Case No.: 30122
Date Established: May 16, 2023

DRAFT STORAGE FACILITY PERMIT

STORAGE FACILITY FOR CARBON SEQUESTRATION UNDER THE NORTH DAKOTA UNDERGROUND INJECTION CONTROL PROGRAM

In compliance with North Dakota Century Code Chapter (NDCC) 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), DCC West Project LLC (DCC West) has applied for a carbon dioxide storage facility permit. A draft permit does not grant the authorization to inject. This is a document prepared under NDAC 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission has consulted with the Department of Environmental Quality and determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC 43-05-01-07.3 and 43-05-01-07.4. A fact sheet is included and contains the following information:

1. A brief description of the type of facility or activity which is the subject of the draft permit.
2. The quantity and quality of the carbon dioxide which is proposed to be injected and stored.
3. A brief summary of the basis for the draft permit conditions, including references to applicable statutory or regulatory provisions.
4. The reasons why any requested variances or alternatives to required standards do or do not appear justified.
5. A description of the procedures for reaching a final decision of the draft permit, including:
    a. The beginning and ending dates of the comment period.
    b. The address where comments will be received.
    c. The date, time, and location of the storage facility permit hearing.
    d. Any other procedures by which the public may participate in the final decision.
6. The name and telephone number of a person to contact for additional information.

This draft permit has been established on May 16, 2023, and shall remain in effect until a storage facility permit is granted under NDAC 43-05-01-05, unless amended or terminated by the Department of Mineral Resources (Commission).

Tamara Madche, Geologist
Department of Mineral Resources
Date: May 16, 2023

I. APPLICANT

Minnkota Power Cooperative, Inc.
c/o DCC West Project LLC
5301 32nd Avenue South
Grand Forks, ND 58201

II. PERMIT CONDITIONS (NDAC 43-05-01-07.3)

1. The storage operator shall comply with all conditions of the permit. Any noncompliance with the permit constitutes a violation and is grounds for enforcement action, including permit termination, revocation, or modification pursuant to NDAC 43-05-01-12.

2. In an administrative action, it shall not be a defense that it would have been necessary for the storage operator to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

3. The storage operator shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with the storage facility permit.

4. The storage operator shall develop and implement an emergency and remedial response plan pursuant to section 43-05-01-13.

5. The storage operator shall at all times properly operate and maintain all storage facilities which are installed or used by the storage operator to achieve compliance with the conditions of the storage facility permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the storage facility permit.

6. The permit may be modified, revoked and reissued, or terminated pursuant to section 43-05-01-12. The filing of a request by the storage operator for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. The injection well permit or the permit to operate an injection well does not convey any property rights of any sort or any exclusive privilege.

8. The storage operator shall furnish to the Commission, within a time specified by the Commission, any information which the Commission may request to determine whether cause exists for modifying, revoking and reissuing, or terminating the

permit, or to determine compliance with the permit. The storage operator shall also furnish to the Commission, upon request, copies of records required to be kept by the storage facility permit.

9. The storage operator shall allow the Commission, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   a. Enter upon the storage facility premises where records must be kept under the conditions of the permit;
   b. At reasonable times, have access to and copy any records that must be kept under the conditions of the permit;
   c. At reasonable times, inspect any facilities, equipment, including monitoring and control equipment, practices, or operations regulated or required under the permit; and
   d. At reasonable times, sample or monitor for the purposes of assuring permit compliance, any substances, or parameters at any location.

10. The storage operator shall prepare, maintain, and comply with a testing and monitoring plan pursuant to section 43-05-01-11.4.

11. The storage operator shall comply with the reporting requirements provided in section 43-05-01-18.

12. The storage operator must obtain an injection well permit under section 43-05-01-10 and injection wells must meet the construction and completion requirements in section 43-05-01-11.

13. The storage operator shall prepare, maintain, and comply with a plugging plan pursuant to section 43-05-01-11.5.

14. The storage operator shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity pursuant to section 43-05-01-11.1.

15. The storage operator shall implement the worker safety plan pursuant to section 43-05-01-13.

16. The storage operator shall comply with leak detection and reporting requirements pursuant to section 43-05-01-14.

17. The storage operator shall conduct a corrosion monitoring and prevention program pursuant to section 43-05-01-15.

18. The storage operator shall prepare, maintain, and comply with the area of review and corrective action plan pursuant to section 43-05-01-05.1.

19. The storage operator shall maintain financial responsibility pursuant to section 43-05-01-09.1.

20. The storage operator shall maintain and comply with post-injection site care and facility closure plan pursuant to section 43-05-01-19.

III. CASE SPECIFIC PERMIT CONDITIONS

1. NDAC 43-05-01-11.4, subsection 1, subdivision b; The operator shall notify the Commission within 24 hours of failure or malfunction of any surface or bottom hole gauges in the proposed IIW-N and IIW-S injectors, and the J-LOC 1 (File No. 37380 – SWNE 27-145N-88W) monitor well.

2. NDAC 43-05-01-11.4, subsection 1, subdivision c and NDAC 43-05-01-11, subsection 14; The operator shall run an ultrasonic or other log capable of evaluating internal and external pipe condition to establish a baseline for corrosion monitoring for the proposed IIW-N and IIW-S wells. The operator shall run logs with the same capabilities for the IIW-N and IIW-S wells on a 5 year schedule, unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.

3. NDAC 43-05-01-11.4; subsection 1, subdivision d and NDAC 43-05-01-13, subsection 2, The operator shall cease injection immediately, take all steps reasonably necessary to identify and characterize any release, implement the emergency and remedial response plan approved by the Commission, and notify the Commission within 24 hours of carbon dioxide detected above the confining zone.

4. NDAC 43-05-01-11.4; subsection 1, subdivision e and NDAC 43-05-01-11.1 subsections 3 and 5, External mechanical integrity shall be continuously monitored with the proposed fiber optic lines for the IIW-N and IIW-S wells. The Commission must be notified within 24 hours should a fiber optic line fail. The Commission must be notified prior to severing the line above the confining zone if such an action becomes necessary for remedial work or monitoring activities.

5. NDAC 43-05-01-11.4, subsection 1, subdivision h, paragraph 1; Surface air and soil gas monitoring is required to be implemented as planned by the operator in Section 5.2 (Surface Facilities Leak Detection Plan) and Section 5.7.1 (Near-Surface Monitoring) of its permit.

6. NDAC 43-05-01-10, subsection 9, subdivision c, NDAC 43-05-01-11, subsection 15, and NDAC 43-05-01-11.1, subsection 2; The operator shall notify the Commission at least 48 hours in advance to witness a mechanical integrity test of the tubing-casing annulus for the injection and monitoring wells. The packer must be set within 100' of the upper most perforation and in the 15CR-80 casing or better

for the IIW-N and IIW-S injectors and 13CR-95 casing for the J-LOC 1 monitor. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the IIW-N and IIW-S injection wells.

7. NDAC 43-05-01-11, subsections 3 and 5; The operator shall continuously monitor the surface casing-long string casing annulus with proposed fiber optic lines, and a gauge not to exceed 300 psi. The Commission must be notified in advance if there is pressure that needs to be bled off.

8. NDAC 43-05-01-05, subsection 1; Any other information that the Commission requires the storage facility permit to include. The operator shall implement a data sharing plan that provides for real-time sharing of data between DCC's West operations, the permitted operations of the east carbon dioxide storage facilities (Minnkota Center MRYS Broom Creek Storage Facility #1 and Minnkota Center MRYS Deadwood Storage Facility #1), and any other third-party sources that are piped in. If a discrepancy in the shared data is observed, the party observing the data discrepancy shall notify all other parties, take action to determine the cause, and record the instance. Copies of such records must be filed with the Commission upon request.

9. NDAC 43-05-01-17, subsection 1; The storage operator must pay fees based upon the carbon dioxide source and the amount of carbon dioxide injected for storage. The Commission must make a determination on the contribution to the energy and agriculture production economy of North Dakota of each additional carbon dioxide source, before it is approved to be stored. If the Commission deems a carbon dioxide source does not contribute to the energy and agricultural production economy of North Dakota, the fees will be determined by hearing.

10. NDAC 43-05-01-11.3, subsection 3; The operator shall fill the annulus between the tubing and the long string casing with a noncorrosive fluid approved by the Commission. The storage operator shall maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger the underground sources of drinking water. Section 5.4 (Wellbore Mechanical Integrity Testing) proposes a nitrogen cushion of 250 psi minimum to maintain constant positive pressure on the well annulus in each injector. Section 11.0 (Injection Well and Storage Operations) proposes a maximum operating injection pressure of 2100 psi.

Fact Sheet

1. Description of Facility

DCC West Project LLC (DCC West) is a wholly owned subsidiary of Minnkota Power Cooperative, Inc. (Minnkota) and intends to primarily serve the geologic storage of carbon dioxide needs of Minnkota. Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a mine-mouth lignite coal-fired power plant. The lignite used as fuel for electrical generation is the primary source of carbon dioxide.

In addition to providing storage services to MRYS's carbon dioxide, to the extent there is additional storage capacity, DCC West may market carbon dioxide storage services to third-party entities. DCC West proposes these sources may include post combustion of fossil fuel electric power generation (natural gas or lignite coal) NAICS 221112, ethanol manufacturing NAICS 325193, manufactured agricultural products NAICS 325311 (e.g., fertilizer, urea, and ammonia), cement/concrete production NAICS 327120, direct air capture, and other industrial sources within the state and regionally.

2. Quantity and Quality of Carbon Dioxide Stream

The storage facility is being designed to receive a maximum operating rate of 6.11 million metric tons annually and a maximum of 122.9 million metric tons over a 20-year injection period.

At the MRYS, the carbon dioxide stream is expected to be captured, dehydrated, compressed, and then injected. The projected composition of the MRYS carbon dioxide stream to be injected is at least 98% carbon dioxide, <1.7% nitrogen, with trace quantities of water, oxygen, hydrogen sulfide, sulfur, hydrocarbons, glycol, amine, aldehydes, nitrogen oxides, and ammonia, equaling less than 0.03% combined.

DCC West is proposing that if third-party carbon dioxide stream is accepted the combined carbon dioxide stream must be at least 96% carbon dioxide, ≤3.7% nitrogen, with trace quantities of water, oxygen, hydrogen sulfide, sulfur, hydrocarbons, glycol, amine, aldehydes, nitrogen oxides, and ammonia, equaling less than 0.03% combined.

3. Summary of Basis of Draft Permit Conditions

The case specific permit conditions are unique to this storage facility, and not indicative of conditions for other storage facility permits. The conditions take into consideration the equipment proposed for this storage facility. Regulatory provisions for these conditions are all cited from NDAC Chapter 43-05-01 (Geologic Storage of Carbon Dioxide).

4. Reasons for Variances or Alternatives

<u>Draft Permit Section III. Case Specific Conditions are referenced below by number from aforementioned section.</u>

4. NDAC 43-05-01-11.4, subsection 1, subdivision e, requires a demonstration of external mechanical integrity at least once per year until the injection well is plugged. NDAC 43-05-01-11.1, subsection 3 requires the storage operator to, at least annually, determine the absence of significant fluid movement outside the casing by running an approved tracer survey or temperature log or noise log. The proposed fiber optic lines shall provide continuous temperature logs for the length of the injection wellbores.

10. NDAC 43-05-01-11.3, subsection 3; The operator shall fill the annulus between the tubing and the long string casing with a noncorrosive fluid approved by the Commission. The storage operator shall maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Commission determines that such a requirement might harm the integrity of the well or endanger the underground sources of drinking water. The proposed nitrogen cushion of 250 psi minimum to maintain constant positive pressure on the well annulus in each injector will provide corrosion protection without risking the creation of a micro annulus by debonding of the long string casing-cement sheath during the operational life of the well. The Commission finds a micro annulus would harm external mechanical integrity and provide a potential pathway for endangerment of USDWs.

5. Procedures Required for Final Decision

The beginning and ending dates of the comment period:
May 16, 2023 to 5:00 P.M. CDT June 29, 2023

The address where comments will be received:
Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512 or brkadrmas@nd.gov

Date, time, and location of the storage facility permit hearing:
June 30, 2023 9:00 A.M. CDT at 1000 East Calgary Avenue, Bismarck, North Dakota 58503

Any other procedures by which the public may participate in the final decision:
At the hearing, the Commission will receive testimony and exhibits of interested parties.
#

6. Contact for Additional Information

Draft Permit Information: Tamara Madche – tjmadche@nd.gov – 701-328-8020
Hearing Information: Bethany Kadrmas – brkadrmas@nd.gov – 701-328-8020#

Minnkota Power
COOPERATIVE
A Touchstone Energy® Cooperative

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

March 10, 2023

DELIVERED VIA-EMAIL: *tjmadche@nd.gov*
rasuggs@nd.gov

North Dakota Industrial Commission
c/o Tamara Madche
State Capitol, Dept 405
600 East Boulevard Avenue
Bismarck, ND 58505-0840

–NOTIFICATION OF ELECTRONIC FILING–

RE: DCC West Project LLC SFP and Class VI applications

Dear Ms. Madche,

DCC West Project LLC (DCC West) is pleased submit a storage facility permit application for the establishment of a geologic storage facility and the operation of two injection wells for the purpose of securely storing carbon dioxide in Oliver County, North Dakota. The site link, is provided below:

Electronic Submission Broom Creek Storage Facility Permit, Link: Dakota Carbon Center West Project Storage Facility Permit

Please find enclosed herewith for filing an original of the following:

1. Permit Application Certification-Broom Creek

Please contact me at (701) 795-4000 or smikula@minnkota.com if you have any questions regarding this filing.

Sincerely,

Shannon R. Mikula
Special Projects Counsel

Enclosure
cc: *Mac McLennan, mmclennan@minnkota,com*
Craig Bleth, cbleth@minnkota.com
Lawrence Bender, lbender@fredlaw.com

Permit Application Certification
-Broom Creek-

BEFORE ME, the undersigned authority, personally appeared Robert McLennan of DCC West Project LLC ("DCC West"). whose office is located at 5301 32nd Avenue South, Grand Forks, ND 58201 who being duly sworn, upon oath stated and certify that:

1. I, Robert McLennan, am over eighteen years of age. I have personal knowledge of the information and facts stated by me in this Certification and that they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.
2. I hold the position of Chief Executive Officer for DCC West. As required accordance with North Dakota Administrative Code § 43-05-01-07.1 and by virtue of my position with DCC West, I am authorized to make the representations on behalf of DCC West.
3. Enclosed are the storage facility permit application requesting permits under Chapter 38-22 of the North Dakota Century Code, and in accordance with Article 43-05 of the North Dakota Administrative Code, for the establishment of carbon dioxide storage facilities located in Oliver County, North Dakota. The application is associated with the Broom Creek formation. Further, enclosed are the accompanying Class VI drilling permit information carbon dioxide two (2) injection wells and (1) monitoring well.
4. Based upon information and reports provided by individuals immediately responsible for compiling and preparing the enclosed permit applications and supporting information, I have personal knowledge and am familiar with the information being submitted in the enclosed documents and attachments to the permit applications. Based upon information and belief, the information contained herein is true, accurate and complete.
5. I affirm under penalty of perjury that the representations contained in this affidavit are true, to the best of my knowledge, information, and belief. I understand that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment.
6. By my signature below, I hereby submit the enclosed applications and supporting documents and information on behalf of DCC West.

Executed this 10th day of March, 2023.

Robert McLennan

STATE OF NORTH DAKOTA)
)SS.
COUNTY OF GRAND FORKS)

Subscribed and sworn to before me this 10th day of March, 2023.

KIMBERLY JOHNSON RUSTAD
Notary Public
State of North Dakota
My Commission Expires Oct. 9, 2026

From:	Olsen, Caitlin
To:	Madche, Tamara J.; Suggs, Richard A.
Cc:	Shannon Mikula; Connors, Kevin
Subject:	DCC West SFP Revised Permit
Date:	Thursday, May 4, 2023 1:26:17 PM
Attachments:	DMR Comments 5.5.23.xlsx

Good Afternoon-

The latest revisions have been addressed and a new permit has been uploaded to the Sharepoint. Attached is a table that explains how we answered each DMR remark.

Thanks,

Caitlin Olsen
Senior Regulatory and Permitting Specialist
Energy & Environmental Research Center | Grand Forks, ND
Phone: 507.272.9217 | www.undeerc.org

DCC WEST PROJECT LLC– CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO_2 Storage Facility Permit Application

Prepared for:

Richard Suggs
Tammy Madche

North Dakota Industrial Commission
Oil & Gas Division
600 East Boulevard Avenue
Department 405
Bismarck, ND 58505-0840

Prepared by:

DCC West Project LLC
5301 32nd Avenue South
Grand Forks, ND 58201

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

April 2023

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LIST OF ACRONYMS

AI	acoustic impedance
ANSI	American National Standards Institute
AOR	area of review
API	American Petroleum Institute
ASLMA	Analytical Solution for Leakage in Multilayered Aquifers
ASTM	ASTM International
AZMI	above-zone monitoring interval
BHA	bottomhole assembly
BHP	bottomhole pressure
BNI	BNI Coal, Inc.
BOP	blowout preventer
bpm	barrels per minute
BTC	buttress thread and coupled
$C_2H_6O_2$	glycol
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CIBP	cast iron bridge plug
CICR	cast iron cement retainer
CIL	casing inspection log
CMG	Computer Modelling Group Ltd.
CMR	combinable magnetic resonance
CO_2	carbon dioxide
COW	control of well
CPR	cardiopulmonary resuscitation
CSE	confined space entry
DAS	distributed acoustic sensing, data acquisition system
DCC	Dakota Carbon Center
DCC East	DCC East Project LLC
DCC West	DCC West Project LLC
DCC West SGS	Dakota Carbon Center West SGS Project
DGC	Dakota Gasification Company
DIC	dissolved inorganic carbon
DMR	Department of Mineral Resources
DOT	Department of Transportation
DST	drillstem test
DTS	distributed temperature sensing
EERC	Energy & Environmental Research Center
EIL	environmental impairment liability
EPA	Environmental Protection Agency
ERR	emergency remedial response
ERRP	emergency remedial response plan

Continued . . .

LIST OF ACRONYMS (continued)

ERT	emergency response team
ESD	emergency shutdown
FADP	financial assurance demonstration plan
FIT	formation integrity test
FNL	from the north line
FWL	from the west line
GFCI	ground fault circuit interrupter
GPR	ground-penetrating radar
GR	gamma ray
H_2O	water
H_2S	hydrogen sulfide
HADES	high-resolution acoustic downhole evaluation system
HazMat	hazardous materials
HAZOP	hazard and operability
HAZWOPER	hazardous waste operations and emergency response
HES	health, environment, and safety
HNA	hearing notification area
HNBR	hydrogenated nitrile
HSE	health, safety, and environmental
ICP	integrated contingency plan
ID	inner diameter
JSA	job safety analysis
K_{int}	intrinsic permeability
ksi	kilopound per square inch
LDS	leak detection system
LOC	loss of containment
LOTO	lockout/tagout
MAG	Midwest AgEnergy Group
mD	millidarcy
MD	measured depth
MDT	modular dynamics testing
MEM	mechanical earth model
MI	mechanical integrity
MICP	mercury injection capillary pressure
MIT	mechanical integrity text
M–M	premium metal-to-metal connection
MM	million
MMI	modified Mercalli intensity
MMscf	million standard cubic feet
MMt	million metric tons
MMt/y	million metric tons per year
MOC	management of change

Continued . . .

LIST OF ACRONYMS (continued)

mol%	mole percent
MPC	Minnkota Power Cooperative
MRYS	Milton R. Young Station
MU	make up
MVA	monitoring, verification, and accounting
MVTL	Minnesota Valley Testing Laboratories
N_2	nitrogen
NACE	National Association of Corrosion Engineers
NAICS	North American Industry Classification System
NDAC	North Dakota Administrative Code
NDCC	North Dakota Century Code
NDIC	North Dakota Industrial Commission
NEC	National Electrical Code
NFPA	National Fire Protection Association
NIOSH	National Institute of Occupational Safety and Health
NMPA	Northern Municipal Power Agency
NU	nipple up
O_2	oxygen
OD	outer diameter
OEM	original equipment manufacturer
OGI	optical gas imaging
OLCV	Oxy Low Carbon Ventures
OSHA	Occupational Safety and Health Administration
P&A	plugged and abandoned
PBTD	plug back total depth
PHIE	effective porosity
PHIT	total porosity
PISC	postinjection site care, postinjection site closure
PLC	programmable logic controller
PLT	production logging tool
PNL	pulsed-neutron log
POOH	pull out of hole
PPE	personal protective equipment
ppg	pounds per gallon
ppmv	parts per million by volume
P/T	pressure/temperature
QA/QC	quality assurance/quality control
QASP	quality assurance and surveillance plan
QI	qualified individual
RIH	run in hole
RST	reservoir saturation tool
RU	rig up

Continued . . .

LIST OF ACRONYMS (continued)

SCADA	supervisory control and data acquisition
SDS	safety data sheets
SFP	storage facility permit
SGP	soil gas profile
SGS	secure geologic storage
SIMOPS	simultaneous operations
SLRA	screening-level risk assessment
SP	spontaneous potential
spf	shots per foot
SWC	sidewall core, State Water Commission
sx	sacks
TA	temporarily abandoned
TBD	to be determined
TD	total depth
TDA	thermal decomposition amalgamation
TDS	total dissolved solids
TF	task force
TIH	trip in hole
TOC	top of cement, total organic carbon
TOOH	trip out of hole
TVD	true vertical depth
UCS	uniaxial compressive strength
UIC	underground injection control
UPS	uninterrupted power supply
USDW	underground source of drinking water
USGS	U.S. Geological Survey
USIT	ultrasonic imaging tool
VDL	variable-density log
VSP	vertical seismic profile
WBM	water-based mud
WHP	wellhead pressure
WHT	wellhead temperature
WLEG	wireline entry guide
WOC	wait on cement
WSP	worker safety plan
XRD	x-ray diffraction
XRF	x-ray fluorescence

DAKOTA CARBON CENTER WEST SGS – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION

PERMIT SUMMARY

General Applicant and Project Information. DCC West Project LLC (DCC West), a wholly-owned subsidiary of Minnkota Power Cooperative, Inc. (Minnkota), prepared this supporting documentation for its storage facility permit (SFP) and underground injection control (UIC) Class VI permit applications to establish a storage reservoir and construct and operate two injection wells located in Oliver County, North Dakota, operated for the secure geologic storage (SGS) of carbon dioxide (CO_2) over a 20-year injection period. DCC West is the project sponsor of Dakota Carbon Center West SGS Project (DCC West SGS) operation. Minnkota anticipates contributing a portion of the total equity of the proposed DCC West SGS, but the equity participants have not yet been identified. As such, the application names DCC West as the sole storage facility operator and applicant. Current mailing address for the DCC West SGS and DCC West, as the storage facility operator, is the following:

Minnkota Power Cooperative, Inc.
c/o DCC West Project LLC
5301 32nd Avenue South
Grand Forks, ND 58201

DCC West, as a wholly-owned subsidiary entity of Minnkota, intends to primarily serve the SGS needs of Minnkota and any remaining storage capacity would be marketed to third-party industrial sources. Minnkota is a regional generation and transmission cooperative headquartered in Grand Forks, North Dakota, providing wholesale power to 11 member-owner rural electric distribution cooperatives in eastern North Dakota and northwestern Minnesota. Minnkota is also affiliated with the Northern Municipal Power Agency (NMPA), which serves the electric needs of 12 municipalities in the same geographic region as the Minnkota member-owners. Minnkota serves as the operating agent of NMPA. Figure PS-1 provides a map showing the Minnkota and NMPA service territory. Minnkota's primary generating resource is the two-unit Milton R. Young Station (MRYS), a minemouth lignite coal-fired power plant. The mine providing the lignite coal for MRYS is owned and operated by BNI Coal, Inc. (BNI) and is adjacent to the MRYS facility. The lignite used as the fuel for electrical generation also serves as the primary source of the captured CO_2 that will be securely sequestered by DCC West. The standard industrial classification code for the principal products and services provided by Minnkota is best reflected as NAICS (North American Industry Classification System) 221112, Fossil Fuel Electric Power Generation.

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

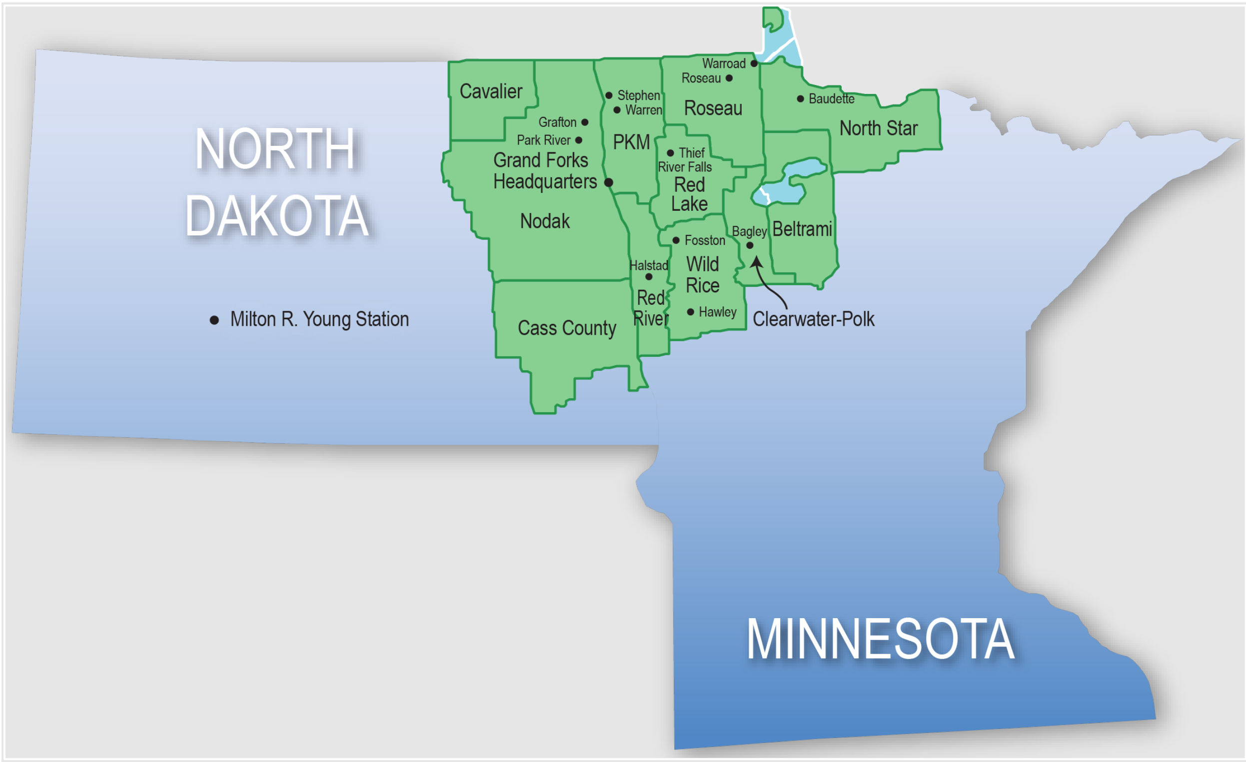

Figure PS-1. Map of the Minnkota and NMPA service territory.

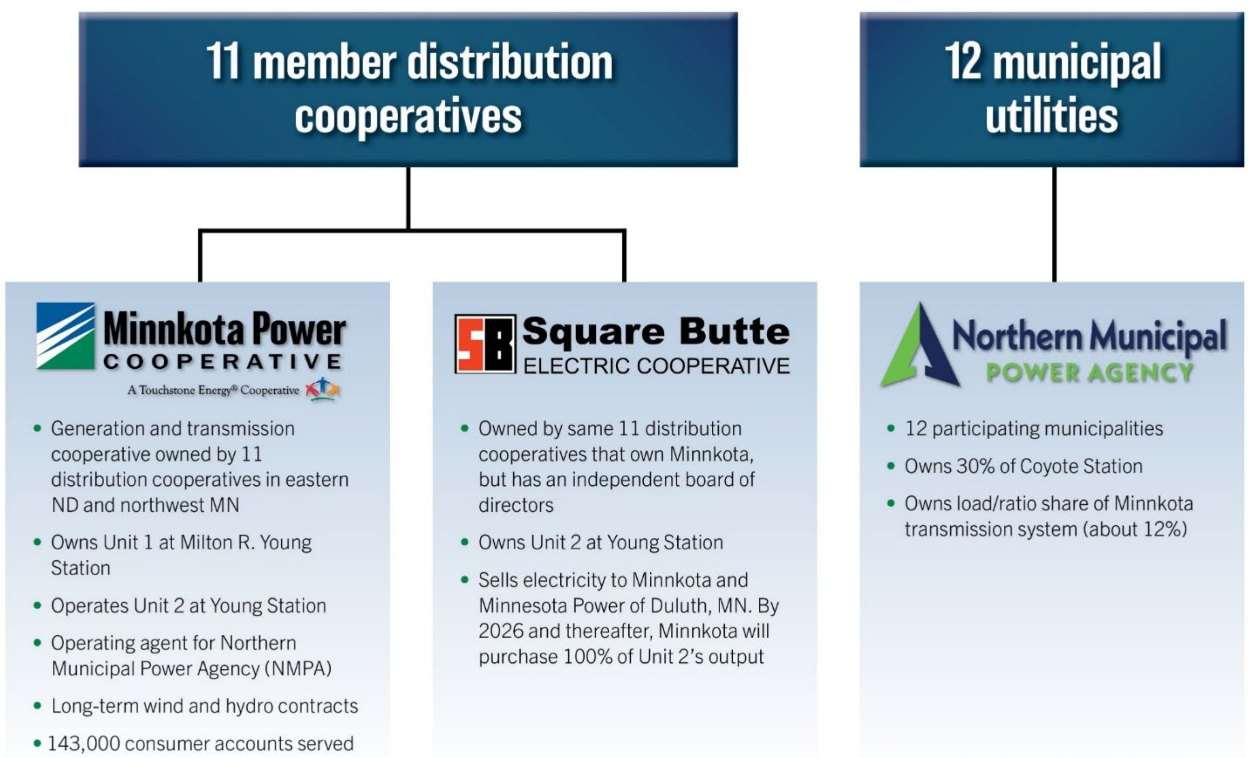

Figure PS-2. Chart showing the relationships between Minnkota and its affiliated organizations.

In addition to providing storage services to MRYS CO_2, to the extent there is additional storage capacity, DCC West may market CO_2 storage services to third-party entities. DCC West proposes the following industrial sources of CO_2 may be available over the life of the proposed 20 years of operation of the storage project: postcombustion of fossil fuel electric power generation (natural gas or lignite coal) NAICS 221112, ethanol manufacturing NAICS 325193, manufactured agricultural products NAICS 325311 (e.g., fertilizer, urea, and ammonia), cement/concrete production NAICS 327120, direct air capture, and other industrial sources within the state and regionally. DCC West is requesting a commercial permit for the operation of the storage facility to provide flexibility to receive sources so long as any source can meet or exceed 96% CO_2. DCC West has confirmed the system and injection zone characteristics can safely accept such a stream composition. Refer to Section 2.3.4, Geochemical Information of Injection Zone, for further support.

The proposed DCC West SGS injection site is approximately 7 miles west of MRYS and the location of the Minnkota Center MRYS Broom Creek Storage Facility #1 created and established by North Dakota Industrial Commission (NDIC) Order No. 31583 and the Minnkota Center MRYS Deadwood Storage Facility #1 created and established by NDIC Order No. 31586. At or about the time of this application, Minnkota has filed a request to transfer the Minnkota Center MRYS Broom Creek Storage Facility #1 and Minnkota Center MRYS Deadwood Storage Facility #1 to DCC East LLC (DCC East). Upon review and issuance of regulatory orders authorizing the transfer of ownership from Minnkota to DCC East, the Minnkota Center MRYS Broom Creek Storage Facility #1, shall be renamed DCC East Center Broom Creek Storage Facility #1 and Minnkota Center MRYS Deadwood Storage Facility #1 shall be renamed DCC East Center Deadwood Storage Facility #1 (Table PS-1).

Table PS-1. Facility Name Changes.

Original NDIC Order No.	NDIC Facility Name	Modified NDIC Facility Name
31583	Minnkota Center MRYS Broom Creek Storage Facility #1	DCC East Center Broom Creek Storage Facility #1
31586	Minnkota Center MRYS Deadwood Storage Facility #1	DCC East Center Deadwood Storage Facility #1

The DCC West SGS injection site is located southeast of the town of Center (see Figure PS-3) and will include two injection wells, one dedicated Fox Hills monitoring well for the lowest underground source of drinking water (USDW), and associated surface facility infrastructure that will accept CO_2 transported via an approximately 7.4-mi CO_2 flowline entirely contained within and connecting the storage facility boundary of the proposed DCC West storage facility and the DCC East SGS Project. In addition, one reservoir-monitoring well is proposed to be installed approximately 3.7 miles northeast of the DCC West SGS injection site. All the aforementioned injection surface facilities and underground equipment will be contained on Minnkota-owned property, and the flowline will be constructed and maintained with private landowner access right-of-way, Figure PS-3.

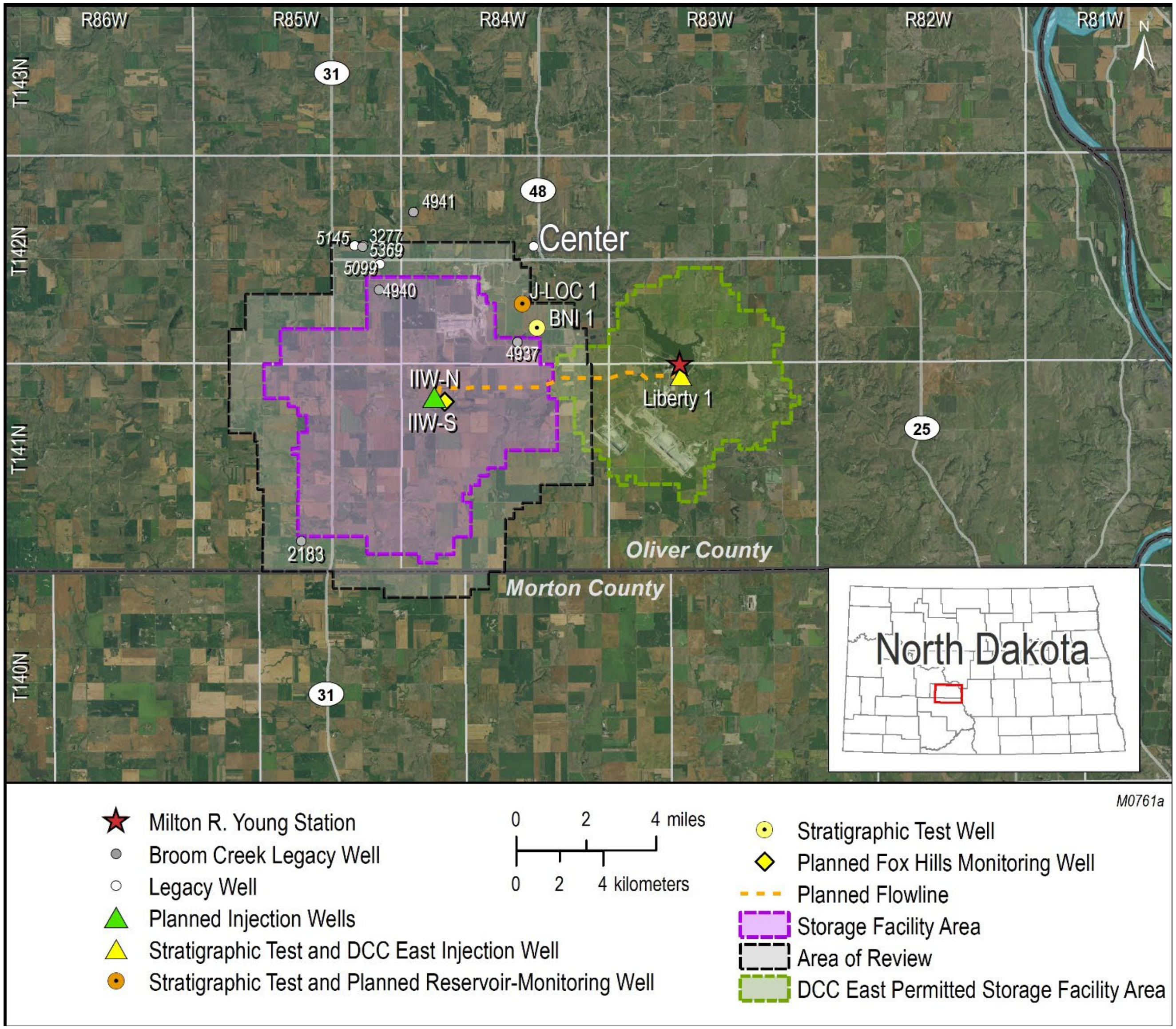

Figure PS-3. DCC West SGS project map in relation to DCC East SGS.

Storage Reservoir Boundary/Area of Review (AOR). DCC West defines the storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start of injection until the end of injection. The storage reservoir boundary is identified based on the computational numerical model output of the areal extent of the subsurface CO_2 volume at the end of the injection period (20 years) in which a CO_2 saturation is predicted to be greater than or equal to 5%. To identify the storage reservoir boundaries, reservoir simulation software was used to model the hydrologic, chemical, thermal processes, and chemical interactions with the aqueous fluids and rock minerals. The volume is determined from the numerical model and the resulting map area is displayed in Figure PS-3.

The primary objective of the AOR is delineating the region encompassing DCC West SGS where USDWs may be endangered by the injection activity (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). The AOR is generally defined as the horizontal extent of a pressure increase threshold caused by injection.

Also shown in Figure PS-3, the AOR has been defined for the targeted CO_2 storage reservoir. This area is used to identify the existence of any confining zone penetrations (i.e., existing wells that may penetrate the cap rock). Within the AOR, six existing wellbores penetrate the Broom Creek Formation (NDIC Well Nos. 2183, 3277, 4937, 4940, 34244 [BNI 1], and 37380 [J-LOC 1]). Two of those wellbores are stratigraphic test holes drilled in the past 7 years as part of geologic characterization efforts supporting this SFP application (BNI 1 and J-LOC 1). Of the six existing wellbores that penetrate the Broom Creek Formation, one (J-LOC 1) is proposed as a planned reservoir-monitoring well as discussed further in Section 5. Surface bodies of water and other pertinent surface features, administrative boundaries, and roads within the AOR are shown in Figure PS-3.

DCC West incorporated the AOR assessment into the corrective action evaluation and testing and monitoring plan. The deep subsurface monitoring plan and near-surface monitoring plan are each tailored to the proposed AOR delineation. The AOR assessment of these penetrating wells indicates that none could serve as conduits for the movement of fluids from the injection zone into USDWs. Therefore, no corrective actions on existing wells need to be taken. Additionally, there are no subsurface cleanup sites, quarries, or tribal lands within the AOR.

Construction and Operations Plan. DCC West SGS is designed to securely store the injected CO_2 within the storage reservoir. DCC West anticipates operating the site in concert with the DCC East SGS Project, because by surface facility design, CO_2 would flow from east to west along the 7.4-mi flowline connecting the DCC East SGS Project and the DCC West SGS injection site. Since both DCC East SGS Project and DCC West SGS are being developed to primarily serve Minnkota's SGS needs at MRYS and since the system interconnection point for third party CO_2 is located within the DCC East permitted storage facility area, the DCC East SGS Project storage facility will be constructed first and DCC West SGS storage facility will be constructed simultaneously or following validation of excess storage capacity availability and demand for additional MRYS storage or third-party storage opportunities.

At MRYS, the captured CO_2 stream will be at least 99% purity, dehydrated, and compressed to 1800 psi before entering the CO_2 flowline. At these conditions, the CO_2 will be in a dense fluid phase, noncorrosive, and nonflammable. The approximately 7.4-mile flowline will be 20 in. in outer diameter (OD) and have a maximum design flow rate of 7 MMt/yr (224 MMscf/d). Because of the short distance between the compressor and the wellsite (7.4 mi), CO_2 pressure is not anticipated to decrease significantly as the CO_2 travels the length of the flowline to the DCC West SGS injection site.

For DCC West SGS, at the injection wellheads, the pressure may be increased for injection up to a maximum of 2100 psi through the use of a booster pump downstream of the custody transfer metering station. However, based on the current operating assumptions (both wells operating together) the injection wellhead pressure at the DCC West SGS site is a maximum pressure of 2459 psi (IIW-S) and 1997 psi (IIW-N). To preserve operational flexibility and opportunity for operational variability DCC West SGS is presenting wellhead pressures at maximum rate as constrained by bottomhole pressure, rather than surface equipment limitation.

The DCC West SGS site design was optimized for receiving the CO_2 at a combined maximum operating rate of 6.11 MMt/yr, which represents 100% capacity factor for the system design. Two wells are proposed for the Broom Creek storage reservoir (to be named IIW-N and IIW-S) in a twin-well design. The injection well designs afford an optimized storage reservoir operation. The design also takes into account the need for redundancy for planned or unplanned outage of any of the wells for maintenance or repair. IIW-N and IIW-S injection wells will be drilled from a common well pad with 100-ft spacing between wellheads, both will be completed as deviated injectors with bottomhole location 1000 ft offset, the IIW-N injection well will be offset to the north, and the IIW-S injection well will be offset to the south. The maximum rates of the two injector wells and the associated equipment were based on operational flexibility, which includes site-specific (DCC West SGS) consideration of the bottomhole pressure constraint, surface facility infrastructure constraints, and operating capacity of two injection well designs (currently designed for 7" or 6 5/8" tubing, 7" was used for simulations for determining the storage facility boundary). These two injection wells will be operated together to receive CO_2 at a rate not to exceed the maximum safe operating rate of approximately 6.11 MMt/yr.

DCC West will primarily operate to serve MRYS CO_2 sequestration needs. At MRYS, the captured CO_2 stream will exceed 98% purity. DCC West calculated a CO_2 stream specification from the MRYS, as shown in Table PS-2. In addition to providing storage services to the MRYS CO_2, to the extent there is excess storage capacity, DCC West will market CO_2 storage services to third-party entities. If third-party CO_2 is accepted, the combined CO_2 stream will meet composition requirements as shown in Table PS-3. DCC West is requesting a commercial permit for the operation of the storage facility to provide flexibility to receive sources so long as any source can meet or exceed a 96% CO_2. A CO_2 stream composition was modeled for the DCC West site for the purposes of establishing the storage facility boundary using a 98.25% CO_2, stream composition, which represents the averaged stream composition (stream may range from minimum composition of 96% CO_2 to 99.9% CO_2). The composition of carbon dioxide streams from other sources may vary but will be required at the custody transfer meter to meet or exceed a composition of 96% carbon dioxide DCC West modeled a less stringent CO_2 to avoid underestimation of the impact to the injection reservoir and confining formations; refer to Section 2.3.4 for further support.

Table PS-2. Calculated MRYS Stream Composition

Component	Composition	Volume %
CO_2	≥ 98%	≥ 98.0%
N_2	< 17,000 ppmv*	< 1.7%
H_2	0 ppmv	0.000%
O_2	< 69 ppmv	< 0.0069%
H_2S	< 10 ppmv	< 0.0010%
Total Sulfur	< 1.25 ppmv	< 0.000125%
Moisture – No Free Water	< 642 ppmv	< 0.0642%
Hydrocarbons	< 1800 ppmv	< 0.18%
Glycol	< 7 ppmv	< 0.0007%
Amine	< 1.25 ppmv	< 0.000125%
Aldehydes	< 5 ppmv	< 0.0005%
NO_x	< 50 ppmv	< 0.005%
NH_3	< 1 ppmv	< 0.0001%
TOTAL		100.0%

Table PS-3. Calculated MRYS and Third-Party Stream Composition

Component	Composition	Volume %
CO_2	≥ 96%	≥ 96.0%
N_2	< 37,000 ppmv*	< 3.7%
H_2	0 ppmv	0.000%
O_2	< 100 ppmv	< 0.0100%
H_2S	< 10 ppmv	< 0.0010%
Total Sulfur	< 1.25 ppmv	< 0.000125%
Moisture – No Free Water	< 642 ppmv	< 0.0642%
Hydrocarbons	< 1800 ppmv	< 0.18%
Glycol	< 7 ppmv	< 0.0007%
Amine	< 1.25 ppmv	< 0.000125%
Aldehydes	< 5 ppmv	< 0.0005%
NO_x	< 50 ppmv	< 0.005%
NH_3	< 1 ppmv	< 0.0001%
TOTAL		100.0%

DCC West proposes to conduct storage operations utilizing two Class VI injection wells for CO_2 injection into the Broom Creek Formation (i.e., storage reservoir). Permit applications for each of these proposed injection wells have been prepared and will be submitted, with the supporting documentation for each of the wells collectively provided within this storage facility application and attachments. This application and its supporting documents have been prepared in accordance with the North Dakota Century Code and the NDAC. The applications and supporting documentation are based on currently available data, including regional data and site-specific data derived from two stratigraphic test wells (J-LOC 1 and Liberty 1 [NDIC File No. 37672]) drilled by Minnkota in 2020 and one stratigraphic test well drilled by the Energy & Environmental Research Center (EERC) in 2018 and all located within 7.4 miles of the proposed injection wells.

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

Testing and Monitoring Plan. An extensive monitoring, verification, and accounting (MVA) system will be implemented to verify that injected CO_2 is effectively contained within the injection zone. The objectives of the MVA program are to proactively account for corrosion and leakage in well equipment and surface facilities, track the lateral extent of CO_2 within the injection zones, characterize any geochemical or geomechanical changes that occur within the injection and confining zones that may affect containment, and track the areal extent of the injected CO_2 through indirect monitoring techniques such as geophysical and surveillance methods. The monitoring network, as described in Section 5, will be designed to account for and verify the location of CO_2 injected.

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

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

The proposed monitoring program includes one reservoir-monitoring well which traverses the Broom Creek injection zone and the upper and lower confining zones to verify CO_2 is contained within the storage reservoir. In addition, a groundwater monitoring well will be completed at the DCC West SGS site in the Fox Hills Formation to be protective of this lowermost USDW. Monitoring of the storage facility area will continue for a minimum of 10 years after injection has ceased.

Financial Responsibility Plan. DCC West has developed a plan to maintain financial responsibility for the construction, operation, closure, and monitoring of the proposed injection wells and to undertake any emergency or remedial response actions that may be necessary. To ensure that sufficient funds will be available, DCC West has obtained an estimate of the cost of hiring a third party to undertake any necessary actions to protect USDWs within the AOR. DCC West will also obtain a third-party insurance policy that would be available for conducting any emergency or remedial response actions.

Conclusion. DCC West prepared its SFP and Class VI UIC permit applications and supporting documentation to demonstrate that 1) the proposed DCC West SGS comprises the injection zone with sufficient areal extent, thickness, porosity, and permeability to receive up to 122.9 MMt of CO_2 over 20 years of operation and 2) the confining zone and secondary confining zones are free of faults and fractures and are of sufficient areal extent and integrity to vertically contain the injected CO_2, allowing the injection of CO_2 at the proposed pressures and volumes without initiating or propagating fractures in the reservoir or confining zones. These findings are supported by the data and information gathered from coring, logging, sampling, and testing the characteristics in three stratigraphic wells that provided site-specific geologic data as well as available regional data.

DCC West has developed comprehensive construction and operations, testing and monitoring, injection well plugging, and PISC plans, as well as an ERRP to protect USDWs. To ensure that sufficient funds are available to undertake these actions, DCC West has also developed a financial responsibility demonstration.

DCC West is confident that its permit application and supporting documentation demonstrate compliance with NDAC 43-05-01 (Geologic Storage of Carbon Dioxide) and the North Dakota Legislature's authorizing statute. Table PS-4 provides a crosswalk between the regulatory requirements in that rule and the organization of DCC West's supporting documentation.

Table PS-4. Crosswalk Between Applicable Regulatory Provisions in NDAC Rule and the DCC West SGS SFP Application and Supporting Documents

NDAC Rule/Regulatory Requirements	DCC West SGS SFP Application
43-05-01-05: Storage Facility Permit	Sections 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12
43-05-01-05.1: Area of Review and Corrective Action	Sections 3, 4, 7
43-05-01-08: Storage Facility Permit Hearing. [Notice Requirements]	Section 1
43-05-01-09: Well Permit Application Requirements	Sections 4, 5, 9, and Form 25 (NorthSTAR)
43-05-01-09.1: Financial Responsibility	Section 12, Appendix F
43-05-01-10: Injection Well Permit	Project Summary
43-05-01-11: Injection Well Construction and Completion Standards	Sections 2, 5, 11
43-05-01-11.1: Mechanical Integrity – Injection Wells	Sections 5, 6, 7, 10, 12
43-05-01-11.2: Logging, Sampling, and Testing Prior to Injection Well Operation	Sections 2, 5, 11
43-05-01-11.3: Injection Well Operating Requirements	Sections 5, 11
43-05-01-11.4: Testing and Monitoring Requirements	Section 5, Appendix C
43-05-01-11.5: Injection Well Plugging	Sections 6, 10, 12
43-05-01-11.6: Injection Depth Waiver Requirements	Not applicable
43-05-01-13: Emergency and Remedial Response Plan	Section 7
43-05-01-14: Leak Detection and Reporting	Section 5
43-05-01-15: Storage Facility Corrosion Monitoring and Prevention Requirements	Section 5
43-05-01-19: Postinjection Site Care and Facility Closure	Sections 6, 12

SECTION 1.0

PORE SPACE

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31, Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is required, in good faith, to attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith effort, they were able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of pore space. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of this SFP application (NDCC § 38-22-06[3] and [4]) and North Dakota Administrative Code (NDAC) § 43-05-01-08[1] and [2]).

All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates there was no severance of pore space or leasing of pore space to a third party from the surface estate prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record.

1.1 Storage Reservoir Pore Space

DCC West Project LLC (DCC West) defines the proposed storage reservoir boundaries as the projected vertical and horizontal migration of the CO_2 plume from the start of injection until the end of injection. The storage reservoir's vertical and horizontal boundaries are identified based on the computational numerical model output of the areal extent of the CO_2 plume volume at the end of the injection period (20 years) in which a CO_2 saturation is predicted to be greater than or equal to 5%. The model utilizes applicable geologic and reservoir-engineering information and analyses as detailed in Sections 2 and 3. The operational inputs for the simulation scenarios assume storage at the maximum designed injection rates based upon the bottomhole pressure constraints of 90% of the formation fracture gradient and wellhead pressure constraint of 2100 psi as a result of surface facility equipment maximum operating specifications. In addition to DCC West's consideration of the surface- and bottomhole-pressure constraints, DCC West considered surface facility infrastructure constraints, and operating capacity of two injection well designs (currently designed for 7" or 6 5/8" tubing, 7" was used for simulations for determining the storage facility boundary).

Additionally, the DCC East SGS Project operation assumption is included in the numerical model and simulated as injecting simultaneously with DCC West SGS. The DCC East SGS Project consists of two Broom Creek injection wells, which are proposed to inject a maximum annual combined gas rate of 4.3 MMt, with the combined operating gas rate of an annual average of 4 MMt/yr for the first 15 years of project operations and 3.5 MMt/yr for the last 5 years for a total of 20 years of CO_2 injection operations.

The numerical model simulation with the aforementioned operating assumption results support an available maximum injection rate of 6.11 MMt/yr and a maximum of 122.9 MMt of CO_2 injected over the 20-year operations project into the DCC West SGS Broom Creek storage reservoir. To ensure a conservative buffer was included in the storage facility boundary, DCC West did not include planned maintenance requirements and testing requirements of the DCC West SGS equipment in the model input; said differently, there is no pause or reduction in the operations reflected.

1.1.1 Horizontal Boundaries

The proposed horizontal boundary of the storage reservoir, including an adequate buffer area, is defined by the simulated migration of the CO_2 plume, using the maximum rate of injection, from the start of injection until the end of injection. DCC West modeled a 98.25% CO_2 stream composition for purposes of establishing the storage facility boundary, which represents the averaged stream composition (stream may range from a minimum composition of 96% CO_2 to 99.9% CO_2). Additionally, by defining the storage reservoir boundary based on the maximum rate rather than the actual operating rate, the project has a built-in storage contingency in the proposed boundary. Further, the horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off of a maximum design life of the surface equipment. The simulated horizontal storage reservoir boundary results are identified in Figure 1-1.

The simulated storage reservoir models will be updated regularly with operating data, and the operator will provide evidence of the CO_2 plume migration as part of the reevaluations required under NDAC §§ 43-05-01-05.1 and 43-05-01-11.4.

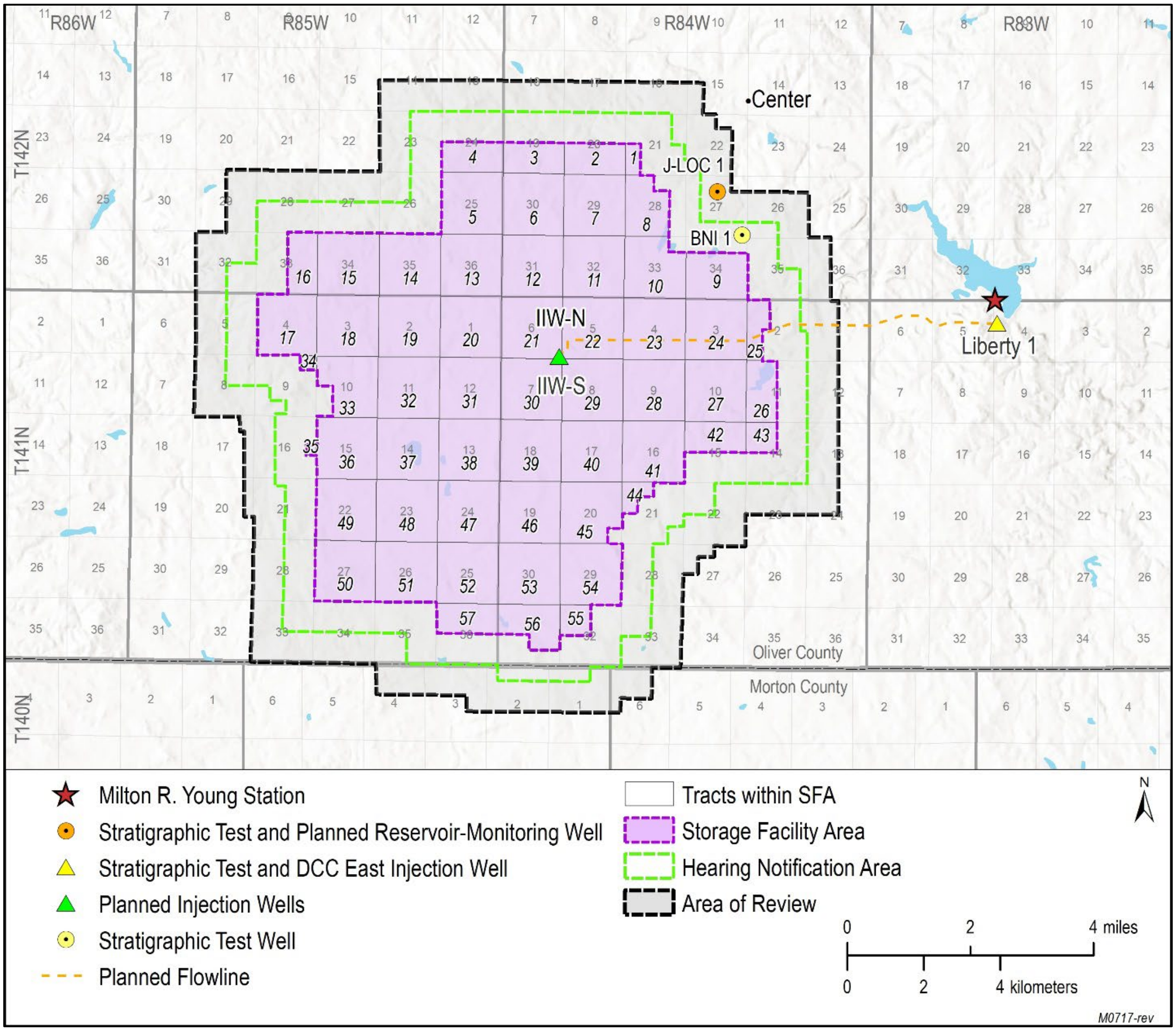

Figure 1-1. Map showing the proposed CO_2 flowline, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing notification area (HNA) for DCC West SGS.

