well to induce radial flow of fluid away from the well in the injection interval. During drilling of BNI-1, J-LOC1, and J-ROC1, the MDT tool was deployed to perform pressure tests for obtaining estimates of pore pressure in the Inyan Kara Formation. The estimated pore pressure gradient for the Inyan Kara Formation at MRY was approximately 0.4198 pounds per square inch per foot (psi/ft), based on pressure tests at four depths within the formation at J-ROC1 (Table C-3, Appendix C). This pressure gradient was comparable to results from multiple pressure tests completed in the Inyan Kara Formation at BNI-1 and J-LOC1. At the top of the injection interval (3,667 ft bgs), the estimated pore pressure is 1,539 psi, which is used in groundwater flow and transport modeling and estimating formation fracture pressure.

Using the formation fluid specific gravity calculated in Section 4.3.1.8 and the estimated pore pressure at the top of the injection interval, the static potentiometric surface of the Inyan Kara Formation at the locations of the proposed Class I injection well(s) is estimated to be approximately 1,899 ft amsl using Equation 2.

$$H_{static} = \frac{144P_{otop}}{\rho_{form}} + z_{perf\ top} \qquad \text{(Eq.2)}$$

Where:

P_{otop} = static formation pressure at top of injection interval (1,539 psi)
H_{static} = static potentiometric surface elevation (ft amsl)
ρ_{form} = formation fluid density (lb/ft^3) (Section 4.3.1.8)
$z_{perf\ top}$ = elevation of top of perforated interval (1,663 ft below msl)

For use in the AquiferWin32 model simulations, the magnitude and direction of the regional hydraulic gradient was estimated using Figure 3-15. Within a five-mile radius of the proposed injection site at MRY, the average hydraulic gradient is approximately 2.7E^{-4} feet per foot (ft/ft) (1.43 ft/mile). The general flow direction in the Lower Cretaceous aquifer system near MRY is to the northeast; for modeling purposes, the direction was estimated to be 54 degrees north of east.

4.3.1.3 Formation Effective Porosity

Formation porosity (ϕ) is the ratio of the volume of voids (pores) to the total volume of material. In the Inyan Kara Formation, which is a confined unit, the void space is assumed to be 100% saturated with water. Effective porosity (ϕ_e) is the ratio of the volume of interconnected void spaces to the total volume of material.

Interconnected void space allows groundwater to flow into and out of porous material. Formation effective porosity has a small impact on the formation pressure response to injection; however, lower formation effective porosity values cause fluid particle velocities within the formation to increase, which in turn results in greater particle travel distances (the opposite is also true).

Estimates of effective porosity within the interpreted sandstone intervals of the Inyan Kara Formation were obtained from the CMR logs at J-ROC1 (Figure 4-2). The average effective sandstone interval porosity of 0.151 calculated from the CMR free fluid (CMFF) log at J-ROC1 is used for groundwater flow and transport modeling. The data presented in the CMFF curve is considered appropriate for modeling because it represents fluid that is free, rather than fluid that is bound to the formation grains by capillary and other forces (effective porosity).

4.3.1.4 Formation Permeability

Permeability, reported in units of millidarcies, is the ability of a rock to transmit fluid through its pore spaces and is a measure of the interconnectedness of those pore spaces. Permeability is not dependent upon the properties of the flowing fluid, only the formation properties.

Inyan Kara Formation permeability (k) was estimated using data from the CMR logs collected at the J-ROC1 test borehole. The CMR logs presented results from two models for estimating permeability: 1) the Schlumberger-Doll Research (SDR) model, and 2) the Timur-Coates model (Figure 4-1).

The CMR logs from J-ROC1 provide estimated formation permeability values at 0.5-foot-depth intervals using the SDR and Timur-Coates models. For each model, bulk formation permeability was estimated as the depth-weighted average of permeability values over the approximate 90-foot-thick permeable zone described in Section 4.3.1.1. In general, the SDR model tended to produce permeability estimates that were lower than permeability estimates using the Timur-Coates model. The average of these two bulk formation permeability values over the 90-foot-thick permeable zone, 950 mD, is used in this permit application.

The selected formation permeability value of 950 mD is conservative compared to other permeability estimates from the Inyan Kara Formation near MRY. The average of the bulk formation permeability estimates using the SDR and Timur-Coates models from CMR logs collected at J-LOC1 over the permeable zones is approximately 2,700 mD (Figure 4-3). Aquifer falloff testing conducted in the Inyan Kara Formation at the J-LOC1 test well indicated a permeability of approximately 1,566 mD (Figure 4-3). Additionally, laboratory permeability tests were performed on core samples collected from the Inyan Kara Formation at J-LOC1; the results of the lab testing compared well with the CMR log (Figure 4-3).

4.3.1.5 Formation Fluid Temperature

Formation temperature (T_{form}) is used to help estimate the properties of fluids (viscosity and specific gravity) within the injection interval. Higher formation fluid temperature results in lower viscosity and lower density of the formation fluid. Temperature probes were deployed during drilling of BNI-1, J-LOC1, and J-ROC1. Temperatures obtained by the MDT tool (collocated with the pore pressure measurements described in Section 4.3.1.2) ranged between 107 and 126°F, with temperatures generally increasing with depth (Table C-3, Appendix C). The formation fluid temperature is assumed to be 120°F for flow and transport modeling.

4.3.1.6 Formation Fluid Total Dissolved Solids Concentration

Formation TDS concentration (TDS_{form}) is used to help estimate the properties of fluids (viscosity and specific gravity) within the injection interval. Higher TDS concentration results in higher viscosity and higher density. During drilling of J-LOC1, a fluid sample from the Inyan Kara Formation was collected and analyzed for water chemistry. The TDS concentration of the unfiltered fluid sample from the Inyan Kara Formation at J-LOC1 was 3,450 mg/L (Table E-1, Appendix E), which is consistent with regional contour maps of TDS concentrations (Downey 1986), and has been used for estimating formation fluid properties for this permit application.

4.3.1.7 Formation Fluid Viscosity

The absolute viscosity (referred to as viscosity in this report) of a fluid is a measure of that fluid's internal friction, or resistance to flow, when acted upon by an external force, such as a pressure differential. Within a porous media, such as the sandstone intervals of the Inyan Kara Formation, the greater the viscosity of the fluid flowing through the media, the greater the resistance to flow and the greater the pressure differential required to produce the same flow rate. Formation fluid viscosity (μ_{form}) is strongly dependent upon the fluid temperature, moderately dependent on TDS concentration, and minimally dependent on pressure. Viscosity as a function of fluid temperature, TDS concentration, and pressure is calculated as 0.546 centipoise (cP) using Equation 3. TDS concentration is converted to a percentage by dividing the concentration in mg/L by 1.0E^6.

$$\mu_{form} = \left(-4.518E^{-2} + 9.312E^{-2}TDS_{form} - 3.93E^{-4}TDS_{form}^2 + \frac{70.365 + 9.576E^{-2}TDS_{form}^2}{T_{form}}\right)\Big(1 + 3.5E^{-12}(P_i + 14.696)^2(T_{form} - 40)\Big) \qquad \text{(Eq.3)}$$

Where:

μ_{form} = viscosity of formation fluid (cP)
TDS_{form} = TDS concentration of formation fluid, expressed as a percent (0.35%)
T_{form} = temperature of formation fluid (120°F)
P_i = assumed formation pressure during injection (2,714 psi)

4.3.1.8 Formation Fluid Specific Gravity

The specific gravity of a liquid is the ratio of the density of the liquid to the density of water at 4°C and allows for the conversion between formation pore pressure and potentiometric elevation (total hydraulic head). Formation fluid specific gravity (γ_{form}) as a function of fluid temperature, TDS concentration, and pressure is calculated as 0.997, equivalent to a density of 62.226 pounds per cubic foot (lb/ft^3), using Equation 4.

$$\gamma_{form} = (7.572E^{-3}TDS_{form} + 0.998238)\left(1.002866exp^{\left[3.0997E^{-6}P_i - 2.2139E^{-4}(T_{form}-59) - 5.0123E^{-7}(T_{form}-59)^2\right]}\right) \qquad \text{(Eq.4)}$$

Where:

γ_{form} = specific gravity of formation fluid (-)
TDS_{form} = TDS concentration of formation fluid, expressed as a percent (0.35%)
T_{form} = temperature of formation fluid (120°F)
P_i = assumed formation pressure during injection (2,714 psi)

4.3.1.9 Total Compressibility

Compressibility is the ratio of the percent change in volume to the change in pressure applied to a fluid or rock. Total compressibility (c_t) is the sum of compressibility of the fluid phases present (water, oil, and gas) and the pore volume compressibility (c_f). Because the injection interval is assumed to be 100% saturated with water (Section 4.3.1.3), the oil and gas saturation fractions are assumed to be zero and therefore oil and gas do not contribute to total compressibility. Total compressibility is calculated using Equation 5.

$$c_t = c_f + c_w \quad \text{(Eq.5)}$$

Where:

c_t = total compressibility (1/psi)
c_f = pore volume compressibility (1/psi)
c_w = water compressibility (1/psi)

Pore volume compressibility (also referred to as formation compressibility) is calculated as a function of effective porosity using a regression of the formation compressibility versus effective porosity data presented by Hall (1953) using Equation 6 presented by Lei et al. (2019). Using the estimated effective porosity of 0.151 (see Section 4.3.1.3), the calculated pore volume compressibility is 4.07E^{-6} 1/psi. These effective porosity and pore volume compressibility values compare well to the database of pore volume compressibility versus effective porosity measurements for cemented sandstones at initial reservoir stress conditions (Crawford et al. 2011).

$$c_f = \frac{1.7836E^{-6}}{\phi^{0.4358}} \quad \text{(Eq.6)}$$

Additionally, laboratory pore volume compressibility testing was performed on one core sample retrieved from 4,041 ft below KB at J-LOC1. Analysis of the pore volume versus confining pressure data using the exponential relationship described by de Oliveira (2013) yielded estimates of pore volume compressibility ranging from 4.9E^{-6} 1/psi to 2.5E^{-5} 1/psi. The calculated pore volume compressibility of 4.07E^{-6} 1/psi falls within this range.

Bulk volume compressibility (aquifer skeleton compressibility) is calculated as 6.14E^{-7} 1/psi using Equation 7 (Crawford et al. 2011).

$$c_m = \phi c_f \quad \text{(Eq.7)}$$

Water compressibility is calculated as 3.33E^{-6} 1/psi using Equation 8 and assuming a bulk modulus of elasticity of water of 3.00E^{5} psi (Lohman 1972).

$$c_w = \frac{1}{E_w} \quad \text{(Eq.8)}$$

As a result, the total compressibility assuming the formation is 100% saturated with water is 7.40E^{-6} 1/psi (calculated using Equation 5).

4.3.1.10 Formation Storage Coefficient

The storage coefficient of a formation is a unitless measure of the volume of water, per unit surface area of the formation, released from (or taken into) storage per unit fall (or rise) in head. A greater storage coefficient results in a smaller pressure increase because the formation can absorb more water into storage per unit increase in head. Storage coefficient (S) is calculated using Equation 9.

$$S = hS_s \quad \text{(Eq.9)}$$

Where:

S = storage coefficient (-)
h = net sandstone thickness (90 ft) (Section 4.3.1.1)
S_s = specific storage (1/ft)

Specific storage is the amount of water per unit volume of a saturated formation that is stored or expelled from storage due to the compressibility of the aquifer skeleton and the pore water per unit increase (or decrease) in head. Specific storage is calculated as $4.83E^{-7}$ 1/ft using Equation 10 (Fetter 2001).

$$S_s = \frac{\rho_{form}}{144}(c_m + \phi c_w) \quad \text{(Eq.10)}$$

The resulting storage coefficient is calculated as $4.34E^{-5}$ using Equation 9.

4.3.1.11 Formation Volume Factor

The formation volume factor (B) is the ratio of the volume of water at the reservoir conditions (pressure and temperature) to the volume of water at standard conditions. The formation volume factor is assumed equal to 1.0.

4.3.1.12 Formation Hydraulic Conductivity (Formation Fluid)

Formation saturated hydraulic conductivity (K) is a measure of the ability of a porous medium to transmit fluid with particular properties; therefore, it is a function of both the permeability of the formation and the density and viscosity of the flowing fluid. For the same porous medium, a low-viscosity fluid (lower internal resistance to flow) results in a higher hydraulic conductivity (greater ability to transmit that fluid). The formation hydraulic conductivity, assuming native formation fluid, is calculated using Equation 11. The constant of 3574 in the denominator of Equation 11 is the result of dimensional analysis for unit conversions.

$$K = \frac{\kappa \rho_{form} g}{3574 \mu_{form}}$$

Where: (Eq.11)

K = hydraulic conductivity (ft/day)
κ = formation permeability (950 mD)
ρ_{form} = density of formation fluid (0.997 g/cm^3)
g = acceleration due to gravity (9.81 m/s^2)
μ_{form} = viscosity of formation fluid (0.546 cP)

A hydraulic conductivity value of 4.86 ft/day was calculated using Equation 11.

4.3.1.13 Formation Transmissivity (Formation Fluid)

Formation transmissivity (T) is a measure of the rate at which water is transmitted through a unit width of the formation under a unit hydraulic gradient applied across the vertical thickness of the formation. For a confined system, such as the Inyan Kara Formation, transmissivity is equal to the product of the net sandstone thickness (determined in Section 4.3.1.1) and hydraulic conductivity (determined in Section 4.3.1.12). Assuming all other formation properties are held constant, injection into a formation with higher transmissivity results in a lower pressure increase and a greater particle travel distance, while injection into a formation with lower transmissivity results in a higher pressure increase and a shorter particle travel distance. A formation transmissivity value of 437.8 square feet per day (ft^2/day) is calculated for the hydraulic conductivity value developed in Section 4.3.1.12.

4.3.1.14 Skin Factor

Skin factor is a numerical value used to represent the damage to the injection interval around the wellbore, which can either decrease (positive skin factor) or increase (negative skin factor) the permeability of the injection interval near the wellbore. This numerical value is used to analytically model the difference between the head loss predicted by Darcy's law and the actual head loss, which is influenced by the damage near the wellbore.

Formation damage is the impairment to the injection interval caused by wellbore fluids used during drilling and completion of the well and subsequent injection operations. Skin factor can typically range between negative six (-6), where the injection interval is highly stimulated, and positive 100, where the injection interval has been severely damaged. For this permit application, a skin factor of zero was assumed (no wellbore damage). While a larger skin factor is possible in practice, a well-designed drilling program, proper well development, and periodic maintenance of the well and near wellbore via surging, jetting, blasting, acidizing, or other methods can limit the development of large head losses due to skin effects.

4.3.2 Injectate Fluid Properties

4.3.2.1 Injectate Fluid Temperature

Injectate fluid temperature (T_{inj}) is used to help estimate the properties of injectate fluids (viscosity and specific gravity). MPC measures temperature of the MRY scrubber pond on a daily basis. Between 2014 and March 2021, these temperatures have ranged between 36°F and 89°F. Process waters from the proposed CCS (described in Section 1.2.1) are anticipated to be relatively warm because the majority of the water will be cooling tower blowdown. As a result, the temperatures in the scrubber pond are not anticipated to change significantly. The temperature of the injectate fluid is assumed to reflect fluctuations in environmental temperatures and is conservatively set at 55°F for modeling purposes.

4.3.2.2 Injectate Fluid Total Dissolved Solids Concentration

Injectate fluid TDS concentration (TDS_{inj}) is used to help estimate the properties of injectate fluids (viscosity and specific gravity). MPC measures TDS concentration in the MRY scrubber pond approximately once per week. Between 2014 and August 2020, these TDS concentrations ranged between approximately 15,000 and 130,000 mg/L, with an average of approximately 76,000 mg/L. As described in Section 1.2, wastewaters from the proposed carbon capture and sequestration system are planned to be routed to the MRY scrubber system. Because the combined wastewater from the carbon capture system is anticipated to have a relatively low TDS concentration (approximately 10,000 mg/L) and a relatively high flow rate (up to 1,100 gpm), the average TDS concentration of combined water is anticipated to be less than 76,000 mg/L. A TDS concentration of 40,000 mg/L is used in this permit application.

4.3.2.3 Injectate Fluid Viscosity and Specific Gravity

The injectate fluid viscosity, assuming a fluid temperature of 55°F (Section 4.3.2.1), a TDS concentration of 40,000 mg/L (Section 4.3.2.2), and a pressure of 2,714 psi, is calculated as 1.294 cP using Equation 3. Using the same input assumptions, the injectate fluid specific gravity is calculated as 1.041 using Equation 4 (equivalent to a density of 64.994 lb/ft^3).

4.3.2.4 Formation Storage Coefficient (Injectate Fluid)

Specific storage of the formation assuming injectate fluid properties is calculated as 5.04E^{-7} 1/ft using Equation 12 (Fetter 2001).

$$S_s = \frac{\rho_{inj}}{144}(c_m + \phi c_w) \qquad \text{(Eq.12)}$$

Where:

ρ_{inj} = injectate fluid density (64.994 lb/ft3) (Section 4.3.2.3)

The resulting storage coefficient is calculated as 4.54E^{-5} using Equation 9.

4.3.2.5 Formation Hydraulic Conductivity and Transmissivity (Injectate Fluid)

Using the formation permeability value of 950 mD estimated in Section 4.3.1.4 and the injectate fluid properties estimated in Section 4.3.2, a hydraulic conductivity value of 2.14 ft/day was calculated using Equation 11. For this hydraulic conductivity value, the corresponding formation transmissivity is 192.9 ft^2/day.

4.3.3 Confining Unit Properties

4.3.3.1 Vertical Hydraulic Conductivity

The vertical hydraulic conductivity of the confining unit (K') controls the rate at which water migrates vertically through the confining unit. The proposed injection interval (Inyan Kara Formation) is isolated from the lowermost USDW (Fox Hills Sandstone) by calcareous shales within the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations, which make up the Cretaceous Confining Unit. The vertical hydraulic conductivity of the Cretaceous Confining Unit was estimated to be $2.84E^{-7}$ ft/day, based on literature values (Milly 1978; Neuzil 1980) reported for the Pierre Shale in South Dakota.

4.3.3.2 Thickness

Based on formation descriptions in the North Dakota Stratigraphic Column (Figure 3-2) the formations separating the Inyan Kara Formation from the Fox Hills Sandstone are assumed to be composed primarily of low-permeability shales. Consequently, the thickness of the confining unit (b') is based on the total thickness between the base of the Fox Hills Sandstone and the top of the Inyan Kara Formation. Based on the geologic cross sections provided in Figures 3-9 and 3-10 and the J-ROC1 Well File, the confining unit thickness in the vicinity of MRY is approximately 2,500 feet.

4.3.3.3 Leakage Factor

When injecting into a leaky injection interval, the piezometric level of the injection interval increases and spreads radially outward, creating a difference in hydraulic head between the injection interval and the confining unit. Consequently, groundwater in the injection interval will move vertically upward into the confining unit. The pressure increase as a result of injection into the leaky injection interval is described by Hantush and Jacob (1955). Leakage through the confining unit is a function of the injection interval transmissivity and the confining unit thickness and vertical hydraulic conductivity. The leakage factor is calculated using Equation 13.

$$^{1}/_{B} = \left(\frac{K'}{Tb'}\right)^{1/2} \qquad \text{(Eq.13)}$$

Where:

$^{1}/_{B}$ = leakage factor (1/ft)

T = formation transmissivity (ft^2/day)

b' = confining unit thickness (2,500 ft)

K' = confining unit vertical hydraulic conductivity ($2.84E^{-7}$ ft/day)

Larger leakage factors are indicative of leakier formations, and can be the result of lower formation transmissivity, lower confining unit thickness, or higher confining unit vertical hydraulic conductivity. The leakage factors calculated using the transmissivity values developed in Sections 4.3.1.13 and 4.3.2.5 are presented in Table C-2 (Appendix C).

4.3.3.4 Lowermost Underground Source of Drinking Water Properties

The static potentiometric surface elevation of the Fox Hills Sandstone at MRY is approximately 1,800 ft amsl, based on water level elevations measured in monitoring well NDSWC Well Index 9442 (142-084-24 BBA), which is completed in the Fox Hills Sandstone and is located approximately 4.5 miles northwest of MRY (NDSWC n.d.). The elevation of the bottom of the USDW is approximately 840 ft amsl, which is the approximate elevation of the top of the Pierre Shale formation (J-ROC1 Well File).

4.3.4 Well Construction Properties

The well design assumes an injection tubing diameter of 7 inches. A perforated casing completion with 0.52-inch entrance diameter and 24-inch penetrations at a rate of 4 to 12 perforations per foot within the identified sandstone layers will be used (perforation rate to be determined after borehole drilling). The tubular sizes and hole diameters are provided in Table 2.

Table 2: Preliminary Well Tubular and Hole Sizing

Component	7-Inch Injection Tubing	
	Tubular	Hole Diameter
Injection tubing	7-inch OD Long thread coupling	-
Production casing	9.625-inch OD Long thread coupling	12.25-inch hole (1.3125-inch annulus)
Surface casing	13.375-inch OD Buttress thread coupling	17.5-inch hole (2.0625-inch annulus)
Conductor casing	20-inch OD Buttress thread coupling or welded	26-inch hole (3-inch annulus)

OD = outside diameter

4.4 Model Results

The following modeling results were calculated using the methods described in Section 4.2 and the model inputs described in Section 4.3 for both injection scenarios described in Section 1.2 (one well at 950 gpm or two wells at 850 gpm each).

4.4.1 Formation Pressure Response

The required formation pressure at the radius of the wellbore and at the top of the injection interval following 20 years of continuous injection was evaluated using Equation 1 and using AquiferWin32. Because the maximum formation pressure occurs at the wellbore (formation face), injectate fluid properties (Section 4.3.2) were used in the calculation, rather than formation fluid properties. The calculated formation pressure (evaluated at the top of the injection interval) versus time is provided in Figure 4-4 for the two injection scenarios described in Section 1.2. The maximum formation pressure following 20 years of continuous injection for one well operating at 950 gpm is estimated to be 2,454 psi. The maximum formation pressure for two injection wells operating concurrently, each at 850 gpm and spaced 0.5 miles apart, is estimated to be 2,490 psi. The formation fracture pressure of 2,714 psi, also shown in Figure 4-4, is estimated in Section 5.0. The expected maximum formation pressure for either injection scenario is less than the formation fracture pressure.

The formation pressure response at the wellbore after 20 years of continuous injection was evaluated for flow rates ranging from 200 to 1,400 gpm for the two injection scenarios described in Section 1.2. The calculated required formation pressures (evaluated at the top of the injection interval) versus injection flow rate are provided in Figure 4-5. Based on the estimated formation pressure response to injection, a maximum flow rate of greater than 950 gpm is expected to be feasible without fracturing the formation.

Formation pressure response results from the confirmatory modeling using AquiferWin32 compare well to the modeling results using the diffusivity equation, as shown in Figures 4-4 and 4-5.

4.4.2 Formation Pressure Response with Radial Distance

Using Equation 1 and the formation fluid properties estimated in Section 4.3.1, the formation pressure response (evaluated at the top of the injection interval) versus radial distance from FREEMAN-1 was calculated after 20 years of continuous injection for both injection scenarios. The formation pressure increase versus radial distance from FREEMAN-1 for both injection scenarios is provided in Figure 4-6. This figure provides an understanding of the pressure impacts in the injection interval radially out into the formation. Formation pressure response results from the confirmatory modeling using AquiferWin32 compare well to the modeling results using the diffusivity equation, as shown in Figures 4-6.

4.4.3 Radius of Fluid Displacement

The radius of fluid displacement due to injection and the regional hydraulic gradient was calculated using AquiferWin32, using the modeling inputs described in Section 4.3. The radius of fluid displacement versus time, assuming constant injection at the maximum permitted flow rate(s) and displacement due to the regional hydraulic gradient, is provided in Figure 4-7.

After 20 years of continuous injection with one injection well at 950 gpm, the radius of fluid displacement is expected to be less than 1.1 miles. With two injection wells operating continuously for 20 years at 850 gpm each (wells spaced 0.5 miles apart), the radius of fluid displacement from either well is expected to be less than 1.3 miles.

These scenarios are considered conservative (continuous operation at maximum flow rates) because the injection well(s) are likely to be operated at lower flow rates and on a more intermittent basis due to changes in water demand and maintenance needs. The predicted radius of fluid displacement will be updated annually during operation to evaluate the potential for fluid displacement beyond MPC's property boundaries. Based on these conservative analyses, the injected fluid would be expected to remain within MPC's property boundaries until after approximately 13 years of continuous injection for the one-well scenario and approximately 5 years of continuous injection for the two-well scenario. It is anticipated that the initial permit to inject from the NDDEQ will have a five-year renewal period, allowing for fluid displacement modeling and operating conditions to be updated prior to the current minimum estimated time for fluid displacement beyond MPC's property boundaries. MPC will work with adjacent landowners with respect to pore space rights if actual well operations and hydrogeologic conditions indicate that injected fluid will impact adjacent landowners.

4.5 Modeling Conclusions

Using the estimated properties of the injection interval, formation fluid, and injectate fluid, the maximum formation pressure at the wellbore face is estimated to be approximately 2,454 psi for the scenario in which one injection well is operating; this is approximately 260 psi less than the estimated fracture pressure (Section 5.0). For the scenario in which two injection wells are operating, the maximum formation pressure at either wellbore face is estimated to be approximately 2,490 psi, which is approximately 224 psi less than the estimated fracture pressure. The injectate is not expected to travel more than 1.3 miles laterally from the injection site in the injection interval for either injection scenario.

5.0 FRACTURE PRESSURE

The following section includes a discussion of fracture propagation pressure for the proposed injection interval at MRY. The United States Environmental Protection Agency (USEPA) regulatory standard for maximum injection pressures for Class I non-hazardous injection wells is established in 40 CFR § 146.13(a), as follows:

> Except during stimulation, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water. (USEPA n.d.)

Fractures are formed when the pressure at the formation face exceeds the local stress and the tensile strength of the formation. Fractures are propagated when the pressures in the fracture exceed the minimum in situ stress. The local stress at the formation face is a function of the minimum in situ stress, the pore pressure at the location, and the stress concentration due to the presence of the well. In the absence of tectonic stresses, the minimum in situ stress is normally horizontal, and any fractures formed tend to be vertical planes normal to this minimum horizontal stress.

5.1 Inyan Kara Fracture Pressure

Measured formation fracture pressure, which is used in this permit application, is based on step rate testing conducted on the Inyan Kara Formation at the J-LOC1 well. A fracture pressure gradient is determined from this testing, which is then used to estimate fracture pressure at the top of the proposed injection interval (3,667 ft bgs) at MRY. For comparison, the fracture pressure is also estimated using methods described in the literature (Eaton 1969; Ward et al. 1995); the results of these approaches are provided in Table D-1 (Appendix D).

In the fall of 2020, a step rate test was conducted on a 10-foot-thick interval of the Inyan Kara Formation (4,015 to 4,025 ft below KB) at J-LOC1. Injection volume, flow rate, and downhole pressure were measured during the test. Pressure within the test interval was measured downhole using a main quartz gauge and an auxiliary strain gauge. Natural leak off and pressure falloff was observed after the first fracture propagation cycle and rebound and flowback tests were conducted after injection to verify the creation of a fracture. A fracture pressure gradient of 0.740 psi/ft was estimated using fracture pressures developed from the step rate test. This equates to a fracture pressure of 2,714 psi at the top of the injection interval at MRY (3,667 ft bgs).

To corroborate the fracture pressure measurement obtained from step rate testing at J-LOC1, fracture pressure was estimated with two analytical equations (Eaton 1969; Ward et al. 1995) using overburden stress gradient estimates from the J-ROC1 open hole bulk density logs. Ward et al. (1995) estimates the fracture propagation pressure (which is less than the fracture initiation pressure) using Equation 14.

$$P_{fp} = (1 - \phi)(\sigma_v - P_o) + P_o \quad \text{(Eq.14)}$$

Where:

P_{fp} = fracture pressure (psi)
ϕ = porosity (-) (effective porosity used)
σ_v = overburden stress (psi)
P_o = static pore pressure (psi)

Eaton's method (1969), presented in Equation 15, also estimates the formation fracture propagation pressure.

$$P_{fp} = \frac{\mu}{1 - \mu}(\sigma_v - P_o) + P_o \quad \text{(Eq.15)}$$

Where:

μ = Poisson's ratio (-)

Poisson's ratio is an elastic constant that is a measure of the compressibility of material perpendicular to applied stress (ratio of latitudinal to longitudinal strain). Poisson's ratio is calculated using Equation 16 (Desroches and Bratton n.d.).

$$\mu = \frac{0.5\left(\frac{VP_c}{VS_c}\right)^2 - 1}{\left(\frac{VP_c}{VS_c}\right)^2 - 1} \quad \text{(Eq.16)}$$

Where:

VP_c = compression wave velocity (km/s)
VS_c = shear wave velocity (km/s)

Compression wave velocity and shear wave velocity are calculated using Equations 17 and 18, respectively (Castagna et al. 1985).

$$VP_c = 6.5 - 7.0\phi - 1.5V_c \quad \text{(Eq.17)}$$

$$VS_c = 3.52 - 6.0\phi - 1.8V_c \quad \text{(Eq.18)}$$

Where:

ϕ = porosity (0.151, effective porosity used)
V_c = clay volume (-)

A lower injection interval clay volume results in a lower Poisson's ratio, which is conservative when used to estimate the fracture pressure of the injection interval. As such, a clay volume of zero was conservatively selected to calculate the compression wave velocity (5.44 kilometers per second [km/s]) and the shear wave velocity (2.61 km/s). Using these velocities, Poisson's ratio is estimated to be approximately 0.35, which is the value used to estimate formation fracture pressure and maximum allowable injection pressure.

The overburden stress at the top of the injection interval is calculated as 3,581 psi by integrating with depth the bulk density log from the J-ROC1 well. The static pore pressure at the top of the injection interval is 1,539 psi (Section 4.3.1.2). Porosity is approximately 0.151 (Section 4.3.1.3). Formation fracture propagation pressures and fracture pressure gradients measured in J-LOC1 and calculated using Equations 14 and 15 are presented in Table 3.

Table 3: Estimated Fracture Pressure and Gradient at the Top of the Inyan Kara Formation

Estimation Method	Fracture Pressure (psi)	Fracture Pressure Gradient (psi/ft)
J-LOC1 Step-Rate Test	2,714	0.740
Ward et al. (1995) (Equation 14)	3,273	0.893
Eaton (1969) (Equation 15)	2,639	0.720

The fracture pressure of 2,714 psi measured from the J-LOC1 step rate test is within the range of fracture pressures estimated at J-ROC1 (2,639 to 3,273 psi) using methods found in the literature.

5.2 Confining Unit Fracture Pressure

The fracture pressure of the overlying confining unit was estimated at the top of the injection interval (3,667 ft bgs) as 2,958 psi using Equation 15 (Eaton 1969), with an overburden stress of 3,581 psi, pore pressure of 1,539 psi, and a Poisson's ratio of approximately 0.41 (estimated from the sonic scanner log at J-ROC1). This corresponds to a fracture pressure gradient of 0.807 psi/ft, which is consistent with the NDIC's prescriptive value for shale confining units of 0.8 psi/ft, used for permitting Class II injection wells in North Dakota.

5.3 Maximum Allowable Injection Pressure

To prevent propagation of existing fractures within the injection interval, the maximum allowable injection pressure at ground surface is calculated as the difference between the formation fracture pressure (2,714 psi, based on step rate test at J-LOC1) and the formation hydrostatic pressure, using Equation 19.

$$MAIP = P_{fp} - P_{hydtop}$$

Where:

MAIP = maximum allowable injection pressure (psi) (Eq.19)

P_{fp} = fracture pressure (2,714 psi)

P_{hydtop} = hydrostatic pressure at top of injection interval (psi)

Hydrostatic pressure at the top of the injection interval is defined herein as the pressure exerted at the top of the injection interval by a hypothetical column filled with injectate fluid to ground surface and is calculated using Equation 20.

$$P_{hydtop} = \frac{D_{screen\ top}\rho_{inj}}{144} \quad \text{(Eq.20)}$$

Where:

$D_{perf\ top}$ = depth from ground surface to top of injection interval (3,667 ft bgs, see Section 4.3.1.1)

ρ_{inj} = density of injectate (64.994 lb/ft^3, see Section 4.3.2.3)

The hydrostatic pressure at the top of the injection interval is presented in Table 4. The maximum pressure that can be applied at the surface (by a pump) to achieve the desired injection flow rate without fracturing the injection interval is estimated as the pressure difference between the calculated fracture pressure and this hypothetical column of injectate fluid (see Table 4). Due to injection tubing friction head losses and near-well losses, the pressure exerted on the injection interval under the calculated maximum allowable injection pressure (MAIP) will be less than the formation fracture pressure. Because these downhole well losses are neglected in the calculation of MAIP, no reduction has been applied to the MAIP value.

Table 4: Hydrostatic Pressure at Top of Injection Interval and MAIP

Hydrostatic Pressure at Top of Injection Interval (psi)	Fracture Pressure (psi)	MAIP (psi)
1,655	2,714 (J-LOC1 step rate test)	1,059

6.0 GEOCHEMISTRY

6.1 Overview

Geochemical modeling was conducted to assess the compatibility between the proposed injectate (cooling tower blowdown and scrubber pond water) and formation solids and liquids comprising the proposed injection interval. Meaningful geochemical compatibility models require that three parameters be well understood:

1) formation water chemistry (as well as dissolved gas concentrations or gas cap pressures) and temperature;
2) chemistry and temperature of the solution to be injected; and
3) mineralogical and chemical composition of the receiving formation solids.

The purpose of the geochemical modeling effort is to identify potentially detrimental geochemical effects associated with underground injection, such as formation souring, mineral scaling, and changes in the permeability or porosity of the receiving formation.

6.2 Formation and Injectate Water Chemistry

6.2.1 Data Sources

The chemistry data used to represent the composition of the formation water was collected from J-LOC1 (Section 2.2) on June 13, 2020 (Table E-1, Appendix E). The two samples (Minnesota Valley Testing Laboratories, Inc. [MVTL] and Energy and Environmental Research Center [EERC]-Unfiltered) were collected using the Schlumberger MDT tool. The decrease in pressure that occurs when the water sample is brought to the surface (approximately 1,670 psi within the formation at J-LOC1 versus approximately 15 psi at the surface) can cause rapid degassing of dissolved carbon dioxide (CO_2) and increase the pH. Formation gas cap and dissolved gas were not measured during sampling. Additionally, regional water chemistry for the proposed injection interval was not readily available from public sources.

MPC plans to discharge excess process water from the Project Tundra CCS system, which includes cooling tower blowdown, reverse osmosis reject, water treatment softening sludge, wet electrostatic precipitator discharge, and polishing scrubber blowdown to their existing FGD scrubber blowdown vaults. FGD blowdown from the Unit 1 and Unit 2 scrubber absorber towers is delivered to the scrubber blowdown vaults and then sluiced to Scrubber Pond Cell 4, which is a composite-lined impoundment with a capacity of 307 million gallons below the permitted maximum operating elevation (2,093 ft amsl). Additional inflow to the FGD scrubber system includes makeup water from Nelson Lake, runoff, leachate from the closed scrubber pond cells (i.e., Cells 1, 2, and 3), and other site process waters. Free water in Scrubber Pond Cell 4 (Cells 5 and 6 will be used in the future) is siphoned back to the scrubbers for use in the scrubbing process and sluicing FGD solids. The proposed injectate will be sourced from the Unit 2 Pond Return Tank, which receives water siphoned from Scrubber Pond Cell 4.

Injectate water is expected to be primarily a mixture of cooling tower blowdown and scrubber pond water. The carbon capture process is not operational at this time, so the exact chemistry of the injectate is unknown. The mixing proportions of blowdown with scrubber pond water to be injected is currently not known, so high and low concentration estimates of these two injectate water sources were selected to bound the range of potential injectate water qualities:

- MPC provided estimated cooling tower blowdown (from the proposed carbon capture system) water chemistry (Table E-2, Appendix E). Water chemistry estimates for the Winter Minimum scenario (low TDS) and Summer Peak Full Softening scenario (high TDS) were selected as cooling tower blowdown water in the geochemical model.
- MVTL collected six pond return water samples from Scrubber Pond Cell 3 and Scrubber Pond Cell 4 between July 2014 and July 2019, and the measured water qualities are presented in Table E-3 (Appendix E). Water chemistry for the samples collected from Cell 3 on July 30, 2014 (Cell 3 low TDS); Cell 3 on June 9, 2016 (Cell 3 high TDS); and Cell 4 on July 4, 2019 (Cell 4) were selected to represent scrubber pond water quality in the geochemical model.

6.2.2 Chemistry

A Piper diagram showing the distribution of predominant dissolved constituents in the injection formation, cooling tower blowdown, and scrubber pond is provided as Figure 6-1. Chemical compositions indicate that the three water sources (formation, cooling tower blowdown, and scrubber pond) are sodium sulfate ($Na\text{-}SO_4$) dominant. TDS concentrations for the injection formation, cooling tower blowdown, and scrubber pond samples are summarized in Table 5.

Table 5: TDS Concentrations in Injection Formation, Cooling Tower Blowdown, and Scrubber Pond Waters

Sample Name	TDS Concentration (mg/L)
Formation water	3,450
Cooling tower blowdown Winter Minimum	5,720
Cooling tower blowdown Summer Peak Full Softening	9,586
Scrubber Pond Cell 3 – minimum TDS (July 30, 2014)	49,700
Scrubber Pond Cell 3 – maximum TDS (June 9, 2016)	108,000
Scrubber Pond Cell 4 (July 24, 2019)	10,400

6.2.3 Formation Mineralogy

Water quality compatibility models require that the mineralogy of the receiving formation at the injection site is understood. Mineralogy by X-ray diffraction (XRD) was analyzed at regular intervals (4 to 5 feet; 33 samples) of borehole core along 160 feet of the Inyan Kara Formation at J-LOC1. XRD results are presented in Table E-4 (Appendix E) and a summary is presented in Table 6.

Table 6: Summary of Formation Mineralogy

Mineral Name	Average % Abundance	Maximum % Abundance	Minimum % Abundance
Quartz	70.6%	94.8%	29.0%
Illite/muscovite	9.7%	36.5%	0.0%
Kaolinite	5.4%	14.9%	0.0%
Clintonite	2.6%	14.3%	0.0%
Microcline	2.4%	9.2%	0.0%
Siderite	2.1%	22.9%	0.0%
Orthoclase	1.3%	10.4%	0.0%
Chlorite	1.1%	9.7%	0.0%
Albite	1.0%	9.1%	0.0%
Smectite, goethite, glauconite, anhydrite, pyrite, anatase, calcite, rutile, calcite magnesian, jarosite, dolomite	<1.0%	11.2%	0.0%

6.3 Geochemical Modeling

6.3.1 Modeling Strategy

The geochemical computer code PHREEQC (Parkhurst and Appelo 2013), developed by the USGS, was used for these simulations. PHREEQC version 3.4 is a general purpose geochemical modeling code used to simulate reactions in water and between water and solid mineral phases (e.g., rocks and sediments). Reactions simulated by the model include mixing, aqueous equilibria, mineral dissolution and precipitation, ion exchange, surface complexation, solid solutions, gas–water equilibrium, and kinetic biogeochemical reactions. The Pitzer thermodynamic database (Appelo et al. 2014) was used as a basis for the thermodynamic constants required for modeling. The Pitzer database is specialized for use with high-salinity waters that are beyond the range of the Debye Huckel activity model and can be applied to systems with elevated temperatures and pressures, as are expected in the injection formation. The Pitzer database only contains the most common scaling minerals.

Results reported as less than the detection limit were modeled at the detection limit. Charge imbalances were corrected by allowing the model to balance on sodium.

The potential for mineral precipitation was assessed in PHREEQC using a saturation index (SI) calculated according to Equation 21.

$$SI = log\left(\frac{IAP}{K_{sp}}\right) \qquad \text{(Eq.21)}$$

Where:

IAP = ion activity product

K_{sp}= mineral solubility constant

An SI value greater than zero indicates that the water is supersaturated with respect to a particular mineral phase, and therefore precipitation of the mineral may occur. An evaluation of precipitation kinetics is then required to determine whether the supersaturated mineral will indeed form. An SI value less than zero indicates the water is undersaturated with respect to a particular mineral phase. An SI value close to zero indicates equilibrium conditions exist between the mineral and the solution. SI values between -0.5 and 0.5 are considered to represent equilibrium in this report to account for the uncertainties inherent in the analytical methods and geochemical modeling.

6.3.2 Saturation Evaluation

As discussed in Section 6.2.1, injection formation water chemistry from J-LOC1 and the injectate sources (cooling tower blowdown and scrubber pond), were selected for modeling and are presented in Tables E-1, E-2, and E-3 (Appendix E). Prior to evaluating the scaling potential of water mixtures, the saturation indices of the source waters (formation waters, cooling tower blowdown, and scrubber pond waters) were assessed at their pre-injection temperatures and pressures:

- formation waters at formation conditions prior to injection: 50°C and 1,670 psi
- cooling tower blowdown and scrubber pond waters at surface conditions: 5°C and 14.7 psi

The reported composition of the formation water indicated supersaturation with respect to calcite and barite at formation temperatures and pressure (Table E-5, Appendix E). Calcite precipitation kinetics are fast, and the formation water has a very long residence time; therefore, calcite supersaturation within formation waters is considered highly unlikely. Calcite would be expected to be either in equilibrium in formation water, or undersaturated if the formation does not contain any calcite. The apparent oversaturation with respect to calcite is likely an artifact of the elevated pH value measured at surface after degassing of CO_2 (pH = 8.63). Because the pH of formation water was likely increased by degassing of CO_2 during sample collection, modeling was conducted using two chemistries for the formation water: 1) the concentrations reported by the laboratory, and 2) a simulated injection formation water where dissolved CO_2 was added until the modeled water was in equilibrium with respect to calcite at the formation temperature and pressure (pH = 7.66). The chemistry of the simulated sample is presented in Table E-1 (Appendix E).

The simulated formation water with added CO_2 was in equilibrium with respect to calcite and oversaturated for barite. Formation waters (both as measured and with added CO_2) were undersaturated for magnesite and calcium sulfate minerals associated with scaling (gypsum and anhydrite).

The saturation evaluation indicated that cooling tower blowdown waters (Winter Minimum and Peak Summer Full Softening scenarios) are oversaturated with respect to barite, calcite, and magnesite at surface temperature and pressure. The cooling tower blowdown water quality was in equilibrium with respect to gypsum and undersaturated for anhydrite.

Scrubber pond waters (Cell 3 minimum TDS, Cell 3 maximum TDS, and Cell 4) are oversaturated with respect to barite at surface temperature and pressure. All three scrubber pond water qualities were in equilibrium with respect to gypsum and undersaturated with respect to anhydrite. Only the Cell 4 Scrubber Pond water was in equilibrium with respect to calcite. The Cell 3 minimum TDS and Cell 4 water qualities were both in equilibrium with respect to magnesite.

All solutions modeled were undersaturated with respect to halite.

6.3.3 Compatibility Evaluation

The compatibility of the injected water with the receiving formation water and solids can be evaluated by simple mixing simulations at different temperatures and pressures. After a period of injection, solutions near the wellbore will have a composition and temperature reflecting the injected water. With increasing distance from the wellbore, mixing between the injected water and formation water takes place and compositions and temperature begin to reflect those of the pre-injection formation water. To account for this gradual mixing process, the general modeling procedure is a three-step process:

1) Evaluate aqueous speciation models for the injectate (cooling tower blowdown or scrubber pond water) and receiving formation water.

2) Create a model simulating the mixing of the two solutions over a range of mixing ratios.

3) Evaluate saturation indices of the resulting mixed solutions for the minerals of interest to assess whether or not they are likely to dissolve or precipitate.

Given that aqueous dissociation constants and mineral solubility products are temperature and pressure dependent, downhole reservoir temperatures and pressures should be constrained as closely as possible. Based on the measured temperatures within the formation, a temperature of 50°C is used for modeling of the downhole reservoir temperature (Section 4.3.1.5), which is consistent with the estimated geothermal gradient in the region. The injection pressure is expected to be approximately 2,400 psi (Section 4.4.1).

6.3.4 Mixing Models

Saturation indices as a result of mixing the cooling tower blowdown or scrubber pond water injectate with formation waters (as measured or simulated with the addition of CO_2) are shown as a function of mixing fraction in Tables E-6 through E-9. A mixing ratio of 100:0 represents the formation water and is therefore reflective of conditions distant from the wellbore where the composition is equivalent to that of the initial groundwater. Conversely, a mixing ratio of 0:100 represents the injectate, and therefore reflects conditions at the wellbore where compositions mimic those of the injectate.

Assuming available pH values for the formation water bracket the range of actual downhole conditions, the chemistry of groundwater from the formation is unable to dilute cooling tower and scrubber pond water qualities to bring calcite, magnesite, and barite below saturation. Solutions near the wellbore appear to have a propensity for scaling carbonates (calcite and magnesite) and barite, which may cause issues with well fouling and formation plugging. Mixtures of formation waters (measured and simulated) with scrubber pond waters (Cell 3 maximum TDS and Cell 4) were in equilibrium with respect to gypsum. The geochemical model does not predict gypsum will precipitate, but it is a possibility if actual concentrations or temperatures are slightly different than the scenarios modeled.

Uncertainly in the modeling results exists because of the uncertainty in two variables:

1) pH: It is not known to what extent formation CO_2 concentrations will lower the pH. The approach presented herein does bracket the likely range of possibilities for the formation waters, but the risk of scaling persists over that range. In general, pH lowering significantly increases calcite solubility, making it less likely to precipitate.

2) Temperature: The modeling assumes isothermal mixing at temperatures representative of formation conditions. More likely, however, is that a lower temperature aureole exists around the wellbore after

injection. A decreased temperature would decrease saturation levels and the scaling propensity for calcite. Careful thermal modeling would be required to accurately assess thermal effects on mineral solubility near the injection area.

Conservatively assuming the injection rate of 950 gpm (Scenario #1 from Section 1.2.2) and equilibrium precipitation, the range of calculated volumes of precipitated minerals are presented in Tables E-6 through E-9 (Appendix E). A summary of calculated volumes of precipitated barite, calcite, and magnesite are presented in Table 6-3. The values clearly suggest that carbonates (calcite and magnesite) present a far greater scaling risk than barite in terms of the anticipated scaling mass. Management strategies to decrease the risk of scaling during injection include the addition of amendments (i.e., antiscalants) to the injectate that prevent mineral precipitation and/or the addition of an acid to decrease pH.

Other processes that could potentially occur in the formation, but were not modeled due to lack of available data, include:

- Acidification: Oxygen-rich injection waters could potentially oxidize pyrite and other sulfides potentially present (Section 6.2.3), which could result in a decrease in pH. Corrosion and increased dissolution of formation minerals are potential associated deleterious effects.
- Reservoir souring: Microbes and reducing formation waters (e.g., due to the presence of organic matter) can reduce sulfate present in the injection waters to form hydrogen sulfide and CO_2. Corrosion, bio-plugging, and toxicity are potential associated deleterious effects.
- Retardation: Clays, organic material, and hydrous amorphous phases present in the formation solids have the ability to adsorb components from the injected solution, changing its solubility characteristics.

Table 7: Predicted Volumes per Day of Mineral Precipitates Formed During Injection

Sample Name	Predicted Barite Precipitation Volume (m^3/day)		Predicted Calcite Precipitation Volume (m^3/day)		Predicted Magnesite Precipitation Volume (m^3/day)	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Mixed with Formation Water as Sampled						
Blowdown Winter Minimum	0.00016	0.00087	0.017	0.33	0	0
Blowdown Summer Peak Full Softening	0.00016	0.00087	0.017	0.14	0	0
Scrubber Pond Cell 3 – minimum TDS	0.00031	0.00087	0	0.060	0	0.19
Scrubber Pond Cell 3 – maximum TDS	0.00053	0.00087	0	0.060	0	0.14
Scrubber Pond Cell 4	0.00018	0.00087	0	0.19	0	0.076

Sample Name	Predicted Barite Precipitation Volume (m^3/day)		Predicted Calcite Precipitation Volume (m^3/day)		Predicted Magnesite Precipitation Volume (m^3/day)	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
Mixed with Simulated Formation Water with Added CO_2						
Blowdown Winter Minimum	0.00016	0.00087	0	0.33	0	0
Blowdown Summer Peak Full Softening	0.00016	0.00087	0	0.10	0	0
Scrubber Pond Cell 3 – minimum TDS	0.00035	0.00087	0	0	0	0.083
Scrubber Pond Cell 3 – maximum TDS	0.00035	0.00087	0	0	0	0.083
Scrubber Pond Cell 4	0.00018	0.00087	0	0.12	0	0.057

m^3/day: cubic meters of precipitated mineral per day

7.0 INJECTION WELL DE3SIGN AND CONSTRUCTION

This section describes procedures for the design and construction of the injection well(s) and includes details on the casing and cementing program, logging procedures, drilling and testing program, and proposed annulus fluid. Well design and construction procedures follow the requirements of 40 CFR § 146.12 (USEPA n.d.) and NDAC Article 33.1-25 (North Dakota Legislative Council 1978) for Class I non-hazardous injection wells. The proposed well construction diagram, which is applicable for both injection wells, is shown in Figure 7-1.

The proposed injection interval for the Class I injection wells is between 3,667 and 3,838 ft bgs and will encompass the sandstone intervals of the Inyan Kara Formation. The drilling program provided in this section contains specifications and information on drilling procedures, casing lengths, and materials. General procedures to be required of the drilling contractor and site personnel are included throughout the program. Some of the drilling and completion details that are not relevant to overall permitting requirements may be modified in the field, as necessary. The logging program includes both open-hole and cased-hole logs that will be used to locate the lowest USDW, target the injection interval, and evaluate the mechanical integrity of the wells.

7.1 Well Drilling and Completion Program

Target depths and elevations for the drilling program are summarized in Table 8.

Table 8: Proposed Injection Well Data

Well Property	FREEMAN-1	RUBEN-1	Comments
Location (approximate)	N: 509,872 ft E: 1,790,841 ft	N: 507,250 ft E: 1,791,090 ft	
Ground surface elevation (approximate)	2,004 ft amsl	2,004 ft amsl	Ground surface elevation at completion of well
Top of proposed injection interval	3,667 ft bgs	3,667 ft bgs	Approximate
Base of proposed injection interval	3,838 ft bgs	3,838 ft bgs	Approximate

Depths are approximate and will be modified in the field based on injection well location-specific data.

7.1.1 Construction Procedures

The general procedures for the construction of each Class I injection well are as follows:

1) Install a 20-inch-diameter conductor casing cemented at an estimated depth of 80 feet in nominal 26-inch-diameter hole.
2) Drill 17.5-inch-diameter hole to approximately 1,260 ft bgs (100 feet below the bottom of the USDW). Run deviation surveys every 250 feet.
3) Conduct open-hole testing (wireline geophysical logs).
4) Run 13.375-inch-diameter surface casing to approximately 1,260 ft bgs (100 feet below the bottom of the USDW).
5) Grout surface casing annulus to ground surface using approximately 12 to 15 pounds (lbs) of Haliburton VariCem cement (or equivalent) per gallon of fresh water to ensure adequate sealing of the annular space.
6) Run cement bond log.
7) Drill 12.25-inch-diameter hole to approximately 3,940 ft bgs (approximately 50 feet below injection zone). Run deviation surveys every 1,000 feet.
8) Conduct open-hole testing (wireline geophysical logs and DST).
9) Run 9.625-inch-diameter production casing to approximately 3,888 ft bgs (approximately 50 feet below bottom of injection interval). Grout annulus to ground surface using approximately 12 to 15 lbs of Haliburton ElastiCem (or equivalent) cement per gallon of fresh water to ensure adequate sealing of the annular space.
10) Run cement bond log.
11) Perform pressure test on well casing.
12) Perforate production casing in the injection interval (approximately 3,667 to 3,838 ft bgs) with 0.52-inch entrance diameter and 24-inch penetrations at a rate of 4 to 12 shots per foot within the identified sandstone layers (perforation rate to be determined after borehole drilling).
13) Perform physical/chemical development of the well.
14) Install 7-inch-diameter injection tubing and packer to approximately 3,617 ft bgs (approximately 50 feet above injection zone). PermaPak single-bore packer (or equivalent) constructed to match production casing and injection tubing.
15) Place annular fluid.
16) Complete well surface features.