1.1.2 Vertical Boundaries

For DCC West SGS, distinct vertical boundaries are described herein and are specifically based upon the geologic analysis and simulations further described in Sections 2 and 3 of this SFP application.

The proposed Broom Creek injection zone is made up of the Broom Creek Formation having an average thickness of 280 ft, with a measured top depth of 4908 ft; see discussion in Section 2.3. The overlying confining zone is made up of the Opeche–Picard interval with a top formation depth of 4784 ft and an average thickness of 234 ft, and the underlying confining zone, the Amsden Formation, has a starting depth of 5210 ft and is on average 257-ft-thick. Upper and underlying confining zone characteristics are discussed in detail in Section 2.4.

The applicant requests amalgamation of the injection zone pore space within the Broom Creek Formation, as identified in Table 1-1. In addition to the injection zone, the applicant requests the permitted storage complex consist of the Opeche–Picard interval as the upper confining zone and the Amsden Formation as the lower confining zone, as identified in Table 1-1.

Table 1-1. Formations Comprising the DCC West SGS CO_2 Storage Complex (average values calculated from the simulation model shown in Figure 2-3)

	Formation	Purpose	Thickness at J-LOC 1, ft	Depth at J-LOC 1, MD,* ft	Average Thickness, ft	Average Depth, MD,* ft	Lithology
Storage Complex	Opeche–Picard	Upper confining zone	124	4784	234	5010	Siltstone, dolostone, evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	302	4908	280	5244	Sandstone, dolostone, anhydrite
	Amsden	Lower confining zone	259	5210	257	5524	Dolostone, sandstone, anhydrite

* Measured depth.

1.2 Persons Notified

DCC West will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 miles of its outside boundary. DCC West will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.

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

- A map showing the extent of the pore space that will be occupied by CO_2 over the injection period, including the storage reservoir boundary and 0.5 mi (0.8 km) outside of the storage reservoir boundary (the HNA) (Figure 1-1).

- Identification of all pore space (surface) owners, each owner's mailing address, and a legal description of pore space landownership within the HNA.

- Identification of each owner of record of minerals and each mineral lessee of record within the HNA.

Note: All surface owners and pore space owners and lessees are the same owner of record.

Fredrikson

Fredrikson & Byron, P.A.
Attorneys and Advisors

1133 College Drive, Suite 1000
Bismarck, ND 58501-1215
Main: 701.221.8700
fredlaw.com

May 10, 2023

HAND DELIVERED

Mr. Rich Suggs
Petroleum Resource Geologic Analyst
North Dakota Industrial Commission
Oil and Gas Division
600 East Boulevard
Bismarck, North Dakota 58505-0310

RE: On a motion of the Commission to consider the application of DCC West Project LLC for a storage facility permit for geologic storage of carbon dioxide pursuant to NDCC Ch. 38-22 and NDAC Ch. 43-05-01.

Dear Mr. Suggs:

Please find enclosed herewith the following for filing:

1. STORAGE AGREEMENT, TUNDRA WEST BROOM CREEK – SECURE GEOLOGIC STORAGE, OLIVER COUNTY, NORTH DAKOTA

Should you have any questions, please advise.

Sincerely,

LAWRENCE BENDER

LB/leo
Enclosure
cc: Ms. Shannon Mikula - (w/enc.) *Via Email*
Mr. Wade Boeshans – (w/enc.) *Via Email*

79097490 v1

STORAGE AGREEMENT
TUNDRA WEST BROOM CREEK – SECURE GEOLOGIC STORAGE
OLIVER COUNTY, NORTH DAKOTA

STORAGE AGREEMENT
TUNDRA WEST BROOM CREEK – SECURE GEOLOGIC STORAGE
OLIVER COUNTY, NORTH DAKOTA

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

RECITALS:

A. It is in the public interest to promote the geologic storage of carbon dioxide in a manner which will benefit the state and the global environment by reducing greenhouse gas emissions and in a manner which will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens;

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

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

AGREEMENT:

It is agreed as follows:

ARTICLE 1
DEFINITIONS

As used in this Agreement:

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

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

1.3 **Effective Date** is the time and date this Agreement becomes effective as provided in Article 14.

1.4 **Facility Area** is the land described by Tracts in Exhibit "B" and shown on Exhibit "A" containing 29,775.55 acres, more or less.

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

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

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

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

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

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

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

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

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

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

1.15 **Storage Reservoir** consists of the Pore Space and confining subsurface strata underlying the Facility Area described as the Opeche-Picard (Upper Confining Zone), Broom Creek (Storage Reservoir/Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at two stratigraphic wells, the J-LOC 1 well (File No. 37380) and the J-ROC 1 well (File No. 37672). The log suites included caliper, gamma ray (GR), density, porosity (neutron, density), dipole sonic, resistivity, spectral GR, a combinable magnetic resonance (CMR), and fracture finder log. Further, the logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from two 3D seismic surveys covering an area totaling 18.5 miles in and around the J-ROC 1 (located in Section 4, Township 141 North, Range 83 West) and the J-LOC 1 (located in Section 27, Township 142 North, Range 84 West) stratigraphic wells located in Oliver County, North Dakota. Formation top depths were picked from the top of the Pierre Formation to the top of the Precambrian. These logs and data which encompass the stratigraphic interval from an average depth of 4,650 feet to an average depth of 5,450 feet within the limits of the Facility Area.

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

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

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

ARTICLE 2
EXHIBITS

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

2.1.1 Exhibit "A" is a map that shows the boundary lines of the Tundra West Broom Creek Facility Area and the tracts therein;

2.1.2 Exhibit "B" is a schedule that describes the acres of each Tract in the Tundra West Broom Creek Facility Area;

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

2.1.4 Exhibit "D" is a form of Surface Use and Pore Space Lease.

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

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

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

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

ARTICLE 3
CREATION AND EFFECT OF STORAGE FACILITY

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

3.2 **Amalgamation of Pore Space.** All Pore Space Interests in and to the Tracts are hereby amalgamated and combined insofar as the respective Pore Space Interests pertain to the Storage Reservoir, so that Storage Operations may be conducted with respect to said Storage

Reservoir as if all of the Pore Space Interests in the Facility Area had been included in a single lease executed by all Pore Space Owners, as lessors, in favor of Storage Operator, as lessee and as if the lease contained all of the provisions of this Agreement.

3.3 **Amendment of Leases and Other Agreements.** The provisions of the various leases, agreements, or other instruments pertaining to the respective Tracts or the storage of the Storage Substances therein, including the Surface Use and Pore Space Lease attached hereto as Exhibit "D", are amended to the extent necessary to make them conform to the provisions of this Agreement, but otherwise shall remain in effect.

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

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

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

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

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

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

3.10 **Border Agreements.** Storage Operator may enter into an agreement or agreements with owners of adjacent lands with respect to operations which may enhance the injection of the

Storage Substances in the Storage Reservoir in the Facility Area or which may otherwise be necessary for the conduct of Storage Operations.

ARTICLE 4
STORAGE OPERATIONS

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

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

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

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

ARTICLE 5
TRACT PARTICIPATIONS

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

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

ARTICLE 6
ALLOCATION OF STORAGE SUBSTANCES

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

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

ARTICLE 7
TITLES

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

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

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

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

ARTICLE 8
EASEMENTS OR USE OF SURFACE

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

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

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

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

ARTICLE 9
ENLARGEMENT OF STORAGE FACILITY

9.1 **Enlargement of Storage Facility.** The Storage Facility may be enlarged from time to time to include acreage and formations reasonably proven to be geologically capable of storing

Storage Substances. Any expansion must be approved in accordance with the rules and regulations of the Commission.

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

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

ARTICLE 10
TRANSFER OF TITLE PARTITION

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

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

ARTICLE 11
RELATIONSHIP OF PARTIES

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

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

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

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

ARTICLE 12
LAWS AND REGULATIONS

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

ARTICLE 13
FORCE MAJEURE

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

ARTICLE 14
EFFECTIVE DATE

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

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

ARTICLE 15
TERM

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

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

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

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

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

ARTICLE 16
APPROVAL

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

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

16.3 **Approval by the North Dakota Industrial Commission.**

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

ARTICLE 17
GENERAL

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

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

ARTICLE 18
SUCCESSORS AND ASSIGNS

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

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

Dated: __________, 20__

STORAGE OPERATOR

DCC West Project LLC

By:________________________________
Mac McLennan
Its: President and Chief Executive Officer

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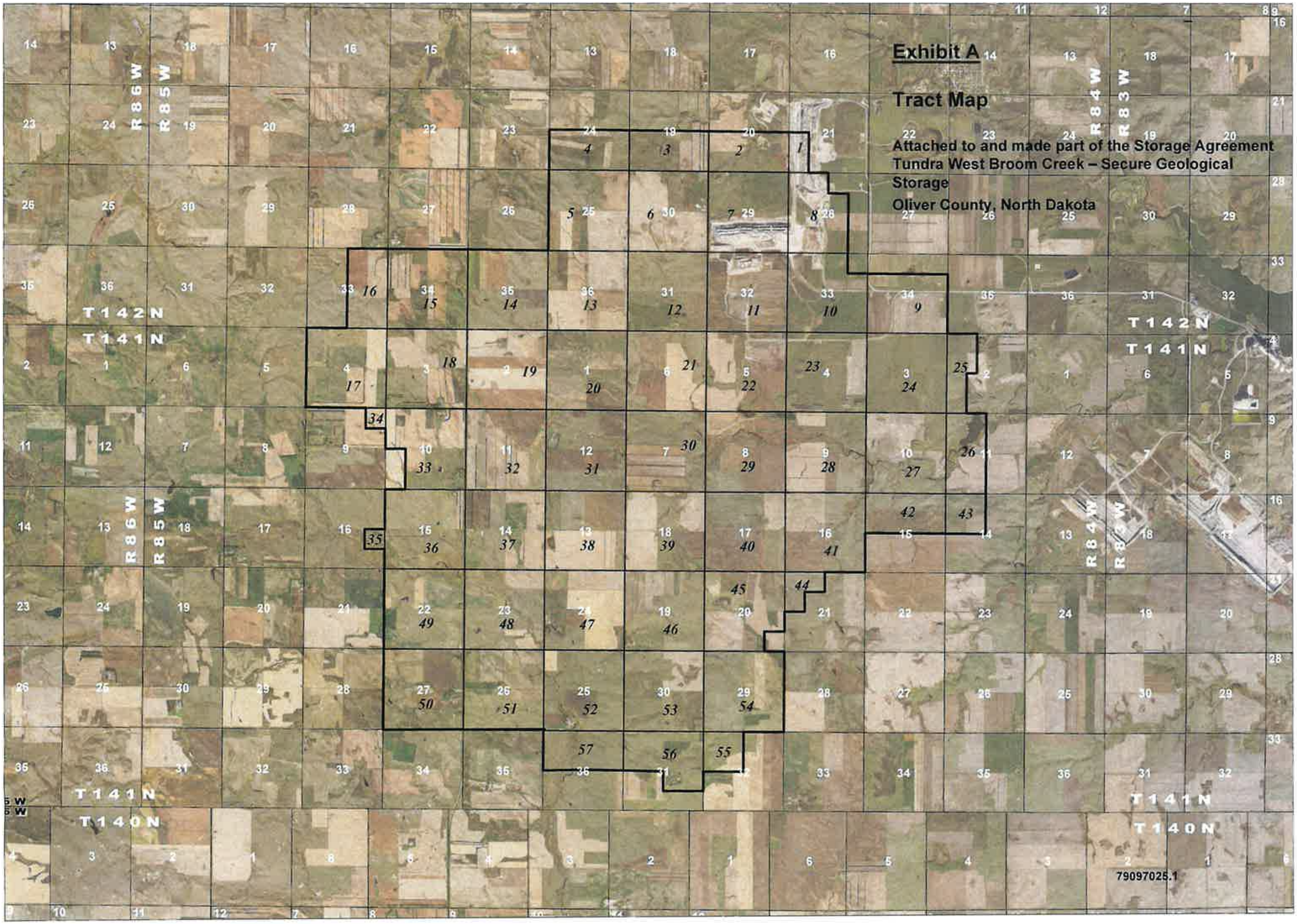


Exhibit A
Tract Map
Attached to and made part of the Storage Agreement
Tundra West Broom Creek – Secure Geological Storage
Oliver County, North Dakota
R 86 W
R 85 W
R 84 W
R 83 W
T 142 N
T 141 N
T 140 N
79097025.1

EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
Tundra West Broom Creek - Secure Geological Storage
Oliver County, North Dakota

Tract No.	Land Description	Owner Name	Tract Net Acres	Tract Participation	Storage Facility Participation
1	Section 21-T142N-R84W	Patricia M. Pella	13.333	16.66666667%	0.04477947%
		Keith Franklin Arthur	13.333	16.66666667%	0.04477947%
		Ross D. Langseth	6.667	8.33333333%	0.02238973%
		Ronal J. Langseth and Wendy Langseth	6.667	8.33333333%	0.02238973%
		Jeanette R. Lange	13.333	16.66666667%	0.04477947%
		Virginia C. Miller	13.333	16.66666667%	0.04477947%
		Jacqueline T. Gullickson	13.333	16.66666667%	0.04477947%
		Tract Total:	**80.000**	**100.00000000%**	
2	Section 20-T142N-R84W	Donna Yonne Pella	53.333	16.66666667%	0.17911788%
		Keith Franklin Arthur	26.667	8.33333333%	0.08955894%
		Heirs/Devisees of Susan Virginia Arthur Geiger, deceased	26.667	8.33333333%	0.08955894%
		Ross D. Langseth	26.667	8.33333333%	0.08955894%
		Ronal J. Langseth and Wendy Langseth	26.667	8.33333333%	0.08955894%
		Jeanette R. Lange	53.333	16.66666667%	0.17911788%
		Virginia C. Miller	53.333	16.66666667%	0.17911788%
		Jacqueline T. Gullickson	53.333	16.66666667%	0.17911788%
		Tract Total:	**320.000**	**100.00000000%**	
3	Section 19-T142N-R84W	Pfliger L.L.P.	317.170	100.00000000%	1.06520283%
		Tract Total:	**317.170**	**100.00000000%**	
4	Section 24-T142N-R85W	Loren Henke	320.000	100.00000000%	1.07470727%
		Tract Total:	**320.000**	**100.00000000%**	
5	Section 25-T142N-R85W	Duane F. Bueligen and Mildred Bueligen, as joint tenants (CFD Seller)		0.00000000%	0.00000000%
		Wesley M. Eggers and Ruth Eggers, as joint tenants (CFD Buyer)	103.000	16.09375000%	0.34592140%
		Eldon Hintz and Judith Hintz, as joint tenants (CFD Seller and Life Estate)	377.000	58.90625000%	1.26613950%
		Aaron Hintz and Jodi Hintz, as joint tenants (CFD Buyer and Remainderman)		0.00000000%	0.00000000%
		Kent Albers and Deborah Albers, as Joint Tenants	53.333	8.33333333%	0.17911788%
		Chris Albers and Nicole Albers, as Joint Tenants	53.333	8.33333333%	0.17911788%

		Josh Albers and Kelly Albers, as Joint Tenants	53.333	8.33333333%	0.17911788%
		Tract Total:	**640.000**	**100.00000000%**	
6	Section 30-T142N-R84W	Henry J. Maertens and Mary Ann Maertens	120.000	18.92386299%	0.40301523%
		Nathan Dagley and Elizabeth Dagley	40.000	6.30795433%	0.13433841%
		Dale M. Miller and Virginia C. Miller	472.120	74.45278496%	1.58559624%
		Hannover School District No. 3	2.000	0.31539772%	0.00671692%
		Tract Total:	**634.120**	**100.00000000%**	
7	Section 29-T142N-R84W	Lucille Bobb and John Bobb, Jr.	320.000	50.00000000%	1.07470727%
		Brenda Schwalbe and Rolland Schwalbe	53.333	8.33333333%	0.17911788%
		Myron Yantzer	5.714	0.89285714%	0.01919120%
		Eugene P. Yantzer and Betty L. Yantzer	72.381	11.30952381%	0.24308855%
		Daryl R. Yantzer and Billie R. Yantzer	5.714	0.89285714%	0.01919120%
		Carol A. Yantzer	5.714	0.89285714%	0.01919120%
		David G. Yantzer	5.714	0.89285714%	0.01919120%
		Tim P. Yantzer	5.714	0.89285714%	0.01919120%
		Arlis Muth a/k/a Arlyce Muth a/k/a Arlyce M. Muth	19.048	2.97619048%	0.06397067%
		Ila Vandenburg	8.000	1.25000000%	0.02686768%
		Eldon Vandenburg	8.000	1.25000000%	0.02686768%
		Wayne Vandenburg	8.000	1.25000000%	0.02686768%
		Donna Vandenburg	8.000	1.25000000%	0.02686768%
		Willetta Bartz	8.000	1.25000000%	0.02686768%
		Maynard A. Skager and Arlene J. Skager	40.000	6.25000000%	0.13433841%
		Ashley N. Torgerson	66.667	10.41666667%	0.22389735%
		Tract Total:	**640.000**	**100.00000000%**	
8	Section 28-T142N-R84W	BNI Coal, Ltd.	440.000	100.00000000%	1.47772249%
		Tract Total:	**440.000**	**100.00000000%**	
9	Section 34-T142N-R84W	BNI Coal, Ltd.	480.000	100.00000000%	1.61206090%
		Tract Total:	**480.000**	**100.00000000%**	
10	Section 33-T142N-R84W	BNI Coal, Ltd.	600.000	107.14285714%	2.01507613%
		Tract Total:	**600.000**	**100.00000000%**	
11	Section 32-T142N-R84W	Eugene P. Yantzer and Betty L. Yantzer, husband and wife, as joint tenants	72.381	11.30952381%	0.24308855%
		Arlis Muth, a/k/a Arlyce M. Muth	19.048	2.97619048%	0.06397067%
		Ashley N. Torgerson	66.667	10.41666667%	0.22389735%
		Brenda Schwalbe and Rolland Schwalbe, wife and husband, as joint tenants	53.333	8.33333333%	0.17911788%
		Myron Yantzer	5.714	0.89285714%	0.01919120%
		Daryl R. Yantzer and Billie R. Yantzer, husband and wife, as joint tenants	5.714	0.89285714%	0.01919120%
		Carol A. Yantzer	5.714	0.89285714%	0.01919120%
		David G. Yantzer	5.714	0.89285714%	0.01919120%

		Tim P. Yantzer	5.714	0.89285714%	0.01919120%
		Ila Vandenburg	8.000	1.25000000%	0.02686768%
		Eldon Vandenburg	8.000	1.25000000%	0.02686768%
		Wayne Vandenburg	8.000	1.25000000%	0.02686768%
		Donna Vandenburg	8.000	1.25000000%	0.02686768%
		Willetta Bartz	8.000	1.25000000%	0.02686768%
		Maynard A. Skager and Arlene J. Skager, a/k/a Arlene Skager, husband and wife	40.000	6.25000000%	0.13433841%
		Thomas Lipp and Kathleen Lipp, as joint tenants	320.000	50.00000000%	1.07470727%
		Tract Total:	**640.000**	**100.00000000%**	
12	Section 31-T142N-R84W	Brenda Schwalbe and Rolland Schwalbe, wife and husband, as joint tenants	79.330	12.51261830%	0.26642665%
		Myron Yantzer	11.333	1.78751690%	0.03806095%
		Eugene P. Yantzer and Betty L. Yantzer, husband and wife, as joint tenants	11.333	1.78751690%	0.03806095%
		Daryl R. Yantzer and Billie R. Yantzer, husband and wife, as joint tenants	11.333	1.78751690%	0.03806095%
		Carol A. Yantzer	11.333	1.78751690%	0.03806095%
		David G. Yantzer	11.333	1.78751690%	0.03806095%
		Tim P. Yantzer	11.333	1.78751690%	0.03806095%
		Arlyce M. Muth	11.333	1.78751690%	0.03806095%
		Ila Vandenburg	15.866	2.50252366%	0.05328533%
		Eldon Vandenburg	15.866	2.50252366%	0.05328533%
		Wayne Vandenburg	15.866	2.50252366%	0.05328533%
		Donna Vandenburg	15.866	2.50252366%	0.05328533%
		Willetta Bartz	15.866	2.50252366%	0.05328533%
		Maynard A. Skager and Arlene J. Skager, a/k/a Arlene Skager, husband and wife	79.330	12.51261830%	0.26642665%
		Steven Ralph Fricke and Marlene B. Fricke, husband and wife, joint tenants	316.680	49.949526817%	1.06355718%
		Tract Total:	**634.000**	**100.00000000%**	
13	Section 36-T142N-R85W	Kent Albers and Deborah Albers	53.333	8.33333333%	0.17911788%
		Chris Albers and Nicole Albers	53.333	8.33333333%	0.17911788%
		Josh Albers and Kelly Albers	53.333	8.33333333%	0.17911788%
		Eldon H. Hintz and Judith Hintz	160.000	25.00000000%	0.53735363%
		Kal Klingenstein	80.000	12.50000000%	0.26867682%
		Alice Klingenstein	80.000	12.50000000%	0.26867682%
		Thomas Lipp and Kathleen Lipp	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
14	Section 35-T142N-R85W	Leslie Henke and Correne Henke, husband and wife, as joint tenants	160.000	25.00000000%	0.53735363%
		Lee Henke and Claire Henke, husband and wife, as joint tenants	80.000	12.50000000%	0.26867682%
		Kelly Hintz and Judith Hintz, husband and wife, as joint tenants	80.000	12.50000000%	0.26867682%
		Donald Haag	160.000	25.00000000%	0.53735363%

		Dale M. Haag and Susan Haag, husband and wife, as joint tenants	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
15	Section 34-T142N-R85W	Jerry Scott Henke and Paulette Henke, HW, JT	60.000	9.37500000%	0.20150761%
		Linda Splichal and Duane Splichal, HW, JT	20.000	3.12500000%	0.06716920%
		Kelly Hintz and Judith Hintz, HW, JT	160.000	25.00000000%	0.53735363%
		Lee J. Henke and Claire J. Henke, HW, JT	80.000	12.50000000%	0.26867682%
		Rabe Land Partnership, Kyle Rabe managing partner	320.000	50.00000000%	1.07470727%
		Tract Total:	**640.000**	**100.00000000%**	
16	Section 33-T142N-R85W	Kyle A. Rabe (CFD Seller)	0.000	0.00000000%	0.00000000%
		Corey J. Hintz and Briana R. Hintz (CFD Buyer)	80.000	25.00000000%	0.26867682%
		Lilly Hintz Henke (CFD Seller)	0.000	0.00000000%	0.00000000%
		Kelly Hintz and Judith Hintz (CFD Buyer)	80.000	25.00000000%	0.26867682%
		Kyle A. Rabe	160.000	50.00000000%	0.53735363%
		Tract Total:	**320.000**	**100.00000000%**	
17	Section 4-T141N-R85W	James E. Kitzmann and JoAnn E. Kitzmann	159.560	24.97691092%	0.53587591%
		Gregory C. Maier and Diane Maier	159.270	24.93151543%	0.53490196%
		Jerome D. Kitzmann and Sharon Ann Kitzmann	320.000	50.09157366%	1.07470727%
		Tract Total:	**638.830**	**100.00000000%**	
18	Section 3-T141N-R85W	Kelly Hintz and Judith M. Hintz	318.060	49.84797668%	1.06819186%
		Patricia L. Kitzmann	7.010	1.09864276%	0.02354281%
		James Edward Kitzmann and Joann E. Kitzmann	152.990	23.97736890%	0.51381083%
		BBS Family, LLP	147.600	23.13262076%	0.49570873%
		LeRoy James Fyhrie and Angelika Fyhrie	12.400	1.94339090%	0.04164491%
		Tract Total:	**638.060**	**100.00000000%**	
19	Section 2-T141N-R85W	Donald Haag	159.390	24.96397695%	0.53530497%
		Dale Haag, a/k/a Dale M. Haag, and Susan Haag	159.090	24.91699035%	0.53429744%
		Conrad Haag	320.000	50.11903270%	1.07470727%
		Tract Total:	**638.480**	**100.00000000%**	
20	Section 1-T141N-R85W	Lee Henke and Claire Henke	319.640	49.98279906%	1.07349822%
		Lee J. Henke	79.930	12.49882721%	0.26844172%
		Claire J. Henke	79.930	12.49882721%	0.26844172%
		Steven R. Fricke and Marlene B. Fricke	160.000	25.01954652%	0.53735363%
		Tract Total:	**639.500**	**100.00000000%**	
21	Section 6-T141N-R84W	Marie Mosbrucker	321.130	50.52709422%	1.07850233%
		Steven Ralph Fricke and Marlene B. Fricke	157.060	24.71206495%	0.52747976%

		Thomas Lipp and Kathleen Lipp	157.370	24.76084083%	0.52852088%
		Tract Total:	**635.560**	**100.00000000%**	
22	Section 5-T141N-R84W	Marie Mosbrucker	481.170	75.00350724%	1.61599030%
		Thomas Lipp and Kathleen Lipp	160.570	25.02922700%	0.53926796%
		Tract Total:	**641.740**	**100.03273424%**	
23	Section 4-T141N-R84W	BNI Coal, Ltd.	620.520	96.95625000%	2.08399173%
		Baukol-Noonan, Inc.	20.000	3.12500000%	0.06716920%
		Tract Total:	**640.520**	**100.08125000%**	
24	Section 3-T141N-R84W	Minnkota Power Cooperative, Inc.	639.900	100.00000000%	2.14907869%
		Tract Total:	**639.900**	**100.00000000%**	
25	Section 2-T141N-R84W	BNI Coal, Ltd.	104.550	49.96177005%	0.35112702%
		Eugene Yantzer and Betty Yantzer, as joint tenants	104.710	50.03822995%	0.35166437%
		Tract Total:	**209.260**	**100.00000000%**	
26	Section 11-T141N-R84W	David O. Berger and Debra A. Berger, as joint tenants	160.000	50.00000000%	0.53735363%
		Lee Dresser	160.000	50.00000000%	0.53735363%
		Tract Total:	**320.000**	**100.00000000%**	
27	Section 10-T141N-R84W	Kenneth W. Reinke and Darlene Reinke	640.000	100.00000000%	2.14941454%
		Tract Total:	**640.000**	**100.00000000%**	
28	Section 9-T141N-R84W	BNI Coal, Ltd.	160.000	25.00000000%	0.53735363%
		Jeff Reinke	320.000	50.00000000%	1.07470727%
		Brian V. Letzring and Joell M. Letzring, husband and wife, as joint tenants	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
29	Section 8-T141N-R84W	Calvin K. Mosbrucker	79.500	12.42187500%	0.26699759%
		Dean M. Mosbrucker	79.500	12.42187500%	0.26699759%
		Brian D. Mosbrucker	79.500	12.42187500%	0.26699759%
		Lorie A. Makelke	79.500	12.42187500%	0.26699759%
		Church School District #4	2.000	0.31250000%	0.00671692%
		Tim G. Doll and Dianne R. Doll	240.000	37.50000000%	0.80603045%
		Patrick J. Doll and Katherine K. Doll	80.000	12.50000000%	0.26867682%
		Tract Total:	**640.000**	**100.00000000%**	
30	Section 7-T141N-R84W	Keith Dahl and Vivian Dahl, as joint tenants	320.000	50.33979361%	1.07470727%
		Steve Fricke and Marlene Fricke, as joint tenants	315.680	49.66020639%	1.06019872%
		Tract Total:	**635.680**	**100.00000000%**	
31	Section 12-T141N-R85W	Thomas Haag and Sharon Haag, as joint tenants	280.000	43.75000000%	0.94036886%

		Patrick and Katherine Doll, as joint tenants	200.000	31.25000000%	0.67169204%
		Edward Meyhoff and Rosemary Meyhoff, as joint tenants (CFD Seller)		0.00000000%	0.00000000%
		Jeffery and Shelly Meyhoff, as joint tenants (CFD Buyer)	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
32	Section 11-T141N-R85W	Duane Maier and Karen Maier	320.000	50.00000000%	1.07470727%
		Patrick J. Doll and Katherine K. Doll	320.000	50.00000000%	1.07470727%
		Tract Total:	**640.000**	**100.00000000%**	
33	Section 10-T141N-R85W	Douglas Bauer and DeLana Bauer	99.590	17.76489476%	0.33446905%
		Cheryl Peltz and Steven D. Peltz	60.900	10.86336068%	0.20453023%
		Deborah Bueligen and Daniel Bueligen	83.650	14.92151267%	0.28093520%
		Anton J. Heidrich and Cynthia Heidrich	36.460	6.50374599%	0.12244946%
		Duane R. Maier	232.100	41.40206921%	0.77949862%
		Jesse Maier and Carrie Maier	7.900	1.40920442%	0.02653184%
		James Edward Kitzmann and Joann E. Kitzmann	40.000	7.13521227%	0.13433841%
		Tract Total:	**560.600**	**100.00000000%**	
34	Section 9-T141N-R85W	Jerome D. Kitzmann and Sharon Kitzmann, as joint tenants	40.000	100.00000000%	0.13433841%
		Tract Total:	**40.000**	**100.00000000%**	
35	Section 16-T141N-R85W	State of North Dakota	40.000	100.00000000%	0.13433841%
		Tract Total:	**40.000**	**100.00000000%**	
36	Section 15-T141N-R85W	Duane R. Maier and Karen Maier	306.780	47.93437500%	1.03030842%
		Duane R. Maier and Karen Maier (CFD Seller)	0.000	0.00000000%	0.00000000%
		Jacob Maier (CFD Buyer)	13.220	2.06562500%	0.04439884%
		Lilly Hintz Henke, f/k/a Lilly Hintz (CFD Seller)	0.000	0.00000000%	0.00000000%
		Kelly Hintz and Judith M. Hintz (CFD Buyer)	160.000	25.00000000%	0.53735363%
		Jacob Gappert and Elizabeth Gappert	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	2.14941454%
					0.00000000%
37	Section 14-T141N-R85W	Patrick J. Doll and Katherine Maier Doll	320.000	50.00000000%	1.07470727%
		Jo Anne Hoesel	160.000	25.00000000%	0.53735363%
		Jacob Gappert and Elizabeth Gappert	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
38	Section 13-T141N-R85W	Ruby Meyhoff	160.000	25.00000000%	0.53735363%
		Jeffrey E. Meyhoff and Shelly Meyhoff, husband and wife, as joint tenants	240.000	37.50000000%	0.80603045%

		Bryan Hoesel and Vicki Hoesel, as joint tenants	240.000	37.50000000%	0.80603045%
		Tract Total:	**640.000**	**100.00000000%**	
39	Section 18-T141N-R84W	Lyle M. Mosbrucker and Karen Mosbrucker	318.320	49.94978659%	1.06906506%
		Delton Heid	118.960	18.66683404%	0.39952243%
		Todd C. Heid, a/k/a Todd Heid, and Denise Heid	200.000	31.38337936%	0.67169204%
		Tract Total:	**637.280**	**100.00000000%**	
40	Section 17-T141N-R84W	Jean L. Kautzman	160.000	25.00000000%	0.53735363%
		James Berg	120.000	18.75000000%	0.40301523%
		Susan Jones	360.000	56.25000000%	1.20904568%
		Tract Total:	**640.000**	**100.00000000%**	
41	Section 16-T141N-R84W	State of North Dakota	320.000	50.00000000%	1.07470727%
		Jean L. Kautzman	160.000	25.00000000%	0.53735363%
		Beatrice Mosbrucker	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
42	Section 15-T141N-R84W	Russell A. Hoesel	320.000	100.00000000%	1.07470727%
		Tract Total:	**320.000**	**100.00000000%**	
43	Section 14-T141N-R84W	Lee Dresser	120.000	75.00000000%	0.40301523%
		Burton & Etheleen Enterprises, LLC	40.000	25.00000000%	0.13433841%
		Tract Total:	**160.000**	**100.00000000%**	
44	Section 21-T141N-R84W	Wallace D. Arensmeier and Dorothy E. Arensmeier, as Trustees for the Wallace & Dorothy Arensmeier Trust, dated October 25, 2016	120.000	100.00000000%	0.40301523%
		Tract Total:	**120.000**	**100.00000000%**	
45	Section 20-T141N-R84W	Wallace D. Arensmeier and Dorothy E. Arensmeier, as Trustees for the Wallace & Dorothy Arensmeier Trust, dated October 25, 2016	328.000	54.66666667%	1.10157495%
		Dustin Henke	112.000	18.66666667%	0.37614754%
		Daniel Bueligen and Deborah Bueligen	160.000	26.66666667%	0.53735363%
		Tract Total:	**600.000**	**100.00000000%**	
46	Section 19-T141N-R84W	Lauretta I. Wolff and Jerome Wolff	320.000	50.15516755%	1.07470727%
		Michael J. Doll	80.000	12.53879189%	0.26867682%
		Marvin Bethke	238.020	37.30604056%	0.79938070%
		Tract Total:	**638.020**	**100.00000000%**	
47	Section 24-T141N-R85W	Daniel Bueligen and Deborah Bueligen	160.000	25.00000000%	0.53735363%
		Bryan Russel Hoesel and Vicki Jane Hoesel	320.000	50.00000000%	1.07470727%
		PL Land Holdings LLP	159.000	24.84375000%	0.53399517%

		Eunice Bueligen	1.000	0.15625000%	0.00335846%
		Tract Total:	**640.000**	**100.00000000%**	
48	Section 23-T141N-R85W	Josh Eggers	238.000	37.18750000%	0.79931353%
		Fairfiew School District No. 16	2.000	0.31250000%	0.00671692%
		L. Michael Rockne and Karen Rockne	160.000	25.00000000%	0.53735363%
		M. James Stroup	33.333	5.20833333%	0.11194867%
		Larry Stroup	33.333	5.20833333%	0.11194867%
		Thomas Stroup	33.333	5.20833333%	0.11194867%
		Elizabeth Stroup Menge	33.333	5.20833333%	0.11194867%
		Robyn Stroup-Vinje	26.667	4.16666667%	0.08955894%
		Daniel Bueligen	40.000	6.25000000%	0.13433841%
		Deborah Bueligen	40.000	6.25000000%	0.13433841%
		Tract Total:	**640.000**	**100.00000000%**	
49	Section 22-T141N-R85W	L. Michael Rockne and Karen Rockne	80.000	12.50000000%	0.26867682%
		M. James Stroup	16.667	2.60416667%	0.05597434%
		Larry Stroup	16.667	2.60416667%	0.05597434%
		Thomas Stroup	16.667	2.60416667%	0.05597434%
		Elizabeth Stroup Menge	16.667	2.60416667%	0.05597434%
		Robyn Stroup-Vinje	13.333	2.08333333%	0.04477947%
		Frances Windhorst, formerly Frances Klingenstein	160.000	25.00000000%	0.53735363%
		Daren Klingenstein and Cheri Klingenstein	317.200	49.56250000%	1.06530358%
		Roger Klingenstein and Marvel Klingenstein	0.730	0.11406250%	0.00245168%
		Dusty J. Backer and Patricia J. Backer	2.070	0.32343750%	0.00695201%
		Tract Total:	**640.000**	**100.00000000%**	
50	Section 27-T141N-R85W	Eunice Bueligen	461.400	72.09375000%	1.54959354%
		David Bueligen and DeAnn Bueligen	18.600	2.90625000%	0.06246736%
		Duane Bueligen and Mildred Bueligen (CFD Seller)	0.000	0.00000000%	0.00000000%
		Shane A. Tellmann and Janna M. Tellman (CFD Buyer)	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
51	Section 26-T141N-R85W	Warren E. Reiner	480.000	75.00000000%	1.61206090%
		Josh Eggers	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
52	Section 25-T141N-R85W	Daniel Bueligen and Deborah Bueligen, as joint tenants	320.000	50.00000000%	1.07470727%
		Bryan Russel Hoesel and Vicki Hoesel, Trustees of the Bryan Hoesel Revocable Living Trust dated March 30, 2023	320.000	50.00000000%	1.07470727%
		Tract Total:	**640.000**	**100.00000000%**	
53	Section 30-T141N-R84W	Berger & Miller, LLC	637.640	100.00000000%	2.14148857%

		Tract Total:	**637.640**	**100.00000000%**	
54	Section 29-T141N-R84W	Paul L. Brandt and Cynthia Brandt	320.000	50.00000000%	1.07470727%
		Jamie T. Mosbrucker and Brooke M. Mosbrucker	160.000	25.00000000%	0.53735363%
		Terrence P. Mosbrucker and Diane K. Mosbrucker	160.000	25.00000000%	0.53735363%
		Tract Total:	**640.000**	**100.00000000%**	
55	Section 32-T141N-R84W	Churchtown Cemetary Association	10.000	6.25000000%	0.03358460%
		Brian V. Letzring and Joell M. Letzring, as joint tentants	150.000	93.75000000%	0.50376903%
		Tract Total:	**160.000**	**100.00000000%**	
56	Section 31-T141N-R84W	Berger & Miller, LLC	259.190	64.92898119%	0.87047930%
		Brian V. Letzring and Joell M. Letzring, as joint tentants	60.000	15.03043663%	0.20150761%
		Leslie Brandt and Laurie Brandt	80.000	20.04058218%	0.26867682%
		Tract Total:	**399.190**	**100.00000000%**	
57	Section 36-T141N-R85W	Berger & Miller, LLC	233.000	72.81250000%	0.78252123%
		Daniel Bueligen and Deborah Bueligen, as joint tenants	7.000	2.18750000%	0.02350922%
		Brian V. Letzring and Joell M. Letzring, as joint tentants	80.000	25.00000000%	0.26867682%
		Tract Total:	**320.000**	**100.00000000%**	
	79097399.1	**Total Acres:**	**29775.550**	**Total Participation:**	**100.00000000%**

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Storage Agreement
Tundra West Broom Creek - Secure Geological Storage
Oliver County, North Dakota

Tract No.	Acres	Tract Participation Factor
1	80.000	0.26867682%
2	320.000	1.07470727%
3	317.170	1.06520283%
4	320.000	1.07470727%
5	640.000	2.14941454%
6	634.120	2.12966679%
7	640.000	2.14941454%
8	440.000	1.47772249%
9	480.000	1.61206090%
10	600.000	2.01507613%
11	640.000	2.14941454%
12	634.000	2.12926378%
13	640.000	2.14941454%
14	640.000	2.14941454%
15	640.000	2.14941454%
16	320.000	1.07470727%
17	638.830	2.14548514%
18	638.060	2.14289912%
19	638.480	2.14430968%
20	639.500	2.14773531%
21	635.560	2.13450297%
22	641.740	2.15525826%
23	640.520	2.15116094%
24	639.900	2.14907869%
25	209.260	0.70279138%
26	320.000	1.07470727%
27	640.000	2.14941454%
28	640.000	2.14941454%
29	640.000	2.14941454%
30	635.680	2.13490599%
31	640.000	2.14941454%
32	640.000	2.14941454%
33	560.600	1.88275280%
34	40.000	0.13433841%
35	40.000	0.13433841%
36	640.000	2.14941454%
37	640.000	2.14941454%
38	640.000	2.14941454%
39	637.280	2.14027952%
40	640.000	2.14941454%
41	640.000	2.14941454%
42	320.000	1.07470727%
43	160.000	0.53735363%
44	120.000	0.40301523%
45	600.000	2.01507613%
46	638.020	2.14276479%
47	640.000	2.14941454%
48	640.000	2.14941454%
49	640.000	2.14941454%
50	640.000	2.14941454%
51	640.000	2.14941454%
52	640.000	2.14941454%
53	637.640	2.14148857%
54	640.000	2.14941454%
55	160.000	0.53735363%
56	399.190	1.34066373%
57	320.000	1.07470727%
Total:	**29775.550**	**100.00000000%**

Exhibit D

Form of Surface Use and Pore Space Lease

Attached to and made part of the Storage Agreement
Tundra West Broom Creek – Secure Geological Storage
Oliver County, North Dakota

SURFACE USE AND PORE SPACE LEASE

THIS SURFACE USE AND PORE SPACE LEASE (**"Lease"**) is made, entered into, and effective as of the _______day of ____________________, 2023 (**"Effective Date"**) by and between ________________, whose address is ________________________ (whether one or more, **"Lessor"**), and Minnkota Power Cooperative, Inc., a Minnesota cooperative association, whose address is ___________________________ (whether one or more, **"Lessee"**). Lessor and Lessee are sometimes referred to in this Lease individually as a **"Party"** and collectively as the **"Parties."**

1. DEFINITIONS. The following terms shall have the following meanings in this Lease:

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

"Commencement of Operations" means the date on which Carbon Dioxide is first injected into a Reservoir for commercial operations under this Lease, provided that the performance of test injections and related activities shall not be deemed Commencement of Operations.

"Commission" means the North Dakota Industrial Commission.

"Completion Notice" means a certificate of project completion issued to Lessee by the Commission pursuant to Chapter 38-22 of the North Dakota Century Code.

"Environmental Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the Operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits.

"Environmental Incentives" means any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into the Operations, environmental benefits of Operations, or other similar programs available from any regulated entity or any Governmental Authority.

"Facilities" means all facilities, structures, improvements, fixtures, equipment, and any other personal property at any time acquired or constructed by or for Lessee that are necessary or desirable in connection with any use of Reservoirs and their Formations or Operations, including without limitation wells, pipelines, roads, utilities, metering or monitoring equipment, and buildings.

"Financing Parties" means person or persons providing construction or permanent financing to Lessee in connection with construction, ownership, operation and maintenance of Facilities or Operations, including financial institutions, leasing companies, institutions, tax equity partners, joint venture partners and/or private lenders.

"Formation" means the geological formation of which any Reservoir is a part.

"Hazardous Substance" means any chemical, waste or other substances, expressly excluding Carbon Dioxide and Non-Native Carbon Dioxide, (a) which now or hereafter becomes defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "extremely hazardous wastes," "restricted hazardous wastes," "toxic substances," "toxic pollutants," "pollutions," "pollutants," "regulated substances," or words of similar import under any law pertaining to environment, health, safety or welfare, (b) which is declared to be hazardous, toxic or polluting by any Governmental Authority, (c) exposure to which now or hereafter prohibited, limited or regulated by any Governmental Authority, (d) the storage, use, handling, disposal or release of which is restricted or regulated by any Governmental Authority, or (e) for which remediation or cleanup is required by any Governmental Authority.

"Leased Premises" means the surface and subsurface of the land, excluding mineral rights, described in **Exhibit A** of this Lease.

"Native Oil and Gas" means all oil, natural gas, and other hydrocarbons present in and under the Leased Premises and not injected by Lessor, Lessee or any third party.

"Non-Native Carbon Dioxide" means Carbon Dioxide that is not naturally occurring in the Reservoir together with incidental associated substances, fluids, minerals, oil, and gas, excluding that which, independent of Operations, originates from an accumulation meeting the definition of a Pool. All Non-Native Carbon Dioxide will be considered personal property of the Lessee and its successor and assigns under this Agreement.

"Operating Year" means the calendar year or portion of the calendar year following Commencement of Operations during which Operations occur.

"Operations" means the transportation and injection of Carbon Dioxide into a Reservoir after Commencement of Operations, and any withdrawal of this Carbon Dioxide, as well as the withdrawal of Non-Native Carbon Dioxide, for sale or disposal in accordance with applicable law.

"Option Money" means 20 percent of the Initial Term Payment (as such term is defined in that certain Option to Lease between Lessor and Lessee with respect to the Leased Premises).

"Pool" means an underground Reservoir containing a common accumulation of Native Oil and Gas that is economically recoverable. A zone of a structure that is completely separated from any other zone in the same structure is a Pool.

"Pore Space" means a cavity or void, whether natural or artificially created, in a Reservoir.

"Related Person" means any member, partner, principal, officer, director, shareholder, predecessor-in-interest, successor-in-interest, employee, agent, heir, representative, contractor, lessee, sublessee, licensee, invitee, permittee of a Party, Financing Parties or any other person or entity that has obtained or in future obtains rights or interests from, under or through a Party (excluding the other Party itself).

"Reservoir" means any subsurface stratum, sand, formation, aquifer, cavity or void, whether natural or artificially created, wholly or partially within the Leased Premises, suitable for the storage or sequestration of carbon dioxide or other gaseous substances.

"Storage Fee" means Lessor's proportionate share of [fifty and 0/100th] cents ($0.[50]) per metric ton of Carbon Dioxide ("Storage Rate") as determined by the Lessee's last meter before injection as part of Operations. The Storage Rate was determined based on an agreed commercial value of the lease of the Leased Premises as of the Effective Date. If there is a subsequent change in the commercial value of the lease of the Leased Premises because of a change in Applicable Law resulting in a change in, or Lessee's qualification for, the $85 per metric ton IRC section 45Q tax credit (including for inflation adjustments or changes in Applicable Law), the Storage Rate shall be proportionately changed based on the ratio of the Storage Rate on the Effective Date ($0.[50]) and $85. (effective as of the effective date of the change in the IRC section 45Q tax credit amount) The Storage Fee shall be: (i) calculated separately for each Amalgamated Unit as created and established by the Commission that includes any portion of the Leased Premises; (ii) limited to the Carbon Dioxide injected in said Amalgamated Unit in the immediately preceding Operating Year; and (iii) based on the Lessor's proportionate per net acre share of said unit. For avoidance of doubt, the Lessor shall receive a separate Storage Fee for each Amalgamated Unit created and established by the Commission that includes any portion of the Leased Premises on a net acre basis within the Lessor's interest being the numerator and the acres in the Amalgamated Unit being the denominator.

"Tax Credits" means any and all (a) investment tax credits, (b) production tax credits, (c) credits under 26 U.S.C. §45Q credits, and (d) similar tax credits or grants under federal, state or local law relating to construction, ownership or Operations

2. LEASE RIGHTS. In consideration of the compensation, covenants, agreements, and conditions set forth in this Lease, Lessor grants, demises, leases and lets to Lessee the exclusive right to use all Pore Space, Reservoirs and their Formations in the Leased Premises for any purpose not previously granted or reserved by an instrument of record related to the capture, injection, storage, sequestration, sale, withdrawal or disposal of Carbon Dioxide, Non-Native Carbon Dioxide and incidental associated substances, fluids, and minerals, provided that Lessee shall have no right to use potable water from within the Leased Premises in Operations; together with the following exclusive rights:

(a) to use the Leased Premises for developing, constructing, installing, improving, maintaining, replacing, repowering, relocating, removing, abandoning in place, expanding, and operating Facilities;

(b) to lay, maintain, replace, repair, and remove roads on the Leased Premises to allow Lessee, in its sole discretion, to exercise its rights under this Lease; and

(c) to enter upon and use the Leased Premises for the purposes of conducting:

(i) any investigations, studies, surveys, and tests, including without limitation drilling and installing test wells and monitoring wells, seismic testing, and other activities as Lessee deems necessary or desirable to determine the suitability of the Leased Premises for Operations,

(ii) any inspections and monitoring of Reservoirs and Carbon Dioxide as Lessee or any governmental authority deems necessary or desirable during the term of this Lease, and

(iii) any maintenance to the Facilities that Lessee or any governmental authority deems necessary or as required by applicable law.

Lessor also hereby grants and conveys unto Lessee all other and further easements across, over, under and above the Leased Premises as reasonably necessary to provide access to and services reasonably required for Lessee's performance under the Lease. The easements granted hereunder shall run with and burden the Leased Premises for the term of this Lease. Notwithstanding the surface easements granted herein, Lessee shall provide notice to Lessor prior to accessing the surface of the Property, and if such activity requires permit then prior notice shall be in form and not be less than that required by law or rule.

Lessee may exercise its rights under this Lease in conjunction with related operations on other properties near the Leased Premises. Lessee shall have no obligation, express or implied, to begin, prosecute or continue storage operations in, upon or under the Leased Premises, or to store and/or sell or use all or any portion of the gaseous substances stored thereon. The timing, nature, manner and extent of Lessee's operations, if any, under this Lease shall be at the sole discretion of Lessee. All obligations of Lessee are expressed herein, and there shall be no covenants implied under this Lease, it being agreed that all amounts paid hereunder constitute full and adequate consideration for this Lease.

3. INITIAL TERM. This Lease shall commence on the Effective Date and shall continue for an initial term of twenty (20) years ("Initial Term") unless sooner terminated in accordance with the terms of this Lease. Lessee may, but is not obligated to, extend the Initial Term for up to four successive five-year periods (each individually an "Extension Period") by paying Lessor $25.00 per net acre in the Leased Premises per five-year Extension Period (the "Renewal Payment") on or prior to the last day of the Initial Term or expiring five-year Extension Period, as applicable. The Initial Term together with any Extension Periods exercised by Lessee are referred to as the "Primary Term." Beginning in the 19th year of the Initial Term, and each successive Extension Period thereafter, the Renewal Payment in this Section 3 shall each be adjusted for inflation as follows: Renewal Payment = (existing Renewal Payment) x (the applicable Cumulative CPI Percentage increase, expressed as a percentage, since the last adjustment, if any) + (existing Renewal Payment). For illustration only, the CPI in 2023 will be compared to the CPI in 2042 and the amount for the five year Extension Period commencing 2043 through 2048 shall be increased by the percentage difference determined as follows: Cumulative CPI Percentage = (CPI for 2042 - CPI for 2023) / (CPI for 2023) x (100). Further, for the second Extension Period for years 2049 through 2054, the CPI in 2042 will be compared to the CPI in 2048 and the amount for years 2049 through 2054 will be increased by the percentage difference, determined as follows: Cumulative CPI percentage = (CPI for 2048 - CPI for 2042) / (CPI for 2042) x (100), and so on.

For purposes of this Section 3, CPI means Consumer Price Index published by the Bureau of Labor Statistics of the United States Department of Labor for Urban Wage Earners and Clerical Workers (CPI-W) for the Midwest Region, all items, not seasonally adjusted, reference base period of 1982-84= 100. In the event the Consumer Price Index is converted to a different standard reference base or otherwise revised, the determination of Renewal Payment will be made with the use of such conversion factor, formula or table for converting the Consumer Price Index as may be published by the Bureau of Labor Statistics. If the Consumer Price Index ceases to be published and there is no successor thereto, such other index as Lessor and Lessee may agree upon will be substituted for the Consumer Price Index.

4. OPERATIONAL TERM. Upon Commencement of Operations at any time during the Primary Term, this Lease shall continue for so long as any portion of the Leased Premises or Lessee's Facilities are subject to a permit issued by the Commission or under the ownership or control of the State of North Dakota ("Operational Term"); *provided*, *however*, that all of Lessee's obligations under this Lease shall terminate upon issuance of a Completion Notice, except for payment of the Final Royalty Payment (as applicable), and Final Occupancy Fee (as applicable). If Commencement of Operations does not occur during the Primary Term, this Lease shall terminate, and Lessee shall execute a document evidencing termination of this Lease in recordable form and shall record it in the official records of the county in which the Leased Premises is located.

5. COMPENSATION.

(a) **Initial Term Payment.** Lessee shall pay to Lessor the greater of $50.00 per net acre in the Leased Premises ("Initial Term Payment") or a one-time flat $500.00 payment, the receipt and sufficiency of which are hereby acknowledged.

(b) **Royalty.** During the Operational Term, Lessee shall annually on or before May 31st pay to Lessor a royalty for the portions of the Leased Premises in an Amalgamated Unit, equal to the greater of a flat $100.00 payment or the Storage Fee(s) for the immediately preceding Operating Year. During the Operational Term, in addition to the forgoing royalty payment, Lessee shall annually on or before May 31st pay to the Lessor a $5.00 per acre payment for portions of the Leased Premises not in an Amalgamated Unit. For the Operating Year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay a pro rata share of the Storage Fee(s) ("Final Royalty Payment"), as applicable, and said payment shall be made within sixty days after the date the Completion Notice was issued.

(c) **Occupancy Fee.** Within sixty days of the anniversary of the Effective Date after which any Facilities are installed or used, Lessee shall pay Lessor, as applicable, a one-time fee of (i) $3,000.00 per net surface acre of the Leased Premises occupied by Facilities (excluding pipelines), and (ii) $1.50 for each linear foot of pipeline in place on the Leased Premises. For the year in which Lessee provides Lessor with a Completion Notice, Lessee shall pay any fees owed pursuant to this provision ("Final Occupancy Fee") within sixty days after the date the Completion Notice was issued.

Lessor and Lessee agree that the Lease shall continue as specified herein even in the absence of Operations and the payment of royalties.

6. AMALGAMATION. (a) Lessee, in its sole discretion, shall have the right and power, at any time (including both before and after Commencement of Operations), to pool, unitize, or amalgamate any Reservoir or portion of a Reservoir with any other lands or interests into which that Reservoir extends and document such unit in accordance with applicable law or agency order ("Amalgamated Unit" or "Amalgamated Units"). Amalgamated Units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated Units may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide has commenced prior to the effective date of amalgamation. In exercising its amalgamation rights under this Lease and if required by law, Lessee shall record or cause to be recorded a copy of the Commission's amalgamation order or other notice thereof in the county in which the Amalgamated Unit. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other Amalgamated Units, and Lessee shall have the recurring right to revise any Amalgamated Unit formed under this Lease by expansion or contraction or both. Lessee may dissolve any Amalgamated Unit at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit agreements and operating agreements with respect to the operation of any Amalgamated Units formed under this Lease.