A summary of casing and injection tubing specifications (diameters, weight, grade, thread type, strengths, lining, and seat depth), and the cement program design are provided in Table F-1 (Appendix F). These construction specifications may change based on material availability and conditions encountered during drilling.

7.2 Logging Program

Cuttings from the drilling will be logged by a geologist at approximately 20-foot intervals from the ground surface to the top of the proposed injection interval, and at approximately 10-foot intervals from the top of the proposed injection interval to total depth.

The site lithology and stratigraphy information established by logging of the drill cuttings will be supplemented by open-hole wireline geophysical logging of the entire length of the borehole prior to installation of the surface casing string and production casing string. The wireline geophysical logging will occur in two stages:

- Stage 1: Log surface casing borehole (ground surface to minimum 1,260 ft bgs).
- Stage 2: Log production casing borehole (bottom of surface casing to total depth).

The geophysical logging for the surface casing borehole will, at a minimum, include caliper, dual induction (resistivity), and spontaneous potential. The geophysical logging for the production casing borehole will, at a minimum, include caliper, natural gamma ray, dual induction (resistivity), spontaneous potential, compensated density, and compensated neutron logs. The geophysical logs will be reviewed by the geologist responsible for logging the boring, and the cuttings observations and laboratory analyses will be compared with the geophysical testing results to validate the site lithology and stratigraphy.

7.3 Formation Testing Program

The proposed formation testing program is designed to obtain data on static fluid pressure, temperature, and permeability of the injection interval. The program is also designed to collect data to characterize the physical, chemical, and radiological characteristics of the formation fluid.

7.3.1 Characteristics of the Injection Interval

Testing will be performed to measure static fluid pressure, temperature, and permeability of the injection interval, and may include completion of drill stem tests (DSTs) within targeted zones of the injection interval and step rate injection, constant rate injection, and falloff testing of the entire injection interval.

7.3.2 Formation Water Sampling

Samples of formation water from the injection interval will be analyzed to determine the physical, chemical, and radiological characteristics of the water. Representative samples of formation water may be collected upon completion of drilling and prior to performing injection testing.

The aqueous analytical suite includes all major cations and anions, as well as the primary general fluid parameters, for purposes of simple QA/QC, charge balance analysis, and geochemical modeling. Additionally, both total and dissolved species will be measured to give an indication of fine suspended particles. Finally, a full suite of trace metals will be analyzed for water quality evaluation and geochemical modeling. The full analytical suite is summarized in Table 9.

Table 9: Full Analytical Suite for Formation Water Samples

Parameter Type	Parameters to be Analyzed
Field parameters	pH, specific conductance, temperature, dissolved oxygen, oxidation reduction potential
Redox couples	Iron speciation: Fe(II), Fe(III) Arsenic speciation: As(III), As(V)
General chemistry	pH, specific conductance, total dissolved solids (TDS), total suspended solids (TSS), turbidity, total hardness (as $CaCO_3$),
Major cations and anions	Alkalinity as $CaCO_3$, bicarbonate alkalinity of $CaCO_3$, carbonate alkalinity as $CaCO_3$, hydroxide alkalinity as $CaCO_3$, fluoride, sulfate, sulfite, chloride, calcium (total and dissolved), magnesium (total and dissolved), sodium (total and dissolved), potassium (total and dissolved), lithium (total and dissolved), ammonia nitrogen (as N), phosphorus (as P)
Other	Nitrate (as N), nitrite (as N), total kjeldahl nitrogen, total organic carbon (TOC), nitrogen (total), silicates (as SiO_2, dissolved)
Trace elements	Aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, chromium, cobalt, copper, iron, lead, manganese, mercury, molybdenum, nickel, selenium, silver, strontium, thallium, tin, vanadium, zinc

All trace elements are analyzed as total and dissolved species.

7.4 Stimulation Program

While the perforated zone will likely be cleaned using a hydrochloric acid solution during well completion, the cleaning will not involve stimulation of the injection interval. No stimulation is expected to be necessary for the target injection interval. However, should it be required, stimulation would be performed using acidation techniques. Acid types, concentrations, quantities, and additives would be determined once the well has been completed. A stimulation plan would be submitted for NDDEQ approval prior to beginning an acidation program.

7.5 Mechanical Integrity Testing

The absence of significant leaks in the casing, tubing, or packer will be demonstrated through a pressure test on the annular space between the tubing and production casing. The test shall be conducted for a minimum of 60 minutes at a pressure equal to the maximum allowable injection pressure estimated in Section 5.3. A cement bond log will be used to demonstrate that there can be no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore.

7.6 Construction Contingency Plan

Drilling operations will be performed according to the current standard of practice. Should unforeseen problems occur with the potential to impact a USDW, drilling will be stopped and the NDDEQ will be contacted. A detailed solution would be developed for review and approval by the NDDEQ prior to resuming operations.

7.7 Surface Infrastructure

The proposed injection well locations and the locations and alignment of injection well supply piping and associated structures are shown in Figure 7-2. Surface infrastructure will include the following:

- A connection pipeline from the existing Unit 2 Pond Return Water Tank to the injection piping, within the Lime Prep Building near the south end of the power block. Also housed within the Lime Prep Building will be a supply pump, potential pre-injection water treatment system, and an injection well screen filter for removal of suspended solids.
- One high-pressure injection well pump (with variable frequency drive) and flow meter will be housed in a separate building near each Class I injection wellhead.
- FREEMAN-1 will be housed in a building on the well pad that will accommodate the injection wellhead, the injection well annulus pressurization equipment, and instrumentation and controls to ensure that the well is operated within the permit limitations for injection pressure and annulus pressure related to FREEMAN-1.
- If required, RUBEN-1 will be housed in a separate building approximately 0.5 miles south of FREEMAN-1 that will also accommodate an injection wellhead, injection well annulus pressurization equipment, and instrumentation and controls to ensure that the well is operated within the permit limitations for injection pressure and annulus pressure related to RUBEN-1.

8.0 INJECTION WELL OPERATIONS

This section describes injection well operating requirements, parameters, and procedures; monitoring and reporting; and recordkeeping.

8.1 Regulatory Requirements

The injection well operating requirements according to 40 CFR § 146.13(a) at a minimum, specify that:

1) Except during stimulation, injection pressure at the wellhead shall not exceed a maximum that shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.
2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.
3) Unless an alternative to a packer has been approved under §146.12(c), the annulus between the tubing and the long string of casings shall be filled with a fluid approved by the director and a pressure, also approved by the director, shall be maintained on the annulus (USEPA n.d.).

8.2 Injection Parameters

8.2.1 Injection Rate

Non-hazardous wastewater from both the scrubber pond system and carbon capture system will be injected at or below the permitted flow rate of either 950 gpm for one injection well, or 850 gpm each for two injection wells. The maximum injection rate for each scenario will be established based on the maximum flow rate that can be sustained while maintaining the surface injection pressure below the maximum allowable injection pressure to prevent the propagation of existing fractures or initiation of new fractures within the injection interval. Increases to the injection rates will be discussed with the NDDEQ prior to implementation.

8.2.2 Injection Pressure

The injection well(s) will be operated so as not to initiate or propagate fractures in the injection interval and to prevent the movement of injectate or formation fluids into a USDW. Injection will occur through tubing as described in Section 7.0 and as shown in Figure 7-1. The maximum allowable surface injection pressure for both Class I injection wells has been estimated to be 1,059 psi based on the difference between the calculated fracture pressure and the estimated hydrostatic pressure (pressure caused by a column of injectate fluid from the top of the injection interval to ground surface) at the top of the injection zone (Section 5.0). Fracture pressure and maximum allowable surface injection pressure may be reevaluated using data collected during drilling for the specific injection well location. The estimated fracture pressure and maximum allowable surface injection pressure are listed in Table 10. Injection pressure will be controlled so that the downhole pressure remains below the fracture pressure.

Table 10: Estimated Fracture and Maximum Allowable Surface Injection Pressures

Item	Pressure (psi)	Source
Downhole fracture pressure	2,714	Estimated fracture pressure reported in Section 5.0
Maximum allowable surface injection pressure	1,059	Downhole injection pressure minus hydrostatic pressure from column of injectate fluid to ground surface

8.2.3 Annulus Pressure

Injection will not occur between the outermost casing intended to protect underground sources of drinking water and the well bore. MPC plans to fill the annulus between the injection tubing and the production casing with 9 to 10 pounds per gallon inhibited brine (or another fluid approved by the NDDEQ) and maintain a minimum differential pressure between the annulus pressure and the injection pressure of 100 psi.

8.3 Well Operations

8.3.1 Schedule

Following the required public comment period and if the NDDEQ deems the application acceptable, the NDDEQ will provide MPC with authorization to drill. After receiving such authorization, MPC will begin well construction and will submit notification to the NDDEQ after construction is complete. The NDDEQ will issue the final injection permit after all requested data have been collected and analyzed. Upon the NDDEQ's issuance of the permit to inject, MPC may begin to inject fluids as authorized by the UIC permit and applicable federal and state regulations.

8.3.2 Procedures

Injectate will be pumped from the existing Unit 2 Pond Return Water Tank in the Lime Prep Building to the wellheads via the piping alignments shown in Figure 7-2.

Pretreatment of the injectate fluid may include the addition of an antiscalant upstream of the injection pumps to reduce the risk of downhole scaling from calcium sulfate and calcium carbonate (Section 6.3.4). Dosing rates will depend on actual injectate fluid chemistry and injection flow rate.

The piping upstream of the wellheads will be equipped with an operable tap to allow for injectate fluid sampling prior to conveyance through the injection tubing string. Monitoring instrumentation will be installed to continuously measure and record surface injection pressure, casing–tubing annulus pressure, flow rate, and injection volumes (see Section 8.4) The maximum allowable surface pressure for injection will be finalized at each well after each well is completed (updated elevations and fluid density), and the wells will be operated so as not to exceed the established injection pressure.

8.3.3 Facilities

Pumps, pipelines, valves, instrumentation and controls, and related appurtenances will be installed and made operational prior to initiating injection well operations. Equipment will be sized appropriately for the design injection rate and pressure. The injection well and related appurtenances will be properly operated and maintained according to manufacturer's recommendations, MPC's internal procedures, and the current standard of practice.

Upon completion of the well, a building will be constructed around the well to protect the wellhead, instrumentation and controls, and related appurtenances and materials from the elements, and to provide a safe working environment for MPC's well operators.

8.3.4 Training

MPC will be responsible for operating the Class I injection well(s). Personnel responsible for the operation and maintenance of the Class I injection wells will have appropriate training and qualifications to ensure the safe, proper operation of the system. MPC is very familiar with operating mechanical and hydraulic systems, maintaining monitoring instrumentation, and ensuring regulatory compliance in their activities. Training will be conducted in areas including, but not limited to:

- site health and safety procedures
- well equipment operations
- regulatory requirements

The appropriate personnel will receive training prior to work, with regular refresher training as necessary to remain familiar with best management practices.

8.3.5 Operational Contingency Plan

Systems will be installed to continuously monitor the well performance (e.g., injection flow rate, surface injection pressure, casing–tubing annulus pressure) and periodically sample for injectate water quality (e.g., chemistry). Controls will be used to prevent the well from operating outside of permitted limits defined by the NDDEQ. In the event that the control system shuts down the injection operations, MPC will evaluate the reasons for the shutdown and consult with the NDDEQ if permit limits are jeopardized or there is a risk to a USDW prior to resuming operation.

In the event of a well shutdown (planned or unplanned), injectate will remain in the existing scrubber pond. Each scrubber pond is operated to maintain a minimum of two feet of freeboard, as required by the North Dakota Solid Waste Management Rules. By design, each pond is engineered for an additional three feet of freeboard while maintaining an acceptable factor of safety. If conditions would arise that necessitate operation of the scrubber pond above the minimum freeboard level, the NDDEQ Division of Waste Management would be consulted. If approved, the additional three feet of airspace (approximately 25 million gallons) would be available for storage of injectate. Assuming all other systems remain operational, there is approximately 18 days of available storage under these conditions at 950 gpm.

If one of the proposed injection wells fail mechanical integrity testing, or if monitoring suggests wellbore failure, MPC will immediately cease injection operations of that Class I injection well. Additional testing will be performed on the wellbore to determine the cause of failure. A plan will be developed for approval by the NDDEQ and implemented to remediate the well.

8.4 Monitoring and Reporting

8.4.1 Injectate Sampling

Except during time periods in which the Class I injection well is not operated, MPC will collect samples of injectate once per month for water chemistry analysis for List C parameters for an abbreviated waste characterization (Table G-3, Appendix G). Based on the results of these analyses, MPC may seek permission from the NDDEQ to reduce the frequency of sampling (monthly to quarterly). Additionally, MPC will collect injectate samples annually for analysis of parameters included in List A (Table G-1, Hazardous Waste Classification) and List B (Table G-2, General Waste Characterization) (Appendix G). Results of the water quality analyses will be provided with MPC's quarterly injection monitoring reports submitted to the NDDEQ.

8.4.2 Injection Monitoring

The primary methods to monitor well operations include continuous recording of the injection pressure and the casing–tubing annulus pressure at the wellhead, and continuous monitoring of the injection flow rate and volume. Before MPC begins injection operations, the following monitoring equipment will be installed and made operational:

- Injection pressure gauge: The surface injection pressure will be monitored using a digital, continuous reading pressure monitoring device installed on the injection piping immediately upstream of each wellhead.
- Wellhead annulus pressure monitoring device: The pressure of the casing–tubing annular space will be monitored using a digital, continuous reading pressure monitoring device installed on the casing–tubing annulus connection on each wellhead.
- Flow meter: Digital totalizer flow meter and digital continuous recording device will be installed in the injection piping upstream of each wellhead to record flow rates and total volumes of injectate delivered to the injection interval via each well.

Monitoring equipment will be calibrated and maintained on a regular basis in accordance with the manufacturer's recommendations to ensure proper working order of the equipment and collection of accurate monitoring data.

8.4.3 Mechanical Integrity Testing

The injection well must demonstrate mechanical integrity to comply with UIC permit requirements, as described in NDAC 33.1-25-01-13. The mechanical integrity demonstration must show that the casing, injection tubing, and injection packer do not contain leaks and that there is not significant fluid movement into a USDW adjacent to the well casing. The mechanical integrity demonstration must follow methods listed under 40 CFR § 146.8(b) (USEPA n.d.):

- Evaluate the absence of significant leaks in the casing, injection tubing, and injection packer by one of these methods:
  - Monitoring of casing–tubing annulus pressure, or
  - Pressure test with liquid or gas.

- Determine the absence of significant fluid movement into underground sources of drinking water through the cemented annular space between the production casing and the production casing borehole by evaluating results of temperature logs, noise logs, or radioactive tracer survey.
- Apply methods and standards generally accepted in the industry. A description of the tests and test methods conducted will be included in mechanical integrity test reports.

Mechanical integrity testing will be performed at least once every five years, and following any testing, rehabilitation, or workover of the well, during the life of the well.

8.4.4 Quarterly Reporting Requirements

As required by 40 CFR § 146.13(c) (USEPA n.d.), MPC will submit quarterly reports to the NDDEQ within 30 days after the last day of March, June, September, and December of each year. Quarterly reports will include:

- results of injectate fluid analyses
- monthly average, maximum, and minimum values for injection pressure, injection flow rate, injection volume, and casing-tubing annular pressure

When applicable, the first quarterly report after completion of the following activities will also contain results of these activities:

- periodic mechanical integrity tests
- annual pressure falloff testing results and analysis
- well rehabilitation or workover activities

8.4.5 Annual Reporting Requirements

Per 40 CFR § 146.13(d) (USEPA n.d.), MPC will monitor the pressure buildup in the injection zone on an annual basis. At a minimum, this will include a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve (typically 24 to 48 hours). In addition, a standard annulus pressure test will be performed on the annular space between the 9.625-inch-diameter production casing and the 7-inch-diameter injection tubing. The annular space will be pressure tested and monitored with a pressure recorder at the surface to detect any leaks in the tubing, packer, or casing. Chemical analysis of the injectate fluids for hazardous waste classification and general waste characterization (Appendix G) will be conducted annually following the first year of operation. The results of the testing and analysis described in this section will be included in the subsequent quarterly report to the NDDEQ.

8.4.6 Immediate Reporting Requirements

MPC will verbally report the following information to NDDEQ within 24 hours from the time MPC becomes aware of the circumstances:

- any monitoring or other information that indicates that any contaminant may cause an endangerment to a USDW, and
- any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between underground sources of drinking water.

Written submission to the NDDEQ will be provided within five days of the time MPC becomes aware of the circumstances.

8.5 Recordkeeping

MPC will maintain the following records and retention times:

- data used for this permit application for at least three years (from date of sample, measurement, report, or application)
- records concerning the nature and composition of injected fluids until three years after completion of well plugging and abandonment
- monitoring records, including items such as calibration and maintenance records, continuous monitoring readings including flow and pressure records, and reports for three years after the injection well has been properly plugged and abandoned

Records may be discarded after this retention time only with written approval from the NDDEQ.

9.0 WELL CLOSURE, PLUGGING AND ABANDONMENT PLAN

9.1 Regulatory Requirements

At least 60 days prior to well closure, MPC will notify the NDDEQ director in writing of the intent to plug and abandon the injection wells. The plugging will be conducted in a manner to ensure that movement of fluids into or between underground sources of drinking water does not occur. The notification will include the following information as required by 40 CFR § 146.14(c) (USEPS n.d.):

- type, number, and placement (including elevation of the top and bottom) of plugs to be used
- type, grade, and quantity of cement to be used, including any additives to be used
- method used to place plugs, including the method used to place the well in a state of static equilibrium prior to placement of the plugs
- procedures used to meet the requirements of 40 CFR § 146.10
- any information on newly constructed or discovered wells, or additional well data, within the Area of Review

Within 60 days of closure, MPC will submit a closure report to the NDDEQ. The report will include either a statement that the well was closed in accordance with this permit application or, if actual closure differed from the plan previously submitted, a written statement that specifies the differences between the previous plan and actual closure. MPC will retain records concerning the nature and composition of injected fluids until three years after completion of plugging and abandonment of the well.

9.2 Plugging and Abandonment Program

MPC plans to abandon the well by removing the wellhead building, wellhead, injection tubing, and injection packer, and placing cement grout plugs as follows:

- a 300-foot plug isolating the injection zone (cement perforated zone and 100 feet into production casing)
- a 200-foot plug at the base of the lowermost USDW (100 feet above and below the base of the Fox Hills Sandstone)
- a 100-foot plug at the surface of the wellbore

The well will be plugged and abandoned following procedures required by the NDDEQ. After removing the wellhead building, wellhead, injection tubing, and injection packer, the 9.625-inch-diameter production casing will remain from the ground surface to total depth. For each Class I injection well, approximately 300 cubic feet of grout will be required to install the plugs described above and as shown in Figure 9-1. The grout plan will be finalized prior to plugging and will likely consist of 15.4 pounds per gallon density cement grout using Class G cement, placed in lifts by either the balance method, dump bailer method, or alternative method approved by the NDDEQ. The well will be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method approved by the NDDEQ prior to placement of the cement plugs. The wellhead will be removed, casing will be cut five feet below the surface, and a steel plate will be welded to the top of the casing stub.

MPC will notify the NDDEQ no less than 60 days before conversion, workover, or abandonment. The injection well will be properly plugged (in accordance with the plugging and abandonment program) after injection operations have ceased for two years, unless MPC demonstrates that the well will be used in the future or that the well will not endanger underground sources of drinking water while temporarily out of use.

MPC will submit a survey plat to the local zoning authority upon completion of the plugging and abandonment. The survey plat will also be included with the final plugging and abandonment report, which will be submitted to the NDDEQ and NDIC.

9.3 Plugging and Abandonment Costs

Total costs for plugging and abandoning the two Class I injection wells have been estimated at approximately $380,000 (2021 dollars). The cost estimate summary provided in Table 11 was developed assuming that the injection intervals will be isolated by the squeeze cementing method through a cement retainer; the remainder of each of the wells was assumed to be cemented using the balance method.

Table 11: Plugging and Abandonment Costs (2021 Dollars)

Item	Estimated Cost FREEMAN-1	Estimated Cost RUBEN-1
Surface structure removal ▪ Remove wellhead building ▪ Remove wellhead ▪ Remove above grade components	$35,000	$35,000
Plug wellbore ▪ Pull tubing and packer ▪ Install plugs	$120,000	$120,000
Site restoration ▪ Regrading ▪ Topsoil, seed, and mulch	$20,000	$20,000
Oversight and documentation	$15,000	$15,000
Total Plugging and Abandonment Costs	**$190,000**	**$190,000**

To estimate the costs for plugging and abandoning FREEMAN-1 and RUBEN-1 over the five-year permit period (2021 through 2026), the 2021 cost estimate was escalated annually based on forecasted contractor costs. Based on experience and professional judgement, a conservative annual escalation rate of 4% is used to forecast plugging and abandonment costs through the permit period. As a reference point, the annual inflation rate (based on consumer price index) for the United States over the last five years (2016 to 2020) has ranged between 1.4% and 2.3%, with an average five-year inflation rate of 2.0% (annual inflation rate information from United States Bureau of Labor Statistics [BLS 2021]). The forecasted plugging and abandonment costs for FREEMAN-1 and RUBEN-1 are provided in Table 12.

Table 12: Forecasted Plugging and Abandonment Costs

Year	Estimated Cost FREEMAN-1	Estimated Cost RUBEN-1
2021	$190,000	$190,000
2022	$198,000	$198,000
2023	$206,000	$206,000
2024	$214,000	$214,000
2025	$223,000	$223,000
2026	$232,000	$232,000

9.4 Financial Assurance

Per the NDDEQ permit application requirements, and in accordance with 40 CFR § 144.63(f) (USEPA n.d.), MPC has provided a letter from their chief financial officer demonstrating that MPC passes a financial test for $462,000 to plug and abandon the proposed Class I injection wells. This letter demonstrates that MPC has the appropriate resources to close, plug, and abandon the injection wells through the permit period (see Appendix H).

10.0 FACILITY PERMITS

This section addresses compliance with applicable portions of NDAC Article 33.1-25 and 40 CFR § 144 and 146 (USEPA n.d.). MPC holds multiple environmental permits for the MRY facility. The following sections address environmental regulations listed in 40 CFR § 144.31(e) and their applicability to proposed underground injection well activities.

10.1 Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA) regulates hazardous waste and provides the framework for regulation of non-hazardous solid wastes. The existing RCRA registration for MRY (Generator ID NDD076514298) will not be affected by injection well activities.

10.2 Safe Drinking Water Act

Under the Safe Drinking Water Act (SDWA), the USEPA sets drinking water quality standards and oversees states, local agencies, and water suppliers who implement the standards. Requirements and provisions for UIC are established under Part C of the SDWA. MPC maintains a permitted existing potable water system (Milton R.

Young Station Well – MPC, ND3310177). With this permit application, MPC complies with SDWA requirements related to underground injection permitting.

10.3 Clean Water Act

The Clean Water Act (CWA) enables the regulation of discharges into waters of the United States and establishment of surface water quality standards. The relevant aspects of the CWA pertaining to this permit application are addressed in the following sections.

10.3.1 NPDES Program

The CWA requires National Pollutant Discharge Elimination System (NPDES) permits for discharges of pollutants from point sources into waters of the United States. MPC maintains a site-wide NPDES industrial wastewater permit issued by the NDDEQ (ND-000370). Additional outfalls are covered under the NPDES general stormwater discharge permit associated with industrial activity; the coverage number for the MRY facility is NDR05-0012. The construction of the Class I injection well(s) should reduce the frequency at which MRY discharges process water under this NPDES permit.

10.3.2 Dredge and Fill Permits

Section 404 of the CWA requires approval from the United States Army Corps of Engineers before placing dredged or fill material into waters of the United States, including rivers, streams, ditches, coulees, lakes, ponds, or adjacent wetlands. MPC does not have a dredge and fill permit for the MRY site, nor need one for construction or operation of the Class I underground injection well(s).

10.4 Clean Air Act

The Clean Air Act (CAA) defines USEPA responsibility for protecting and improving air quality and the ozone layer. Under the CAA, the USEPA has implemented federal regulations and permitting programs and has established National Ambient Air Quality Standards (NAAQS). Prior to construction or modification of large air emission sources, sources must determine Prevention of Significant Deterioration (PSD) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) applicability. Injection well activities that could affect the Title V permit for MRY (T5-F76009) would be addressed separately with NDDEQ's Division of Air Quality.

10.4.1 Marine Protection, Research and Sanctuaries Act

Under the Marine Protection, Research and Sanctuaries Act (MPRSA), Congress requires regulation of the dumping of all types of materials into ocean water of any material which would adversely affect human health, welfare, marine environmental, ecological system, or economics. This regulation is not applicable for the proposed Class I underground injection well(s).

10.5 Other Permits

MPC maintains several other permits for MRY, including the following:

- Solid Waste Management Permit, 30-Year Pond: Permit No. SP-159
- Solid Waste Management Permit, Horseshoe Pit (closed): Permit No. SP-040
- Solid Waste Management Permit, Section 3 (closed): Permit No. IT-205
- Solid Waste Management Permit (closed): Permit No. IT-197

- Solid Waste Management Permit (closed): Permit No. IT-068
- Solid Waste Management Permit, Butterfly Ponds (closed): Permit No. SP-030
- NDSWC Annual Water Use Reports: SWC #1324, #1963, #1964, #7097
- Underground Storage Tanks Permit No. ND UST #46 (removed as of May 18, 2021)
- Petroleum Tank Insurance Fund #447
- Radiation Program License #33-81171-01

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Signature Page

Golder Associates Inc.

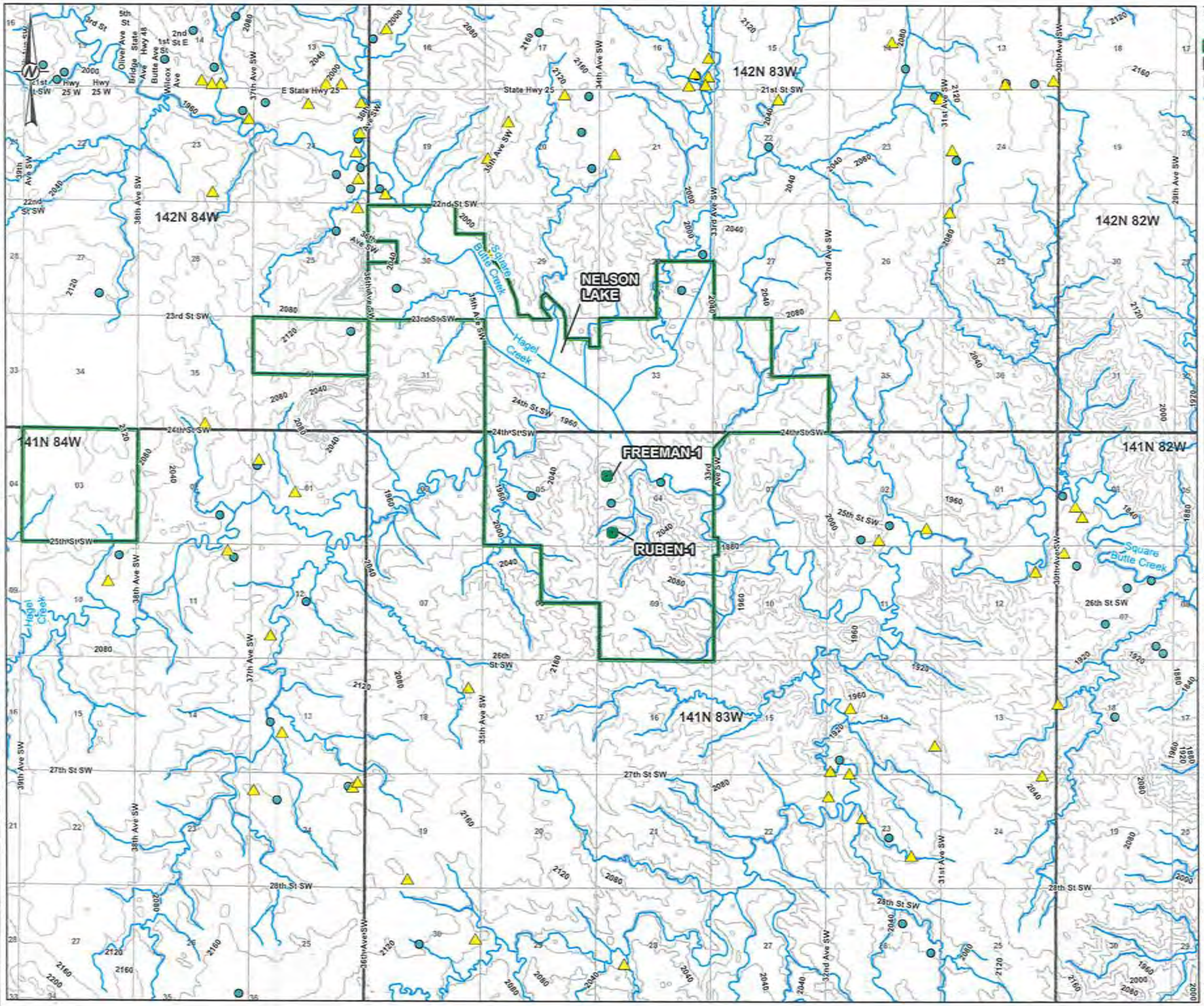
Arlen Striegl, PE (MI, MN, WI)
Senior Project Engineer

Todd Stong, PE (CO, ND)
Associate and Senior Consultant

AS/TS/af

https://golderassociates.sharepoint.com/sites/108764/project files/6 deliverables/reports/31-r-injection_permit_app/31-r-0/19122669-31-r-0-class_i_injection_well_permit_application_07jun21.docx

Figures



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- DOMESTIC WATER WELL
- RESIDENCES
- USGS CONTOUR - 40 FOOT INTERVAL

KEY MAP

0 2,250 4,500 9,000 Feet

REFERENCES
1. TOPOGRAPHIC CONTOURS: U.S. GEOLOGICAL SURVEY, 2013. USGS 1/3 ARC-SECOND N47W102 & N46W102 1 X 1 DEGREE: U.S. GEOLOGICAL SURVEY.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
4. WELL DATA: NORTH DAKOTA WATER COMMISSION AND STATE ENGINEER WELL DRILLERS LOGS, DOWNLOADED 4/14/2021.
5. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

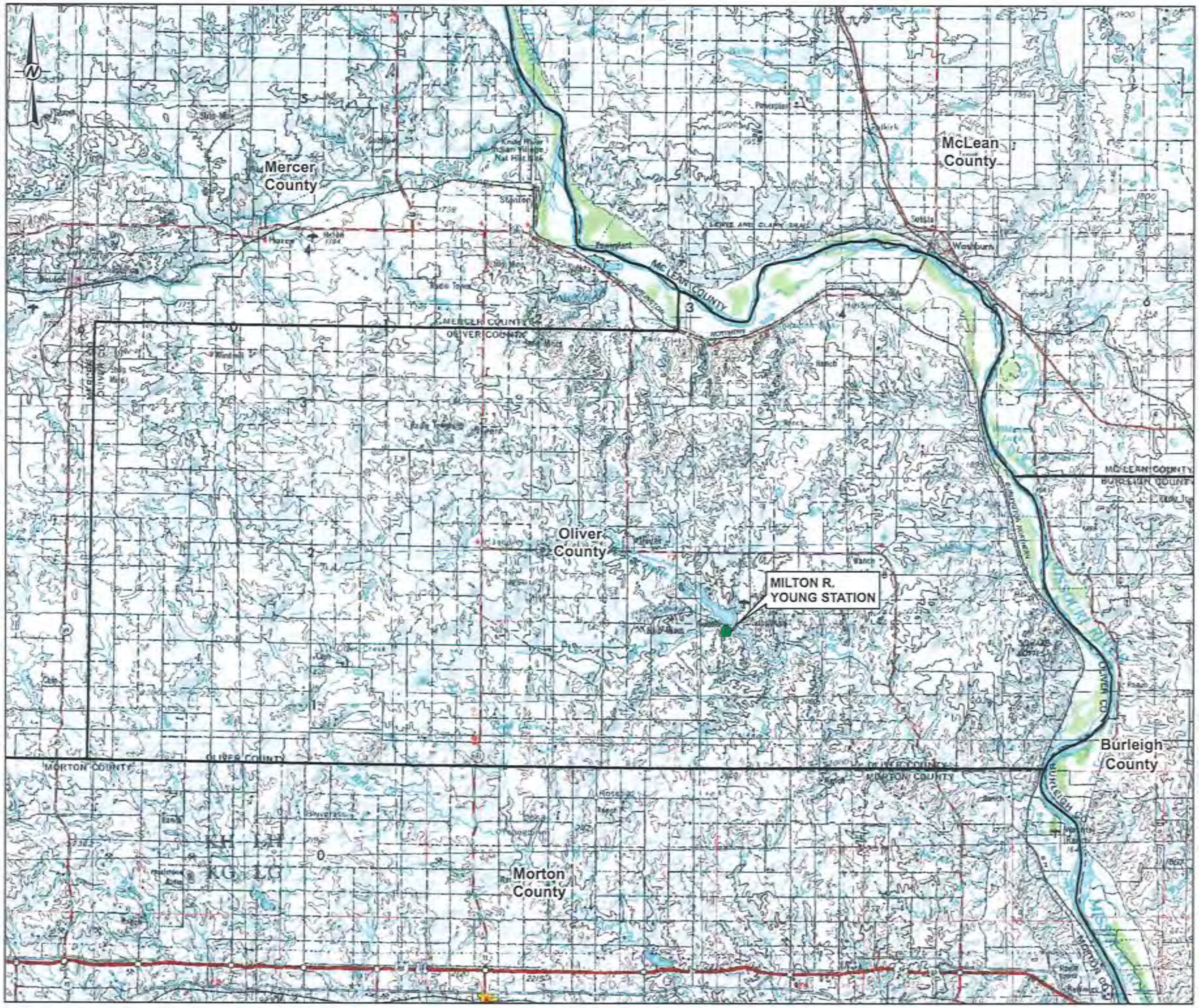
TITLE
SITE VICINITY MAP

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-2

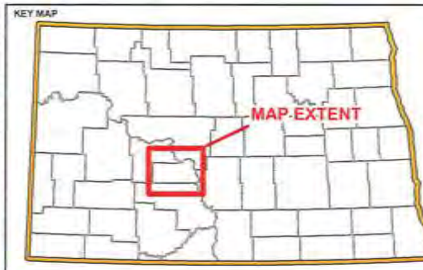


LEGEND

MILTON R. YOUNG STATION

COUNTY BOUNDARY

KEY MAP



0 2 4 8 Miles

REFERENCES

1. TOPOGRAPHIC BACKGROUND: ESRI BASEMAP SERVICES, USGS.

CLIENT

MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT

CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE

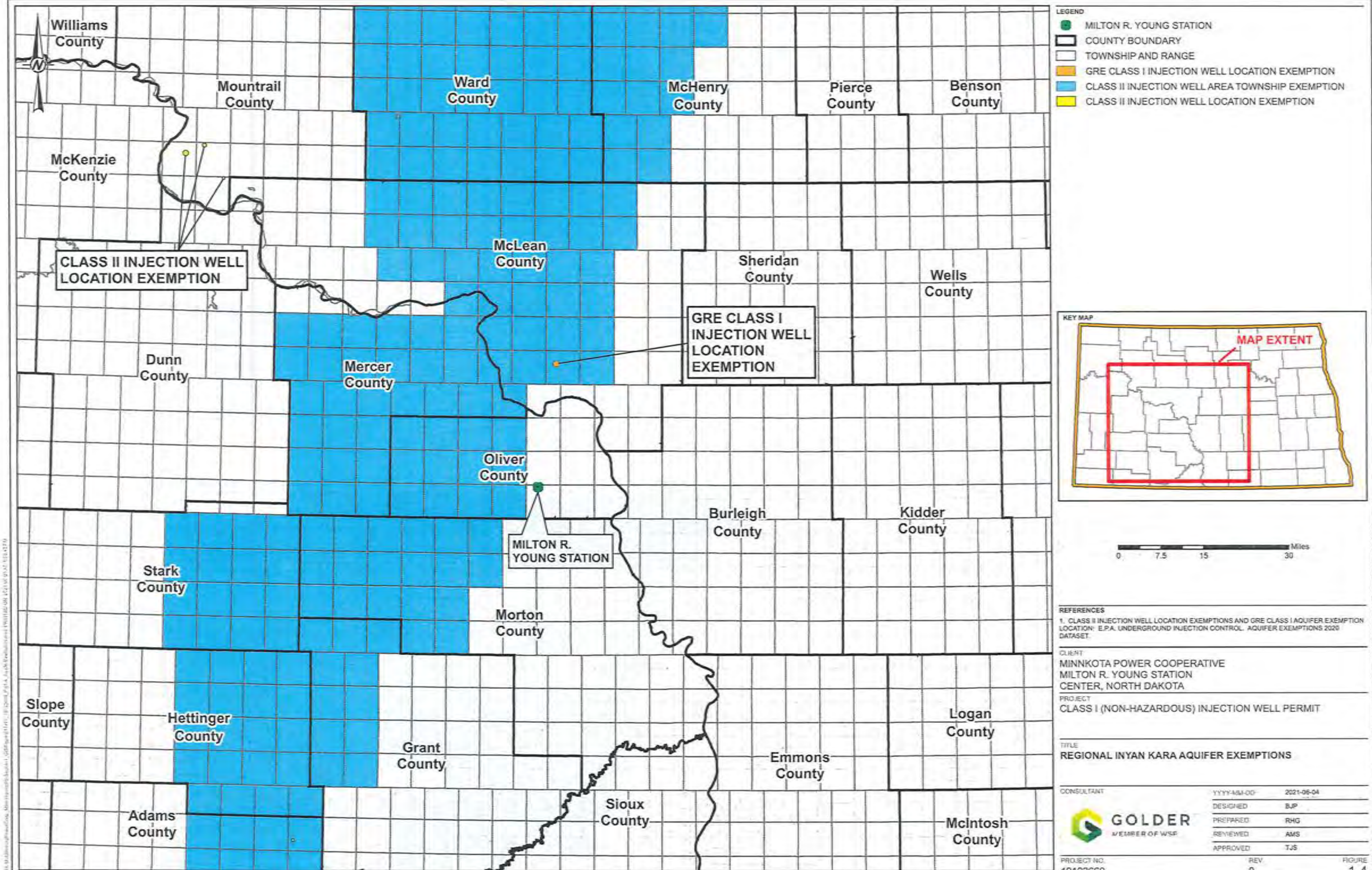
SITE LOCATION MAP

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV	FIGURE
19122669	0	1-1



REFERENCES

1. CLASS II INJECTION WELL LOCATION EXEMPTIONS AND GRE CLASS I AQUIFER EXEMPTION LOCATION: E.P.A. UNDERGROUND INJECTION CONTROL. AQUIFER EXEMPTIONS 2020 DATASET.

CLIENT

MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT

CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE

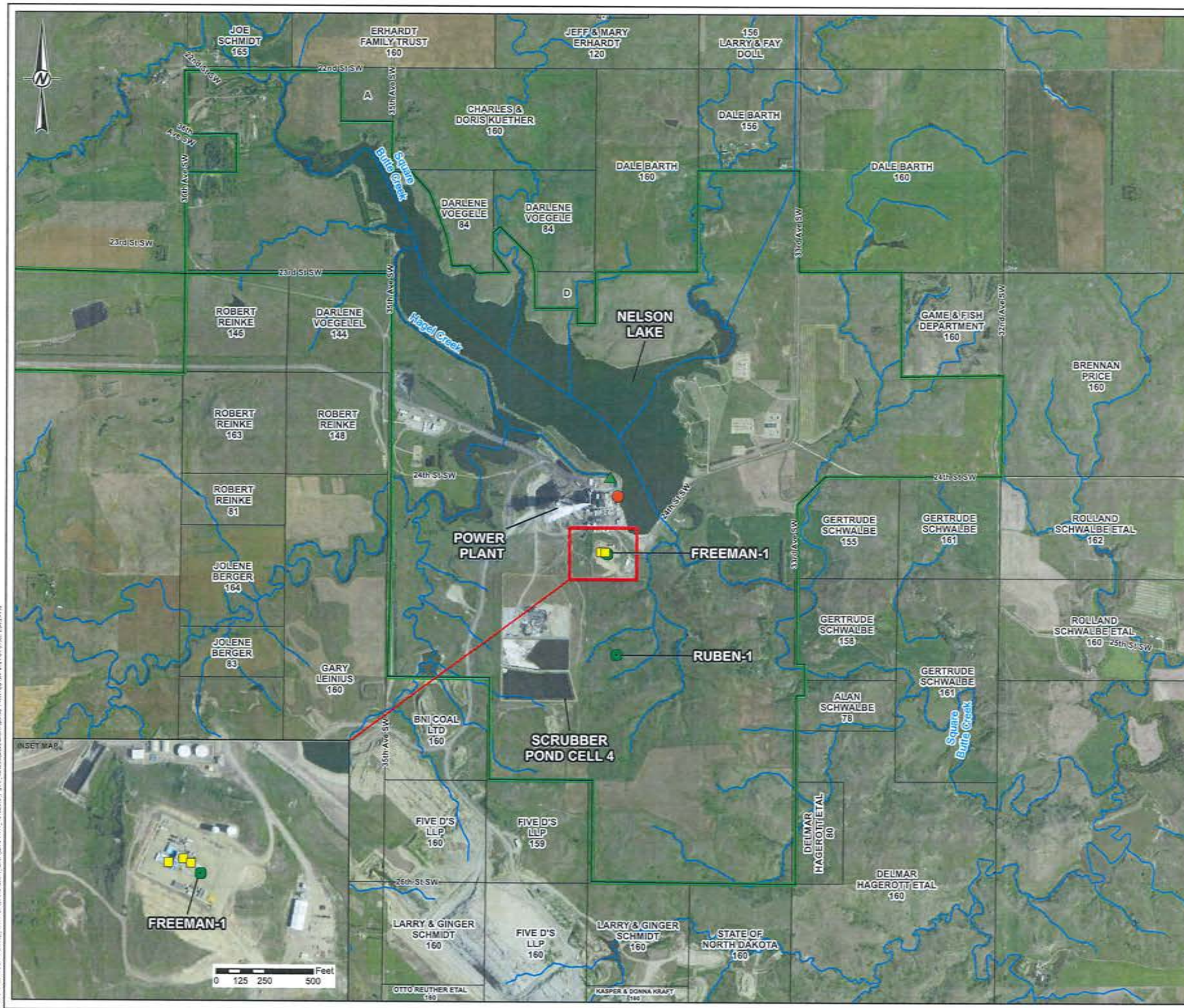
REGIONAL INYAN KARA AQUIFER EXEMPTIONS

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	1-4



REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
4. PARCEL BOUNDARIES: OLIVER COUNTY PLAT BOOK.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

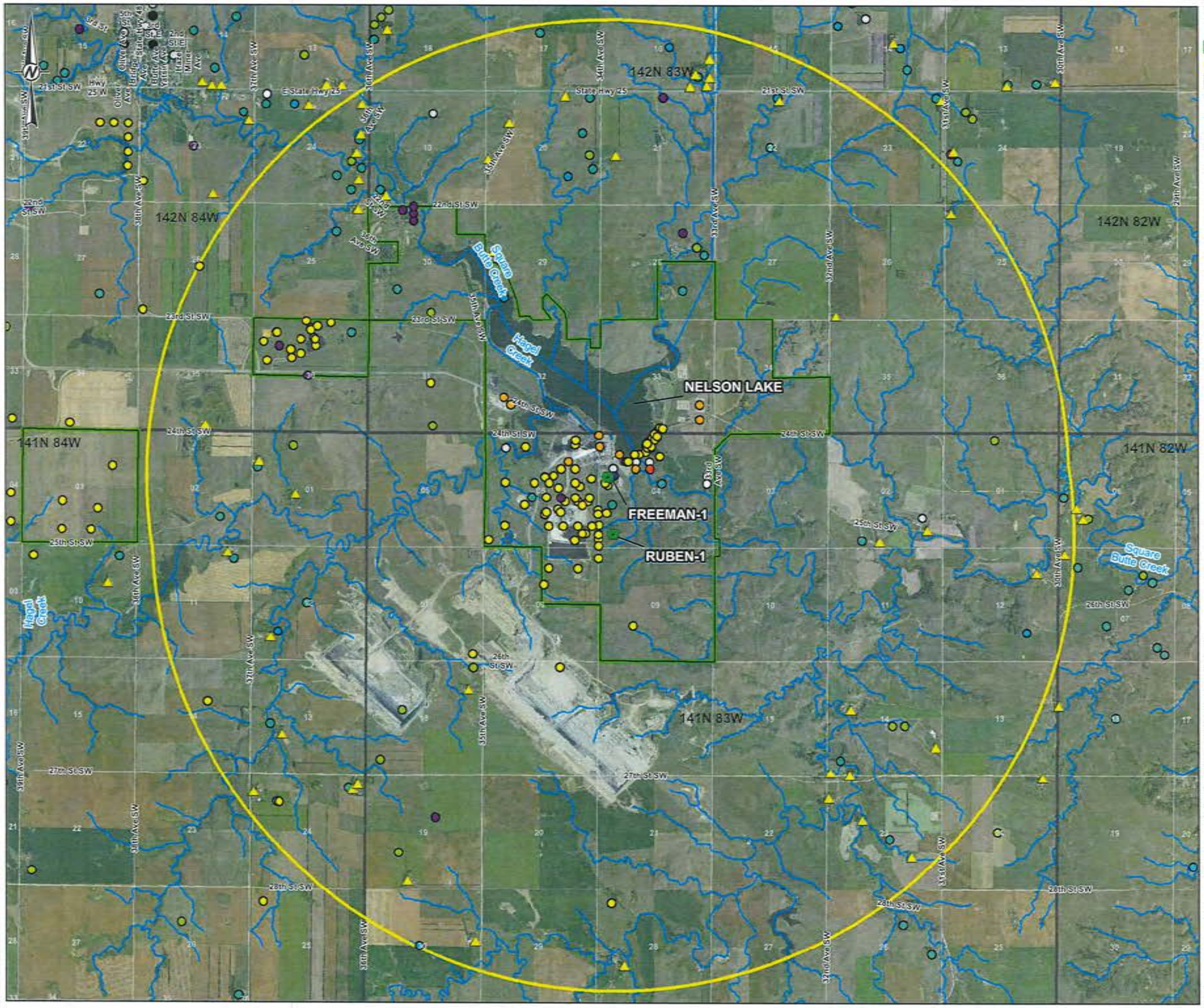
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
SITE MAP

CONSULTANT
GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-3



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- AREA OF REVIEW (4 MILE RADIUS AROUND EACH WELL)
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- RESIDENCES

WATER WELLS

- DOMESTIC
- DOMESTIC/STOCK
- INDUSTRIAL
- MONITORING
- STOCK
- TEST HOLE
- USGS INACTIVE
- MUNICIPAL
- OBSERVATION WELL
- UNKNOWN

KEY MAP

MAP EXTENT

0 2,250 4,500 9,000 Feet

REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. WELL DATA: NORTH DAKOTA WATER COMMISSION AND STATE ENGINEER WELL DRILLERS LOGS. DOWNLOADED 4/14/2021. (LOCATIONS ARE APPROXIMATE)
3. WELL DATA: MINNKOTA POWER COOPERATIVE MILTON R. YOUNG STATION MONITORING WELLS, PROVIDED BY MINNKOTA 4/8/2020.(LOCATIONS ARE APPROXIMATE)
4. WELL DATA: USGS NATIONAL WATER INFORMATION SYSTEM GROUNDWATER SITES DOWNLOAD 4/14/2021. (LOCATIONS ARE APPROXIMATE)
5. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
6. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
7. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

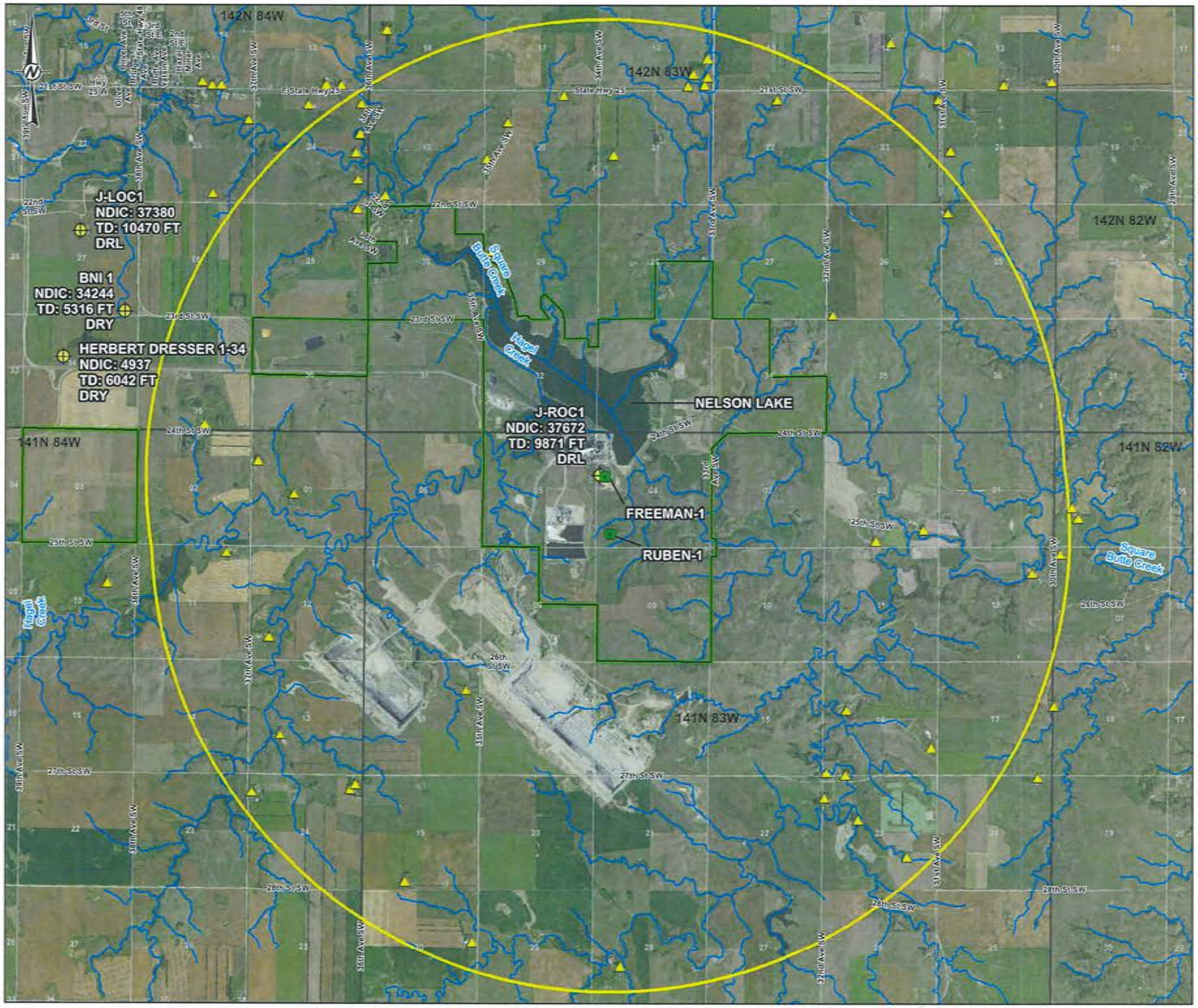
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
AREA OF REVIEW - SHALLOW WELLS

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-6



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MPC PROPERTY BOUNDARY
- AREA OF REVIEW (4 MILE RADIUS AROUND EACH WELL)
- TOWNSHIP
- SECTION
- LINEAR SURFACE WATER FEATURES
- RESIDENCES
- DEEP WELLS (SEE REF. 3)

WELL NAME
NDIC FILE NO.
TOTAL DEPTH
WELL STATUS

KEY MAP

0 2,250 4,500 9,000 Feet

NOTE
1. BASED ON REVIEW OF WELL RECORDS WITH THE NORTH DAKOTA INDUSTRIAL COMMISSION, OIL & GAS CONSERVATION DIVISION, AND THE NORTH DAKOTA STATE WATER COMMISSION THERE ARE NO EXISTING INJECTION WELLS WITHIN THE AREA OF REVIEW.

REFERENCES
1. AERIAL IMAGERY: NATIONAL AGRICULTURE IMAGERY PROGRAM (NAIP), USDA. IMAGE FLOWN 8/10/2020.
2. STREAMS DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.
3. DEEP WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL & GAS DIVISION, FEBRUARY 2020.
4. ROAD DATA: U.S. CENSUS BUREAU, TIGER ROAD DATA 2019.
5. RESIDENCES: BASED ON AERIAL IMAGERY.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

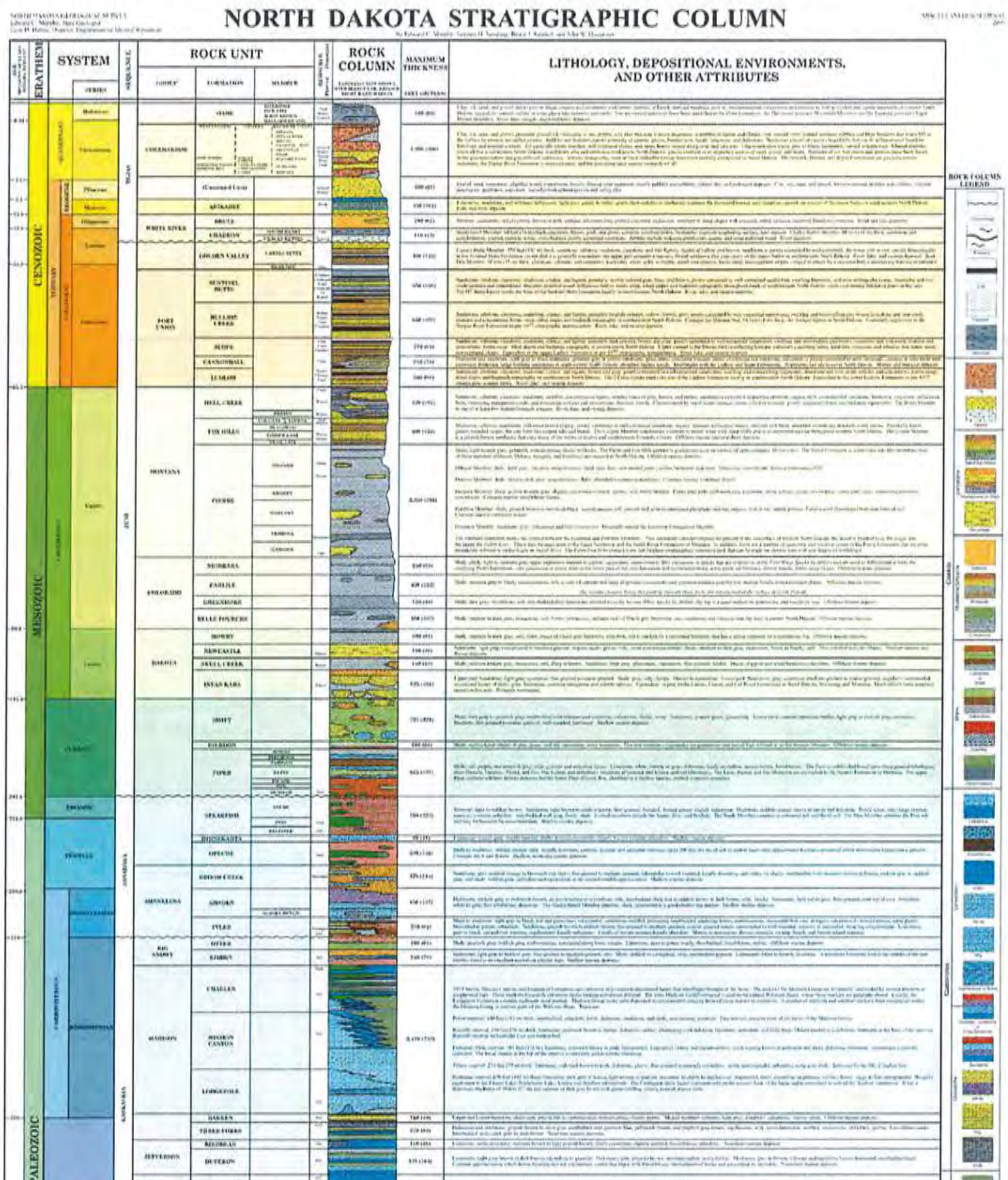
TITLE
AREA OF REVIEW MAP - DEEP WELLS

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 1-5



CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

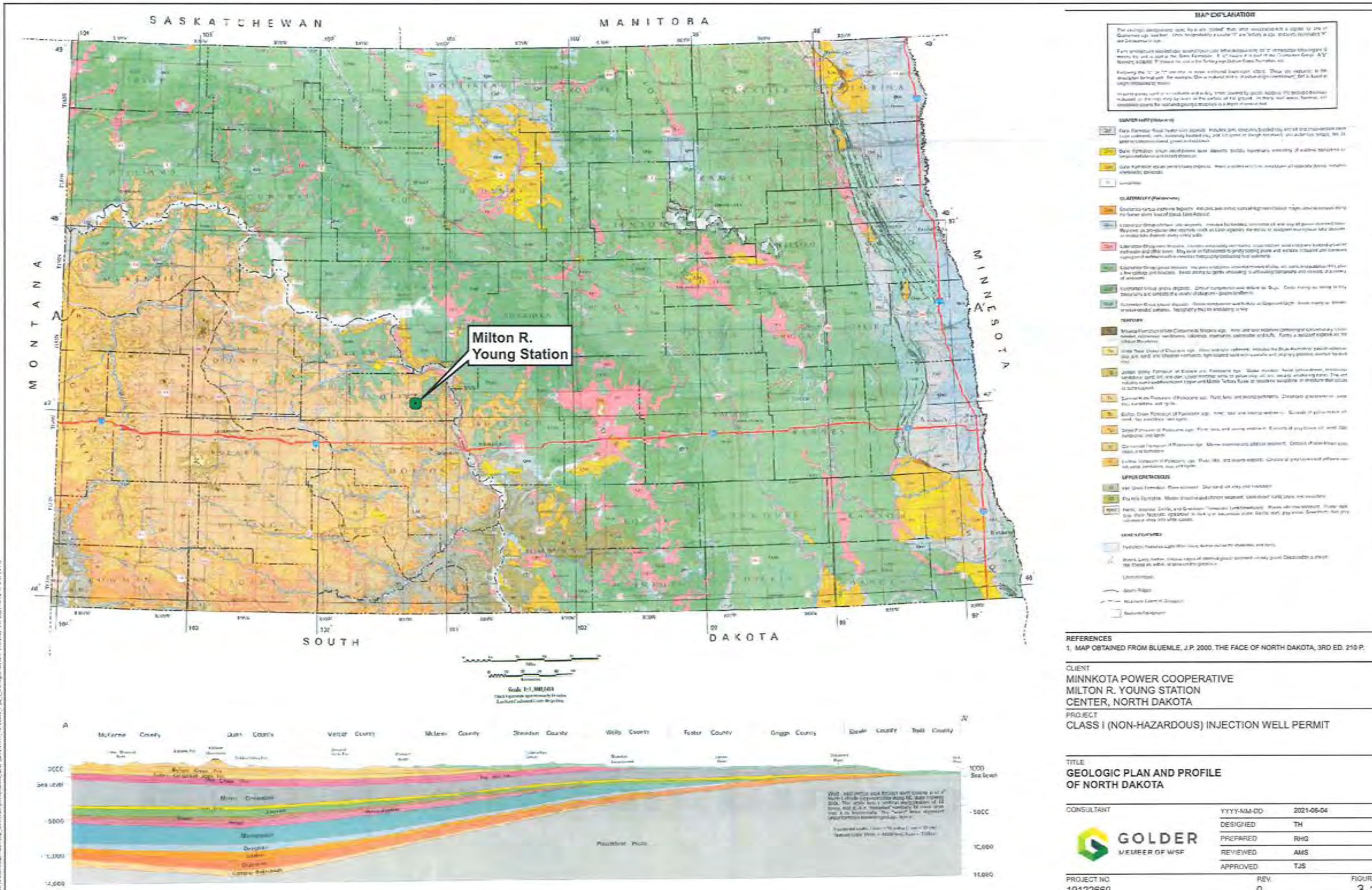
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
NORTH DAKOTA STRATIGRAPHIC COLUMN

CONSULTANT		
GOLDER MEMBER OF WSP	YYYY-MM-DD	2021-06-04
	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

REFERENCE(S)
1. NORTH DAKOTA STRATIGRAPHIC COLUMN OBTAINED FROM NORTH DAKOTA GEOLOGICAL SURVEY WEBSITE (HTTPS://WWW.DMR.ND.GOV/NDGS/DOCUMENTS/PUBLICATION_LIST/PDF/STRAT-COLUMN-NDGS-(2009).PDF) ON JUNE 2, 2020.

PROJECT NO.	REV.	FIGURE
19122669	0	3-2



REFERENCES
1. MAP OBTAINED FROM BLUEMLE, J.P. 2000. THE FACE OF NORTH DAKOTA, 3RD ED. 210 P.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

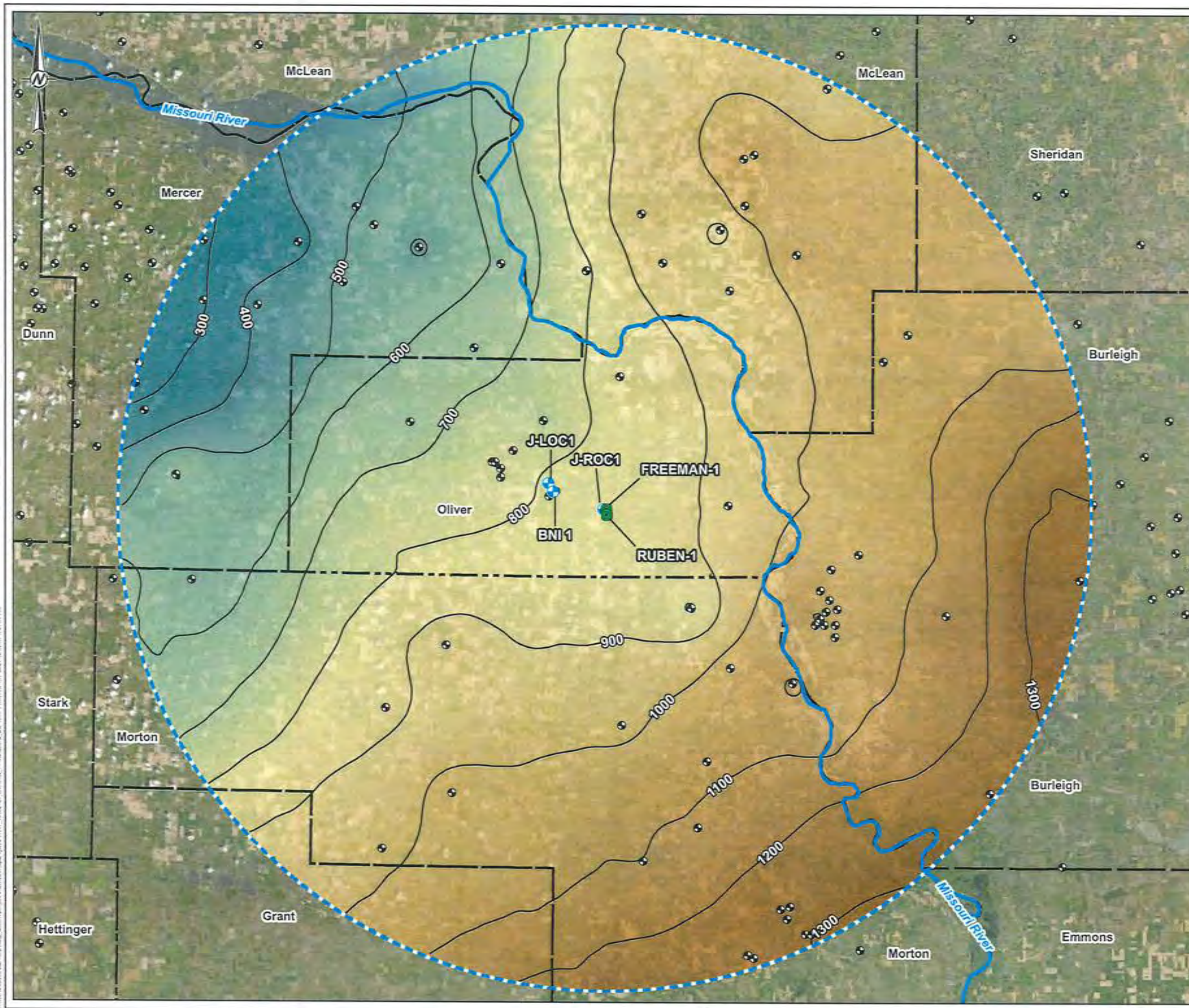
TITLE
GEOLOGIC PLAN AND PROFILE OF NORTH DAKOTA

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 | REV. 0 | FIGURE 3-1



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA. IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

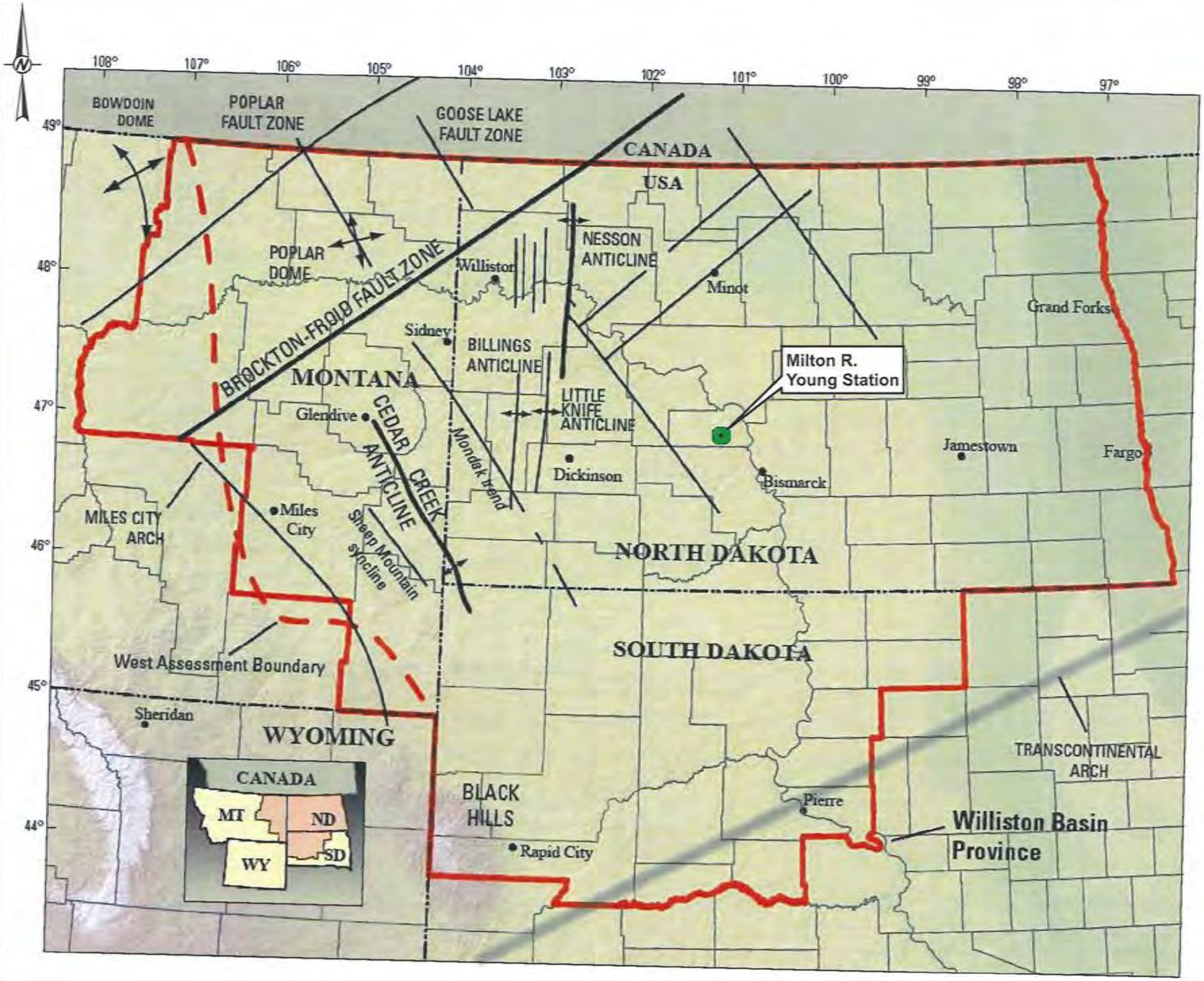
TITLE
FORMATION TOP ELEVATIONS - PIERRE SHALE FORMATION

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-4



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MAJOR LINEAMENTS OR FAULTS (UNLABELED)
- PROVINCE BOUNDARY
- WESTERN BOUNDARY FOR ASSESSMENT UNITS

0 22.5 45 90 Miles

NOTE

1. LOCATION AND PHYSIOGRAPHIC FEATURES OF THE WILLISTON BASIN PROVINCE. BLACK LINES NOT LABELED ARE MAJOR LINEAMENTS OR FAULTS. SOLID RED LINE IS PROVINCE BOUNDARY; DASHED RED LINE REPRESENTS THE WESTERN BOUNDARY FOR ASSESSMENT UNITS. LINEAMENTS AND STRUCTURE LOCATIONS ARE FROM GERHARD AND OTHERS (1982) AND ANNA (1986).

REFERENCES

1. MAP OBTAINED FROM ANNA, L. O., POLLASTRO, R. & GASWIRTH, S.B., 2013. WILLISTON BASIN PROVINCE - STRATIGRAPHIC AND STRUCTURAL FRAMEWORK TO A GEOLOGICAL ASSESSMENT OF UNDISCOVERED OIL AND GAS RESOURCES, RESTON, VIRGINIA: U.S. GEOLOGICAL SURVEY.

CLIENT

MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT

CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE

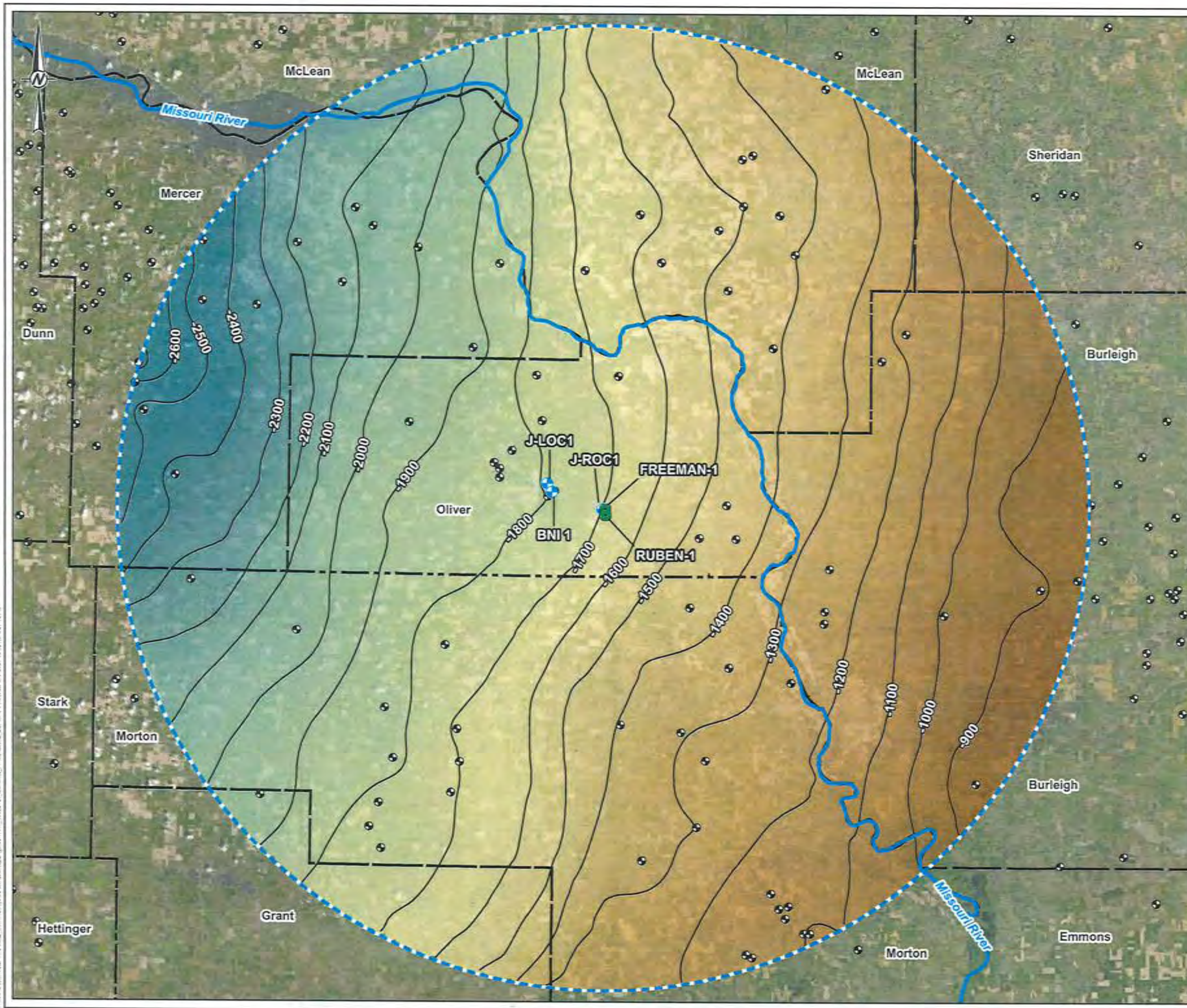
STRUCTURAL FEATURES OF THE WILLISTON BASIN PROVINCE

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-3



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

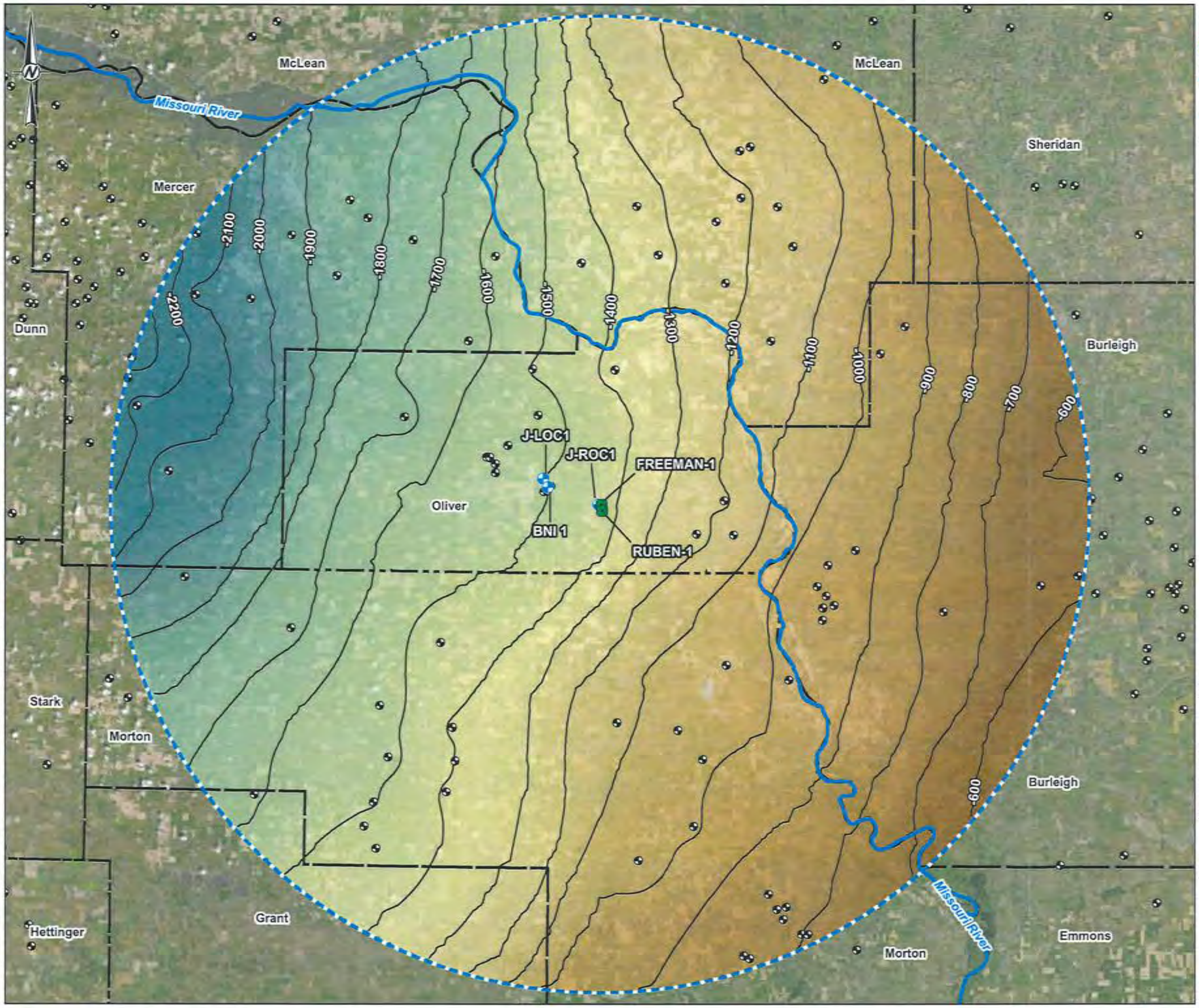
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - INYAN KARA FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-6



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA. IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

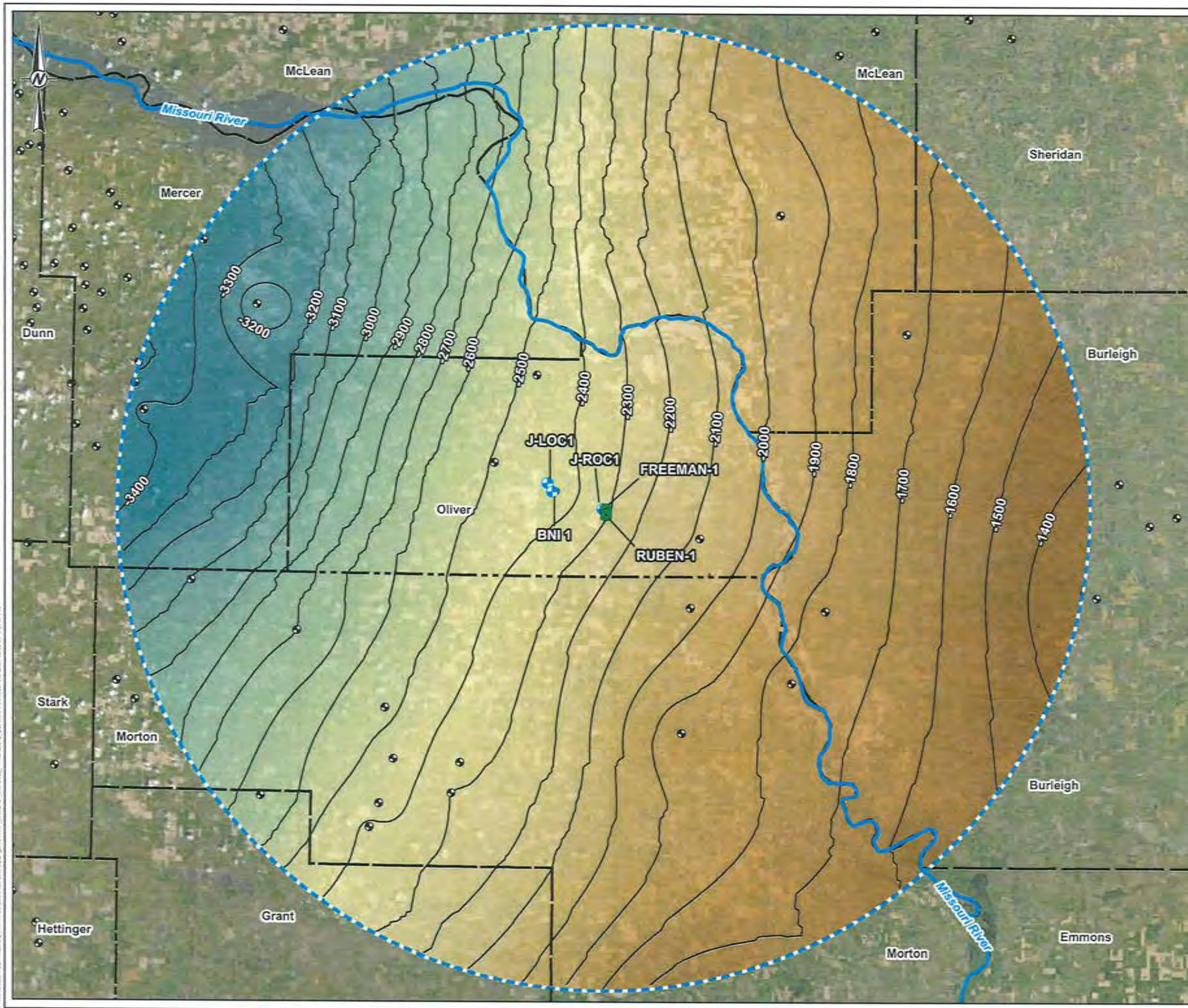
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - MOWRY FORMATION

CONSULTANT: GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-5



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES
1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

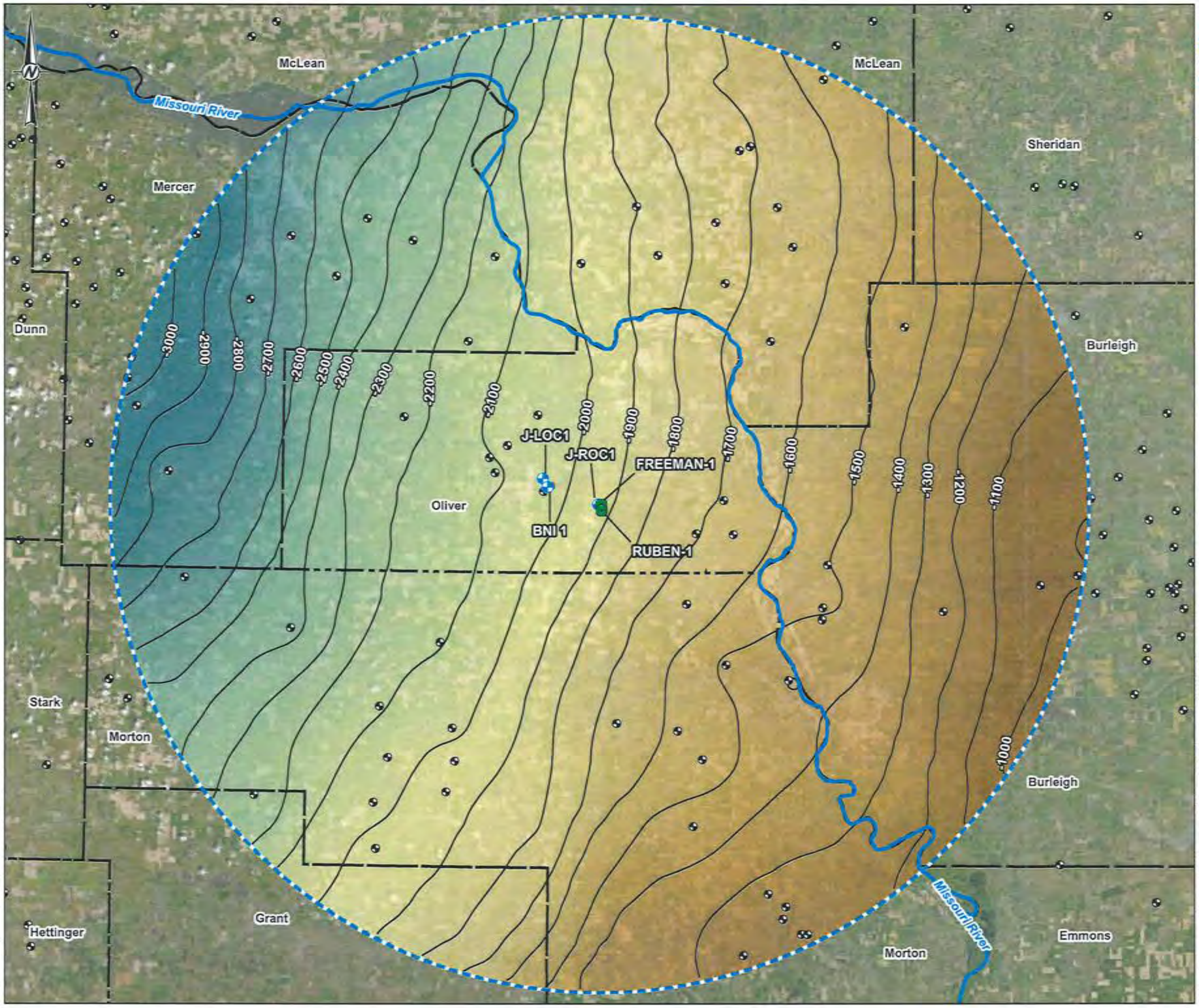
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - RIERDON FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-8



LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- 40-MILE RADIUS
- COUNTY BOUNDARY
- MISSOURI RIVER
- WELL USED FOR MODELLING FORMATION TOPS
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- FORMATION TOP ELEVATION CONTOUR (FT AMSL, 100-FT INTERVAL)

0 4 8 16 Miles

REFERENCES

1. AERIAL IMAGERY: ESRI, DIGITAL GLOBE, VIVID - USA, IMAGERY CAPTURED JULY 2016.
2. WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. RIVER DATASET: NATIONAL HYDROGRAPHY DATASET (NHD), USGS.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

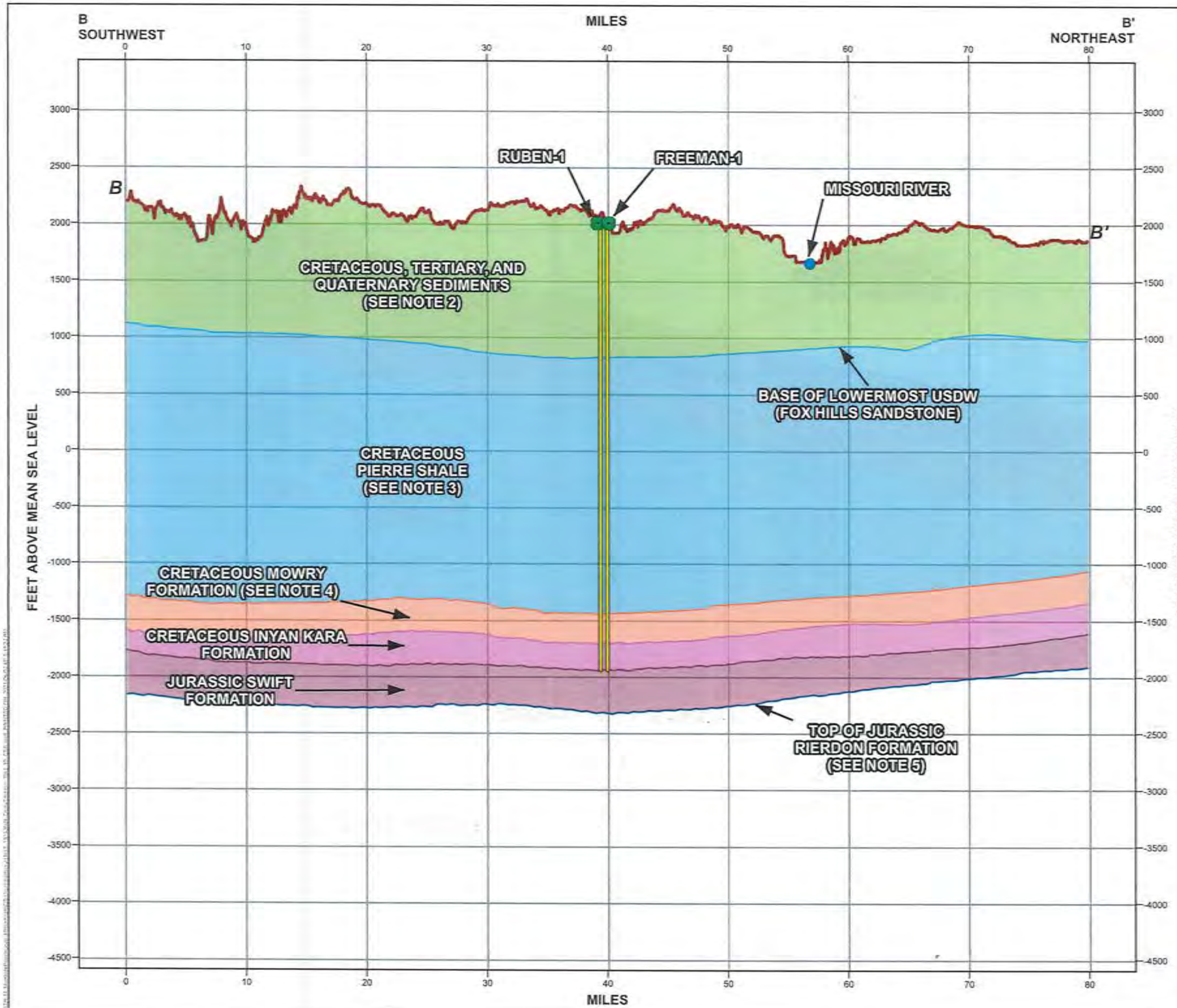
PROJECT
CLASS I (NON-HAZARDOUTS) INJECTION WELL PERMIT

TITLE
FORMATION TOP ELEVATIONS - SWIFT FORMATION

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV 0 FIGURE 3-7



CROSS SECTION LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MISSOURI RIVER
- GROUND SURFACE (REF. 3)

NOTE

1. CROSS SECTIONS SET TO 50X VERTICAL EXAGGERATION.
2. FORMATION CONTACTS ABOVE THE TOP OF THE CRETACEOUS PIERRE SHALE HAVE NOT BEEN DELINEATED.
3. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS PIERRE SHALE AND THE TOP OF THE CRETACEOUS MOWRY FORMATION, INCLUDING THE NIOBRARA, CARLILE, GREENHORN, AND BELLE FOURCHE FORMATIONS, HAVE NOT BEEN DELINEATED.
4. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS MOWRY FORMATION AND THE TOP OF THE CRETACEOUS INYAN KARA FORMATION, INCLUDING THE NEWCASTLE AND SKULL CREEK FORMATIONS, HAVE NOT BEEN DELINEATED.
5. FORMATION CONTACTS BELOW THE TOP OF THE JURASSIC RIERDON FORMATION HAVE NOT BEEN DELINEATED.

REFERENCES

1. REFERENCE BASEMAP: ESRI PROVIDED BASEMAP SERVICES, NATIONAL GEOGRAPHIC BASEMAP.
2. NORTH DAKOTA WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. GROUND SURFACE ELEVATION: USGS NED 1/3 ARC-SECOND RESOLUTION DIGITAL ELEVATION MODEL. PUBLISHED 3/15/2017.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

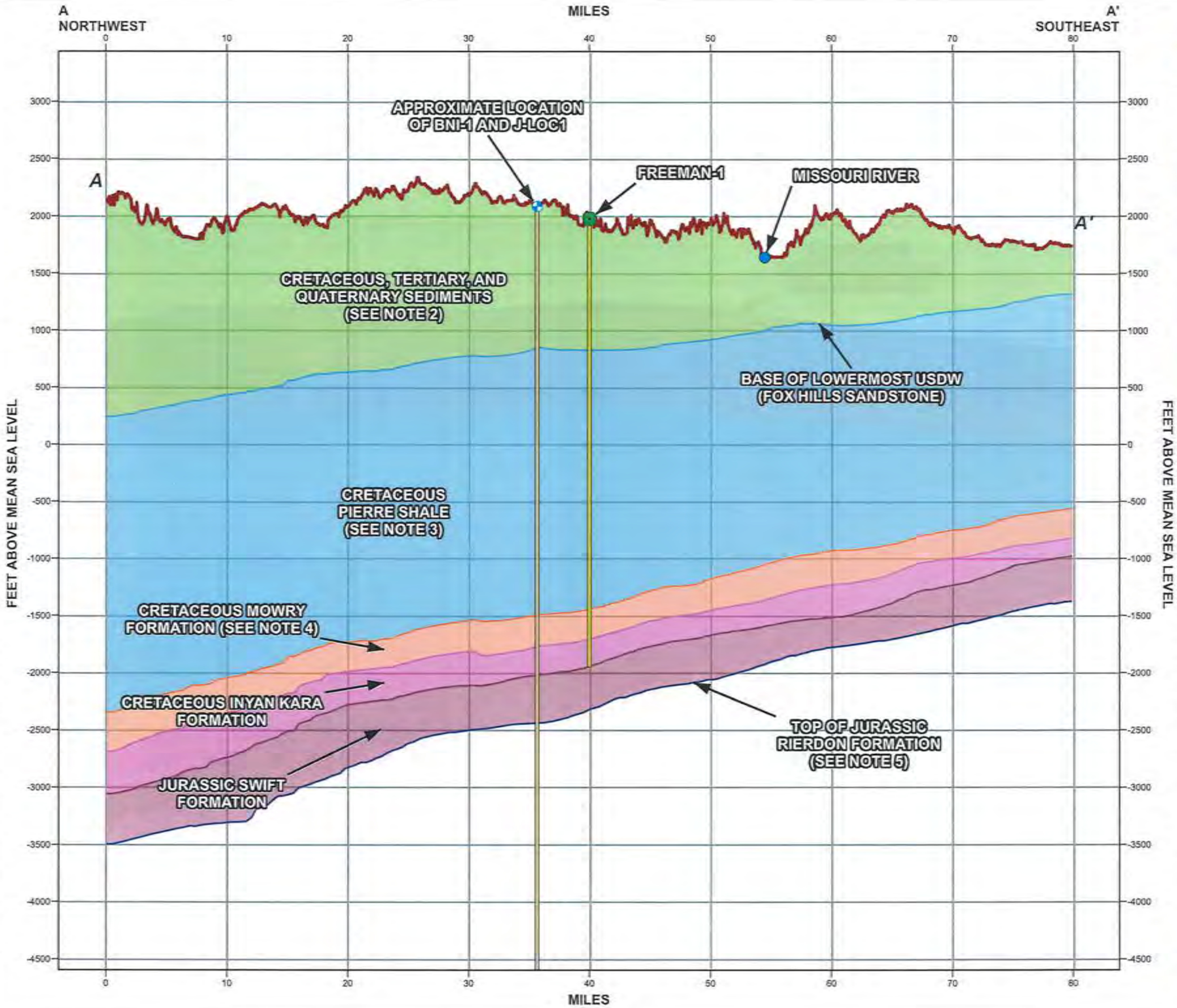
TITLE
GEOLOGIC CROSS SECTION B-B'

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-10



CROSS SECTION LEGEND

- APPROXIMATE PROPOSED INJECTION WELL LOCATION
- MISSOURI RIVER
- STRATIGRAPHIC TEST BOREHOLE / WELL LOCATION
- GROUND SURFACE (REF. 3)

NOTE
1. CROSS SECTIONS SET TO 50X VERTICAL EXAGGERATION.
2. FORMATION CONTACTS ABOVE THE TOP OF THE CRETACEOUS PIERRE SHALE HAVE NOT BEEN DELINEATED.
3. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS PIERRE SHALE AND THE TOP OF THE CRETACEOUS MOWRY FORMATION, INCLUDING THE NIOBRARA, CARLILE, GREENHORN, AND BELLE FOURCHE FORMATIONS, HAVE NOT BEEN DELINEATED.
4. FORMATION CONTACTS BETWEEN THE TOP OF THE CRETACEOUS MOWRY FORMATION AND THE TOP OF THE CRETACEOUS INYAN KARA FORMATION, INCLUDING THE NEWCASTLE AND SKULL CREEK FORMATIONS, HAVE NOT BEEN DELINEATED.
5. FORMATION CONTACTS BELOW THE TOP OF THE JURASSIC RIERDON FORMATION HAVE NOT BEEN DELINEATED.

REFERENCES
1. REFERENCE BASEMAP: ESRI PROVIDED BASEMAP SERVICES, NATIONAL GEOGRAPHIC BASEMAP.
2. NORTH DAKOTA WELL DATA: NORTH DAKOTA INDUSTRIAL COMMISSION, OIL AND GAS DIVISION, FEBRUARY 2020.
3. GROUND SURFACE ELEVATION: USGS NED 1/3 ARC-SECOND RESOLUTION DIGITAL ELEVATION MODEL. PUBLISHED 3/15/2017.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

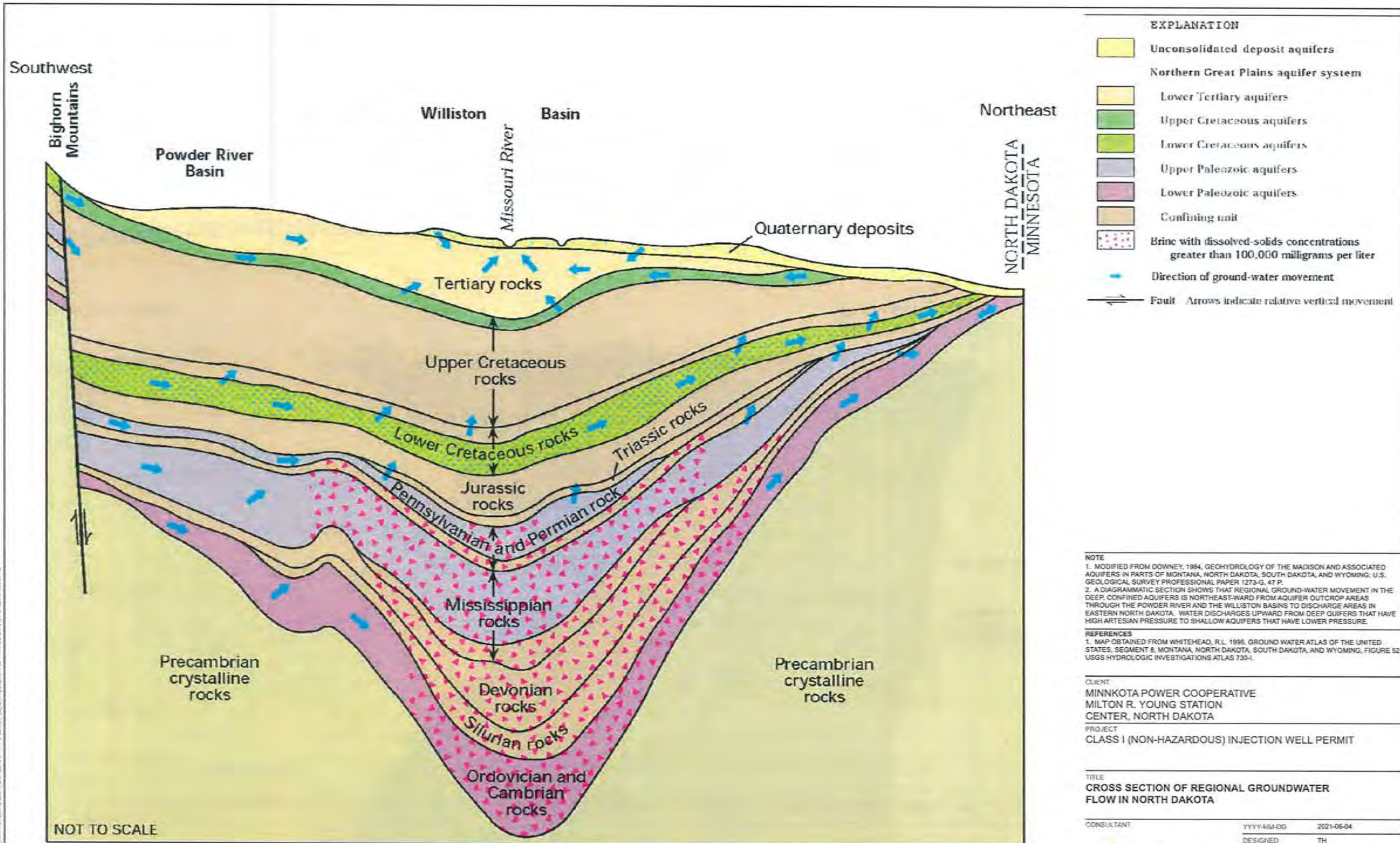
TITLE
GEOLOGIC CROSS SECTION A-A'

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-9



NOTE

1. MODIFIED FROM DOWNEY, 1984, GEOHYDROLOGY OF THE MADISON AND ASSOCIATED AQUIFERS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1273-G, 47 P.
2. A DIAGRAMMATIC SECTION SHOWS THAT REGIONAL GROUND-WATER MOVEMENT IN THE DEEP, CONFINED AQUIFERS IS NORTHEAST-WARD FROM AQUIFER OUTCROP AREAS THROUGH THE POWDER RIVER AND THE WILLISTON BASINS TO DISCHARGE AREAS IN EASTERN NORTH DAKOTA. WATER DISCHARGES UPWARD FROM DEEP QUIFERS THAT HAVE HIGH ARTESIAN PRESSURE TO SHALLOW AQUIFERS THAT HAVE LOWER PRESSURE.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 52. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

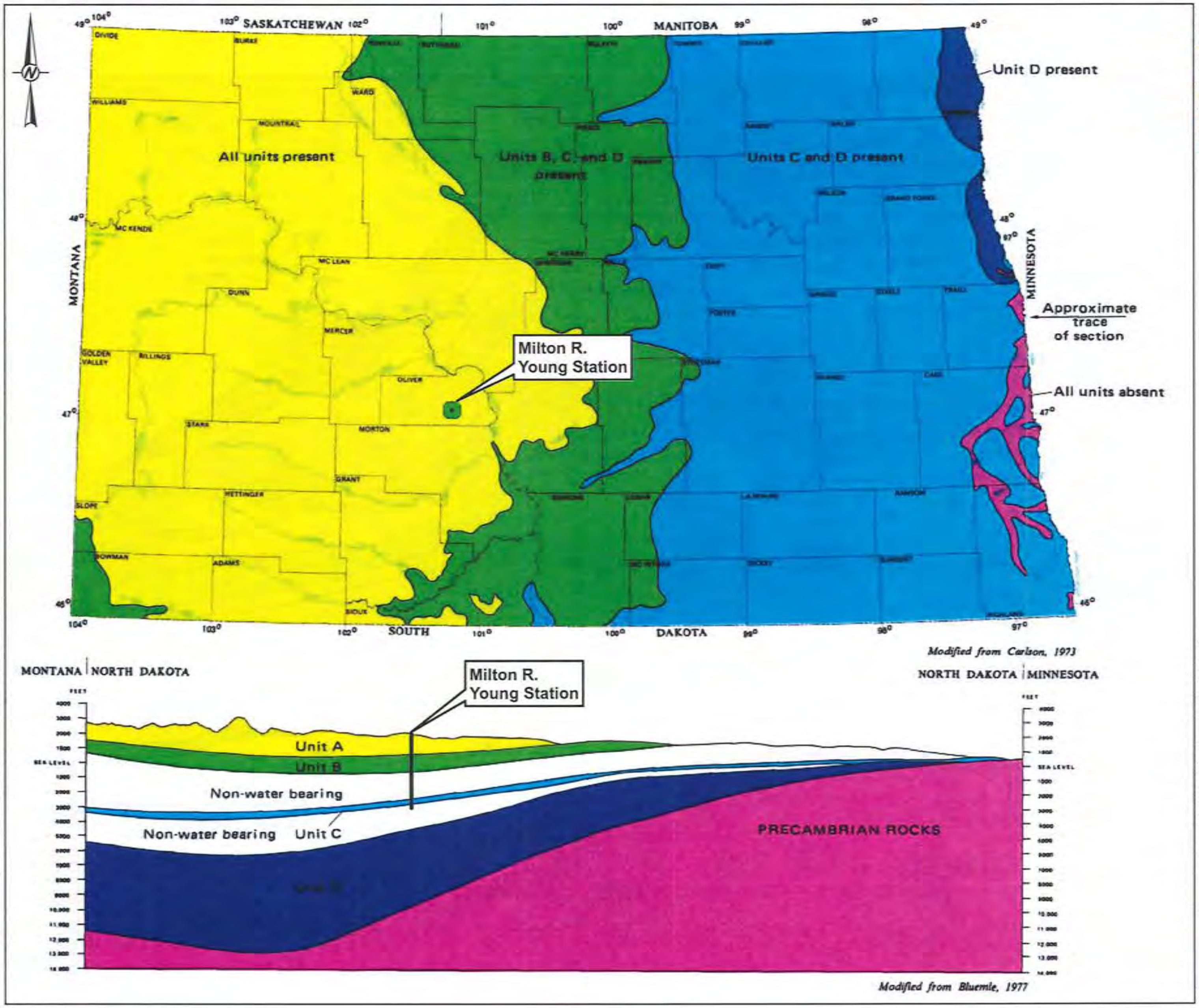
CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
CROSS SECTION OF REGIONAL GROUNDWATER FLOW IN NORTH DAKOTA

CONSULTANT		
GOLDER MEMBER OF WSP	YYYY-MM-DD	2021-06-04
	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-12



NOTE

1. LOCATION AND DEPTHS OF BEDROCK AQUIFER UNITS A, B, C AND D. MORE BEDROCK AQUIFERS ARE AVAILABLE IN WESTERN NORTH DAKOTA THAN IN THE EASTERN PART. HOWEVER, DEPTH TO AQUIFERS INCREASES TOWARDS THE WEST. COLOR ON MAP REPRESENTS UPPERMOST UNIT.