(b) The injection and/or withdrawal of Carbon Dioxide and Non-Native Carbon Dioxide into a Reservoir from any property within a Amalgamated Unit that includes the Leased Premises shall be treated as if Operations were occurring on the Leased Premises, except that the royalty payable to Lessor under Section 5(b) of this Lease shall be Lessor's per net acre proportionate share of the total Storage Fee for the preceding Operating year's injection of Carbon Dioxide into the Amalgamated Unit.

7. ENVIRONMENTAL INCENTIVES. Unless otherwise specified, Lessee is the owner of all Environmental Attributes and Environmental Incentives and is entitled to the benefit of all Tax Credits or any other attributes of ownership of the Facilities and Operations. Lessor shall cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits. Lessor shall not be obligated to incur any out-of-pocket costs or expenses in connection with such actions unless reimbursed by Lessee. If any Environmental Incentives are paid directly to Lessor, Lessor shall immediately pay such amounts over to Lessee.

8. SURRENDER OF LEASED PREMISES. Lessee shall have the unilateral right at any time and from time to time to execute and deliver to Lessor a written notice of surrender and/or release covering all or any part of the Leased Premises for which the subsurface pore space is not being utilized for storage as set forth herein, and upon delivery of such surrender and/or release to Lessor this Lease shall terminate as to such lands, and Lessee shall be released from all further obligations and duties as to the lands so surrendered and/or released, including, without limitation, any obligation to make payments provided for herein, except obligations accrued as of the date of the surrender and/or release.

9. FACILITIES.

(a) Lessee shall in good faith consult with Lessor regarding the location of any Facilities to be constructed on the Leased Premises. The location of the Facilities shall be within the sole discretion of Lessee with consent of the Lessor, not to be unreasonably withheld. The withholding of such consent by the Lessor regarding the location of the Facilities shall be deemed "unreasonable" if the proposed location of the Facility is located more than 500 feet from any currently occupied dwelling or currently used building existing on the Leased Premises as of the Effective Date. Lessee may erect fences around all or part of any above-ground Facilities (excluding roads) to separate Facilities from adjacent Lessor-controlled lands, and shall do so if Lessor so requests. Lessee shall maintain and repair at its expense any roads it constructs on the Leased Premises in reasonably safe and usable condition.

(b) Lessor and Lessee agree that all Facilities and property of whatever kind and nature constructed, placed or affixed on the rights-of-way, easements, patented or leased lands as part of Lessee's Operations, as against all parties and persons whomsoever (including without limitation any party acquiring interest in the rights-of-way, easements, patented or leased lands or any interest in or lien, claim or encumbrance against any of such Facilities), shall be deemed to be and remain the property of the Lessee, and shall not be considered to be fixtures or a part of the Leased Premises. Lessor waives, to the fullest extent permitted by applicable law, any and all rights it may have under the laws of the State of North Dakota, arising under this Lease, by statute or otherwise to any lien upon, or any right to distress or attachment upon, or any other interest in, any item constituting the Facilities or any other equipment or improvements constructed or acquired by or for Lessee and located on the leased Premises or within any easement area. Each Lessor and Lessee agree that the Lessee (or the designated assignee of Lessee or Financing Parties) is the tax owner of any such Facilities, structures, improvements, equipment and property of whatever kind and nature and all tax filings and reports will be filed in a manner consistent with this Lease. Facilities shall at all times retain the legal status of personal property as defined under Article 9 of the Uniform Commercial Code. If there is any mortgage or fixture filing against the Premises which could reasonably be construed as prospectively attaching to the Facilities as a fixture of the Premises, Lessor shall provide a disclaimer or release from such lienholder. Lessor, as fee owner, consents to the filing of a disclaimer of the Facilities as a fixture of the Premises in the Oliver County Recorder's Office, or where real estate records of Oliver County are customarily filed.

10. SURFACE DAMAGE COMPENSATION ACT. The compensation contemplated and paid to Lessor hereunder is compensation for, among other things, damages sustained by Lessor for the lost use of and access to Lessor's land, pore space (to the extent required under North Dakota law), and any other damages which are contemplated under Ch. 38-11.1 of the North Dakota Century Code (to the extent applicable).

11. MINERALS, OIL AND GAS. This Lease is not intended to grant or convey, nor does it grant or convey, any right to or obligation for Lessee to explore for or produce minerals, including Native Oil and Gas, that may exist on the Leased Premises. Lessee shall not engage in any activity or permit its Related Persons to engage in any activity that unreasonably interferes with the Lessor's or third party's (or parties') rights to the granted, leased, or reserved mineral interests. If Lessor owns hydrocarbon mineral interests in the Leased Premises and Lessee should inadvertently discover a Pool in conjunction with its efforts to explore for and develop a Reservoir for Operations, Lessee shall inform Lessor within 60 days of discovery. If Lessee determines that it will not use in conjunction with Operations a well that has encountered a Pool within the Leased Premises, Lessor shall have the option but not the obligation to buy such well at cost, provided Lessor has the ability and assumes all permits and risks and liabilities which are associated with the ownership and operation of an oil, gas or mineral well.

12. FORCE MAJEURE. Should Lessee be prevented from complying with any express or implied covenant of this Lease, from utilizing the Leased Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material failure or breakdown of equipment, or by operation of force majeure (including, but not limited to, riot, insurrection, war (declared or not), mobilization, explosion, labor dispute, fire, flood, earthquake, storm, lightning, tsunami, backwater caused by flood, vandalism, act of the public enemy, terrorism, epidemic, pandemic (including COVID-19), civil disturbances, strike, labor disturbances, work slowdown or stoppage, blockades, sabotage, labor or material shortage, national emergency, and the amendment, adoption or repeal of or other change in, or the interpretation or application of, any applicable laws, orders, rules or regulations of governmental authority), then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and this Lease shall be extended while and so long as Lessee is prevented by any such cause from utilizing the property for underground storage purposes and the time while Lessee is so prevented shall not be counted against Lessee, anything in this Lease to the contrary notwithstanding.

13. DEFAULT/TERMINATION. Lessor may not terminate the Lease for any reason whatsoever unless a Default Event has occurred and is continuing consistent with the terms of this Section 13. Any Party that fails to perform its responsibilities as listed below shall be deemed to be the "Defaulting Party," the other Party shall be deemed to be the "Non-Defaulting Party," and each event of default shall be a "Default Event." A Default Event is: (a) failure of a Party to pay any amount due and payable under this Lease, other than an amount that is subject to a good faith dispute, within thirty (30) days following receipt of written notice from Non-Defaulting Party of such failure to pay; or (b) a material violation or default of any terms of this Lease by a Party, provided the Non-Defaulting Party provides written notice of violation or default and Defaulting Party fails to substantially cure the violation or default within sixty (60) days after receipt of said notice to cure such violations or defaults. Parties acknowledge that in connection with any construction or long-term financing or other credit support provided to Lessee or its affiliates by Financing Parties, that such Financing Parties may act to cure a continuing Default Event and Lessor agrees to accept performance from any such Financing Parties so long as such Financing Parties perform in accordance with the terms of this Lease. If Lessee, its affiliates or Financing Parties, fail to substantially cure such Default Event within the applicable cure period, Lessor may terminate the Lease. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove, plug, and/or abandon in place all

Facilities of Lessee located on the Leased Premises in accordance with applicable permit requirements or other applicable statutes, rules or regulations.

14. ASSIGNMENT. (a) Lessor shall not sell, transfer, assign or encumber the Facilities or any part of Operations, Lessee's title or Lessee's rights under this Lease. (b) Lessee has the right to sell, assign, mortgage, pledge, transfer, use as collateral, or otherwise collaterally assign or convey all or any of its rights under this Lease, including, without limitation, an assignment by Lessee to Financing Parties. (c) In the event Lessee assigns its rights under this Lease, Lessee shall be relieved of all obligations with respect to the assigned portion arising after the date of assignment so long as notice of such assignment is provided to Lessor, and provided that Lessee shall not be relieved from any obligation in respect of any payment or other obligations that have not been satisfied or performed prior to such date of assignment. (d) This Lease shall be binding on and inure to the benefit of the successors and assignees. The assigning Party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; provided, however, that an assigning Party's failure to deliver written notice of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. Further, no change or division in Lessor's ownership of or interest in the Leased Premises or royalties shall enlarge the obligations or diminish the rights of Lessee or be binding on Lessee until after Lessee has been furnished with a written assignment or a true copy of the assignment with evidence that same has been recorded with the Oliver County Recorder's Office.

15. FINANCING. (a) Lessor acknowledges that Lessee may obtain tax equity, construction, long-term financing and other credit support from one or more Financing Parties and that Lessee intends to enter into various agreements and execute various documents relating to such financing, which documents may, among other things, assign this Lease and any related easements to a Financing Party, grant a sublease in the Leased Premises and a lease of the Facilities from such Financing Party to Lessee, grant the Financing Parties a sublease or other real property interest in Lessee's interests in and to the Leased Premises, grant a first priority security interest in Lessee's interest in the Facilities and/or this Lease and Lessee's other interests in and to the Leased Premises, including, but not limited to, any easements, rights of way or similar interests (such documents, "Financing Documents"). Lessor acknowledges notice of the foregoing and consents to the foregoing actions and Financing Documents described above.

(b) Lessor agrees, to execute, and agrees to cause any and all of Lessor's lenders to execute, such commercially reasonable subordination agreements, non-disturbance agreements, forbearance agreements, consents, estoppels, modifications of this Lease and other acknowledgements of the foregoing as Lessee or the Financing Parties may reasonably request (collectively, "Lessor Financing Consent Instruments"). Lessor acknowledges and agrees that (i) Lessee's ability to obtain financing for the construction and operation of the Facilities is dependent upon the prompt cooperation of Lessor and its lenders as contemplated by this Section 15; (ii) if Lessee is unable to close on the financing for the Facilities, the construction of the Facilities and the Commencement of Operations will not likely occur; and (iii) it is in the best interest of both Lessee and Lessor for Lessee to obtain financing from the Financing Parties as contemplated by this Section 15. Therefore, Lessor agrees to act promptly, reasonably and in good faith in connection with any request for approval and execution of all Lessor Financing Consent Instruments. The Lessor shall also reasonably cooperate with the Lessee or the Financing Party in the making of any filings required by such requesting party for regulatory compliance or in accordance with applicable laws and in the operation and maintenance of the Facilities, all solely at the expense of the Lessee.

(c) As a precondition to exercising any rights or remedies as a result of any default or alleged default by Lessee under this Lease, Lessor shall deliver a duplicate copy of the applicable notice of default to each Financing Parties concurrently with delivery of such notice to Lessee, specifying in detail the alleged default and the required remedy, provided Lessor was given notice of such Financing Parties and if no such notice of default is required to be delivered to Lessee under this Lease, Lessor may not terminate this Lease unless Lessor has delivered a notice of default to each Financing Party specifying in detail the alleged default or breach and permitting each Financing Party the opportunity to cure as provided in this Section 15(c). Each Financing Party shall have the same period after receipt of a notice of default to remedy default, or cause the same to be remedied, as is given to Lessee after Lessee's receipt of a notice of default under this Lease, plus, in each instance, the following additional time periods: (i) ten (10)

Business Days in the event of any monetary default; and (ii) sixty (60) days in the event of any non-monetary default; provided, however, that (A) such sixty (60)-day period shall be extended for an additional sixty 60 days to enable such Financing Party to complete such cure, including the time required for such Financing Party to obtain possession of the Facilities (including possession by a receiver), institute foreclosure proceedings or otherwise perfect its right to effect such cure and (B) such Financing Party shall not be required to cure those defaults which are not reasonably susceptible of being cured or performed. Lessor shall accept such performance by or at the instance of a Financing Party as if the performance had been made by Lessee.

(d) If any Lessee Default Event cannot be cured without obtaining possession of all or part of the Facilities and/or the leasehold interest created by the Lease (the "Leasehold Estate"), then any such Lessee Default Event shall nonetheless be deemed remedied if: (i) within sixty (60) days after receiving the notice of default, a Financing Party acquires possession thereof, or commences appropriate judicial or non-judicial proceedings to obtain the same; (ii) such Financing Party is prosecuting any such proceedings to completion with commercially reasonable diligence; and (iii) after gaining possession thereof, such Financing Party performs all other obligations as and when the same are due in accordance with the terms of the Lease. If a Financing Party is prohibited by any process or injunction issued by any court or by reason of any action of any court having jurisdiction over any bankruptcy or insolvency proceeding involving Lessee from commencing or prosecuting the proceedings described above, then the sixty (60)-day period specified above for commencing such proceedings shall be extended for the period of such prohibition.

(e) Financing Parties shall have no obligation or liability to the Lessor for performance of the Lessee's obligations under the Lease prior to the time the Financing Party acquires title to the Leasehold Estate. A Financing Party shall be required to perform the obligations of the Lessee under this Lease only for and during the period the Financing Party directly holds such Leasehold Estate. Any assignment pursuant to this Section 15 shall release the assignor from obligations accruing under this Lease after the date the liability is assumed by the assignee.

(f) Each Financing Party shall have the absolute right to do one, some or all of the following things: (i) assign the rights, mortgage or pledge held by Financing Party (the "Financing Party's Lien"); (ii) enforce the Financing Party's Lien; (iii) acquire title (whether by foreclosure, assignment in lieu of foreclosure or other means) to the Leasehold Estate; (iv) take possession of and operate the Facilities or any portion thereof and perform any obligations to be performed by Lessee under the Lease, or cause a receiver to be appointed to do so; (v) assign or transfer the Leasehold Estate to a third party; or (vi) exercise any rights of Lessee under this Lease. Lessor's consent shall not be required for any of the foregoing; and, upon acquisition of the Leasehold Estate by a Financing Party or any other third party who acquires the same from or on behalf of the Financing Party or any purchaser who purchases at a foreclosure sale, Lessor shall recognize the Financing Party or such other party (as the case may be) as Lessee's proper successor, and this Lease shall remain in full force and effect.

(g) If this Lease is terminated for any reason whatsoever, including a termination by Lessor on account of a Lessee Default Event, or if this Lease is rejected by a trustee of Lessee in a bankruptcy or reorganization proceeding or by Lessee as a debtor-in-possession (whether or not such rejection shall be deemed to terminate this Lease), if requested by Financing Party, Lessor shall execute a new lease (the "New Lease") for the Leased Premises with the Financing Parties (or their designee(s), if applicable) as Lessee, within thirty (30) days following the date of such request. The New Lease shall be on substantially the same terms and conditions as are in this Lease (except for any requirements or conditions satisfied by Lessee prior to the termination or rejection). Upon execution of the New Lease by Lessor, Financing Parties (or their designee, if applicable) shall pay to Lessor any and all sums owing by Lessee under this Lease that are unpaid and that would, at the time of the execution of the New Lease, be due and payable under this Lease if this Lease had not been terminated or rejected. The provisions of this Section 15(g) shall survive any termination of this Lease prior to the expiration of the Term, and any rejection of this Lease in any bankruptcy or reorganization proceeding.

(h) Lessor consents to each Financing Party's security interest, if any, in the Facilities and waives all right of levy for rent and all claims and demands of every kind against the Facilities, such waiver to continue so long as any sum remains owing from Lessee to any Financing Parties. Lessor agrees that the Facilities shall not be subject to distraint or execution by, or to any claim of, Lessor.

(i) Notwithstanding Lessor's obligations and consents under this Section 15 Lessor shall not be obligated to execute any mortgage or grant of security interest in Lessor's interest in and to the Leased Premises for the benefit of Lessee.

16. INDEMNIFICATION; WAIVER. (a) Each Party shall indemnify, defend, and hold harmless the other Party and its Related Persons from and against any and all third-party suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of physical damage to property and physical injuries to any person, including death, caused by the indemnifying Party or its Related Persons except to the extent such claims arise out of the negligence or willful misconduct of the indemnified Party or its Related Persons. (b) Each Party shall indemnify, defend and hold harmless the other Party and its Related Persons from and against all suits, claims, or damages suffered or incurred by the indemnified Party and its Related Persons arising out of or relating to the existence at, on, above, below or near the Leased Premises of any Hazardous Substance, except to the extent deposited, spilled or otherwise caused by the indemnified Party or any of its contractors or agents, provided that Lessee shall not be obligated to indemnify Lessor with respect to any Hazardous Substance on the Leased Premises prior to the Effective Date.

17. INSURANCE. Lessee shall, at its sole cost and expense, keep and maintain in force commercial general liability insurance including broad form property damage liability, personal injury liability, and contractual liability coverage, on an "occurrence" basis, with a combined single limit, which may be effected by primary and excess coverage, of not less than Five Million Dollars ($5,000,000.00) during the primary term, except that such limit in the Primary Term shall be instead not less than One Million Dollars ($1,000,000.00) until such time as Lessee commences physical testing of any injection wells or other similar commercial activities, with such commercially reasonable deductibles as Lessee, in its discretion, may deem appropriate. Lessor shall be named as an additional insured in such policy but only to the extent of the liabilities specifically assumed by the Lessee under this Lease. The policy shall contain provisions by which the insurer waives any right of subrogation it may have against Lessor and shall be endorsed to provide that the insurer shall give Lessor thirty days written notice before any material modification or termination of coverage. Upon Lessor's request, Lessee shall promptly deliver certificates of such insurance to Lessor.

18. MISCELLANEOUS.

(a) **Confidentiality.** Lessor shall maintain in the strictest confidence, and shall require each of Lessor's Related Persons to hold and maintain in the strictest confidence, for the benefit of Lessee, all information pertaining to the compensation paid under this Lease, any information regarding Lessee and its business, operations on the Leased Premises or on any other lands, the capacity and suitability of the Reservoir, and any other information that is deemed proprietary or that Lessee requests or identifies to be held confidential, in each such case whether disclosed by Lessee or discovered by Lessor.

(b) **Liens.** (i) Lessee shall protect the Leased Premises from liens of every character arising from its activities on the Leased Premises, provided that Lessee may, at any time and without the consent of Lessor, encumber, hypothecate, mortgage, pledge, or collaterally assign (including by mortgage, deed of trust or personal property security instrument) all or any portion of Lessee's right, title or interest under this Lease (but not Lessor's right, title or interest in the Leased Premises), as security for the repayment of any indebtedness and/or the performance of any obligation. (ii) Lessor shall not directly or indirectly cause, create, incur, assume or allow to exist any mortgage, pledge, lien, charge, security interest, encumbrance or other claim of any nature on or with respect to the Facilities, Operations or any interest therein. Lessor shall immediately notify Lessee in writing of the existence of any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim, shall promptly cause the same to be discharged and released of record without cost to Lessee, and shall indemnify the Lessee against all costs and expenses (including reasonable attorneys' fees) incurred in discharging and releasing any such mortgage, pledge, lien, charge, security interest, encumbrance or other claim.

(c) **Warranty of Title.** Lessor represents and warrants to Lessee that Lessor is the owner in fee of the surface and subsurface pore space of the Leased Premises. Lessor hereby warrants and agrees to defend title to the Leased Premises and Lessor hereby agrees that Lessee, at its option, shall have the right to discharge any tax, mortgage, or other lien upon the Leased Premises, and in the event Lessee does so, Lessee shall be subrogated to such lien with the right to enforce the same and apply annual rental payments or any other such payments due to Lessor toward satisfying the same. At any time on or after the Effective Date, Lessee may obtain for itself and/or any Financing Party, at Lessee's expense, a policy of title insurance in a form and with exceptions acceptable to Lessee and/or such Financing Party in its sole discretion (the "Title Policies"). Lessor agrees to cooperate fully and promptly with Lessee in its efforts to obtain the Title Policies, and Lessor shall take such actions as Lessee or any Financing Party may reasonably request in connection therewith.

(d) **Conduct of Operations.** Each Party shall, at its expense, use best efforts to comply (and cause its Related Persons to comply) in all material respects with all laws applicable to its (or their) activities on the Leased Premises, provided that each Party shall have the right, in its sole discretion, to contest, by appropriate legal proceedings, the validity or applicability of any law, and the other Party shall cooperate in every reasonable way in such contest, at no out-of-pocket expense to the cooperating Party. During the Primary Term, Lessee, its agents, affiliates, servants, employees, nominees and licensees shall be entitled to: (i) apply for and obtain any necessary permits, approvals and other governmental authorizations (collectively called "Governmental Authorizations") required for the development, construction, operation and maintenance of the Project and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to the Governmental Authorizations upon Lessee's written request and at Lessee's direction, cost and expense; and (ii) apply for any approvals and permits and any zoning amendment of any area of the Leased Premises required in connection with the Project, and Lessor agrees to co-operate, execute, obtain or join with Lessee in any applications or proceedings relating to such approvals, permits and zoning amendments upon Lessee's written request and at Lessee's direction, cost and expense.

(e) **Title to Carbon Dioxide.** As between Lessor and Lessee, all right, title, interest and ownership to all Carbon Dioxide injected into any Reservoir shall belong to Lessee, as measured by corresponding Storage Fee payment to Lessor.

(f) **Hazardous Substances.** Lessee shall have no liability for any regulated hazardous substances located on the Leased Premises prior to the Effective Date or placed in, on or within the Leased Premises by Lessor or any of its Related Persons on or after the Effective Date, and nothing in this Lease shall be construed to impose upon Lessee any obligation for the removal of such regulated hazardous substances.

(g) **Interference.** Lessee shall peaceably and quietly have, hold and enjoy the Leased Premises against any person claiming by, through or under the Lessor and without disturbance by the Lessor, unless Lessee is found in default of the terms of this Lease and such default is continuing. Lessor shall not unreasonably interfere with Lessee's access to or maintenance of the Facilities or associated use of Leased Premises under this Lease; endanger the safety of Lessor, Lessee, the general public, private or personal property, or the Facilities; or install or maintain or permit to be installed or maintained vegetation, undergrowth, trees (including overhanging limbs and foliage and any trees standing which are substantially likely to fall), buildings, structures, installations, and any other obstructions which unreasonably interfere to Lessee access or use of the Facilities, Formations or Lessee's use of the Leased Premises under this Lease. Lessor shall not engage in any activity or permit its Related Persons to engage in any activity that might damage or undermine the physical integrity of any Formation or interfere with Lessee's use of the Leased Premises under this Lease, provided however that it is understood by Lessee that Lessor has no right to permit or to prohibit the exercise of any mineral rights not owned by Lessor at the time of entering into the Option to Lease between Lessor and Lessee with respect to the Leased Premises. Neither Lessee nor its agents will engage in any activity that damages existing oil, gas and other mineral exploration and development activities occurring on the Leased Premises without first obtaining permission from the relevant mineral rights holder.

(h) **Reservations.** Lessor reserves the right to sell, lease, or otherwise dispose of any interest in the Leased Premises subject to the rights granted in this Lease and agrees that sales, leases, or other dispositions of any interest or estate in the Leased Premises shall be expressly made subject to the terms of this Lease and shall not unreasonably interfere with Lessee's rights under this Lease.

(i) **Taxes.** Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall pay any taxes, assessments, fines, fees, and other charges levied by any governmental authority against its Facilities on the Leased Premises. The Parties agree to cooperate fully to obtain any available tax refunds or abatements with respect to the Leased Premises. Lessee shall have the right to pay all taxes, assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

(j) **Amendments.** Lessee reserves the right to revise this Lease to remedy any mistakes, including correcting the names of the Parties, the legal description of the Leased Premises, or otherwise. In the event that any amendment alters the bonus and royalty payable under Section 5(a)-(b) of this Lease, the Lessee shall pay the Lessor the amount owed under the Lease as amended. Any amendments must be in writing and signed by both parties.

(k) **Remedies.** Notwithstanding anything to the contrary in this Lease, neither Party shall be liable to the other for any indirect, special, punitive, incidental or exemplary damages, whether foreseeable or not and whether arising out of or in connection with this Lease, by statute, in contract, tort, including negligence, strict liability or otherwise, and all such damages are expressly disclaimed.. This provision does not limit Lessee's obligation to indemnify Lessor for third-party suits, claims, or damages under Section 16 of this Lease.

(l) **Financial Responsibility.** Lessee will comply with all applicable law regarding financial responsibility for Carbon Dioxide storage, and will post bonds or other financial guarantees as required by the government entities.

(m) **Attorneys' Fees.** If any suit or action is filed or arbitration commenced by either Party against the other Party to enforce this Lease or otherwise with respect to the subject matter of this Lease, the prevailing party shall be entitled to recover reasonable costs and attorneys' fees incurred in investigation of related matters and in preparation for and prosecution of such suit, action, or arbitration as fixed by the arbitrator or court, and if any appeal or other form of review is taken from the decision of the arbitrator or any court, reasonable costs and attorneys' fees as fixed by the court.

(n) **Representations and Warranties.** Lessor represents and warrants to Lessee the following as of the Effective Date and covenants that throughout the Term: (i) Lessor has the full right, power and authority to grant rights, interests and license as contained in this Lease. Such grant of the right, interests and license does not violate any law, ordinance, rule or other governmental restriction applicable to the Lessor or the Leased Premises and is not inconsistent with and will not result in a breach or default under any agreement by which the Lessor is bound or that affects the Leased Premises. (ii) Neither the execution and delivery of this Lease by Lessor nor the performance by Lessor of any of its obligations under this Lease conflicts with or will result in a breach or default under any agreement or obligation to which Lessor is a party or by which Lessor or the Leased Premises is bound. (iii) All information provided by Lessor to Lessee, as it pertains to the Leased Premises' physical condition, along with Lessor's rights, interests and use of the Leased Premises, is accurate in all material respects. (iv) Lessor has no actual or constructive notice or knowledge of Hazardous Substances at, on, above, below or near the Leased Premises. (v) Each of the undersigned represents and warrants that they have the authority to execute this Lease on behalf of the Party for which they are signing.

(o) **Severability.** Should any provision of this Lease be held, in a final and unappealable decision by a court of competent jurisdiction, to be either invalid, void or unenforceable, the remaining provisions of this Lease shall remain in full force and effect, unimpaired by the holding. If the easements or other rights under this Lease are found to be in excess of the longest duration permitted by applicable law, the term of such easements or other rights shall instead expire on the latest date permitted by applicable law.

(p) **Memorandum of Lease.** This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county in which the Leased Premises is situated. A recorded copy of said memorandum shall be furnished to Lessor within thirty (30) days of recording.

(q) **Notices.** All notices required to be given under this Lease shall be in writing, and shall be deemed to have been given upon (a) personal delivery, (b) one (1) Business Day after being deposited with FedEx or another reliable overnight courier service, with receipt acknowledgment requested, or (c) upon receipt or refused delivery deposited in the United States mail, registered or certified mail, postage prepaid, return receipt required, and addressed to the respective Party at the addresses set forth at the beginning of this Lease, or to such other address as either Party shall from time to time designate in writing to the other

Party.

(r) **No Waiver.** The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Lease or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provision or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

(s) **Estoppels.** Either party hereto (the "Receiving Party"), without charge, at any time and from time to time, within ten (10) Business Days after receipt of a written request by the other party hereto (the "Requesting Party"), shall deliver a written statement, duly executed, certifying to such Requesting Party, or any other person, firm or entity specified by such Requesting Party: (i) that this Lease is unmodified and in full force and effect, or if there has been any modification, that the same is in full force and effect as so modified and identifying the particulars of such modification; (ii) whether or not, to the knowledge of the Receiving Party, there are then existing any offsets or defenses in favor of such Receiving Party against enforcement of any of the terms, covenants and conditions of this Lease and, if so, specifying the particulars of same and also whether or not, to the knowledge of such Receiving Party, the Requesting Party has observed and performed all of the terms, covenants and conditions on its part to be observed and performed, and if not, specifying the particulars of same; and (iii) such other information as may be reasonably requested by the Requesting Party. Any written instrument given hereunder may be relied upon by the recipient.

(t) **Counterparts.** This Lease may be executed in any number of counterparts, each of which, when executed and delivered, shall be an original, but all of which shall collectively constitute one and the same instrument.

(u) **Governing Law.** This Lease shall be governed, interpreted, and enforced in accordance with the laws of the state of North Dakota.

(v) **Further Action.** Each Party will execute and deliver all documents, provide all information, and take or forbear from all actions as may be necessary or appropriate to achieve the purposes of this Lease, including without limitation executing a memorandum of easement and all documents required to obtain any necessary government approvals.

(w) **Entire Agreement.** This Lease, into which the attached **Exhibit A** is incorporated by reference, contains the entire agreement of the Parties. There are no other conditions, agreements, representations, warranties, or understandings, express or implied.

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

IN WITNESS OF THE ABOVE, Lessor and Lessee have caused this Lease to be executed and delivered by their duly authorized representatives as of the Effective Date.

LESSOR:

By:____________________________________
Print:__________________________________

By:____________________________________
Print:__________________________________

LESSEE:

MINNKOTA POWER COOPERATIVE, INC.

By:____________________________________
Print:__________________________________
Its:____________________________________

Exhibit A

LEGAL DESCRIPTION OF THE PROPERTY

The Leased Premises consists of the lands located in Oliver County, North Dakota that are owned by the Lessor and generally described as follows:

For purposes of calculating the royalty payable under Section 5(b) of this Lease, the Parties stipulate that the Leased Premises consists of ____________ acres.

79096916.1

SECTION 2.0

GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The proposed Dakota Carbon Center West SGS (secure geologic storage) injection site (DCC West SGS) will be situated approximately 7 miles to the west of the Milton R. Young Station (MRYS) located southeast of Center, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.

Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the EERC-led Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for permanent CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015).

The target CO_2 storage reservoir for DCC West SGS is the Broom Creek Formation, a predominantly sandstone horizon lying 4908 ft below the surface at the J-LOC 1 stratigraphic test well (NDIC File No. 37380). Unconformably overlying the Broom Creek Formation is 29 ft of the undifferentiated Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation"), comprising predominantly siltstone with interbedded dolostone and anhydrite. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish (above) and Opeche (below); since the Minnekahta is absent at the J-LOC 1 location, and due to the similarity in lithology between the two units, the Opeche and Spearfish are undifferentiated here. Overlying the Opeche/Spearfish Formation is 95 ft of the lower portion of the Piper Formation from the top of the Picard Member to the undifferentiated Opeche/Spearfish, comprising siltstone, dolostone, and interbedded evaporites. Together, the Opeche/Spearfish and lower Piper Formations (hereafter "Opeche–Picard interval") serve as the primary confining zone (Figure 2-2). The Amsden Formation (dolostone, sandstone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche–Picard interval and the Broom Creek and Amsden Formations comprise the storage complex for DCC West SGS (Table 2-1).

Including the Opeche–Picard interval, there is 851 ft (thickness at the J-LOC 1 well) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2638 ft (thickness at the J-LOC 1 well) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

2.2 Data and Information Sources

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

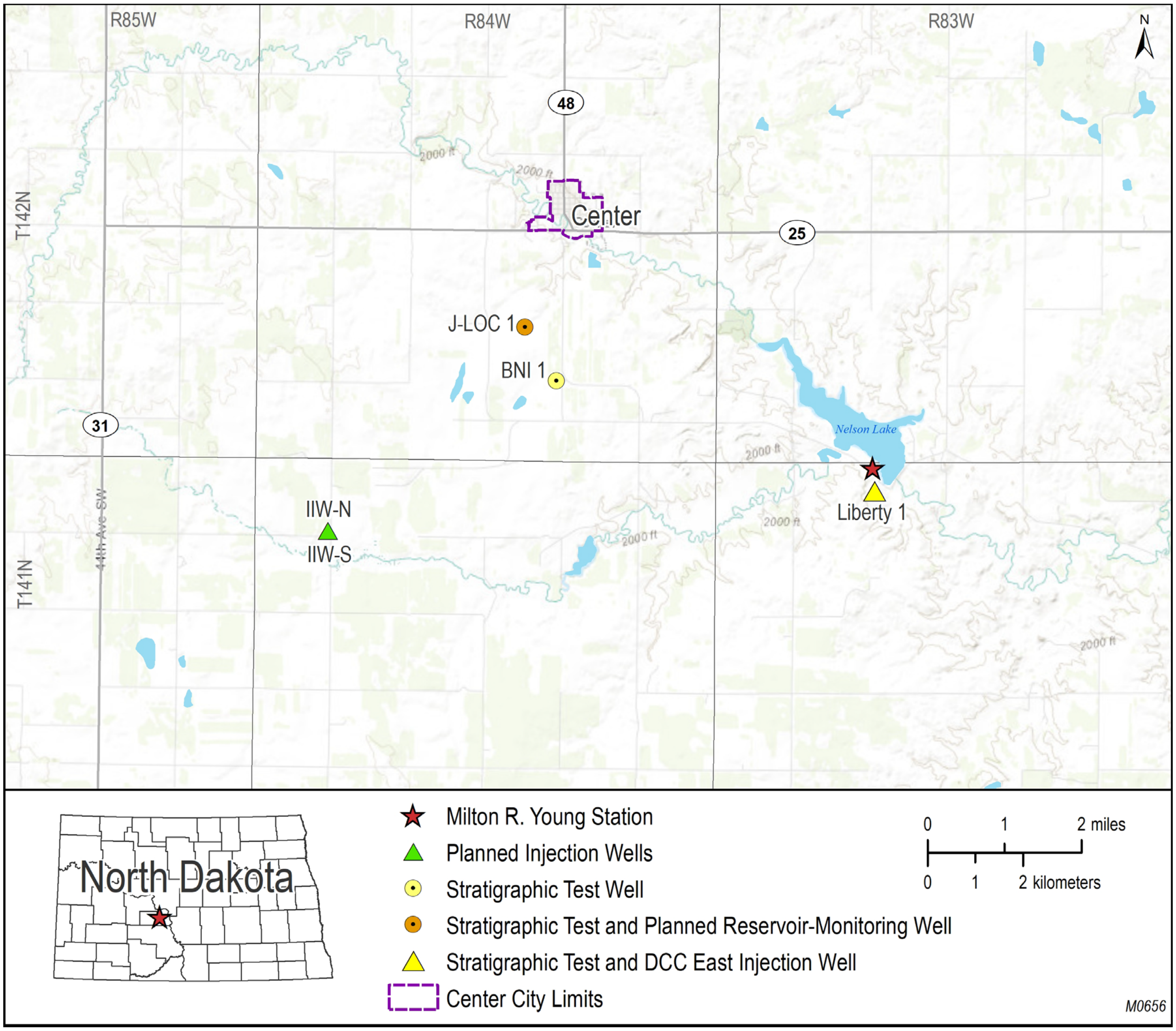


Figure 2-1. Topographic map of DCC West SGS showing well locations and MRYS in relation to the city of Center.

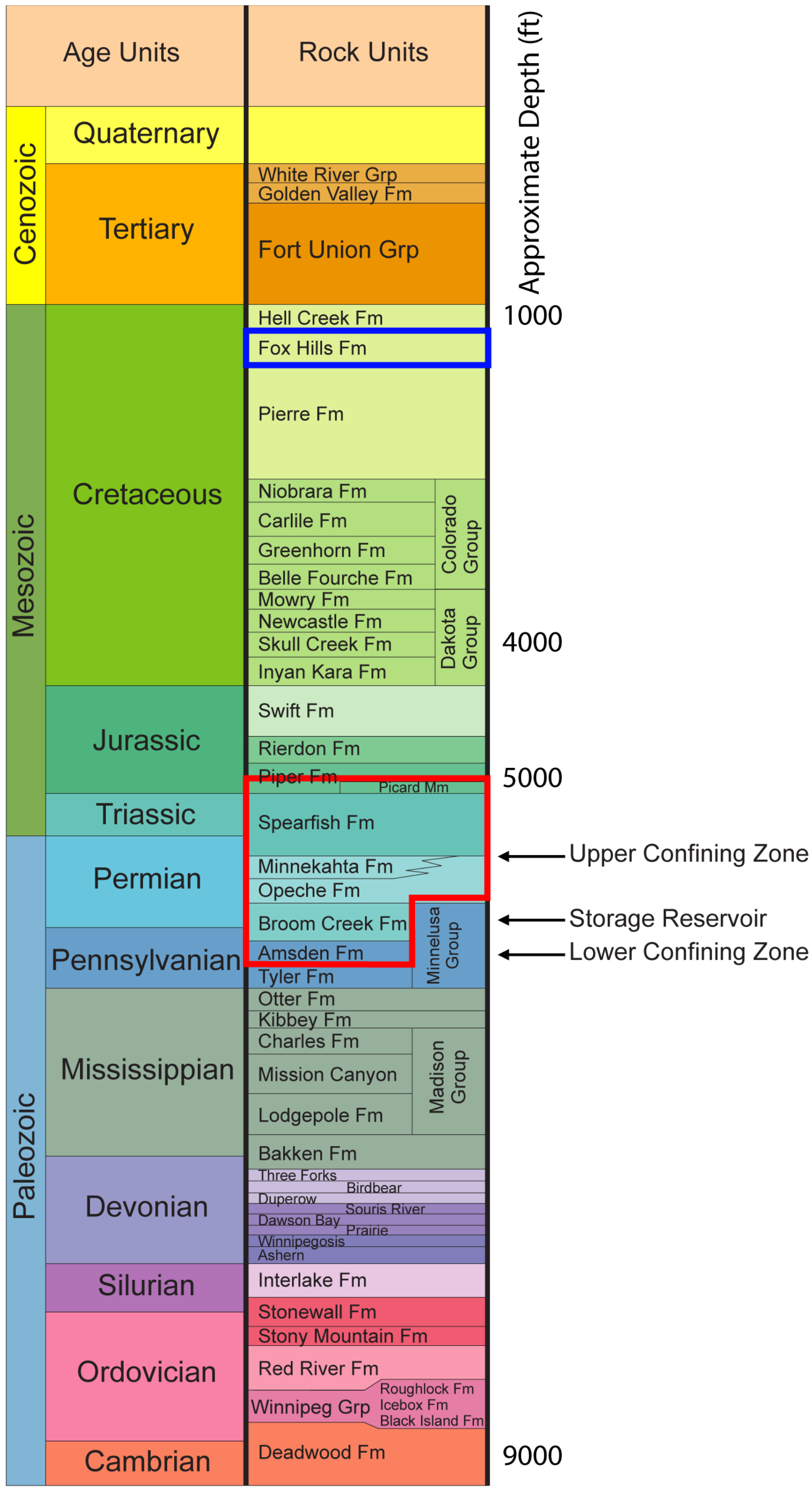


Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue).

Table 2-1. Formations Comprising the DCC West SGS CO_2 Storage Complex (average values calculated from the simulation model shown in Figure 2-3)

	Formation	Purpose	Thickness at J-LOC 1, ft	Depth at J-LOC 1, MD,* ft	Average Thickness, ft	Average Depth, MD,* ft	Lithology
Storage Complex	Opeche–Picard	Upper confining zone	124	4784	234	5010	Siltstone, dolostone evaporites
	Broom Creek	Storage reservoir (i.e., injection zone)	302	4908	280	5244	Sandstone, dolostone, anhydrite
	Amsden	Lower confining zone	259	5210	257	5524	Dolostone, sandstone, anhydrite

* Measured depth.

2.2.1 Existing Data

The existing data used to characterize the geology beneath the DCC West SGS area included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission's (NDIC's) online database and purchased digitized well logs. Well log data and interpreted formation top depths were acquired for 115 wellbores within a 4070-mi^2 (74-mi × 55-mi) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Existing 2D and 3D seismic data were also used to characterize the subsurface geology.

Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were evaluated. Existing wells with core data include the Flemmer 1 (NDIC File No. 34243), BNI 1 well (NDIC File No. 34244), Liberty 1 (NDIC File No. 37672), MAG 1 (NDIC File No. 37833), Coteau 1 (NDIC File No. 38379), Milton Flemmer 1 (NDIC File No. 38594), Archie Erickson 2 (NDIC File No. 38622), Slash Lazy H 5 (NDIC File No. 38701), and ANG 1 (ND-UIC-101) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with site-specific data.

2.2.2 Site-Specific Data

Site-specific efforts to characterize the storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, whole core, and 2D and 3D seismic data. In 2020, the J-LOC 1 well was drilled specifically to gather subsurface geologic data to support development of a storage facility. The J-LOC 1 well was drilled to a depth of 10,470 ft. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche–Picard interval and the Broom Creek and Amsden Formations) (Figure 2-5).

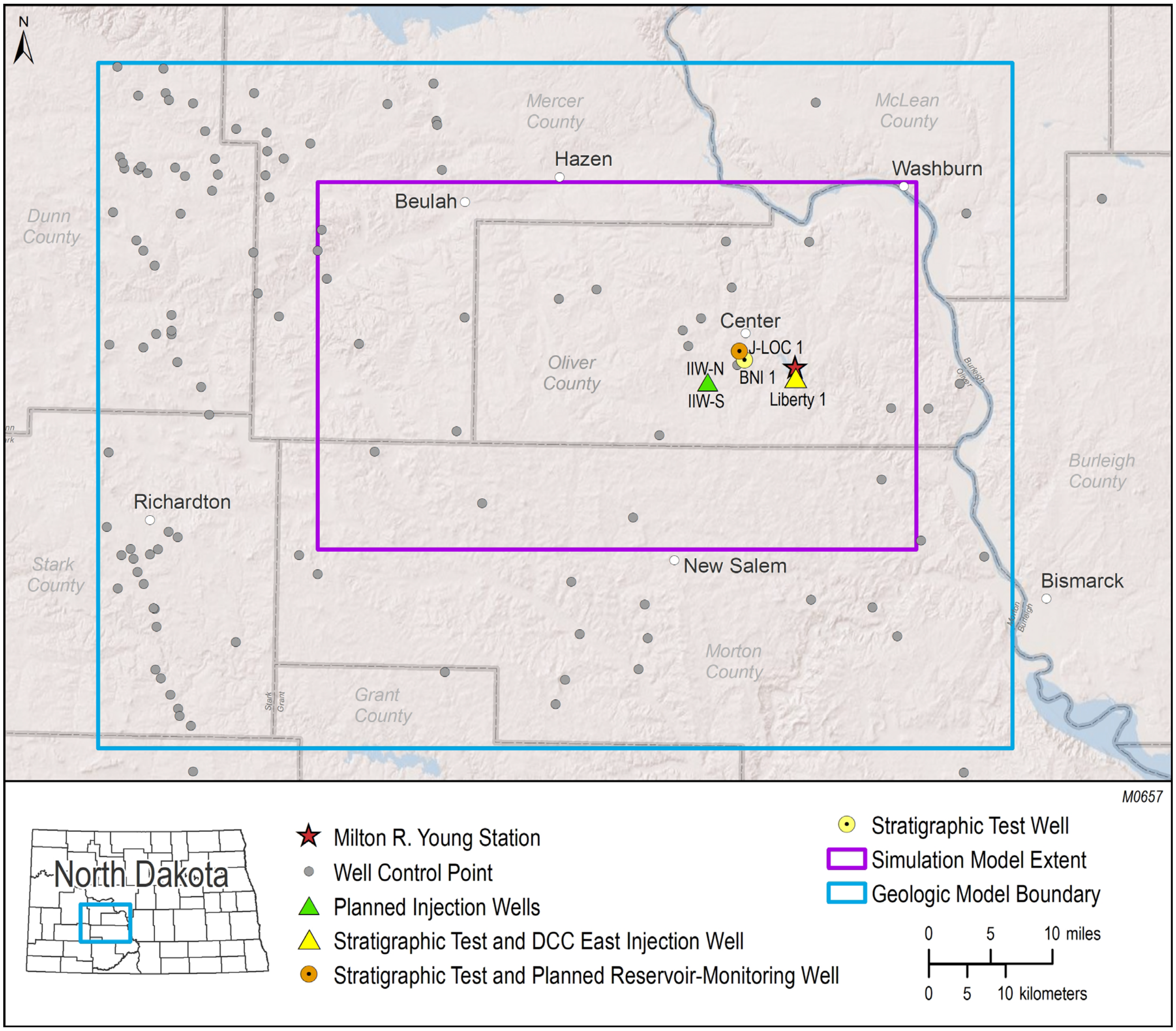


Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

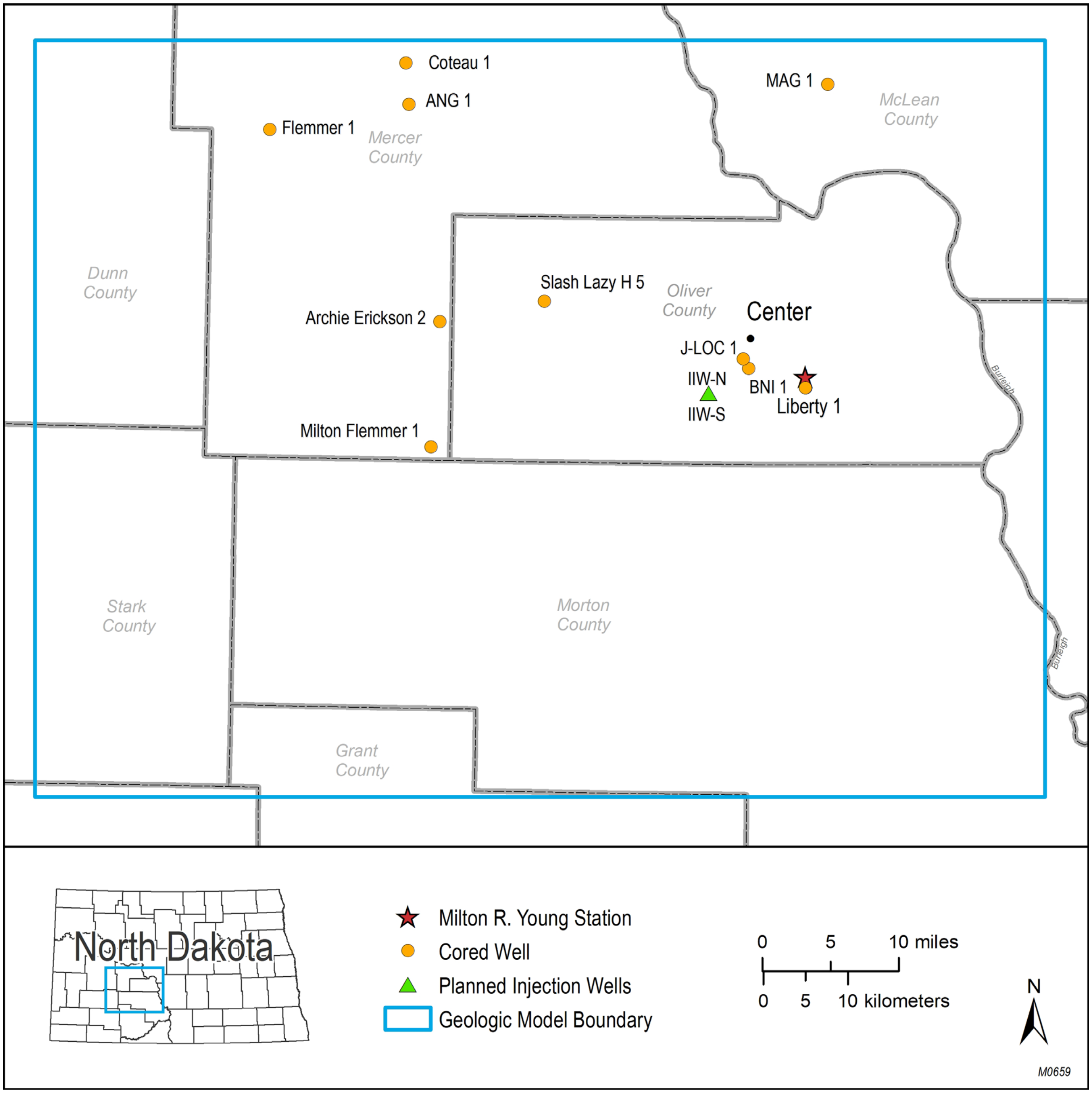


Figure 2-4. Map showing the spatial relationship between the wells where core samples were collected from the formations comprising the storage complex.

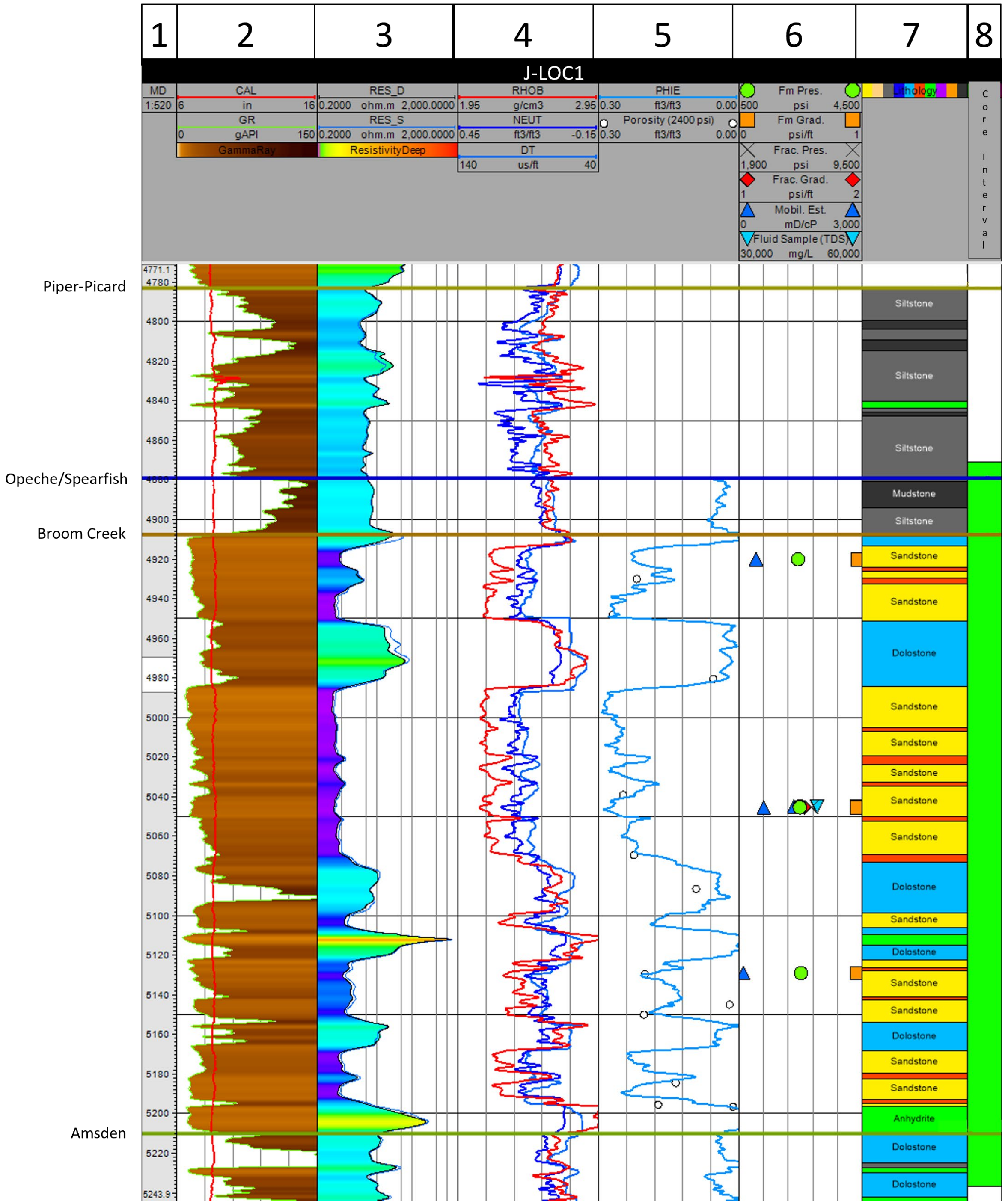


Figure 2-5. Schematic showing vertical relationship of coring and testing intervals in the Opeche–Picard interval and the Broom Creek and Amsden Formations in the J-LOC 1 well. Well logs displayed in tracks from left to right are 2) gamma ray (GR) (green) and caliper (red); 3) resistivity deep (black) and resistivity shallow (blue); 4) delta time (light blue), neutron porosity (dark blue), and density (red); 5) effective porosity (light blue) and core sample porosity (white dots); 6) testing intervals; 7) facies (lithology); and 8) core interval.

Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific and existing data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3), geochemical simulation (Sections 2.3.4, 2.4.1.2, and 2.4.3.2), and geomechanical analysis (Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.

2.2.2.1 Geophysical Well Logs

Openhole wireline geophysical well logs were acquired in the J-LOC 1 well along the entire open section of the wellbore. The logging suite included caliper, GR, density, porosity (neutron, density), dipole sonic, resistivity, combinable magnetic resonance (CMR), spectroscopy, and image log.

The acquired well logs were used to pick formation top depths, interpret lithology and petrophysical properties, and create synthetic seismic traces for tying depth to time. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The site-specific formation top depths were added to the existing data of 115 wellbores within the 4070-mi^2 area covered by the model (Figure 2-3) to understand the geologic extent, depth, and thickness of the subsurface geologic strata. The formation top depths were interpolated to create structural surfaces which served as inputs for geologic model construction.

2.2.2.2 Core Sample Analyses

From the Broom Creek Formation storage complex in the J-LOC 1 well, 365 ft of core was collected. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche/Spearfish, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

2.2.2.3 Formation Temperature and Pressure

Temperature data recorded from logging the J-LOC 1 wellbore were used to derive a temperature gradient for the proposed injection site (Table 2-2). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the simulation model of the DCC West SGS area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

Formation pressure testing at the J-LOC 1 well was performed with the Schlumberger MDT (modular formation dynamics testing) tool. The MDT is a wireline-conveyed tool assembly incorporated with a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection. The MDT tool formation pressure measurements from the Broom Creek Formation are included in Table 2-3. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-2. Description of J-LOC 1 Temperature Measurements and Calculated Temperature Gradients

Formation	Test Depth**, ft	Temperature, °F
Broom Creek	4920.0	136.26
Broom Creek	5045.1	136.60
Broom Creek	5129.1	137.26
Mean Broom Creek Temp., °F	136.71	
Broom Creek Temperature Gradient, °F/ft	0.02*	

* The temperature gradient is an average of the MDT tool-measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.
** Measured depth.

Table 2-3. Description of J-LOC 1 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Test Depth**, ft	Formation Pressure, psi
Broom Creek	4920.0	2415.86
Broom Creek	5045.1	2471.43
Broom Creek	5129.1	2509.60
Mean Broom Creek Pressure, psi	2465.63	
Broom Creek Pressure Gradient, psi/ft	0.49*	

* The pressure gradient is an average of the MDT tool-measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.
** Measured depth.

2.2.2.4 Microfracture In Situ Stress Tests

Using the Schlumberger MDT tool, microfracture in situ stress tests were performed in the J-LOC 1 wellbore. As shown in Figure 2-6, in situ reservoir stress-testing measurements provided real-time formation pressure and formation temperature, as well as formation, fracture breakdown, propagation, and closure pressures.