REFERENCES

1. MAP OBTAINED FROM PAULSON, Q. F. 1983. GUIDE TO NORTH DAKOTA'S GROUND-WATER RESOURCES, FIGURE 8. U.S. GEOLOGICAL SURVEY WATER-SUPPLY PAPER 2236.

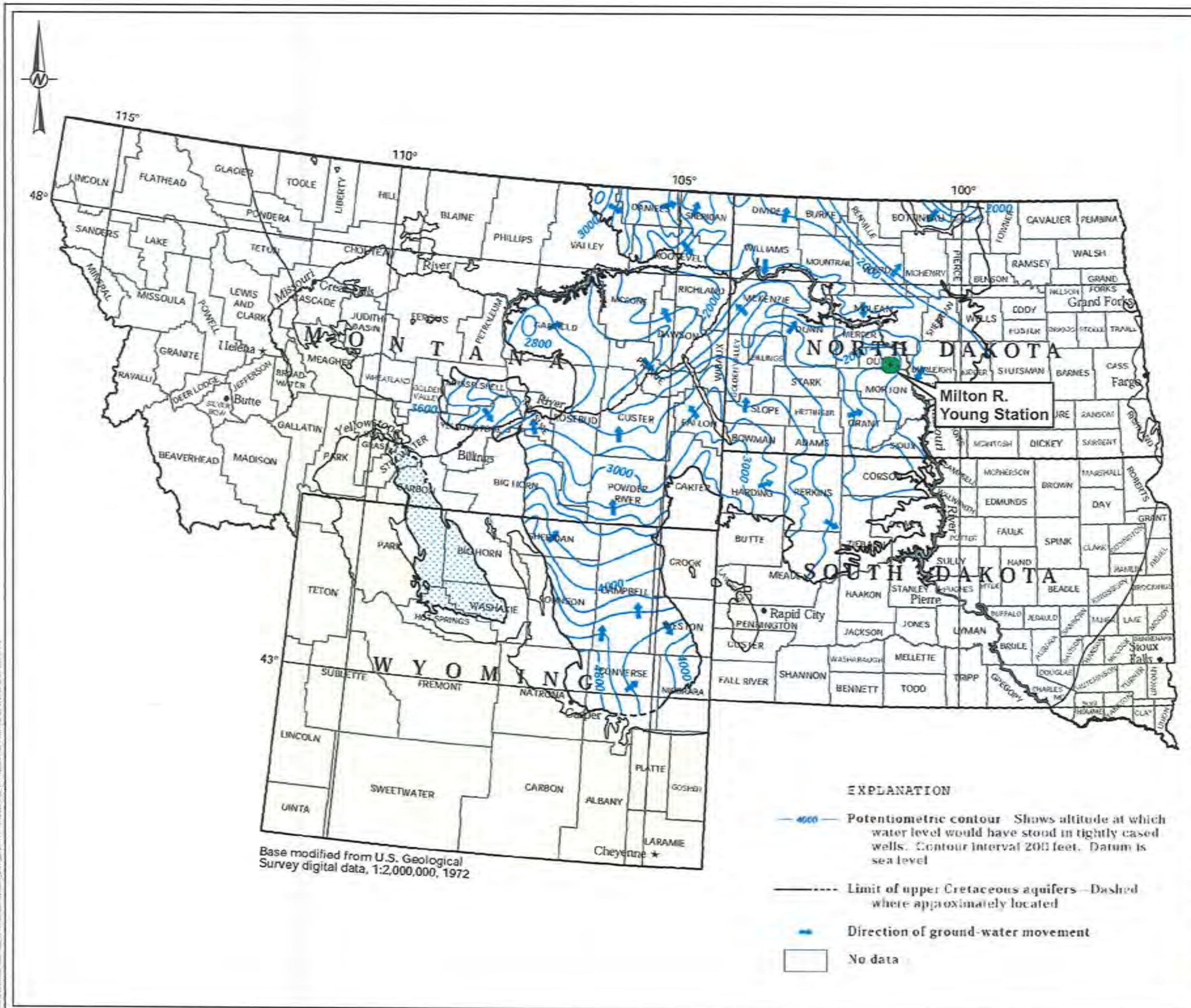
CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
CONCEPTUAL DEPICTION OF AQUIFER EXTENTS

CONSULTANT	YYYY-MM-DD	2021-06-04
GOLDER MEMBER OF WSP	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

PROJECT NO.	REV	FIGURE
19122669	0	3-11



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE

1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.
2. WATER IN THE UPPER CRETACEOUS AQUIFERS GENERALLY MOVES NORTHWARD IN WYOMING AND NORTHEASTWARD ELSEWHERE. REGIONAL MOVEMENT IS FROM AQUIFER RECHARGE AREAS AT HIGHER ALTITUDES TOWARD LOW-LYING MAJOR STREAMS.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 56. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

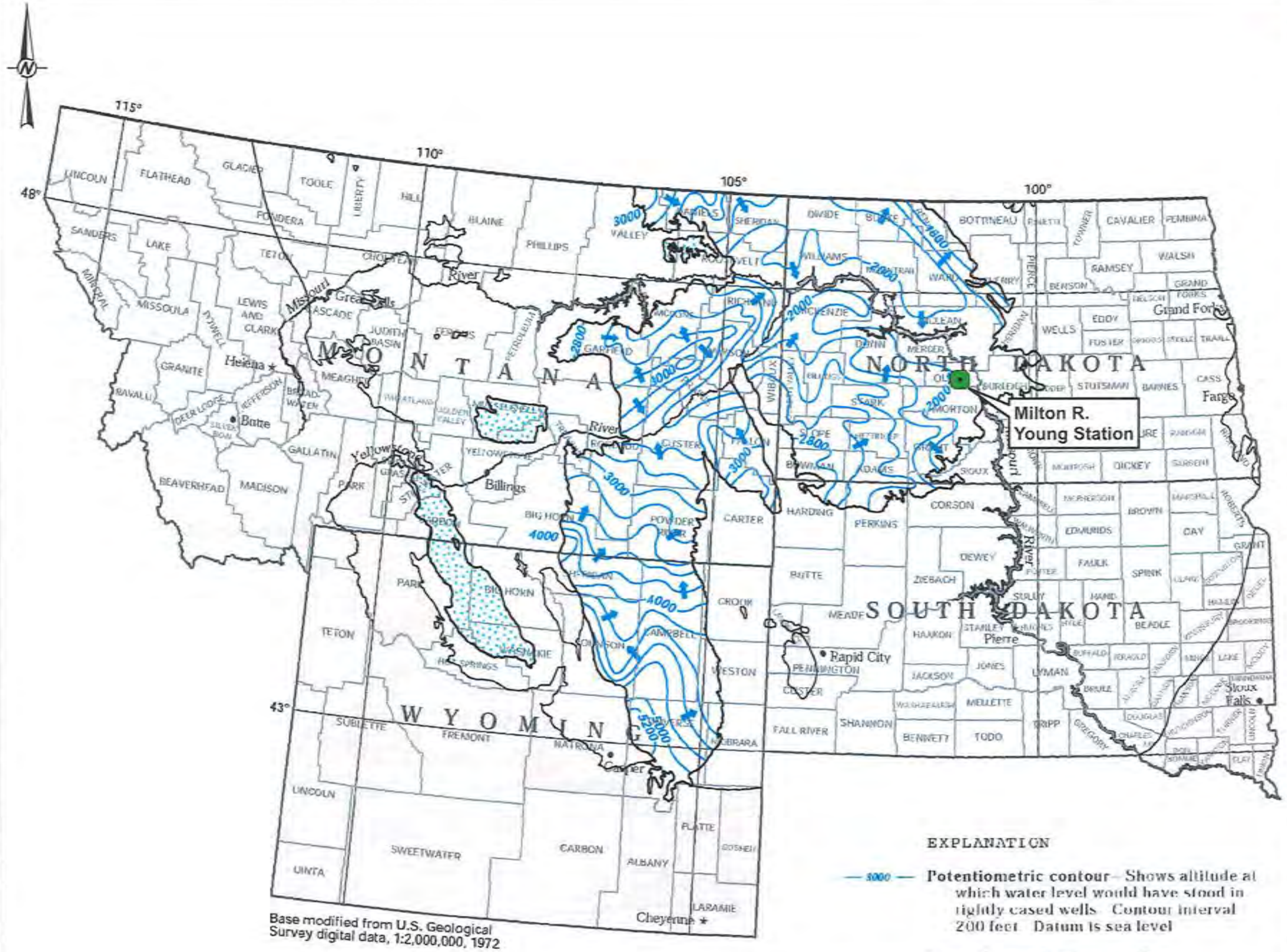
CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE UPPER CRETACEOUS AQUIFER SYSTEM

CONSULTANT	YYYY-MM-DD	2021-06-04
GOLDER MEMBER OF WSP	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-14



EXPLANATION

— 3000 — Potentiometric contour—Shows altitude at which water level would have stood in tightly cased wells. Contour interval 200 feet. Datum is sea level

Limit of lower Tertiary aquifers

Direction of ground-water movement

No data

LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE
1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.
2. WATER IN THE LOWER TERTIARY AQUIFERS GENERALLY MOVES NORTHWARD AND NORTHEASTWARD FROM RECHARGE AREAS AT HIGHER ALTITUDES. THE REGIONAL TREND OF MOVEMENT CHANGES LOCALLY WHERE THE AQUIFER DISCHARGES WATER TO LARGE STREAMS.

REFERENCES
1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996, GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 55. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

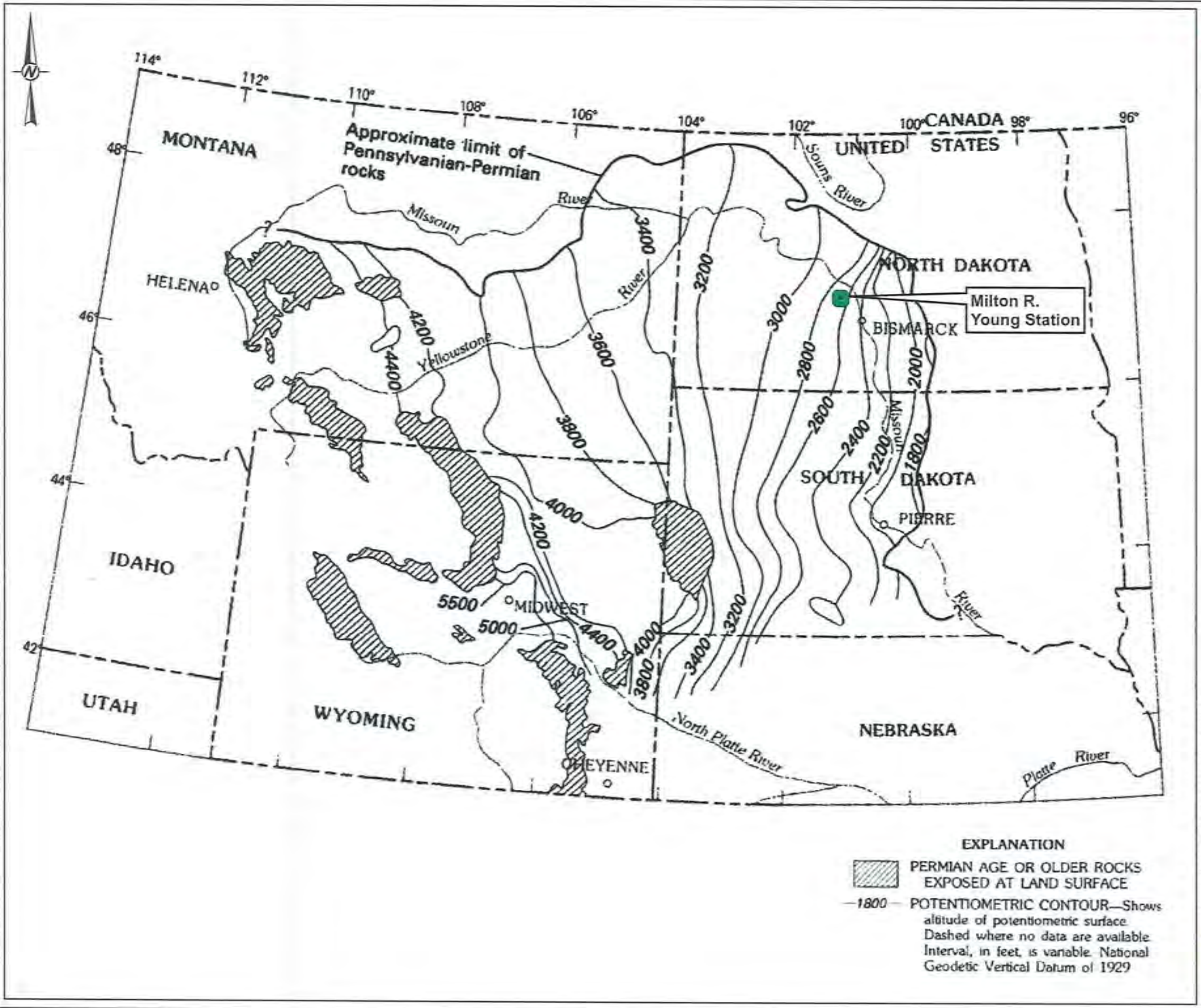
TITLE
POTENTIOMETRIC SURFACE OF THE LOWER TERTIARY AQUIFER SYSTEM

CONSULTANT

GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669 REV. 0 FIGURE 3-13



REFERENCES
1. MAP OBTAINED FROM DOWNEY, J.A. 1986. GEOHYDROLOGY OF BEDROCK AQUIFERS IN THE NORTHERN GREAT PLAINS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 44. U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-E.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

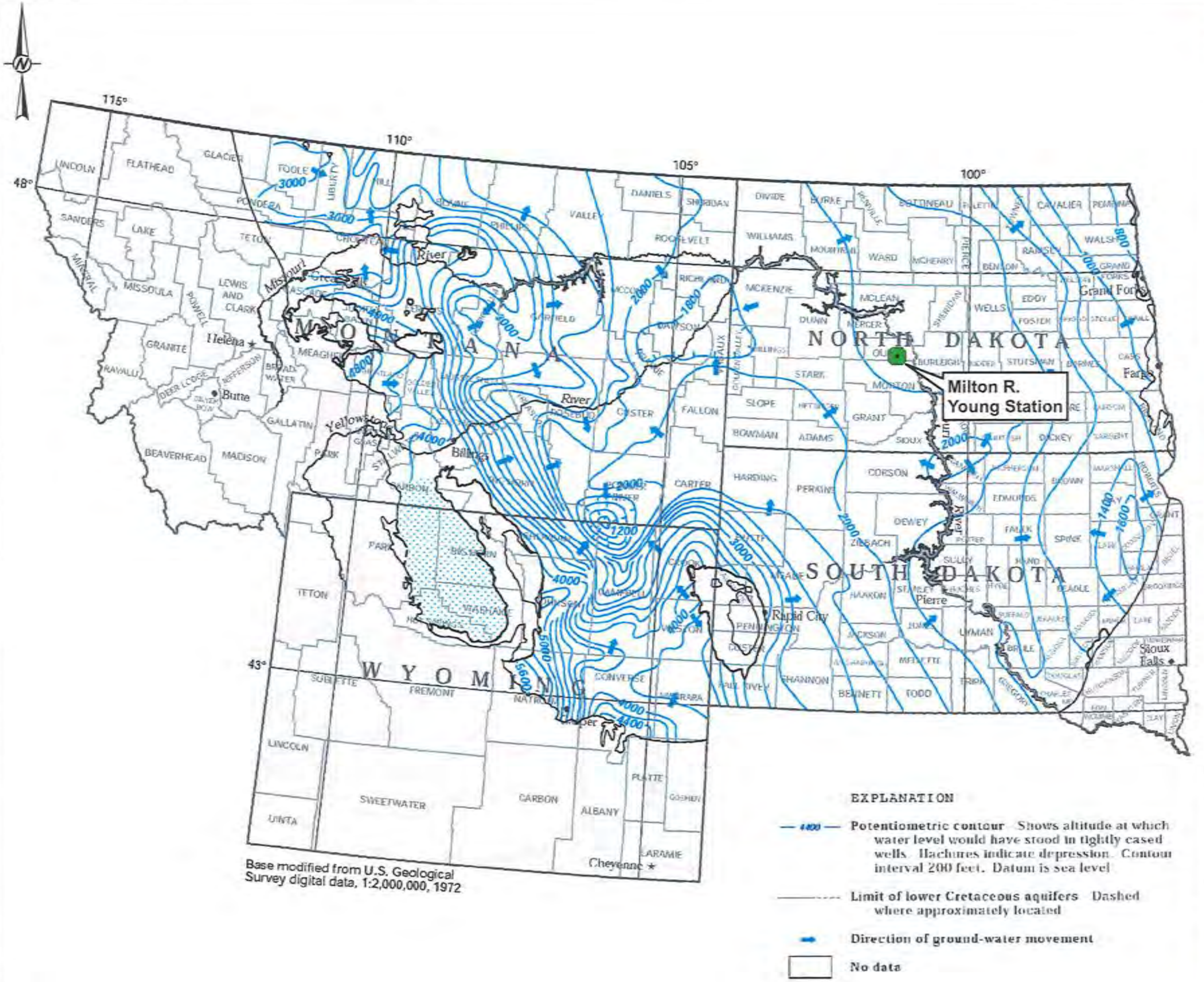
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE PENNSYLVANIAN AQUIFER SYSTEM

CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO. 19122669
REV. 0
FIGURE 3-16



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE

1. MODIFIED FROM LOBMEYER, D.H., 1985, FRESHWATER HEADS AND GROUND-WATER TEMPERATURES IN AQUIFERS OF THE NORTHERN GREAT PLAINS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-D, 11 P.
2. WATER MOVES REGIONALLY NORTHEASTWARD THROUGH THE DEEPLY BURIED LOWER CRETACEOUS AQUIFERS. SOME OF THE WATER MOVES HUNDREDS OF MILES FROM AQUIFER RECHARGE AREAS AROUND STRUCTURAL UPLIFTS ON THE WEST TO DISCHARGE AREAS IN EASTERN NORTH DAKOTA AND SOUTH DAKOTA.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996. GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 58. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

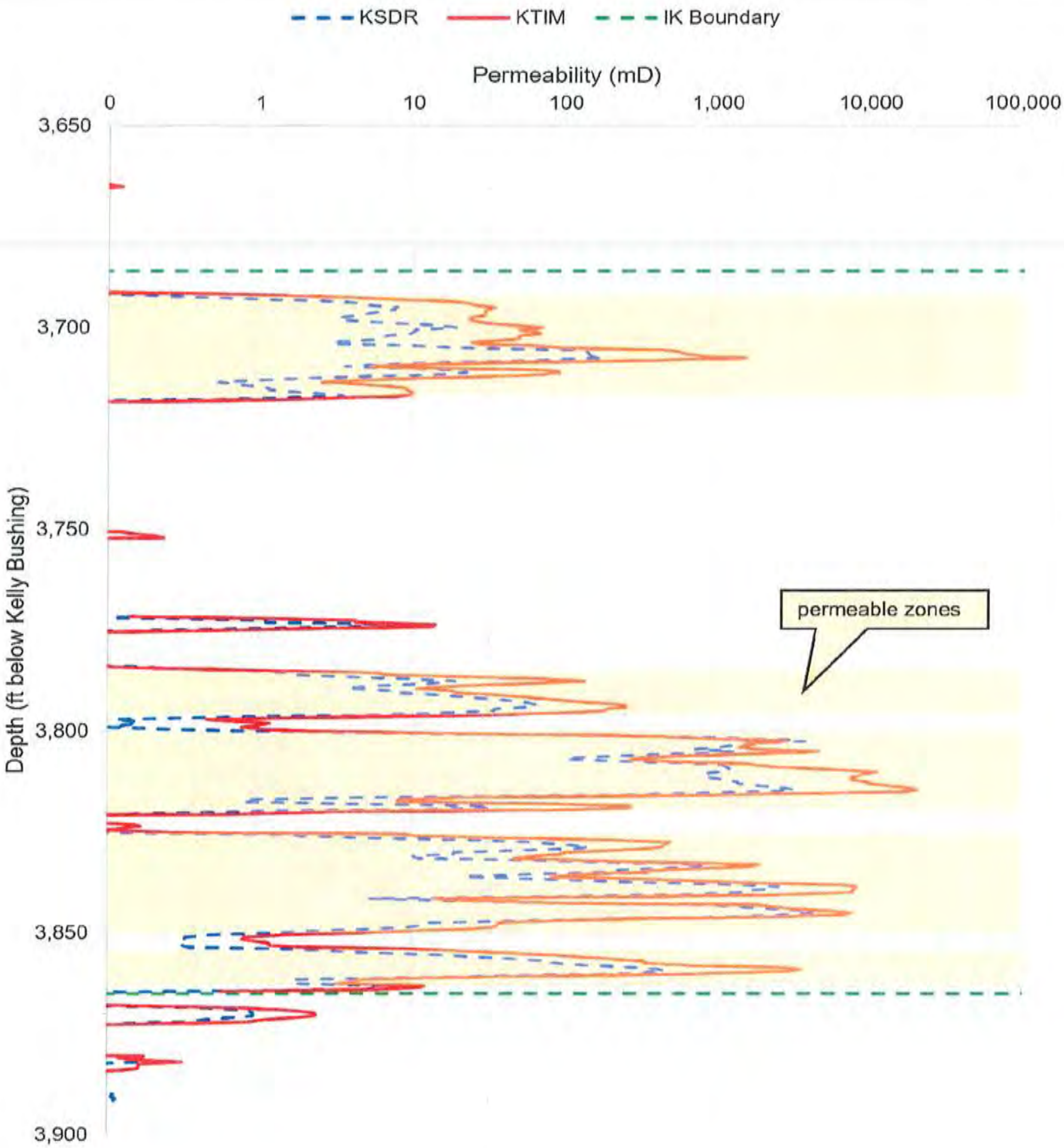
PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE
LOWER CRETACEOUS AQUIFER SYSTEM

CONSULTANT: GOLDER MEMBER OF WSP

YYYY-MM-DD	2021-06-04
DESIGNED	TH
PREPARED	RHG
REVIEWED	AMS
APPROVED	TJS

PROJECT NO.	REV.	FIGURE
19122669	0	3-15

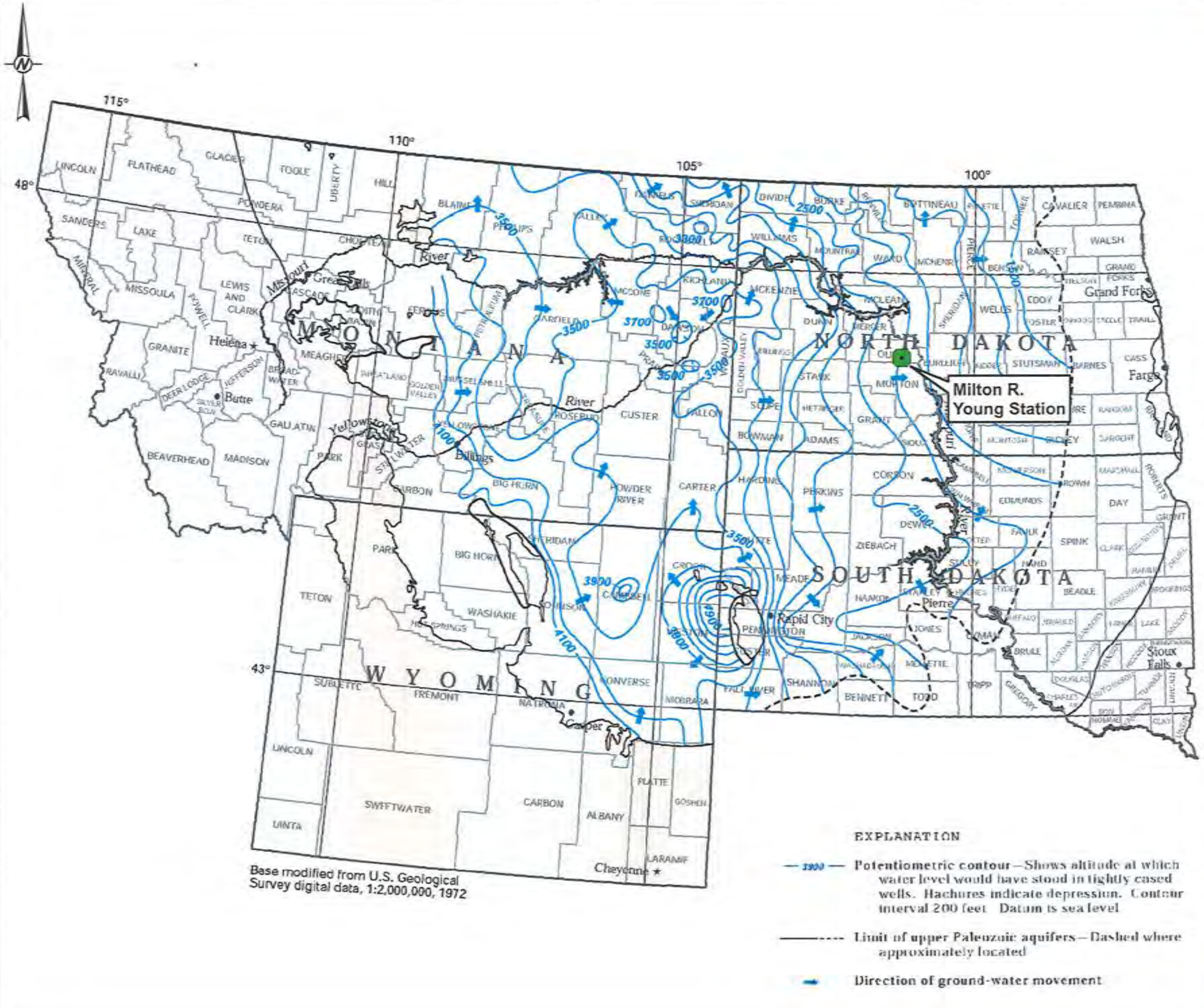


Notes:
1. KSDR = Schlumberger-Doll Research permeability
2. KTIM = Timur-Coates permeability
3. IK = Inyan Kara Formation

GOLDER

CMR Log at J-ROC 1 - Permeability

Client	Project No.	19122669	By	BJP	6/4/2021	Figure 4-1
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	**0**	Review	TJS	6/4/2021	



LEGEND

APPROXIMATE PROPOSED INJECTION WELL LOCATION

0 40 80 160 Miles

NOTE

1. MODIFIED FROM DOWNEY, J.S., AND DINWIDDIE, G.A., 1988, THE REGIONAL AQUIFER SYSTEM UNDERLYING THE NORTHERN GREAT PLAINS IN PARTS OF MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING - SUMMARY: U.S. GEOLOGICAL SURVEY PROFESSIONAL PAPER 1402-A, 64 P.
2. WATER IN THE UPPER PALEOZOIC AQUIFERS MOVES REGIONALLY NORTHEASTWARD FROM AQUIFER RECHARGE AREAS THAT ARE ON THE FLANKS OF STRUCTURAL UPLIFTS. LOCALLY, THE WATER MOVES RADIALLY AWAY FROM THE BLACK HILLS UPLIFT OR TOWARD DEPRESSIONS.

REFERENCES

1. MAP OBTAINED FROM WHITEHEAD, R.L. 1996. GROUND WATER ATLAS OF THE UNITED STATES, SEGMENT 8, MONTANA, NORTH DAKOTA, SOUTH DAKOTA, AND WYOMING, FIGURE 60. USGS HYDROLOGIC INVESTIGATIONS ATLAS 730-I.

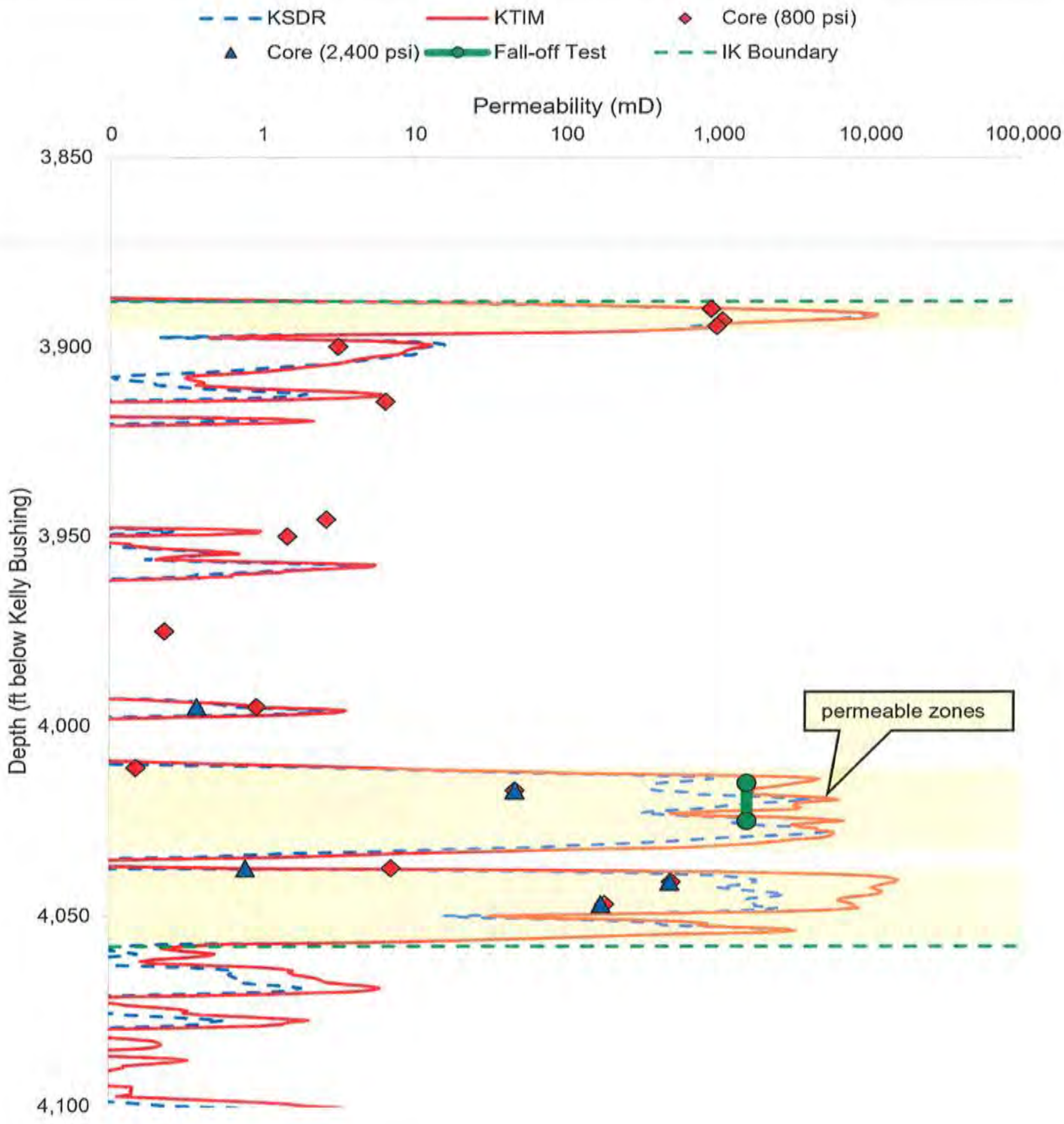
CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
POTENTIOMETRIC SURFACE OF THE
UPPER PALEOZOIC AQUIFER SYSTEM

CONSULTANT		
GOLDER MEMBER OF WSP	YYYY-MM-DD	2021-06-04
	DESIGNED	TH
	PREPARED	RHG
	REVIEWED	AMS
	APPROVED	TJS

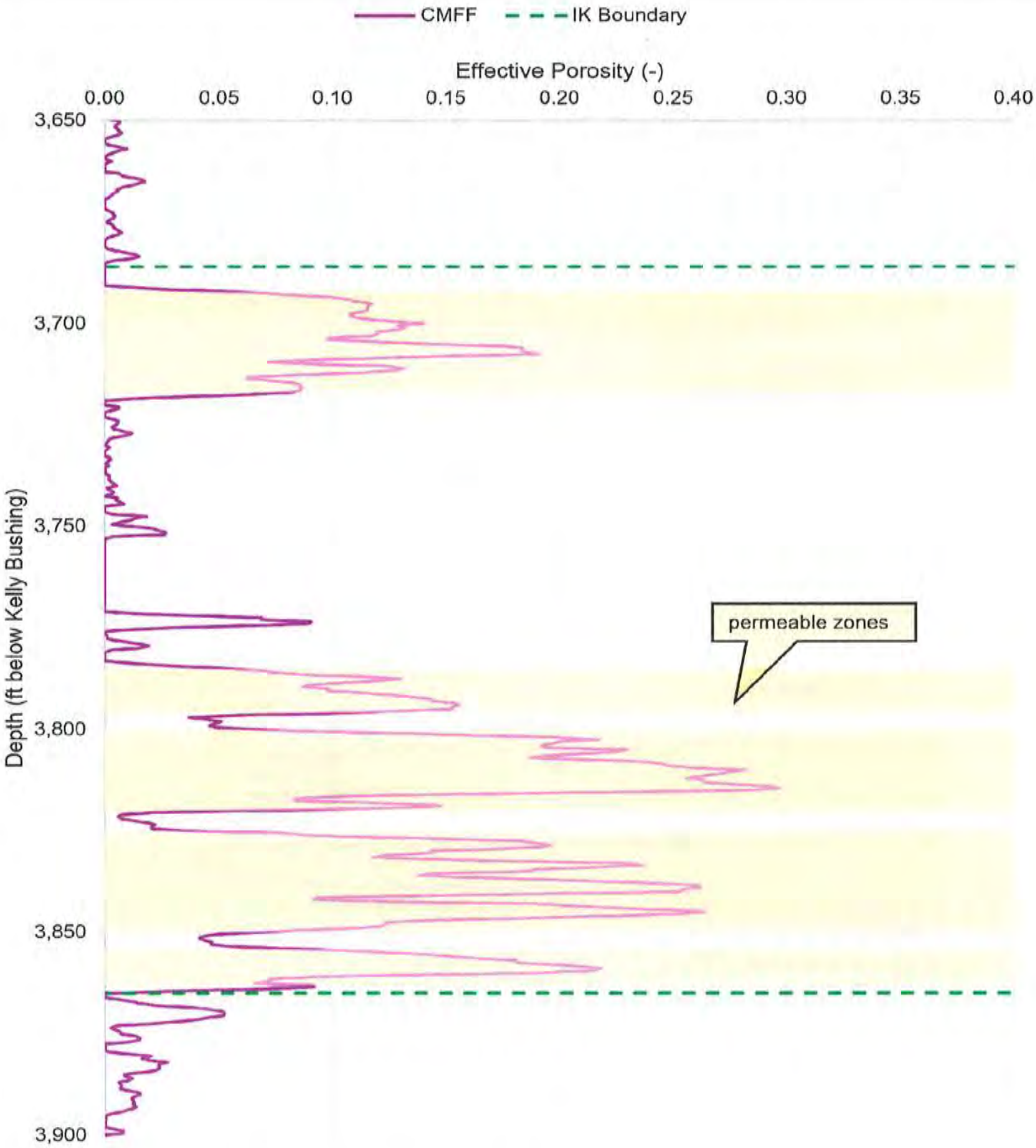
PROJECT NO.	REV.	FIGURE
19122669	0	3-17



Notes:

1. KSDR = Schlumberger-Doll Research permeability
2. KTIM = Timur-Coates permeability
3. Core sample permeability tested at two confining pressures (800 psi and 2,400 psi).
4. IK = Inyan Kara Formation

GOLDER	CMR Log at J-LOC 1 - Permeability					
Client	Project No.	19122669	By	BJP	6/4/2021	Figure 4-3
Minnkota Power	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Cooperative	Revision	**0**	Review	TJS	6/4/2021	

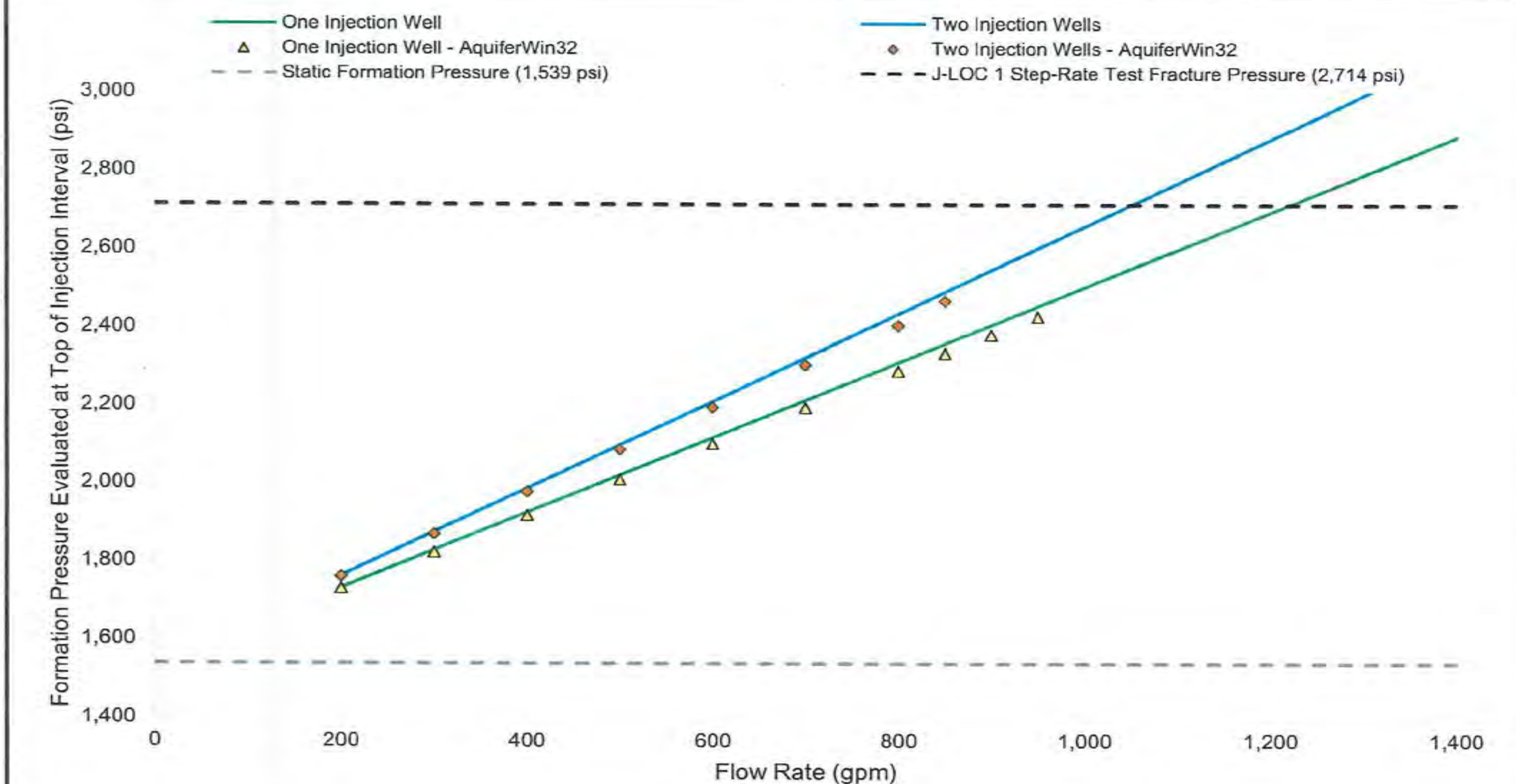


Notes:
1. CMFF = Combinable Magnetic Resonance Free Fluid Porosity
2. IK = Inyan Kara Formation

GOLDER

CMR Log at J-ROC 1 - Effective Porosity

Client	Project No.	19122669	By	BJP	6/4/2021	Figure 4-2
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	0	Review	TJS	6/4/2021	



Notes:

1. Injectate fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.
2. Permeability = 950 mD, Skin factor = 0

GOLDER

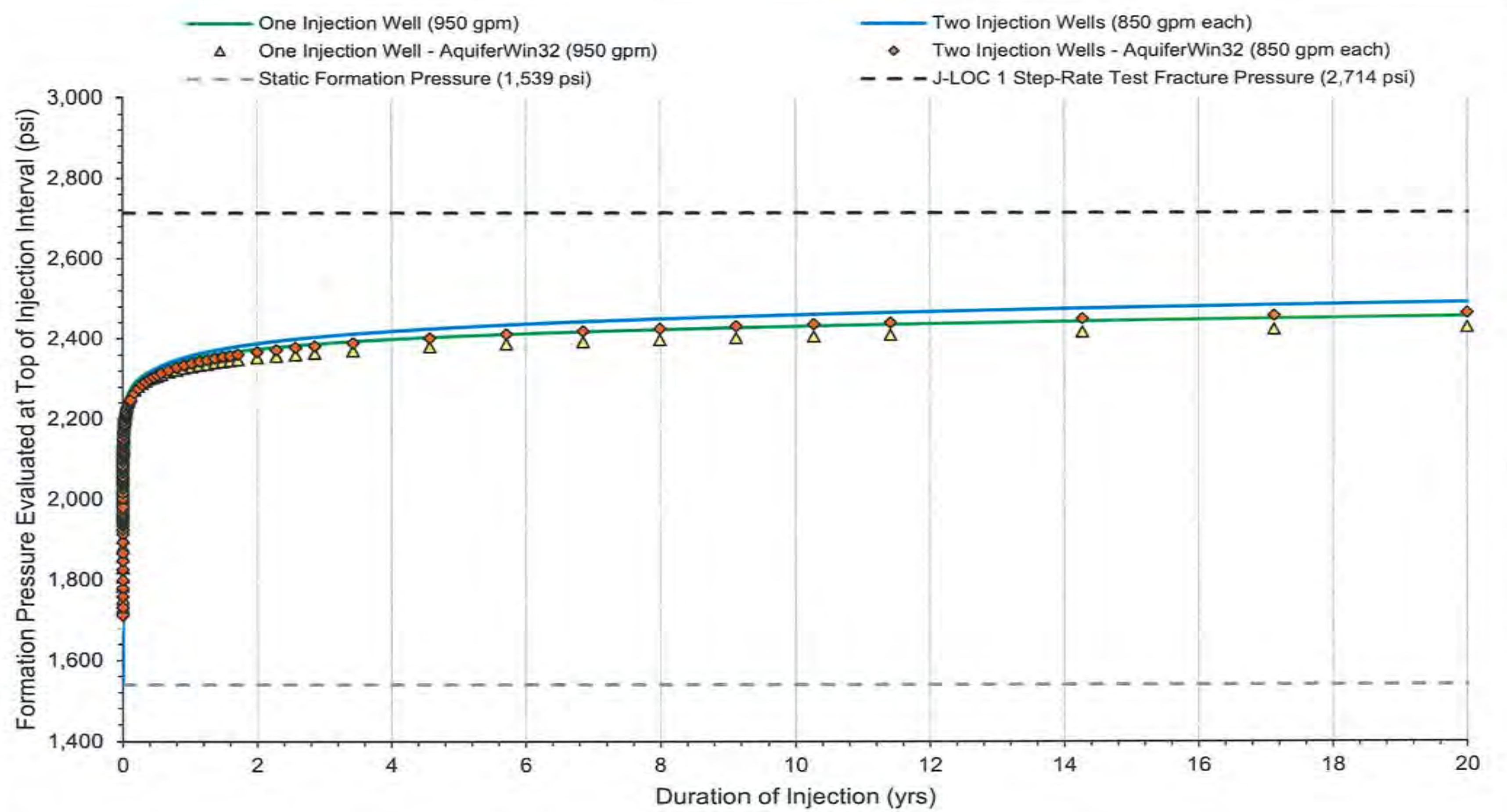
DENVER, COLORADO USA

Formation Pressure After 20 Years of Continuous Injection vs. Injection Flow Rate

Client

Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-5
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	0	Review	TJS	6/4/2021	



Notes:

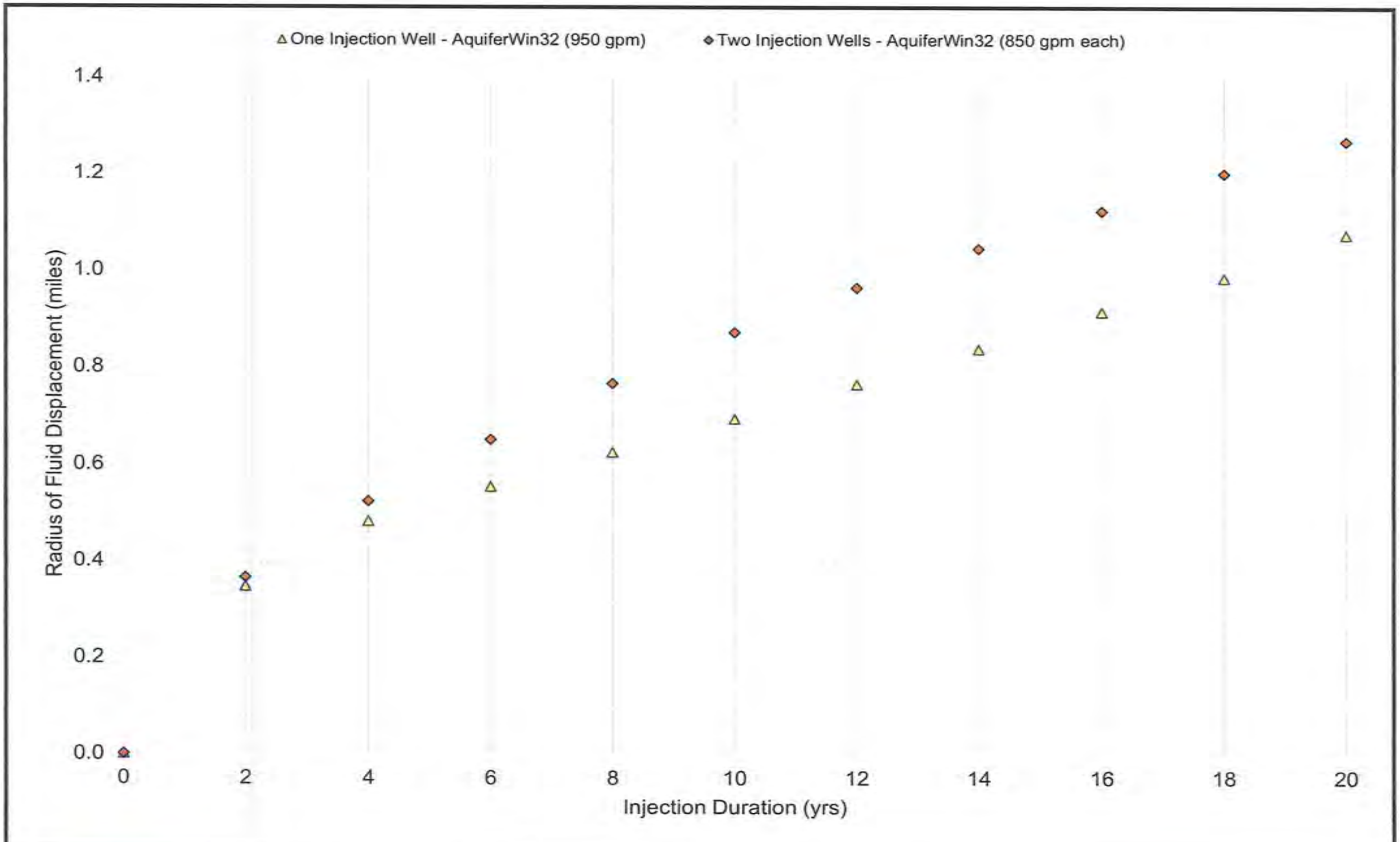
1. Injectate fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.
2. Permeability = 950 mD, Skin factor = 0

GOLDER

DENVER, COLORADO USA

Formation Pressure Response with Time at the Wellbore

Client	Project No.	19122669	By	BJP	6/4/2021	Figure 4-4
Minnkota Power Cooperative	Title	Minnkota Injection Well	Check	AMS	6/4/2021	
	Revision	0	Review	TJS	6/4/2021	



GOLDER

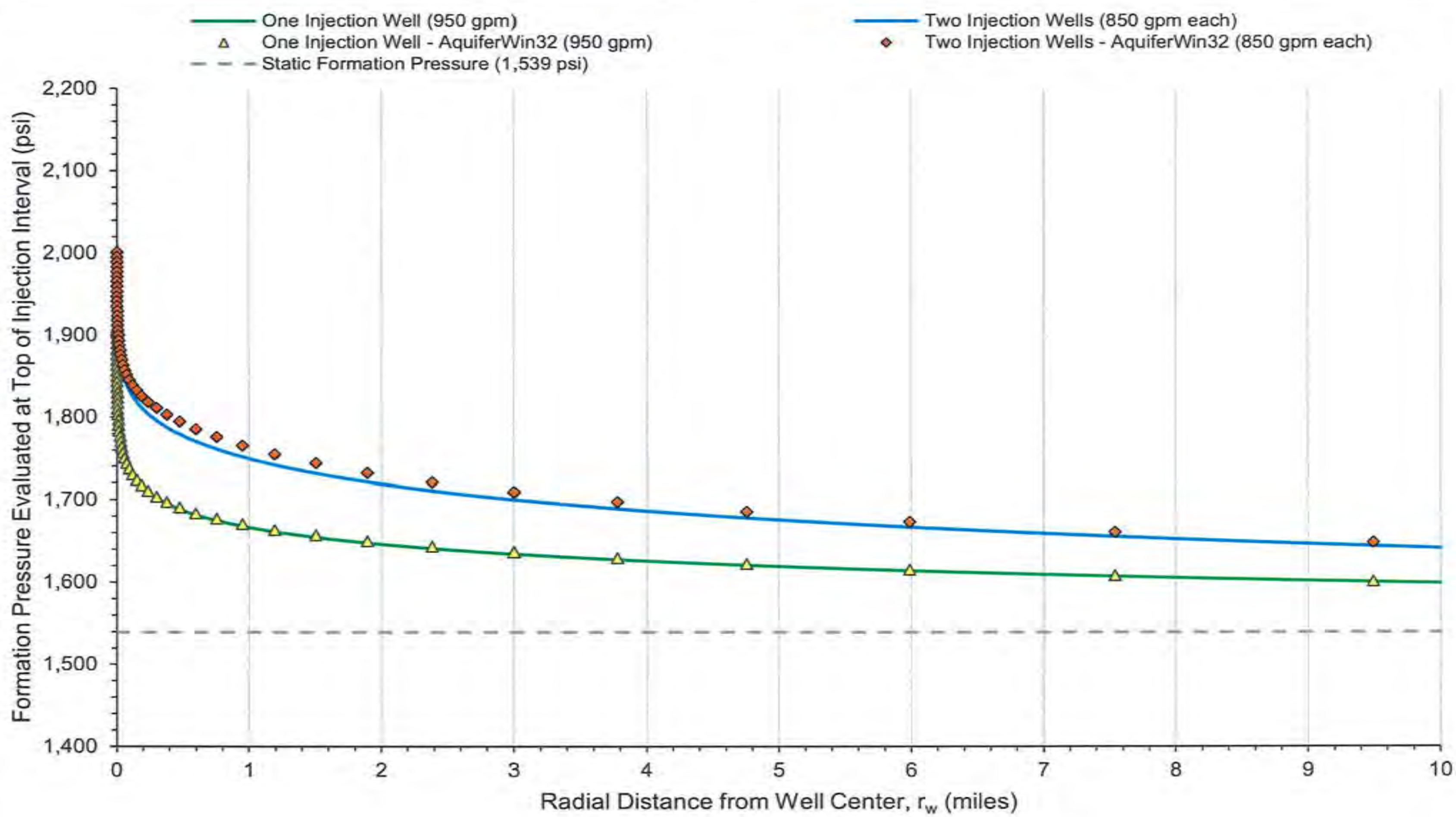
DENVER, COLORADO USA

Radius of Fluid Displacement

Client

Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-7
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	**0**	Review	TJS	6/4/2021	



Notes:

1. Formation fluid properties (viscosity) used for Diffusivity Equation inputs and to calculate transmissivity for AquiferWin32 confirmatory modeling.

GOLDER

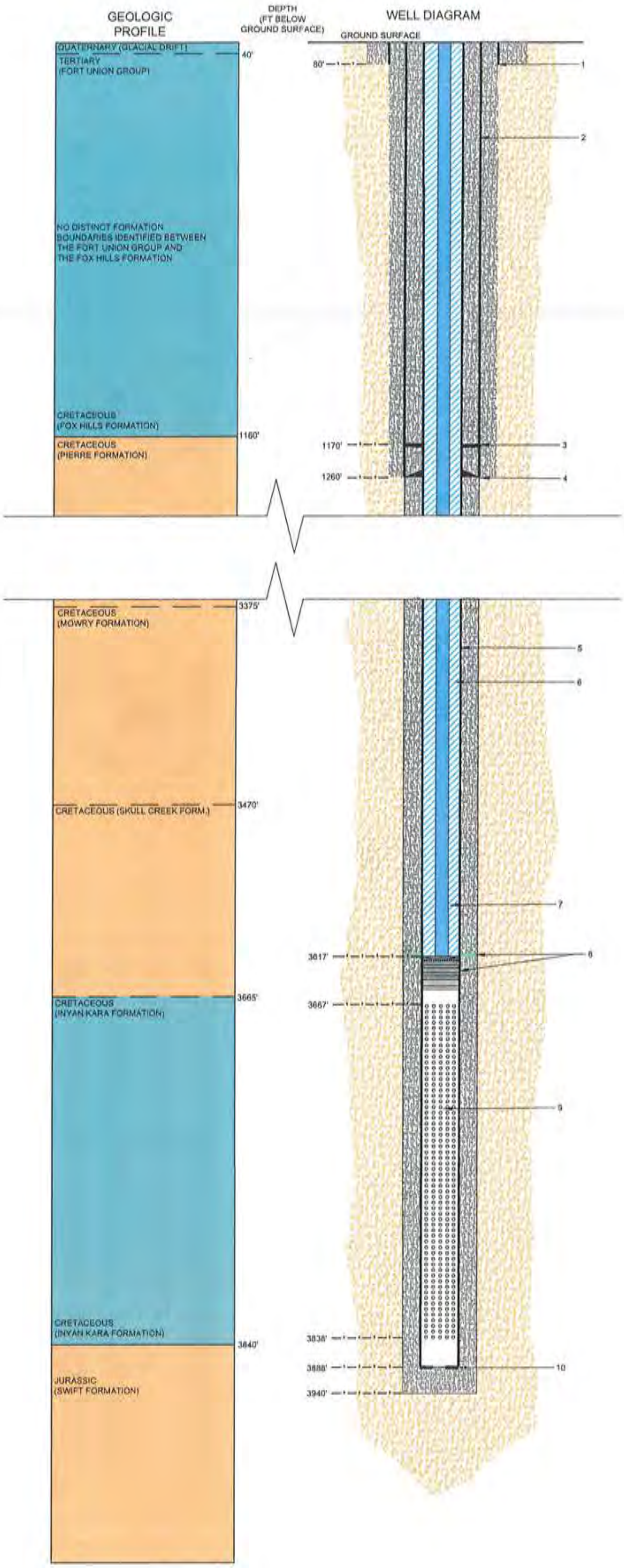
DENVER, COLORADO USA

Formation Pressure Response with Radial Distance from Wellbore After 20 Years of Continuous Injection

Client

Minnkota Power Cooperative

Project No.	19122669	By	BJP	6/4/2021	Figure 4-6
Title	Minnkota Injection Well	Check	AMS	6/4/2021	
Revision	0	Review	TJS	6/4/2021	



LEGEND

- CASING CEMENT
- EXISTING SUBSURFACE MATERIAL
- ANNULAR FLUID
- AQUIFER
- CONFINING UNIT
- FLOATS (SEE NOTE 3)
- DIFFERENTIAL VALVE TOOL (SEE NOTE 8)

NOTES

ALL DEPTHS ARE APPROXIMATE.

1. 20" CONDUCTOR CASING SET TO 80' BGS IN 26" HOLE; CEMENTED TO SURFACE.
2. 13-3/8" SURFACE CASING IN 17-1/2" HOLE, SET TO 1260' BGS (APPROXIMATELY 100' BELOW BASE OF FOX HILLS FORMATION). CEMENTED TO SURFACE.
3. FLOAT COLLAR ABOVE THE LOWEST JOINT OF THE SURFACE CASING AT AN APPROXIMATE DEPTH OF 1,170' BGS (TWO CASING JOINTS ABOVE THE FLOAT SHOE).
4. FLOAT SHOE AT THE BOTTOM OF THE LOWEST JOINT OF SURFACE CASING AT AN APPROXIMATE DEPTH OF 1,260' BGS.
5. 9-5/8" PRODUCTION CASING IN 12-1/4" HOLE SET TO 3,888' BGS (APPROXIMATELY 50' BELOW INJECTION ZONE). CEMENT TO SURFACE ABOVE INJECTION PACKER.
6. ANNULAR FLUID.
7. 7" INTERNALLY LINED INJECTION TUBING SET IN 9-5/8" CASING TO 3,617' BGS (APPROXIMATELY 50' ABOVE INJECTION ZONE).
8. INJECTION PACKER TOP SET AT 3,617' BGS (APPROXIMATELY). COMPRISED OF INTERNAL SEAL SHOE AND EXTERNAL CHROME PACKER. DIFFERENTIAL VALVE TOOL LOCATED DIRECTLY ABOVE THE PACKER AT 3,615' BGS.
9. PERFORATIONS PLANNED AT AT RATE OF 4 TO 12 SHOTS PER FOOT, 0.52" ENTRANCE WITH 24" PENETRATION. PENETRATIONS WILL BE PLACED WITHIN THE SANDSTONE INTERVALS OF THE INYAN KARA FORMATION (APPROXIMATELY 3,667' TO 3,838' BGS).
10. FLOAT COLLAR AND FLOAT SHOE AT BOTTOM OF PRODUCTION CASING.

NOT TO SCALE

CLIENT
MINNKOTA POWER COOPERATIVE
MILTON R. YOUNG STATION
CENTER, NORTH DAKOTA

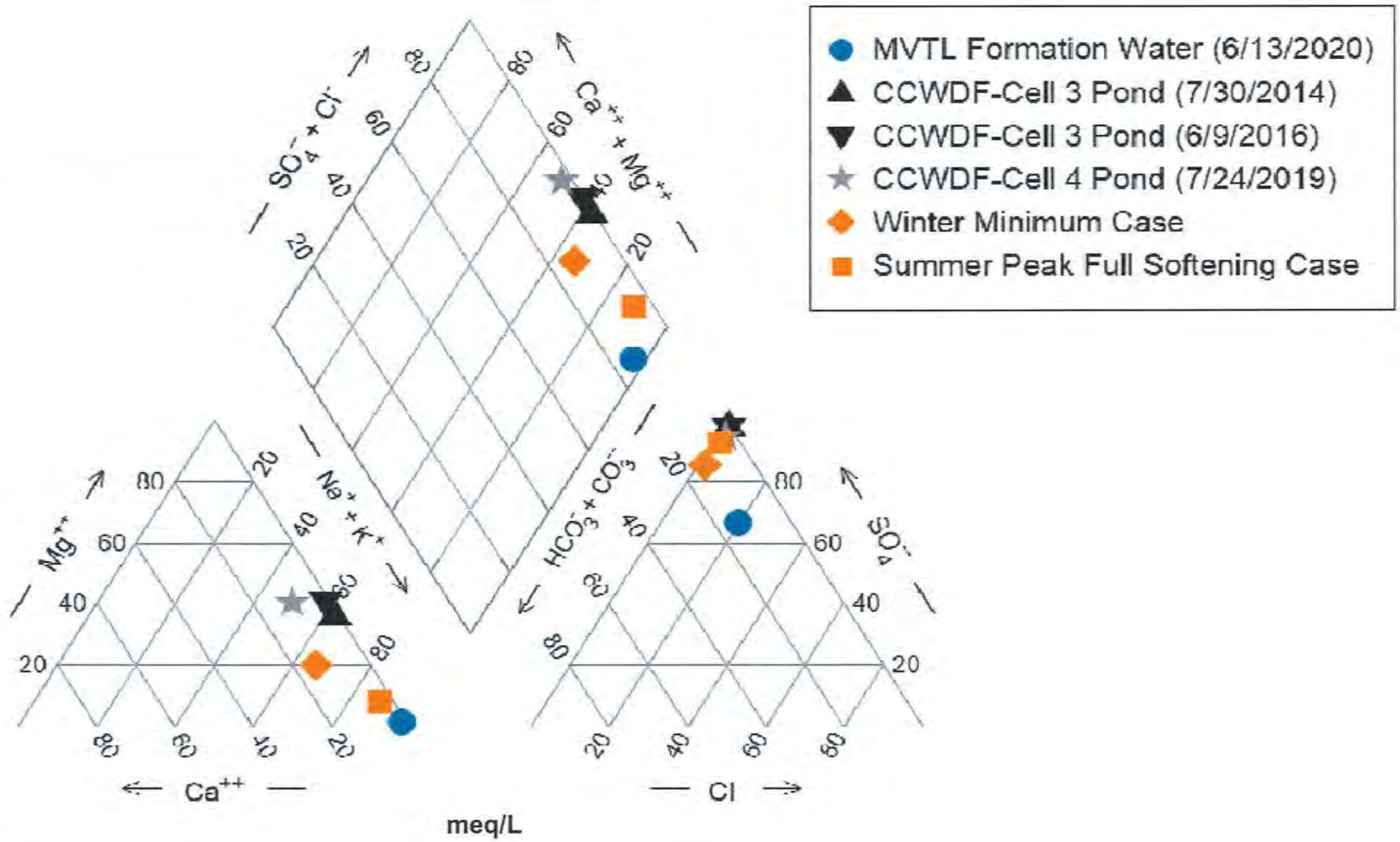
CONSULTANT
GOLDER
MEMBER OF WSP

YYYY-MM-DD	2021-06-04
PREPARED	BJP
DESIGN	BJP
REVIEW	AMS
APPROVED	TJS

PROJECT
CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT

TITLE
GEOLOGICAL PROFILE AND PROPOSED INJECTION WELL CONSTRUCTION DIAGRAM

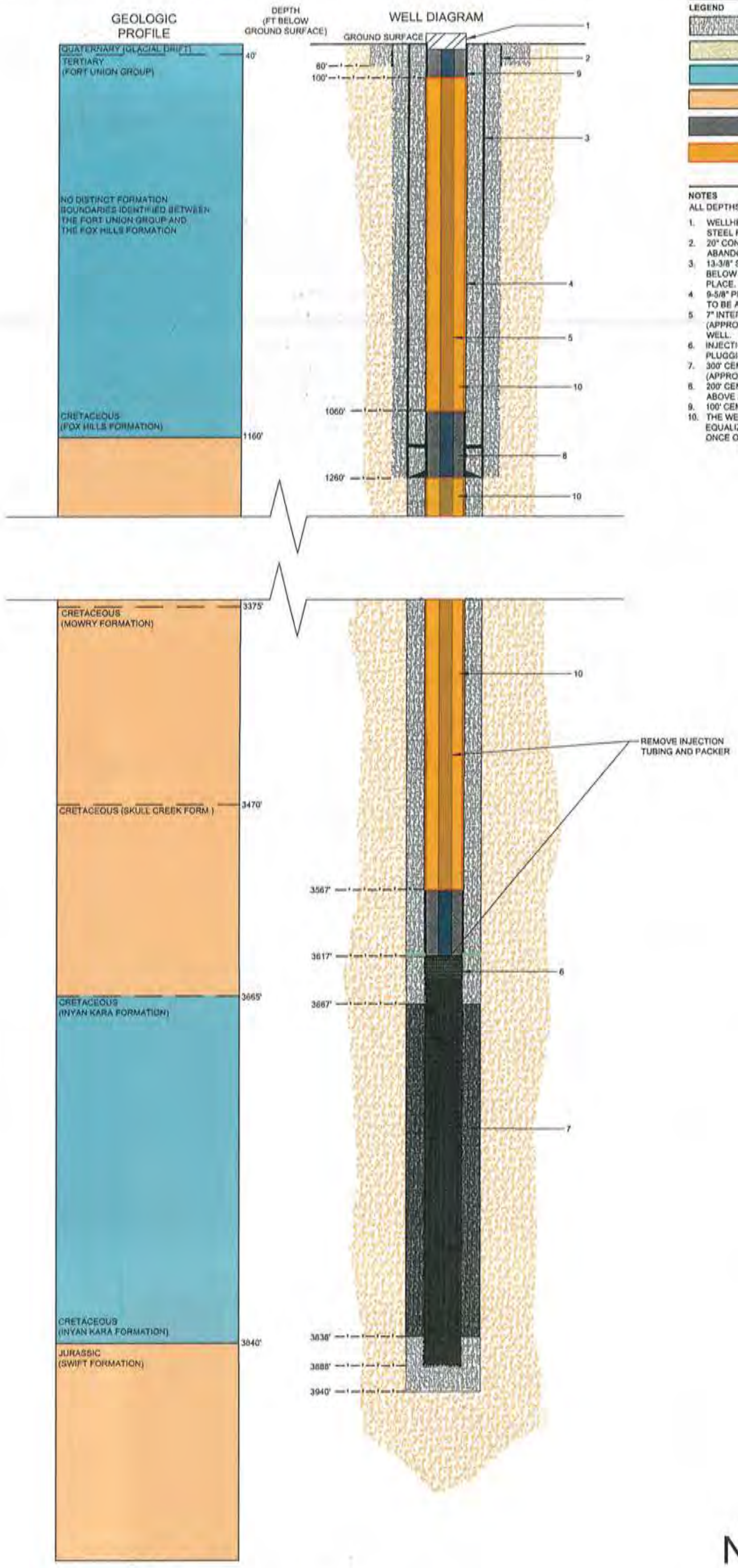
PROJECT No.	Rev.	FIGURE
19122669	0	7-1



Notes:

meq/L: milliequivalents per liter

GOLDER	Piper Diagram of Formation Water, Cooling Tower Blowdown, and Scrubber Pond Water				
Client: **Minnkota Power Cooperative**	Project No.	19122669	By	GOL	6/4/2021
	Title	Minnkota Injection Well	Check	SH	6/4/2021
	Revision	0	Review	TR	6/4/2021
					Figure 6-1



LEGEND

- CASING CEMENT
- EXISTING SUBSURFACE MATERIAL
- AQUIFER
- CONFINING UNIT
- CLASS G CEMENT GROUT PLUG
- STATICALLY EQUALIZED MUD FILL

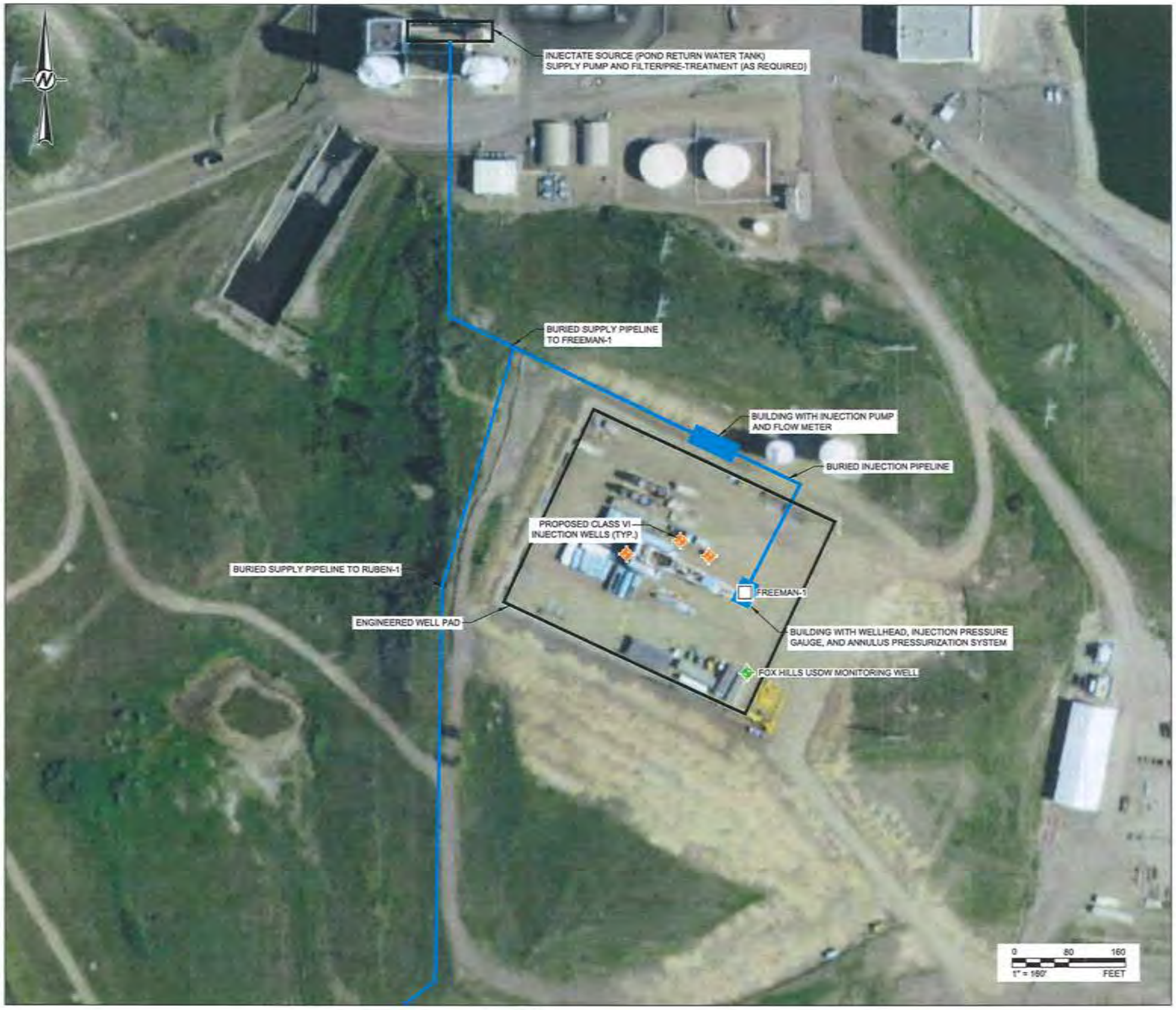
NOTES

ALL DEPTHS ARE APPROXIMATE.

1. WELLHEAD TO BE REMOVED AND CASING STUB TO BE CUT 5' BELOW GROUND SURFACE. STEEL PLATE TO BE WELDED TO CASING STUB.
2. 20" CONDUCTOR CASING SET TO 80' BGS IN 26" HOLE; CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
3. 13-3/8" SURFACE CASING IN 17-1/2" HOLE, SET TO 1,260' BGS (APPROXIMATELY 100' BELOW BASE OF FOX HILLS FORMATION). CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
4. 9-5/8" PRODUCTION CASING IN 12-1/4" HOLE SET TO 3,888' BGS. CEMENTED TO SURFACE. TO BE ABANDONED IN PLACE.
5. 7" INTERNALLY LINED INJECTION TUBING SET IN 9-5/8" PRODUCTION CASING TO 3,617' BGS (APPROXIMATELY 50' ABOVE INJECTION ZONE). TO BE REMOVED PRIOR TO PLUGGING OF WELL.
6. INJECTION PACKER SET AT 3,617' BGS (APPROXIMATELY). TO BE REMOVED PRIOR TO PLUGGING OF WELL.
7. 300' CEMENT PLUG TO BE INSTALLED BETWEEN BOTTOM OF WELL AND 3,567 BGS (APPROXIMATELY 100' ABOVE INJECTION ZONE). PERFORATED ZONE TO BE SQUEEZED.
8. 200' CEMENT PLUG TO BE INSTALLED AT THE BASE OF THE FOX HILLS FORMATION (100' ABOVE AND 100' BELOW THE BASE OF THE FOX HILLS FORMATION).
9. 100' CEMENT PLUG TO BE INSTALLED AT THE SURFACE OF THE WELLBORE.
10. THE WELL WILL BE IN A STATE OF STATIC EQUILIBRIUM WITH THE MUD WEIGHT EQUALIZED TOP TO BOTTOM, EITHER BY CIRCULATING THE MUD IN THE WELL AT LEAST ONCE OR BY COMPARABLE METHOD.

NOT TO SCALE

CLIENT MINNKOTA POWER COOPERATIVE MILTON R. YOUNG STATION CENTER, NORTH DAKOTA		PROJECT CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT	
CONSULTANT GOLDER MEMBER OF WSP	YYYY-MM-DD: 2021-06-04 PREPARED: BJP DESIGN: BJP REVIEW: AMS APPROVED: TJS	TITLE PLUGGING AND ABANDONMENT PLAN	
		PROJECT No. 19122669	Rev. 0 / FIGURE 9-1

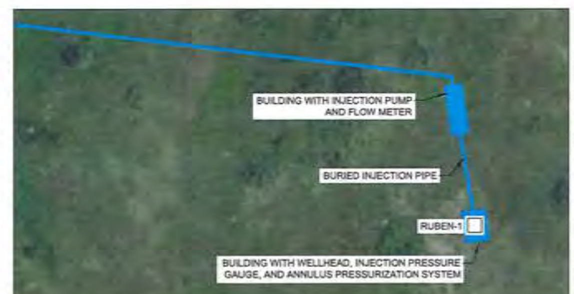


SCALE 1" = 160' (1 / 7-2) FREEMAN-1 PLAN VIEW

LEGEND

- PROPOSED CLASS I INJECTION WELL
- PROPOSED CLASS VI INJECTION WELL
- FOX HILLS USDW MONITORING WELL
- BURIED INJECTION PIPES

KEY MAP



SCALE 1" = 160' (2 / 7-2) RUBEN-1 PLAN VIEW

CLIENT	MINNKOTA POWER COOPERATIVE MILTON R. YOUNG STATION CENTER, NORTH DAKOTA
CONSULTANT	GOLDER MEMBER OF WSP
YYYY-MM-DD	2021-06-04
DESIGNED	BJP
PREPARED	AGD
REVIEWED	AMS
APPROVED	TJS
PROJECT	CLASS I (NON-HAZARDOUS) INJECTION WELL PERMIT
TITLE	SURFACE INFRASTRUCTURE PLAN
PROJECT NO.	19122669
REV.	0
FIGURE	7-2

IF THIS MEASUREMENT DOES NOT MATCH WHAT IS SHOWN, THE SHEET SIZE HAS BEEN MODIFIED FROM: ANSI B

CLASS I UIC PERMIT APPLICATION
NORTH DAKOTA DEPARTMENT OF ENVIRONMENTAL QUALITY
WATER QUALITY DIVISION
SFN 8294 (April 2019)

Return completed form to:
North Dakota Department of Environmental Quality
Division of Water Quality
918 E. Divide Ave., 4th Floor
Bismarck, ND 58501-1947
Telephone Number: 701.328.5210
E-mail Address: juhlman@nd.gov

Name of Facility: Milton R. Young Station		Application Date: 06/07/2021	
Name of Facility Contact: Daniel Laudal	Title: Environmental Manager		
Mailing Address: 5301 32nd Avenue South	City: Grand Forks	State: ND	Zip Code: 58201
Facility Location: Address, Legal Description (Twp, Rng, Sec, Qtrs): 3401 24th Street SW		Latitude: 47.0661056	Longitude: -101.2138806
County: Oliver	City: Center	State: ND	Zip Code: 58530

SIC Codes: List in descending order of significance the four 4-digit Standard Industrial Classification (SIC) Codes found in the "Standard Industrial Classification Manul" which best describe your facility in terms of the principal products or services you produce or provide. Also, specify each classification in words.		SIC No.	Name
	1st Div. E	4911	Electric Services
	2nd		
	3rd		
	4th		

Name of Operator: Minnkota Power Cooperative	Telephone Number: 701-795-4216

STATUS: ☐ F=Federal ☐ S=State ☑ P=Private ☐ M=Public (Other than Federal or State) ☐ O=Other (Specify)

Mailing Address: 5301 32nd Avenue South	City: Grand Forks	State: ND	Zip Code: 58201

TRIBAL LANDS: Is this facility located on Tribal Land? ☑ No ☐ Yes

EXISTING ENVIRONMENTAL PERMITS		
	UIC-Underground Injection Fluids	Permit No.: NA
	NPDES-Discharge to Surface Water	Permit No.: ND-000370
	RCRA-Hazardous Wastes	Permit No.: NDD076514298
	PSD-Air Emissions from Proposed Sources	Permit No.: T5-F76009
	Other (Specify) see below	Permit No.: see below

Brief Description of Nature of Business

Coal-fired power generation - Permits: Solid Waste Management Permits: SP-159, SP-040, IT-205, IT-197, IT-068, SP-030; NDSWC Annual Water Use Reports: SWC #1324, #1963, #1964, #7097; Underground Storage Tanks: ND UST #46; Petroleum Tank Insurance Fund #447

Certification: I certify, under penalty of the law, that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe the information is true, accurate, and complete. I am aware there are significant penalties for submitting false information, including the possiblity of imprisonment.

SEE BACK OF FORM FOR DETAILS ON MAP AND ENGINEERING REPORT THAT MUST BE SUBMITTED WITH THIS APPLICATION.	NAME (Typed) Craig Bleth
	TITLE (Typed) Senior Manager of Power Production
	Signature Craig J. Bleth

APPENDIX A

NDDEQ Permit Application Form and Checklist

APPENDIX B

Wells Within the Area of Review

Table A-1: Permit Application Checklist (SFN 8294, April 2019)

Item	Reference	Permit Application Location
Mapping		
Attach to this application, a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the following: 1. Outline of the facility; 2. Location of each of its existing and proposed intake and discharge structures; 3. Each hazardous waste treatment, storage, or disposal facility; 4. Each well where fluids will be or are injected underground; and 5. All springs, rivers, and other surface waterbodies in map area.	40 CFR 144.31(e)(7)	Section 1.1 Figures 1-2 and 1-3
Engineering Report		
1. **Maps** showing the injection wells for which a permit is sought, and the applicable area of review. The map must show the number or name and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines, quarries, water wells and other pertinent surface features, including residences and roads.	40 CFR 146.14(a)(2)	Section 1.3 Figures 1-5 and 1-6
2. A **tabulation** of data on all wells within the area of review which penetrate into the proposed injection zone.	40 CFR 146.14(a)(3)	Section 1.3 and Appendix B
3. **Maps and cross-sections** indicating the general vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation and the direction of water movement, where known, in each USDW which may be affected by the proposed injection.	40 CFR 146.14(a)(4)	Section 3.3 Figures 3-1 to 3-17
4. **Maps and cross-sections** detailing the geologic structure of the local area.	40 CFR 146.14(a)(5)	Section 3.2 Figures 3-3 to 3-10
5. **Generalized maps and cross-sections** illustrating the regional geologic setting.	40 CFR 146.14(a)(6)	Section 3.1 Figures 3-1 and 3-2
6. **Proposed operating data** which should include average and maximum daily rate and volume of fluid to be injected, average and maximum injection pressure, and source and analysis of chemical, physical, radiological and biological characteristics of injection fluids.	40 CFR 146.14(a)(7)(i) 40 CFR 146.14(a)(7)(ii) 40 CFR 146.14(a)(7)(iii)	Section 1.2 Section 6.2
7. **Proposed formation testing program** to obtain analysis of chemical, physical and radiological characteristics and other information on the receiving formation, including estimated formation fracture pressure.	40 CFR 146.14(a)(8)	Section 7.3
8. **Proposed stimulation program**	40 CFR 146.14(a)(9)	Section 7.4
9. **Proposed injection procedure**	40 CFR 146.14(a)(10)	Section 8.3
10. **Engineering drawings** of the surface and subsurface construction details of the system.	40 CFR 146.14(a)(11)	Section 7.0 Figures 7-1 and 7-2
11. **Contingency plans** to cope with all shut-ins or well failures so as to prevent migration of fluids into any underground source of drinking water.	40 CFR 146.14(a)(12)	Section 8.3.5
12. **Corrective action** proposed to be taken for wells within the area of review which penetrate the injection zone and are not properly completed or plugged.	40 CFR 146.14(a)(14)	Section 1.3.4
13. **Construction procedures** including the cementing and casing program, logging procedures, deviation checks and a drilling testing and coring program.	40 CFR 146.14(a)(15)	Section 7.0
14. Information on **expected changes** in pressure, native fluid displacement and direction of movement of injection fluid.		Section 4.0 Figures 4-4 to 4-7
15. **Discussion** of the qualifications and training of injection operations supervisory personnel.		Section 8.3.4
16. A **certificate** that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well.	40 CFR 146.14(a)(16)	Section 9.4 Appendix H
17. **Any other information** the staff requires to properly evaluate the application, such as proposed observation wells, etc. (permitting strategy, geochemistry, estimated formation fracture pressures)		See below
Estimated formation fracture pressure		Section 5.0 Appendix D
Signed and completed application	NDAC 33-25-01-06(1)(a)	Appendix A
Activities conducted that require permits under RCRA, UIC, NPDES, Clean Air Act	40 CFR 144.31(e)(1)	Section 1.1 Section 10.0
Name, mailing address, and location of facility	40 CFR 144.31(e)(2)	Section 1.1
SIC codes which best reflect principal products or services	40 CFR 144.31(e)(3)	Section 1.1
Operators name and contact information	40 CFR 144.31(e)(4)	Section 1.1
Facility landownership	40 CFR 144.31(e)(5)	Section 1.1 Figure 1-3
Other permits	40 CFR 144.31(e)(6)	Section 10.5
Description of business	40 CFR 144.31(e)(8)	Section 1.1
Names and addresses of landowners within one-quarter mile	40 CFR 144.31(e)(9)	Figure 1-3
Plugging and abandonment plan	40 CFR 144.31(e)(10)	Section 9.0 Figure 9-1

Table B-2A: Shallow Wells Within the Area of Review (North Dakota State Water Commission Database)

NDSWC File No.	Location	Well Type	Latitude	Longitude	Date Drilled
45677	14208330BAAC	Commercial	47.09560623120	-101.24885670400	6/21/1991
45676	14208330BAB	Commercial	47.09606761670	-101.25084664100	7/7/1999
45396	14108206CBB	Domestic	47.06055884580	-101.12891594200	9/8/1997
45414	14108302CDC	Domestic	47.05474270490	-101.16599525600	8/28/1986
45415	14108302DCB	Domestic	47.05658273520	-101.16073805300	5/15/1977
45419	14108304ACC	Domestic	47.06178361930	-101.20290605400	6/17/1975
45421	14108304CB	Domestic	47.05906513890	-101.21201067300	5/25/1975
45422	14108305CAA	Domestic	47.05989192760	-101.22667512000	6/27/1984
45448	14108314CC	Domestic	47.02679973910	-101.16970285400	4/17/1998
46273	14108323DBB	Domestic	47.01694051410	-101.16054717500	7/19/1999
45464	14108330	Domestic	47.00286671730	-101.24677469300	10/30/1980
45468	14108401BCB	Domestic	47.06333985880	-101.27720190500	7/31/1984
45470	14108402D	Domestic	47.05701188750	-101.28398731700	8/14/1987
45492	14108411AA	Domestic	47.05165014420	-101.28133741300	12/3/1973
45496	14108412	Domestic	47.04616310460	-101.26795959400	11/1/1972
45497	14108413CBA	Domestic	47.03083559140	-101.27445769700	8/28/1985
45503	14108424AA	Domestic	47.02278268180	-101.26003496800	5/20/1993
45505	14108424AA	Domestic	47.02278268180	-101.26003496800	11/4/1993
45502	14108424B	Domestic	47.02095393610	-101.27315646700	8/16/1978
45644	14208316DD	Domestic	47.11333666090	-101.19675383900	5/14/1996
45646	14208316DD	Domestic	47.11333666090	-101.19675383900	10/11/1978
46292	14208316DD	Domestic	47.11333666090	-101.19675383900	4/4/2002
45647	14208317	Domestic	47.11864602190	-101.22586864700	8/1/1973
45652	14208319CC	Domestic	47.09857667410	-101.25500955600	11/7/1990
45656	14208320AAA	Domestic	47.11062078970	-101.21661903900	5/30/1975
45655	14208320AD	Domestic	47.10603360640	-101.21792717000	9/27/1984
71649	14208320DAD	Domestic	47.10145864060	-101.21595452700	8/11/2014
45658	14208322	Domestic	47.10445610800	-101.18340649800	6/1/1979
45671	14208328ADD	Domestic	47.09074561340	-101.19544069100	7/15/1983
45670	14208328D	Domestic	47.08619509890	-101.19932787400	5/6/1974
74842	14208330C	Domestic	47.08600960180	-101.25176569100	9/13/2017
28591	14208424ADD	Domestic	47.10486211140	-101.25904158800	6/14/1977
45733	14208424D	Domestic	47.10033366110	-101.26299702000	9/17/1974
69798	14208424DAD	Domestic	47.10125690180	-101.25855688800	10/17/2012
45736	14208424DD	Domestic	47.09852225670	-101.26035725200	9/3/1976
45738	14208425A	Domestic	47.09319925830	-101.26297183200	10/1/1979
45765	14208436AA	Domestic	47.08048421820	-101.26015784200	11/6/1985
46270	14108312D	Domestic/Stock	47.04325606030	-101.13559645600	7/30/2004
45465	14108330	Domestic/Stock	47.00286671730	-101.24677469300	11/14/1980
45495	14108412C	Domestic/Stock	47.04252236110	-101.27318222700	6/20/1975
45645	14208316DB	Domestic/Stock	47.11698150430	-101.20203096400	7/19/1983
45653	14208320D	Domestic/Stock	47.10052791410	-101.22053984300	7/14/1980
46500	14208322ABB	Domestic/Stock	47.11082789900	-101.18209405900	6/7/2002
45674	14208329CCA	Domestic/Stock	47.08511096240	-101.23210285500	9/18/1980
45420	14108304B	Industrial	47.06450481880	-101.20941031100	7/1/1974
46264	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/19/2002
46266	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/21/2002
46268	14108304BBD	Industrial	47.06541260330	-101.21071043800	8/19/2002
62855	14108304BDB	Industrial	47.06359657560	-101.20773703900	8/24/2007
45423	14108305A	Industrial	47.06444396780	-101.22007952000	2/25/1975
45683	14208332C	Industrial	47.07157165140	-101.23073422500	7/19/1983
45684	14208332CBD	Industrial	47.07248736720	-101.23204302200	7/15/1984
62723	14208333DD	Industrial	47.06994730160	-101.19600191900	6/20/2007
58496	14108304B	Monitoring	47.06450481880	-101.20941031100	8/24/1993
58499	14108304B	Monitoring	47.06450481880	-101.20941031100	8/25/1993
58503	14108304B	Monitoring	47.06450481880	-101.20941031100	8/26/1993
58506	14108304B	Monitoring	47.06450481880	-101.20941031100	8/26/1993
45417	14108304BCC	Monitoring	47.06178533360	-101.21331072200	9/8/1992
58519	14108304BCC	Monitoring	47.06178533360	-101.21331072200	8/1/1995
77595	14108304BDB	Monitoring	47.06449072010	-101.20902890900	8/13/2020
45416	14108304CB	Monitoring	47.05906513890	-101.21201067300	6/9/1975
45426	14108305AAB	Monitoring	47.06717497090	-101.21876377900	9/3/1992
45438	14108305AAB	Monitoring	47.06717497090	-101.21876377900	6/24/1992
45439	14108305AC	Monitoring	47.06262318760	-101.22271949900	6/24/1992
58520	14108305ACA	Monitoring	47.06353358540	-101.22139953200	8/2/1995
73844	14108305ACC	Monitoring	47.06169917890	-101.22358581600	10/6/2016
58510	14108305ADB	Monitoring	47.06353364760	-101.21876317200	7/17/2000
58523	14108305ADC	Monitoring	47.06171298480	-101.21876286800	8/2/1995
58524	14108305ADC	Monitoring	47.06171298480	-101.21876286800	8/22/1995
45434	14108305BA	Monitoring	47.06626411980	-101.22799737700	9/4/1992
70411	14108305BCD	Monitoring	47.06169240830	-101.23158683300	9/26/2013
70410	14108305BDD	Monitoring	47.06169060340	-101.22625006000	9/26/2013
70412	14108305BDD	Monitoring	47.06169060340	-101.22625006000	9/30/2013
58511	14108305CA	Monitoring	47.05898146850	-101.22799490900	7/14/2000
58517	14108305CA	Monitoring	47.05898146850	-101.22799490900	12/6/1997
64007	14108305CCA	Monitoring	47.05628804250	-101.23157737800	9/16/2008
45440	14108305CCC	Monitoring	47.05442894260	-101.23459317900	6/22/1992
58518	14108305DA	Monitoring	47.05897926820	-101.21744230100	12/6/1997
58522	14108305DAA	Monitoring	47.05988960620	-101.21612233400	7/27/1995
45437	14108305DAB	Monitoring	47.05989232110	-101.21876256400	9/2/1992
45431	14108305DBA	Monitoring	47.05989225890	-101.22139874500	11/21/1991
58521	14108305DBA	Monitoring	47.05989225890	-101.22139874500	7/27/1995
58515	14108305DBB	Monitoring	47.05989211090	-101.22403893900	12/18/2001
68204	14108305DBB	Monitoring	47.05989214820	-101.22359756900	9/2/2010
68205	14108305DBB	Monitoring	47.05989214820	-101.22359756900	9/2/2010

Table B-1: Deep Wells Within the Area of Review

NDIC File No.	Well Operator	Well Type	Well Status	Latitude	Longitude	Spud Date	Total Depth (ft bgs)	Surface Casing Depth (ft bgs)	Depth to Pierre Formation (ft bgs)	Surface Casing Depth Below USDW (ft)	Plug Depths Between USDW and Inyan Kara Fm.	Plugs Types Between USDW and Inyan Kara Fm.	Top of Inyan Kara Formation (ft bgs)	Cement Depth Above Inyan Kara Formation (ft)	Surface Casing Cement Bond Log
37672 (J-ROC1)	Minnkota Power Cooperative, Inc.	ST	DRL	47.0627540	-101.2132330	9/8/2020	9,871	1,997	1,185	812	•Inyan Kara Plug: 3,400-3,715 ft bgs •Base of Surface Casing Plug: 1,800-2,050 ft bgs •Surface Plug: 30-90 ft bgs	•Inyan Kara Plug: 145 sacks EverCRETE •Base of Surface Casing Plug: 125/220 sacks Class G •Surface Plug: 45 sacks Class G	3,694	294	Yes Good bond from 1,800 to 1,935 ft bgs

Notes:
ST = stratigraphic test
DRL = drilled
bgs = below ground surface
USDW = underground source of drinking water

Table B-2A: Shallow Wells Within the Area of Review (North Dakota State Water Commission Database)

NDSWC File No.	Location	Well Type	Latitude	Longitude	Date Drilled
45435	14108305DBC	Monitoring	47.05807144640	-101.22403845600	8/31/1992
58509	14108305DBD	Monitoring	47.05806885270	-101.22139831500	12/18/2001
62224	14108305DCA	Monitoring	47.05629497510	-101.22093313700	5/31/2006
62223	14108305DCB	Monitoring	47.05629468630	-101.22359722500	6/1/2006
45428	14108305DD	Monitoring	47.05533793760	-101.21744178300	8/31/1992
62226	14108305DDA	Monitoring	47.05629544240	-101.21559292600	6/1/2006
64006	14108305DDA	Monitoring	47.05629544240	-101.21559292600	9/16/2008
62225	14108305DDB	Monitoring	47.05629796890	-101.21826507400	5/31/2006
45424	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/22/1991
45430	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/22/1991
45433	14108305DDC	Monitoring	47.05442758350	-101.21876161600	11/21/1991
45442	14108307DDD	Monitoring	47.03987361290	-101.23730201600	6/22/1992
45444	14108307DDD	Monitoring	47.03987361290	-101.23730201600	6/23/1992
75424	14108308AAC	Monitoring	47.05089676300	-101.21818880300	4/10/2018
75425	14108308ABC	Monitoring	47.05089632660	-101.22350440900	4/4/2018
45445	14108309CAC	Monitoring	47.04374031500	-101.20800881800	6/24/1992
45446	14108309CAC	Monitoring	47.04374031500	-101.20800881800	6/24/1992
45450	14108317ABA	Monitoring	47.03831048430	-101.22134947500	6/23/1992
45454	14108317ABA	Monitoring	47.03831048430	-101.22134947500	6/23/1992
70195	14108328BB	Monitoring	47.00850829930	-101.21159727700	8/16/2013
70196	14108328BB	Monitoring	47.00850829930	-101.21159727700	8/16/2013
75609	14108414AC	Monitoring	47.03354034840	-101.28599885700	7/9/2018
75610	14108414AC	Monitoring	47.03354034840	-101.28599885700	7/9/2018
71993	14108424B	Monitoring	47.02090999740	-101.27275888800	4/13/2015
71994	14108424B	Monitoring	47.02090999740	-101.27275888800	4/14/2015
74661	14108424B	Monitoring	47.02090999740	-101.27275888800	4/13/2015
74662	14108424B	Monitoring	47.02090999740	-101.27275888800	4/14/2015
45682	14208331DBB	Monitoring	47.07421357470	-101.24546374500	11/2/1994
45742	14208426DBB	Monitoring	47.08859870920	-101.28811425400	6/25/1992
45766	14208436ABC	Monitoring	47.07957126200	-101.26674785100	6/25/1992
68211	14208436ABC	Monitoring	47.07956557860	-101.26636644400	9/1/2010
68213	14208436ABC	Monitoring	47.07956557860	-101.26636644400	9/1/2010
58551	14208436B	Monitoring	47.07865795490	-101.27333362100	7/14/2000
58552	14208436B	Monitoring	47.07865795490	-101.27333362100	7/11/2000
58553	14208436B	Monitoring	47.07865795490	-101.27333362100	7/13/2000
58554	14208436B	Monitoring	47.07865795490	-101.27333362100	7/13/2000
45763	14208436BAD	Monitoring	47.07957286780	-101.26938102400	4/24/1996
45764	14208436BAD	Monitoring	47.07957286780	-101.26938102400	4/24/1996
46298	14208436BAD	Monitoring	47.07957286780	-101.26938102400	6/26/2003
76702	14208436BC	Monitoring	47.07684094790	-101.27563942400	9/24/2019
46297	14208436BDA	Monitoring	47.07774670240	-101.26938293700	6/27/2003
62936	14108301BAA	Stock	47.06769659220	-101.14172881700	9/18/2007
46271	14108314DBA	Stock	47.03134264290	-101.15793313800	7/30/2002
62952	14108314DBB	Stock	47.03137121000	-101.16012311000	9/14/2007
45457	14108318AAA	Stock	47.03819346360	-101.23719472000	11/9/1973
66247	14108318BDC	Stock	47.03272363460	-101.25025782700	6/27/2009
74664	14108318CC	Stock	47.02636107210	-101.25419897000	7/28/2017
45458	14108319CAC	Stock	47.01456594600	-101.25070183900	7/13/1972
45467	14108401BA	Stock	47.06606821900	-101.27067222700	7/3/1973
45494	14108412C	Stock	47.04252236110	-101.27318222700	10/24/1989
45654	14208320DAA	Stock	47.10328061860	-101.21662135900	8/12/1983
45668	14208328A	Stock	47.09347770090	-101.19932645100	11/30/1997
45672	14208328AD	Stock	47.09165631590	-101.19673723900	11/25/1992
46293	14208330DCC	Stock	47.08314362950	-101.24554365800	4/15/2002
62368	14208331DCC	Stock	47.06880096510	-101.24503541000	1/11/2007
45737	14208424DA	Stock	47.10214709710	-101.26036045000	10/8/1987
58508	14108304B	Test Hole	47.06450481880	-101.20941031100	8/26/1993
45425	14108305ADC	Test Hole	47.06171298480	-101.21876286800	4/22/1996
45432	14108305DBA	Test Hole	47.05989225890	-101.22139874500	4/22/1996
58513	14108305DBB	Test Hole	47.05989211090	-101.22403893900	12/18/2001
45459	14108319AC	Test Hole	47.01915004050	-101.24404209400	9/29/1994
45460	14108319AC	Test Hole	47.01915004050	-101.24404209400	9/1/1994
45657	14208321ABB	Test Hole	47.11070119990	-101.20314157600	5/27/1975
45666	14208328A	Test Hole	47.09347770090	-101.19932645100	11/30/1997
45678	14208330BAAB	Test Hole	47.09653026350	-101.24885755800	10/26/1990
45679	14208330BAAC	Test Hole	47.09560623120	-101.24885670400	10/28/1990
45675	14208330BAB	Test Hole	47.09606761670	-101.25084664100	7/8/1999
45680	14208330BADB	Test Hole	47.09468494050	-101.24885588800	10/28/1990
45770	14208436	Test Hole	47.07500532680	-101.26806329300	4/22/1996
45768	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45769	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45771	14208436B	Test Hole	47.07865795490	-101.27333362100	4/22/1996
45469	14108402B	Unknown	47.06423385790	-101.29443382100	7/25/1983
470630101144201	14208319ACB	USGS Groundwater	47.10832816000	-101.24542600000	8/1/1967
470358101135201	14108305BBD	USGS Groundwater	47.06610565000	-101.23153490000	5/1/1967
470349101124101	14108304BC	USGS Groundwater	47.06360540000	-101.21181200000	5/1/1967
470352101122601	14108304BDB	USGS Groundwater	47.06443869000	-101.20764520000	8/1/1967
470359101121701	14108304BAD	USGS Groundwater	47.06638310000	-101.20514520000	8/1/1967
470352101121701	14108304BDA	USGS Groundwater	47.06443866000	-101.20514510000	8/1/1967
470346101113901	14108304ADD	USGS Groundwater	47.06277186000	-101.19458920000	8/1/1967
470328101091601	14108302DDB1	USGS Groundwater	47.05777138000	-101.15486560000	5/1/1967

Notes:

1. No attempt was made to remove well records that may be duplicates between the records presented in this table and the records presented in Table B-2B.
2. NDSWC File Numbers for USGS Groundwater wells are USGS file numbers.
3. Locations of wells are approximate.