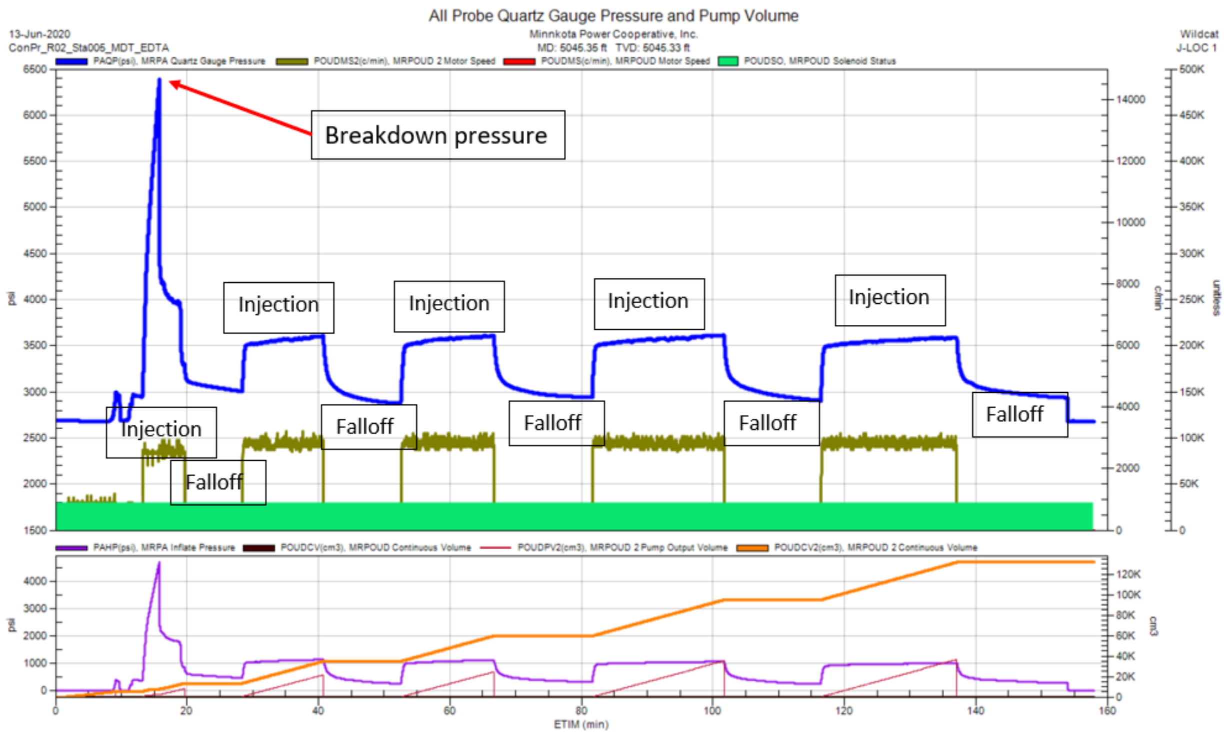


Figure 2-6. J-LOC 1 MDT stress test results for the Broom Creek Formation at 5045 ft MD.

Microfracture in situ stress tests were performed in the Opeche/Spearfish and Broom Creek Formations (Table 2-4). The use of the dual-packer module on the MDT tool assembly to isolate the designated intervals tested a 1.5-ft section of the zone of interest. This small representative sample should be taken into consideration in the analysis of the pressures. Fracture propagation pressures determined from the microfracture test were used to calculate pressure constraints related to the maximum allowable bottomhole pressure (BHP).

Table 2-4. Description of J-LOC 1 Microfracture In Situ Stress Tests

	Test Depth*	Breakdown Pressure		Propagation Pressure		Closure Pressure (GFunction)	
Formation	**ft**	**psi**	**Gradient psi/ft**	**Avg., psi**	**Gradient psi/ft**	**Avg., psi**	**Gradient psi/ft**
Opeche/ Spearfish	4887.7	No observed formation breakdown. Maximum applied injection pressure = 8162.49 psi					
	4888.8	No observed formation breakdown. Maximum applied injection pressure = 8150.95psi					
Broom Creek	5045.4	6384.5	1.265	3592.5	0.712	3203.42	0.635

* Measured depth.

In the J-LOC 1 wellbore, two microfracture in situ stress tests were performed in the Opeche/Spearfish Formation at 4887.7 and 4888.8 ft, with the interpretation of the results provided in Table 2-4. Of the two tests attempted in the Opeche/Spearfish Formation, in which a formation breakdown was not achieved, one predominant reason included limitations with the dual-packer mechanical specifications, with a maximum differential pressure between the upper packer and hydrostatic pressure of 5500 psi. The inability to break down the Opeche/Spearfish Formation at the two depths indicated that the formation is very tight competent rock and exhibits sufficient geologic integrity to contain the injected CO_2 stream. One microfracture in situ stress test was performed in the Broom Creek Formation at 5045.4 ft, with interpretation of the results provided in Table 2-4.

2.2.2.5 Fluid Samples

A fluid sample from the Broom Creek Formation was collected from the J-LOC 1 wellbore via an MDT tool, as shown in Table 2-5. Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab, and confirmed by the Energy & Environmental Research Center (EERC). Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations. Fluid sample analysis reports can be found in Appendix A.

Table 2-5. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value for J-LOC 1

Formation	Well	Test Depth*, ft	MVTL TDS, mg/L	EERC Lab TDS, mg/L
Broom Creek	J-LOC 1	5044.8	49,000	49,000
Inyan Kara	J-LOC 1	4018.9	3450	3360

* Measured depth.

In situ fluid pressure testing was performed in the Opeche/Spearfish Formation with the MDT tool. This test utilized the tool's large-diameter probe to test both the mobility and reservoir pressure. The probe (MDT) was unable to draw down reservoir fluid in order to determine the reservoir pressure or to collect an in situ fluid sample, and the formation was unable to rebound (build pressure) because of low to almost zero permeability. The testing results provide further evidence of the confining properties of the Opeche/Spearfish Formation, ensuring sufficient geologic integrity to contain the injected carbon dioxide stream.

2.2.2.6 Seismic Survey

Approximately 45 miles of 2D seismic data were licensed and reprocessed for characterization of subsurface structure within the DCC West SGS area (Figure 2-7). The seismic data allowed for the visualization of deep geologic formations. The 2D data were tied to nearby 3D seismic surveys to the east. Together, the 2D and 3D seismic data and J-LOC 1 well logs were used to interpret surfaces for the formations of interest within the project area. The surfaces were converted to depth using the time-to-depth relationship derived from the J-LOC 1 sonic log. These surfaces captured detail about structure and varying thicknesses of the formations away from well control. Interpretation of the seismic data suggests no major stratigraphic pinch-outs or structural features with associated spill points are located within the DCC West SGS area. No structural features, faults, or discontinuities were observed in the seismic data that cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation.

Additionally, 3D seismic data from the Beulah 3D seismic (a 200-mi^2 survey to the west of the site) was interpreted to evaluate the subsurface (Figure 2-7). Data products generated from the interpretation and inversion of the seismic data from the three 3D seismic surveys were used as inputs into the geologic model (Figure 2-7). Acoustic impedance (AI) volumes were created using the 3D seismic and petrophysical data (e.g., dipole sonic and density logs) from the J-LOC 1, Liberty 1, Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 wells. The AI volumes were used to classify facies of the Broom Creek Formation and distribute facies through the geologic model, as well as inform petrophysical property distribution in the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

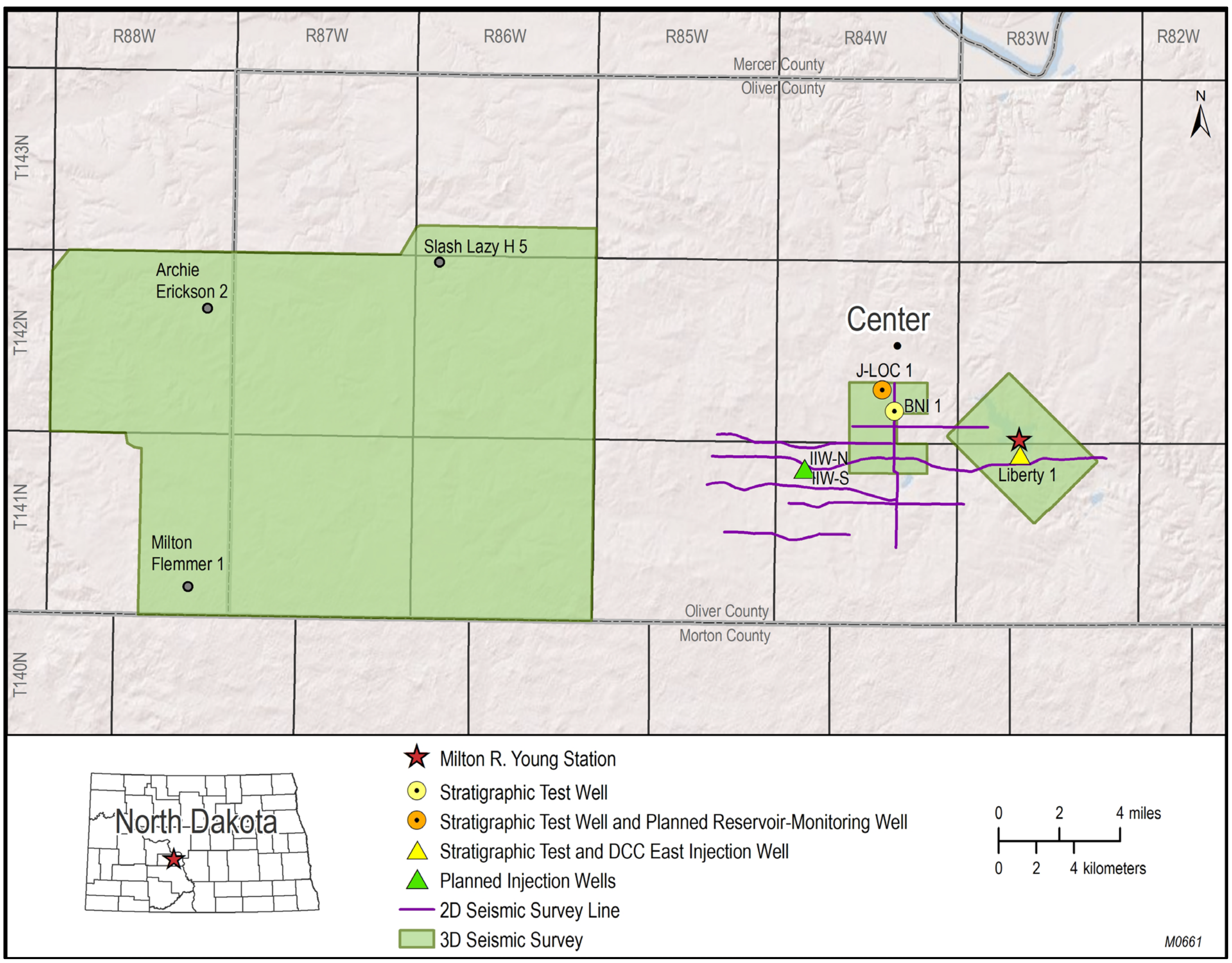


Figure 2-7. Map showing the 2D and 3D seismic surveys used to characterize the DCC West SGS area and inform the construction of the geologic model. The 3D seismic surveys from west to east are the Beulah 3D, Center 3D, and Minnkota 3D.

2.3 Storage Reservoir (injection zone)

Regionally, the Broom Creek Formation is laterally extensive in the project area (Figure 2-8). Broom Creek Formation core comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with anhydrite layers. The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Opeche/Spearfish Formation (Figure 2-2) (Murphy and others, 2009).

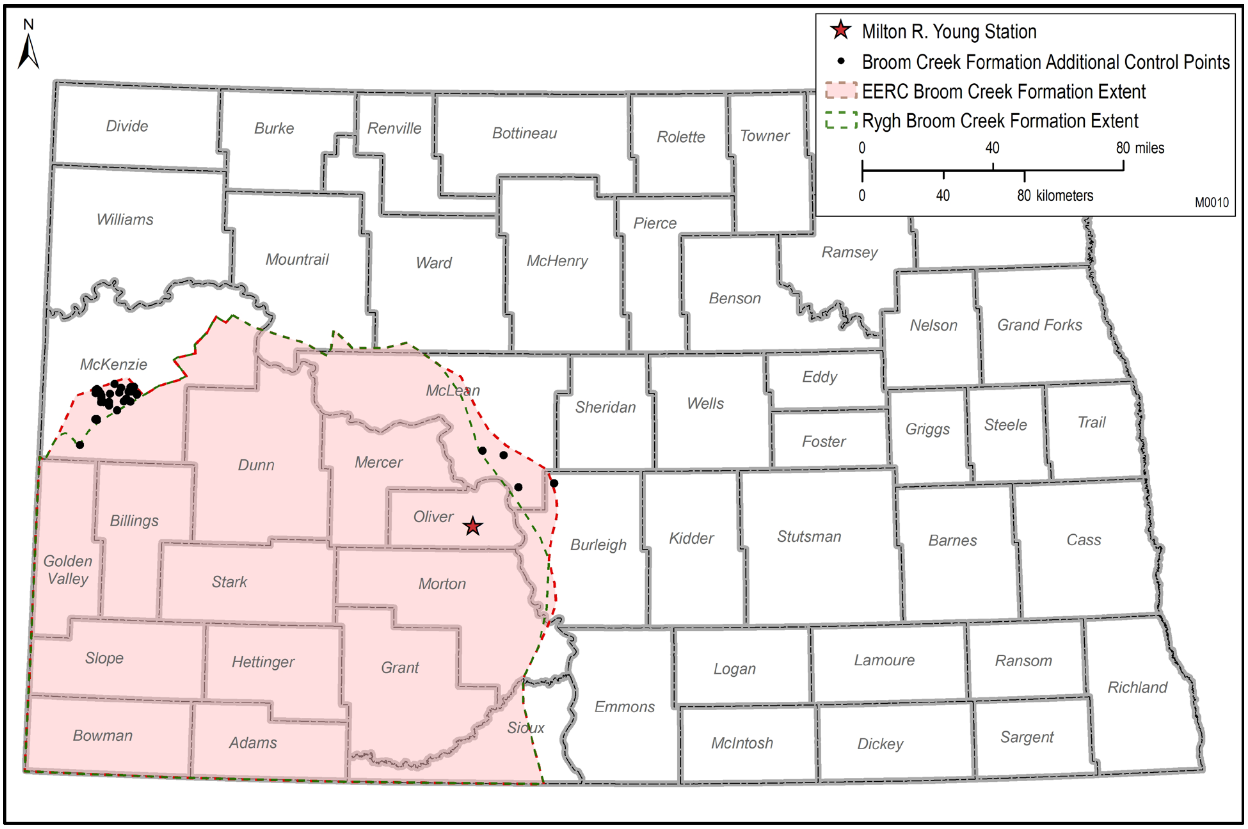


Figure 2-8. Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green line has been modified based on new well control.

Across the simulation model area, the Broom Creek Formation varies in thickness from 139 to 492 ft (Figure 2-9), with an average thickness of 280 ft. Based on offset well data and geologic model characteristics, the net sandstone thickness within the simulation model averages 140 ft.

The top of the Broom Creek Formation was picked across the DCC West SGS area based on the transition from a relatively high GR signature representing the siltstones of the Opeche/Spearfish Formation to a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation (Figure 2-10). The top of the Amsden Formation

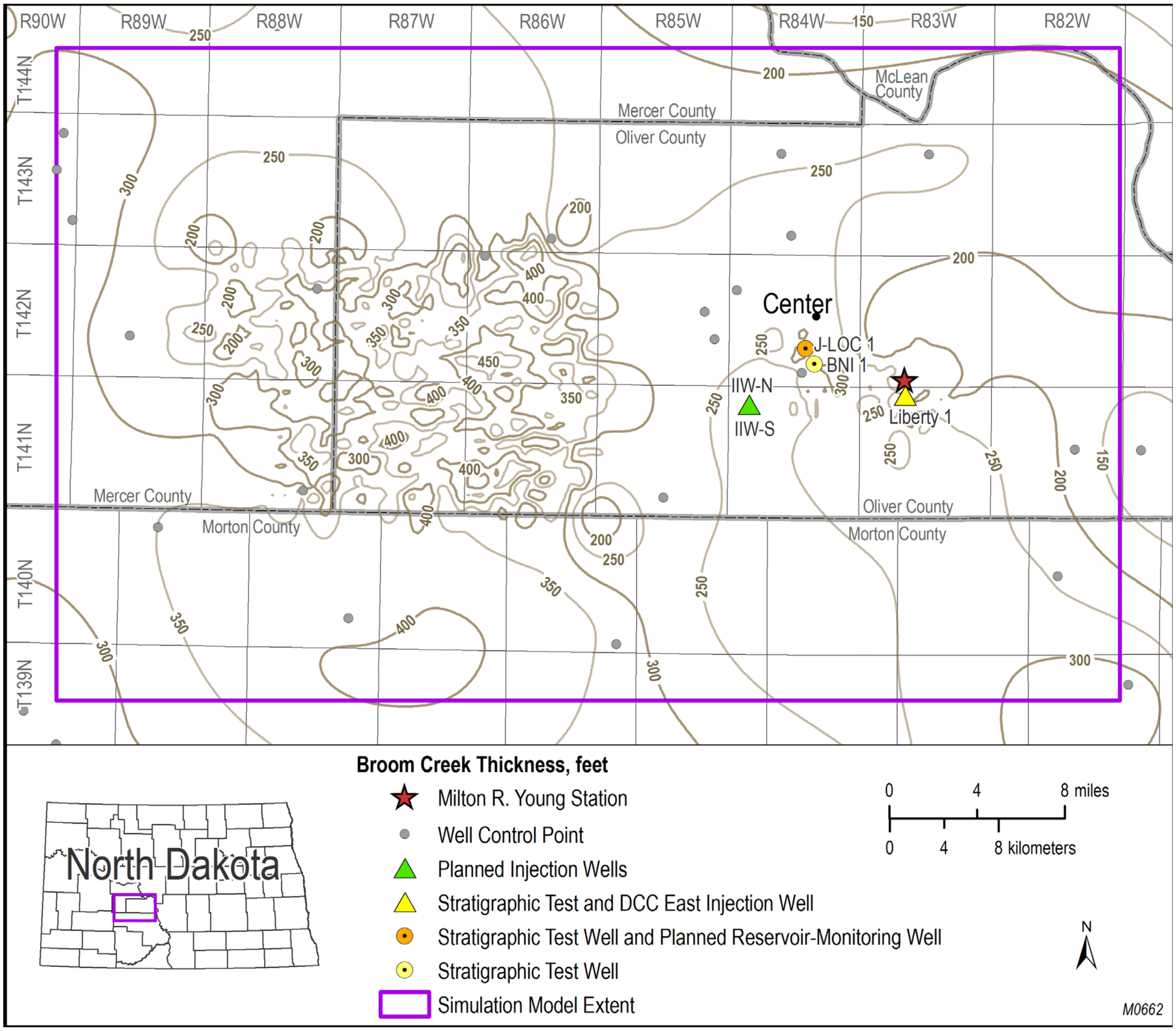


Figure 2-9. Isopach map of the Broom Creek Formation in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

was placed at the bottom of a relatively high GR signature representing an argillaceous dolostone that could be correlated across the entirety of the DCC West SGS area. Seismic data collected as part of site characterization efforts (Figure 2-7) were used to reinforce structural correlation and thickness estimations of the storage reservoir.

The Broom Creek Formation is estimated to pinch out ~30 mi to the east of the planned injection wells. There are no detectable features with associated spill points (e.g., folds, domes, or fault traps) in the Broom Creek Formation in the DCC West SGS area (Figures 2-11a, 2-11b, 2-12, and 2-13).

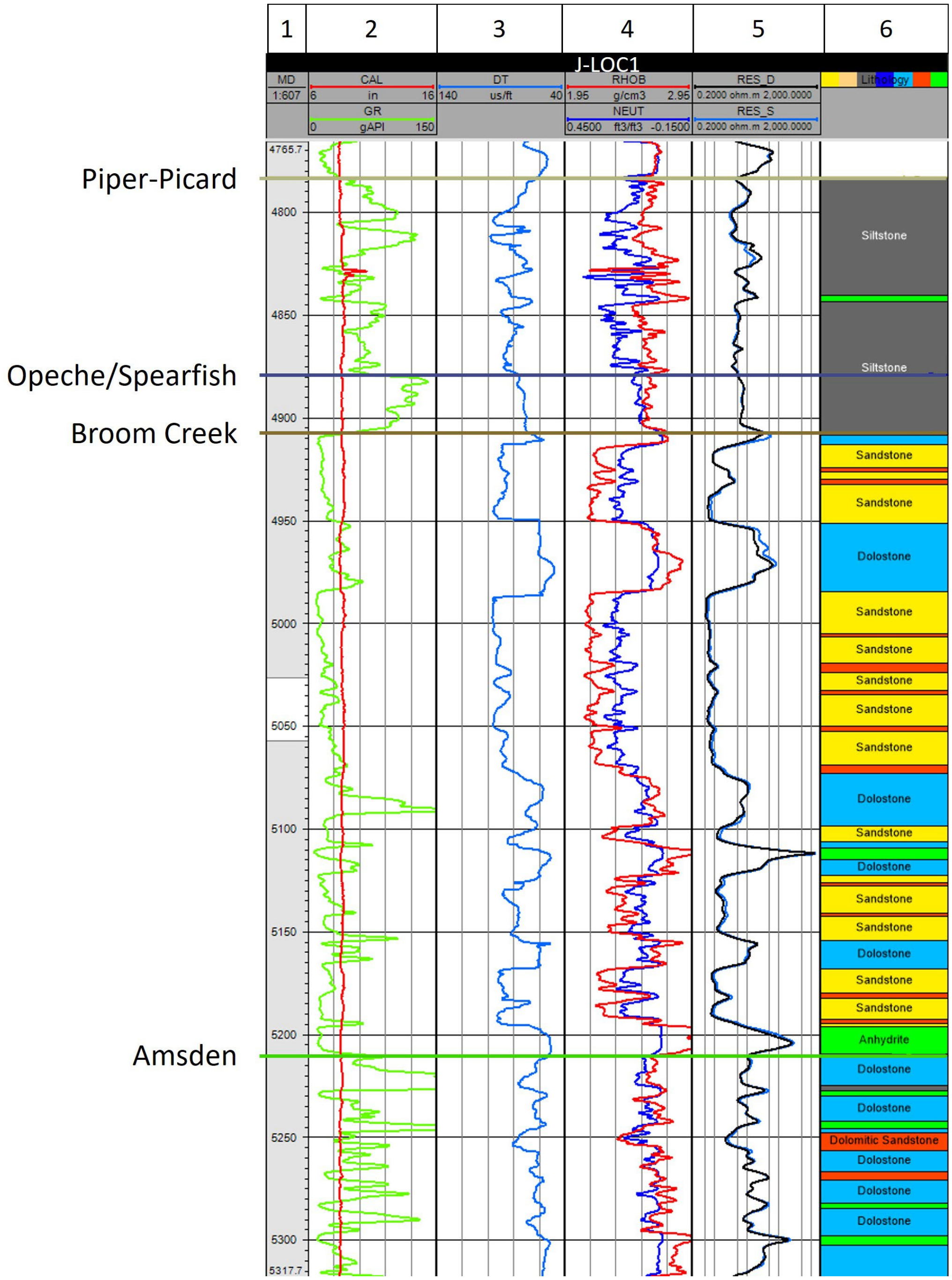


Figure 2-10. Well log display of the interpreted lithologies of the Opeche–Picard interval and Broom Creek and Amsden Formations in J-LOC 1 well. Well logs displayed in tracks from left to right are 2) GR (green) and caliper (red), 3) delta time (light blue), 4) neutron porosity (blue) and density (red), 5) resistivity deep (black) and resistivity shallow (light blue), and 6) facies (lithology).

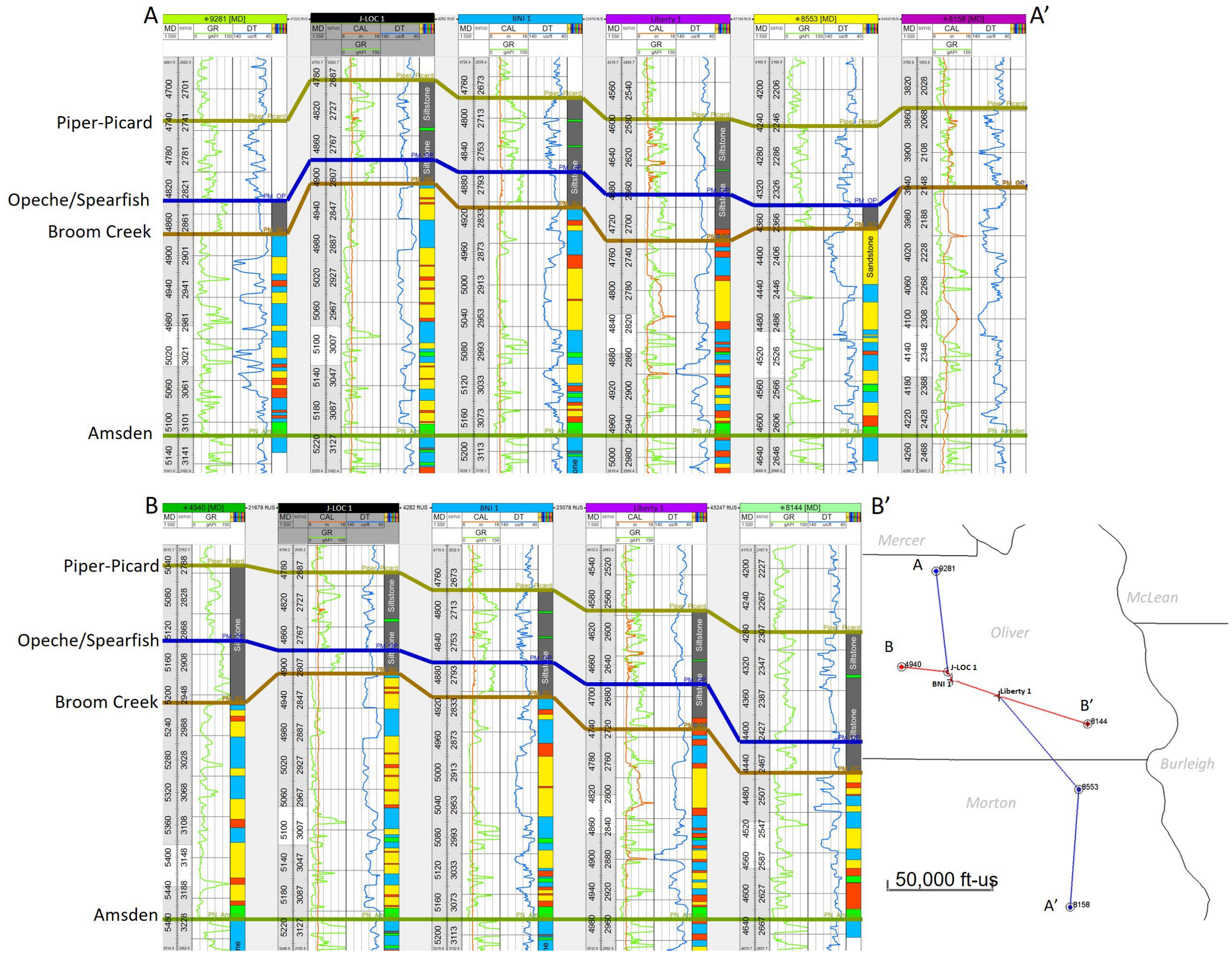


Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche–Picard interval and the Broom Creek Formation flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Cross-sections scaled in SSTVD (SubSea True Vertical Depth).

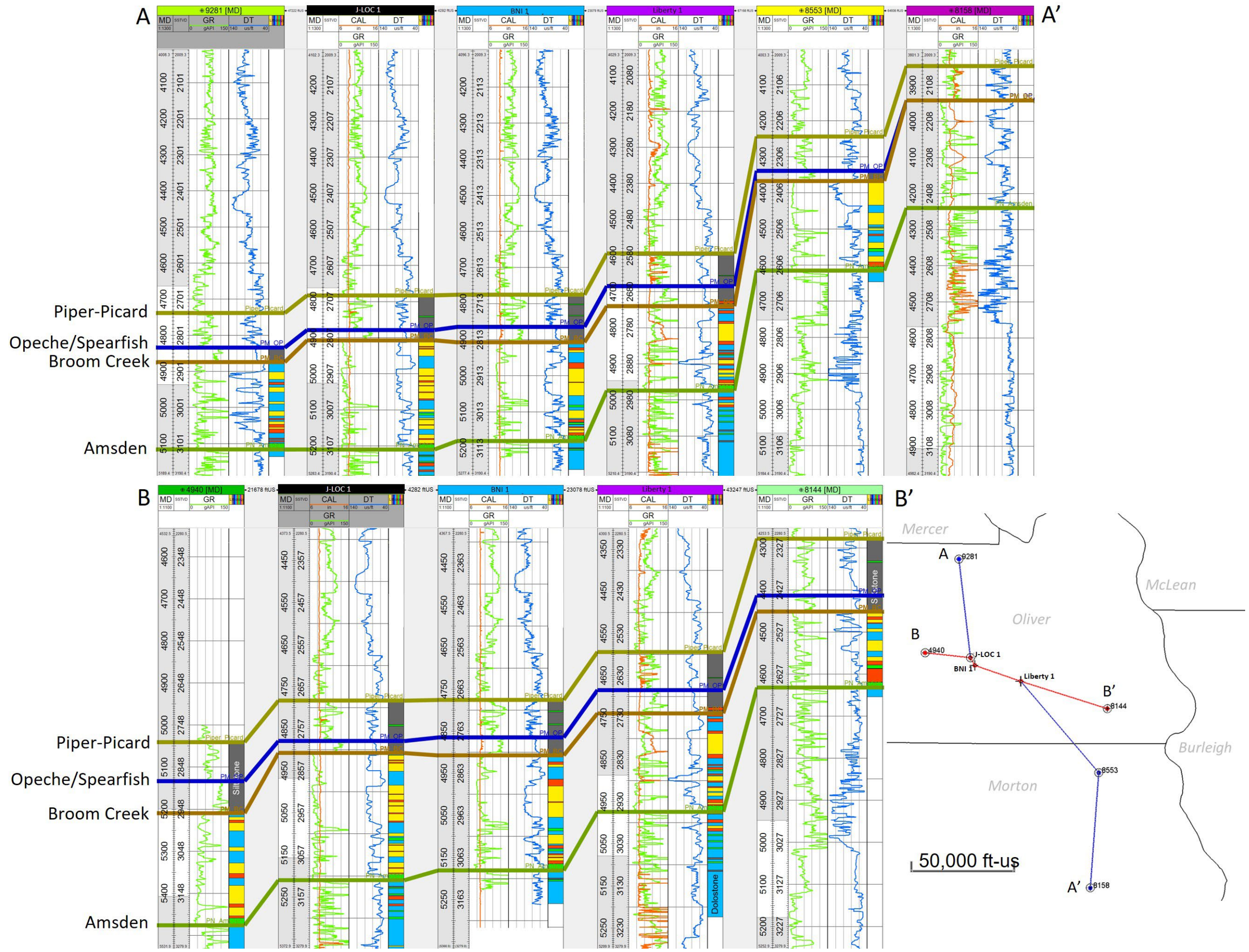


Figure 2-11b. Regional well log structural cross sections of the Opeche–Picard interval and the Broom Creek and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is. Cross-sections scaled in SSTVD.

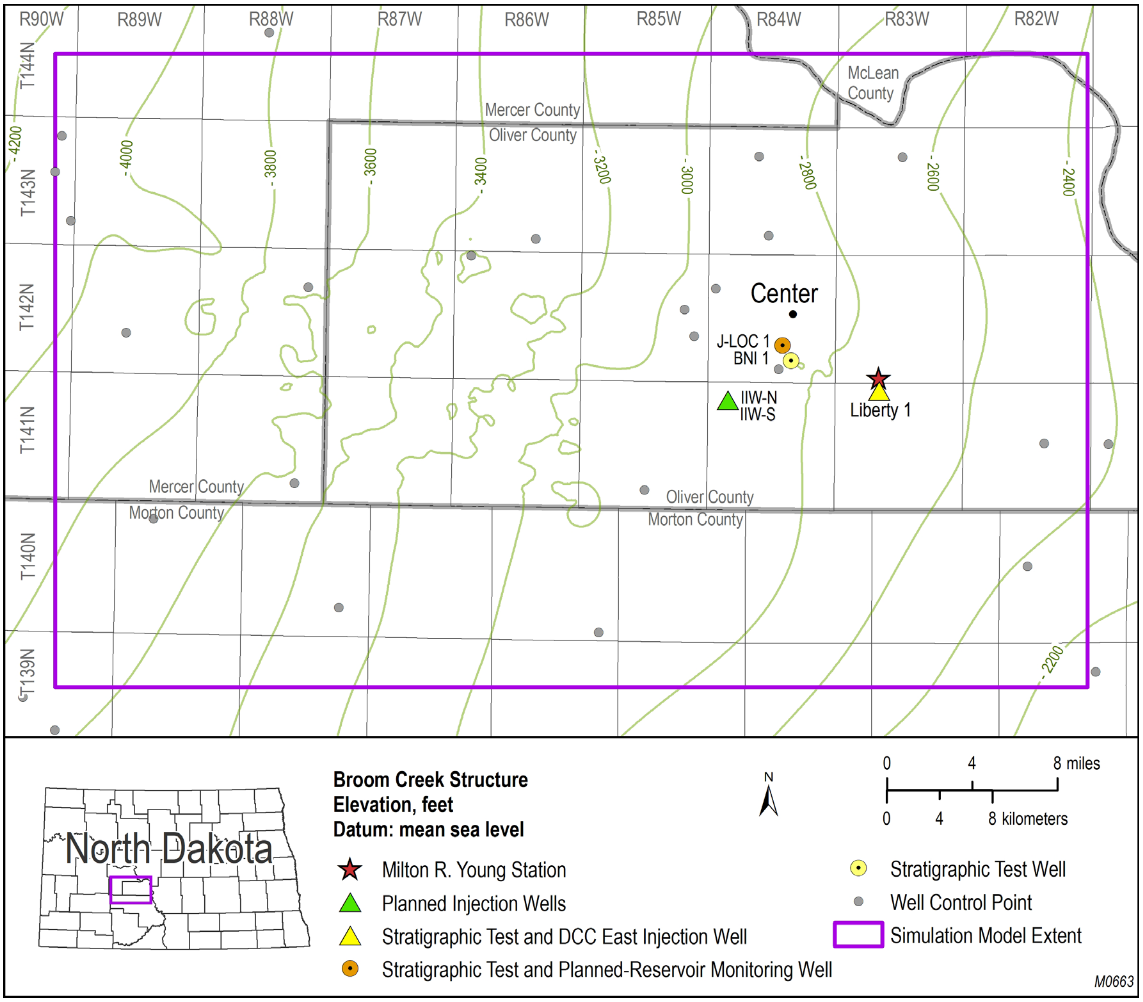


Figure 2-12. Structure map of the Broom Creek Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

Seventeen (17) 1-in.-diameter core plug samples were taken from the sandstone and dolostone facies of the Broom Creek Formation core retrieved from the J-LOC 1 well. These core samples were used to determine the distribution of porosity and permeability values throughout the formation (Figure 2-14).

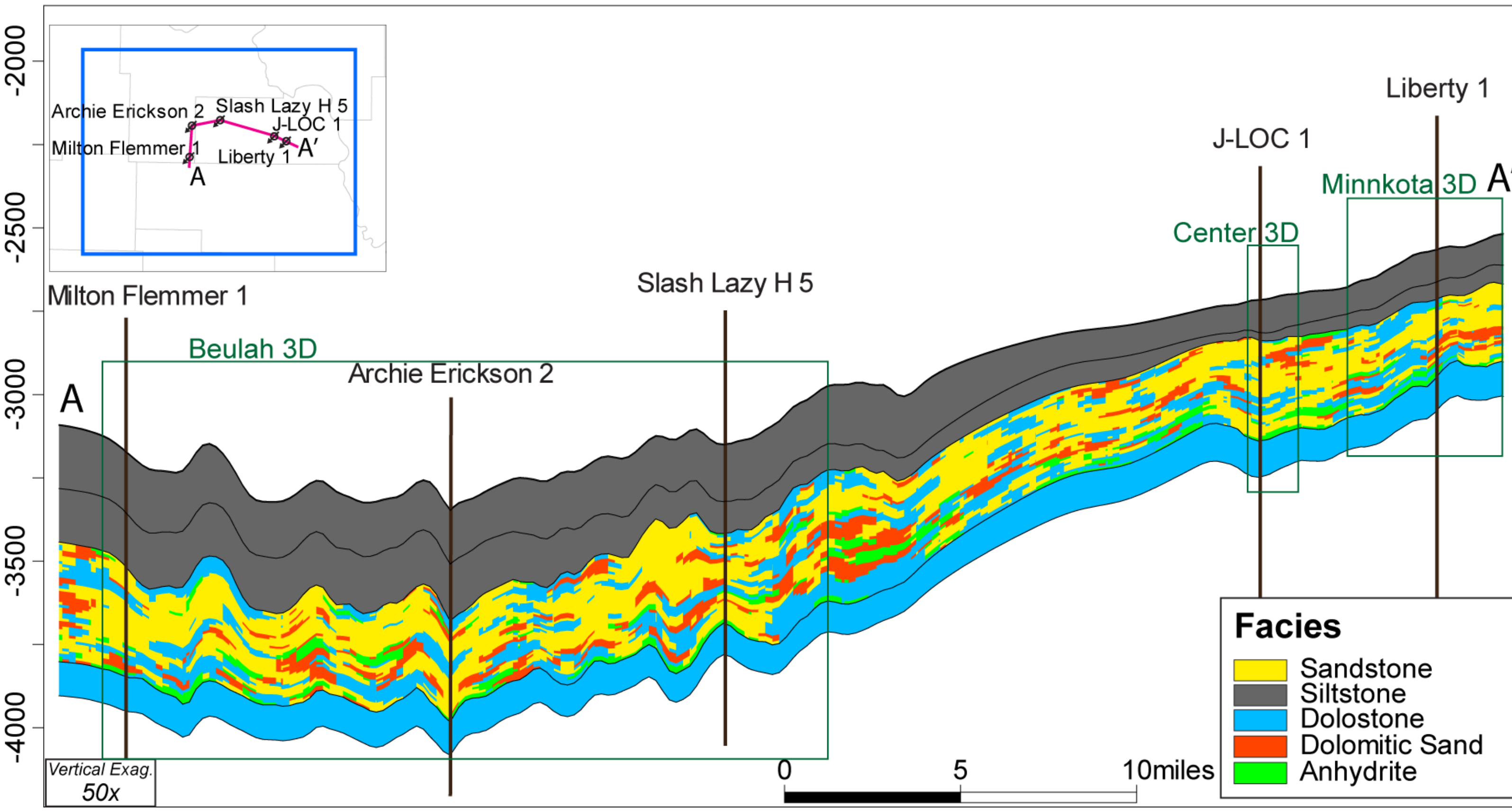


Figure 2-13. Cross section from A-A' of the DCC West SGS area from the geologic model showing facies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. Geologic model extent is displayed by dark blue box in the upper-left corner.

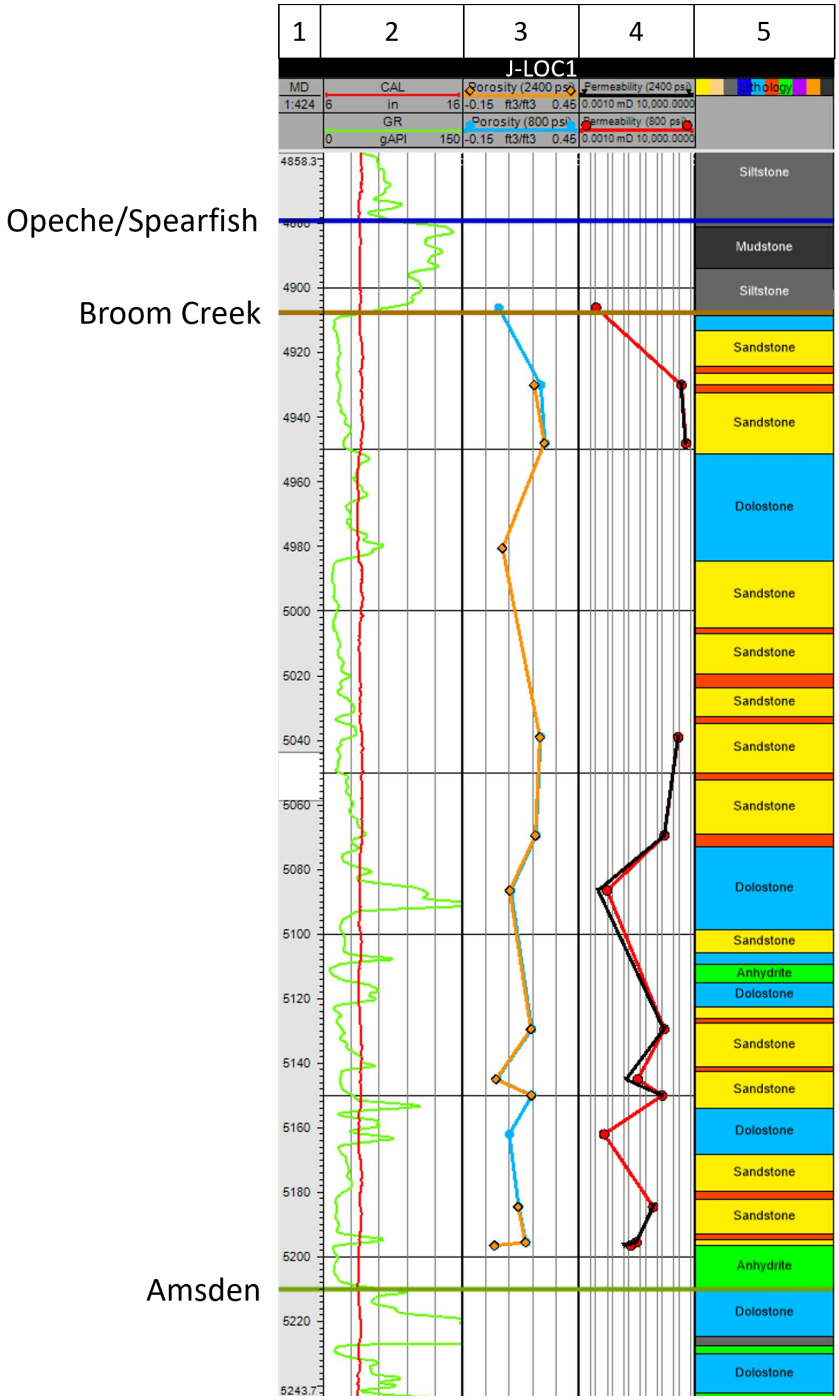


Figure 2-14. Vertical distribution of core-derived porosity and permeability values in the J-LOC-1 well. Well logs displayed in tracks from left to right are 2) GR (green) and caliper (red), 3) core porosity (800 psi) (blue) and core porosity (2400 psi) (orange), 4) core permeability (800 psi) (red) and core permeability (2400 psi) (black), and 5) facies (lithology).

Core-derived measurements were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The core sample measurements showed good agreement with the wireline logs collected from the J-LOC 1 well. This agreement allowed for confident extrapolation of porosity and permeability from offset well logs, thus creating a spatially and computationally larger data set to populate the geologic model. The model property distribution statistics, shown in Table 2-6, are derived from a combination of the core analysis and larger data set derived from offset well logs. A 2.5 multiplier for permeability was applied to the geologic model based on injection test results (Section 3.0).

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

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC 1 Well

Injection Zone Properties			
Property	**Description**		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, dolomitic sandstone, anhydrite		
Formation Top Depth*, ft	4908		
Thickness, ft	Sandstone, 169 Dolostone, 89 Dolomitic sandstone, 27 Anhydrite, 17		
Capillary Entry Pressure (CO_2/brine), psi	0.20		
Geologic Properties			
Facies	**Property**	**Laboratory Core Analysis**	**Simulation Model Property Distribution**
Broom Creek (sandstone)	Porosity, %**	19.51 (2.46–27.38)	21.96 (0.0005–35.30)
	Permeability, mD***	69.28 (0.06–2690)	136.96 (0.0–3401.2)
Broom Creek (dolostone)	Porosity, %	8.11 (5.48–8.97)	4.39 (0.0–34.93)
	Permeability, mD	0.03 (0.02–0.05)	2.07 (0.0–919.6)

* Measured depth.
** Porosity values are reported as the arithmetic mean measured at 800 psi followed by the range of values in parentheses.
*** Permeability values are reported as the geometric mean measured at 800 psi followed by the range of values in parentheses.

2.3.1 J-LOC 1 Injectivity Tests

The J-LOC 1 formation well testing was performed specifically to characterize the injectivity and obtain the breakdown pressure of the Broom Creek Formation. The well testing consisted of a step rate test, extended injection test, and pressure falloff test. The well was perforated from 4912 to 4922 ft with 4 shots per foot (spf) and 90° phasing. To record the BHP, a tandem downhole memory gauge was installed at depths of 4862 and 4868 ft. The well test data were interpreted by GeothermEx, a Schlumberger Company.

The step rate test was performed with a total of ten injection rates. The initial injection rate was 1.27 barrels per minute (bpm), and final injection rate was 16 bpm. From the step rate test evaluation, the fracture opening pressure was observed at 3424 psi, as shown in Figure 2-15.

A 12-hour extended injection rate was performed at a constant rate of 5 bpm followed by a 24-hour pressure falloff test. The interpretation of the pressure falloff data shows a permeability of 4485 mD with reservoir pressure of 2410 psi. No lateral boundary was observed from the pressure falloff test within the radius of investigation of 24,804 ft, as shown in Figures 2-16 and 2-17. Broom Creek Formation well testing is summarized in Table 2-7.

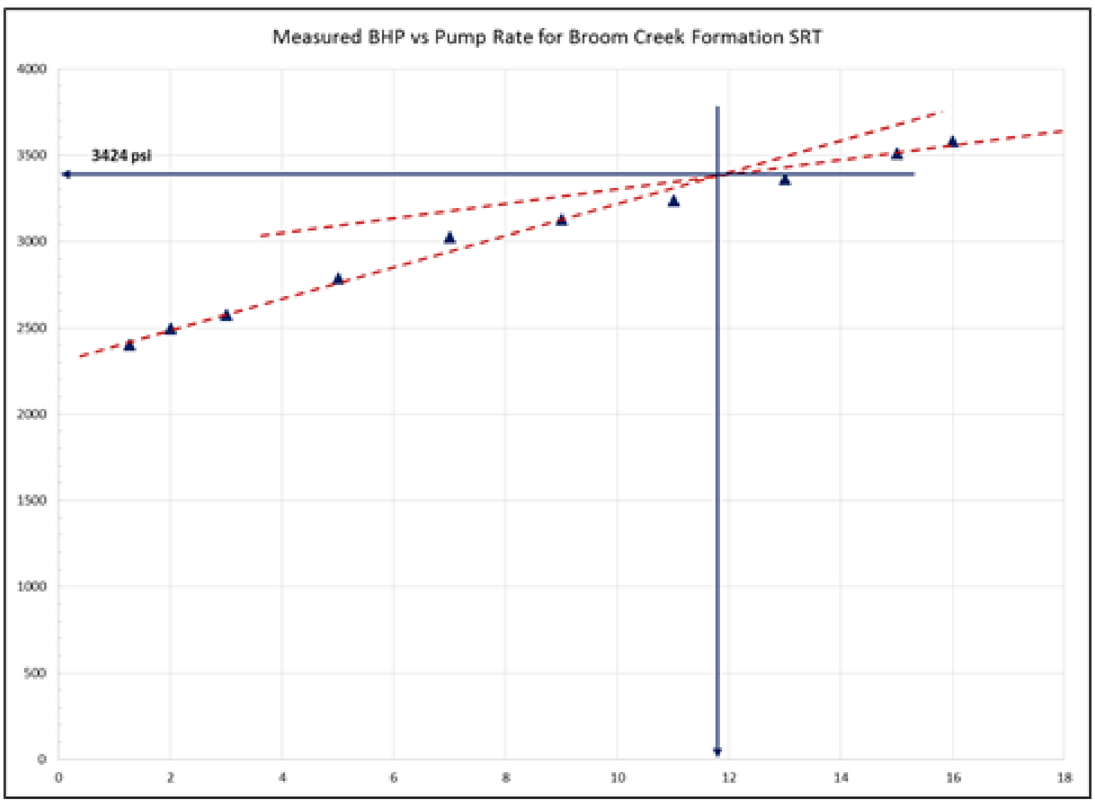


Figure 2-15. Step rate test data of the Broom Creek Formation with fracture opening observed at 3424 psi (courtesy of GeothermEx, a Schlumberger Company). The x-axis is injection rate in bpm, while the y-axis is bottomhole injection pressure in psi.

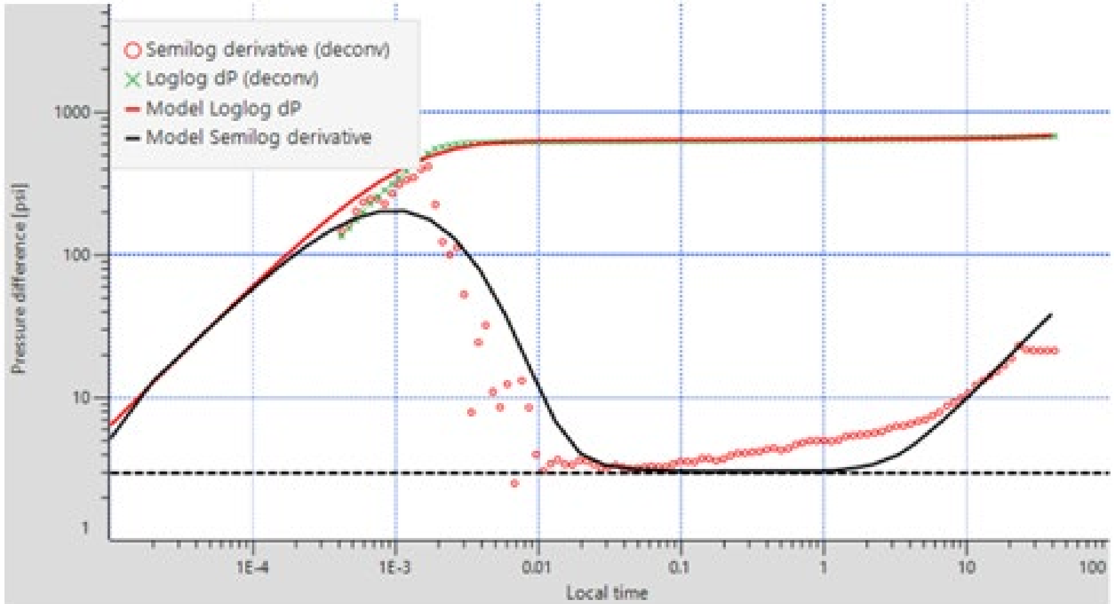


Figure 2-16. GeothermEx interpretation of the Broom Creek Formation pressure formation falloff test results (courtesy of GeothermEx, a Schlumberger Company).

Formation	**Broom Creek**
Perforation Interval (ft)	4,912 to 4,922
Estimated Formation Thickness (ft)	38
Tested Interval Thickness (ft)	38
Formation Transmissibility (mD.ft)	170,458
Formation Permeability (mD)	4,485
Skin Factor	89.6
Investigation Radius (ft)	24,804
Boundary Condition	Infinite Acting
Comments	Quality PFO test, good confidence in formation parameters assessed with numerical model. Noted skin damage changing between the step rate and constant rate test.

Figure 2-17. Broom Creek Formation well test summary of J-LOC 1 well (modified from Schlumberger presentation).

Table 2-7. J-LOC 1 Broom Creek Formation Test Summary

Parameters	Value	Unit
Reservoir Pressure	2410	psi
Permeability	4485	mD
Radius of Investigation	24,804	ft
Type of Boundary	Infinite acting	
Fracture Opening Pressure	3424	psi

2.3.2 Mineralogy

The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with anhydrite layers. Seventeen (17) depth intervals from the Broom Creek Formation from the J-LOC 1 were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. Thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals shows that quartz (~85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (~4%), dolomite (~5%), and anhydrite as cement (~6%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The contact between grains is long (straight) to tangential.

Two distinct carbonate intervals are notable in the Broom Creek Formation cored interval of the J-LOC 1 well. The first is the presence of a very fine- to fine-grained dolostone (75%), with quartz (~16%) and feldspar (~9%) present. The porosity is intercrystalline and not well-developed, averaging 5.5%. Diagenesis is expressed by dolomitization of the original calcite grains. The second carbonate interval comprises fine-grained dolomite (~78%), quartz (10%), feldspar (8%), and clay (4%). Diagenesis is expressed by the dissolution of dolomite, resulting in vuggy porosity. The porosity averages 9%. The anhydrite intervals are expressed as thin beds that separate different sand bodies. The porosity ranges from 1.5% to 2.5%.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, dolomite, anhydrite, feldspar, clay, and iron oxides (Figure 2-18 and Table 2-8). XRD data show illite is the most prominent type of clay within the formation.