Table B-2B: Shallow Wells Within the Area of Review (MPC Facility Wells)

Name	Facility	Well Type	Latitude	Longitude	Total Depth (ft bgs)
2001-01	30 Year Pond Wells	Monitoring	47.06109923940	-101.22182160300	NA
2006-08-1r	30 Year Pond Wells	Monitoring	47.05843018790	-101.22188337200	NA
2006-08-4r	30 Year Pond Wells	Monitoring	47.05837890790	-101.21454709300	NA
2013-1	30 Year Pond Wells	Monitoring	47.05512100000	-101.22353900000	NA
2013-2	30 Year Pond Wells	Monitoring	46.82604023470	-107.77324319700	NA
2013-3	30 Year Pond Wells	Monitoring	47.05458645700	-101.21447415000	NA
2015-1	30 Year Pond Wells	Monitoring	47.05770507840	-101.22430536100	204
2015-2	30 Year Pond Wells	Monitoring	47.05772696180	-101.22431368100	150
2015-3	30 Year Pond Wells	Monitoring	47.05787335050	-101.21454999300	132
2015-4	30 Year Pond Wells	Monitoring	47.05520430730	-101.21446110900	136
2015-5	30 Year Pond Wells	Monitoring	47.05378223690	-101.21442934600	170
2016-1	30 Year Pond Wells	Monitoring	47.05643365440	-101.21439843200	155
2018-1	30 Year Pond Wells	Monitoring	47.05220225040	-101.21443800900	206
2018-2	30 Year Pond Wells	Monitoring	47.04880745550	-101.22441479200	216
92-1	30 Year Pond Wells	Monitoring	47.05530868560	-101.21674821100	NA
92-2A	30 Year Pond Wells	Monitoring	47.05801110030	-101.21292179200	166
92-2B	30 Year Pond Wells	Monitoring	47.05803316970	-101.21292236600	56
92-3	30 Year Pond Wells	Monitoring	47.06258203830	-101.21307198000	155
92-4	30 Year Pond Wells	Monitoring	47.06660313430	-101.21883755500	211
92-5A	30 Year Pond Wells	Monitoring	47.06248737940	-101.22441330600	187
92-5B	30 Year Pond Wells	Monitoring	47.06243000090	-101.22440282200	75
92-6A	30 Year Pond Wells	Monitoring	47.05787709860	-101.22425504200	NA
92-6B	30 Year Pond Wells	Monitoring	47.05785889830	-101.22430623300	55
92-7	30 Year Pond Wells	Monitoring	47.05942908830	-101.21825559900	272
95-1	30 Year Pond Wells	Monitoring	47.05942022160	-101.22063598000	NA
95-2	30 Year Pond Wells	Monitoring	47.05946441480	-101.21637349800	NA
95-3	30 Year Pond Wells	Monitoring	47.06127616980	-101.21793524400	NA
95-4	30 Year Pond Wells	Monitoring	47.06153601830	-101.21279057400	NA
97-1	30 Year Pond Wells	Monitoring	47.06231069420	-101.21581129100	NA
#8-1	Horseshoe Pit Wells	Monitoring	47.07716741950	-101.27113180500	145
5-1r	Horseshoe Pit Wells	Monitoring	47.07820936450	-101.27119470200	103
5-2r	Horseshoe Pit Wells	Monitoring	47.07821079310	-101.27125970500	NA
2003-6-2r	Horseshoe Pit Wells	Monitoring	47.07873169350	-101.26669968100	95
#6-1	Horseshoe Pit Wells	Monitoring	47.07880836980	-101.26673513500	NA
#4-1	Horseshoe Pit Wells	Monitoring	47.07919381390	-101.27630955600	NA
#10-1r	Horseshoe Pit Wells	Monitoring	47.07975125550	-101.26702307400	103
#3-1	Horseshoe Pit Wells	Monitoring	47.08035096190	-101.27392566700	134
#3-2	Horseshoe Pit Wells	Monitoring	47.08035379810	-101.27389130900	96
#3-3	Horseshoe Pit Wells	Monitoring	47.08035872570	-101.27383952000	171
2003-1	Horseshoe Pit Wells	Monitoring	47.08071794210	-101.26762304400	99
96-2	Horseshoe Pit Wells	Monitoring	47.08097218970	-101.26762965200	NA
96-1	Horseshoe Pit Wells	Monitoring	47.08098003210	-101.26760495800	NA
#12-1	Horseshoe Pit Wells	Monitoring	47.08125035600	-101.26637706200	114
#1-2r	Horseshoe Pit Wells	Monitoring	47.08167998120	-101.26394413700	86
#1-1	Horseshoe Pit Wells	Monitoring	47.08168017530	-101.26391905300	126
#9-1	Horseshoe Pit Wells	Monitoring	47.08186697320	-101.26843144500	147
14108304BBD	Miscellaneous Plant Wells	Industrial	47.06454604040	-101.33672835800	280
14208333DD	Miscellaneous Plant Wells	Industrial	47.06912285030	-101.32236476900	160
MPC-WS-2	Miscellaneous Plant Wells	Industrial	47.06780000000	101.21450000000	107
MPC-WS-1	Miscellaneous Plant Wells	Industrial	47.06640000000	101.21430000000	186
MP-WS-1	Miscellaneous Plant Wells	Industrial	47.07180000000	101.19610000000	NA
3	Nelson Lake Dam Wells	Monitoring	47.06521365040	-101.20328465900	12
9	Nelson Lake Dam Wells	Monitoring	47.06543380510	-101.20710607200	43
10	Nelson Lake Dam Wells	Monitoring	47.06544918470	-101.20793964200	44
7	Nelson Lake Dam Wells	Monitoring	47.06573354620	-101.20588103000	37
SB-3A	Nelson Lake Dam Wells	Monitoring	47.06630617280	-101.20560533700	15
SB-3	Nelson Lake Dam Wells	Monitoring	47.06632603650	-101.20558553400	35
8	Nelson Lake Dam Wells	Monitoring	47.06633597320	-101.20493570900	20
6	Nelson Lake Dam Wells	Monitoring	47.06643840410	-101.20476281800	19
98-4	Nelson Lake Dam Wells	Monitoring	47.06646286610	-101.20479801000	19
SB-2	Nelson Lake Dam Wells	Monitoring	47.06647686460	-101.20585035600	60
98-3	Nelson Lake Dam Wells	Monitoring	47.06660561560	-101.20505698700	24
SB-1	Nelson Lake Dam Wells	Monitoring	47.06662340570	-101.20533944300	37
2	Nelson Lake Dam Wells	Monitoring	47.06672723220	-101.20499722800	28
P1-20W-02-US1	Nelson Lake Dam Wells	Monitoring	47.06683040170	-101.20565596800	62
1	Nelson Lake Dam Wells	Monitoring	47.06696788760	-101.20548566400	60
98-2	Nelson Lake Dam Wells	Monitoring	47.06702061510	-101.20465421000	14
11	Nelson Lake Dam Wells	Monitoring	47.06709314850	-101.20517607200	53
P1-14-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06728642710	-101.20421933200	13
P1-14-02-US1	Nelson Lake Dam Wells	Monitoring	47.06754987780	-101.20467544400	56
12	Nelson Lake Dam Wells	Monitoring	47.06772448420	-101.20448347100	54
P1-16-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06776080160	-101.20381423200	15
P1-16-02-US1	Nelson Lake Dam Wells	Monitoring	47.06802453180	-101.20431449200	56
13	Nelson Lake Dam Wells	Monitoring	47.06840729590	-101.20373045100	54
98-1	Nelson Lake Dam Wells	Monitoring	47.06871201980	-101.20294473000	21
98-5	Nelson Lake Dam Wells	Monitoring	47.06873113710	-101.20293033300	22
P1-20-02-DS1	Nelson Lake Dam Wells	Monitoring	47.06874962460	-101.20281712800	24
P1-20-02-US1	Nelson Lake Dam Wells	Monitoring	47.06883964570	-101.20325171100	56

Notes:

1. No attempt was made to remove well records that may be duplicates between the records presented in this table and the records presented in Table B-2A.
2. Locations of wells are approximate.

APPENDIX C

Modeling Inputs Tables

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Injection Duration	t	years	20	20 years of continuous injection
		days	7,300	
		hours	175,200	
Kelly Bushing Elevation	z_{KB}	ft amsl	2,029	Approximate Kelly Bushing elevation at J-ROC1
Ground Surface Elevation	z_{GS}	ft amsl	2,004	Approximate ground surface elevation at J-ROC1
Borehole Radius	r_w	ft	0.510	Radius of 12.25-inch borehole in injection interval
Injection Interval Properties				
Net Sandstone Thickness				
Depth to Top of Perforated Interval	$D_{perf\ top}$	ft bgs	3,667	Calculated
Depth to Bottom of Perforated Interval	$D_{perf\ bottom}$	ft bgs	3,838	Calculated
Elevation of Top of Perforated Interval	$z_{perf\ top}$	ft amsl	-1,663	Approximate elevation based on CMR log at J-ROC1 (Figure 4-1)
Elevation of Bottom of Perforated Interval	$z_{perf\ bottom}$	ft amsl	-1,834	Approximate elevation based on CMR log at J-ROC1 (Figure 4-1)
Injection Interval Net Sands Thickness	h	ft	90	Total thickness of permeable zones in Inyan Kara Formation based on CMR log at J-ROC1 (Figure 4-1)
Formation Static Pore Pressure				
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Approximate static potentiometric surface at MRY based on measured pressure gradient with depth at J-ROC1 (0.420 psi/ft)
Initial Static Pore Pressure Gradient		psi/ft	0.4198	Measured static pore pressure gradient at J-ROC1
Initial Static Pressure of Injection Interval	P_{otop}	psi	1,539	Static pressure evaluated at the top of the injection interval
Hydrostatic Pressure of Injection Interval	P_{hydtop}	psi	1,655	Hydrostatic pressure evaluated at the top of the injection interval assuming injectate fluid density
Formation Porosity				
Effective Porosity	ϕ	-	0.151	Average CMR free fluid porosity (CMFF) in permeable zones at J-ROC1 (Figure 4-2)
Formation Permeability				
Intrinsic Permeability	κ	mD	950	Average permeability from CMR log in permeable zones at J-ROC1 using SDR and Timur-Coates (Figure 4-1)

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Formation Fluid Properties				
Formation Fluid Properties				
Temperature	T_{form}	°F	120	Approximate Inyan Kara Formation water temperature at MRY, measured using MDT tool
Total Dissolved Solids Concentration	TDS_{form}	mg/L	3,450	Measured TDS concentration from Inyan Kara Formation fluid sample collected at J-LOC1 using MDT tool (June 2020)
		%	0.35	Conversion to volumetric percent
Formation Pressure During Injection	P_i	psi	2,714	Assumed pressure of injection interval during injection for estimating fluid properties (conservatively equal to fracture pressure)
Viscosity	μ_{form}	cP	0.546	Calculated based on formation fluid temperature, TDS concentration, and formation pressure during injection
Specific Gravity	γ_{form}	-	0.997	Calculated based on formation fluid temperature, TDS concentration, and formation pressure during injection
Fluid Density	ρ_{form}	g/cm^3	0.997	Equal to specific gravity
		kg/m^3	996.8	Conversion
		lb/ft^3	62.226	Conversion
Total Compressibility				
Pore Volume Compressibility	c_f	1/psi	4.07E-06	Regression of data from Hall (1953) and presented in Lei et al. (2019): $c_f = \frac{1.7836E^{-6}}{\phi^{0.4358}}$
Bulk Volume Compressibility (Aquifer Skeleton Compressibility)	c_m (α)	1/psi	6.14E-07	Calculated as (Crawford et al. 2011): $c_m = \phi c_f$
Bulk Modulus of Elasticity of Water	E_w	psi	3.00E+05	Lohman (1972)
Water Compressibility	c_w (β)	1/psi	3.33E-06	Calculated as (Lohman 1972): $c_w = \frac{1}{E_w}$
Total Compressibility	c_t	1/psi	7.40E-06	Calculated assuming 100% water saturated with no presence of oil or gas $c_t = c_f + c_w$
Formation Storage Coefficient				
Specific Storage	Ss	1/ft	4.83E-07	Calculated as (Fetter 2001): $S_s = \frac{\rho_{form}}{144}(c_m + \phi c_w)$
Storage Coefficient	S	-	4.34E-05	Calculated as (Fetter 2001): $S = hS_s$
Formation Volume Factor				
Formation Volume Factor	B	bbl/bbl	1.0	Assumption

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Hydraulic Conductivity				
Hydraulic Conductivity	K	ft/day	4.86	Calculated using formation fluid properties $K = \frac{\kappa \rho g}{3500\mu}$
Formation Transmissivity				
Transmissivity	T	ft^2/day	437.8	Calculated using formation fluid properties $T = Kh$
Injectate Fluid Properties				
Injectate Fluid Properties				
Temperature	T	°F	55	Assumption
Total Dissolved Solids	TDS	mg/L	40,000	Assumption
		%	4.00	Conversion to volumetric percent
Formation Pressure During Injection	P_I	psi	2,714	Assumed pressure of injection interval during injection for estimating fluid properties (conservatively equal to fracture pressure)
Viscosity	μ	cP	1.294	Calculated based on injectate fluid temperature, TDS concentration, and formation pressure during injection
Specific Gravity	γ	-	1.041	Calculated based on injectate fluid temperature, TDS concentration, and formation pressure during injection
Fluid Density	ρ	g/cm^3	1.041	Equal to specific gravity
		kg/m^3	1,041.1	Conversion
		lb/ft^3	64.994	Conversion
Formation Storage Coefficient				
Specific Storage	Ss	1/ft	5.04E-07	Calculated as (Fetter 2001): $S_s = \frac{\rho_{inj}}{144}(c_m + \phi c_w)$
Storage Coefficient	S	-	4.54E-05	Calculated as (Fetter 2001): $S = hS_s$
Hydraulic Conductivity				
Hydraulic Conductivity	K	ft/day	2.14	Calculated using injectate fluid properties $K = \frac{\kappa \rho g}{3500\mu}$
Formation Transmissivity				
Transmissivity	T	ft^2/day	192.9	Calculated using injectate fluid properties $T = Kh$

Table C-1: Inputs for Diffusivity Equation Modeling

Variable	Sym.	Units	Value	Notes
Lowest Underground Source of Drinking Water Formation Properties				
Elevation of USDW Bottom		ft amsl	840	Approximate top of Pierre Shale - J-ROC1 formation tops ~200 feet shallower than BNI-1 formation tops (top of Pierre Shale at BNI-1 1,282 feet below ground surface
Static Potentiometric Surface Elevation of USDW		ft amsl	1,800	Water level elevation from 142-084-24 BBA, completed in the Fox Hills Formation

Abbreviations:

ft: feet
ft bgs: feet below ground surface
ft amsl: feet above mean sea level
ft/day: feet per day
ft^2/day: square feet per day
cP: centipoise
mD: millidarcies
°F: degrees Fahrenheit
psi: pounds per square inch
bbl/bbl: barrel per barrel
mg/L: milligrams per liter
g/cm^3: grams per cubic centimeter
kg/m^3: kilograms per cubic meter
lb/ft^3: pounds per cubic foot
USDW: underground source of drinking water
TDS: total dissolved solids

Table C-2: Inputs for AquiferWin32 Confirmatory Modeling

Variable	Sym.	Units	Value	Notes
Proposed Injection Site				
FREEMAN-1 Easting	X	ft	1,790,841	Approximate location of FREEMAN-1 in NAD83 State Plane Coordinate System North Dakota South
FREEMAN-1 Northing	Y	ft	509,872	
Ground Surface Elevation	z	ft amsl	2,004	Table C-1
RUBEN-1 Easting	X	ft	1,791,090	Approximate location of RUBEN-1 in NAD83 State Plane Coordinate System North Dakota South
RUBEN-1 Northing	Y	ft	507,250	
Ground Surface Elevation	z	ft amsl	2,004	Table C-1
Injection Duration	t	yrs	20	Table C-1
Injection Interval Properties				
Regional Hydraulic Gradient	I	ft/ft	2.7E-04	Approximate regional hydraulic gradient estimated from Figure 3-15
Direction of Regional Hydraulic Gradient	θ	degrees	54° N of E	Approximate direction of regional hydraulic gradient estimated from Figure 3-15
Injection Interval Net Sands Thickness	h	ft	90	Table C-1
Effective Porosity	ϕ	-	0.151	Table C-1
Intrinsic Permeability	κ	mD	950	Table C-1
Injection Interval Static Head				
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Table C-1
Reference Head	H_{ref}	ft amsl	2,034.58	Reference head set to result in static potentiometric surface elevation at FREEMAN-1
Reference Head Easting	X_{ref}	ft	1,363,680	Reference head location in NAD83 State Plane Coordinate System North Dakota South
Reference Head Northing	Y_{ref}	ft	199,521	
Reference Head Distance from Well	Δ_{ref}	miles	100	Reference head situated sufficiently far from the well to not influence simulation results
Hydraulic Properties Estimated Using Native Formation Fluid Properties				
Hydraulic Conductivity	K	ft/day	4.86	Table C-1
Transmissivity	T	ft^2/day	437.8	Table C-1
Storage Coefficient	S	-	4.34E-05	Table C-1
Leakage Factor	1/B	1/ft	5.09E-07	Calculated $^1/_B = \left[\frac{K'}{Tb'}\right]^{1/2}$

Table C-2: Inputs for AquiferWin32 Confirmatory Modeling

Variable	Sym.	Units	Value	Notes
Hydraulic Properties Estimated Using Injectate Fluid Properties				
Hydraulic Conductivity	K	ft/day	2.14	Table C-1
Transmissivity	T	ft^2/day	192.9	Table C-1
Storage Coefficient	S	-	4.54E-05	Table C-1
Leakage Factor	1/B	1/ft	7.67E-07	Calculated $1/_B = \left[\frac{K'}{Tb'}\right]^{1/2}$
Confining Unit Properties				
Vertical Hydraulic Conductivity	K'	ft/day	2.84E-07	Mid-range of literature values reported for the Pierre Shale in South Dakota, 2.84E-6 to 2.84E-8 ft/day (Milly, 1978; Neuzil, 1980)
Thickness	b'	ft	2,500	Approximate thickness of Cretaceous Confining Unit (top of Pierre Shale to top of Inyan Kara Formation)
Simulated Well Properties				
Casing Inner Diameter	D_c	ft	0.730	Inside diameter of 9.625-inch OD 43.5# N-80 steel casing (ID = 8.755 inches)
Borehole Diameter	D_b	ft	1.021	Diameter of 12.25-inch borehole through injection interval
Screen Length	L_s	ft	90	Equal to the net sandstone thickness
Screen Top Depth	d_{ST}	ft	0	Distance from the top of the injection interval to the top of the well screen (fully penetrating well)

Abbreviations:

ft/day: feet per day
ft: feet
ft amsl: feet above mean sea level
mD: millidarcies
OD: outside diameter
ID: inside diameter

Table C-3: Modular Formation Dynamics Testing Results at Test Boreholes/Wells

Borehole / Well	Kelly Bushing Elevation	Ground Surface Elevation	Measurement Depth		Measurement Elevation	Measured Pore Pressure	Pore Pressure Gradient	Temperature
	(ft amsl)		(ft below KB)	(ft bgs)	(ft amsl)	(psi)	(psi/ft)	(°F)
BNI-1	2,085	2,067	3,996	3,978	-1,911	1,652	0.4153	123.73
			4,030	4,012	-1,945	1,666	0.4153	124.90
J-LOC1	2,093	2,068	3,892	3,867	-1,799	1,610	0.4163	123.75
			4,019	3,994	-1,926	1,664	0.4166	124.19
			4,040	4,015	-1,947	1,673	0.4167	124.75
			4,019	3,994	-1,926	1,663	0.4165	125.95
J-ROC1	2,029	2,004	3,794	3,769	-1,765	-	-	107.20
			3,796	3,771	-1,767	1,583	0.4197	108.14
			3,810	3,785	-1,781	1,588	0.4197	108.86
			3,846	3,821	-1,817	1,604	0.4198	109.56
			3,845	3,820	-1,816	1,605	0.4201	113.91

Notes:

1. ft = feet
2. ft amsl = feet above mean sea level
3. ft bgs = feet below ground surface
4. KB = Kelly Bushing
5. psi = pounds per square inch
6. °F = degrees Fahrenheit
7. Information provided by Energy & Environmental Research Center (not currently publicly available).

APPENDIX D

Fracture Pressure Calculation

Table D-1: Fracture Pressure Calculation

Variable	Sym.	Units	Value	Notes
Inyan Kara Formation Properties				
Ground Surface Elevation	z_{GS}	ft amsl	2,004	Table C-1
Depth to Top of Screened Interval	$D_{screen\ top}$	ft bgs	3,667	Table C-1
Static Potentiometric Surface Elevation of Injection Interval	H_{static}	ft amsl	1,899	Table C-1
Overburden Stress Gradient		psi/ft	0.977	Evaluated using J-ROC1 bulk density logs at top of screened int.
Overburden Stress	σ_v	psi	3,581	Calculated based on depth to top of screened interval
Pore Pressure at Top of Injection Interval	P_o	psi	1,539	Table C-1
Pore Pressure Gradient		psi/ft	0.420	Pore pressure divided by depth to top of screened interval
Vertical Effective Pressure	σ_e	psi	2,042	Calculated as: $\sigma_e = \sigma_v - P_o$
Porosity	ϕ	-	0.151	Table C-1, effective porosity used
Clay Volume	V_c	-	0.00	Assumption
Compression Wave Velocity	VP_c	km/s	5.443	Calculated as (Castagna, et al. 1985): $VP_c = 6.5 - 7.0\phi - 1.5V_c$
Shear Wave Velocity	VS_c	km/s	2.614	Calculated as (Castagna, et al. 1985): $VS_c = 3.52 - 6.0\phi - 1.8V_c$
Poisson's Ratio	μ	-	0.350	Calculated as (Desroches & Bratton n.d.): $\mu = \dfrac{0.5\left(\frac{VP_c}{VS_c}\right)^2 - 1}{\left(\frac{VP_c}{VS_c}\right)^2 - 1}$
Fracture Propagation Pressure Calculation				
Ward et al (1995)				
Fracture Pressure, P_{fp}		psi	3,273	$P_{fp} = (1-\phi)(\sigma_v - P_o) + P_o$
Fracture Pressure Gradient		psi/ft	0.893	Calculated with reference to top of injection interval
Eaton (1969)				
Fracture Pressure, P_{fp}		psi	2,639	$P_{fp} = \dfrac{\mu}{1-\mu}(\sigma_v - P_o) + P_o$
Fracture Pressure Gradient		psi/ft	0.720	Calculated with reference to top of injection interval
J-LOC 1 Step-Rate Test				
Fracture Pressure, P_{fp}		psi	2,714	Calculated as fracture pressure gradient multiplied by depth to top of injection interval
Fracture Pressure Gradient		psi/ft	0.740	Propagation pressure gradient calculated from Step-Rate test at J-LOC1 well

APPENDIX E

Geochemical Modeling

Table E-1: Formation Water Quality Results

Constituent	Units	MVTL 6/13/2020	EERC - Unfiltered 6/13/2020	Geomean of Formation Water Samples	Simulated Formation Water with Added CO_2
pH	SU	8.63		8.63	7.66
Temperature	Deg C	21		21	21
Conductivity (EC)	µmhos/cm	4,774		4,774	4,774
Total Dissolved Solids	mg/L	3,450		3,450	3,450
Alkalinity as $CaCO_3$	mg/L $CaCO_3$	544		544	544
Bicarbonate Alkalinity as $CaCO_3$	mg/L $CaCO_3$	501		501	
Carbonate Alkalinity as $CaCO_3$	mg/L $CaCO_3$	43		43	
Hydroxide Alkalinity as $CaCO_3$	mg/L $CaCO_3$	<20		<20	
Phenolphthalein Alkalinity as $CaCO_3$	mg/L $CaCO_3$	22		22	
Sulfate	mg/L	2,450		2,450	2,450
Chloride	mg/L	554		554	554
Calcium, Total	mg/L	17	14	16	16
Magnesium, Total	mg/L	<5	<1	<3	3.0
Sodium, Total	mg/L	1,120	1,270	1,193	1,193
Potassium, Total	mg/L	5.7	5.1	5.4	5.4
Ammonia-Nitrogen as N	mg/L	1.1		1.1	1.1
Nitrate-Nitrite as N	mg/L	0.16		0.16	0.16
Total Organic Carbon (TOC)	mg/L	1,340		1,340	1,340
Aluminum, Total	mg/L		0.17	0.17	0.17
Antimony, Total	mg/L		<0.005	<0.005	0.0050
Arsenic, Dissolved	mg/L	<0.002		<0.002	0.0020
Arsenic, Total	mg/L		<0.005	<0.005	0.0050
Barium, Dissolved	mg/L	0.26		0.26	0.26
Barium, Total	mg/L		0.78	0.78	0.78
Beryllium, Total	mg/L		<0.004	<0.004	0.0040
Boron, Total	mg/L		2.7	2.7	2.7
Cadmium, Dissolved	mg/L	<0.0005		<0.0005	0.00050
Cadmium, Total	mg/L		<0.002	<0.002	0.0020
Chromium, Dissolved	mg/L	0.030		0.030	0.030
Chromium, Total	mg/L		<0.010	<0.010	0.010
Cobalt, Total	mg/L		0.055	0.055	0.055
Copper, Dissolved	mg/L	<0.05		<0.05	0.050
Copper, Total	mg/L		< 0.05	< 0.05	0.050
Iron, Total	mg/L	0.33	< 0.1	0.33	0.33
Lead, Dissolved	mg/L	<0.0005		<0.0005	0.00050
Lead, Total	mg/L		< 0.005	< 0.005	0.0050
Lithium, Total	mg/L		0.24	0.24	0.24
Manganese, Total	mg/L	<0.05	<0.02	<0.035	0.035
Mercury, Total	mg/L		<0.0001	<0.0001	0.00010
Molybdenum, Dissolved	mg/L	<0.1		<0.1	0.10
Molybdenum, Total	mg/L		0.069	0.069	0.069
Nickel, Total	mg/L		0.061	0.061	0.061
Selenium, Dissolved	mg/L	<0.005		<0.005	0.0050
Selenium, Total	mg/L		<0.005	<0.005	0.0050
Silver, Total	mg/L	<0.0005	<0.005	<0.005	0.0050
Strontium, Dissolved	mg/L	0.32		0.32	0.32
Strontium, Total	mg/L		< 1	< 1	1.0
Thallium, Total	mg/L		<0.005	<0.005	0.0050
Vanadium, Total	mg/L		< 0.01	< 0.01	0.010
Zinc, Total	mg/L		0.059	0.059	0.059

Notes:
SU: standard units
Deg C: Degrees Celcius
µmhos/cm: microohms per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-2: Cooling Tower Blowdown Water Quality Estimates

Parameter Name	Units	Winter Minimum Case	Summer Peak Full Softening Case	Summer Peak Case	Annual Average Case
pH	SU	8.0 - 8.3	8.0 - 8.3	8.0 - 8.3	8.0 - 8.3
Conductivity (estimated)	µS/cm	9,725	16,298	13,488	11,571
TDS (estimated)	mg/L	5,720	9,586	7,933	6,806
TSS	mg/L	219	244	223	220
HCO3-	mg/L $CaCO_3$	451	308	363	405
CO3 (-2)	mg/L $CaCO_3$	51	23	34	42
CO2	mg/L	ND	ND	ND	ND
Ca	mg/L $CaCO_3$	643	293	525	583
Mg	mg/L $CaCO_3$	909	586	795	849
Sodium	mg/L	1,358	2,982	2,370	1,784
Potassium	mg/L	52	93	76	64
Bromide	mg/L	5.2	9.3	7.6	6.4
Chloride	mg/L	57	101	92	70
Fluoride	mg/L	ND	ND	ND	ND
SO4 (-2)	mg/L	3,211	5,812	4,703	3,930
Ammonia	mg/L	ND	ND	ND	ND
Nitrate	mg/L	0.75	1.3	1.1	0.92
Ortho-PO4 (-3)	mg/L	ND	ND	ND	ND
Aluminum (Al+3)	mg/L	0.62	1.1	0.90	0.76
Arsenic (III & V)	mg/L	ND	ND	ND	ND
Barium	mg/L	<0.1	<0.1	<0.1	<0.1
Boron	mg/L	1.0	1.7	1.4	1.2
Iron (Fe+2/Fe+3)	mg/L	0.81	1.5	1.2	1.0
Manganese (Mn+2)	mg/L	0.20	0.35	0.28	0.24
Si (as SiO2)	mg/L	56	85	63	59
Strontium	mg/L	2.9	5.2	4.3	3.6
Zinc	mg/L	<0.1	<0.1	<0.1	<0.1

Notes:
SU: standard units
µS/cm: microsiemens per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-3: Scrubber Pond Water Quality Results

Parameter Name	Units	Scrubber Pond Cell 3					Scrubber Pond Cell 4
		7/30/2014	3/23/2015	6/9/2016	12/10/2017	6/26/2018	7/24/2019
pH - Field	SU	7.11	6.02	5.80	5.85	5.86	7.80
pH - Lab	SU	7.0	5.9	5.7	5.7	5.8	
Temperature - Field	Deg C	22	--	23	5.6	25	28
Field Electrical Conductivity	µmhos/cm	42,005	55,580	67,264	59,496	58,791	10,894
Lab Specific Conductance	µmhos/cm	41,946	70,210	71,130	56,823	59,307	10,505
Total Dissolved Solids	mg/L	49,700	69,900	108,000	79,800	98,900	10,400
Total Alkalinity	mg/L $CaCO_3$	185	286	488	306	430	214
Bicarbonate	mg/L $CaCO_3$	185	286	488	306	430	214
Carbonate	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Hydroxide	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Phenolphthalein Alk	mg/L $CaCO_3$	<20	<20	<20	<20	<20	<20
Fluoride	mg/L	60	96	132	123	135	14
Sulfate	mg/L	33,000	49,900	77,600	54,700	70,600	6,980
Chloride	mg/L	431	672	1,270	1,110	992	142
Calcium, Total	mg/L	157	278	389	350	568	332
Magnesium, Total	mg/L	3,580	4,500	7,550	6,580	7,240	820
Sodium, Total	mg/L	11,100	13,000	19,200	15,300	17,400	1,830
Potassium, Total	mg/L	1,310	1,340	1,990	1,530	1,800	174
Nitrate-Nitrite as N	mg/L	0.10	2.2	5.4	5.8	6.6	<0.5
Arsenic, Dissolved	mg/L	0.25	0.26	0.16	0.098	0.092	0.018
Barium, Dissolved	mg/L	0.19	0.30	0.34	0.26	0.35	0.11
Beryllium, Dissolved	mg/L	--	--	--	0.0060	--	
Boron, Dissolved	mg/L	190	273	374	264	279	29
Cadmium, Dissolved	mg/L	0.011	0.018	0.0030	0.0027	<0.01	<0.0005
Chromium, Dissolved	mg/L	<0.04	0.031	0.041	0.020	<0.02	<0.002
Iron, Dissolved	mg/L	--	6.9	2.6	<5	2.8	<0.5
Iron, Total	mg/L	<1	--	--	--	--	
Lead, Dissolved	mg/L	<0.008	0.0074	<0.002	<0.002	<0.002	<0.0005
Manganese, Dissolved	mg/L	--	3.3	2.6	2.7	2.0	0.32
Manganese, Total	mg/L	2.3	--	--	--	--	
Mercury, Dissolved	mg/L	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002	<0.0002
Molybdenum, Dissolved	mg/L	3.3	4.7	4.4	3.8	3.9	0.25
Phosphorus as P, Total	mg/L	0.14	<1	0.28	0.21	0.20	0.31
Selenium, Dissolved	mg/L	0.96	1.5	2.5	2.0	2.3	0.048
Silver, Dissolved	mg/L	<0.02	0.0024	<0.008	<0.002	<0.01	<0.0005

Notes:
SU: standard units
Deg C: Degrees Celcius
µmhos/cm: microohms per centimeter
mg/L: milligrams per liter
mg/L $CaCO_3$: milligrams of calcium carbonate per liter

Table E-4: Formation Mineralogy Results

Sample Location	STAR #	Depth (feet)	Smectite	Glauconite	Clintonite	Kaolinite	Illite/ Muscovite	Chlorite	Orthoclase	Microcline	K-feldspar	Albite	P-feldspar	Quartz	Jarosite	Calcite	Calcite, magnesian
Inyan Kara Formation	129299	3,890								6.4%	6.4%			89.1%			
Inyan Kara Formation	129301	3,893		3.8%		3.8%	3.9%	2.4%	2.9%		2.9%			83.2%			
Inyan Kara Formation	129302	3,895					3.9%		3.9%		3.9%			92.2%			
Inyan Kara Formation	129303	3,900				5.3%	5.9%			4.4%	4.4%			83.5%			
Inyan Kara Formation	129304	3,911				10.5%	14.5%	9.7%		4.4%	4.4%	3.4%	3.4%	57.5%			
Inyan Kara Formation	129305	3,915	4.5%	5.2%		6.7%	17.8%	2.4%		4.4%	4.4%			41.2%			
Inyan Kara Formation	129306	3,917			6.9%	13.7%	5.8%	1.9%	4.1%		4.1%			42.1%			
Inyan Kara Formation	129307	3,918	1.0%			4.9%	2.5%		4.8%		4.8%			78.0%			
Inyan Kara Formation	129308	3,920	5.2%		10.3%	12.3%	22.5%	4.8%	2.8%		2.8%			42.1%			
Inyan Kara Formation	129309	3,925	2.4%		7.5%	8.4%	33.2%	2.6%	5.6%		5.6%	4.1%	4.1%	29.0%			
Inyan Kara Formation	129310	3,935	2.4%		8.7%	9.7%	13.8%			6.0%	6.0%	5.1%	5.1%	51.3%			
Inyan Kara Formation	129311	3,946	2.2%		8.7%	4.4%	12.0%	1.6%		6.3%	6.3%	3.1%	3.1%	58.2%			
Inyan Kara Formation	129312	3,950				6.1%	8.3%							85.6%			
Inyan Kara Formation	129313	3,956				4.8%	11.3%			5.5%	5.5%			78.4%			
Inyan Kara Formation	129314	3,960				2.1%				4.7%	4.7%			92.4%			
Inyan Kara Formation	129315	3,969				10.2%	9.1%		10.4%		10.4%			52.2%			
Inyan Kara Formation	129316	3,975				5.9%	36.5%					3.5%	3.5%	42.9%		11.2%	
Inyan Kara Formation	129318	3,980	0.5%		14.3%	8.7%	22.8%			9.2%	9.2%			29.6%	2.5%		
Inyan Kara Formation	129319	3,989	3.3%		11.0%	9.9%	20.3%			6.5%	6.5%			43.4%			
Inyan Kara Formation	129320	3,995		5.6%		2.1%	8.2%	2.7%	3.0%		3.0%			78.4%			
Inyan Kara Formation	129321	3,999				7.4%	27.7%	2.4%		3.5%	3.5%			56.6%			
Inyan Kara Formation	129322	4,003			100.0%	12.4%	9.7%	2.8%				9.1%	9.1%	49.1%			
Inyan Kara Formation	129323	4,007	2.8%	2.9%	7.2%	14.9%	7.9%					4.8%	4.8%	52.5%			
Inyan Kara Formation	129324	4,011				2.8%	0.8%		1.6%		1.6%			94.0%			
Inyan Kara Formation	129325	4,017					1.5%			4.4%	4.4%			92.3%			
Inyan Kara Formation	129326	4,020				1.3%	3.5%	1.7%	2.2%		2.2%			91.3%			
Inyan Kara Formation	129327	4,021				2.9%	2.7%							94.4%			
Inyan Kara Formation	129328	4,029				0.9%	2.2%			1.8%	1.8%			94.8%			
Inyan Kara Formation	129329	4,032				0.7%	1.5%			3.7%	3.7%			93.5%			
Inyan Kara Formation	129330	4,038				2.9%	2.6%			3.4%	3.4%			87.4%			2.8%
Inyan Kara Formation	129331	4,041			2.1%	1.3%	3.0%			2.6%	2.6%			90.4%			
Inyan Kara Formation	129332	4,047					3.0%			3.4%	3.4%			93.6%			
Inyan Kara Formation	129333	4,050					2.1%		2.9%		2.9%			90.7%			

Notes:
%: percent

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Table E-4: Formation Mineralogy Results

Sample Location	STAR #	Depth (feet)	Dolomite	Siderite	Goethite	Pyrite	Anatase	Rutile	Anhydrite	Sum
Inyan Kara Formation	129299	3,890				4.5%				100%
Inyan Kara Formation	129301	3,893								100%
Inyan Kara Formation	129302	3,895								100%
Inyan Kara Formation	129303	3,900		0.9%						100%
Inyan Kara Formation	129304	3,911								100%
Inyan Kara Formation	129305	3,915		17.8%						100%
Inyan Kara Formation	129306	3,917		22.9%			2.6%			100%
Inyan Kara Formation	129307	3,918		7.2%			1.0%	0.6%		100%
Inyan Kara Formation	129308	3,920								100%
Inyan Kara Formation	129309	3,925					1.2%	1.1%	4.9%	100%
Inyan Kara Formation	129310	3,935		3.0%						100%
Inyan Kara Formation	129311	3,946	0.7%			2.0%	0.8%			100%
Inyan Kara Formation	129312	3,950								100%
Inyan Kara Formation	129313	3,956								100%
Inyan Kara Formation	129314	3,960			0.8%					100%
Inyan Kara Formation	129315	3,969		15.3%	1.3%	1.5%				100%
Inyan Kara Formation	129316	3,975								100%
Inyan Kara Formation	129318	3,980		3.2%	5.0%		1.0%		3.2%	100%
Inyan Kara Formation	129319	3,989			4.0%		1.6%			100%
Inyan Kara Formation	129320	3,995								100%
Inyan Kara Formation	129321	3,999			1.3%		1.1%			100%
Inyan Kara Formation	129322	4,003			1.4%		1.4%		4.1%	100%
Inyan Kara Formation	129323	4,007			1.8%		1.2%	0.9%	3.1%	100%
Inyan Kara Formation	129324	4,011			0.4%			0.4%		100%
Inyan Kara Formation	129325	4,017				1.8%				100%
Inyan Kara Formation	129326	4,020								100%
Inyan Kara Formation	129327	4,021								100%
Inyan Kara Formation	129328	4,029			0.3%					100%
Inyan Kara Formation	129329	4,032			0.6%					100%
Inyan Kara Formation	129330	4,038			0.9%					100%
Inyan Kara Formation	129331	4,041				0.6%				100%
Inyan Kara Formation	129332	4,047								100%
Inyan Kara Formation	129333	4,050			0.6%	3.7%				100%

Notes:

%: percent

Table E-5: Saturation Evaluation Results for Injection Formation, Cooling Tower Blowdown, and Scrubber Pond Waters

Sample Type		Geomean Formation Water (As Sampled)		Formation Water (Simulated with added CO_2)	Blowdown Winter Minimum Case	Blowdown Summer Peak Full Softening Case	Cell 3 Min TDS	Cell 3 Max TDS	Cell 4
Pressure (pounds per square inch)		14.7	1,670	1,670	14.7	14.7	14.7	14.7	14.7
Temperature (degrees Celcius)		50	50	50	5	5	5	5	5
MINERAL PHASES - Saturation Indices									
Anhydrite	$CaSO_4$	-1.6	-1.7	-1.7	-0.8	-1.1	-1.0	-0.6	-0.6
Gypsum	$CaSO_4{:}2H_2O$	-1.5	-1.6	-1.6	**-0.2**	**-0.5**	**-0.4**	**-0.1**	**0.0**
Barite	$BaSO_4$	**1.5**	**1.4**	**1.4**	**1.3**	**1.4**	**1.4**	**1.4**	**1.4**
Calcite	$CaCO_3$	**1.0**	**0.9**	**0.0**	**1.1**	**0.4**	-1.3	-2.0	**0.2**
Magnesite	$MgCO_3$	**-0.4**	**-0.5**	-1.4	**0.8**	**0.3**	**-0.2**	-0.9	**0.3**
Halite	NaCl	-4.8	-4.8	-4.8	-5.9	-5.3	-4.3	-3.5	-5.4

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.0	-1.0	-1.1	-1.1	-1.2	-1.3	-1.3	-1.5	-1.6	-1.8	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.2**	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**
Calcite	$CaCO_3$	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**	**0.9**	**0.9**	**0.8**	**0.7**	**0.6**	**0.2**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.4**	**0.3**	**0.1**	-0.9
Halite	NaCl	-5.9	-5.6	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.15	0.15	0.14	0.14	0.13	0.12	0.11	0.10	0.085	0.061	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.5**	-0.5	-0.6	-0.6	-0.7	-0.8	-0.8	-1.0	-1.1	-1.3	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**0.7**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.7**	**1.7**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**1.5**	**1.4**	**1.3**	**0.9**
Magnesite	$MgCO_3$	**1.1**	**1.1**	**1.1**	**1.0**	**1.0**	**1.0**	**0.9**	**0.8**	**0.7**	**0.5**	-0.5
Halite	NaCl	-6.0	-5.7	-5.5	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00057	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.33	0.32	0.31	0.30	0.28	0.27	0.25	0.22	0.19	0.14	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.2	-1.3	-1.3	-1.4	-1.4	-1.5	-1.6	-1.7	-1.8	-2.0	-2.2
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.3**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**	**0.5**	**0.4**	**0.4**	**0.3**	**0.2**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.2**	**0.2**	**0.1**	**-0.1**	-0.9
Halite	NaCl	-5.4	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.8	-4.7	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00019	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.023	0.029	0.035	0.040	0.044	0.047	0.049	0.048	0.043	0.034	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-6: Mixing Model Results for Formation Water as Measured and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.7	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.0**	**0.9**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.7**	**0.6**	**0.6**	**0.6**	**0.5**	**0.3**	-0.5
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.0	-5.0	-4.9	-4.9	-4.9	-4.8	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00058	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.13	0.12	0.097	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.1	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-1.5	-1.7	-1.9	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.5**	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-1.5	-1.4	-1.2	-1.1	-1.0	-0.8	-0.7	-0.6	**-0.4**	**-0.2**	**0.2**
Magnesite	$MgCO_3$	**-0.4**	**-0.2**	**-0.1**	**0.0**	**0.1**	**0.3**	**0.4**	**0.5**	**0.5**	**0.6**	-0.9
Halite	NaCl	-4.4	-4.4	-4.4	-4.4	-4.4	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.017
Magnesite	$MgCO_3$	0	0	0	0.0076	0.033	0.057	0.078	0.094	0.10	0.100	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.7	-0.7	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.6	-0.7	-0.7	-0.8	-0.9	-1.0	-1.1	-1.3	-1.6
Barite	$BaSO_4$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**	**1.4**
Calcite	$CaCO_3$	-0.9	-0.7	-0.5	**-0.4**	**-0.3**	**-0.1**	**0.0**	**0.1**	**0.3**	**0.5**	**0.9**
Magnesite	$MgCO_3$	**0.0**	**0.2**	**0.3**	**0.5**	**0.6**	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	-0.5
Halite	NaCl	-4.4	-4.5	-4.5	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7	-4.7	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00031	0.00036	0.00042	0.00047	0.00053	0.00058	0.00064	0.00069	0.00075	0.00080	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.060
Magnesite	$MgCO_3$	0.0064	0.036	0.063	0.089	0.11	0.14	0.16	0.18	0.19	0.18	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Late:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.6	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.7	-0.9	-1.6
Barite	$BaSO_4$	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	**1.5**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-2.1	-2.0	-2.0	-1.9	-1.8	-1.7	-1.6	-1.5	-1.3	-1.0	**0.2**
Magnesite	$MgCO_3$	-1.0	-0.9	-0.9	-0.8	-0.7	-0.7	-0.6	**-0.4**	**-0.3**	**0.0**	-0.9
Halite	NaCl	-3.5	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.3	-4.4	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00063	0.00066	0.00068	0.00071	0.00073	0.00075	0.00078	0.00080	0.00083	0.00085	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.017
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Late:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.8	-1.0	-1.6
Barite	$BaSO_4$	**0.7**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	-1.5	-1.4	-1.3	-1.3	-1.2	-1.0	-0.9	-0.7	**-0.5**	**0.0**	**0.9**
Magnesite	$MgCO_3$	-0.6	-0.5	**-0.5**	**-0.4**	**-0.3**	**-0.2**	**-0.1**	**0.0**	**0.3**	**0.6**	-0.5
Halite	NaCl	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.2	-4.3	-4.5	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00053	0.00057	0.00060	0.00063	0.00067	0.00070	0.00073	0.00076	0.00079	0.00083	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0.018	0.083	0.14	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

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Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.5**	-0.6	-0.7	-0.8	-1.1	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.2**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	-0.9
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00020	0.00027	0.00034	0.00041	0.00047	0.00054	0.00061	0.00067	0.00074	0.00081	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0.017	0.017
Magnesite	$MgCO_3$	0.014	0.028	0.040	0.051	0.061	0.069	0.074	0.076	0.071	0.042	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-7: Mixing Model Results for Formation Water as Measured and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**	**1.2**	**0.9**
Magnesite	$MgCO_3$	**0.6**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**	-0.5
Halite	NaCl	-5.5	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00038	0.00045	0.00052	0.00058	0.00065	0.00072	0.00078	0.00085
Calcite	$CaCO_3$	0.088	0.11	0.13	0.15	0.17	0.18	0.19	0.18	0.15	0.12	0.060
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0.016	0.035	0.043	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

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Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.0	-1.0	-1.1	-1.1	-1.2	-1.3	-1.3	-1.5	-1.6	-1.8	-2.2
Gypsum	$CaSO_4{:}2H_2O$	-0.3	-0.4	-0.4	-0.5	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.6
Barite	$BaSO_4$	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8
Calcite	$CaCO_3$	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.6	0.5	0.3	-0.1
Magnesite	$MgCO_3$	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.3	0.1	-0.2	-1.2
Halite	NaCl	-5.9	-5.6	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.15	0.14	0.14	0.13	0.12	0.11	0.092	0.077	0.058	0.033	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Winter Minimum:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	**-0.5**	-0.5	-0.6	-0.6	-0.7	-0.8	-0.8	-1.0	-1.1	-1.3	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**0.7**	**0.9**	**1.0**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.7**	**1.6**	**1.5**	**1.4**	**1.3**	**1.2**	**1.1**	**0.9**	**0.7**	**0.4**	**0.0**
Magnesite	$MgCO_3$	**1.1**	**1.0**	**0.9**	**0.8**	**0.7**	**0.6**	**0.4**	**0.3**	**0.0**	**-0.3**	-1.4
Halite	NaCl	-6.0	-5.7	-5.5	-5.4	-5.3	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00057	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.33	0.31	0.29	0.27	0.24	0.21	0.18	0.14	0.10	0.054	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-1.2	-1.3	-1.3	-1.4	-1.4	-1.5	-1.6	-1.7	-1.8	-2.0	-2.2
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**0.2**	**0.1**	**-0.1**
Magnesite	$MgCO_3$	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.0**	**0.0**	**-0.1**	**-0.4**	-1.2
Halite	NaCl	-5.4	-5.2	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.8	-4.7	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00019	0.00025	0.00032	0.00039	0.00046	0.00053	0.00060	0.00067	0.00073	0.00080	0.00087
Calcite	$CaCO_3$	0.023	0.025	0.027	0.028	0.029	0.028	0.027	0.023	0.018	0.0085	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-8: Mixing Model Results for Formation Water with Added Carbon Dioxide and Cooling Tower Blowdown

Sample Type		Mixture (Blowdown Summer Peak Full Softening:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.7	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.4	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**1.0**	**0.9**	**0.8**	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.0**
Magnesite	$MgCO_3$	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**	**0.0**	**-0.1**	**-0.3**	-0.6	-1.4
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.0	-5.0	-4.9	-4.9	-4.9	-4.8	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00016	0.00023	0.00030	0.00037	0.00044	0.00051	0.00058	0.00064	0.00071	0.00078	0.00085
Calcite	$CaCO_3$	0.10	0.096	0.092	0.086	0.079	0.071	0.061	0.050	0.035	0.018	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-1.1	-1.1	-1.2	-1.2	-1.3	-1.3	-1.4	-1.5	-1.7	-1.9	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.5**	-0.5	-0.5	-0.6	-0.6	-0.7	-0.8	-0.9	-1.0	-1.2	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-1.5	-1.4	-1.2	-1.1	-1.0	-0.9	-0.8	-0.7	-0.6	**-0.4**	**-0.1**
Magnesite	$MgCO_3$	**-0.4**	**-0.2**	**-0.1**	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	-1.2
Halite	NaCl	-4.4	-4.4	-4.4	-4.4	-4.4	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Min TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-0.7	-0.7	-0.7	-0.8	-0.8	-0.9	-1.0	-1.1	-1.2	-1.4	-1.7
Gypsum	$CaSO_4{:}2H_2O$	-0.6	-0.6	-0.6	-0.7	-0.7	-0.8	-0.9	-1.0	-1.1	-1.3	-1.6
Barite	$BaSO_4$	**0.7**	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**	**1.4**
Calcite	$CaCO_3$	-0.9	-0.7	-0.6	-0.6	**-0.5**	**-0.4**	**-0.3**	**-0.3**	**-0.2**	**-0.1**	**0.0**
Magnesite	$MgCO_3$	**0.0**	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.5**	**0.5**	**0.5**	**0.4**	-1.4
Halite	NaCl	-4.4	-4.5	-4.5	-4.5	-4.5	-4.5	-4.6	-4.6	-4.7	-4.7	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Max TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	-0.7	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.6	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.7	-0.9	-1.6
Barite	$BaSO_4$	**1.3**	**1.3**	**1.4**	**1.4**	**1.5**	**1.5**	**1.6**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	-2.1	-2.0	-2.0	-1.9	-1.8	-1.7	-1.6	-1.5	-1.3	-1.0	**-0.1**
Magnesite	$MgCO_3$	-1.0	-0.9	-0.9	-0.8	-0.7	-0.7	-0.6	**-0.5**	**-0.3**	**-0.1**	-1.2
Halite	NaCl	-3.5	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.3	-4.4	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00035	0.00041	0.00046	0.00051	0.00056	0.00061	0.00067	0.00072	0.00077	0.00082	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0.00043	0.023	0.044	0.062	0.076	0.083	0.074	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 3 Max TDS:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.7
Gypsum	$CaSO_4{:}2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.8	-1.0	-1.6
Barite	$BaSO_4$	**0.7**	**0.7**	**0.8**	**0.9**	**0.9**	**1.0**	**1.1**	**1.2**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	-1.5	-1.4	-1.4	-1.3	-1.2	-1.1	-1.0	-0.9	-0.7	**-0.5**	**0.0**
Magnesite	$MgCO_3$	-0.6	-0.6	**-0.5**	**-0.4**	**-0.4**	**-0.3**	**-0.2**	**-0.1**	**0.0**	**0.2**	-1.4
Halite	NaCl	-3.6	-3.7	-3.7	-3.8	-3.9	-4.0	-4.1	-4.2	-4.3	-4.5	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00053	0.00057	0.00060	0.00063	0.00067	0.00070	0.00073	0.00076	0.00079	0.00083	0.00085
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0.010	0.049	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		5										
MINERAL PHASES - Saturation Indices [(a)]												
Anhydrite	$CaSO_4$	-0.8	-0.8	-0.9	-0.9	-1.0	-1.1	-1.2	-1.3	-1.5	-1.7	-2.2
Gypsum	$CaSO_4{:}2H_2O$	**-0.1**	**-0.2**	**-0.2**	**-0.3**	**-0.4**	**-0.5**	-0.6	-0.7	-0.8	-1.1	-1.6
Barite	$BaSO_4$	**1.3**	**1.4**	**1.5**	**1.6**	**1.6**	**1.7**	**1.7**	**1.7**	**1.8**	**1.8**	**1.8**
Calcite	$CaCO_3$	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.2**	**-0.1**
Magnesite	$MgCO_3$	**0.1**	**0.2**	**0.3**	**0.4**	**0.4**	**0.4**	**0.5**	**0.4**	**0.4**	**0.2**	-1.2
Halite	NaCl	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-4.9	-4.9	-4.8	-4.8	-4.7
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4{:}2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00020	0.00027	0.00034	0.00041	0.00047	0.00054	0.00061	0.00067	0.00074	0.00081	0.00087
Calcite	$CaCO_3$	0	0	0	0	0	0	0	0	0	0.0083	0
Magnesite	$MgCO_3$	0.014	0.025	0.034	0.043	0.049	0.054	0.057	0.055	0.047	0.020	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

Table E-9: Mixing Model Results for Formation Water with Added Carbon Dioxide and Scrubber Pond Water