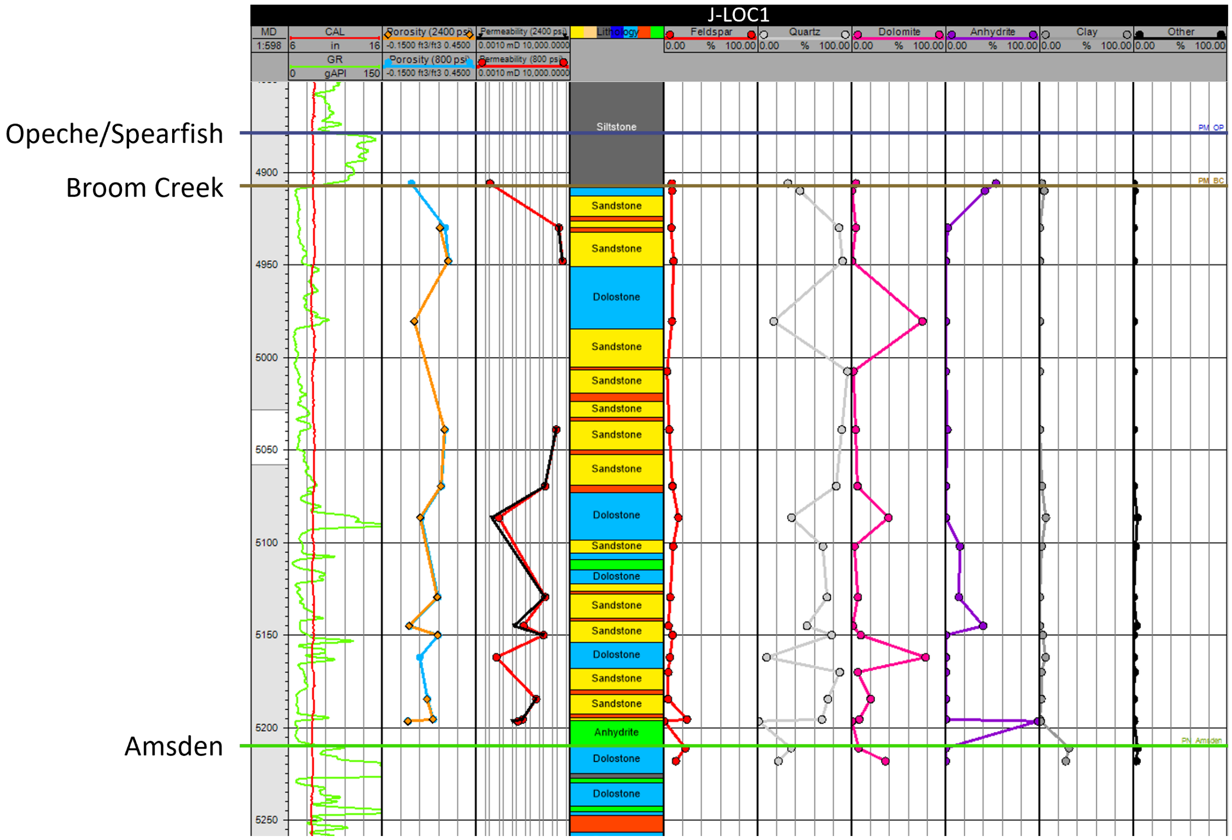


Figure 2-18. XRD data displaying mineralogic characteristics of the Broom Creek Formation in the J-LOC 1 well.

XRF data are shown in Figure 2-19 for the Broom Creek Formation. As shown, the majority of the sandstone and dolomite intervals are confirmed through the high percentages of SiO_2 (70%–80%), CaO (0%–30%), and MgO (0%–20%). High percentages of CaO and SO_3 indicate the presence of thin layers of anhydrite. The formation shows very little clay, with a range of 0% to 6% observed.

Table 2-8. XRD Analysis in the Broom Creek Reservoir from J-LOC 1. Only major constituents are shown.

Sample Name	Depth, feet*	Feldspar	Quartz	Dolomite	Anhydrite	Clay	Other	Illite/ Total Clay**
Opeche/Spearfish	4906	8.2%	31.9%	4.3%	53.3%	2.3%		100%
Broom Creek	4910	8.4%	44.7%		41.5%	4.5%	0.8%	100%
Broom Creek	4930	7.6%	86.3%	4.2%	1.9%			NA
Broom Creek	4948	10.0%	90.0%					NA
Broom Creek	4980.5	8.4%	16.6%	75.0%				NA
Broom Creek	5007.5	3.1%	95.3%	1.6%				NA
Broom Creek	5039	5.4%	89.2%	3.9%	1.5%			NA
Broom Creek	5069.5	8.9%	83.2%	5.8%		2.1%		100%
Broom Creek	5086.5	15.2%	35.6%	38.9%		6.4%	3.9%	81%
Broom Creek	5129.5	6.5%	73.5%	6.3%	13.7%			NA
Broom Creek	5145	4.6%	52.1%	0.7%	41.2%		1.5%	NA
Broom Creek	5150	9.1%	78.4%	9.3%		3.2%		81%
Broom Creek	5162	6.2%	9.1%	78.5%		6.3%		57%
Broom Creek	5184.5	4.2%	74.4%	19.9%		1.5%		100%
Broom Creek	5195.5	24.3%	67.9%	7.7%				NA
Broom Creek	5196.5		0.6%	0.4%	98.2%	0.8%		100%
Amsden	5211	22.7%	35.0%	9.3%		31.2%	1.8%	73%
Amsden	5218	12.4%	21.7%	38.4%		27.5%		72%

* Sample depth correspond to cored depth. A depth shift must be applied to align the values with log depth.
** Illite component of clays.

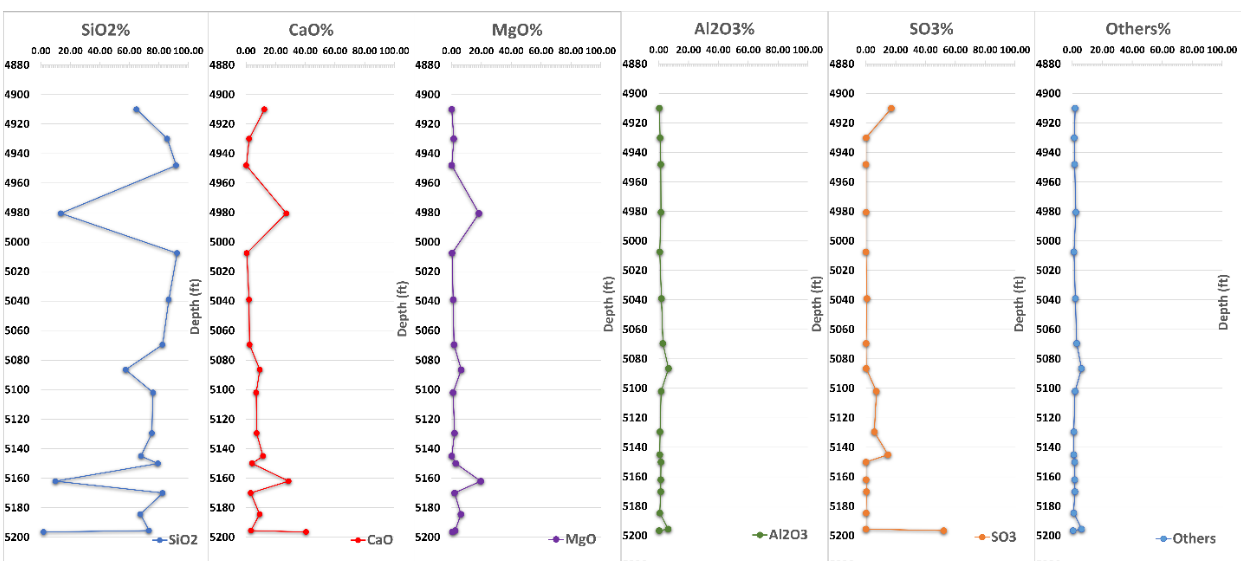


Figure 2-19. XRF data from the Broom Creek Formation in the J-LOC 1.

2.3.3 Mechanism of Geologic Confinement

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

2.3.4 Geochemical Information of Injection Zone

Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluating the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of one injection well injecting for a 20-year period with maximum BHP and maximum wellhead pressure (WHP) of 2100 psi as it was simulated during the evaluation of CO_2 injection. A postinjection period of 25 years was run in the model to evaluate dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped.

The composition of the injected gas will be to a minimum standard consisting of at least 96% dry CO_2 (by volume), with trace quantities (4% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C_2^+, and hydrocarbons. The CO_2 stream, shown in Table 2-9, that was used for geochemical modeling, contains a higher amount of O_2 than the anticipated injection stream. This stream containing ~95% CO_2 and 2% O_2 was used to represent a conservative scenario with the higher oxygen concentration, because oxygen is the most reactive constituent in the anticipated CO_2 stream. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (87% of bulk reservoir volume) and average formation brine composition (13% of bulk reservoir volume). XRD data from core samples from the J-LOC 1 well with depths from 4910 to 5196.5 ft were averaged and used for calculating the mineralogical composition of the Broom Creek Formation (Table 2-10). Reported ionic composition of the Broom Creek Formation water from the J-LOC 1 well is listed in Table 2-11 and used as input for the aqueous phase for the geochemical modeling. The geochemistry case was run for the 20-year injection period followed by 25 years of postinjection monitoring.

For computational efficiency, only the most representative minerals from the XRD test and water ions with higher concentration were included in the model to reduce the number of geochemical reactions, Table 2-10. Therefore, only anhydrite, illite, K-feldspar, albite, dolomite, chlorite, and quartz were included as minerals from the XRD report.

Table 2-9. CO_2 Stream Composition Used For Geochemical Modeling

Component	mol%
CO_2	94.999
N_2	3
O_2	2
H_2S	0.001

Table 2-10. XRD Core Sample Results for J-LOC 1 Well in Broom Creek Formation

Minerals	wt%*
Illite	2.09
K-Feldspar	5.17
Chlorite	1.54
Quartz	49.04
Dolomite	14.74
Anhydrite	23.91
Albite	3.50

* Values are averages calculated from multiple samples.

Table 2-11. Broom Creek Formation Water Ionic Composition, expressed as molality

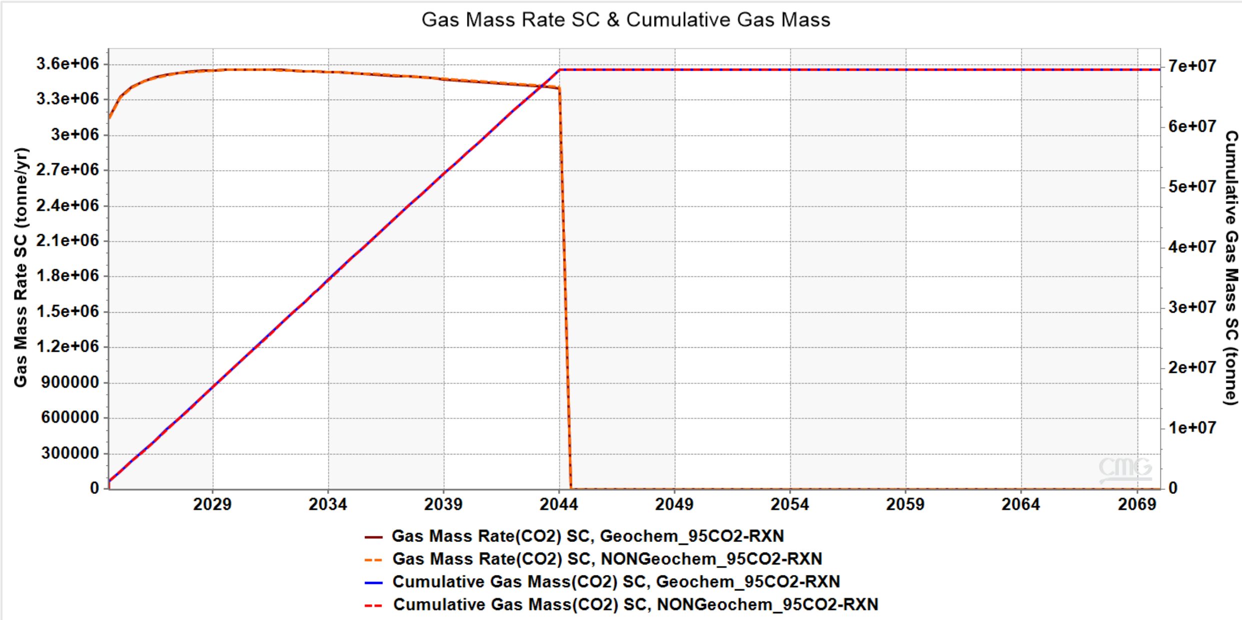
Component	Molality
SO_4^{2-}	0.02865
K^+	0.005135
Na^+	0.70365
Ca^{2+}	0.04809
Mg^{2+}	0.01546
CO_3^{2-}	3.1657E-4
Cl^-	0.79259
HCO_3^-	0.001193
Al^{3+}	9.6107E-06
$SiO_2(aq)$	1.0E-08
Fe^{2+}	1.72939E-05

Figure 2-20 shows that reservoir performance results for the case with and without geochemical modeling are nearly identical. As a result of geochemical reactions in the reservoir, cumulative injection rate has no observable difference. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.

Figure 2-21a shows the cross section for the concentration of CO_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model scenario, and Figure 2-21b shows the same information for the nongeochemistry simulation case for comparisons. The results do not show an evident difference in the CO_2 gas molality fraction between both cases, as seen in Figure 2-20 for the rates injected and injection pressure simulation results.

For the geochemistry case, the pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-22a. The initial pH of the Broom Creek Formation native brine prior to injection is 7.4. The pH declines to approximately 4.2 to 4.9, in the CO_2-flooded areas near the well, during the first 3 years of injection as a result of CO_2 dissolution in the native brine (Figure 2-22b). However, the pH increases to a maximum value of 5.5 because of mineral reactions during the rest of the injection and postinjection periods.

Figures 2-23a and 2-23b show the cross section for O_2 molality in the Broom Creek Formation. Figure 2-23a shows the cross section for the concentration of O_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model scenario, and Figure 2-23b shows the same information for the nongeochemistry simulation case for comparisons. The results do not show an evident difference in the O_2 gas molality fraction between both cases. After being injected, the oxygen (O_2, 2%) in the CO_2 stream is dissolved in the brine and likely to cause oxidative reactions of the minerals which may induce dissolution/precipitation of reactive minerals and formation of secondary minerals in the reservoir. The simulation results showed no significant precipitation caused by the high concentration of O_2 that would affect the CO_2 injection volume as demonstrated by the comparison in injection rates between the case with and without geochemical modeling shown in Figure 2-20.



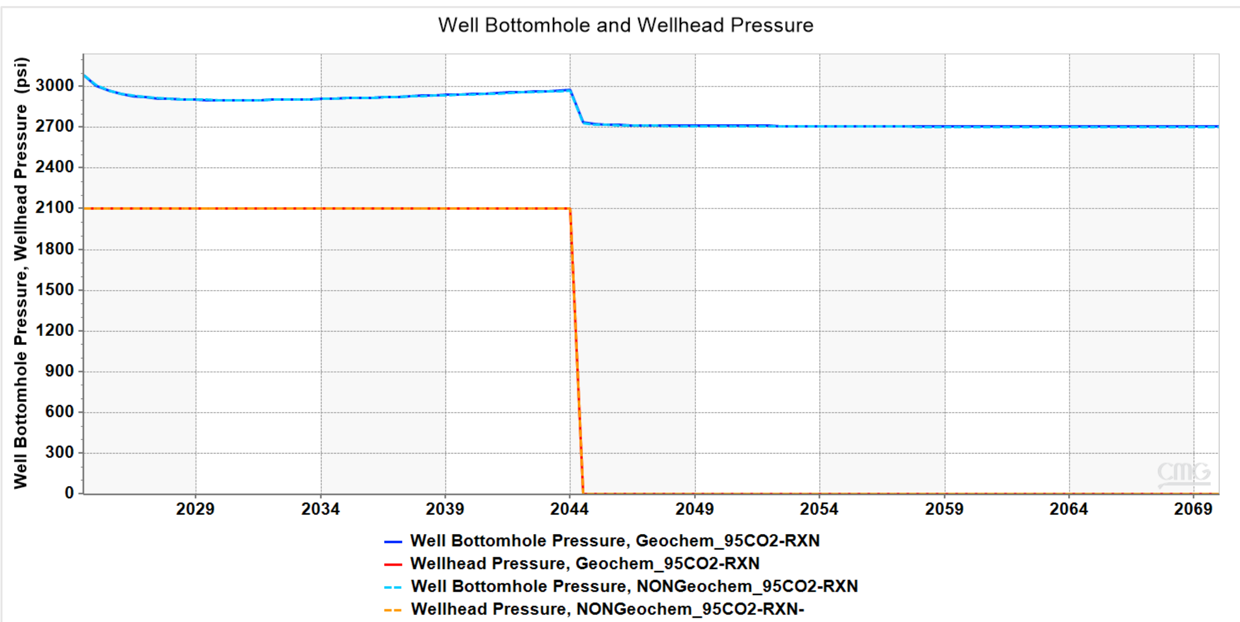


Figure 2-20. Upper graph shows cumulative injection and gas mass rate vs. time. There is no observable difference in injection due to geochemical reactions. The lower graph shows the wellhead injection pressure for the two cases is the same: 2100 psi. The solid line represents the geochemical modeling case, and the dashed line represents the case without geochemical interactions. There is no observable difference in gas rate injection and pressures due to geochemical reactions.

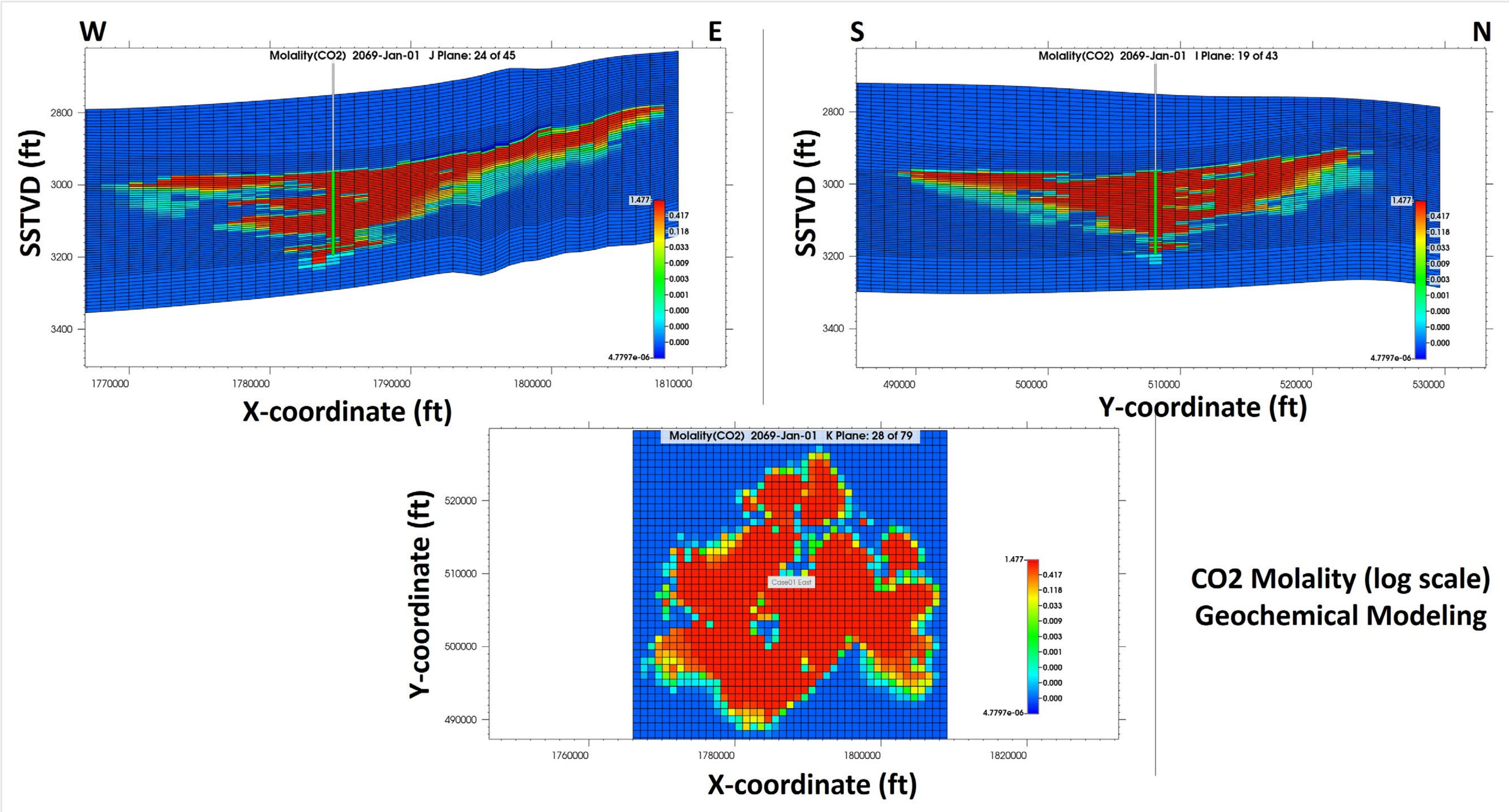


Figure 2-21a. CO_2 molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection, showing the distribution of CO_2 molality in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

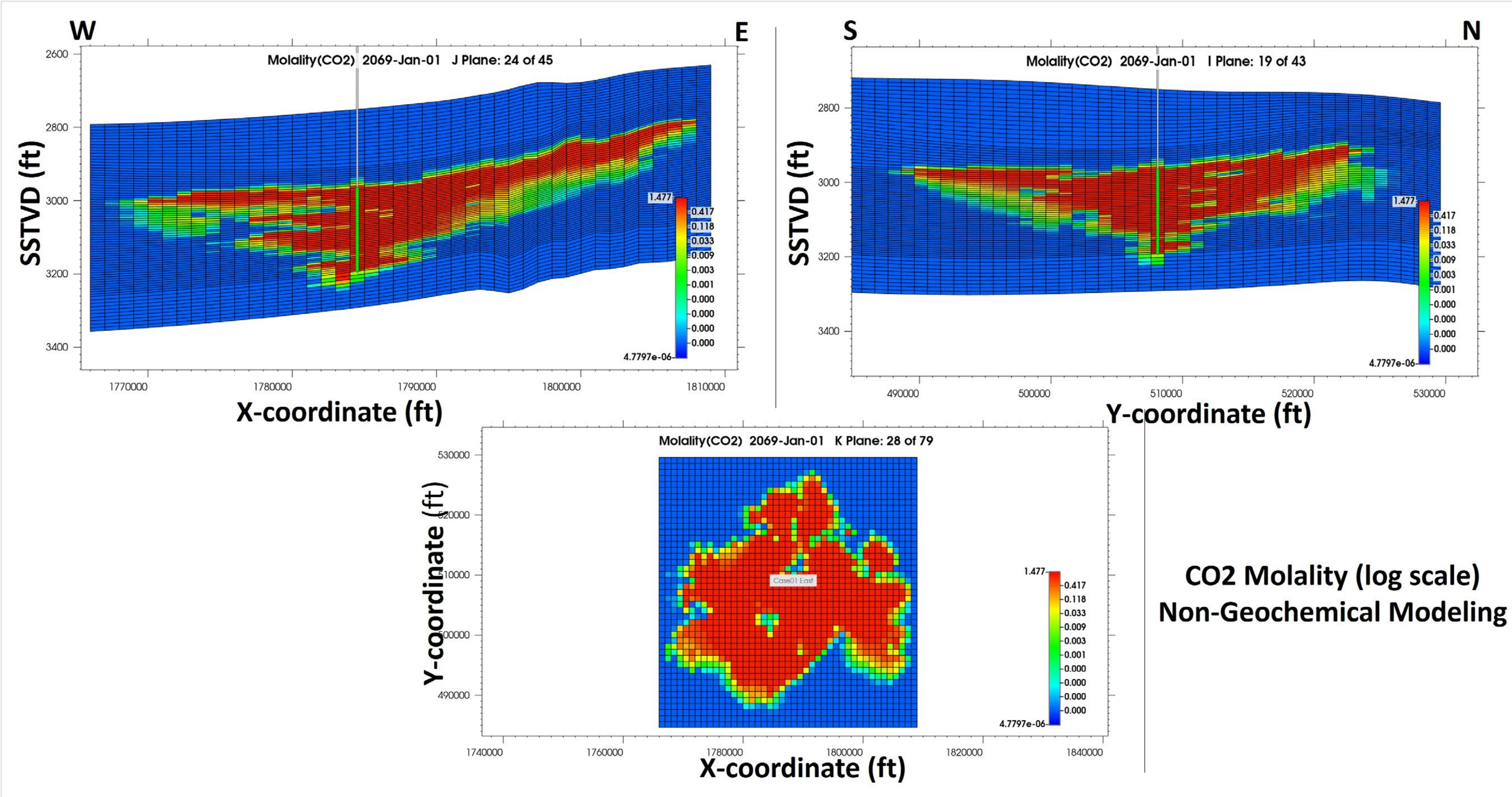


Figure 2-21b. CO_2 molality for the nongeochemistry simulation results after 20 years of injection + 25 years postinjection, showing the distribution of CO_2 molality in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

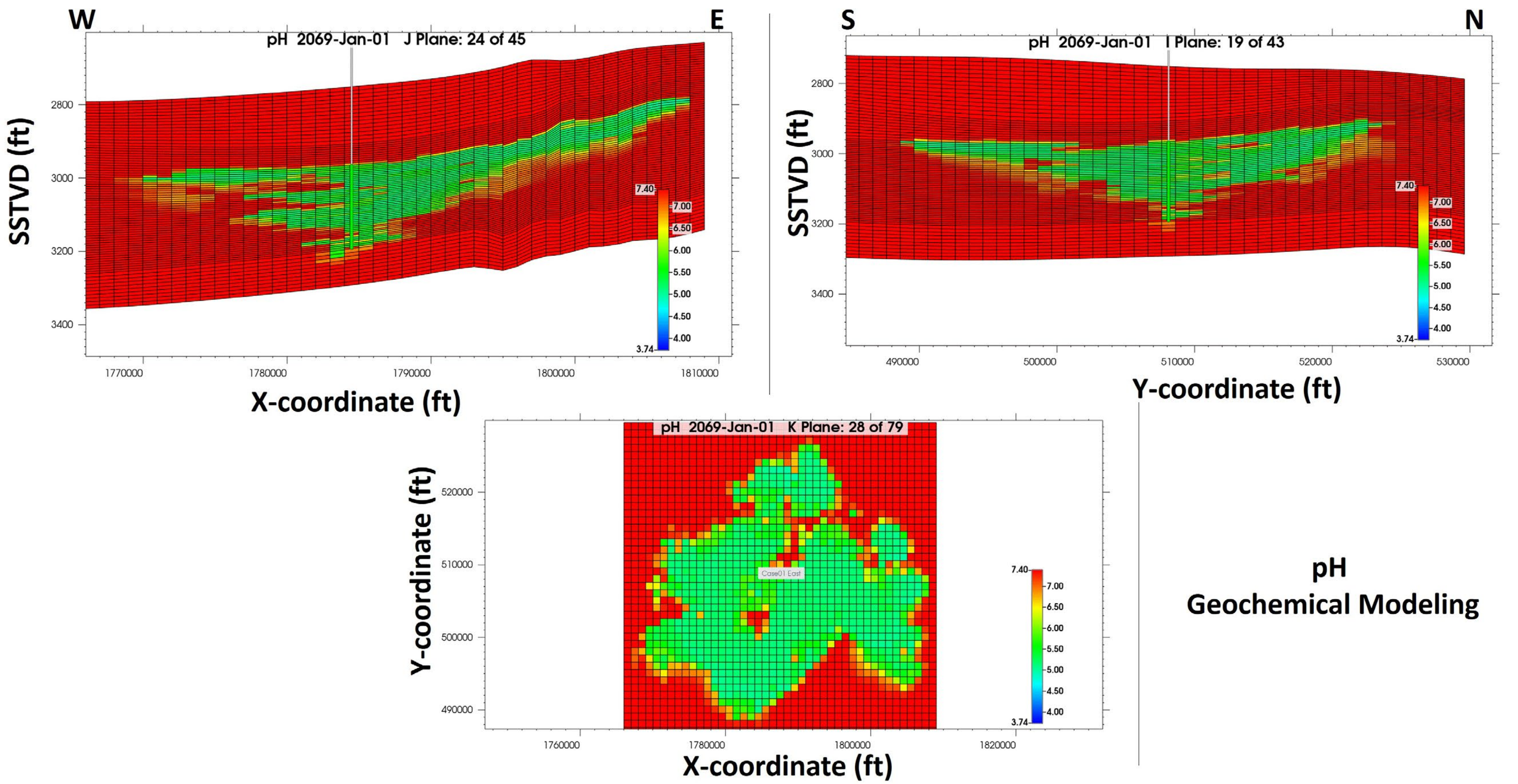


Figure 2-22a. Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

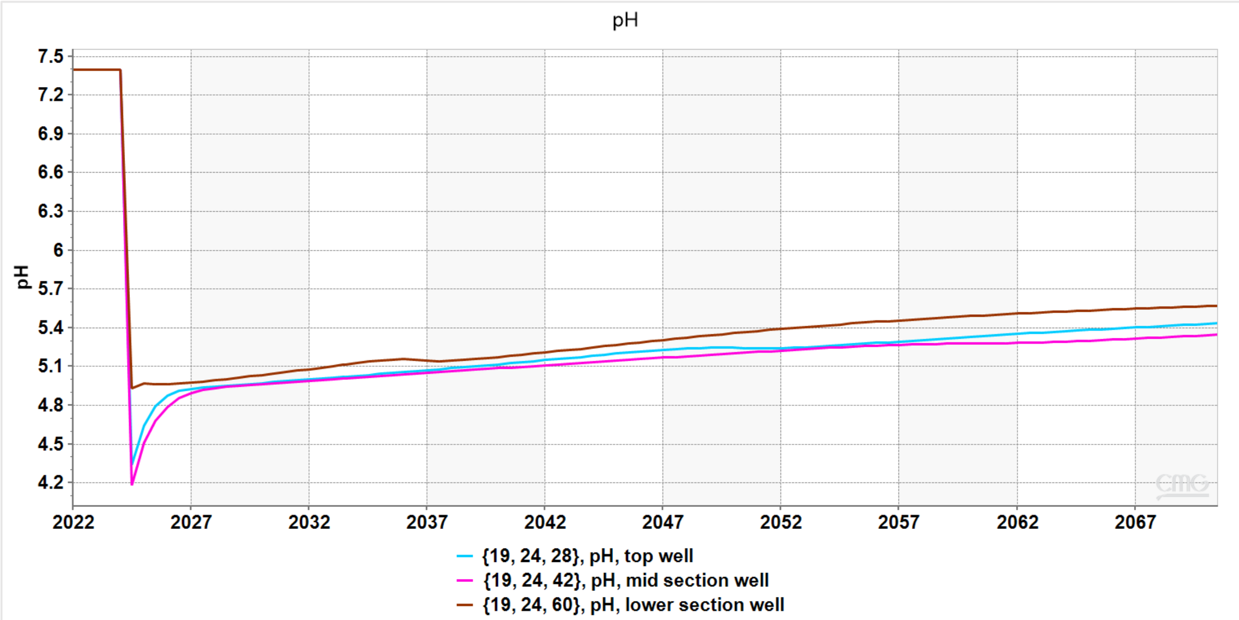


Figure 2-22b. Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine at the wellbore vs. time for layers 28 at 2980.8 ft (SSTVD), layer 42 at 3053.8 ft, and layer 60 at 3147.8 ft.

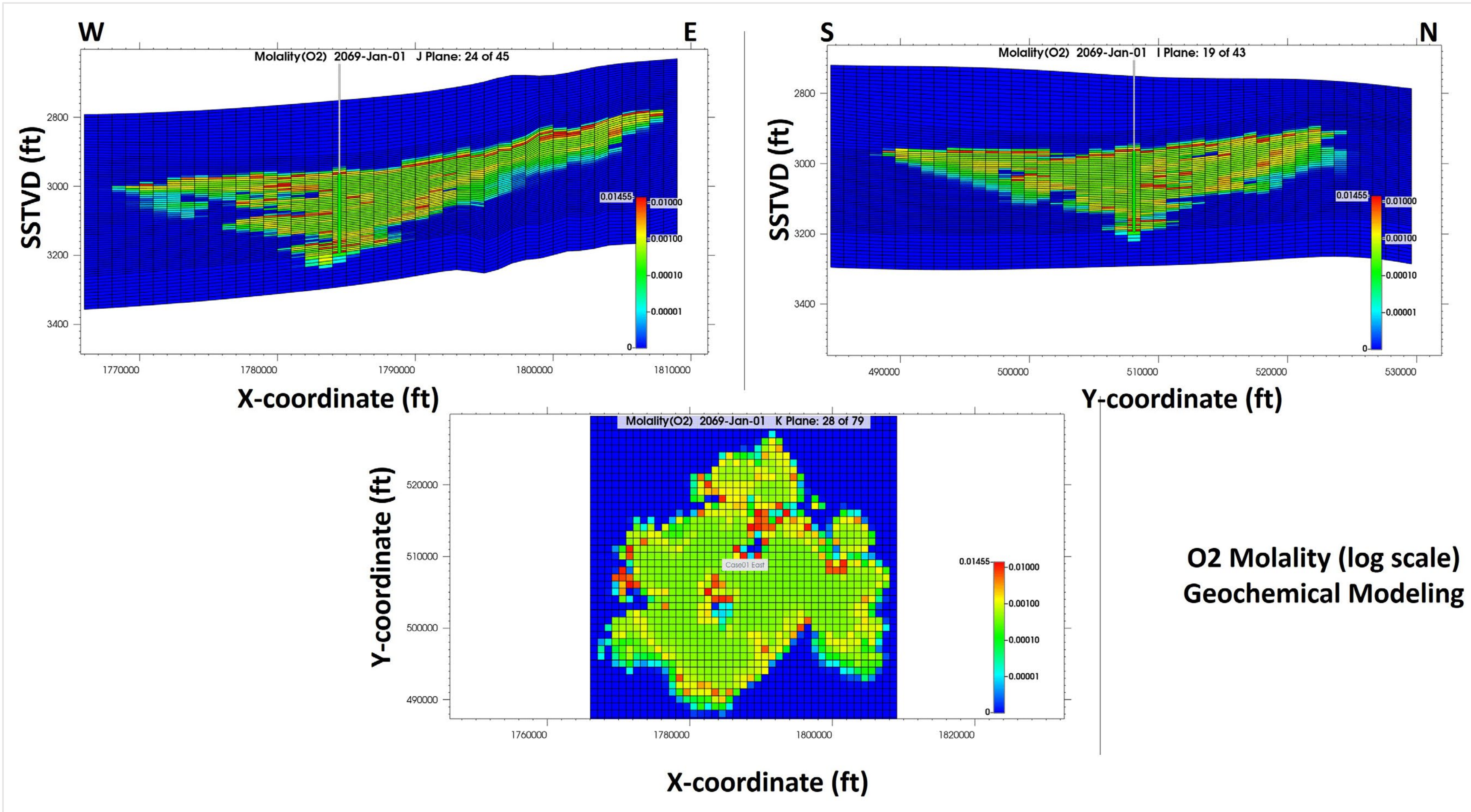


Figure 2-23a. Cross section for O_2 molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of O_2 in gas phase in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

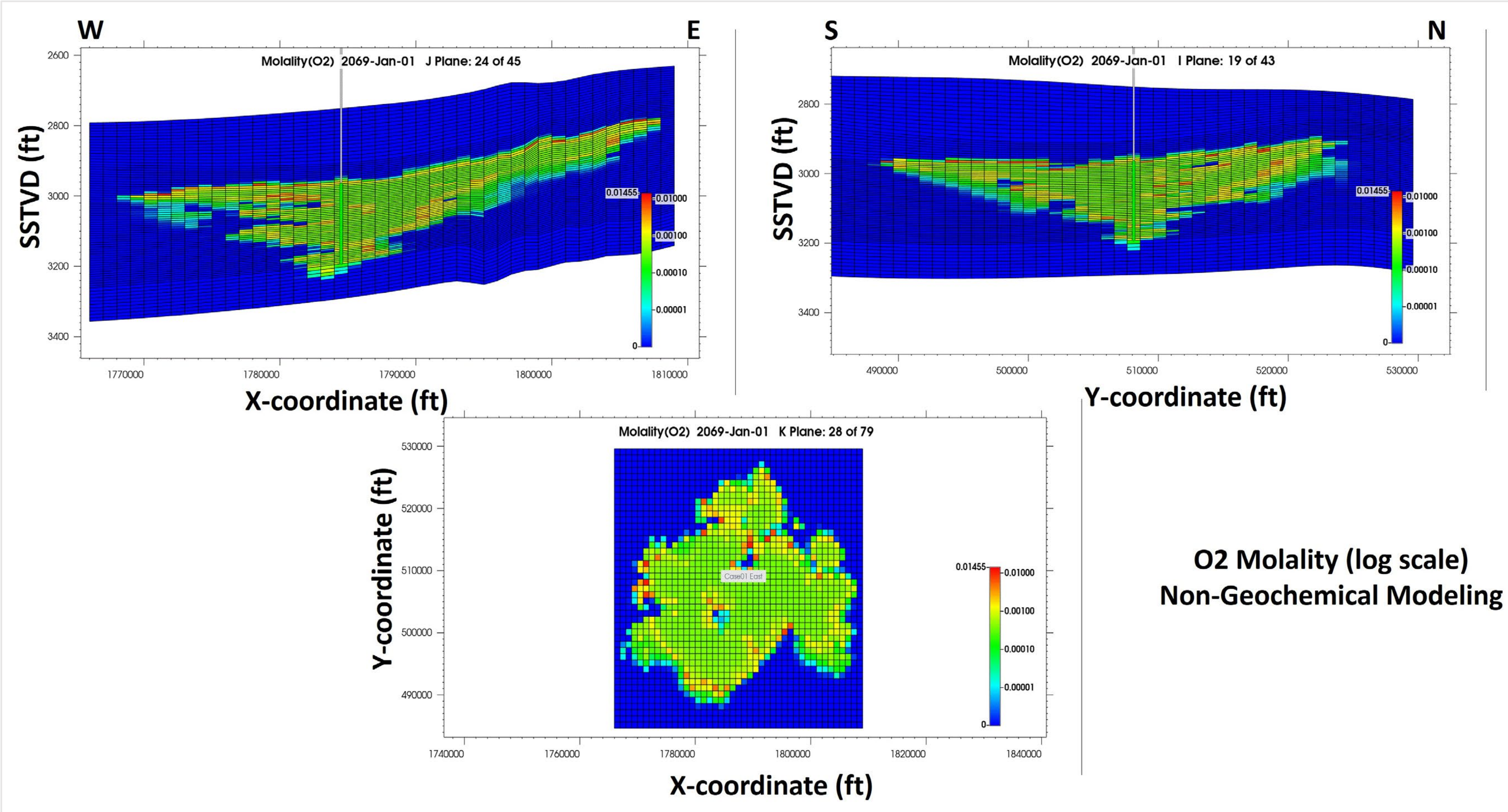


Figure 2-23b. Cross section for O_2 molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of O_2 in gas phase in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

Figure 2-24a shows the mass of mineral dissolution and precipitation due to geochemical reactions in the Broom Creek Formation. Illite is the most prominent dissolution mineral, followed by K-feldspar, anhydrite, albite and chlorite during the 20 years injection. Anhydrite dissolution will increase with time and would be the most prominent mineral in dissolution after 15 years of postinjection. Secondary minerals hematite and ferric hydroxide mineral are also in dissolution but in a very small amount, Figure 2-24b. Chlorite can be sensitive to acid and oxygenated waters, and if present in a high volume in the injection zone, the oxygen may react with the iron (Fe^{+2}) from Chlorite causing the precipitation of the gelatinous ferric hydroxide ($Fe(OH)_3$). The decrease in pH may lead to the precipitation of secondary minerals such as siderite. Results show that quartz and dolomite are the primary precipitation minerals followed by siderite precipitation likely induced by chlorite dissolution. Secondary mineral ankerite is also precipitated but in small amount over time, Figure 2-24b. There is a small amount of dolomite net dissolution during the first 6 years of the injection period because somewhat larger quantities of minerals are dissolved rather than precipitated.

The presence of H_2S in the stream plus SO_4^{2-} in the brine and sulfur-bearing minerals such as anhydrite also contribute to the reduction of pH which results in the formation and dissolution of a secondary mineral like hematite and the precipitation of siderite (Figure 2-24a and b).

Simulation results are showing that, during CO_2 injection, the supercritical CO_2 (free-CO_2 gas) is dominant, and the mineralized CO_2 gradually increases during the injection and postinjection periods (Figure 2-25). The slowdown on the supercritical CO_2 and dissolution during the postinjection time as the geochemical reactions continue may indicate a gradual conversion into mineralized CO_2, increasing the safety of trapped CO_2 over time.

Figures 2-26 and 2-27 provide an indication of the changes in distribution of the minerals that experienced the most dissolution, illite and anhydrite, and the mineral that experienced significant precipitation, dolomite, in the Broom Creek Formation (Figure 2-28). The simulation results show that most of the geochemical reactions in the reservoir, dissolution and/or precipitation, occur around the region near the injection well, the area where CO_2 has most displaced the formation brine. Considering the apparent net precipitation and dissolution of minerals in the system, as indicated in Figure 2-24a, there is an associated change in porosity of the affected area, as shown in Figure 2-29. However, this porosity change is small, less than maximum 0.1% porosity units, equating to a maximum in average porosity from the initial 16.6% to a net porosity change between 16.5% - 16.7% (precipitation and/or dissolution, respectively) after the 20-year injection period plus 25 years of postinjection.

Results of the simulation show that geochemical processes will be at work in the Broom Creek Formation during and after CO_2 injection. Mineral dissolution and precipitation are expected to occur during the simulated time span of 45 years. Fluid pH will decrease in the area of the CO_2 accumulation from 7.4 to approximately 5.5, and there will be a slight net decrease in system porosity. However, these changes are not significant enough to create observable changes in the reservoir performance parameters such as injection rate or wellhead injection pressure.

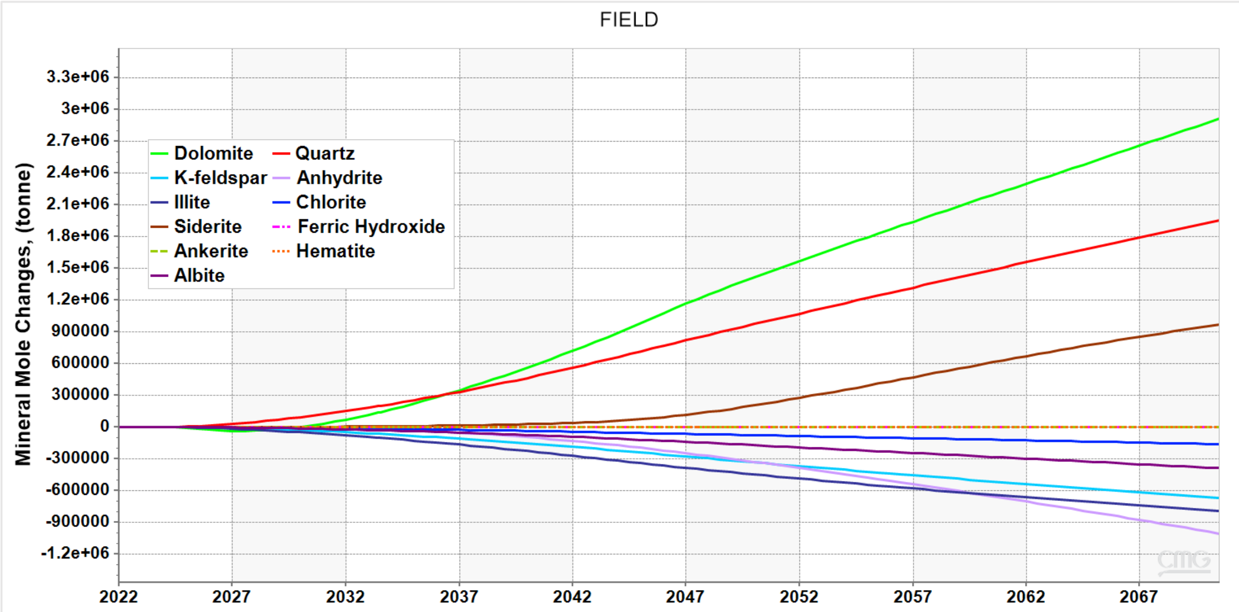


Figure 2-24a. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of illite, anhydrite, chlorite, albite, and K-feldspar with precipitation of quartz, dolomite, and siderite was observed. Ankerite, hematite and ferric hydroxide are showing very small values and account as net zero in this figure due to the scale.

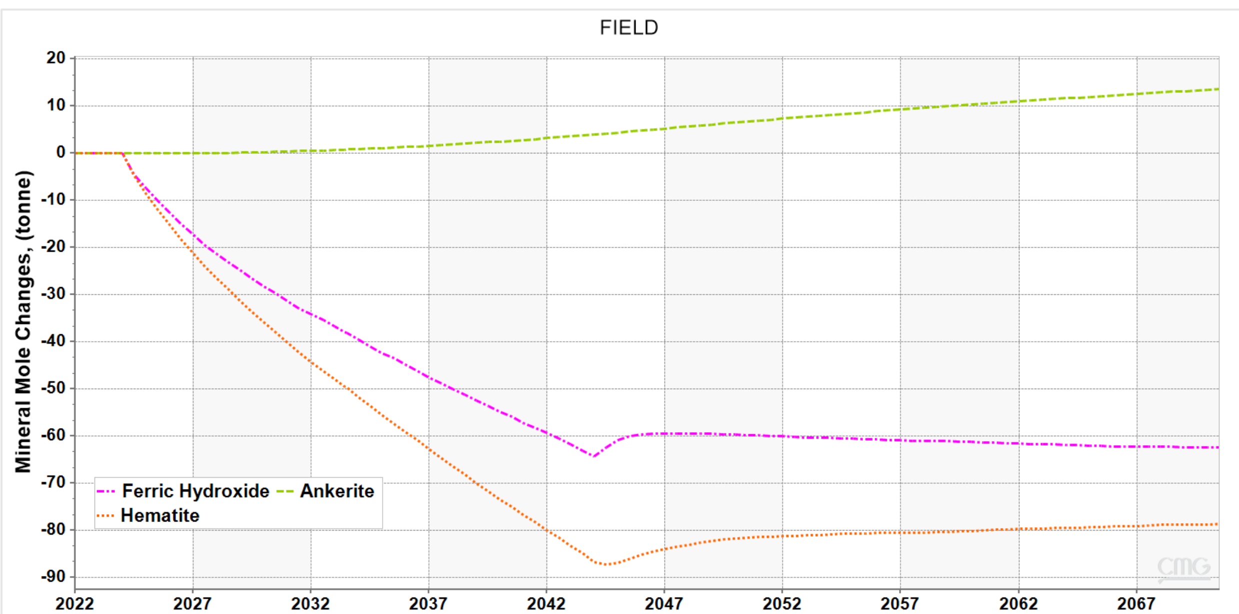


Figure 2-24b. Dissolution of ferric hydroxide and hematite with precipitation of ankerite was observed. These secondary minerals can be formed but in a small volume in the Broom Creek Formation. There is not enough Chlorite minerals present in the injection area to cause the precipitation of ferric hydroxide.

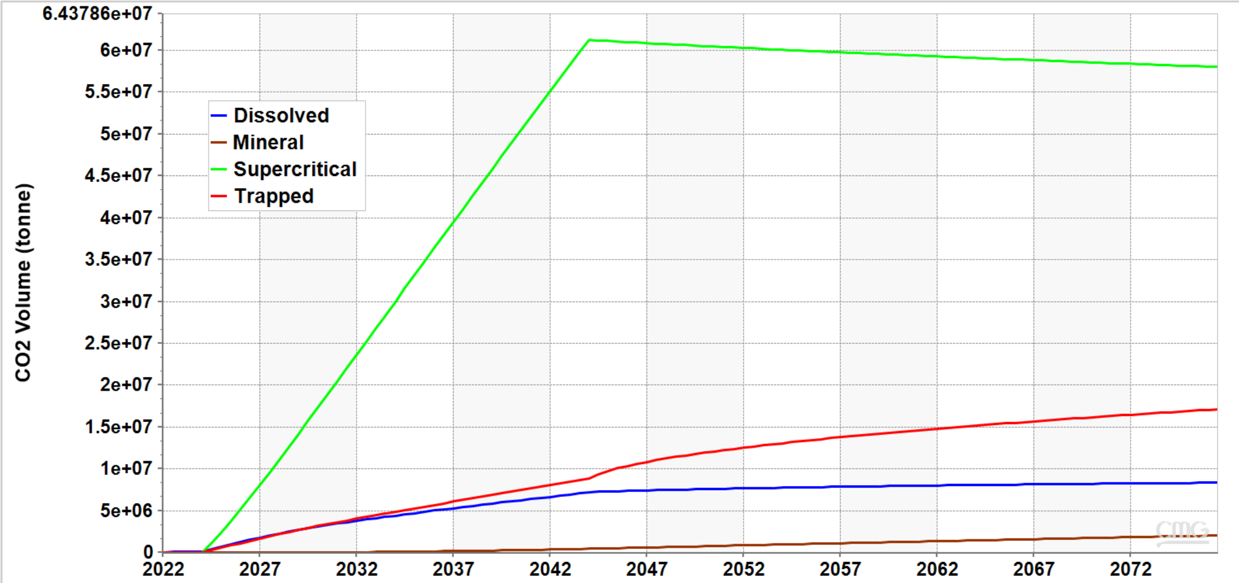


Figure 2-25. Mineral mass changes, in metric tons (tonnes), for the different CO_2-trapping mechanisms present during CO_2 injection with geochemical modeling in the injection zone for the Broom Creek Formation.

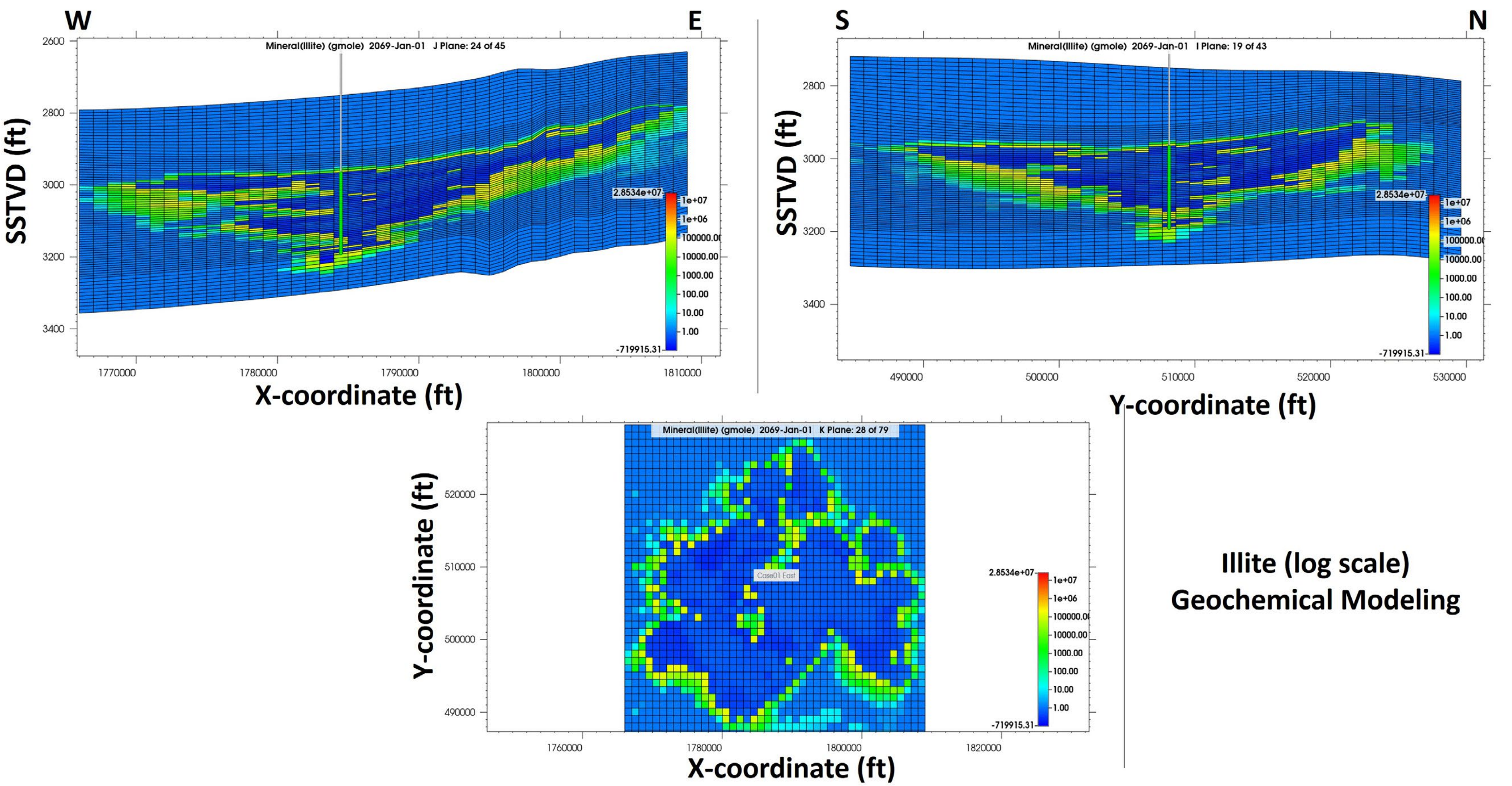


Figure 2-26. Change in molar distribution of illite, the most prominent dissolved mineral at the end of the injection period in the injection zone of Broom Creek Formation. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

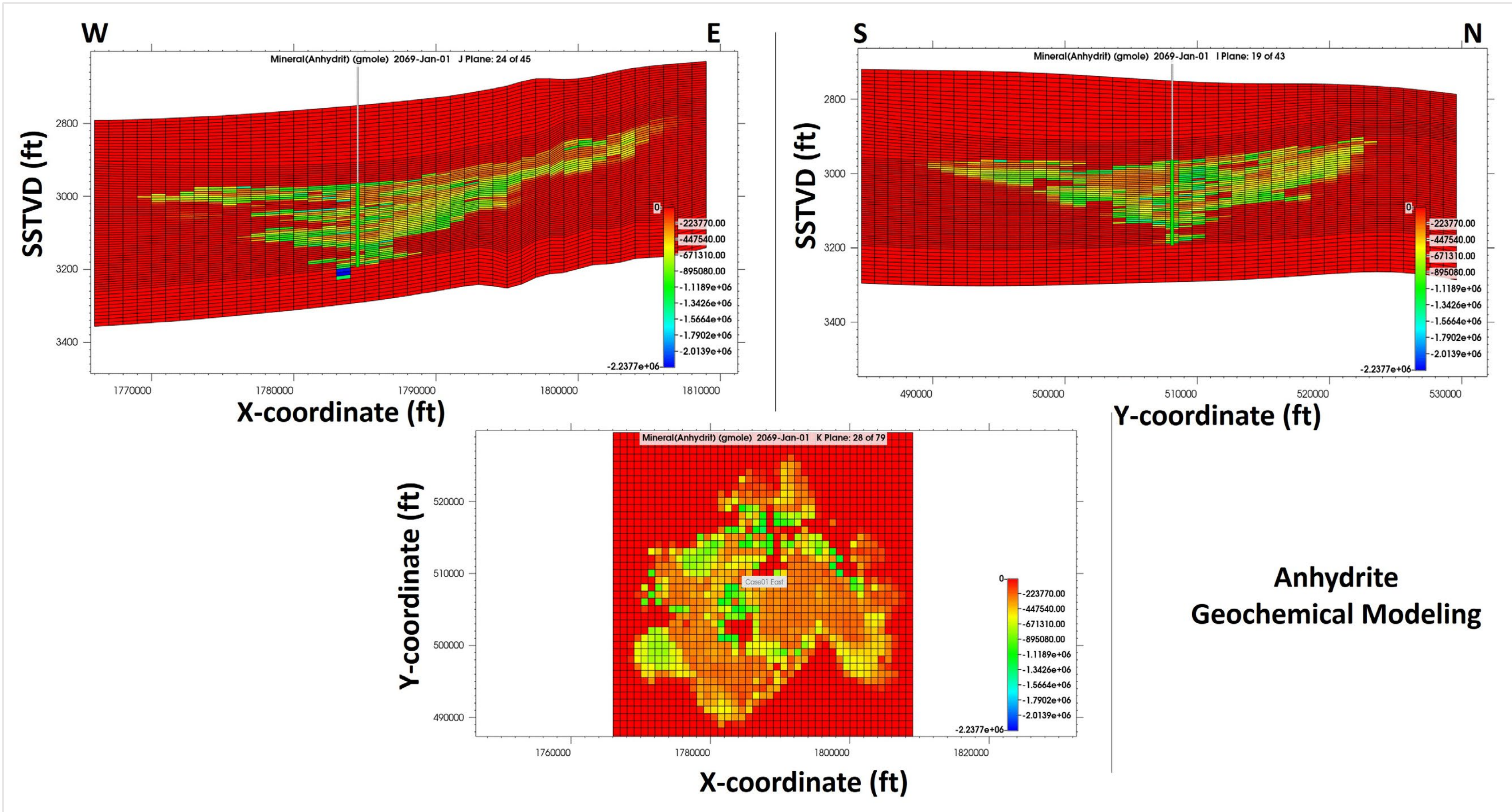


Figure 2-27. Change in molar distribution of anhydrite mineral in dissolution at the end of the injection + 25 years postinjection period in the injection zone of Broom Creek Formation. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

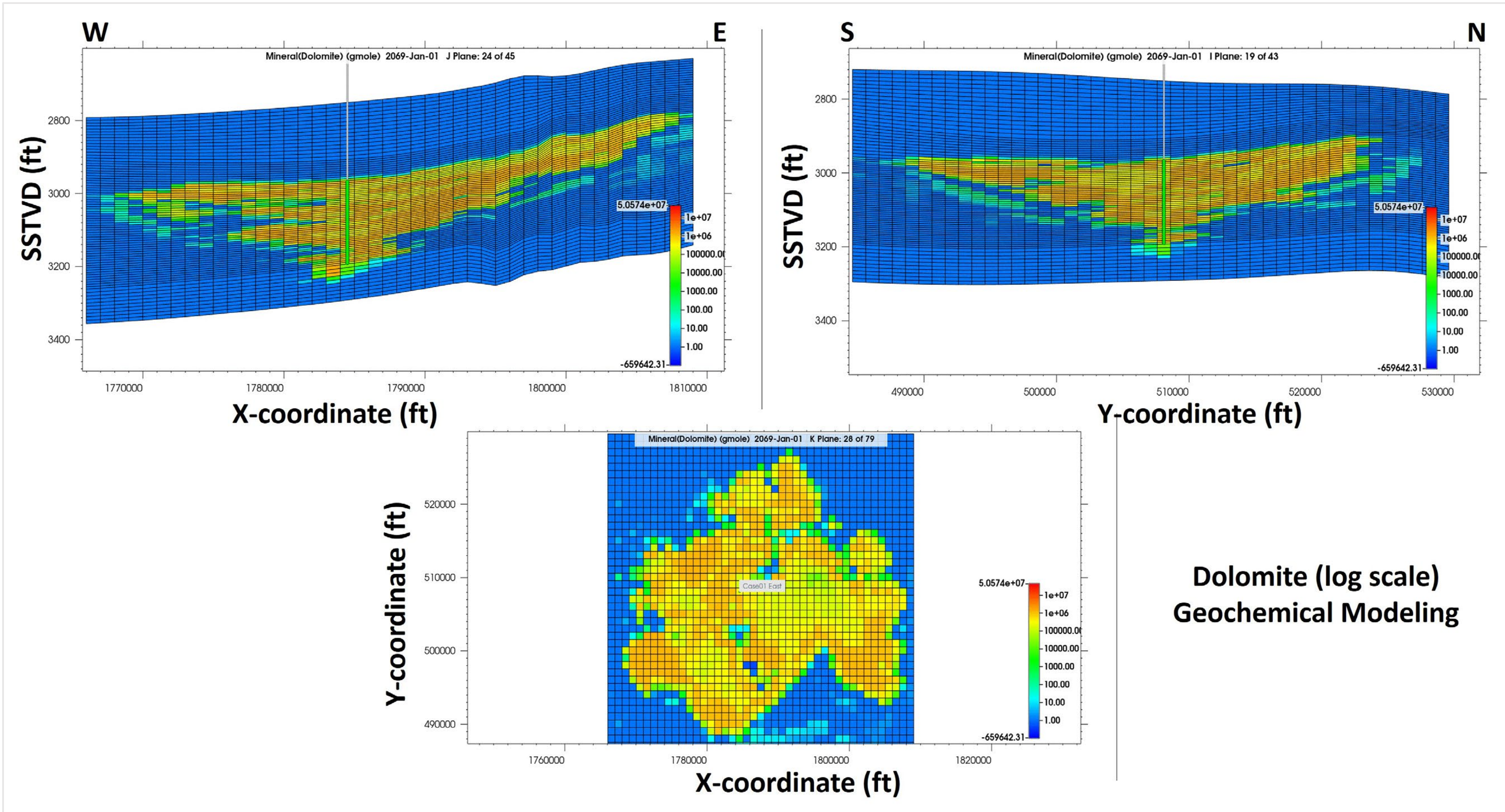


Figure 2-28. Change in molar distribution of dolomite, the most prominent precipitated mineral, at the end of the injection + 25 years postinjection period in the injection zone of Broom Creek Formation. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

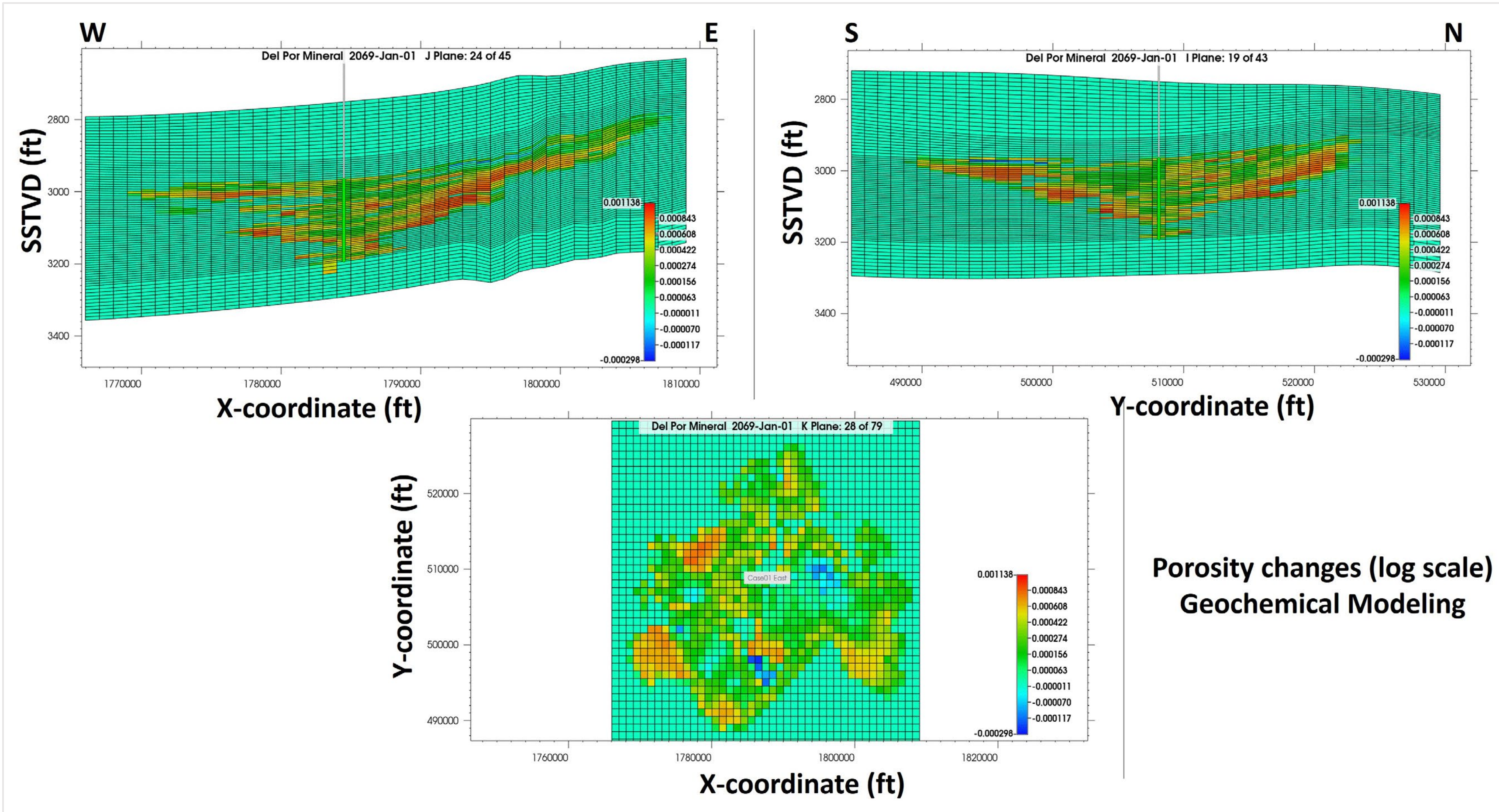


Figure 2-29. Change in porosity due to net geochemical dissolution after the 20-year injection + 25 years postinjection period. Maximum porosity change is less than 0.1%. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD).

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the Opeche–Picard interval and underlying Amsden Formation (Figure 2-2, Table 2-12). Both the Amsden Formation and Opeche–Picard interval consist of impermeable rock layers.

Table 2-12. Properties of Upper and Lower Confining Zones at the J-LOC 1 Well

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Stratigraphic Unit	Opeche–Picard	Amsden
Lithology	Siltstone/evaporites/ dolostone	Dolostone/ anhydrite/sandstone
Formation Top Depth (MD), ft	4784	5210
Thickness, ft	124	259
Capillary Entry Pressure (brine/CO_2), psi	20.59	69.03
Depth below Lowest Identified USDW, ft	3534	3960

Formation	Property	Laboratory Analysis*	Simulation Model Property Distribution**
Opeche/Spearfish	Porosity, %	3.53	2.14 (0.00–14.64)
	Permeability, mD	0.0104	0.0021 (0.00–6.37
Amsden	Porosity, %	5.4, 7.3	2.92 (0.00–35.05)
	Permeability, mD	0.0053, 0.0062	0.0070 (0.00–156.05)

* Porosity values recorded at 800-psi confining pressure from the J-LOC 1 well. Permeability values are recorded at 800-psi confining pressure from the J-LOC 1 well. Values measured from Opeche/Spearfish zone for the upper confining zone.

** Porosity values from the model are reported as the arithmetic mean (sum of values divided by number of values) followed by the range of values in parentheses. Permeability values from the model are reported as the geometric mean (product of values raised to the inverse series length of the series) followed by the range of values in parentheses.

2.4.1 Upper Confining Zone

In the DCC West SGS area, the lower Piper Formation (Picard Member and lower) consists of siltstone, dolostone, and interbedded evaporates and the Opeche/Spearfish Formation consists of predominantly siltstone with interbedded dolostone and anhydrite. The upper confining zone (Opeche–Picard interval) is laterally extensive across the DCC West SGS area (Figure 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4784 ft below the land surface and 124 ft thick as measured at the J-LOC 1 well (Table 2-12 and Figures 2-31 through 2-34). The contact between the upper confining zone and underlying Broom Creek Formation sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-10).

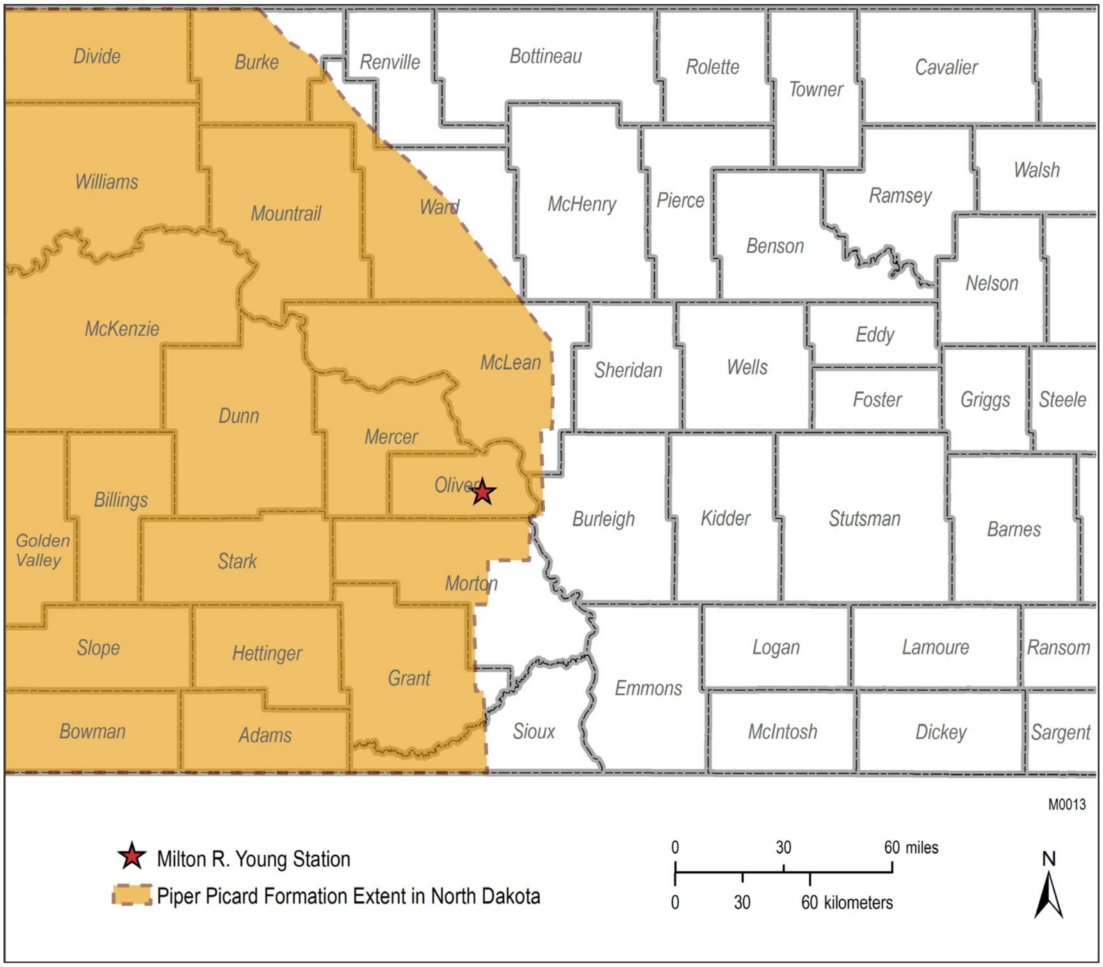


Figure 2-30. Areal extent of the Piper Picard Formation in western North Dakota (modified from Carlson, 1993).

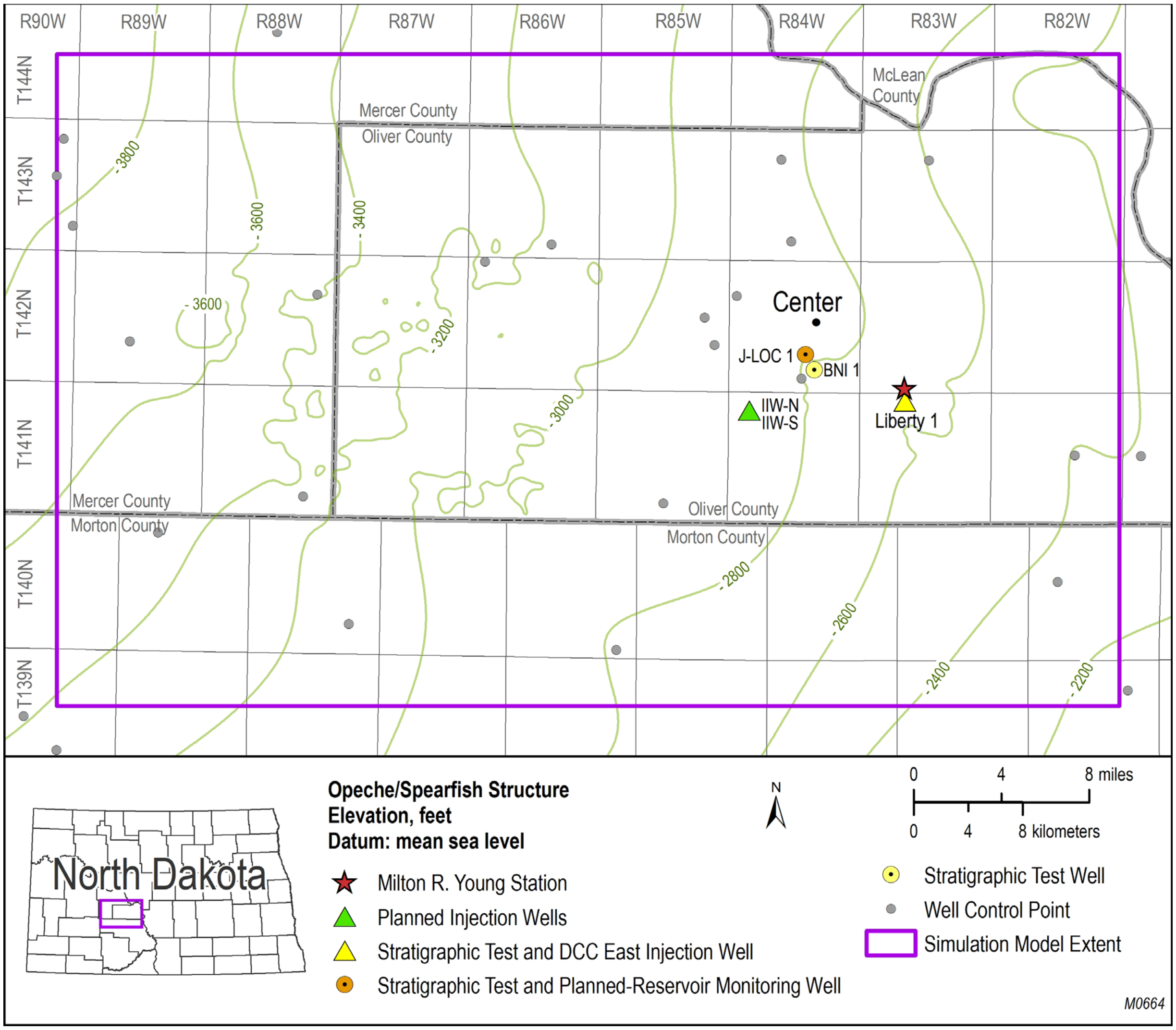


Figure 2-31. Structure map of the Opeche/Spearfish Formation of the upper confining zone across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

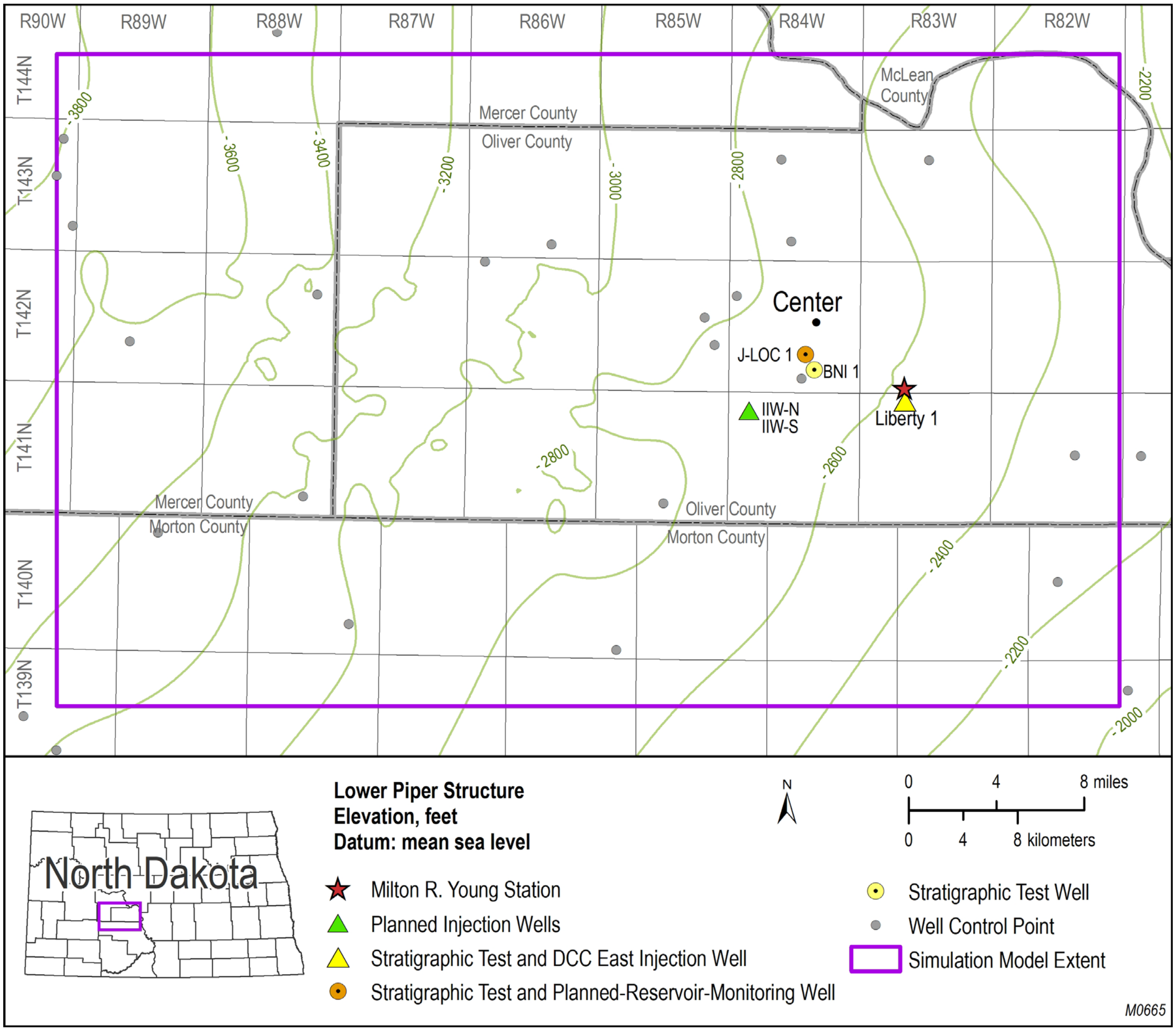


Figure 2-32. Structure map of the lower Piper of the upper confining zone across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

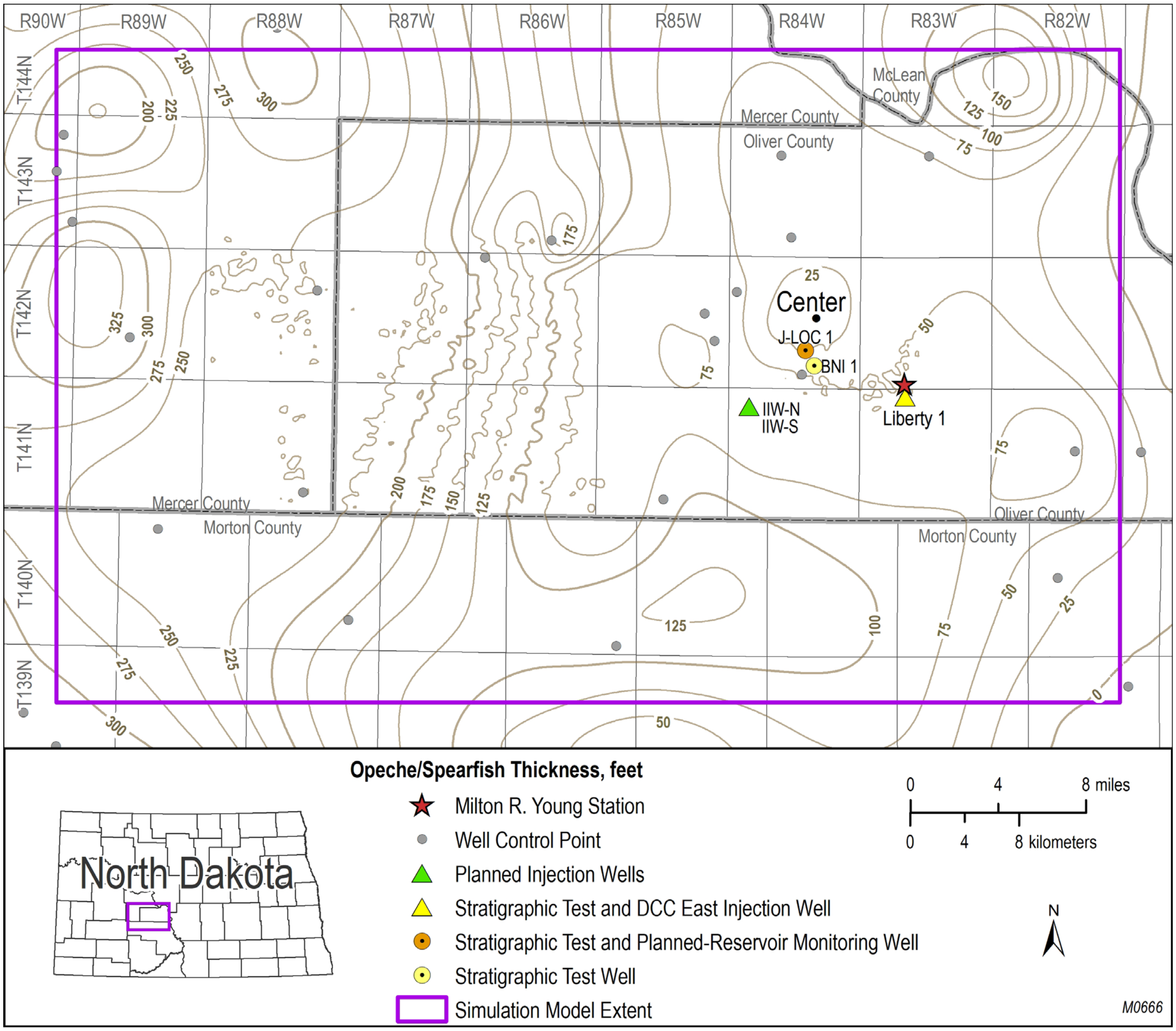


Figure 2-33. Isopach map of the Opeche/Spearfish Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

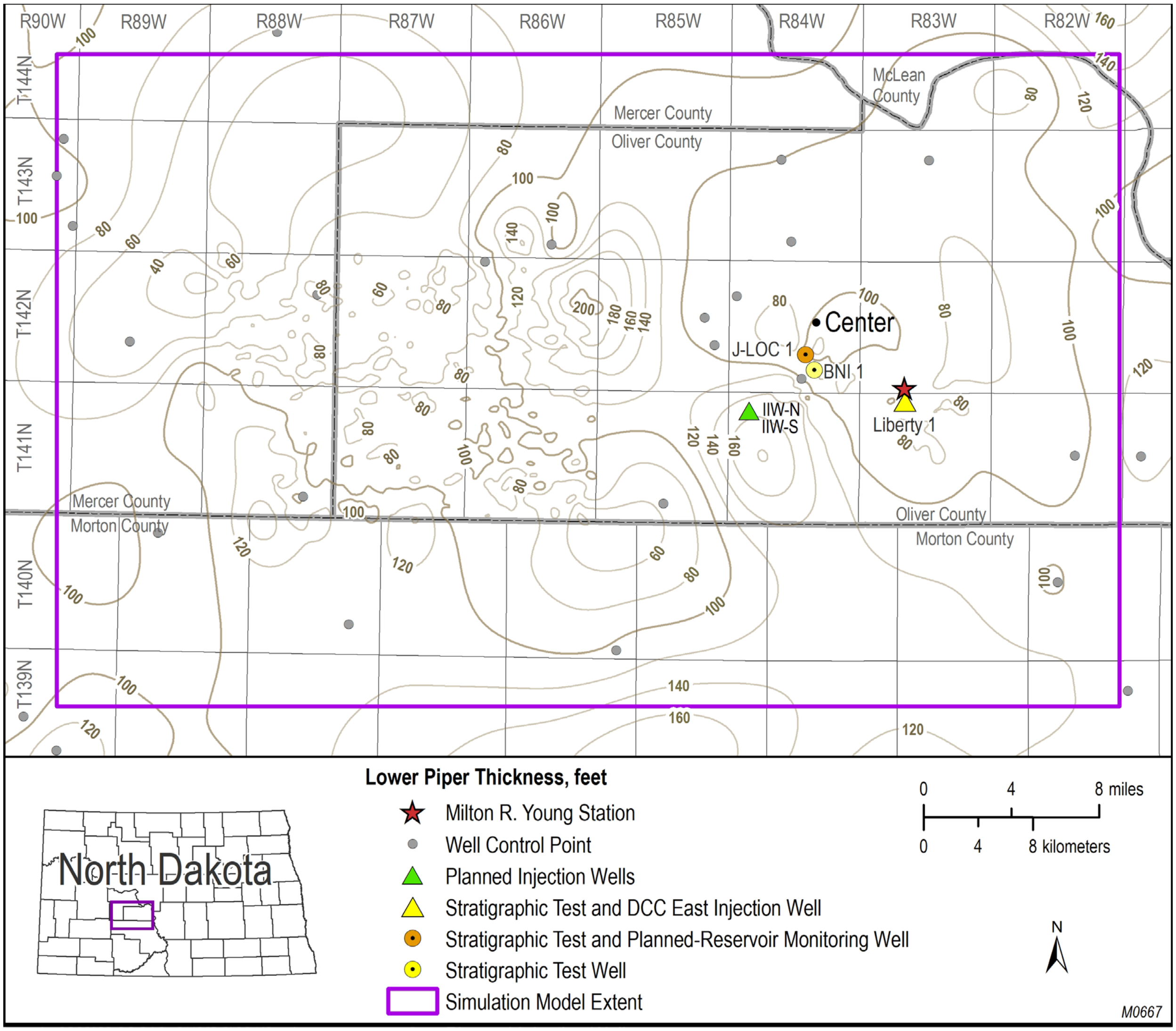


Figure 2-34. Isopach map of the lower Piper Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

Microfracture in situ stress tests were performed using the MDT tool in the J-LOC 1 wellbores. For the J-LOC 1 well, in the Opeche/Spearfish Formation, at 4887.7 and 4888.8 ft, the MDT tool was unable to cause breakdown in the formation with applied maximum injection pressure of 8162.49 and 8150.95 psi, respectively, Figures 2-35 and 2-36. The maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool.

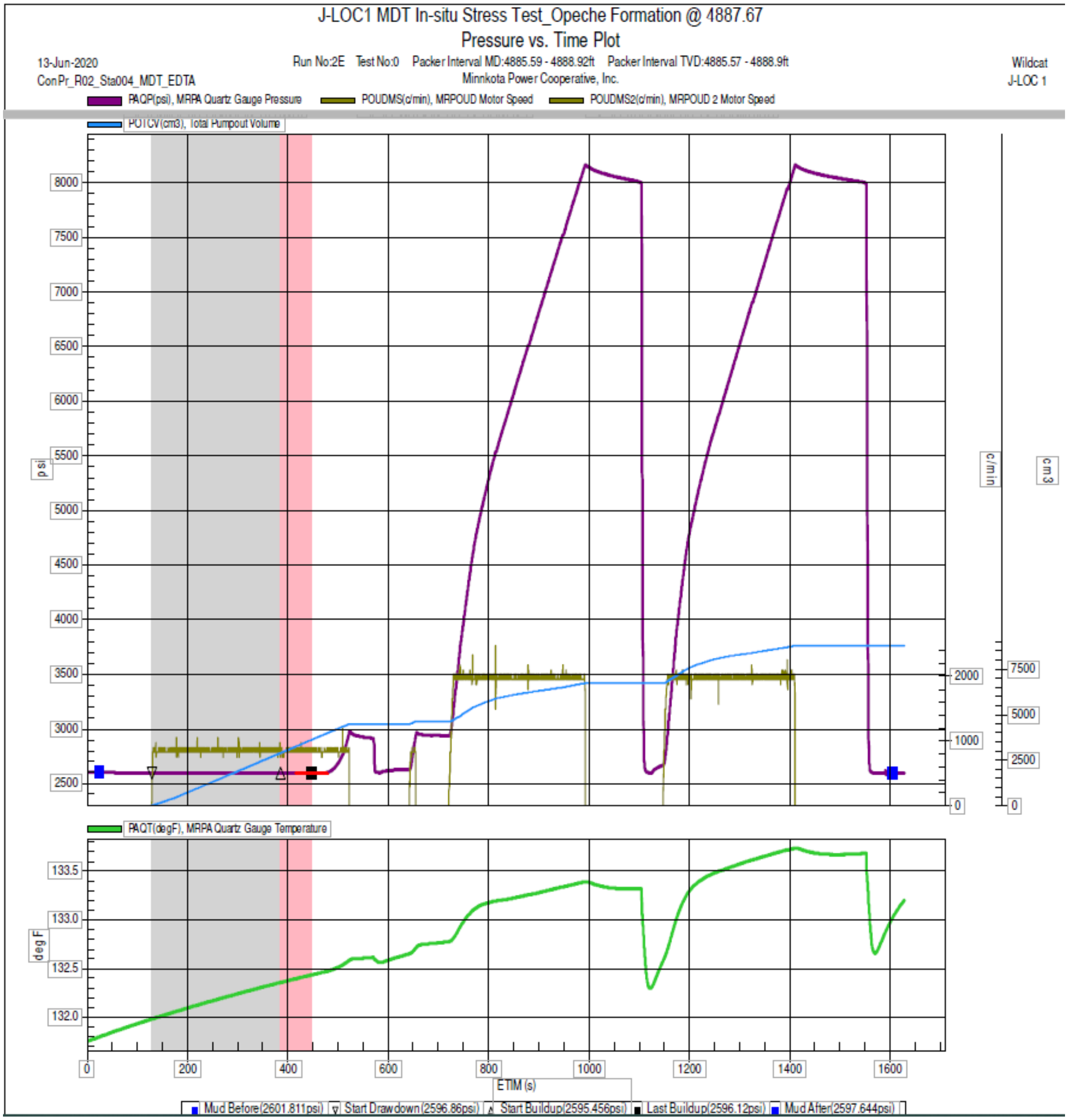


Figure 2-35. J-LOC1 Opeche/Spearfish Formation MDT microfracture in-situ stress pump cycle graph at 4887.7 ft.

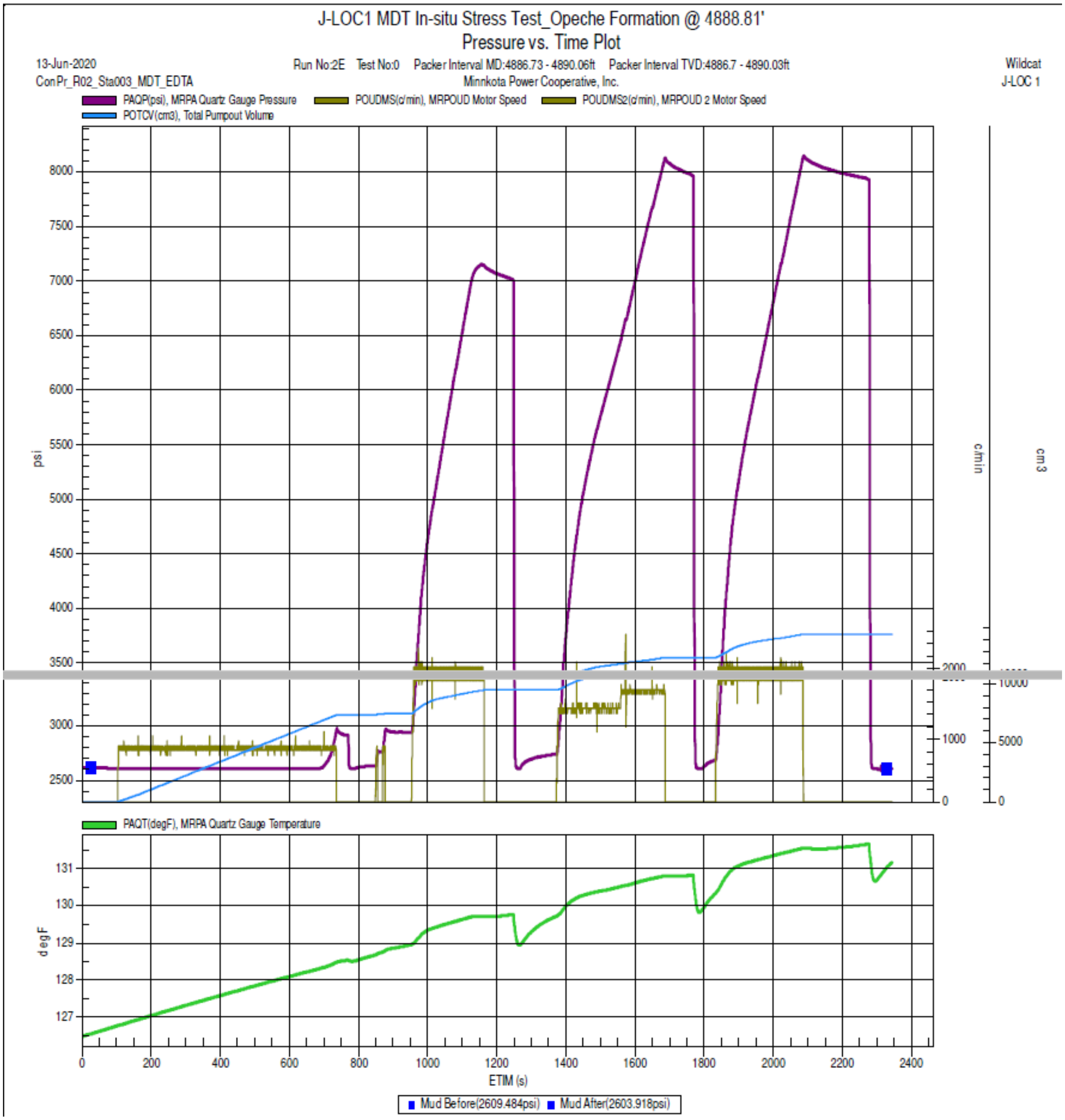


Figure 2-36. J-LOC1 Opeche/Spearfish Formation MDT microfracture in-situ stress pump cycle graph at 4888.8 ft.

2.4.1.1 Mineralogy

Thin-section investigation shows that the Opeche/Spearfish Formation comprises predominantly siltstone with interbedded dolostone and anhydrite. Thin sections were created from the base of the Opeche/Spearfish and the transition zone present at the top of the Broom Creek which comprises clay-rich siltstone. The transition zone has similar characteristics as the Opeche/Spearfish Formation and will also act as a seal. The mineral components present in these samples are anhydrite, quartz, feldspar, dolomite, clay, and iron oxides. The grains are typically surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. Log interpretations and visual inspection of the collected core validate consistent mineral assemblage within the Opeche/Spearfish Formation.

XRD data from samples in the J-LOC 1 well core supported facies interpretations from core descriptions and thin-section analysis. The Opeche/Spearfish Formation mainly comprises anhydrite, quartz, clay, and dolomite.

XRF analysis of the Opeche/Spearfish Formation identifies the major chemical constituents to be dominated by SiO_2 (~47%), SO_3 (~18%), CaO (~16%), Al_2O_3 (~4%), and MgO (~2%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by the XRD (Table 2-13). These results correlate with XRD, core description, and thin-section analysis.

Table 2-13. XRF Data for the Opeche/Spearfish Formation from J-LOC 1

4906* ft	
Component	**Percentage**
SiO_2	47.41
Al_2O_3	3.78
CaO	16.58
MgO	2.17
SO_3	18.26
Others	11.8

* Sample depth correspond to cored depth. A depth shift must be applied to align the values with log depth.

2.4.1.2 Geochemical Interaction

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 stream on the Opeche/Spearfish Formation. Note: PHREEQC's unit of measure is metric. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells, where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche/Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche/Spearfish Formation was honored (Table 2-14). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-15). The composition of the injected gas will be to a standard consisting of at least 96% dry CO_2 (by volume), with trace quantities (4% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C_2^+, and hydrocarbons. The CO_2 stream,

Table 2-14. Mineral Composition of the Opeche/Spearfish Formation Derived from XRD Analysis of J-LOC 1 Core Samples

Minerals, wt%	
Illite	2.2
K-Feldspar	5.6
Albite	2.7
Quartz	31.9
Dolomite	4.3
Anhydrite	53.3

Table 2-15. Formation Water Chemistry from Broom Creek Fluid Samples from J-LOC 1

pH	7.3	TDS	49,000 mg/L
Total Alkalinity	67 mg/L $CaCO_3$	Calcium	1990 mg/L
Bicarbonate	67 mg/L $CaCO_3$	Magnesium	376 mg/L
Carbonate	<20 mg/L $CaCO_3$	Sodium	16,300 mg/L
Hydroxide	<20 mg/L $CaCO_3$	Potassium	223 mg/L
Selenium	0.1204 mg/L	Iron	<2 mg/L
Sulfate	2620 mg/L	Manganese	<2 mg/L
Chloride	29,900 mg/L	Barium	<2 mg/L
Nitrate	25.1 mg/L	Strontium	45.2 mg/L

shown in Table 2-16 that was used for geochemical modeling contains a higher amount of O_2 (2%) than the anticipated injection stream. This stream containing ~95% CO_2 and 2% O_2 was used to represent a conservative scenario, as oxygen is the most reactive constituent among all others. The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/yr (Espinoza and Santamarina, 2017). This overestimate was used to ensure that the degree and pace of geochemical change would not be underestimated. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at elevated reservoir pressure and temperature conditions.

Table 2-16. Modeled Composition of the Injection Stream

Component Flows	mol%
CO_2	94.999
N_2	3
O_2	2
H_2S	0.001

Results showed geochemical processes at work. Figures 2-37 through 2-41 show results from geochemical modeling. Figure 2-37 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, Cell 1 (C1), the pH starts declining from the initial pH of 7.3 and begins to stabilize to a level of 5.3 after 10 years of injection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 24. Lastly, the pH is unaffected in C3, indicating CO_2 does not penetrate this cell within the first 45 years.

Figure 2-38 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. The net change due to precipitation or dissolution in C2 is less than 10 kg per cubic meter per year during active injection, with little to no precipitation or dissolution taking place after injection ceases in Year 2044. Any effects in C3 are not significant to represent at this scale of C1 mineral dissolution and precipitation.

Figure 2-39 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table 2-14. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1, albite, anhydrite, K-feldspar, and dolomite are the primary minerals that dissolve. In C2, albite is the primary mineral that dissolves, but it is too small to be seen (0.02%) in Figure 2-39.

Figure 2-40 represents expected minerals to be precipitated in weight (%) shown for C1 and C2 of the model. In C1, illite, quartz, and calcite are the minerals to be precipitated. In C2, illite is the primary mineral to be precipitated (<1.0 wt%).

Figure 2-41 shows change in porosity of the cap rock for C1–C3. C1 experiences an initial increase in porosity as it is first exposed to CO_2 because of dissolution. The porosity decreases to nearly its initial condition after Year 13 because of precipitation. As dissolution occurs in C1, reaction products move into C2, where they precipitate, causing the porosity to slightly decrease. The net porosity changes from dissolution and precipitation represented in Figure 2-41 are miniscule and, in later years, are unchanging. These results suggest that geochemical change from exposure to CO_2 is minor and will not cause substantive deterioration of the Opeche/Spearfish cap rock.

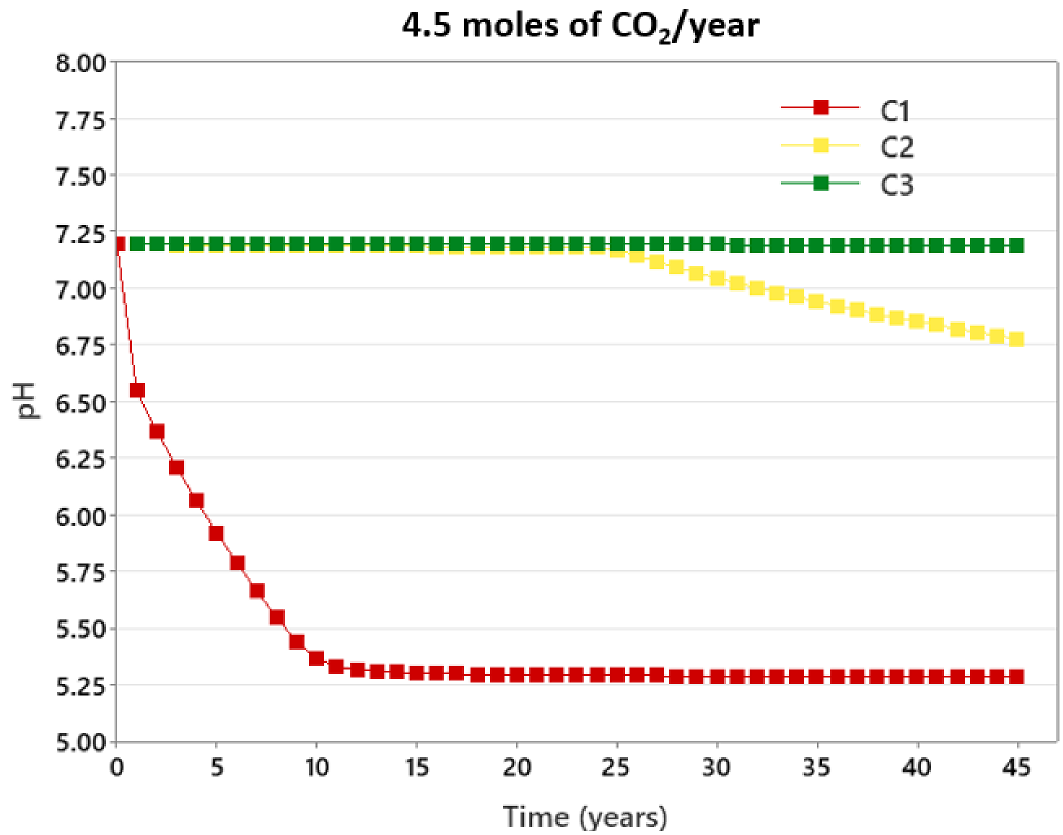


Figure 2-37. Change in fluid pH vs. time. Red line shows pH for the center of C1, 0.5 meters above the Opeche/Spearfish Formation cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. pH for C2 does not begin to change until after Year 24.

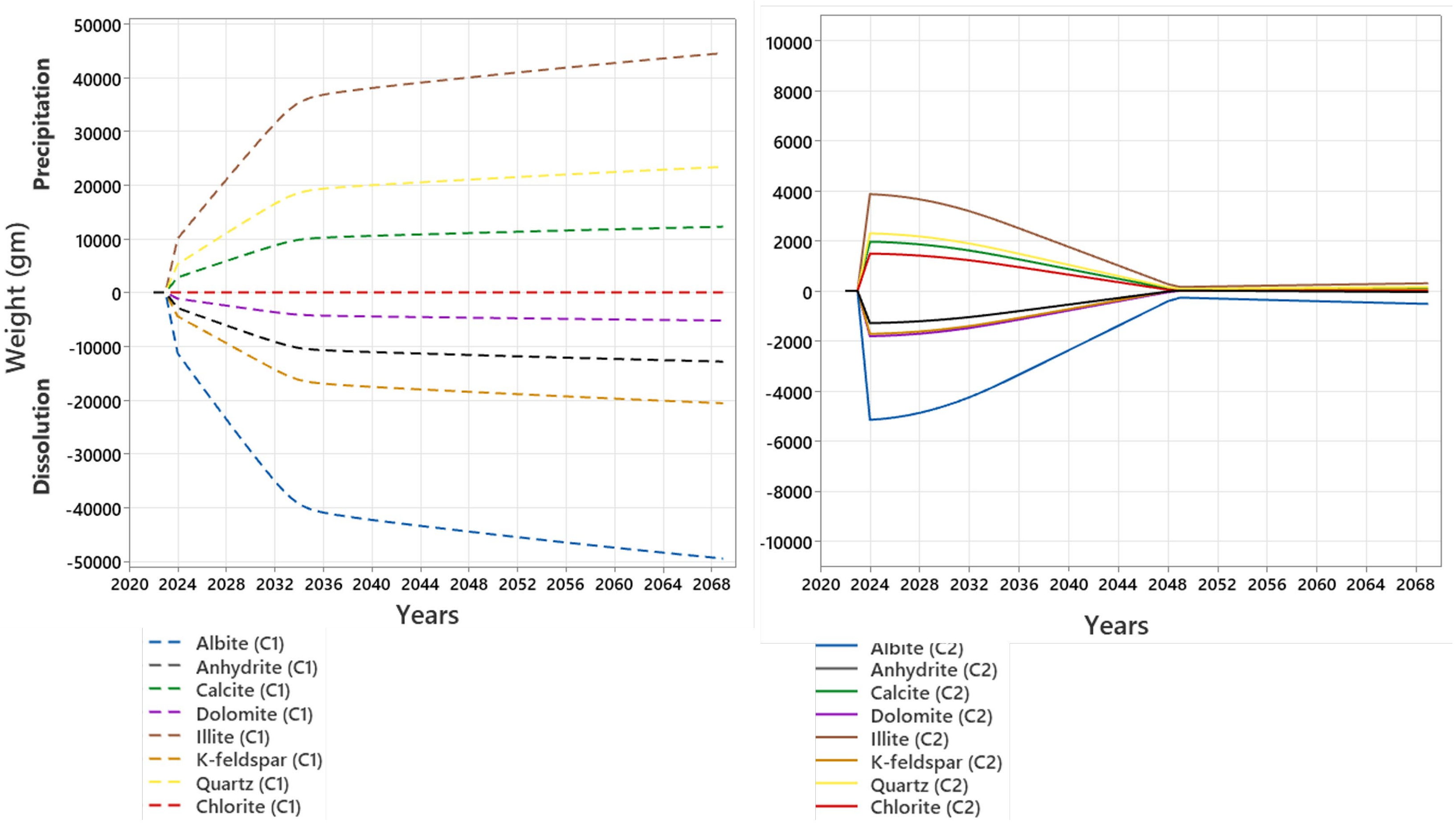


Figure 2-38. Dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1 at 0.5 meters above the cap rock base. Solid lines show results for C2, 1.5 meters above the cap rock base.

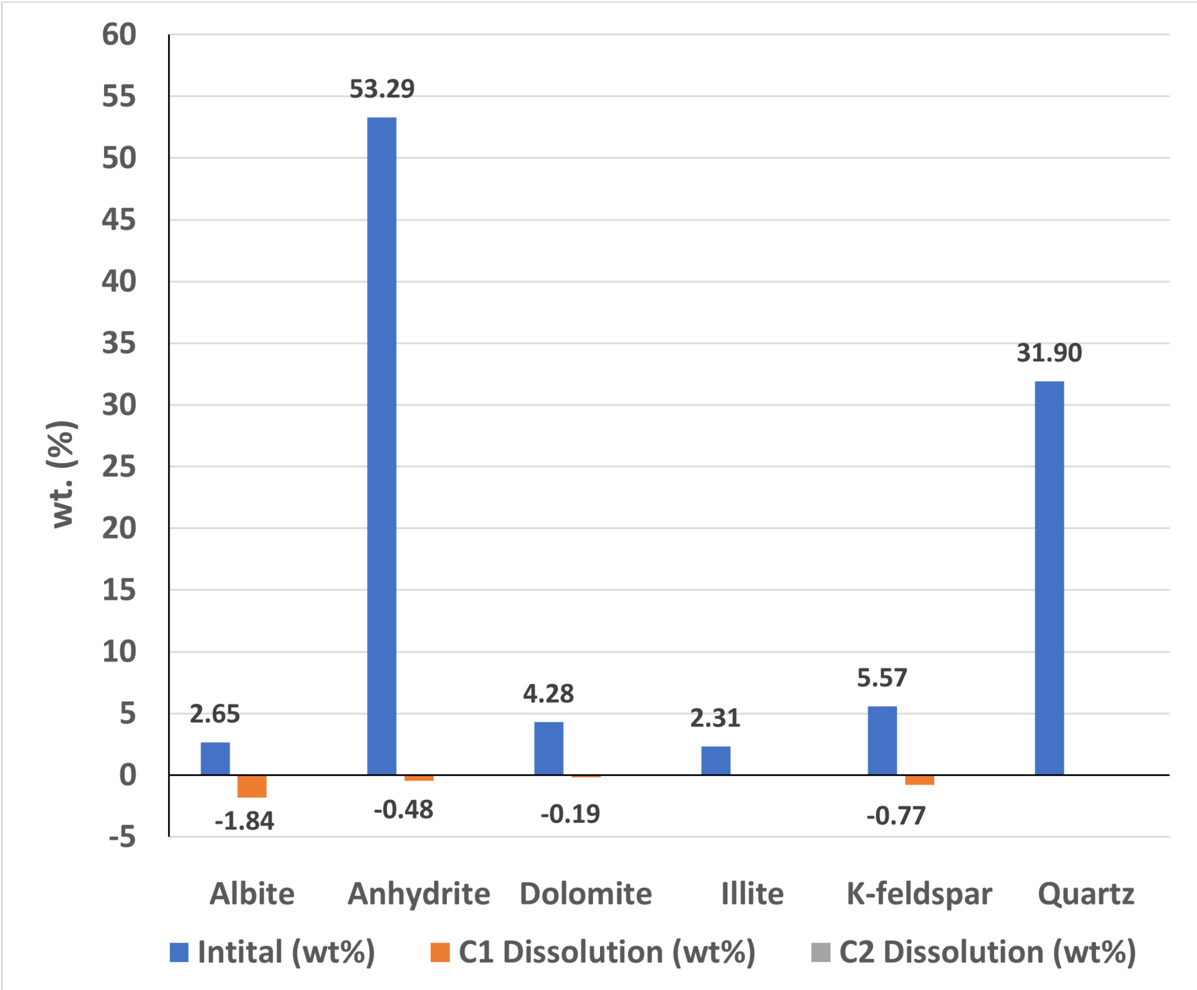


Figure 2-39. Weight percentage (wt.%) of potentially reactive minerals present in the Opeche/Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2(gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt.% associated with dissolution.