Sample Type		Mixture (Cell 4:Formation Water with added CO_2)										
Sample Name		100:0	90:10	80:20	70:30	60:40	50:50	40:60	30:70	20:80	10:90	0:100
Pressure (pounds per square inch)		2,400										
Temperature (degrees Celcius)		50										
MINERAL PHASES - Saturation Indices [a]												
Anhydrite	$CaSO_4$	**-0.3**	**-0.4**	**-0.4**	**-0.5**	-0.5	-0.6	-0.7	-0.8	-1.0	-1.2	-1.7
Gypsum	$CaSO_4$:$2H_2O$	**-0.2**	**-0.3**	**-0.3**	**-0.4**	**-0.4**	-0.5	-0.6	-0.7	-0.9	-1.1	-1.6
Barite	$BaSO_4$	**0.8**	**0.9**	**1.0**	**1.1**	**1.1**	**1.2**	**1.2**	**1.3**	**1.3**	**1.3**	**1.4**
Calcite	$CaCO_3$	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.6**	**0.5**	**0.4**	**0.0**
Magnesite	$MgCO_3$	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.4**	**0.3**	**0.1**	-1.4
Halite	NaCl	-5.5	-5.4	-5.3	-5.2	-5.1	-5.1	-5.0	-5.0	-4.9	-4.9	-4.8
Mineral Volume Preciptiated - (m^3/day)												
Anhydrite	$CaSO_4$	0	0	0	0	0	0	0	0	0	0	0
Gypsum	$CaSO_4$:$2H_2O$	0	0	0	0	0	0	0	0	0	0	0
Barite	$BaSO_4$	0.00018	0.00025	0.00032	0.00038	0.00045	0.00052	0.00058	0.00065	0.00072	0.00078	0.00085
Calcite	$CaCO_3$	0.088	0.097	0.10	0.11	0.12	0.12	0.11	0.10	0.085	0.051	0
Magnesite	$MgCO_3$	0	0	0	0	0	0	0	0	0	0	0
Halite	NaCl	0	0	0	0	0	0	0	0	0	0	0

Notes:

Saturation indices greater than -0.5 identified by bold type and grey shading

m^3/day = cubic meters per day assuming 950 gpm injection rate

GOLDER
MEMBER OF WSP

APPENDIX F

Well Design Summary

Table F-1: Casing and Cement Design

Variable	Units	Conductor Casing	Surface Casing	Production Casing	Injection Tubing
Casing					
Borehole diameter	in	26	17.5	12.25	--
Borehole depth	ft bgs	80	1,260	3,940	-
Casing type	-	--	API	API	Internally Lined
Casing outside diameter	in	20	13.375	9.625	7
Casing wall thickness	in	0.375	0.380	0.435	0.272
Casing inside diameter	in	19.250	12.615	8.755	6.456
Drift	in	--	12.459	8.599	6.331
Casing weight	lb/ft	78.7	54.5	43.5	20
Casing grade	-	STD WT	J-55	N-80	J-55
Casing threads	-	--	BT&C	LT&C	LT&C
Collapse pressure	psi	--	1,130	3,810	2,270
Burst pressure	psi	--	2,730	6,330	3,740
Joint strength	1000 lbs	--	909	825	257
Internal lining	-	--	-	-	Lining
Casing seat depth	ft bgs	80	1,260	3,888	3,617
Cementing Program					
Cement type	-	Portland	Haliburton VariCem (or equivalent)	Halliburton ElastiCem (or equivalent)	-
Grout Mix Ratio	lb/gal water		12-15	12-15	-
Grout Volume (neat)	ft^3	120	903	1,296	-

Abbreviations:

API: American Petroleum Institute
BT&C: Buttress Thread and Coupling
ft: feet
ft bgs: feet below ground surface
ft^3: cubic feet
gal: gallon
in: inch
lb: pound
LT&C: Long Thread & Coupling
psi: pounds per square inch
STD WT: standard weight

APPENDIX G

NDDEQ Injectate Chemical Analysis Requirements

Table G-1: List A Hazardous Waste Classification for Injectate

Chemical Name	Units	Regulatory Level
Toxicity Characteristics		
Corrosivity by pH	pH Units	pH < 2 or pH > 12.5
Reactive Cyanides	mg/L	--
Reactive Sulfides	mg/L	--
Setaflash Flashpoint	deg F	Ignitable if Flashpoint is < 140 deg F
TCLP Metals		
Arsenic	mg/L	5.0
Barium	mg/L	100.0
Cadmium	mg/L	1.0
Chromium	mg/L	5.0
Lead	mg/L	5.0
Mercury	mg/L	0.2
Selenium	mg/L	1.0
Silver	mg/L	5.0
TCLP Pesticides		
Endrin	mg/L	0.02
Chlordane	mg/L	0.03
Heptachlor	mg/L	0.008
Heptachlor Epoxide	mg/L	0.008
Methoxychlor	mg/L	10.0
Toxaphene	mg/L	0.5
Lindane	mg/L	0.4
TCLP Herbicides		
2,4-D	mg/L	10.0
2,4,5-TP	mg/L	1.0
TCLP Volatile Organic Compounds		
Benzene	mg/L	0.5
Carbon Tetrachloride	mg/L	0.5
Chlorobenzene	mg/L	100.0
Chloroform	mg/L	6.0
1,2-Dichloroethane	mg/L	0.5
1,1-Dichloroethylene	mg/L	0.7
Methyl Ethyl Ketone	mg/L	200.0
Tetrachloroethylene	mg/L	0.7
Trichloroethylene	mg/L	0.5
Vinyl Chloride	mg/L	0.2

Table G-1: List A Hazardous Waste Classification for Injectate

Chemical Name	Units	Regulatory Level
TCLP Semi Volatile Compounds		
Cresol1	mg/L	200.0
o-Cresol[1]	mg/L	200.0
m-Cresol[1]	mg/L	200.0
p-Cresol[1]	mg/L	200.0
Pentachlorophenol	mg/L	100.0
1,4-Dichlorobenzene	mg/L	7.5
2,4-Dinitrotoluene	mg/L	0.13
Hexachlorobenzene	mg/L	0.13
Nitrobenzene	mg/L	2.0
Pyridine	mg/L	5.0
2,4,5-Trichlorophenol	mg/L	400.0
2,4,6-Trichlorophenol	mg/L	2.0

Table G-2: List B General Waste Characterization for Injectate

Chemical Name	Units
Alkalinity, Total	mg/L
Aluminum	ug/L
Ammonia (as N)	mg/L
Antimony	ug/L
Arsenic (dissolved)	ug/L
Barium (dissolved)	ug/L
Bicarbonate, Alkalinity	mg/L
Bromide	mg/L
Cadmium (dissolved)	ug/L
Calcium	mg/L
Carbonate, Alkalinity	mg/L
Chemical Oxygen Demand (COD)	mg/L
Chloride	mg/L
Copper	ug/L
Cyanide	mg/L
Fluoride	mg/L
Hardness as CaCO3	mg/L
Iron	ug/L
Lead (dissolved)	ug/L
Magnesium	mg/L
Manganese (dissolved)	ug/L
Mercury (dissolved)	ug/L
Molybdenum (dissolved)	ug/L
Nickel (dissolved)	ug/L
Nitrogen (Nitrate)	mg/L
Nitrogen (Nitrite)	mg/L
pH	pH units
Phosphorus (dissolved)	ug/L
Potassium (total)	mg/L
Selenium (dissolved)	ug/L
Semi Volatile Organic Comounds (SVOCs)	
Silver (dissolved)	ug/L
Sodium	mg/L
Specific Conductivity	umhos/cm
Specific Gravity	none
Strontium	ug/L
Sulfate	mg/L
Sulfite	mg/L
Total Chromium (dissolved)	ug/L
Total Dissolved Solids (TDS)	mg/L
Total Kjeldahl Nitrogen	mg/L
Total Organic Carbon (TOC)	mg/L
Total Suspended Solids (TSS)	mg/L
Turbidity	ntu
Viscosity, Kinematic	
Zinc (dissolved)	ug/L

Table G-3: List C Abbreviated Waste Characterization for Injectate

Chemical Name	Units
pH	s.u.
pH (field)	s.u.
Temperature (field)	°C
Specific Gravity	@ 60°/60° F
Total Organic Carbon	mg/L
Sulfate	mg/L
Chloride (Cl-)	mg/L
Total Dissolved Solids	mg/L
Total Calcium	mg/L
Total Magnesium	mg/L
Total Potassium	mg/L

APPENDIX H

Minnkota Power Cooperative Financial Assurance

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

June 1, 2021

NDDEQ
Department of Water Quality
918 East Divide Ave., 4th Floor
Bismarck, ND 58501

RE: Financial Assurance – Injection Wells #1 & #2

Enclosed you will find financial assurance documentation for injection wells for Minnkota Power Cooperative, Inc. (Minnkota).

Also, pursuant to subpart F of 40 CFR part 144, enclosed is an annual report for Minnkota, including an independent certified public accountant's report on examination of financial statements for the latest fiscal year. Also included is an independent accountant's report on applying agreed upon procedures.

If you have any questions regarding the materials submitted, please contact me at (701) 795-4266.

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Kay Schraeder

Kay Schraeder
Vice President & CFO

Enclosures

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

5301 32nd Ave S
Grand Forks, ND 58201-3312
Phone 701.795.4000
www.minnkota.com

June 1, 2021

NDDEQ
Division of Water Quality
918 East Divide Ave., 4th Floor
Bismarck, ND 58501

I am the Vice President and Chief Financial Officer of Minnkota Power Cooperative, Inc. This letter is in support of this firm's use of the financial test to demonstrate financial assurance, as specified in subpart F of 40 CFR part 144.

1. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is demonstrated through the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by the test is shown for each injection well:

Injection Well #1	$232,000
Injection Well #2	232,000
Total	$464,000

2. This firm guarantees, through the corporate guarantee specified in subpart F of 40 CFR part 144, the plugging and abandonment of the following injection wells owned or operated by subsidaries of this firm. The current cost estimate for plugging and abandonment so guaranteed is shown for each injection well: None.

3. In States where EPA is not administering the financial requirements of subpart F of 40 CFR part 144, this firm, as owner or operator or guarantor, is demonstrating financial assurance for the plugging and abandonment of the following injection wells through the use of a test equivalent or substantially equivalent to the financial test specified in subpart F of 40 CFR part 144. The current plugging and abandonment cost estimate covered by such a test is shown for each injection well: None.

4. This firm is the owner or operator of the following injection wells for which financial assurance for plugging and abandonment is not demonstrated either to EPA or a State through the financial test or any other financial assurance mechanism specified in subpart F of 40 CFR part 144 or equivalent or substantially equivalent State mechanisms. The current plugging and abandonment cost estimate not covered by such financial assurance is shown for each injection well: None.

Minnkota Power Cooperative, Inc. is not required to file a form 10K with the securities and exchange commission for the latest fiscal year.

The fiscal year of this firm ends on December 31. Attachment A provides the relevant information concerning the financial statements of this firm for the latest completed fiscal year, ended December 31, 2020.

I hereby certify that the wording of this letter is identical to the wording specified in 40 CFR 144.70(f) as such regulations were constituted on the date shown immediately below.

Effective date: June 1, 2021

Sincerely,

MINNKOTA POWER COOPERATIVE, INC.

Kay Schraeder

Kay Schraeder
Vice President & CFO

Attachment

Attachment A
2020 Financial Assurance
Class 1 Injection Wells (#1 & #2)

1.	Current plugging and abandonment cost	$ 464,000	
2.	Current Credit Rating – Moody's	Baa2	
3.	Date of issuance of bond	N/A	
4.	Date of maturity of bond	N/A	
5.	Tangible net worth	$ 167,592,067	
6.	Total assets in United States	$ 1,139,298,514	
		YES	NO
7.	Is line 5 at least $10 million?	X	
8.	Is line 5 at least 6 times line 1?	X	
9.	Are at least 90% of firm's assets located in the United States?	X	
10.	Is line 6 at least 6 times line 1?	X	

BradyMartz

INDEPENDENT ACCOUNTANT'S REPORT
ON APPLYING AGREED-UPON PROCEDURES

To the Management of Minnkota Power
Cooperative, Inc. and the North Dakota
State Department of Environmental Quality,
Division of Water Quality

We have performed the procedures enumerated below, which were agreed to by the Management of Minnkota Power Cooperative, Inc., (the Company), to selected accounting records of Minnkota Power Cooperative, Inc. solely to assist you in connection with the letter from the Vice President and Chief Financial Officer of Minnkota Power Cooperative, Inc. dated June 1, 2021, to the North Dakota State Department of Environmental Quality, Division of Water Quality. This letter is regarding the guarantee by Minnkota Power Cooperative, Inc. for the plugging and abandonment of injection wells. The management of Minnkota Power Cooperative, Inc. is responsible for the accounting records and the letter. The sufficiency of these procedures is solely the responsibility of the parties specified in the report. Consequently, we make no representations regarding the sufficiency of the procedures described below either for the purpose for which this report has been requested or for any other purpose.

The statements, procedures, and associated findings are set forth below:

1. We compared the data referred to in Alternative 2 in the June 1, 2021 letter from the Company's Vice President and Chief Financial Officer to the North Dakota State Department of Environmental Quality, Division of Water Quality, to the Company's December 31, 2020 financial statements audited by Brady, Martz & Associates, P.C.

   No exceptions were noted as a result of these comparisons.

This engagement to apply agreed-upon procedures was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants. We were not engaged to, and did not, conduct an examination or review of the data, the objective of which would be the expression of an opinion on the accounting records. Accordingly, we do not express such an opinion. Had we performed additional procedures; other matters might have come to our attention that would have been reported to you.

This report is intended solely for the use of the specified users listed above and should not be used by those who have not agreed to the procedures and taken responsibility for the sufficiency of the procedures for their purposes.

Brady Martz

BRADY, MARTZ & ASSOCIATES, P.C.
GRAND FORKS, NORTH DAKOTA

June 1, 2021

MINNKOTA POWER COOPERATIVE, INC.

We power on.

2020 ANNUAL REPORT

We power on.

Living rooms turned into home offices.

Students occupied small squares on a computer screen as they learned online.

Hospitals and essential businesses showed perseverance and innovation to meet community needs.

Electric cooperatives powered on.

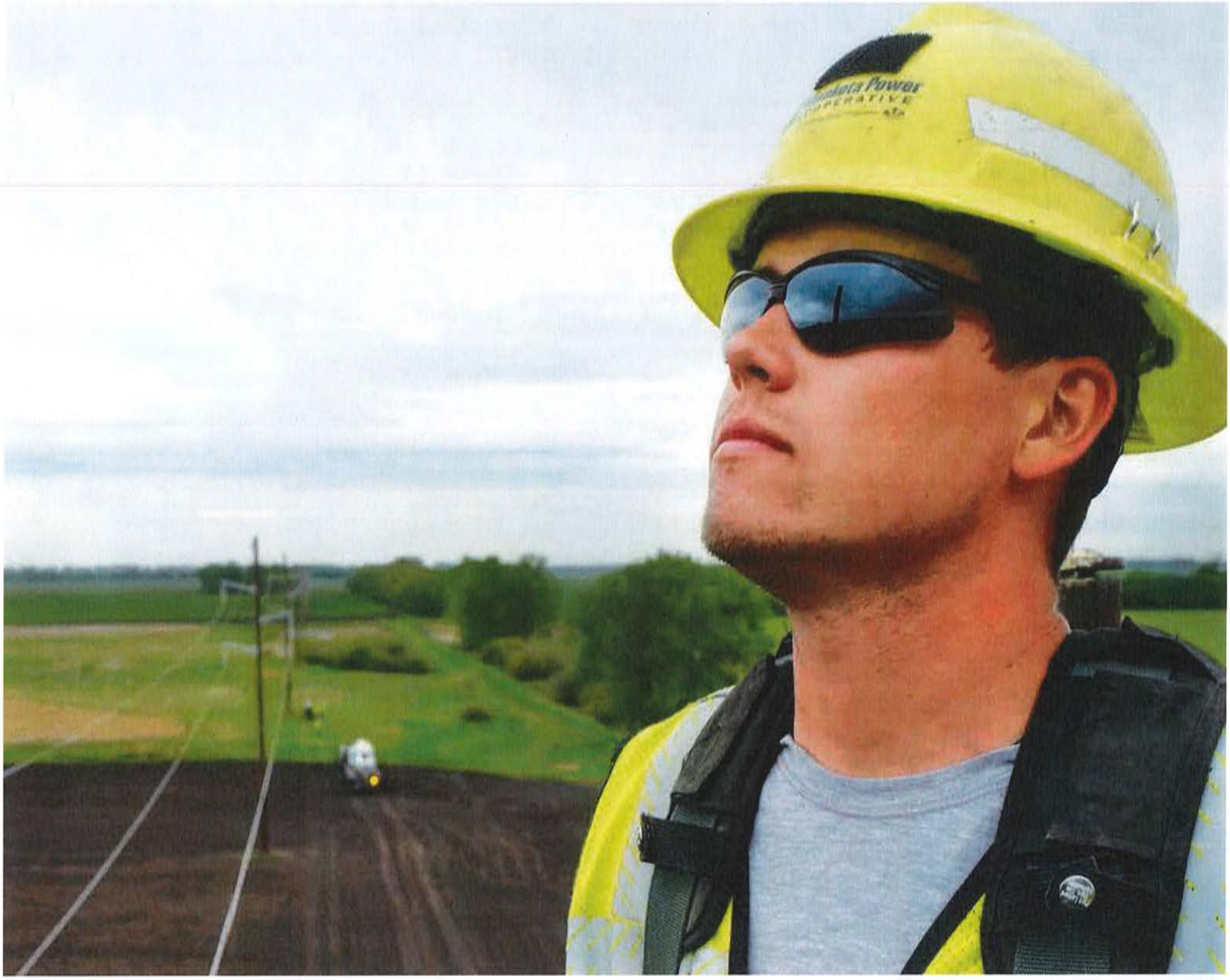
When faced with a global pandemic, reliable electricity is more important than ever. Minnkota took unprecedented actions in 2020 to protect the health of its employees, while continuing to keep power flowing into communities 24 hours a day.

It goes without saying that 2020 was a year like no other. Although there were challenges and turmoil, there were also moments of generosity, compassion and connection. While none of us know what the next chapter of the COVID-19 pandemic will bring, there is optimism for the future. Minnkota and its members will be there every step of the way.

We'll power on to help you power on.

On the cover: Adam Streitz, apprentice electrician, was one of 400 Minnkota employees who helped the cooperative power on despite the challenges and obstacles presented by the COVID-19 pandemic.

Right: From his bucket truck, Minnkota lineworker Shawn Reimers helps string wire on a completely rebuilt section of 69-kilovolt transmission line near Cavalier, N.D.



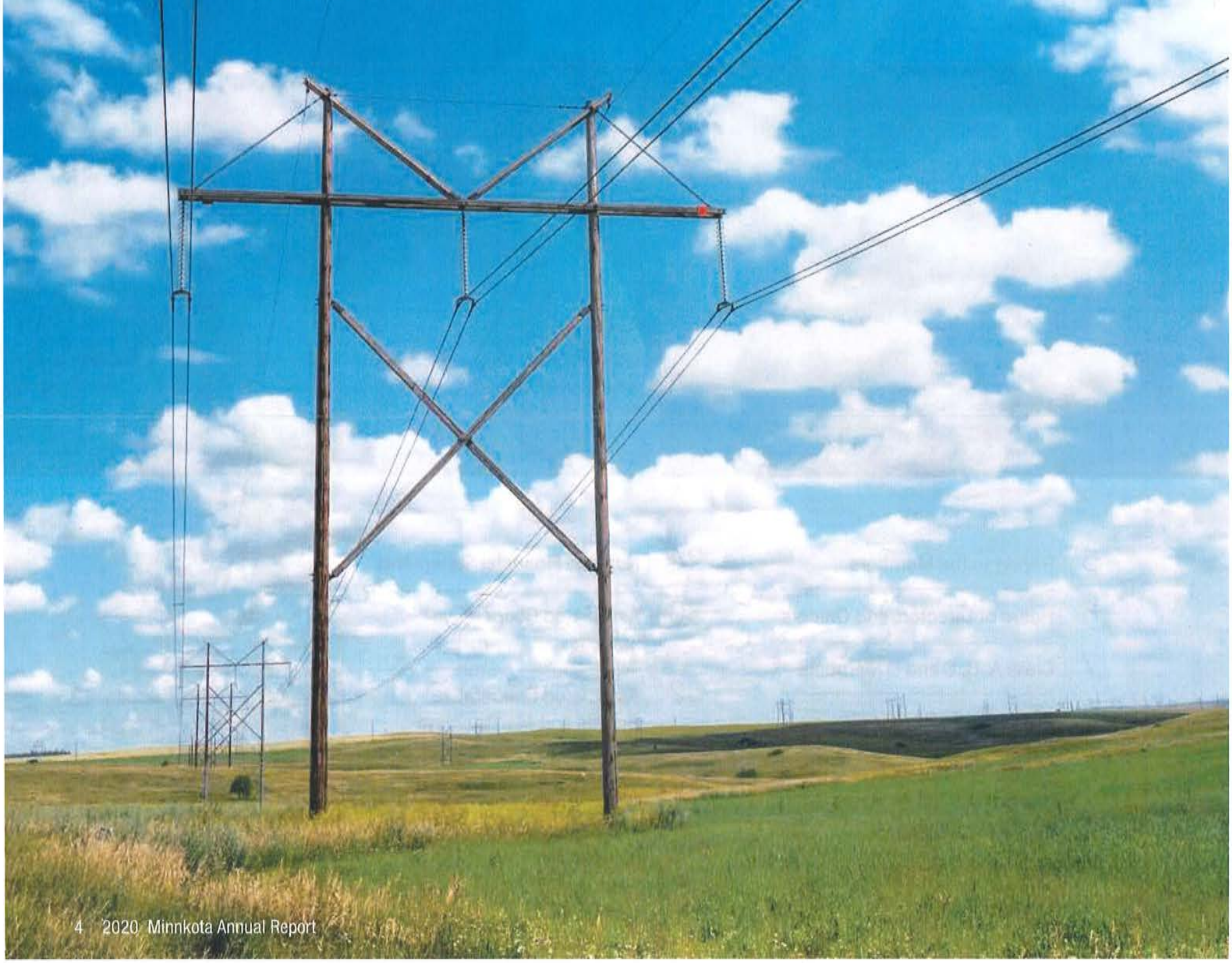
Cooperative Profile

Minnkota Power Cooperative is a generation and transmission (G&T) cooperative headquartered in Grand Forks, N.D. Through 11 member-owner distribution cooperatives, three in eastern North Dakota and eight in northwestern Minnesota, Minnkota provides valuable electric energy to more than 143,000 residential, commercial and industrial consumers.

Minnkota is committed to delivering safe, reliable, affordable and environmentally responsible electricity. The cooperative's electric generation portfolio includes a diverse mix of coal, wind and hydro resources. The Milton R. Young Station, located 35 miles northwest of Bismarck, N.D., provides baseload power to the membership. Energy purchased from three North Dakota wind farms and hydroelectricity purchased from the Garrison Dam in central North Dakota also help support the members' needs.

Minnkota serves as operating agent for the Northern Municipal Power Agency (NMPA), headquartered in Thief River Falls, Minn. NMPA is an association of 12 municipal utilities located in the same 35,000-square-mile service area as the Minnkota member cooperatives. NMPA owns a 30% share of the Coyote

Station, a lignite-based power plant located near Beulah, N.D. Together, the Minnkota/NMPA Joint System serves approximately 158,000 member-consumer accounts.



Les Windjue
Board Chair

Mac McLennan
President & CEO

Report to the Members

Despite challenges and obstacles throughout the year, Minnkota's employees continually found creative solutions to problems and proved to be innovative in collaborating and keeping projects moving forward.

The world changed in 2020.

In most years, that would seem like an overstatement, but there are very few periods over the course of modern history that have tested our resiliency and reshaped our communities, culture and politics quite like 2020. Undoubtedly, the start of this decade has been defined by the COVID-19 pandemic. Many families, businesses and schools faced incredible struggle in the wake of stay-at-home orders and general COVID-19 uncertainty. During this difficult time, Minnkota remained committed to keeping the power flowing safely and reliably into local communities. Significant mitigation strategies were implemented to limit potential exposure to the virus among the workforce, including face mask requirements, workplace modifications to accommodate social distancing and enhanced sanitization practices. With the rollout of vaccines at year-end, our hope is for a swift return to normalcy in 2021.

Despite challenges and obstacles throughout the year, Minnkota's employees continually found creative solutions to problems and proved to be innovative in collaborating and keeping projects moving forward. Most importantly, the work was completed safely as overall on-the-job injuries and OSHA-recordable injuries remained low during the year.

In the field, power delivery crews didn't let the pandemic stall progress on the many projects that are important to the membership. Efforts to address aging infrastructure and improve service continued in 2020, as substations and transmission lines were rebuilt, equipment was upgraded and enhanced communication technologies were implemented. This work continues to limit outages and helps crews be more responsive to system issues.

At the Milton R. Young Station, employees kept the units running reliably and efficiently. Strategies were incorporated to be more flexible in responding to wholesale energy market conditions and limiting costs related to maintenance outages. The highlight of the year at the coal-based facility was celebrating Unit 1's 50th year of operation. Commitment from past and present employees has helped the Young Station reach one of its better years of operation in 2020 with each generating unit being available more than 93% of the time.

While there are many positives to take from this year, COVID-19 had financial impacts on Minnkota and its members. The pandemic and mild weather throughout 2020 contributed to less electricity usage and a historically depressed wholesale energy market. Previous years of financial stability and expense-reduction measures helped the cooperative manage through 2020, but we recognize the economic downturn may be our new normal for years to come.

The pandemic has not slowed progress on the research and engineering of a potential carbon capture facility at the Young Station. Minnkota is leading the effort, known as Project Tundra, to significantly reduce CO_2 emissions from the coal-based power plant. State and federal grant funding was utilized in 2020 to support a Front-End Engineering and Design (FEED) study, research of the underground storage facility and the refinement of project economics. We anticipate that our research and evaluation process will be completed in 2021 and a decision will be made on whether to move forward with the project late next year.

In a year full of change, Minnkota experienced a significant leadership transition on the board of directors. Longtime board members Collin Jensen, Jeff Folland, Leroy Riewer and Sid Berg retired in 2020 after many years of service and commitment to the membership. This group exemplified honesty, integrity and sound judgment in our cooperative family. We look forward to working with new directors Marcy Svenningsen, Mark Habedank, Greg Spaulding and Mike Wahl, each of whom brings a wealth of knowledge and experience.

As Minnkota celebrated its 80th anniversary in 2020, it is a good time to reflect on our past. We have faced many challenges since 1940. Storms have destroyed our power delivery system. Floods have inundated our facilities. Unexpected plant outages have required countless hours of labor. Each time, we have become stronger as a cooperative. The common thread is that people pulled together and did the best they could – for their co-workers, their communities and the membership. The same is true today as we face the COVID-19 pandemic and related impacts. We want to thank our employees at the power plant, in the control centers, in the field and at home who helped to safely and effectively energize our region in 2020. Our power will always be our people.

Les Windjue

Mac McLennan

Board of Directors and Officers

Les Windjue
Chair
Nodak
Electric Cooperative

Steve Arnesen
Vice Chair
North Star
Electric Cooperative

Colette Kujava
Secretary/Treasurer
Red Lake
Electric Cooperative

Rick Coe
Beltrami
Electric Cooperative

Mark Habedank
Wild Rice
Electric Cooperative

Roger Krostue
Red River Valley
Cooperative Power
Association

Donald Skjervheim
Cavalier Rural
Electric Cooperative

Greg Spaulding
Clearwater-Polk
Electric Cooperative

Marcy Svenningsen
Cass County
Electric Cooperative

Mike Wahl
Roseau
Electric Cooperative

Tom Woinarowicz
PKM
Electric Cooperative

Lucas Spaeth
Northern Municipal
Power Agency

Mac McLennan
President & CEO

Gerad Paul
General Counsel
and Assistant Secretary

Class A Members

1. **Beltrami Electric Cooperative, Inc.**
   Bemidji, Minnesota
2. **Cass County Electric Cooperative, Inc.**
   Fargo, North Dakota
3. **Cavalier Rural Electric Cooperative, Inc.**
   Langdon, North Dakota
4. **Clearwater-Polk Electric Cooperative, Inc.**
   Bagley, Minnesota
5. **Nodak Electric Cooperative, Inc.**
   Grand Forks, North Dakota
6. **North Star Electric Cooperative, Inc.**
   Baudette, Minnesota
7. **PKM Electric Cooperative, Inc.**
   Warren, Minnesota
8. **Red Lake Electric Cooperative, Inc.**
   Red Lake Falls, Minnesota
9. **Red River Valley Cooperative Power Association**
   Halstad, Minnesota
10. **Roseau Electric Cooperative, Inc.**
    Roseau, Minnesota
11. **Wild Rice Electric Cooperative, Inc.**
    Mahnomen, Minnesota

Class B, C and D Members

Basin Electric Power Cooperative
Bismarck, North Dakota

Central Iowa Power Cooperative
Cedar Rapids, Iowa

Dairyland Power Cooperative
LaCrosse, Wisconsin

Interstate Power Company
Dubuque, Iowa

Lincoln Electric System
Lincoln, Nebraska

Manitoba Hydro
Winnipeg, Manitoba, Canada

MidAmerican Energy
Davenport, Iowa

Midcontinent Independent Transmission System Operator (MISO)
Carmel, Indiana

Minnesota Power
Duluth, Minnesota

Montana-Dakota Utilities Company
Bismarck, North Dakota

Nebraska Public Power District
Columbus, Nebraska

Northern Municipal Power Agency
Thief River Falls, Minnesota

NorthWestern Corporation
Sioux Falls, South Dakota

Omaha Public Power District
Omaha, Nebraska

Otter Tail Power Company
Fergus Falls, Minnesota

U.S. Department of the Air Force
Grand Forks Air Force Base, North Dakota

Western Area Power Administration
Billings, Montana

Wisconsin Power and Light
Madison, Wisconsin

Xcel Energy
Minneapolis, Minnesota

All-of-the-above energy strategy

Minnkota is proud to use North Dakota's home-grown resources to generate reliable, cost-effective and environmentally responsible electricity for its members. Maintaining an all-of-the-above strategy is a critical part of Minnkota's power supply, which currently consists of lignite coal, wind and hydro.

Resilient generators

The Milton R. Young Station is a key resource in Minnkota's portfolio. Performance milestones in 2020 show the coal-based facility, which came online in the 1970s, is well-positioned to have continued success in the years ahead. Safety and environmental compliance remain the primary focuses in plant operations. The Young Station staff had no lost-time injuries in 2020 and only one OSHA-recordable injury during the year. The facility met 100% compliance with air, water and land quality requirements.

From an operations standpoint, Unit 1 was available 93.9% of the time in 2020, while Unit 2 was available 93% of the time. This level of availability well exceeds industry standards.

Strategies have been implemented in recent years that have helped the plant lower maintenance outage costs and become more flexible in responding to wholesale market conditions. Work also continues with BNI Coal, the plant's fuel provider, on initiatives to improve efficiencies and realize cost savings.

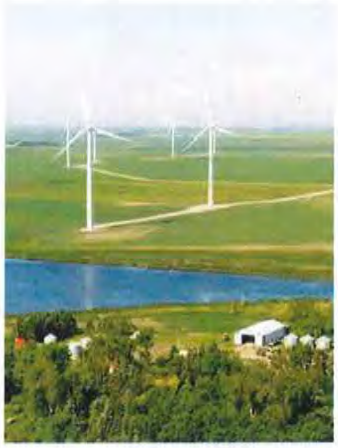
Integrated Resource Plan

In February 2020, the Minnesota Public Utilities Commission (PUC) accepted Minnkota's Integrated Resource Plan (IRP), which establishes the cooperative's plans to meet the electricity needs of the membership over the next 15 years. The plan highlights how Minnkota will maintain or improve electric service to consumers, maintain competitive electric rates and minimize environmental impacts and the risk of adverse effects from financial, social and technological impacts.

Carbon-managed future

Minnkota believes the utility industry will be faced with the need to manage carbon dioxide (CO_2) emissions through regulation, carbon pricing, cap and trade, or another mechanism. The new presidential administration has indicated that climate change and reducing CO_2 emissions will be a primary focus from all departments and agencies. Minnkota will continue to advocate for achievable outcomes and, more importantly, investments in innovation that can lower the cost of transformational CO_2 reduction technologies.

Plant Availability



The Langdon Wind Energy Center in North Dakota provides renewable energy for Minnkota's membership.

Joint System Energy Requirements

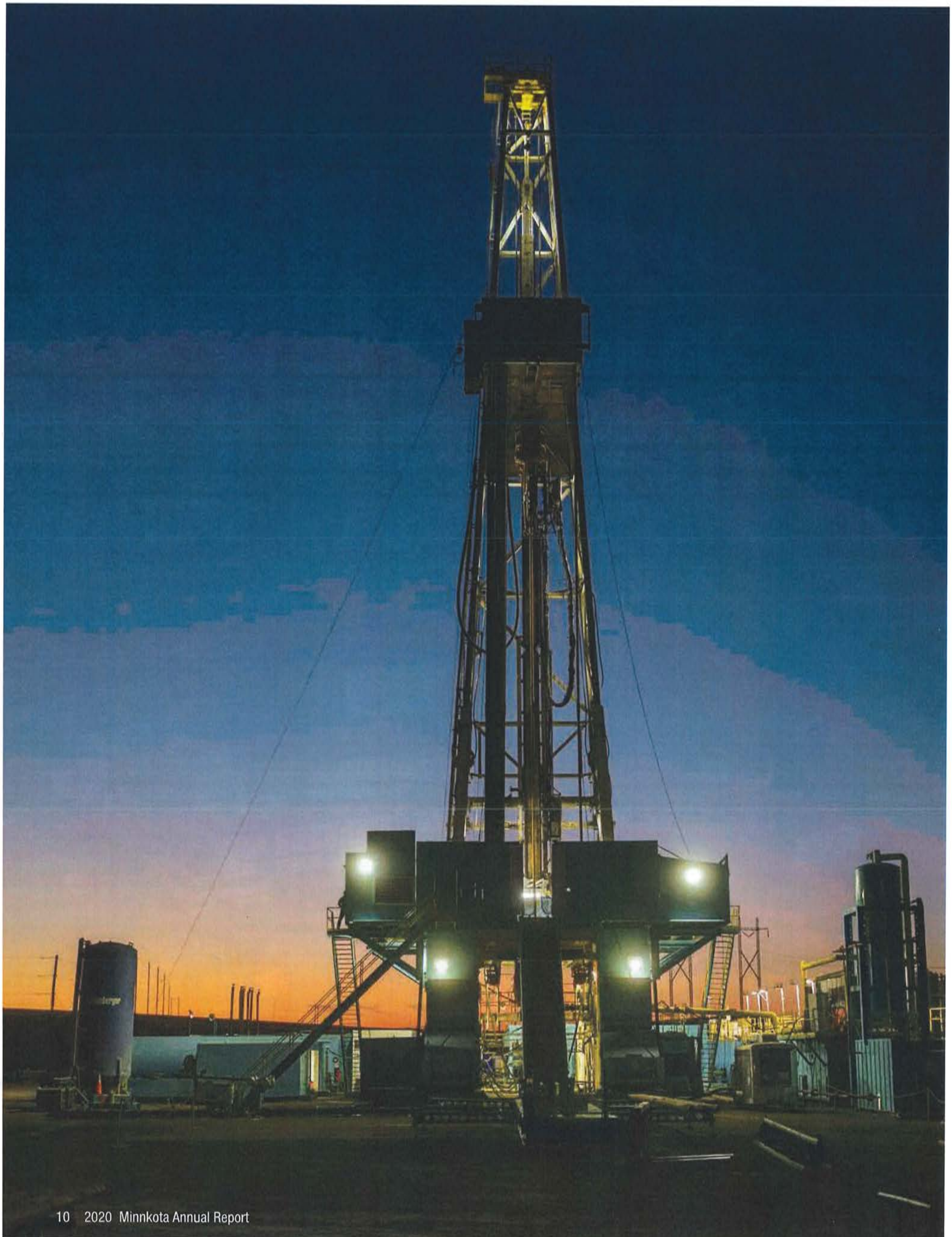
Where it came from	Thousands of MWh	Percent
Young 1	1,734	23.9
Young 2	2,289	31.6
Coyote	713	9.8
WAPA – Firm	535	7.4
Wind – Ashtabula	816	11.2
Wind – Langdon	621	8.6
Wind – Oliver III	456	6.3
Wind – Infinity	4	0.1
MISO	76	1.0
Other	10	0.1
TOTALS	7,254	100.0

Where it went	Thousands of MWh	Percent
Member cooperatives	3,963	54.6
Municipal participants	441	6.1
Off-system sales	2,726	37.6
Other	68	0.9
Losses	56	0.8
TOTALS	7,254	100.0

Generating Plant Performance

	Young 1	Young 2	Coyote
Gross generation – kWh	1,945,599,000	3,229,431,000	2,539,013,000
Net generation – kWh	1,734,357,000	2,933,166,000	2,380,114,000
Station service – kWh	211,240,000	296,265,000	158,899,000
Hours online	8,204	8,104	8,024
Hours offline	580	680	760
Availability – percent	93.9	93.0	91.4
Average net generation – kW	211,000	362,000	297,000

The coal-based Milton R. Young Station near Center, N.D., is a reliable and resilient resource in Minnkota's all-of-the-above energy strategy.



Project Tundra

While about 42% of Minnkota's generation capacity is currently carbon-free, the cooperative is evaluating a project that could significantly increase its percentage of carbon-free power by the end of the decade without sacrificing reliability. Minnkota is in the process of thoroughly evaluating Project Tundra – an effort to build a carbon capture facility at the coal-based Young Station located 35 miles from Bismarck. State-of-the-art technologies are currently being explored to remove an amount of CO_2 equivalent to permanently taking 800,000 gasoline-fueled vehicles off the road. The CO_2 would then be safely and permanently stored more than a mile underground in deep, geologic formations.

Through state and federal grant funding, Minnkota and its partners made progress on a Front-End Engineering and Design (FEED) study that will provide vital technical and economic information. Research is also being conducted on the underground storage facility with leadership from the Energy and Environmental Research Center (EERC) at the University of North Dakota. Test wells have been drilled down 10,000 feet to meticulously review the geology to ensure the injection of CO_2 will be safe. Additional seismic and geophysical surveys have also been conducted.

Project Tundra is estimated to require a more than $1.1 billion capital investment, which would primarily be funded through federal 45Q tax credits. These incentives work similarly to the tax credits that have been used by wind and solar projects for many years. Research, permitting and financing efforts will all continue in 2021 in anticipation of making a decision on whether to continue forward with the project near the end of the coming year.

Minnkota and its members firmly believe that carbon capture technology must be rapidly advanced and deployed if the world is to meet ambitious climate goals. If Project Tundra moves forward, it can help bring this breakthrough technology another step toward widespread adoption.

(Left) Two test wells were drilled approximately 10,000 feet near the Milton R. Young Station to thoroughly study the area's geology and ensure it is safe to store carbon dioxide as part of Project Tundra. (Above) This rendering shows what a carbon capture facility could look like at the Young Station.

A boom truck lifts a Minnkota lineworker up to install blink outage mitigation equipment on a 69-kV transmission structure near Larimore, N.D. This program has helped significantly reduce momentary outages across the system.

Resilient and secure system

Minnkota's power delivery system became smarter, stronger and more resilient in 2020. Even with challenges and delays related to COVID-19, nearly all of the scheduled capital project work was completed during the year. Aging infrastructure and system reliability were the primary focus, as vast stretches of the power delivery system were modified, upgraded or completely rebuilt.

With 3,370 miles of transmission line and 255 substations, prioritizing project work and improvements requires a data-driven and programmatic approach. As Minnkota works methodically to address its legacy infrastructure, positive results are beginning to emerge. Over the last five years, power delivery metrics – including sustained outages, blink outages and total outage time – are all steadily improving thanks to a wide array of programs and routine maintenance.

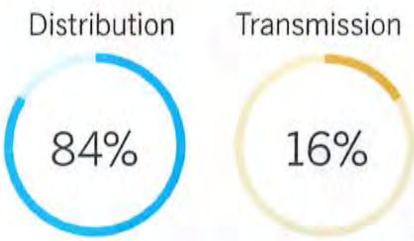
In addition to project work in the field, Minnkota continues to improve its security posture to respond to ever-evolving industry change and potential threats. Security audits, employee training and other efforts are ongoing across the entire organization. From a technology standpoint, staff completed a major upgrade of the Energy Management System (EMS), which is the computer system that allows power system operators to monitor and operate the electric grid from the control center. Staff also completed a redesign of the Information Technology (IT) network to employ a "defense-in-depth" strategy that segregates IT assets and provides additional layers of security.

Minnkota continues to be compliant with North American Electric Reliability Corporation (NERC) standards. In 2020, NERC began enforcement of its Critical Infrastructure Protection supply chain standard. Processes, procedures and review guidelines are now in place to help ensure the cooperative and its equipment vendors are not utilizing equipment that would allow malicious entities cyber access into the bulk electric system.

Power delivery projects

- **Blink outage mitigation:** Minnkota is nearing the end of its accelerated plan to address blink outages. Technologies have been added to about 1,244 miles of existing 69-kV transmission line in recent years, including 216 miles in 2020. This program has shown a blink outage reduction rate of 55-60% over non-mitigated circuits.
- **Northeast North Dakota line rebuild and service improvement:** Minnkota crews rebuilt about 22 miles of 69-kV line in northeastern North Dakota between the Lincoln, Glasston and Hensel substations. The new line includes an enhanced, modern design for greater reliability. Nearby, the cooperative constructed 22 miles of 115-kilovolt transmission line and made major upgrades to the Edinburg substation and Concrete substations to improve service.
- **Substation construction:** Minnkota crews completely rebuilt the Oklee (Minn.) substation, which had aged beyond its useful life. The new substation includes a modern design and new communication technologies. Progress was also made on the Rindal (Minn.) substation rebuild project and the new Berg substation near Grand Forks, both of which will be completed in 2021.
- **Distribution automation:** Minnkota completed 17 distribution automation projects in 2020. This program includes adding new communication technology at existing substation sites, which allows Minnkota personnel to collect, automate, analyze and optimize data. Better system visibility can assist in responding to outages and other issues. Minnkota plans to have all distribution substations equipped with the technology before the end of the decade.
- **Demand response equipment replacement:** To improve the long-term viability and reliability of Minnkota's demand response program, Minnkota replaced the ripple injectors and associated equipment at the West Fargo (N.D.) and Wilton (Minn.) substations in 2020. The equipment, which was originally installed in the 1970s and early 1980s, has reached the end of its useful life. Ten of the 17 injectors have been replaced in recent years, and the current plan is to have all sites completed by the end of 2024.

255 Substations

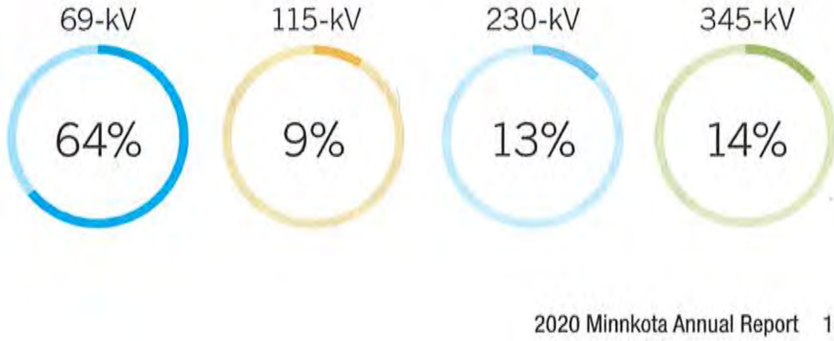


Jason Bjerke, senior technical maintenance technician, adjusts ripple injection equipment at the Wilton substation near Bemidji, Minn. The equipment is critical to Minnkota's demand response system.

From ground level to the top of a transmission structure, Minnkota crews string wire on a rebuilt section of 69-kV line near Cavalier, N.D.

Jimmy Snider, electrician, completes work on the rebuilt Oklee substation in northwest Minnesota. Minnkota budgets to rebuild two of its aging distribution substations annually.

3,370 Miles of Transmission Line



Members of Altru Health System's inpatient care team in Grand Forks enjoyed a Red Pepper sandwich during an appreciation lunch sponsored by Minnkota and member Nodak Electric Cooperative.

We power on

Minnkota has faced many challenges over its 80-year history, but none quite like the COVID-19 pandemic. The cooperative's employees have learned to work and communicate in new ways to ensure they continue to deliver reliable electricity to the members. While many hardships have been experienced over the last year, Minnkota is committed to helping lead the comeback. In addition to reliable electricity, Minnkota and its members can help generate enthusiasm, drive economic development and support a brighter vision for the future.

Commitment to community

Minnkota is grateful for the generosity and inventiveness of its employees, members and consumers in 2020. Minnkota provided financial support to organizations in need, while the cooperative's Employee Jeans Day Fund held special fundraising drives throughout the year to provide additional support to COVID-19 relief funds, food pantries and other critical support organizations. Additional efforts were made to show appreciation for local healthcare workers, the police department and others who bravely served our community throughout the pandemic.

Supporting beneficial electrification

Minnkota and its members continue to support beneficial electrification efforts through rebate programs, education and outreach. In 2020, Minnkota supported members Cass County Electric Cooperative and Nodak Electric Cooperative in installing new Level 3 electric vehicle charging stations in Fargo (3) and Grand Forks (1).

Unmanned Aerial System (UAS) leadership

North Dakota is ranked the #1 most drone-ready state. The cooperative's service area is home to Grand Sky – the United States' first commercial UAS business and aviation park. It is also the first site to receive regulatory approval to host commercial beyond visual line of sight (BVLOS) flights. Minnkota continues to build partnerships with startup UAS companies and supports energy-related research and development.

Business expansion

Reliable electricity is essential to any business. Minnkota works closely with its member cooperatives and associated municipals to ensure local economies can continue to grow and thrive. The following building and expansion efforts are currently being pursued within the Joint System.

- Amazon is constructing a 1.3 million-square-foot distribution center in Fargo. When completed in 2021, it is anticipated to be the largest building in the state of North Dakota.
- Aldevron, a Fargo-based biotechnology company, has begun a major expansion of its campus that will increase its production capacity tenfold, quintuple its warehouse space and create a research and development center.
- Digi-Key Corporation, one of the world's largest electronic components distributors, has begun a 2.2 million-square-foot expansion in Thief River Falls, Minn. The project is scheduled for completion in 2021.
- The North Dakota Mill, the largest flour mill in the United States, has expanded several times over the last decade and is planning another expansion for 2021.

In 2020, Minnkota crews completed an expansion of the existing Anderson substation in Thief River Falls, Minn., which will support the growth of Digi-Key and other areas of the community.

Nodak Electric leaders joined Grand Forks mayor Brandon Bochenski (far left) to cut the ribbon on the new electric vehicle fast charging station the cooperative installed in Grand Forks.

Three new electric vehicle fast charging stations were installed in Fargo by Cass County Electric Cooperative in 2020, including this charger near the Fargo-Moorhead Convention and Visitors Center. Cooperative and city leaders held ribbon-cutting ceremonies in September.

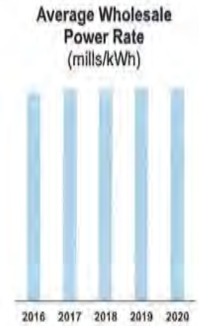
Donning a Santa cap, Minnkota's Troy Karlberg delivers several cots, sleeping bags, pillows and pillow cases to United Way's Lori Ledahl for the homeless shelter in Bismarck before the holiday season.

Minnkota's Jen Regimbal presents a Jeans Day donation check to St. Joseph's Social Care executive director Mickey Munson. The donation was used to combat food insecurity in the Greater Grand Forks area.

Treasurer's Report

Colette Kujava
Secretary/Treasurer

2016	3,813,970
2017	3,926,016
2018	4,114,194
2019	4,107,770
2020	3,962,854



2016	74.56
2017	76.00
2018	75.80
2019	76.38
2020	76.30

This report summarizes the financial results of Minnkota's operations for the year ended Dec. 31, 2020, and its financial position as of Dec. 31, 2020.

Revenues

Revenues in 2020 totaled $391.2 million, down from $402.2 million in 2019. Minnkota's largest revenue source is energy sales to the 11 Class A member-owner distribution cooperatives which were $314.5 million in 2020, or $4.8 million under budget. Class A kilowatt-hour sales were under budget by 4.2%. This prompted the recognition of $12.1 million of previously deferred revenue, as compared to the budgeted recognition of $4.7 million. Minnkota operates with a revenue deferral plan that has been approved by the Rural Utilities Service (RUS). The cooperative had a balance of $27.8 million in its revenue deferral plan at Dec. 31, 2020.

A total of 3.9 billion kWh were sold to Class A members in 2020, down 3.5% from last year. The Class A member average rate was 76.3 mills per kWh in 2020, down slightly from 76.4 mills per kWh in 2019. Energy sales revenue from Class B, C and D members totaled $63.6 million, or $14.4 million under budget. This is mainly due to significantly lower market sales prices and less kWh sold.

Other electric revenue totaled $12.2 million in 2020, which was $0.6 million under budget. The major items included in this category are administrative fees collected from Square Butte Electric Cooperative, sales of renewable energy credits related to Minnkota's purchased power wind contracts, wheeling revenue and transmission services income.

Nonoperating margins in 2020 totaled $0.8 million, or $3.5 million under budget. Nonoperating margins include interest income, capital credit allocations primarily from CoBank, coal royalties received from Square Butte and refined coal revenue.

Expenses

Total expenses were $383.5 million in 2020, down from $390.5 million in 2019. The largest expense category is power supply, which includes generation expenses of Young 1 and purchased power from Young 2, Coyote, Western Area Power Administration, wind farms and other area utilities. Power supply expenses totaled $280.7 million, or $15.1 million under budget. They were under budget primarily due to reduced generation expenses for Young 1 and less purchased power expenses from Square Butte.

Transmission and substation expenses totaled $26.1 million in 2020, or $1.3 million under budget. Administrative and general expenses were $19.3 million in 2020, or $0.8 million under budget. Fixed costs, which include interest and depreciation, totaled $57.4 million in 2020, which is $1.7 million under budget.

Net margins

Margins for 2020 were $7.7 million, down from $11.7 million in 2019. The total margin consisted of an operating margin of $6.8 million and a nonoperating margin of $0.8 million.

Patronage capital

Total patronage capital was $30.8 million at Dec. 31, 2020 and reflects the 2020 operating margin of $6.8 million. The nonoperating margin of $0.8 million will be retained as appropriated margins to be used for future contingencies. Total equity at Dec. 31, 2020, was $167.6 million, 14.7% of total assets.

Electric plant

Net electric plant was $985.8 million at Dec. 31, 2020, up $6.8 million from last year. This increase is mainly due to transmission property additions.

Long-term debt

Minnkota's long-term debt, including current maturities, was $865.6 million as of Dec. 31, 2020, up $10.5 million from last year. In 2020, Minnkota had net loan advances of $35.0 million from RUS and CoBank. Minnkota made $23.1 million in debt principal payments during the year.

This has been a brief review of the 2020 financial statements. For further information, I urge you to review the financial statements, the notes to the financial statements and the Independent Auditor's Report contained in this annual report.