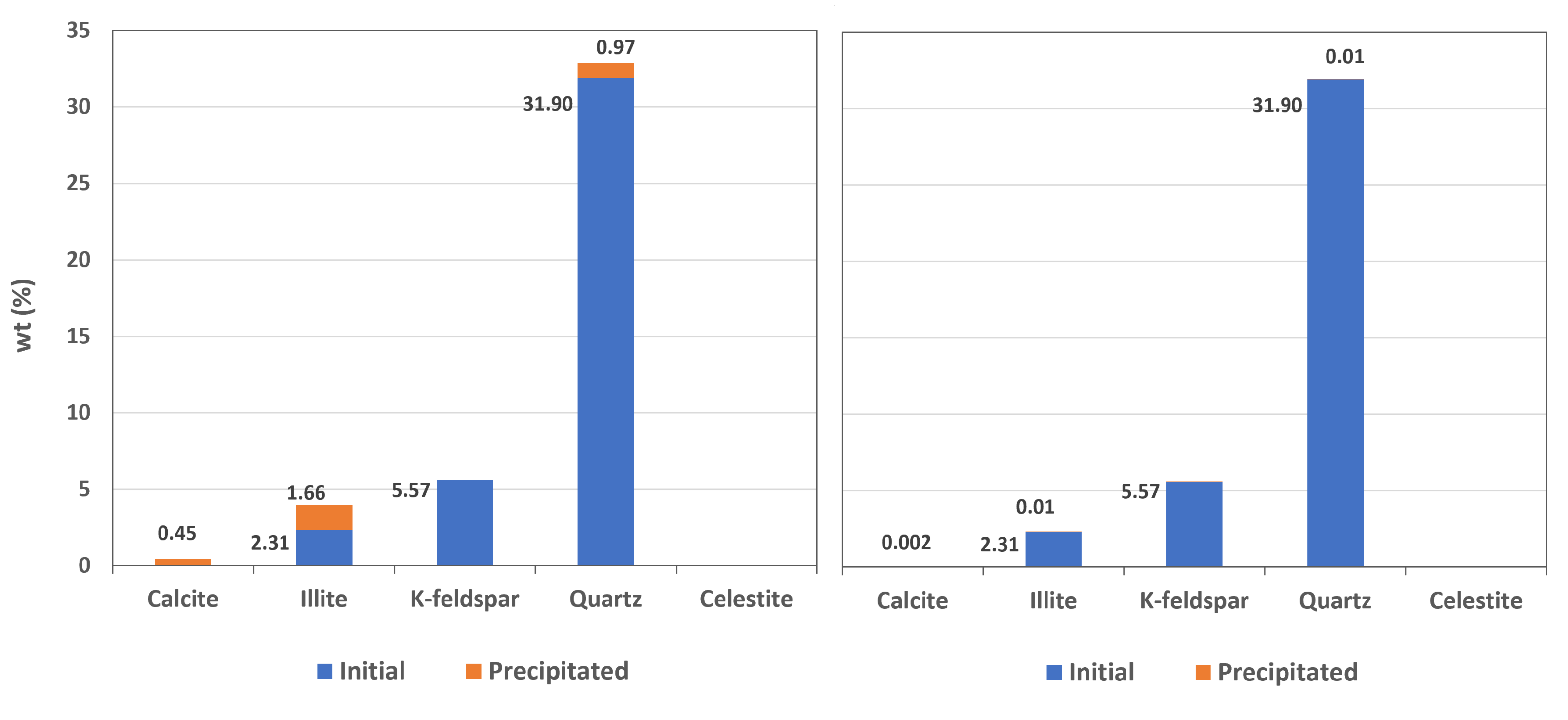


Figure 2-40. Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Minerals precipitated in C2 are too small to be seen in the figure.

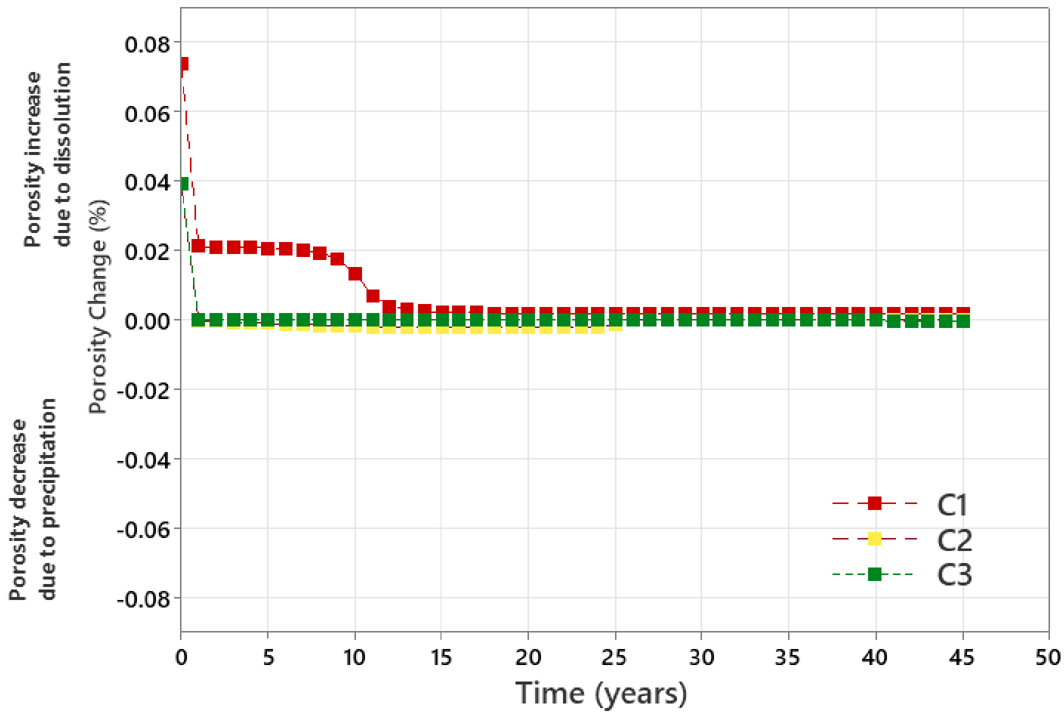


Figure 2-41. Change in percent porosity of the Opeche/Spearfish cap rock. Red line shows porosity change calculated for C1 at 0.5 meters above the cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals and negative change is due to mineral precipitation.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche–Picard interval. Impermeable rocks above the primary seal include the Piper (Kline Member), Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-17). Together with the Opeche–Picard interval, these formations are 851 ft thick (thickness at the J-LOC 1 well) and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-42, Broom Creek to Swift). Above the Inyan Kara Formation, 2638 ft (thickness at the J-LOC 1 well) of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-43, Inyan Kara to Pierre). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-17).

Table 2-17. Description of Zones of Confinement above the Immediate Upper Confining Zone, Opeche–Picard Interval (data based on the J-LOC 1 well)

Name of Formation	Lithology	Formation Top Depth, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Mudstone	1250	1934	0
Greenhorn	Mudstone	3184	401	1934
Mowry	Mudstone	3585	60	2335
Skull Creek	Mudstone	3655	233	2405
Swift	Mudstone	4057	472	2807
Rierdon	Mudstone	4529	146	3279
Piper (Kline Member)	Carbonate	4675	109	3425

These formations, between the Broom Creek Formation and Inyan Kara Formation and between the Inyan Kara Formation and the lowest USDW, have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).

Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and primary sealing interval. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensing (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary confining zones, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation in the DCC West SGS area is 3888 ft, and the formation itself is 169 ft thick measured at the J-LOC 1 well.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, sandstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the DCC West SGS area (Figure 2-10). The Amsden Formation is 5210 ft below land surface and 259 ft thick at the J-LOC 1 well site (Table 2-12, Figures 2-44 and 2-45).

The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the J-LOC 1 well. The lithology of the cored section of the Amsden Formation from the J-LOC 1 well is dolostone and anhydrite, with laminated, fine-grained sandstone.

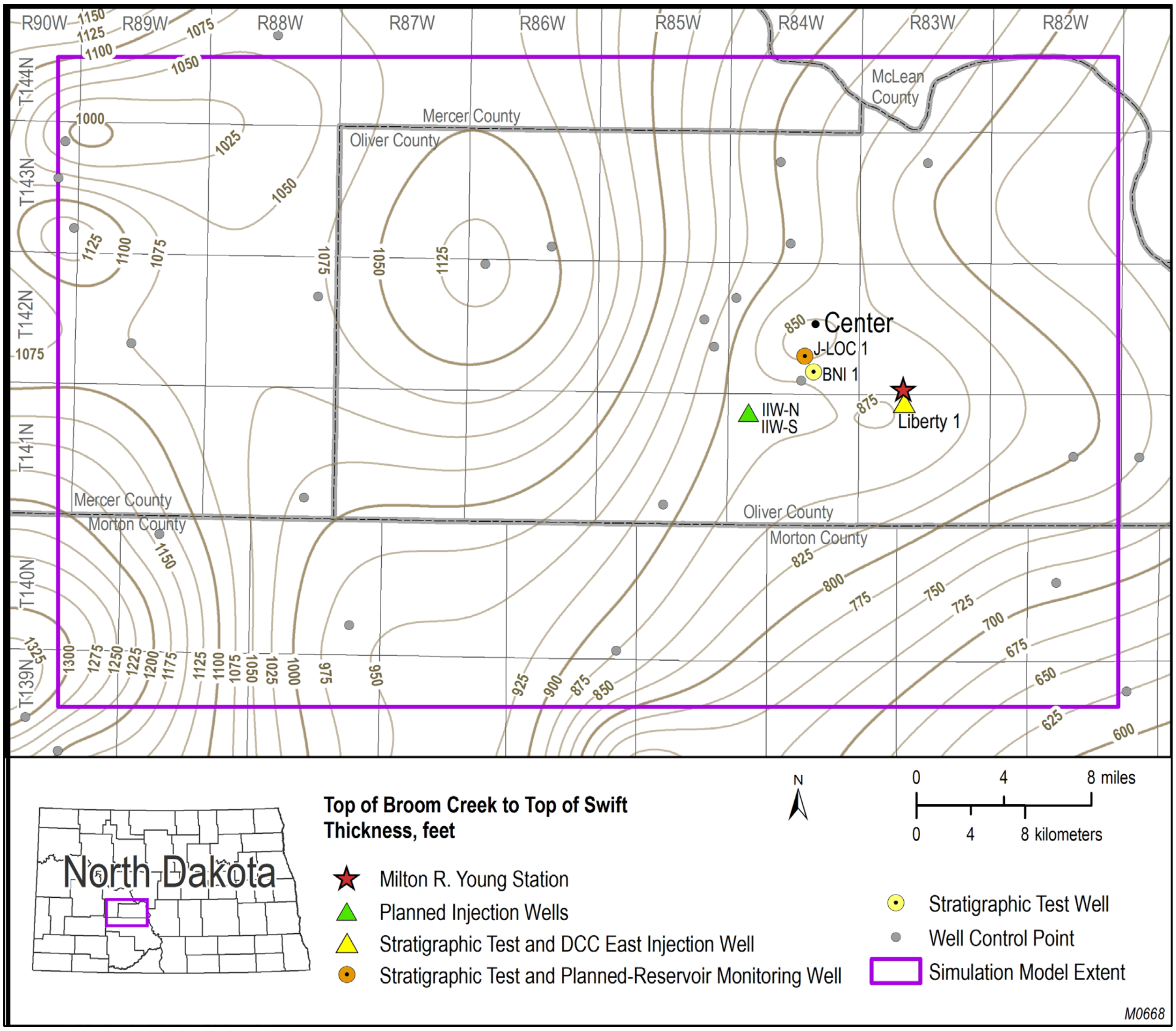


Figure 2-42. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confining zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

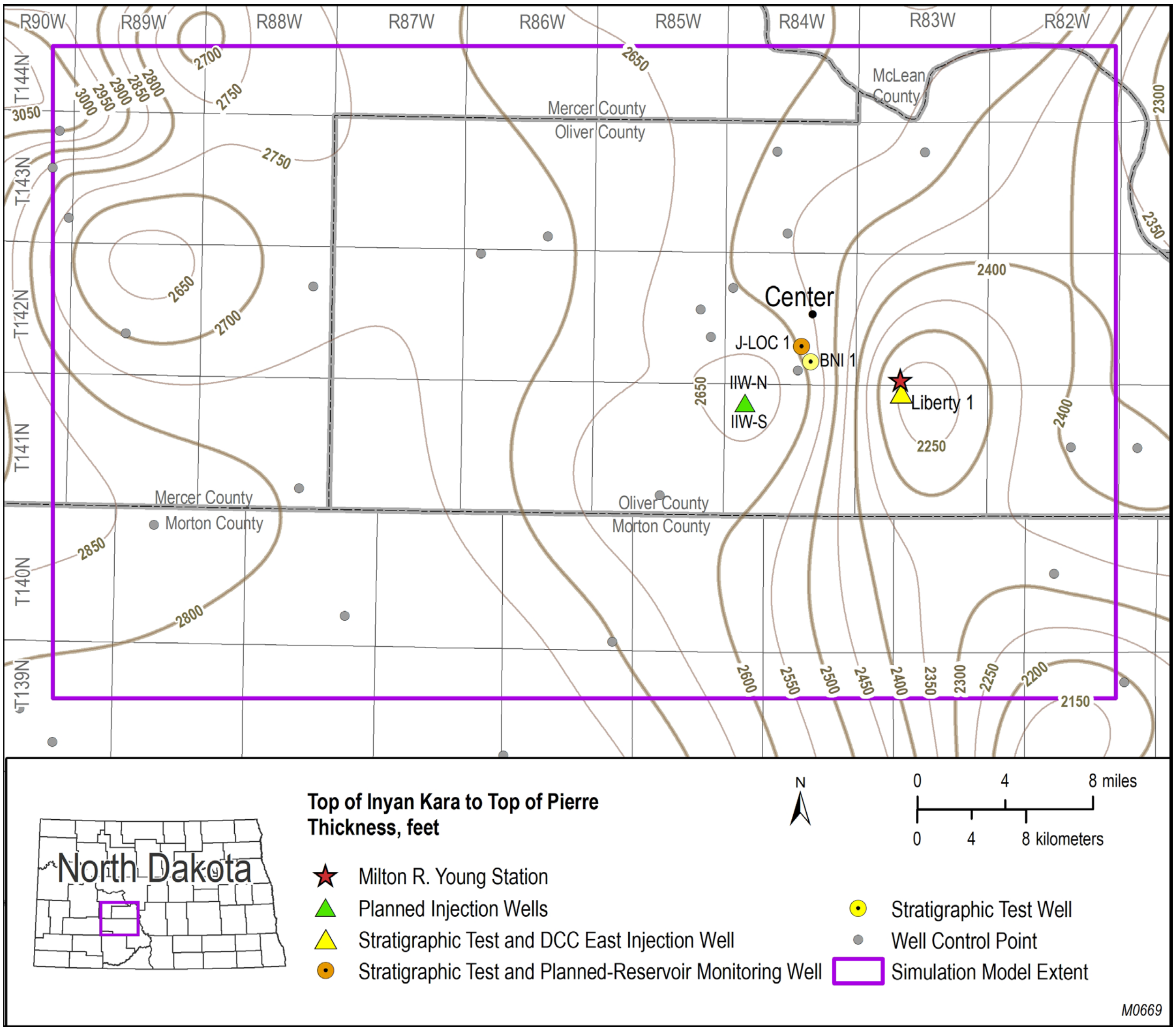


Figure 2-43. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

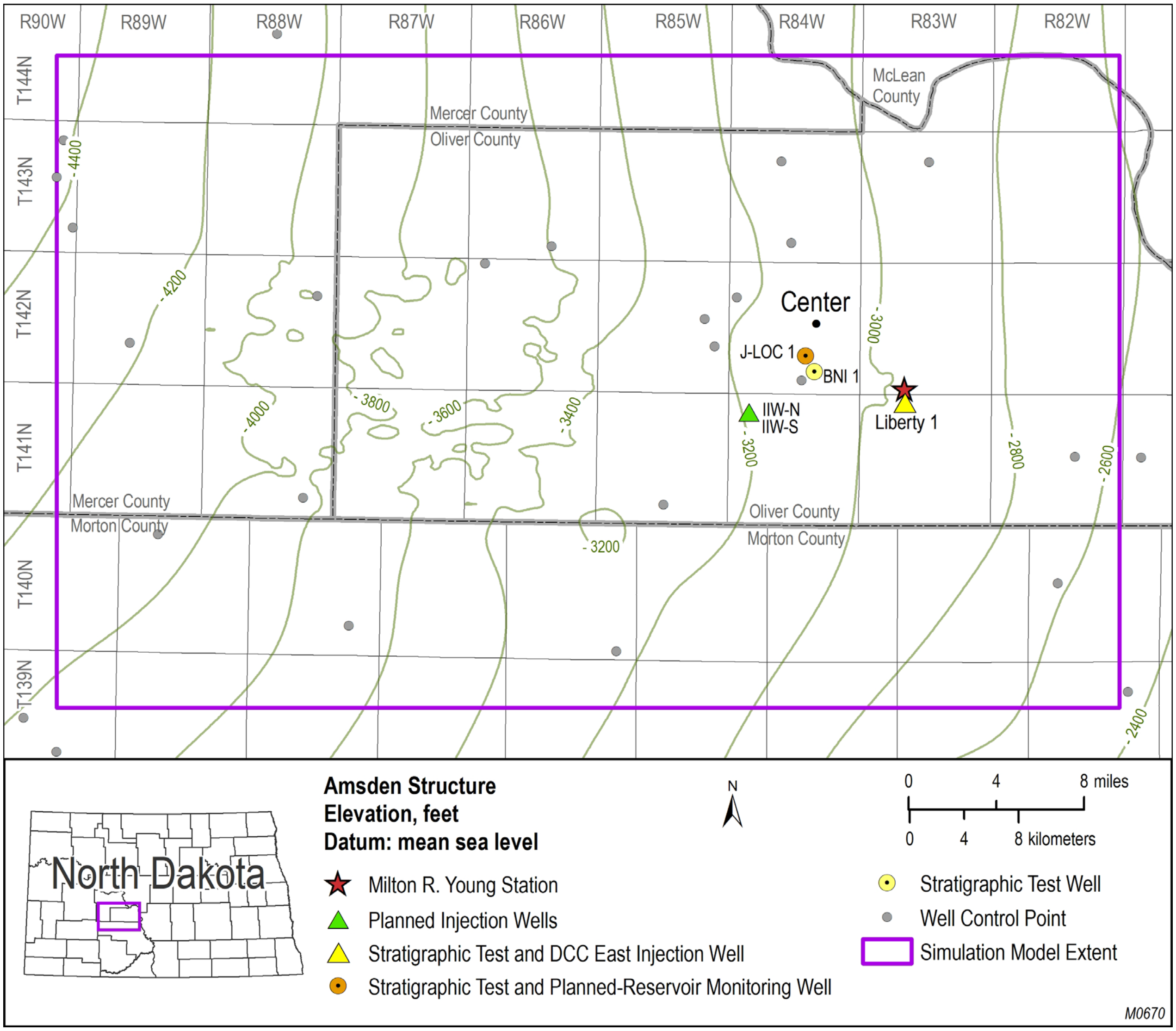


Figure 2-44. Structure map of the Amsden Formation across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

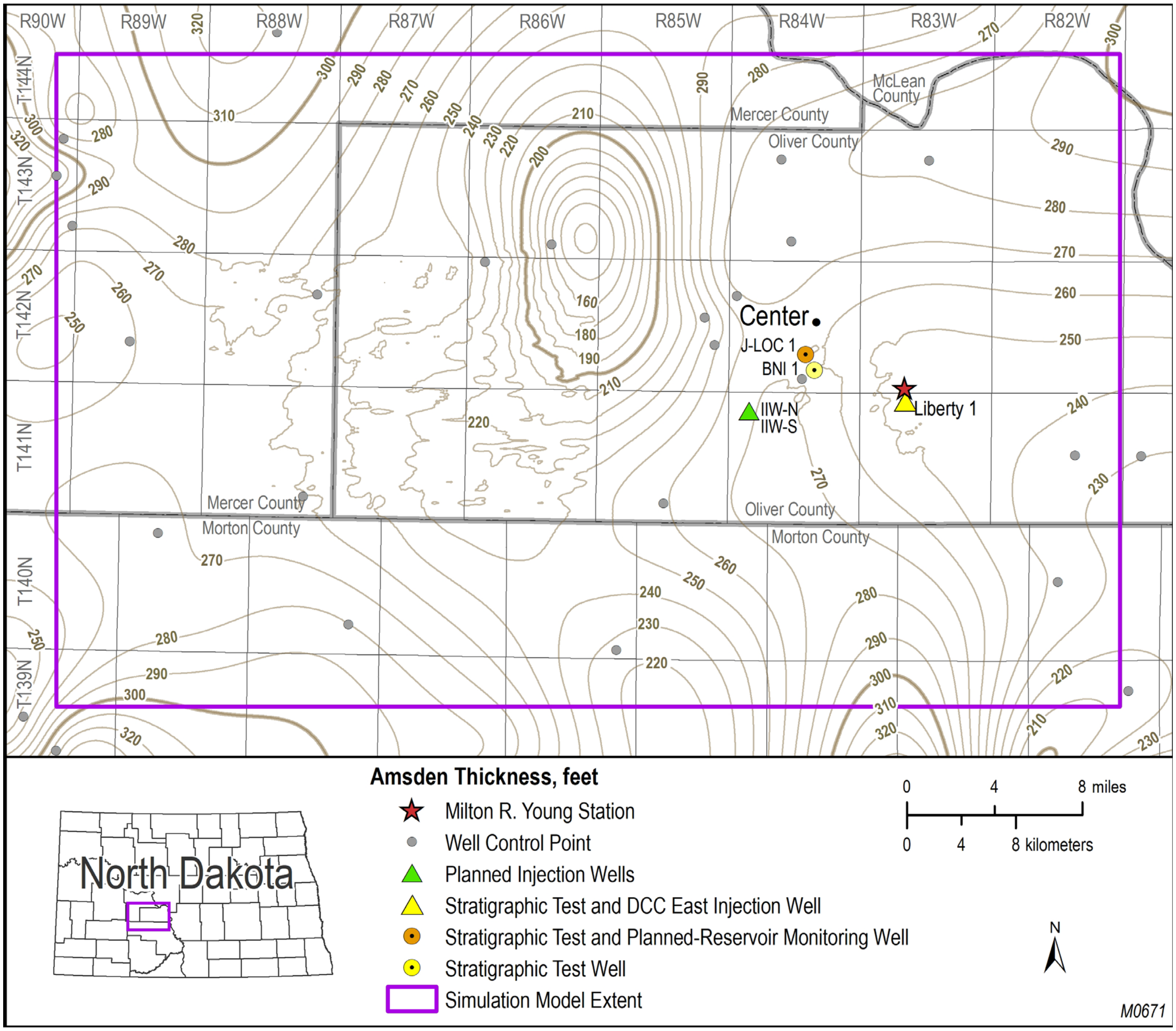


Figure 2-45. Isopach map of the Amsden Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

2.4.3.1 Mineralogy

The well logs and thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, and anhydrite. The dolostone is expressed by very fine- to fine-grained dolomite (35%), with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. Quartz overgrowth and the absence of intercrystalline porosity were observed in thin sections (Figure 2-46). The existing porosity (secondary porosity) is mainly due to the dissolution of feldspar and quartz and averages 5%.

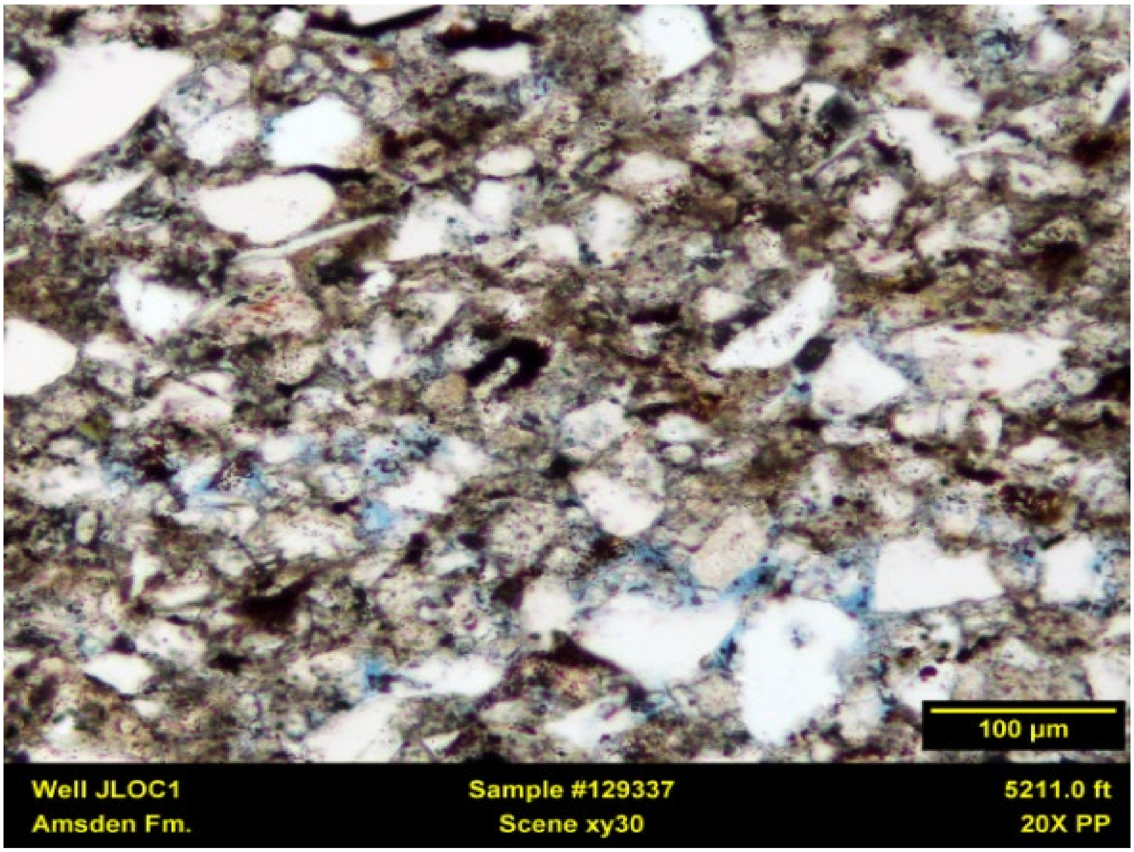


Figure 2-46. Plane-polarized light thin-section image from the J-LOC 1 well, Amsden Formation. This image shows the dolomite–quartz-rich nature of this interval of the Amsden Formation. The example shows dolomite, corroded quartz grains, and iron oxides. Porosity (blue) is due to dissolution.

Anhydrite is present as beds that separate the dolomite intervals and cement and mineral components. It comprises anhydrite minerals with minor inclusions of iron oxides. The porosity is almost null.

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

The shaly sandstone comprises quartz, clay, and dolomite. A minor presence of feldspar, anhydrite, and iron oxides exists. The grains of quartz and anhydrite are frequently separated by clay cement. The porosity is very low, averaging 7%, and is mainly due to the dissolution of feldspar and quartz.

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

XRF data show the Amsden Formation has the same major chemical constituents as the Opeche/Spearfish Formation (Table 2-18). However, the interval at the contact with the Broom Creek Formation is underlain by anhydrite. As the formation gets deeper, the chemistry changes to a more carbonate-rich siltstone, as shown by the higher percentages of SiO_2, CaO, and MgO.

Table 2-18. XRF Data for the Amsden Formation from the J-LOC 1 Well

Sample Depth			
5211 ft		5218 ft	
Component	**Percentage**	**Component**	**Percentage**
SiO_2	62.84	SiO_2	29.48
Al_2O_3	9.24	Al_2O_3	4.93
Fe_2O_3	2.85	Fe_2O_3	2.19
CaO	5.13	CaO	19.43
MgO	3.95	MgO	13.45
K_2O	4.79	K_2O	2.42
Other	9.08	Other	5.41

* Sample depth correspond to cored depth. A depth shift must be applied to align the values with log depth

2.4.3.2 Geochemical Interaction

The Broom Creek Formation's underlying confining layer, the Amsden Formation, was investigated using PHREEQC geochemical software. A vertically oriented 1D simulation was created using a stack of 22 cells; each cell is 1 meter in thickness. The formation was exposed to CO_2 at the top boundary of the simulation, and CO_2 was allowed to enter the system by advection and dispersion processes. Direct fluid flow into the Amsden Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the center of each cell below the confining layer–CO_2 exposure boundary. The mineralogical composition of the Amsden Formation was honored (Table 2-19). Formation brine composition was assumed to be the same as the known composition from the overlying Broom Creek Formation injection zone (Table 2-15). A CO_2 stream containing ~95% CO_2 and 2% O_2 as shown in Table 2-16 was used in the geochemical modeling to represent a conservative scenario, as oxygen is the most reactive constituent among all others. The maximum formation temperature and pressure, projected from CMG simulation results described in Section 3.0, were used to represent the potential maximum pore pressure and temperature level. The higher-pressure results are shown to represent a potentially more rapid pace of geochemical change. These simulations were run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Table 2-19 Mineral Composition of the Amsden Formation Derived from XRD Analysis of J-LOC 1 Core Samples at a Depth of 5211 ft and 5218 MD

Sample Depth			
5211 ft*		5218 ft	
Mineral	**wt.%**	**Mineral**	**wt.%**
Smectite	7	Smectite	9
Illite/Muscovite	18.6	Illite/Muscovite	13.7
Chlorite	1.6	Chlorite	0.7
K-Feldspar	16.4	K-Feldspar	7.9
P-Feldspar	6.2	P-Feldspar	4.5
Quartz	35.2	Quartz	21.6
Dolomite	7.1	Dolomite	35.6
Others	7.9	Others	7.0

* Values at 5211 ft depth were considered for geochemical modeling.

Results show geochemical processes at work. Figures 2-47 through 2-52 show results from the geochemical modeling. Figure 2-47 shows change in fluid pH over 20 years of injection and 25 years of postinjection time in odd-numbered cells as CO_2 enters the system. Initial change in pH in all the cells from 7.3 to 7.1 is related to initial equilibration of the model. For the cell at the CO_2 interface, Cell 1 (C1), the pH declines to a level of 5.2 after 3 years of injection and slowly declines further to 4.8 by the end of the simulation period. Progressively less or slower pH change occurs for each cell that is more distant from the CO_2 interface. The pH for Cells 21–22 did not decline over the 20 years of injection and 25 years of postinjection time.

Figure 2-48 shows that CO_2 does not penetrate more than 20 meters (represented by C21–C22) within the 20 years of injection and 25 years of postinjection time.

Figure 2-49 shows the changes in mineral dissolution and precipitation in grams per cubic meter. For C1 and C2, albite and K-feldspar start to dissolve from the beginning of the simulation while quartz begins to precipitate. Montmorillonite (smectite) and illite clays largely follow mirror-image paths of dissolution and precipitation during the time of the simulation.

Figure 2-50 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table 2-19. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, albite and K-feldspar are the common primary minerals that dissolve. No dissolution is observed for dolomite and quartz. The dissolved minerals are almost completely replaced by the precipitation of other minerals, as shown in Figure 2-51.

Figure 2-51 represents expected minerals to be precipitated in weight percentage (wt%) shown for C1 and C2 of the model. In C1 and C2, quartz, dolomite and hematite are the minerals to be precipitated.

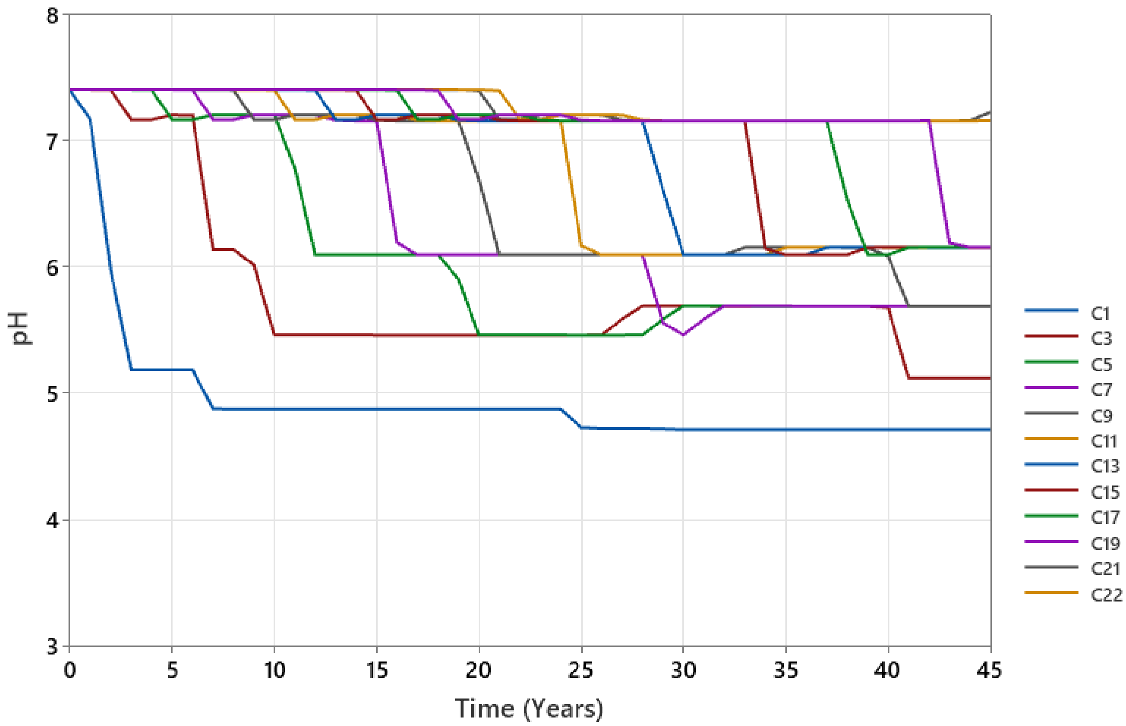


Figure 2-47. Change in fluid pH for C1–C22 in the Amsden Formation underlying confining layer.

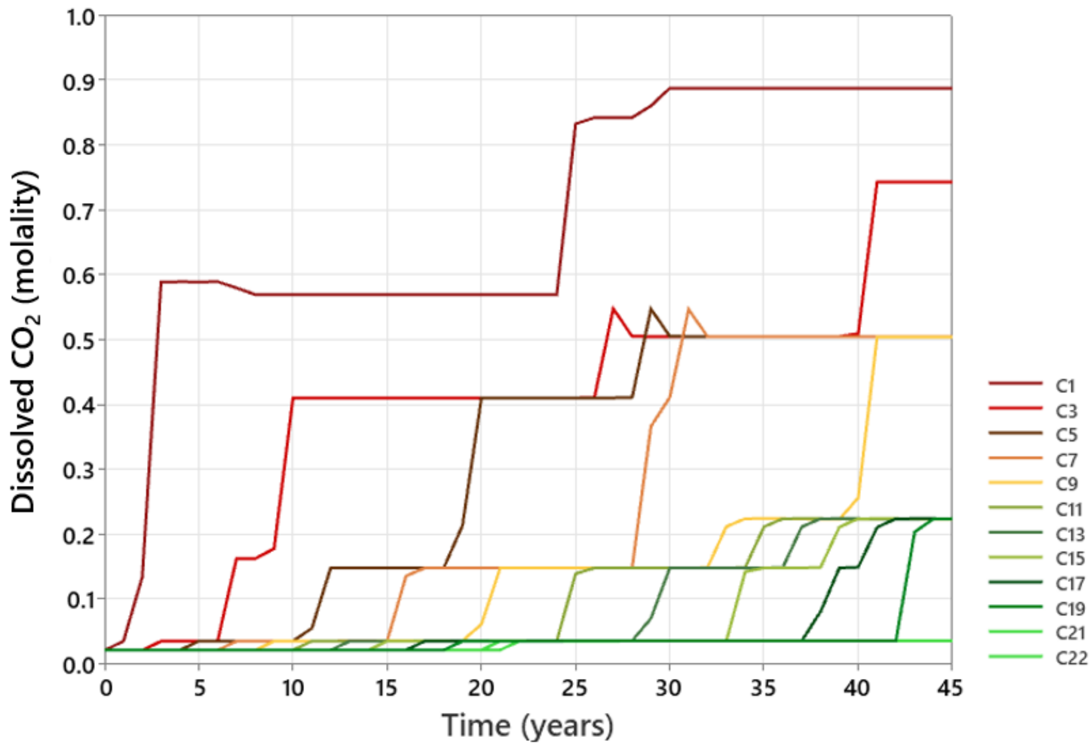


Figure 2-48. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for C1–C22.

Change in porosity (% units) of the Amsden Formation underlying confining layer is displayed in Figure 2-52 for C1–C3. The overall net porosity changes at each time from dissolution and precipitation are minimal, less than 1% change during the life of the simulation. C1 shows an initial porosity increase, of 1%, but this change is temporary, and the cell quickly returns to its near initial porosity. After Year 6, C1 experiences a porosity decrease up to 0.4%. No significant porosity changes were observed in C2–C3 after 7 years of injection. Cells C4–C22 showed similar results, with porosity change being less than 1% at each time step.

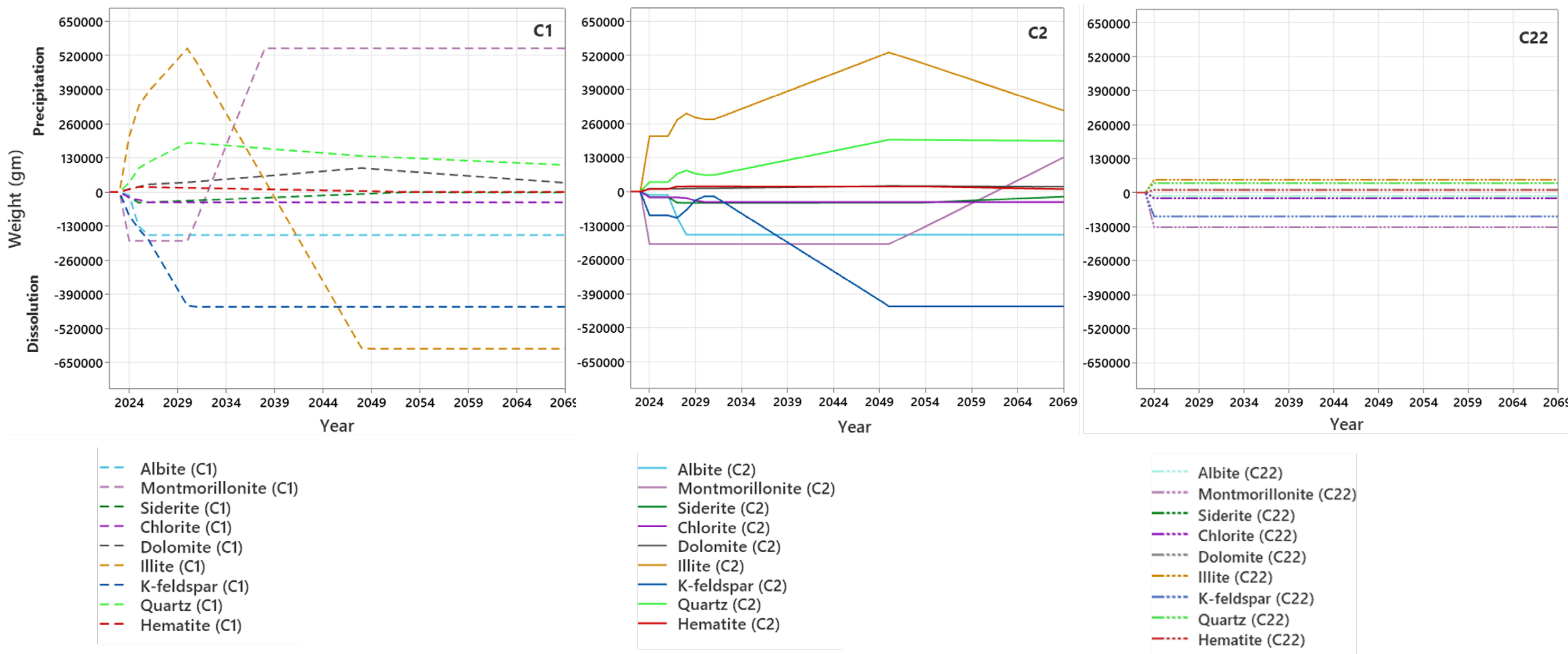


Figure 2-49. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for C1, 0 to 1 meter below the Amsden Formation top. Solid lines show results for C2, 1 to 2 meters below the Amsden Formation top. Dotted lines show the results for C22, 21 to 22 meters below the Amsden Formation top. C22 shows minimal dissolution and precipitation which is associated with the initial model equilibration as CO2 doesn’t penetrate this cell by the end of 45 years simulation.

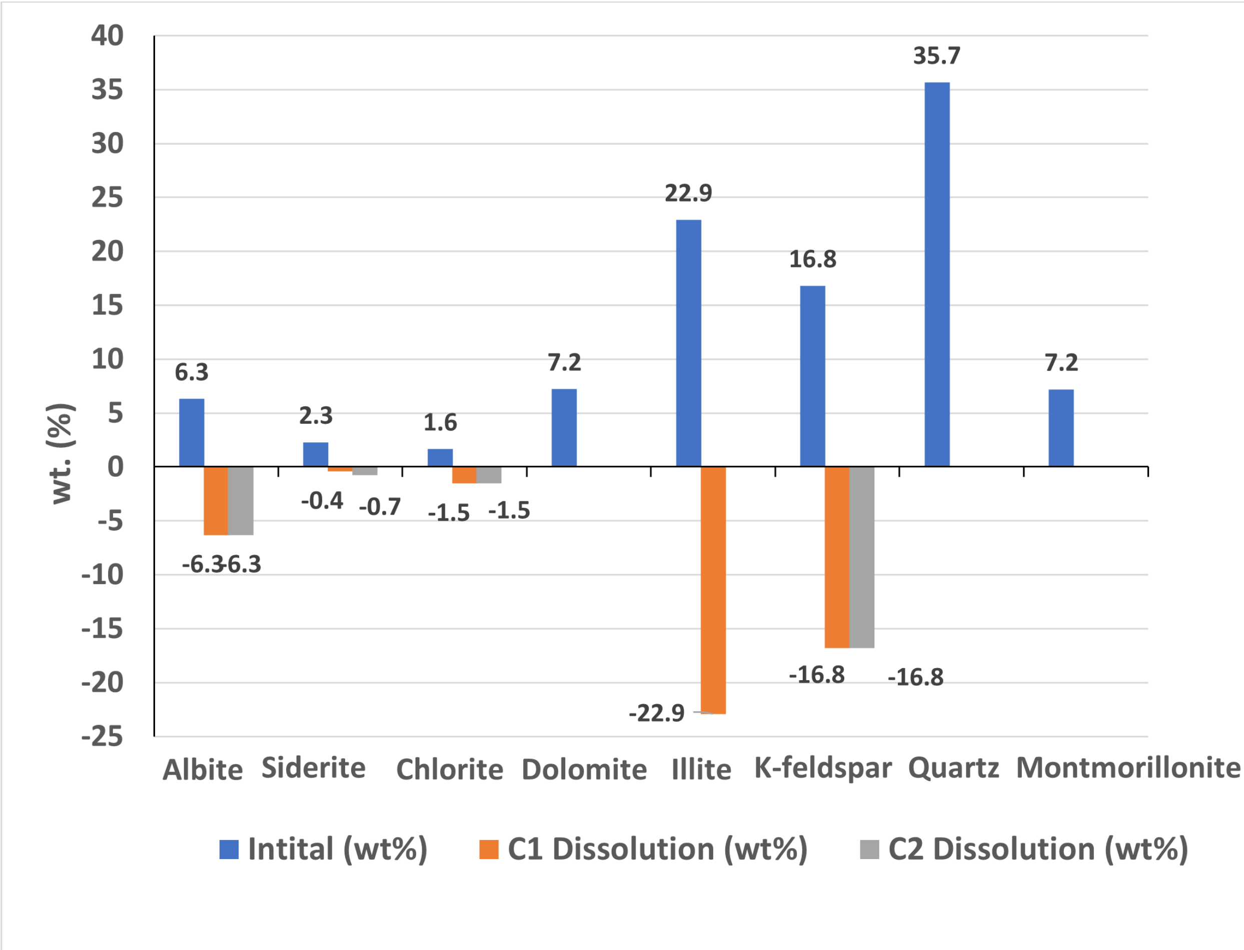


Figure 2-50. Weight percent of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt.% associated with dissolution.

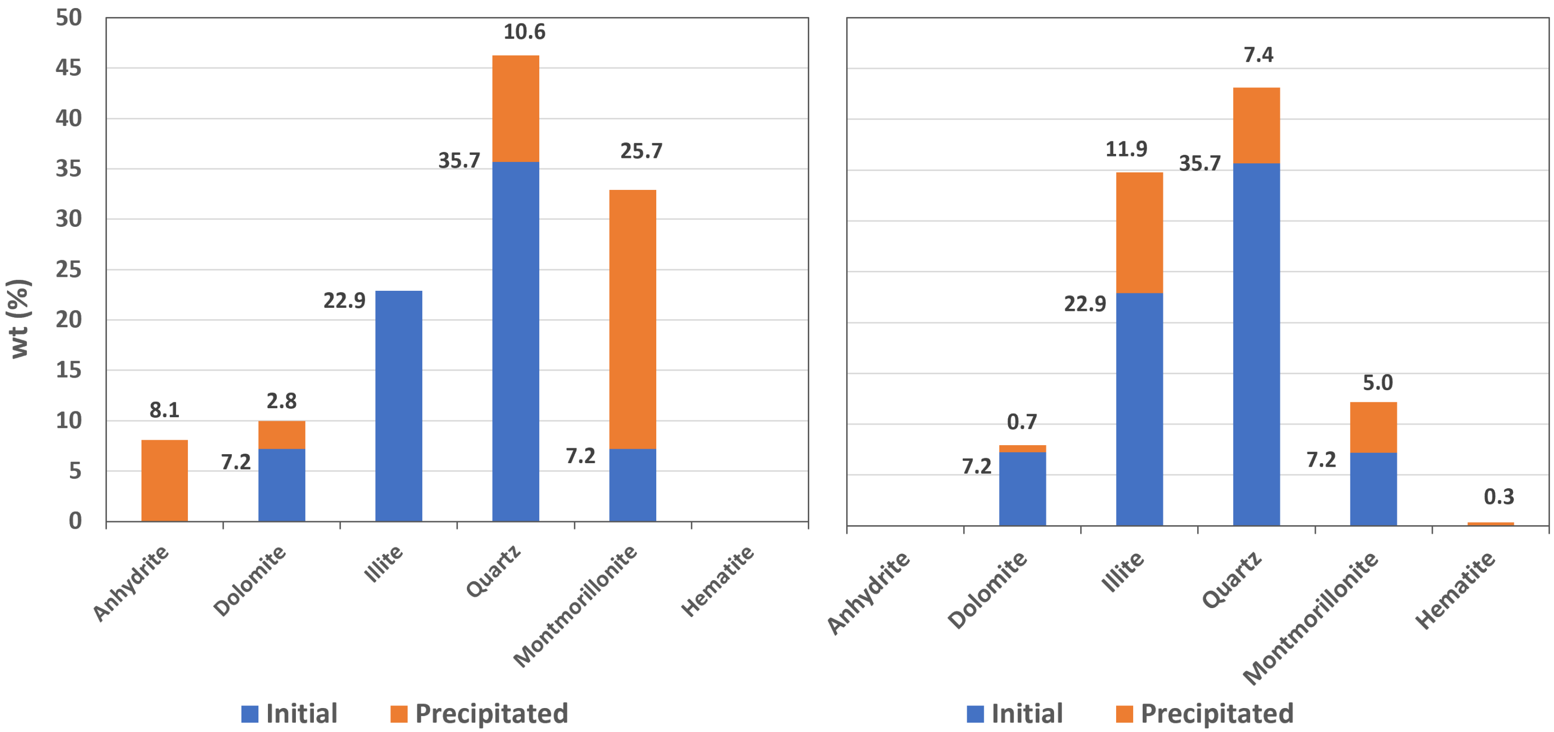


Figure 2-51. Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Hematite precipitation in C1 and C2 is too small to be seen in the figure.

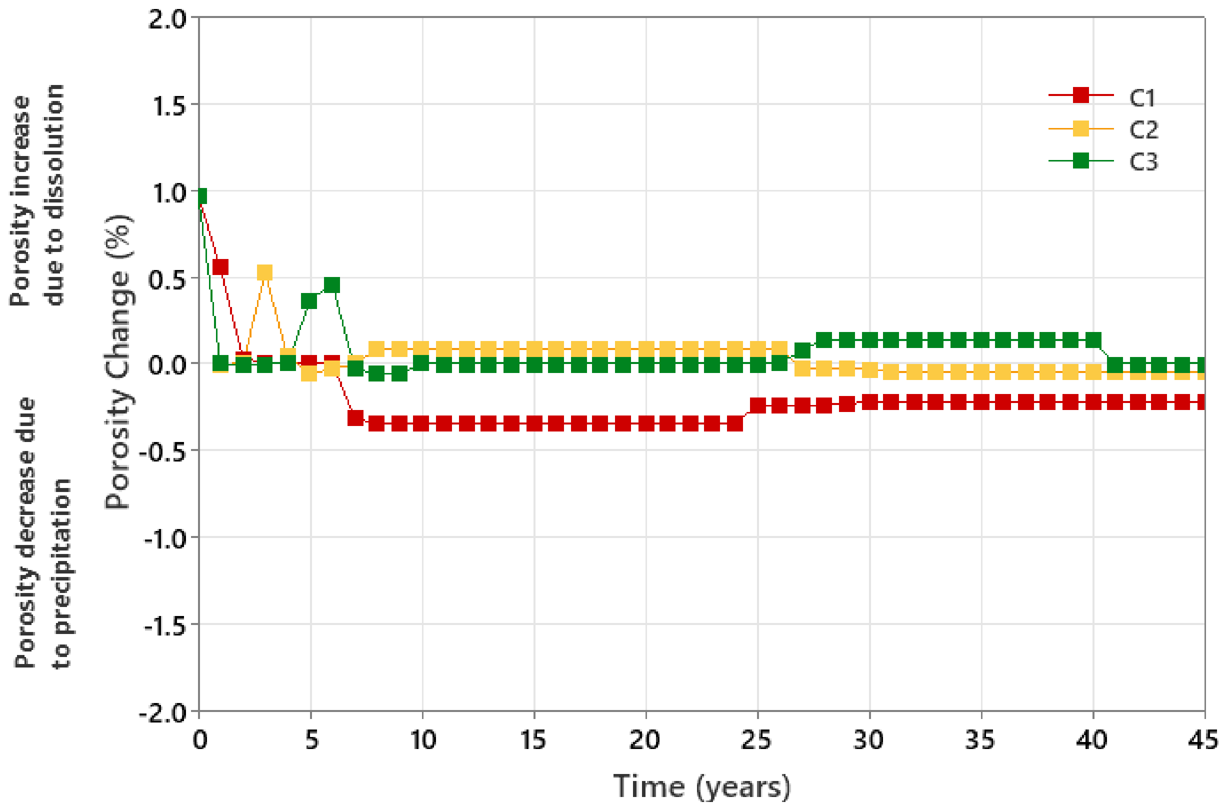


Figure 2-52. Change in percent porosity in the Amsden Formation underlying confining layer red line shows porosity change for C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows C2, 1 to 2 meters below the Amsden Formation top. Green line shows C3, 2 to 3 meters below the Amsden Formation top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation.

2.4.4 Geomechanical Information of Confining Zones

2.4.4.1 Fracture Analysis

Fractures within the overlying confining zone (the Opeche–Picard Formation) and the underlying confining zone (Amsden Formation) were assessed during the description of the J-LOC 1 well core. Observable fractures were categorized by attributes including morphology, orientation, aperture, and origin. Secondly, natural fractures and in situ stress were assessed through the interpretation of the image log acquired during the drilling of the J-LOC 1 well.

2.4.4.2 Fracture Analysis Core Description

Fractures within the Opeche/Spearfish Formation are primarily resistive and mixed. They are commonly filled with anhydrite. However, some conductive fractures are highlighted. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale.

In the Amsden Formation, resistive fractures are common and are coincident with the horizontal compaction features (stylolite) observed. Calcite is the dominant mineral found to fill observable fractures. Very few-to-no connected fractures were observed in the Amsden Formation core interval from the J-LOC 1 well.

2.4.4.3 Borehole Image Fracture Analysis

Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the image log acquired from the J-LOC 1 well. The image log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed.

Figure 2-53 shows the interpreted borehole imagery and primary features observed in the lower Piper Formation and demonstrates that the tool provides information on surface boundaries and bedding features. The far-right track on Figure 2-53 notes the presence and dip orientation of tectonic and sedimentary features, which fall into several categories. The lowest features are dominantly stylolites and anhydrite layers. Several electrically resistive features are present and these are interpreted as a minor anhydrite-filled fracture. Some isolated conductive fractures were identified by the BHI data, and these are likely clay-filled because of their electrically conductive signal. The rose diagrams shown in Figures 2-54 through 2-56 provide the orientation of the conductive, resistive, and mixed fractures in the lower Piper Formation.