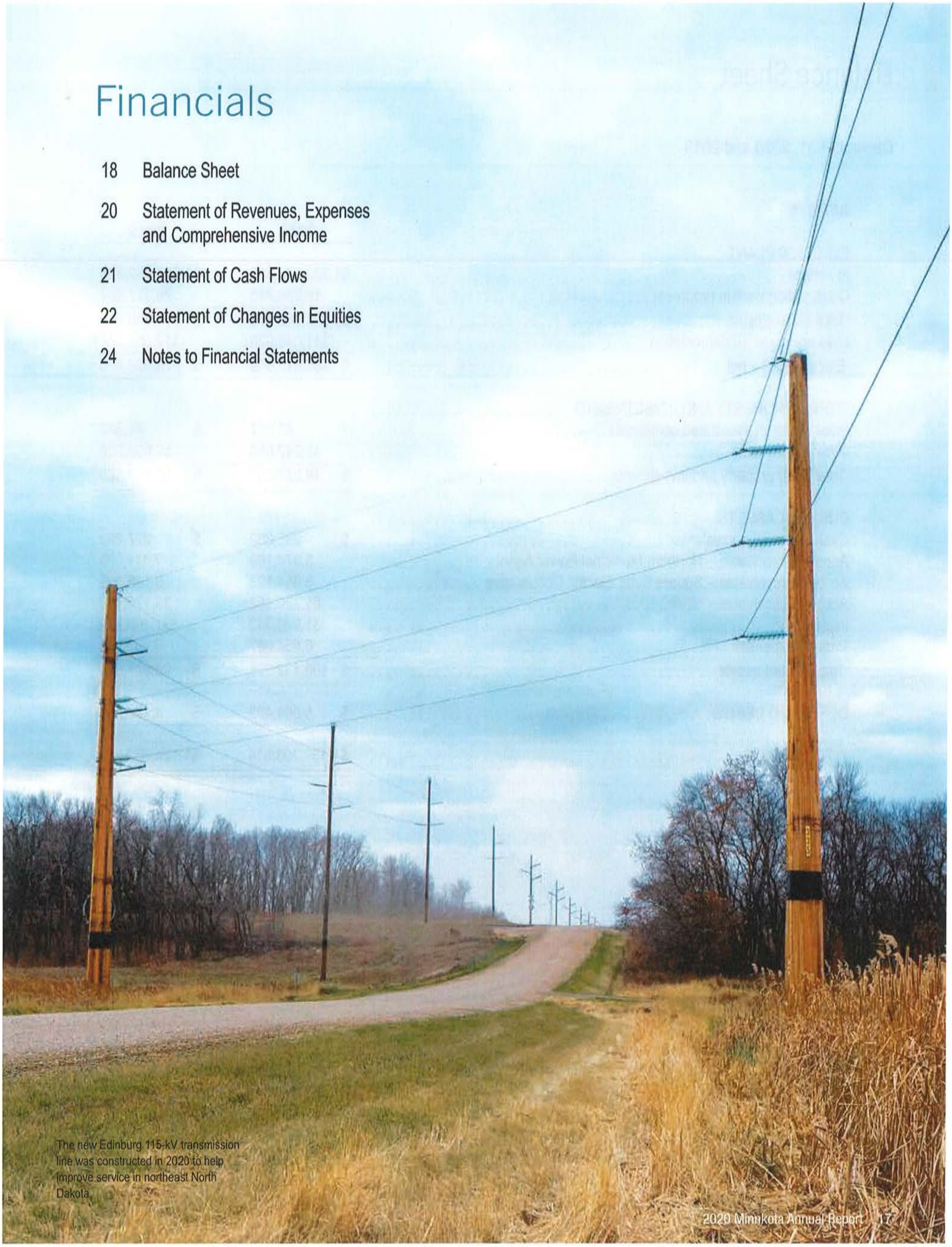
Respectfully submitted,

Colette Kujava
Secretary/Treasurer

2020 Total Revenue

2020 Total Expenses & Margins

Financials



The new Edinburg 115-kV transmission line was constructed in 2020 to help improve service in northeast North Dakota.

Balance Sheet

December 31, 2020 and 2019

ASSETS	2020	2019
ELECTRIC PLANT		
In service	$1,306,873,680	$1,264,952,825
Construction work in progress	19,986,795	26,377,884
Total electric plant	$1,326,860,475	$1,291,330,709
Less accumulated depreciation	(341,046,926)	(312,356,834)
Electric plant – net	$ 985,813,549	$ 978,973,875
OTHER PROPERTY AND INVESTMENTS		
Investments in associated companies	$ 44,917	$ 44,642
Other investments	48,242,650	52,698,923
Total other property and investments	$ 48,287,567	$ 52,743,565
CURRENT ASSETS		
Cash and cash equivalents	$ 295,352	$ 227,693
Accounts receivable – Northern Municipal Power Agency	5,374,169	7,111,095
Accounts receivable – Square Butte Electric Cooperative	3,954,193	5,148,502
Accounts receivable – other	51,729,152	38,370,148
Inventories	31,926,042	31,498,752
Prepaid expenses	6,854,067	6,585,411
Total current assets	$ 100,132,975	$ 88,941,601
DEFERRED DEBITS	$ 5,064,423	$ 4,174,266
TOTAL ASSETS	$1,139,298,514	$1,124,833,307

See Notes to Financial Statements

EQUITIES AND LIABILITIES

	2020	2019
EQUITIES		
Memberships issued	$ 1,136	$ 1,136
Patronage capital	30,791,491	23,966,323
Appropriated margins	141,965,643	141,120,519
Accumulated other comprehensive income (loss)	(5,166,203)	(8,320,585)
Total equities	$ 167,592,067	$ 156,767,393
LONG-TERM DEBT		
Mortgage notes payable, net of current maturities	$ 835,258,078	$ 824,474,677
Accrued pension costs	6,195,270	7,571,592
Total long-term debt	$ 841,453,348	$ 832,046,269
NONCURRENT LIABILITIES		
Postretirement health insurance obligation	$ 4,864,780	$ 4,478,784
Closure cost obligation	2,448,884	2,121,180
Total noncurrent liabilities	$ 7,313,664	$ 6,599,964
CURRENT LIABILITIES		
Accounts payable – Square Butte Electric	$ 9,342,805	$ 8,802,902
Accounts payable – other	28,964,356	25,891,647
Accrued taxes	3,797,957	3,930,899
Accrued interest	829,544	1,038,151
Accrued payroll	628,673	1,846,141
Vested accrued vacation	4,377,695	3,688,636
Current maturities of long-term debt	24,133,599	23,060,926
Line of credit – bank	15,467,000	13,688,000
Total current liabilities	$ 87,541,629	$ 81,947,302
DEFERRED CREDITS	$ 35,397,806	$ 47,472,379
TOTAL EQUITIES AND LIABILITIES	$1,139,298,514	$1,124,833,307

See Notes to Financial Statements

Statement of Revenues, Expenses and Comprehensive Income

Years Ended December 31, 2020 and 2019

	2020	2019
OPERATING REVENUES		
Energy sales to Class A members	$ 314,507,748	$ 308,349,673
Energy sales to Class B, C & D members & other	63,602,524	72,612,269
Other electric revenue	12,228,092	12,509,158
Total operating revenues	$ 390,338,364	$ 393,471,100
OPERATING EXPENSES		
Generation	$ 54,353,815	$ 57,688,257
Power supply cost – Northern Municipal Power Agency	22,924,496	24,272,088
Purchased power – Square Butte Electric Cooperative	80,637,229	81,305,483
Purchased power – other	122,831,779	122,714,834
Transmission and substation	26,069,611	25,226,876
Depreciation and amortization	30,045,351	28,911,758
Administrative and general	19,327,068	18,186,123
Interest on long-term debt	26,818,171	31,921,735
Other interest	504,676	255,200
Total operating expenses	$ 383,513,196	$ 390,482,354
OPERATING MARGIN	$ 6,825,168	$ 2,988,746
NONOPERATING MARGIN		
Interest income	$ 461,737	$ 4,879,670
Coal royalties	1,350,000	1,351,734
Capital credit allocations received	1,195,320	908,333
Nonoperating revenue	1,931,523	1,924,208
Pension and postretirement cost	(4,093,456)	(338,691)
TOTAL NONOPERATING MARGIN	$ 845,124	$ 8,725,254
NET MARGIN	$ 7,670,292	$ 11,714,000
OTHER COMPREHENSIVE INCOME (LOSS)		
Defined benefit pension plans:		
Net income (loss) arising during the period	3,154,382	(5,143,414)
COMPREHENSIVE INCOME	$ 10,824,674	$ 6,570,586

See Notes to Financial Statements

Statement of Cash Flows

Years Ended December 31, 2020 and 2019

		2020		2019
CASH FLOWS FROM OPERATING ACTIVITIES				
Net margins	$	7,670,292	$	11,714,000
Adjustments to reconcile net margin to net cash provided (used) by operating activities				
Depreciation and amortization		30,046,351		28,911,758
Capital credit allocations		(1,195,320)		(908,333)
Effects on operating cash flows due to changes in:				
Accounts receivable		(10,427,769)		181,990
Prepaid expenses		(268,656)		(468,951)
Inventories		(427,290)		(1,676,645)
Deferred debits		(4,557,284)		(2,812,277)
Accounts payable		3,612,612		(4,873,651)
Accrued expenses		726,354		866,978
Deferred credits		(7,511,998)		12,284,656
NET CASH PROVIDED (USED) BY OPERATING ACTIVITIES	$	17,667,292	$	43,219,525
CASH FLOWS FROM INVESTING ACTIVITIES:				
Electric plant additions – net	$	(36,886,025)	$	(43,183,063)
Investment (additions) reductions		5,103,417		(44,988,341)
Capital credits received		547,901		549,979
NET CASH PROVIDED (USED) BY INVESTING ACTIVITIES	$	(31,234,707)	$	(87,621,425)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from long-term debt	$	56,317,000	$	20,380,000
Net proceeds (payments) on line of credit		1,779,000		(2,886,700)
Net proceeds (payments) on bridge loan		(21,400,000)		40,668,000
RUS cushion of credit applied		–		108,295,879
Repayment of long-term debt		(23,060,926)		(122,053,697)
NET CASH PROVIDED (USED) BY FINANCING ACTIVITIES	$	13,635,074	$	44,403,482
NET CHANGE IN CASH AND CASH EQUIVALENTS	$	67,659	$	1,582
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		227,693		226,111
CASH AND CASH EQUIVALENTS, END OF YEAR	$	295,352	$	227,693
SUPPLEMENTAL DISCLOSURE OF CASH FLOWS INFORMATION				
Cash paid for interest	$	27,158,986	$	32,326,480

See Notes to Financial Statements

Statement of Changes in Equities

December 31, 2020 and 2019

	Memberships Issued	Patronage Capital	Appropriated Margins	Accumulated Other Comprehensive Income (Loss)	Total
BALANCE – JANUARY 1, 2019.	$1,136	$20,977,577	$132,395,265	$(3,177,171)	$150,196,807
Operating margin		2,988,746			2,988,746
Nonoperating margin			8,725,254		8,725,254
Other comprehensive income (loss). . . .				(5,143,414)	(5,143,414)
BALANCE – DECEMBER 31, 2019.	$1,136	$23,966,323	$141,120,519	$(8,320,585)	$156,767,393
Operating margin		6,825,168			6,825,168
Nonoperating margin			845,124		845.124
Other comprehensive income (loss). . . .				3,154,382	3,154,382
BALANCE – DECEMBER 31, 2020.	$1,136	$30,791,491	$141,965,643	$(5,166,203)	$167,592,067

See Notes to Financial Statements

Independent Auditor's Report

To the Board of Directors
Minnkota Power Cooperative, Inc.
Grand Forks, North Dakota

Report on the Financial Statements

We have audited the accompanying financial statements of Minnkota Power Cooperative, Inc., which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of revenues, expenses and comprehensive income, changes in equities, and cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in Government Auditing Standards, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Minnkota Power Cooperative, Inc. as of December 31, 2020 and 2019, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Reporting Required by Government Auditing Standards

In accordance with *Government Auditing Standards*, we have also issued our report dated February 17, 2021, on our consideration of Minnkota Power Cooperative, Inc.'s internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with Government Auditing Standards in considering Minnkota Power Cooperative, Inc.'s internal control over financial reporting and compliance.

BRADY, MARTZ & ASSOCIATES, P.C.
GRAND FORKS, NORTH DAKOTA
February 17, 2021

Notes to Financial Statements

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization. Minnkota Power Cooperative, Inc. (Minnkota or the Cooperative) is a generation and transmission cooperative that was formed on March 28, 1940, under the laws of the State of Minnesota with headquarters in Grand Forks, North Dakota. It operates on a non-profit cooperative basis and is engaged primarily in the business of providing wholesale electric service to its retail distribution cooperative member-owners (Members). The eleven members purchase power and energy from Minnkota pursuant to all-requirements wholesale power contracts, which terminate on December 31, 2055.

Minnkota's service area, aggregating approximately 35,000 square miles, is located in northwestern Minnesota and eastern North Dakota, and contains an aggregate population of approximately 300,000 people.

Minnkota is subject to the accounting and reporting rules and regulations of the Rural Utilities Service (RUS). The Cooperative follows the Federal Energy Regulatory Commission's Uniform System of Accounts prescribed for Class A and B Electric Utilities as modified by RUS.

Rates charged to members are established by the board of directors and are subject to deemed approval by RUS.

As a result of the ratemaking process, the Cooperative applies Accounting Standards Codification (ASC) 980 Regulated Operations. The application of generally accepted accounting principles by the Cooperative differs in certain respects from the application by non-regulated businesses as a result of applying ASC 980. Such differences generally related to the time at which certain items enter into the determination of net margins in order to follow the principle of matching costs and revenues.

Electric Plant and Retirements. Electric plant is stated at cost. The cost of additions to electric plant includes contracted work, direct labor and materials and allocable overheads. The cost of units of depreciable property retired is removed from electric plant and charged to accumulated depreciation along with removal costs less salvage. Repairs and the replacement and renewal of items determined to be less than units of property are charged to maintenance expense.

Depreciation. Depreciation is computed using the straight-line method based upon the estimated useful lives of the various classes of property through use of annual composite rates.

Allowance for Funds Used During Construction (AFUDC). The allowance for funds used during construction is interest that is capitalized on all construction projects with a budgeted cost of greater than $50,000. AFUDC is classified as a reduction of interest expense.

Investments. Investments are U.S. treasury bills, savings and patronage allocations from cooperatives and other affiliates stated at cost plus unretired allocations.

Fair Value Measurements. The Cooperative has determined the fair value of certain assets and liabilities in accordance with generally accepted accounting principles, which provides a framework for measuring fair value.

Fair value is defined as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques should maximize the use of observable inputs and minimize the use of unobservable inputs.

A fair value hierarchy has been established, which prioritizes the valuation inputs into three broad levels. Level 1 inputs consist of quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the related asset or liability. Level 3 inputs are unobservable inputs related to the asset or liability.

The Cooperative does not have any assets or liabilities subject to level 1, 2, or 3 valuation as of December 31, 2020 and 2019, and does not anticipate participating in transactions of this type in the future.

The fair value of the Cooperative's long-term debt was estimated based upon borrowing rates currently available to the Cooperative for bank loans with similar terms and average maturities. The estimated fair value of the Cooperative's long-term debt was $927,000,000 and $925,000,000 as of December 31, 2020 and 2019, respectively.

Cash and Cash Equivalents. For purposes of reporting cash flows, the Cooperative considers all highly liquid investments purchased with a maturity of three months or less to be cash equivalents.

Receivables and Credit Policies. Trade receivables are uncollateralized customer obligations due under normal trade terms requiring payment within 30 days from the billing date. Management has deemed that no late fees or interest charges are assessed to the receivables. Management has determined that an allowance for doubtful accounts is not necessary, as all balances are considered fully collectible.

Inventories. Uncovered and undelivered coal inventory is stated at cost using a FIFO (first-in, first-out) basis. All other inventories are stated at the lower of average cost or fair market value.

Deferred Debits. Deferred debits consist of deferred pension costs. See also Note 6 and Note 11.

Deferred Credits. Deferred credits consist primarily of transmission service advance, customer construction prepayments and a revenue deferral as approved by RUS. See also Note 13.

Patronage Capital. The Cooperative operates on a non-profit basis. Amounts received from the furnishing of electric energy in excess of operating costs and expenses are assigned to patrons on a patronage basis. All other amounts received by the Cooperative from its operations in excess of costs and expenses are also allocated to its patrons on a patronage basis to the extent they are not needed to offset current or prior losses.

Revenue Recognition. Revenues are primarily from electric sales to members. Electric revenues are recognized over time as electricity is delivered to members. Electric revenues are based on the reading of members' meters, which occurs on a systematic basis throughout each reporting period and represents the fair value of the electricity delivered.

Revenues are recognized equivalent to the value of the electricity supplied during each period, including amounts billed during each period and changes in amounts estimated to be billed at the end of each period. The Cooperative has elected to apply invoice method to measure progress towards completing performance obligations to transfer electricity to their members.

Business and Credit Risk. The Cooperative maintains its cash balances in a locally owned bank. Such balances are insured by the Federal Deposit Insurance Corporation up to $250,000. The cash balances exceeded insurance coverage at various times during the fiscal years.

Accounting Estimates. The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Income Taxes. The Cooperative is exempt from income taxes under Section 501(c)(12). The Cooperative is annually required to file a Return of Organization Exempt from Income Tax (Form 990) with the IRS.

The Cooperative evaluates its tax positions that have been taken or are expected to be taken on income tax returns to determine if an accrual is necessary for uncertain tax positions. As of December 31, 2020 and 2019, the unrecognized tax benefit accrual was zero. The Cooperative will recognize future accrued interest and penalties related to unrecognized tax benefits in income tax expense if incurred. The Company is no longer subject to Federal and State tax examinations by tax authorities for years before 2017.

Advertising Costs. Advertising and promotional costs are expensed as incurred.

Sales Taxes. The Cooperative pays sales tax on material it purchases to operate and maintain its generation and transmission facilities.

Recently Adopted Accounting Standards. In 2014, the FASB issued ASC 606, Revenue from Contracts with Customers (ASC 606), replacing the existing accounting standard and industry-specific guidance for revenue recognition with a five-step model for recognizing and measuring revenue from contracts with customers. The underlying principle of the standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. ASC 606 became effective on January 1, 2019, and the Cooperative adopted it using the modified retrospective method applied to open contracts and only to the version of contracts in effect as of January 1, 2019. In accordance with the modified retrospective method, the Cooperative's previously issued financial statements have not been restated to comply with ASC 606 and the Cooperative did not have a cumulative-effect adjustment to retained earnings. The adoption of ASC 606 had no significant impact on the timing of revenue recognition compared to previously reported results; however, it requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers, which are included in Note 10.

NOTE 2 – SQUARE BUTTE ELECTRIC COOPERATIVE

Square Butte owns a 488-megawatt (MW) steam electric generating plant (Young 2) adjacent to Minnkota's 256 MW generating plant (Young 1) near Center, North Dakota.

Minnkota, as agent for Square Butte, operates and maintains Young 2.

The long-term power purchase agreement with Square Butte has been evaluated under the accounting guidance for variable interest entities. We have determined that we have no variable interest in the agreement. This conclusion is based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Minnkota Power Cooperative, Inc.'s financial exposure related to the agreement is limited to our capacity and energy payments.

On December 30, 2009, Minnkota, Square Butte and Minnesota Power (MP) completed an agreement in which Minnkota receives additional energy and capacity from Young 2. Between 2014 and 2026, Minnkota has the option to acquire MP's 50% allocation from Young 2. In 2014 Minnkota exercised this option and starting June 1, 2014, purchased an additional 22.5275% allocation of Young 2 from MP. This allocation increased to 28.022% on January 1, 2015. This allocation will increase by approximately 4.4% per year from 2022-2026. From 2027 to 2042, Minnkota will purchase 100% of the output of Young 2 directly from Square Butte. The payment obligation of MP and Minnkota are several and not joint, and are not guarantees of any Square Butte obligations.

As part of this agreement, Square Butte sold its 465-mile, Center to Duluth DC transmission line and related substations to Minnesota Power. Minnesota Power is using the transmission line to deliver wind energy that it is developing near Center, North Dakota, to its service area near Duluth, Minnesota.

In 2014, Minnkota placed in service a new 250-mile, $355 million, 345-kilovolt transmission line from Center, North Dakota, to near Grand Forks, North Dakota. This line allows Square Butte energy to be delivered into the Minnkota system and provides the overall northern Red River Valley service area with additional voltage support.

Minnkota is obligated to pay a proportionate share of Square Butte's annual debt retirement and operating costs based on its entitlement to net capability. Minnkota also receives a minimum annual coal royalty of $1,350,000 from Square Butte.

Minnkota has also issued a $10,000,000 line of credit to Square Butte with a variable interest rate that is 1% below the prime rate. As of December 31, 2020 and 2019, no amounts were outstanding on this line of credit.

Related party transactions include:

	2020	2019
Purchase of wholesale power	$ 80,637,229	$ 81,305,483
Accounts payable to Square Butte	$ 9,342,805	$ 8,802,902
Accounts receivable from Square Butte	$ 3,954,193	$ 5,148,502

NOTE 3 – NORTHERN MUNICIPAL POWER AGENCY

Northern Municipal Power Agency (Northern) is a municipal corporation and a political subdivision of the State of Minnesota. Its membership consists of 10 Minnesota and two North Dakota municipalities each of which owns and operates a municipal electric utility distribution system.

On March 1, 1981, Minnkota entered into a Power Supply Coordination Agreement with Northern. This agreement is effective until the later of December 31, 2041, or the date on which the Coyote Plant is retired from service. All annual debt payments and plant operating cost requirements not provided by Northern's member revenue and the sale of all capacity and energy in excess of Northern's member requirements are an obligation of Minnkota.

Related party transactions include:

	2020	2019
Power supply cost	$22,924,496	$24,272,088
Accounts receivable from Northern	$ 5,374,169	$ 7,111,095

NOTE 4 – ELECTRIC PLANT

	2020		2019	
	Plant	Depreciation Rates	Plant	Depreciation Rates
Production plant	$ 409,343,867	3.13%-5.00%	$ 407,765,727	3.13%-5.00%
Transmission lines	525,099,227	1.78%-2.39%	510,297,171	1.78%-2.39%
Transmission substations	137,156,486	1.69%-4.96%	133,485,386	1.69%-4.96%
Distribution substations	110,906,508	2.48%	97,326,168	2.48%
General plant	124,367,592	2.00%-16.70%	116,078,373	2.00%-16.70%
Electric plant in service	1,306,873,680		1,264,952,825	
Construction work in progress	19,986,795		26,377,884	
Total electric plant	$1,326,860,475		$1,291,330,709	

The Cooperative capitalized interest of $558,763 and $633,927 as of the years ended December 31, 2020 and 2019, respectively.

NOTE 5 – OTHER INVESTMENTS

	2020	2019
CoBank patronage capital credits	$ 6,986,267	$ 7,452,799
US Bank – treasury bills	29,999,924	44,988,341
Associated companies	44,917	44,642
Savings	9,885,000	-
Other	1,371,459	257,783
Total other investments	$ 48,287,567	$52,743,565

Notes to Financial Statements

NOTE 6 – DEFERRED DEBITS

The Cooperative's deferred debit balances are summarized below:

	2020	2019
Deferred pension costs – (see Note 11)	$ 5,064,423	$ 4,174,266
Total deferred debits	$ 5,064,423	$ 4,174,266

NOTE 7 – PATRONAGE CAPITAL AND APPROPRIATED MARGINS

Under provisions of the long-term debt agreements, until the total of equities and margins equals or exceeds 20% of the total assets of the Cooperative, retirement of capital is not permitted.

As provided for in the bylaws, operating margins of the current year not needed to offset operating losses incurred during prior years, shall be capital furnished by the patrons and credited to patronage capital. Nonoperating margins are not assignable to patrons and are credited to appropriated margins and reserved for future contingencies.

NOTE 8 – LONG-TERM DEBT

Long-term debt as of December 31, 2020 and 2019, is shown below. Substantially all of Minnkota's assets are pledged as collateral in accordance with its indenture.

	2020	2019
Rural Utilities Service (RUS)		
Fixed rate mortgage notes (1.074%-5.24%) due in quarterly installments through 2053	$726,388,637	$688,964,773
CoBank		
Fixed and variable rate mortgage notes (1.27%-6.89%) due in quarterly installments maturing at various times through 2039	31,265,647	34,991,543
Variable interest rate bridge loan (see Note 9)	78,600,000	100,000,000
	109,865,647	134,991,543
The Lincoln National Life Insurance Company		
Fixed rate first mortgage note (4.73%) due in semi-annual installments through 2049	22,985,000	23,360,000
Digital press and copier leases	152,393	219,287
Accrued pension costs (see Note 11)	6,195,270	7,571,592
Total long-term debt	865,586,947	855,107,195
Less current portion	(24,133,599)	(23,060,926)
Long-term debt	$841,453,348	$832,046,269

It is estimated that the minimum principal requirements for the next five years will be as follows:

Years Ending December 31,	Amount
2021	$ 24,133,599
2022	26,336,279
2023	26,890,961
2024	104,879,043
2025	24,527,576
Thereafter	658,819,489
Total	$865,586,947

At December 31, 2020, Minnkota had unadvanced loan funds available to the Cooperative in the amount of $11,079,000. Minnkota has a maximum debt limit of $1,100,000,000.

NOTE 9 – LINE OF CREDIT

At December 31, 2020, Minnkota had a line of credit agreement with U.S. Bank-Grand Forks with available borrowings totaling $25,000,000 maturing June 30, 2021. The line of credit had a variable interest rate of 1.6875% and 3.25% at December 31, 2020 and 2019, respectively. Amounts outstanding on the line totaled $15,467,000 and $13,688,000 at December 31, 2020 and 2019, respectively.

The Cooperative also has available a multi-year bridge loan with CoBank totaling $250,000,000 as of the years ended December 31, 2020 and 2019. The purpose of the bridge loan is to temporarily finance projects included in RUS loans. The blended interest rate was 1.35% and 2.95% as of December 31, 2020 and 2019, respectively, and will expire on September 27, 2024. The CoBank bridge loan had an outstanding balance of $78,600,000 and $100,000,000 at December 31, 2020 and 2019, respectively, and is included in long-term debt.

NOTE 10 – REVENUES FROM CONTRACTS WITH CUSTOMERS

The revenues of the Cooperative are primarily derived from providing wholesale electric service to its members. Revenues from contracts with customers represent over 98% of all cooperative revenues. Below is a disaggregated view of the Cooperative's revenues from contracts with customers as well as other revenues, including their location on the statement of revenues, expenses and comprehensive income for December 31, 2020 and 2019:

	2020		
Revenue Streams	**Electric Revenue**	**Other Operating Revenue**	**Nonoperating Revenue**
Energy sales to Class A members	$314,507,748	$ –	$ –
Energy sales to Class B, C and D members	63,602,524	–	–
Other electric revenue	–	12,228,092	–
Other nonoperating revenue	–	–	1,664,851
Total revenue from contracts with customers	$ 378,110,272	$ 12,228,092	$ 1,664,851
Timing of Revenue Recognition			
Services transferred over time	$ 378,110,272	$ 11,242,592	$ 1,664,851
Goods transferred at a point in time	–	985,500	–
Total revenue from contracts with customers	$ 378,110,272	$ 12,228,092	$ 1,664,851

	2019		
Revenue Streams	**Electric Revenue**	**Other Operating Revenue**	**Nonoperating Revenue**
Energy sales to Class A members	$308,349,673	$ –	$ –
Energy sales to Class B, C and D members	72,612,269	–	–

Other electric revenue	-	12,509,158	-
Other nonoperating revenue	-	-	1,616,850
Total revenue from contracts with customers	$380,961,942	$ 12,509,158	$ 1,616,850
Timing of Revenue Recognition			
Services transferred over time	$380,961,942	$ 11,615,235	$ 1,616,850
Goods transferred at a point in time	-	893,923	-
Total revenue from contracts with customers	$380,961,942	$ 12,509,158	$ 1,616,850

Electric Revenue. Electric revenues consist of wholesale electric power sales to members through the member power purchase and service contracts and from participation in the Midcontinent Independent System Operator (MISO) market. All of the electric revenues meet the criteria to be classified as revenue from contracts with customers and are recognized over time as energy is delivered. Revenue is recognized based on the metered quantity of electricity delivered or transmitted at the applicable contractual or market rates.

In 2019, the Cooperative deferred the recognition of $5,394,888 of member electric revenue under regulatory accounting (see Note 12). In 2020, the Cooperative recognized $12,124,900 of deferred member electric revenue.

Other Operating Revenue. Other operating revenue primarily includes: revenue received from wheeling and wind delivery services; revenue received for operating agent fees; revenue for lime preparation facility user fees; and sale of renewable energy credits. All of these revenue streams meet the criteria to be classified as revenue from contracts with customers. Wheeling and wind delivery services revenues is recognized over time as energy in transmitted and delivered based on measured quantities at the contractual rates. Operating agent fees are recognized over time based on actual costs incurred during each month of performance. Lime facility user fees revenue is recognized over time based on an annual fee. Excess renewable energy credits are sold to third parties. Renewable energy credit revenue is recognized at a point in time when the sale is completed with the third party.

Other Nonoperating Revenue. Other nonoperating revenue during 2020 and 2019 included $1,664,851 and $1,616,850 of revenue from coal yard services and license agreements, respectively. Revenue from the coal yard services and license agreements is recognized over time, based on an annual contracted fee.

Balances from accounts receivable and contracts with customers are as follows:

	Accounts Receivable	Contract Liabilities
January 1, 2019	$ 49,721,266	$ 1,847,589
December 31, 2019	$ 45,276,434	$ 7,486,829
December 31, 2020	$ 42,592,663	$ 7,537,156

NOTE 11 – EMPLOYEE BENEFIT PLANS

Minnkota has two pension plans covering substantially all of its employees. Pension Plan A is a defined benefit plan and Pension Plan B is a defined contribution plan. Minnkota's contribution to Plan B was $5,220,104 and $5,024,141 for 2020 and 2019, respectively.

The Plan A benefit is the greater of 1) 1.5 times the average high 60 consecutive months compensation during the 120 months prior to retirement times years of service less the monthly Plan B benefit or 2) 1.1% of the first $417 of monthly salary times years of service to December 31, 1989.

The following table sets forth Plan A's funded status and amounts recognized in Minnkota's balance sheets at December 31:

	2020	2019
Change in benefit obligation:		
Benefit obligation, beginning	$ 7,571,592	$ 2,137,317
Service cost	1,005,252	126,512
Interest cost	205,064	94,646
Actuarial (gain) loss	1,080,489	5,573,224
Benefits paid	(3,667,127)	(360,107)
Benefit obligation, ending	$ 6,195,270	$ 7,571,592
Change in plan assets:		
Fair value of plan assets, beginning	$ 4,174,266	$ 1,722,096
Actual return on plan assets	557,284	312,277
Employer contributions	4,000,000	2,500,000
Benefits paid	(3,667,127)	(360,107)
Fair value of plan assets, ending	$ 5,064,423	$ 4,174,266
Funded status at end of year	$(1,130,847)	$(3,397,326)
Amounts recognized in the balance sheet:		
Noncurrent assets	$ 5,064,423	$ 4,174,266
Noncurrent liabilities	(6,195,270)	(7,571,592)
	$(1,130,847)	$(3,397,326)
Amounts recognized in accumulated other comprehensive income:		
Net loss (gain)	$ 5,166,203	$ 8,320,585
Net periodic benefit cost:		
Service cost	$ 1,005,252	$ 126,512
Interest cost	205,064	94,646
Expected return on plan assets	(189,871)	(102,699)
Amortization of net (gain) loss	821,219	220,232
Settlement expense	3,046,239	-
Net periodic benefit cost	$ 4,887,903	$ 338,691
Assumptions used:		
Discount rate	1.45%	3.15%
Rate of compensation increase	4.00%	4.00%
Expected return on plan assets	6.10%	6.00%
Contributions and benefits:		
Employer contributions	$ 4,000,000	$ 2,500,000
Benefits paid	367,127	360,107
Expected benefit payments:		
2020	N/A	2,123,262
2021	2,372,002	1,361,053
2022	865,713	1,265,007
2023	441,078	682,264
2024	604,433	730,881
2025-2029	N/A	4,407,968
2025	642,085	N/A
2026-2030	5,336,798	N/A
Expected contributions	$ -	$ -

Notes to Financial Statements

The investment strategy for Pension Plan A is to 1) have the ability to pay all benefits and expense obligations when due, 2) maintain a "funding cushion" for unexpected developments and for possible future increases in benefit structure and expense levels and 3) meet a 6.0% return target for the aggregate portfolio, over a full market and economic cycle, while minimizing risk and volatility. The expected return is based on historical returns. The asset classes are 1) US Equity Large Cap Growth: Target – 25.0%, 2) US Equity Large Cap Value: Target – 25.0%, 3) International Equity Growth and Value: Target – 20.0% and 4) Fixed Income: Target – 30.0%. Allowable investments include individual domestic equities, mutual funds, private placements and pooled asset portfolios (e.g. money market funds). Stock options, short sales, letter stocks, Real Estate Investment Trust securities and commodities are not allowable investments.

Plan assets at December 31 were:

	2020	2019
Equity securities:		
Large cap growth	22.13%	18.30%
Large cap value	22.50%	18.24%
International growth	9.21%	7.28%
International core	9.04%	7.27%
Fixed income	37.12%	48.91%
Total	100.00%	100.00%

NOTE 12 – POSTRETIREMENT HEALTH INSURANCE OBLIGATION

Minnkota sponsors a defined benefit postretirement health care plan that covers certain full-time employees. The plan pays varying percentages of health care premiums for retirees from age 60 to age 65. Upon reaching 60, all Center Union participants hired before February 1, 2014, are immediately eligible to receive a 50% premium payment. Upon reaching age 60, only Grand Forks Union participants hired before April 1, 2010, and 50 years of age before April 1, 2013, are immediately eligible to receive a 100% premium payment. Grand Forks Union participants hired before April 1, 2010, and less than 50 years of age at April 1, 2013, will receive a 50% premium payment upon reaching age 60. Upon reaching age 60 and completing 10 years of service, Non-Union participants hired before January 1, 2012, are eligible to receive a 50% premium payment.

Minnkota does not fund this plan. There are no plan assets.

The following table reconciles the plan's funded status to the accrued postretirement health care cost liability as reflected on the balance sheet as of December 31:

	2020	2019
Change in benefit obligation:		
Benefit obligation, beginning	$ 4,478,784	$ 4,215,886
Service cost	175,191	153,484
Interest cost	146,599	187,607
Actuarial (gain) loss	64,206	(78,193)
Benefit obligation, ending	$ 4,864,780	$ 4,478,784
Accrued postretirement health care cost liability	$ 4,864,780	$ 4,478,784
Amounts recognized in the balance sheet:		
Noncurrent liabilities	$ 4,864,780	$ 4,478,784
Net periodic benefit cost:		
Service cost	$ 175,191	$ 153,484
Interest cost	146,599	187,607
Amortization of net (gain) loss	64,206	(78,193)
Net periodic benefit costs (income)	$ 385,996	$ 262,898

For measurement purposes, a 10% annual rate increase in health care premiums was assumed for 2020 and 2019, declining to 5% in five years. The weighted-average discount rate used in determining the accumulated postretirement benefit obligation was 1.45% for 2020 and 3.15% for 2019, respectively.

Benefits paid in 2020 totaled $423,145 and in 2019 totaled $427,484. Benefits expected to be paid in each of the next five years and the aggregate for the next five years thereafter are as follows:

Years Ending December 31,	Amount
2021	$507,677
2022	422,358
2023	361,197
2024	301,931
2025	204,181
2026-2030	769,737

Changing the rate of assumed health care costs by a 1% increase or decrease would change the benefit obligation as of December 31, 2020 and 2019, by approximately $510,550 and $373,805, respectively.

Minnkota has elected to recognize any gains or losses immediately.

NOTE 13 – DEFERRED CREDITS

During the year ended December 31, 2011, the Cooperative implemented a revenue deferral plan. This plan was amended in 2017. Under the plan, the Cooperative may defer revenue to achieve a targeted annual margin between 2.0% and 3.0% of the Cooperative's total cost of service. This plan complies with GAAP and has been approved by RUS. The amount of revenue deferred was $27,759,870 and $39,884,770 as of December 31, 2020 and 2019, respectively. The Cooperative implemented a new plan in 2020 to recognize the remaining $27,759,870 through 2022. RUS requires the Cooperative to segregate cash in an amount equal to the amount of revenue being deferred. The Cooperative had deposits in US Bank investments at December 31, 2020 and 2019, to satisify this requirement.

Customer construction prepayments are the funds received for construction of transmission related projects in excess of completed construction costs as of December 31, 2020 and 2019.

Deferred credit balances are summarized below:

	2020	2019
Deferred revenues	$ 27,759,870	$39,884,770
Customer construction prepayments	565,015	662,910
Transmission service advance payments	6,972,141	6,823,919
Other deferred credits	100,780	100,780
Total deferred credits	$ 35,397,806	$47,472,379

NOTE 14 – OPERATING LEASE

Minnkota had operating leases for 10 diesel generators and related environmental equipment. The original generator lease began in April 2003 and has been renewed several times. The lease for environmental equipment began in December 2014. The leases ended in 2019.

Minnkota has entered into a Heating Demand Waiver Generation Agreement with Cass County Electric Cooperative, Inc. (Cass). Under the terms of this agreement, Cass is obligated to pay all rent under these leases, as well as all other operating and maintenance expenses related to the diesel generators.

NOTE 15 – ACCOUNTING FOR ASSET RETIREMENT OBLIGATIONS

The FASB has issued guidance which provides accounting requirements for retirement obligations associated with tangible long-lived assets. Retirement obligations associated with long-lived assets are those for which there is a legal obligation to settle under existing or enacted law, statute, ordinance, written or oral contract or by legal constructions under the doctrine of promissory estoppels.

Assets considered for potential asset retirement obligations include generating plants and transmission assets on property under easement agreement or license. Asset retirement obligations for generating plant are not recorded as a liability, due to the fact that governmental authorization for construction did not impose post-closure obligations.

In general, retirement actions for transmission assets are required only upon abandonment or cessation of use of the property for the specified purpose. The liability for transmission assets that fall into this category is not estimable because Minnkota intends to utilize these properties indefinitely. For those transmission assets for which there are post-closure obligations (e.g., licenses, permits, and easements of limited duration issued by governmental authorities), the costs do not appear to be material and no liability has been recognized.

Under the current power supply agreement with Square Butte, Minnkota will be obligated for its proportionate share of any of Square Butte's closure obligations. According to the power supply agreement, payment of these obligations is not due until the actual costs of closure are incurred. During the years ended December 31, 2020 and 2019, Minnkota recognized expenses of $327,704 and $832,882, respectively, which were related to the closure cost obligations of Square Butte. A long-term liability of $2,448,884 and $2,121,180 has been recorded as of December 31, 2020 and 2019, respectively.

NOTE 16 – GUARANTEES

Minnkota has provided to the North Dakota Department of Environmental Quality a corporate guarantee on behalf of Northern up to a maximum of $719,221. The guarantee is for closure and post-closure costs relating to solid waste facilities of Northern. Minnkota is bound by the guarantee for as long as Northern must comply with the applicable financial assurance requirements for the solid waste facilities. The guarantee may be terminated upon 120 days notice. Minnkota entered into the guarantee because it was more economical than other financial assurance mechanisms such as reserve accounts, trust funds, surety bonds, letters of credit or insurance. If Northern fails to perform closure and/or post-closure of the solid waste facilities in accordance with plans, permits or other interim status requirements, Minnkota would be required to do so or to establish a trust fund in the amount of the current closure or post-closure cost estimates.

NOTE 17 – COMMITMENTS AND CONTINGENCIES

Minnkota's power plant utilizes North Dakota lignite coal, which is being supplied from the Center Mine by BNI Coal Ltd. Minnkota and BNI Coal Ltd. have a cost-plus contract, which expires in 2037, with an additional 5-year extension at Minnkota's option.

Minnkota has various long-term contracts for the purchase of wind energy. These contracts require Minnkota to purchase all of the output generated by these wind farms for the term of the contracts which expire between 2039 and 2051.

Minnkota participates in federal grant programs, which are governed by various rules and regulations of the grantor agency. Costs charged to the respective grant programs are subject to audit and adjustment by the grantor agency; therefore, to the extent that the Cooperative has not complied with the rules and regulations governing the grants, refunds of any money received may be required.

As of the date December 31, 2020, Minnkota has approximately 50% of its employees covered by collective bargaining agreements. The collective bargaining agreements for Locals 1593 and 1426 are in force through March 31, 2022, and December 31, 2020, respectively.

NOTE 18 – SUBSEQUENT EVENTS

No significant events occurred subsequent to Minnkota's year end. Subsequent events have been evaluated through February 17, 2021, which is the date these financial statements were available to be issued.

Associated Cooperative Statistics

	Beltrami	Cass	Cavalier	Clearwater-Polk	Nodak
Balance Sheet					
Total electric plant	$154,172,460	$296,818,430	$21,662,942	$29,081,193	$169,011,326
Accumulated depreciation	49,055,475	74,490,317	8,400,446	10,585,052	65,637,035
Net electric plant	$105,116,985	$222,328,113	$13,262,496	$18,496,141	$103,374,291
Current and accrued assets	14,653,171	46,272,255	2,350,843	1,384,271	27,006,368
Other assets	10,869,433	20,561,054	1,331,864	1,758,271	12,458,017
Total assets	$130,639,589	$289,161,422	$16,945,203	$21,638,683	$142,838,676
Total equity	$ 47,743,526	$126,085,669	$ 7,103,794	$ 11,812,935	$ 55,573,161
Long-term debt	73,117,251	132,239,289	9,202,676	8,035,221	69,920,612
Other liabilities and credits	9,778,812	30,836,464	638,733	1,790,527	17,344,903
Total liabilities and equity	$130,639,589	$289,161,422	$16,945,203	$21,638,683	$142,838,676
Operations					
Operating revenue	$ 55,937,215	$137,051,334	$ 5,565,974	$ 9,700,653	$102,119,330
Purchased power	37,712,304	101,711,502	2,986,051	6,209,953	83,243,014
Other operating expenses	8,949,245	16,271,823	1,236,267	2,145,111	9,229,905
Depreciation	4,146,050	8,063,313	521,907	778,128	4,492,760
Interest	2,843,336	4,590,972	241,308	313,270	2,222,005
Total cost of electric service	$ 53,650,935	$130,637,610	$ 4,985,533	$ 9,446,462	$ 99,187,684
Operating margin	$ 2,286,280	$ 6,413,724	$ 580,441	$ 254,191	$ 2,931,646
Nonoperating margin	1,373,003	3,443,200	(40,643)	215,493	2,103,749
Total margin	$ 3,659,283	$ 9,856,924	$ 539,798	$ 469,684	$ 5,035,395
Consumers – End of Year					
Residential	20,062	46,933	1,189	4,184	19,989
Residential – seasonal	0	0	0	0	0
Commercial and other	1,579	6,488	314	260	516
Total	21,641	53,421	1,503	4,444	20,505
Increase (decrease) – percent	1.2%	2.6%	-5.8%	1.4%	1.1%
Energy Sales – kWh					
Residential	287,060,736	615,620,376	14,595,125	60,612,312	390,637,948
Residential – seasonal	0	0	0	0	0
Commercial and other	190,710,309	640,940,727	20,550,158	10,792,530	678,799,895
Total	477,771,045	1,256,561,103	35,145,283	71,404,842	1,069,437,843
Increase (decrease) – percent	-3.0%	-2.4%	-1.8%	-3.2%	-5.2%
Miscellaneous					
kWh consumption/resident/month	1,192	1,093	1,023	1,207	1,629
Miles of line	3,537	5,748	1,375	1,510	8,095
Consumers/miles of line	6.12	9.29	1.09	2.94	2.53
Number of employees	61	93	11	15	65
Average rate – residential – (¢/kWh)	13.94	11.74	17.65	13.62	11.75

North Star	PKM	Red Lake	Red River	Roseau	Wild Rice	Total
$48,545,287	$38,101,441	$44,781,036	$52,734,641	$60,554,798	$82,390,243	$997,853,797
17,329,548	14,616,654	19,857,921	16,432,515	30,718,682	27,211,956	334,335,601
$31,215,739	$23,484,787	$24,923,115	$36,302,126	$29,836,116	$55,178,287	$663,518,196
6,976,449	6,839,601	3,548,985	3,741,640	6,104,760	8,768,857	127,647,200
1,664,449	2,465,513	1,801,026	1,993,435	3,283,451	4,330,688	62,517,201
$39,856,637	$32,789,901	$30,273,126	$42,037,201	$39,224,327	$68,277,832	$853,682,597
$15,064,648	$17,330,728	$11,680,070	$17,915,087	$19,688,014	$29,019,612	$359,017,244
21,769,569	13,476,660	15,802,822	20,989,189	16,791,623	34,893,669	416,238,581
3,022,420	1,982,513	2,790,234	3,132,925	2,744,690	4,364,551	78,426,772
$39,856,637	$32,789,901	$30,273,126	$42,037,201	$39,224,327	$68,277,832	$853,682,597
$15,187,703	$14,675,809	$14,867,305	$15,388,122	$19,160,895	$33,205,414	$422,859,754
8,763,420	9,599,253	10,310,114	9,980,606	11,445,320	22,063,271	304,024,808
3,882,207	2,721,524	2,496,459	2,847,626	3,659,875	6,497,997	59,938,039
1,249,865	981,658	1,266,779	1,233,001	1,962,464	2,218,553	26,914,478
675,582	591,326	400,475	794,353	726,446	1,174,458	14,573,531
$14,571,074	$13,893,761	$14,473,827	$14,855,586	$17,794,105	$31,954,279	$405,450,856
$ 616,629	$ 782,048	$ 393,478	$ 532,536	$ 1,366,790	$ 1,251,135	$ 17,408,898
102,364	86,009	48,919	428,001	279,004	214,683	8,253,782
$ 718,993	$ 868,057	$ 442,397	$ 960,537	$ 1,645,794	$ 1,465,818	$ 25,662,680
5,348	3,660	5,198	4,050	5,853	13,586	130,052
613	0	0	0	429	0	1,042
737	272	488	653	308	861	12,476
6,698	3,932	5,686	4,703	6,590	14,447	143,570
1.3%	1.2%	0.9%	0.5%	0.5%	0.4%	1.5%
68,901,367	67,447,486	92,872,160	81,939,006	91,793,349	207,819,552	1,979,299,417
1,158,686	0	0	0	7,405,731	0	8,564,417
36,350,071	50,744,739	28,679,620	36,829,132	50,572,926	54,536,081	1,799,506,188
106,410,124	118,192,225	121,551,780	118,768,138	149,772,006	262,355,633	3,787,370,022
-4.3%	-4.1%	-5.2%	-4.4%	-2.3%	-3.6%	-3.6%
1,074	1,536	1,489	1,686	1,307	4,014	1,268
1,452	2,284	2,637	1,808	2,175	3,997	34,618
4.61	1.72	2.16	2.60	3.03	3.61	4.15
21	17	19	21	27	42	392
14.54	13.67	12.42	12.90	14.41	13.01	12.66

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Sue Kringen, Vice Chair	Bemidji, MN
Murl Nord, Secretary	Blackduck, MN
Judy Honer, Treasurer	Laporte, MN
Rick Coe	Bemidji, MN
Craig Gaasvig	Bemidji, MN
Charlie Parson	Puposky, MN
Charlie Perkins	Redlake, MN
Robert Wallner	Blackduck, MN

Staff

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Arlene Hogquist	Director of Finance & Corporate Services
Sam Mason	Director of Member & Energy Services
Dan Edens	Manager of Operations
Rich Riewer	Manager of Engineering
Jeremy Seibel	Manager of Information Technology
Jolene Kallroos	Manager of Member Services
Lee Pemberton	Line Superintendent
Kay Olson	Human Resources Specialist

Marshal Albright

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Douglas Anderson	Arthur, ND
Sid Berg	Colfax, ND
Terry Kraft	West Fargo, ND
Wendy Loucks	Fargo, ND
Tom Seymour	West Fargo, ND

Staff

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Jodi Bullinger	V.P. Engineering & Operations
Chad Sapa	V.P. Corporate Services/CFO
Paul Matthys	V.P. Member & Energy Services
Tim Sanden	V.P. Information Technology/CIO
Karen Egeberg	Executive Assistant

Deanna Lefebvre

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Mylo Einarson

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Blaine Rekken	Member/Energy Services Manager
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Stephanie Johnson

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Rich Whitcomb

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Leon Emmil	Engineering Manager
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Tracey Stoll

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Alex McMillin	Office Manager

Kristin Dolan

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Randy Bjornson	Hawley, MN
David Hamre	Erskine, MN
Jim Kaiser	Lake Park, MN
Greg LaVoy	Naytahwaush, MN
Roger Winter	Callaway, MN

Staff

Kristin Dolan	President & CEO
Crystal Askelson	Interim Director of Finance
Thomas Houdek	Member Services/Communications Director
Alan Brunner	Director of Operations

Operating Statistics

	2020	2019	2018	2017	2016
Electric plant investment	$ 1,326,860,475	$ 1,291,330,709	$ 1,252,290,053	$ 1,217,284,986	$ 1,166,677,001
Accumulated depreciation	(341,046,926)	(312,356,834)	(287,587,483)	(269,842,873)	(244,518,068)
Net electric plant	$ 985,813,549	$ 978,973,875	$ 964,702,570	$ 947,442,113	$ 922,158,933
Total assets	$ 1,139,298,514	$ 1,124,833,308	$ 1,060,797,950	$ 1,039,451,568	$ 1,017,654,497
Long-term debt	$ 841,453,348	$ 832,046,269	$ 777,323,355	$ 775,582,909	$ 772,842,453
Members' equity	$ 167,592,067	$ 156,767,393	$ 150,196,807	$ 139,893,680	$ 130,156,542
Equity – percent of assets	14.7	13.9	14.2	13.5	12.8
Total revenues	$ 391,183,488	$ 402,196,354	$ 414,061,515	$ 395,642,680	$ 378,425,640
Total expenses	383,513,196	390,482,354	403,962,515	385,992,680	369,195,640
Net margin	$ 7,670,292	$ 11,714,000	$ 10,099,000	$ 9,650,000	$ 9,230,000
Energy sales – MWh					
Class A member co-ops	3,962,855	4,107,770	4,114,194	3,926,016	3,813,970
Other utilities	2,851,123	2,563,245	2,925,749	3,514,078	2,488,220
Total	6,813,978	6,671,015	7,039,943	7,440,094	6,302,190
Energy sources – MWh					
Net generation	4,739,829	4,692,432	5,064,942	5,360,722	4,572,767
Coyote retained by NMPA	(440,546)	(446,011)	(452,702)	(442,681)	(448,447)
Purchases	2,514,695	2,424,594	2,427,703	2,522,053	2,177,870
Total	6,813,978	6,671,015	7,039,943	7,440,094	6,302,190
Connected consumers – December	143,570	141,493	138,188	136,447	134,755
Class A member sales Increase (decrease) – percent	(3.5)	(0.2)	4.8	2.9	(0.8)
Average power rate to Class A members – mills/kWh	76.3	76.4	75.8	76.0	74.6
Miles of transmission line	3,372	3,350	3,350	3,348	3,340
Full-time employees	400	397	386	381	388

Executive Staff and Senior Management

Mac McLennan
President & CEO

Lowell Stave
Vice President &
Chief Operating Officer

Gerad Paul
General Counsel
Vice President – Legal,
Compliance & Risk

Kay Schraeder
Vice President & Chief
Financial Officer

Dan Inman
Vice President &
Chief Information
Security Officer

Jami Hovet
Vice President of
Administration

Gerry Pfau
Senior Manager
Project Development

Stacey Dahl
Senior Manager
External Affairs

Craig Bleth
Senior Manager
Power Production

Kathy Dietz
Executive Coordinator

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APPENDIX I – UNANTICIPATED DISCOVERIES PLAN