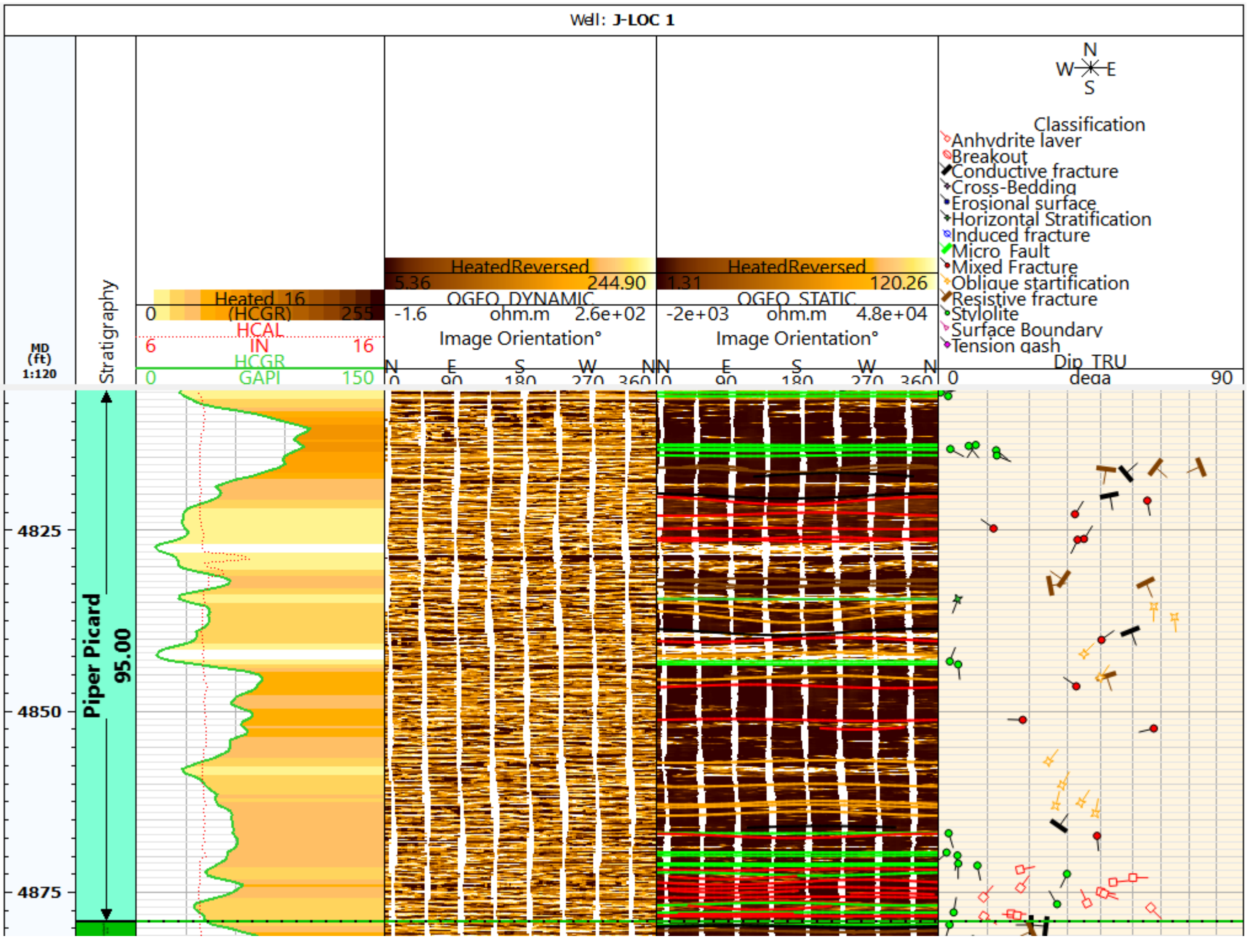


Figure 2-53. Sedimentary and tectonic features in the lower Piper Formation observed on the borehole image log. The figure shows; Track 1: Gamma-ray (HSGR), Caliper (HCal); Track 2: Borehole dynamic image log; Track 3: Borehole static image log. Track4: Tectonic and sedimentary tadpoles' orientation in the interval between 4805 and 4882.5 ft.

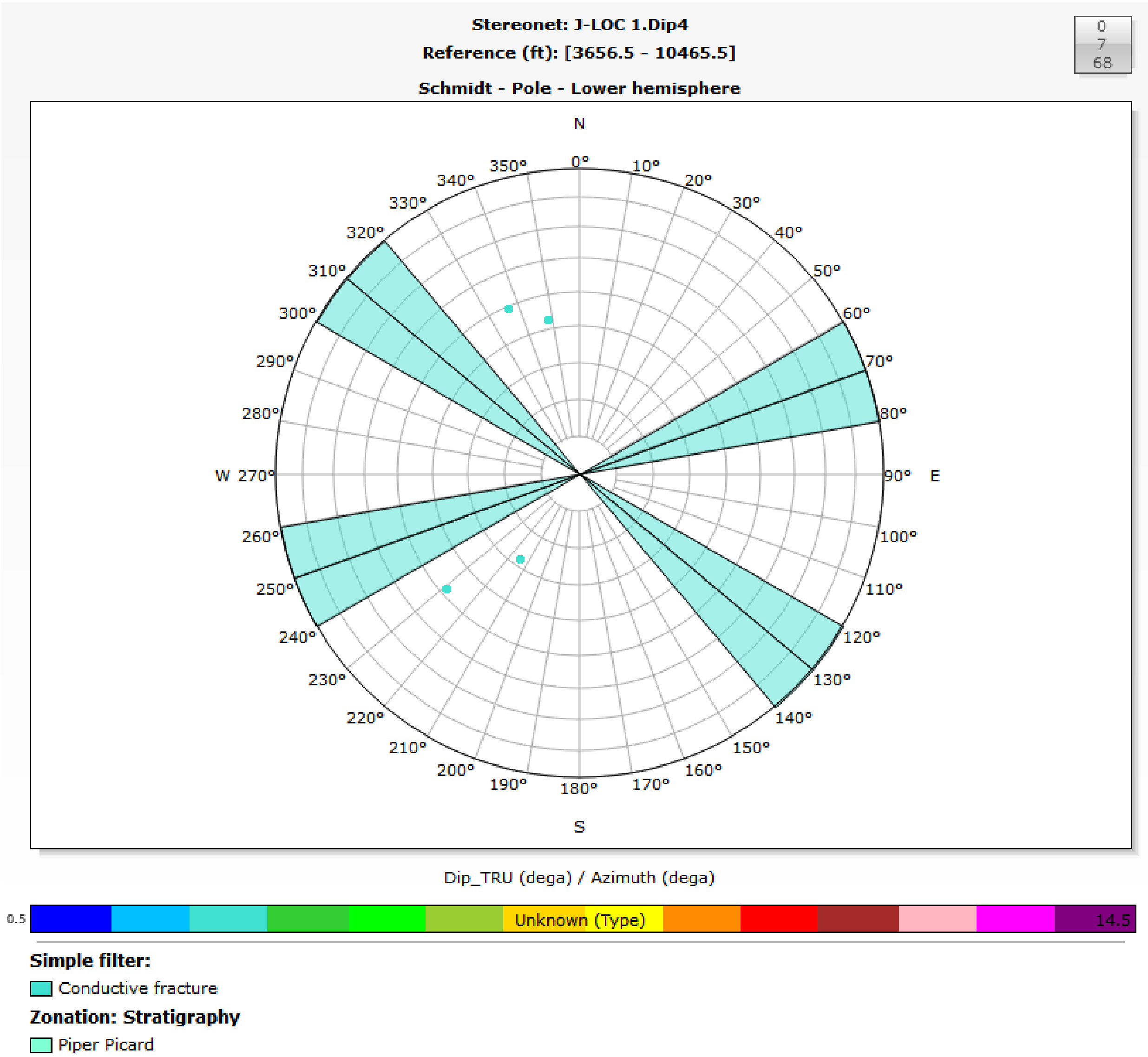


Figure 2-54. Strike orientation of conductive fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

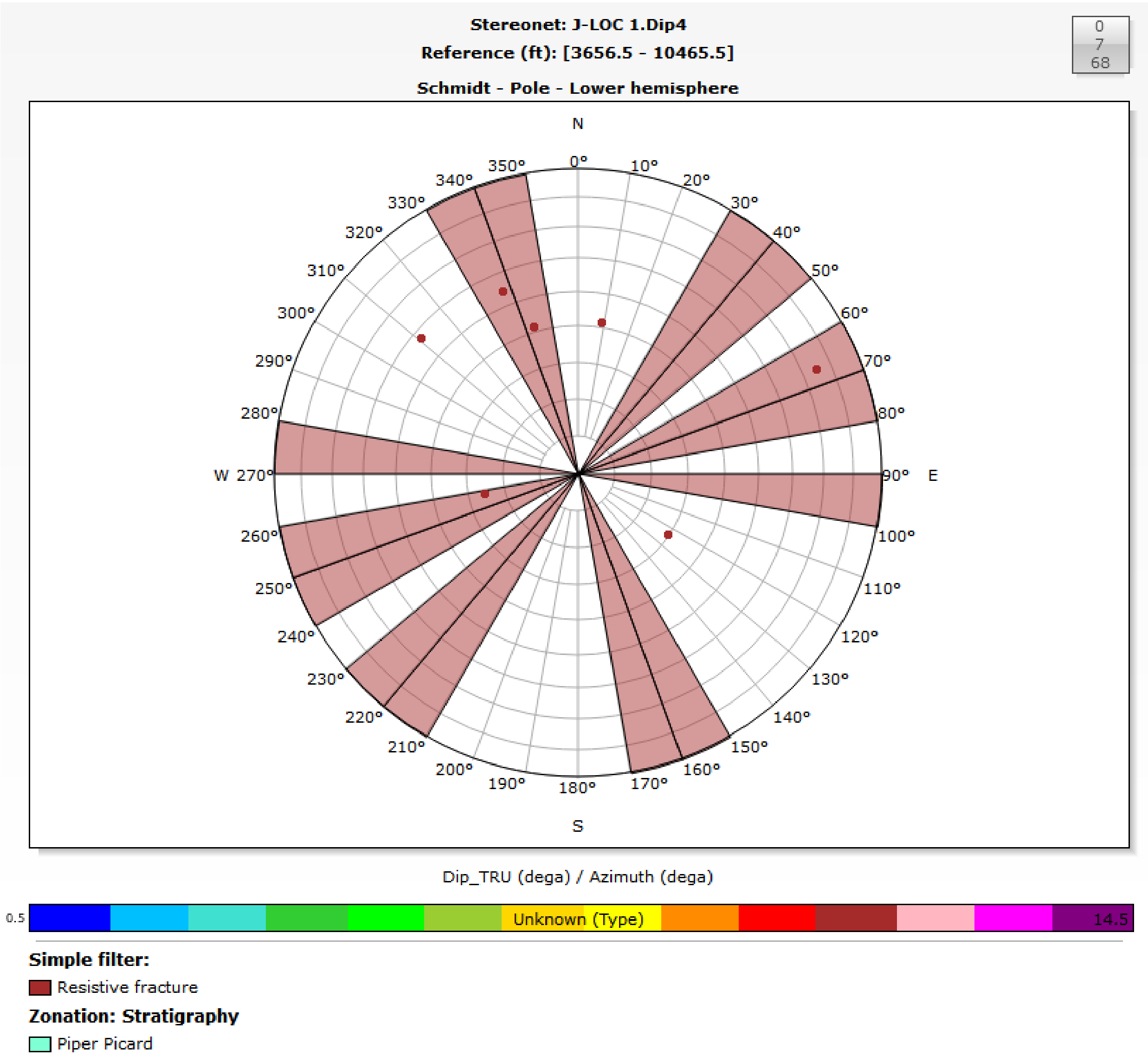


Figure 2-55. Strike orientation of resistive fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

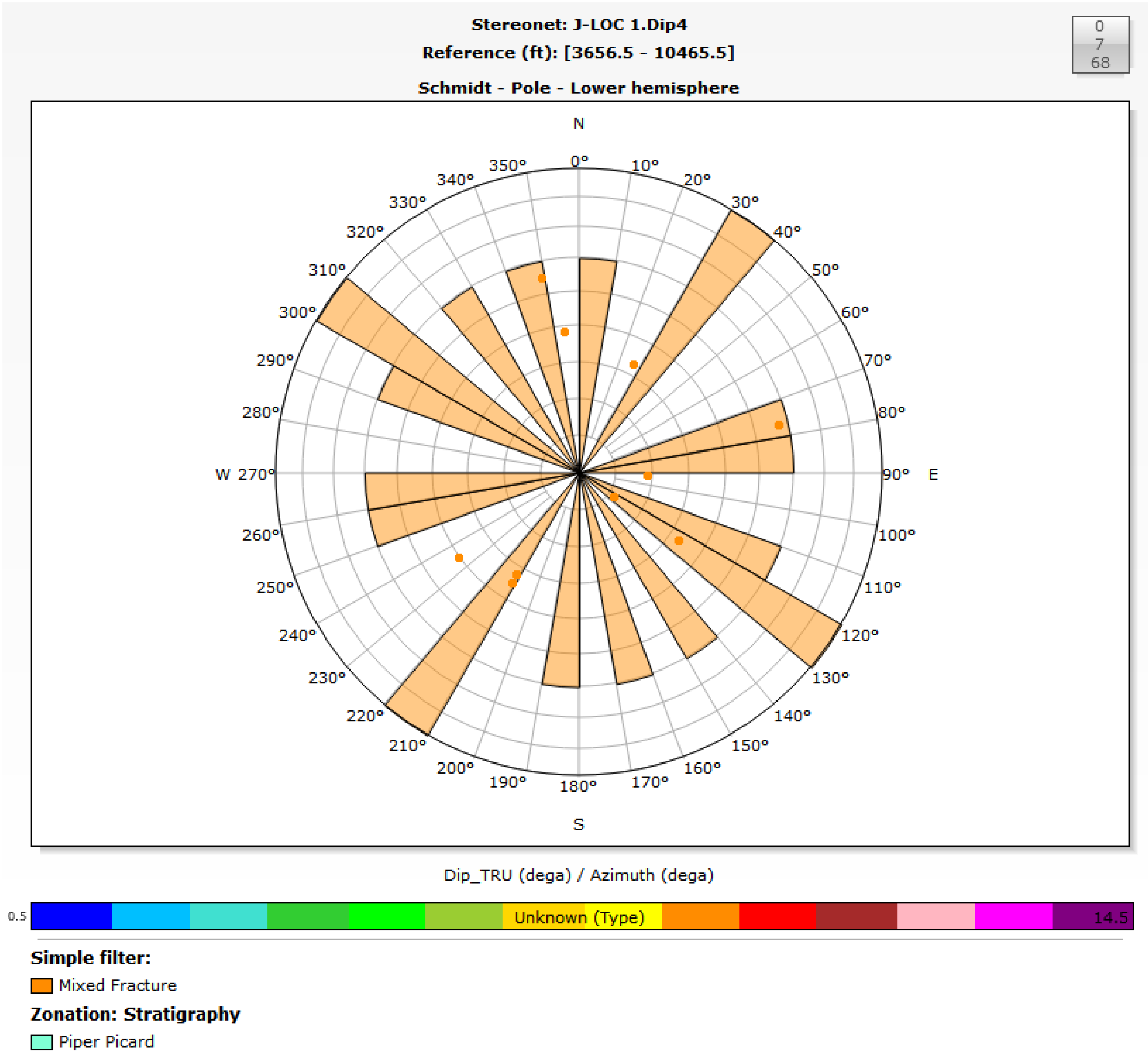


Figure 2-56. Strike orientation of mixed fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

Figure 2-57 shows the logged interval for the Opeche/Spearfish Formation at the J-LOC 1 well. As shown, the section closest to the Broom Creek Formation is dominated by anhydrite layers and compaction features (stylolites) and has corresponding tensional features. The observed stylolites are parallel to bedding and commonly filled with clay minerals. Effectively, these features reduce the porosity of a formation. The midregion of the formation is dominated by electrically resistive features likely due to the presence of anhydrite-filled fractures. Figures 2-58 and 2-59 show two thin-section images and give an indication of different minerals within the reservoir with observed change in the electrical response shown on the image log. The rose diagrams shown in Figures 2-60 through 2-62 provide the orientation of the conductive, resistive, and mixed fractures in the Opeche/Spearfish Formation. The examination of borehole images has effectively pinpointed two small discontinuities, interpreted as healed micro-faults (Figure 2-62b). Displaying an East-West orientation and a dip of 20 to 30 degrees, these features are filled with a resistive material, namely anhydrite. The characteristics of the microfaults including their size suggest they do not have sufficient vertical extent and permeability to act as fluid migration pathways.

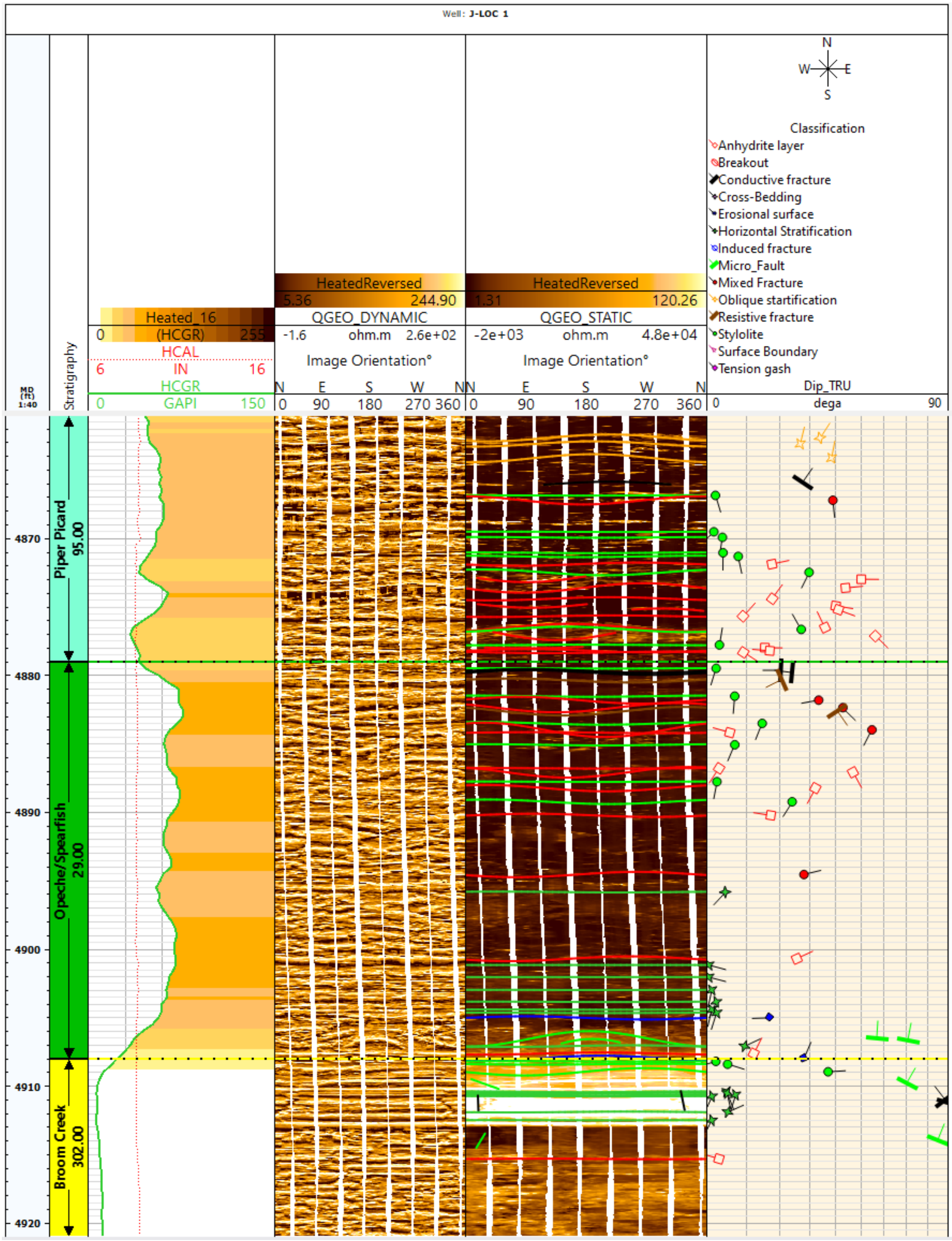


Figure 2-57. Sedimentary and tectonic features in Piper Picard, Opeche/Spearfish, and Broom Creek Formations observed on the borehole image log. The figure shows; Track 1: Gamma-ray (HSGR), Caliper (HCal); Track 2: Borehole dynamic image log; Track 3: Borehole static image log. Track 4: Tectonic and sedimentary tadpoles' orientation. in the interval between 4874 and 4912 ft.

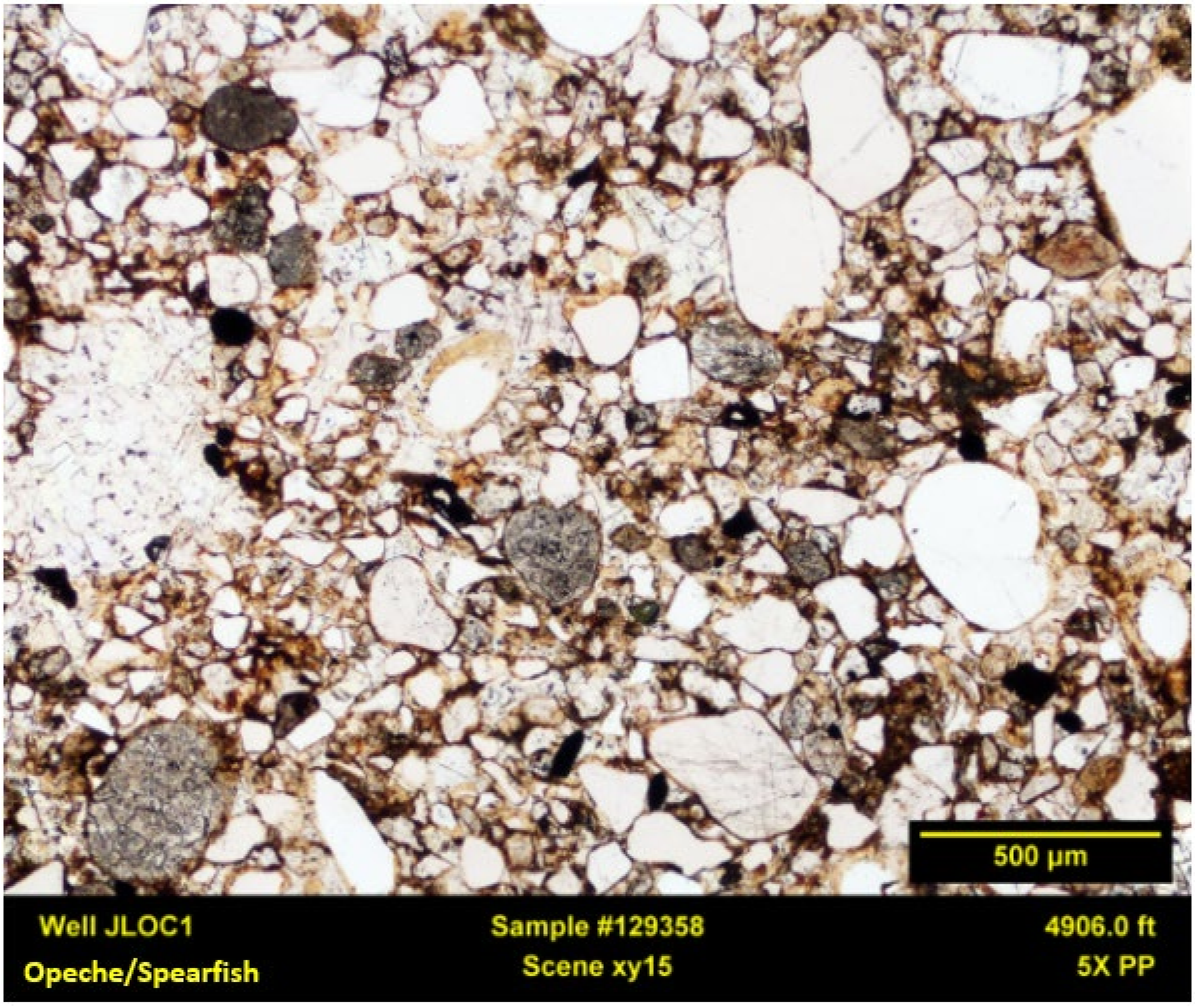


Figure 2-58. Plane-polarized light thin-section image from the J-LOC 1 well Opeche/Spearfish Formation. This image shows the silt-rich nature of this interval of the Opeche/Spearfish Formation. On the example shown, the quartz grains (white) are rimmed by anhydrite and iron.

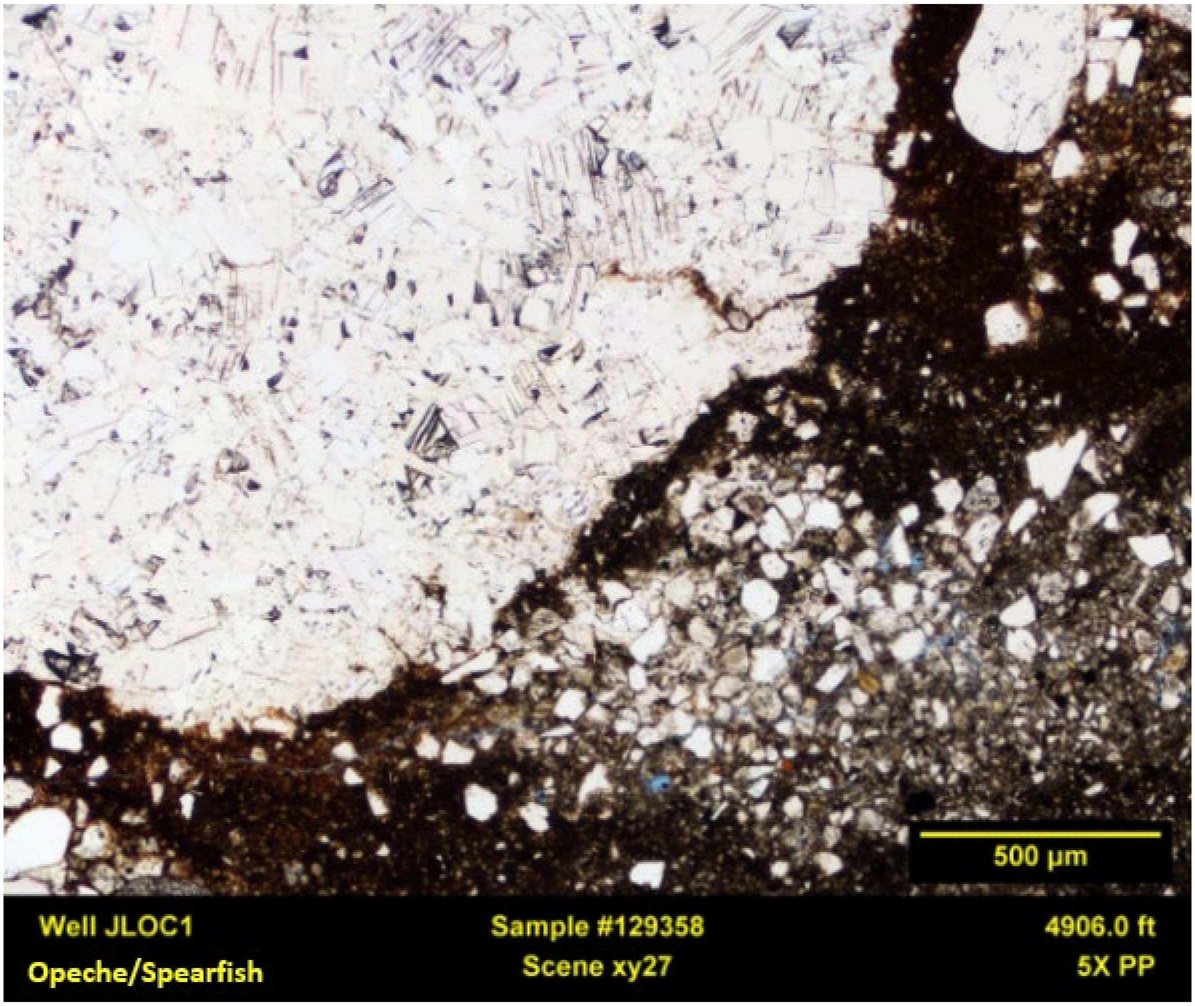


Figure 2-59. Plane-polarized light thin-section image from the J-LOC 1 well Opeche/ Spearfish Formation. This image shows the heterogeneity of this interval. The dark material shown (between the white anhydrite and quartz grains) is clay and is likely responsible for the electrical conductivity identified on the image log.

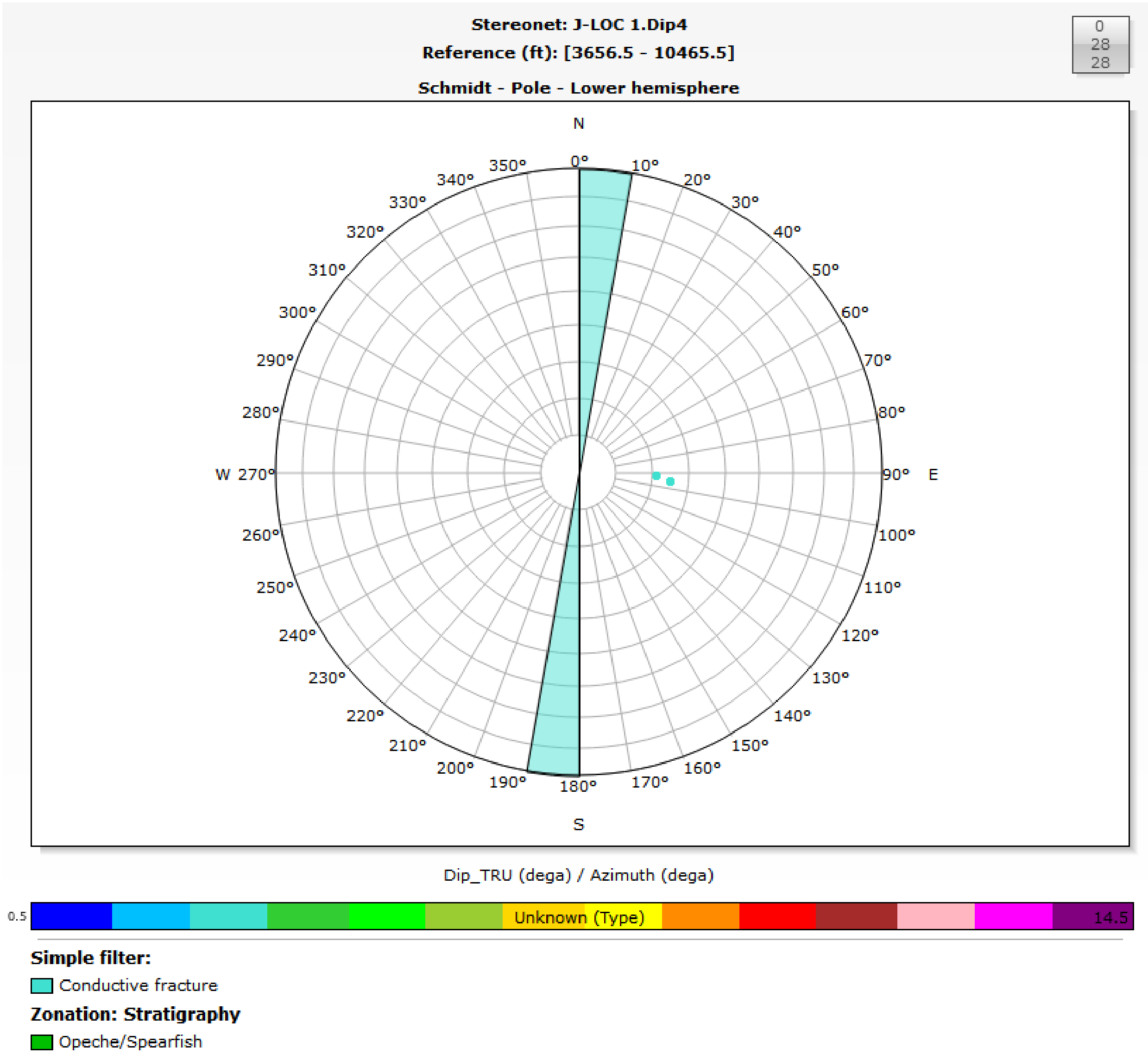


Figure 2-60. Strike orientation of conductive fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

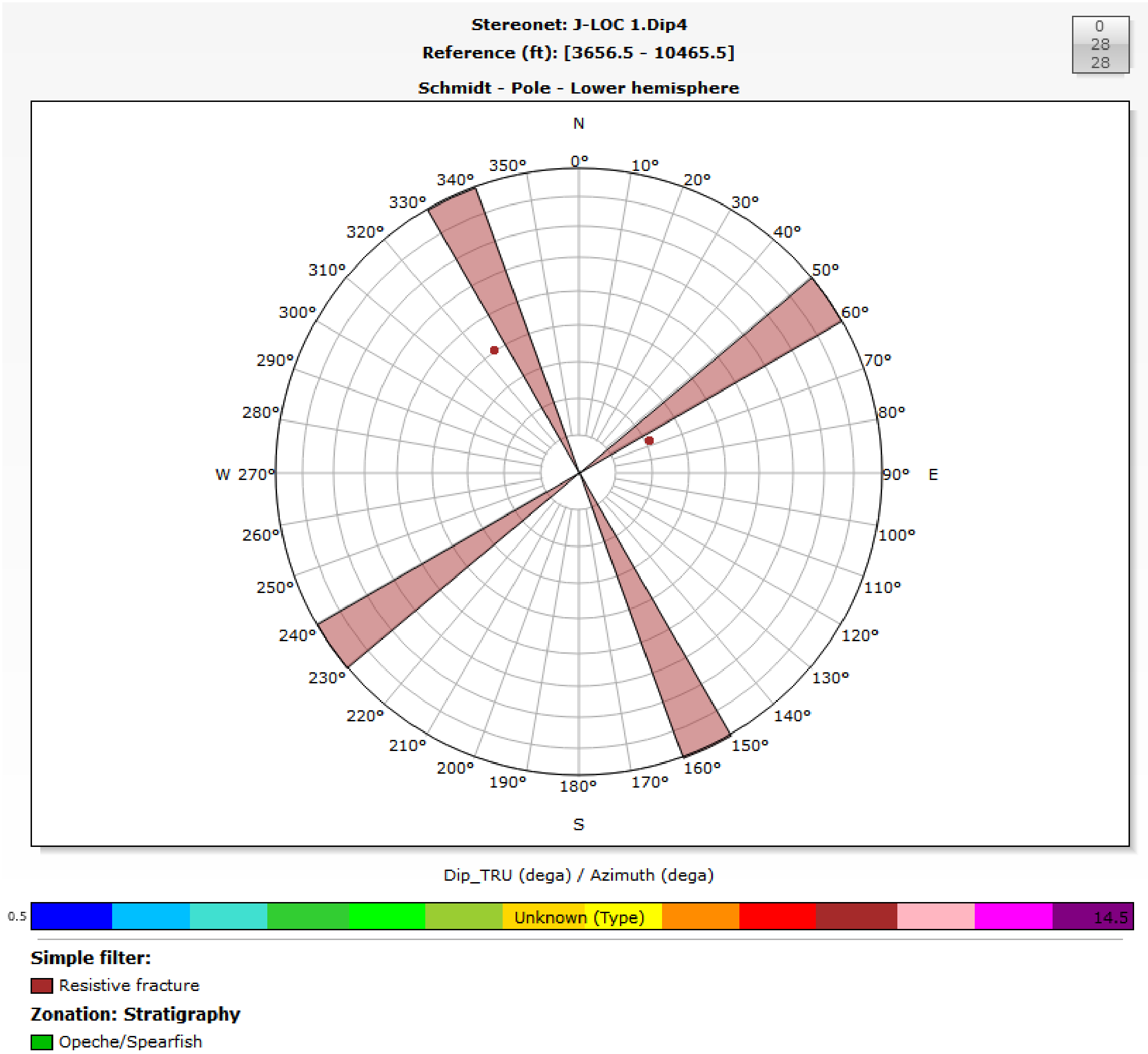


Figure 2-61. Strike orientation of resistive fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

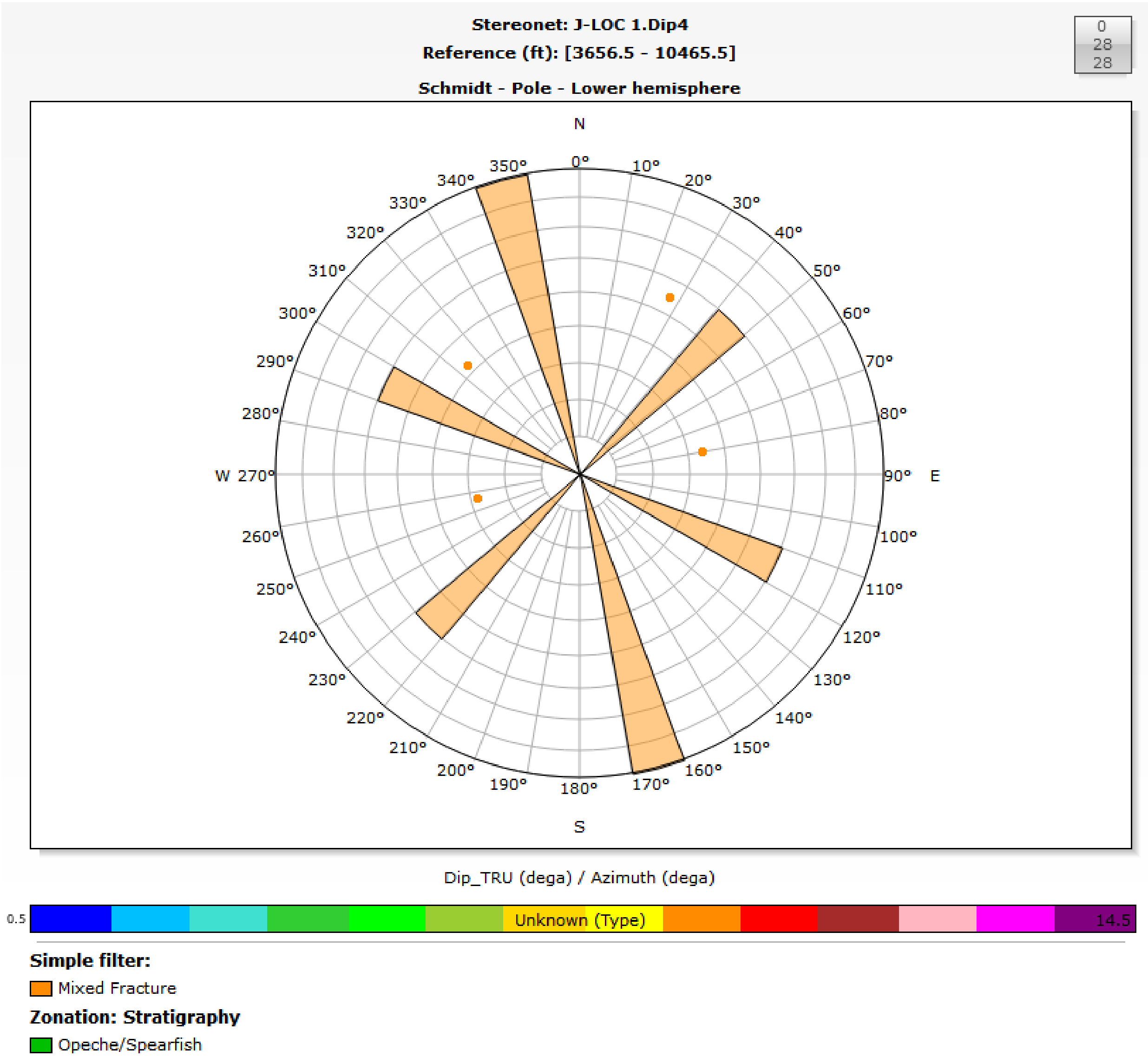


Figure 2-62a. Strike orientation of mixed fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

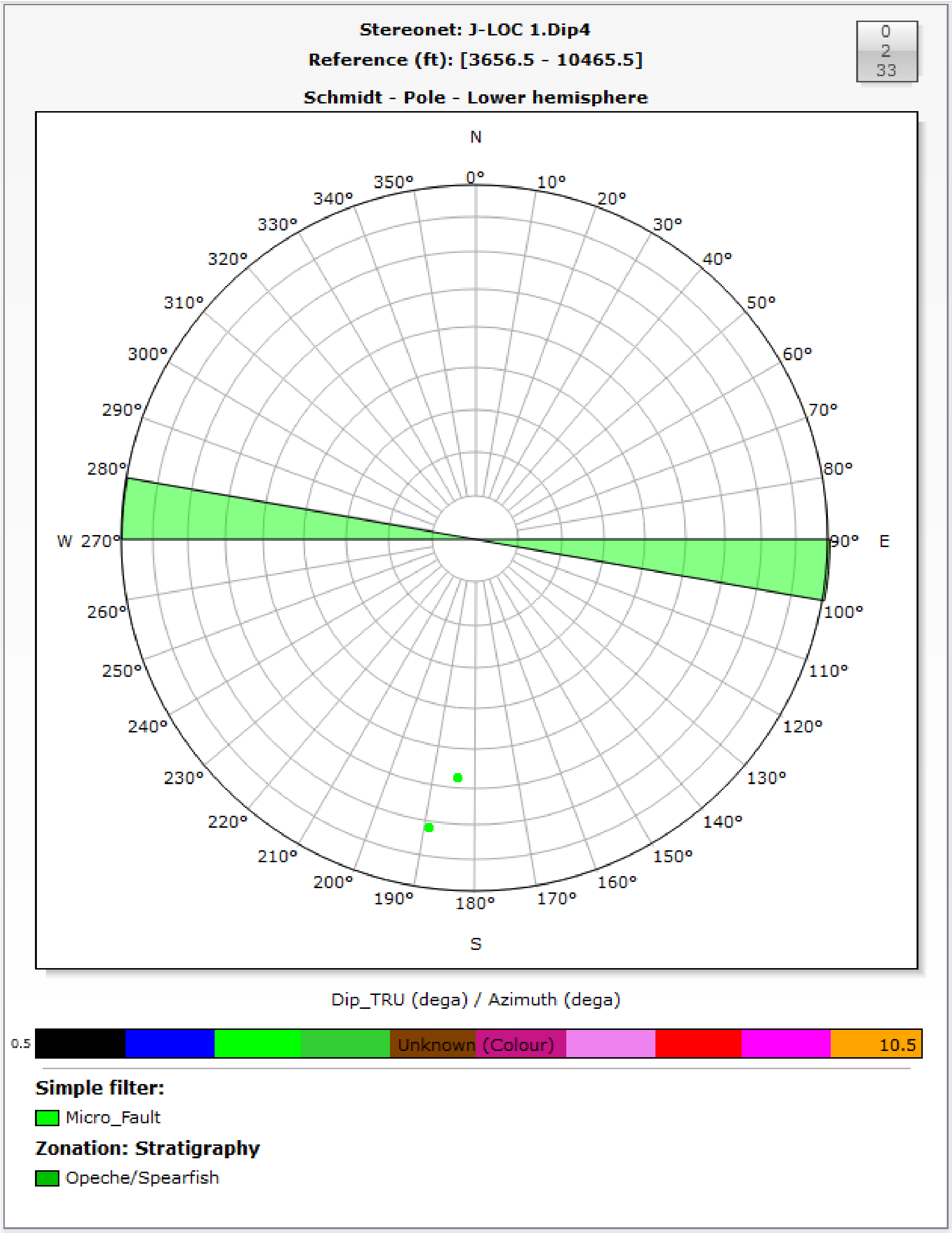


Figure 2-62b. Strike orientation of micro faults that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the microfault.

The logged interval of the Amsden Formation shows that the main features present are stylolite–tension pairs, which are an indication that the formation has undergone a reduction in porosity in response to postdepositional stress. Resistive fractures were also observed in the Amsden Formation (Figure 2-63). The interpretation of this logged interval supports the core-based and thin-section descriptions, suggesting these features are anhydrite-filled. The rose diagrams shown in Figures 2-64 and 2-65 provide the orientation of the mixed and resistive features in the Amsden Formation. As shown in Figure 2-66, only one electrically mixed feature was picked in the Amsden Formation interval with an azimuth-oriented northwest. Some electrically resistive features are present with an azimuth-oriented NE–SW and E–W. Drilling-induced fractures were not identified in the Amsden Formation.

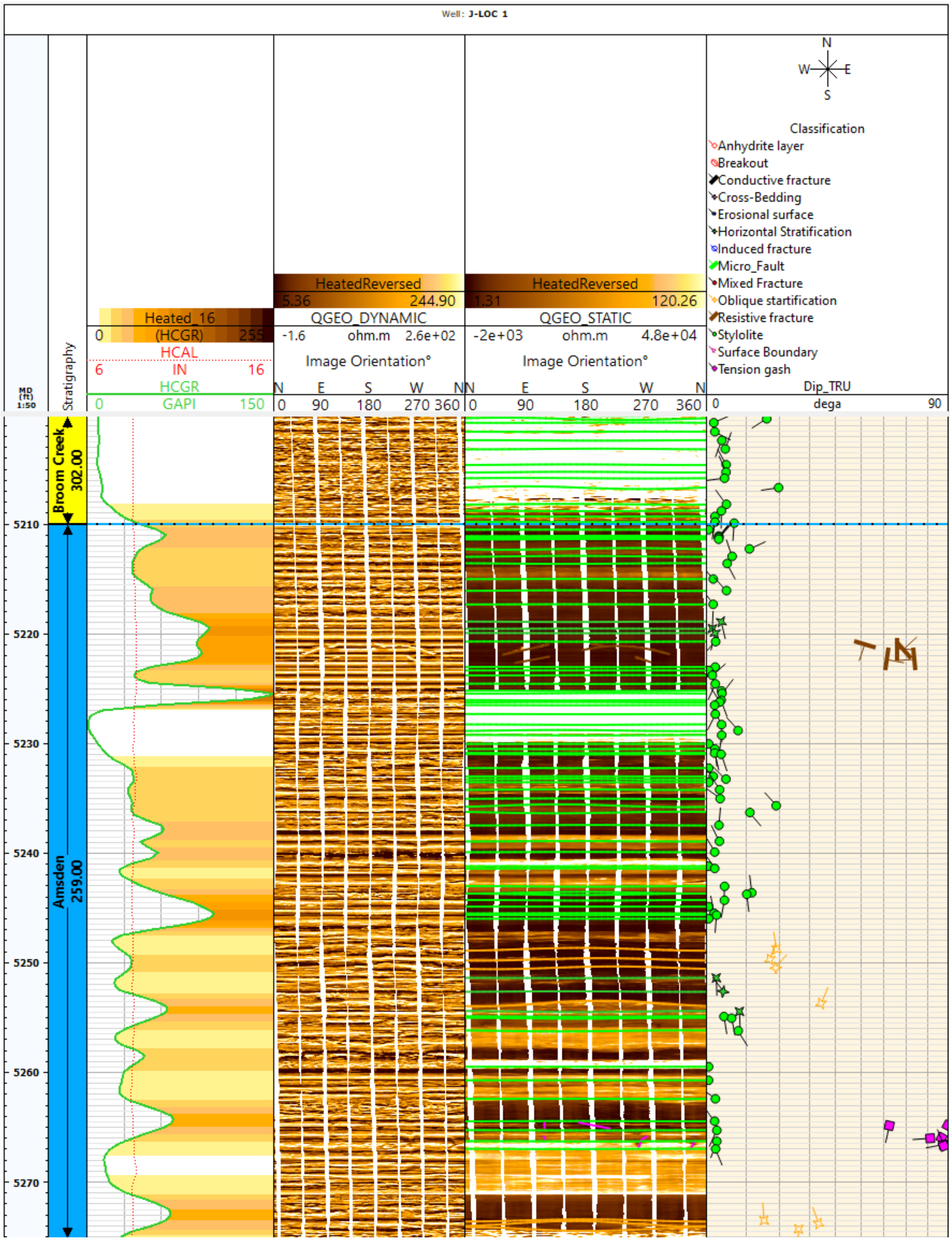


Figure 2-63. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The figure shows; Track 1: Gamma-ray (HSGR), Caliper (HCal); Track 2: Borehole dynamic image log; Track 3: Borehole static image log. Track 4: Tectonic and sedimentary tadpoles' orientation. in the interval between 5204.5 and 5243 ft.

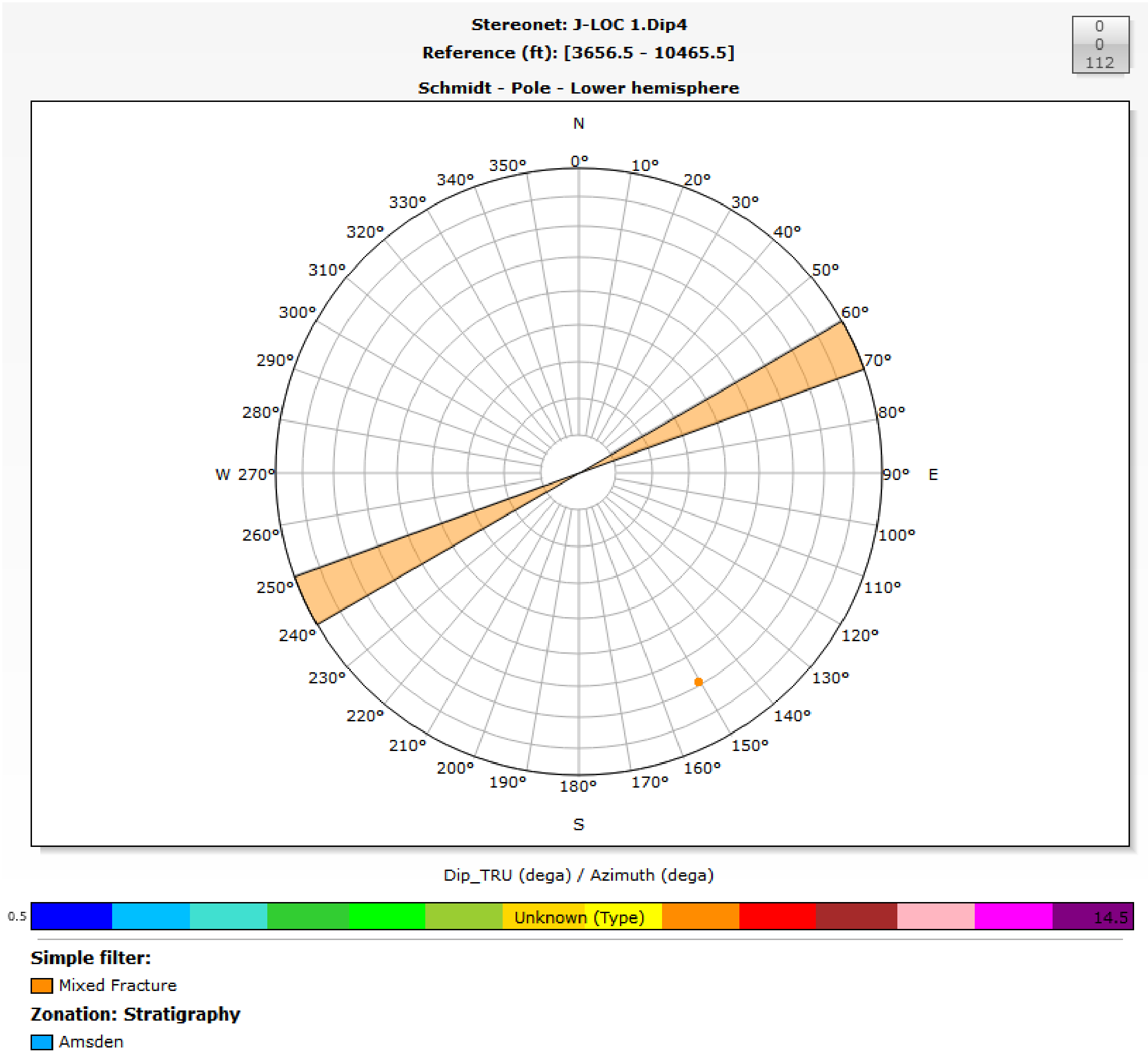


Figure 2-64. Strike orientation of mixed fractures that characterize the Amsden Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

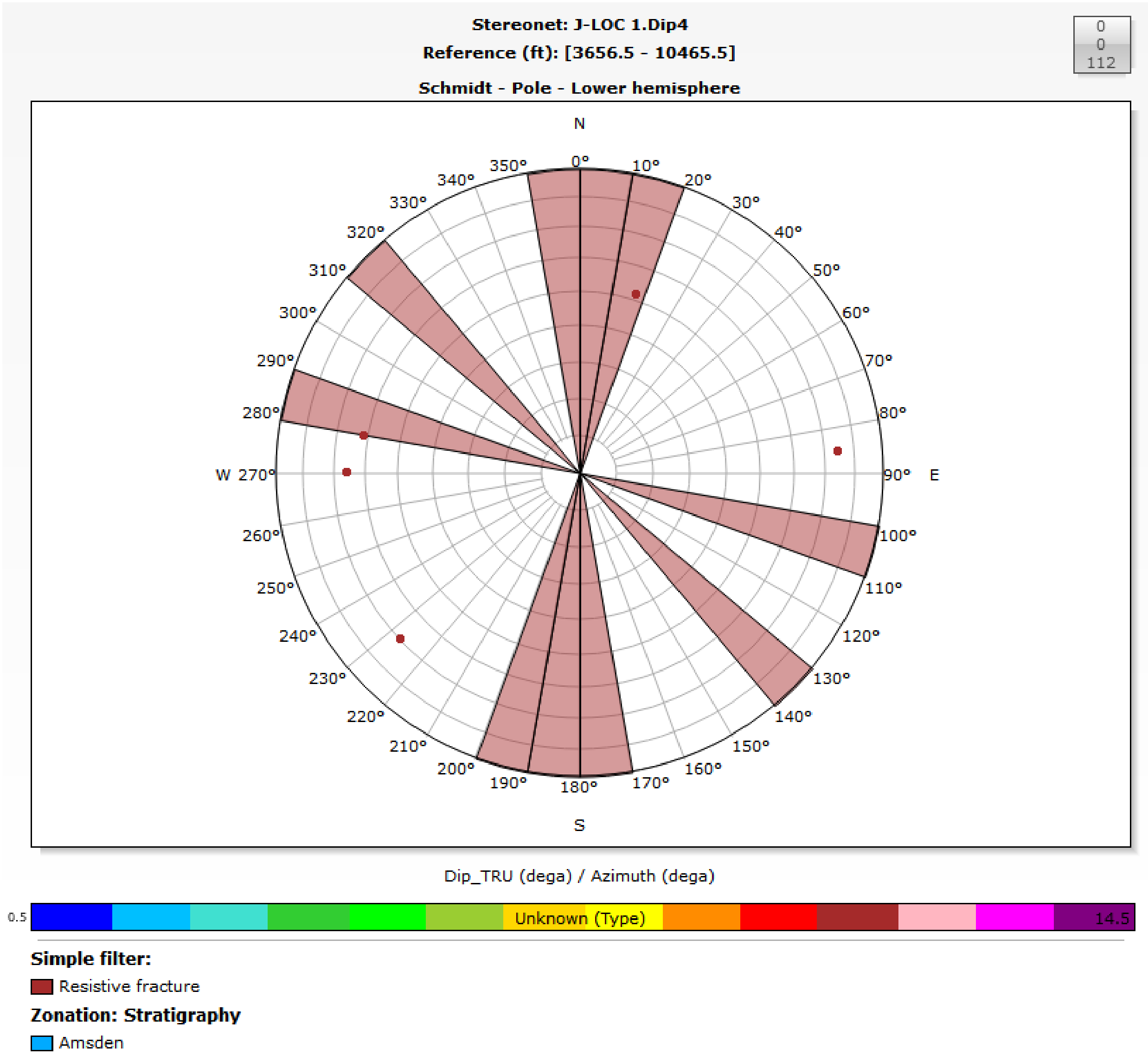


Figure 2-65. Strike orientation of resistive fractures that characterize the Amsden Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

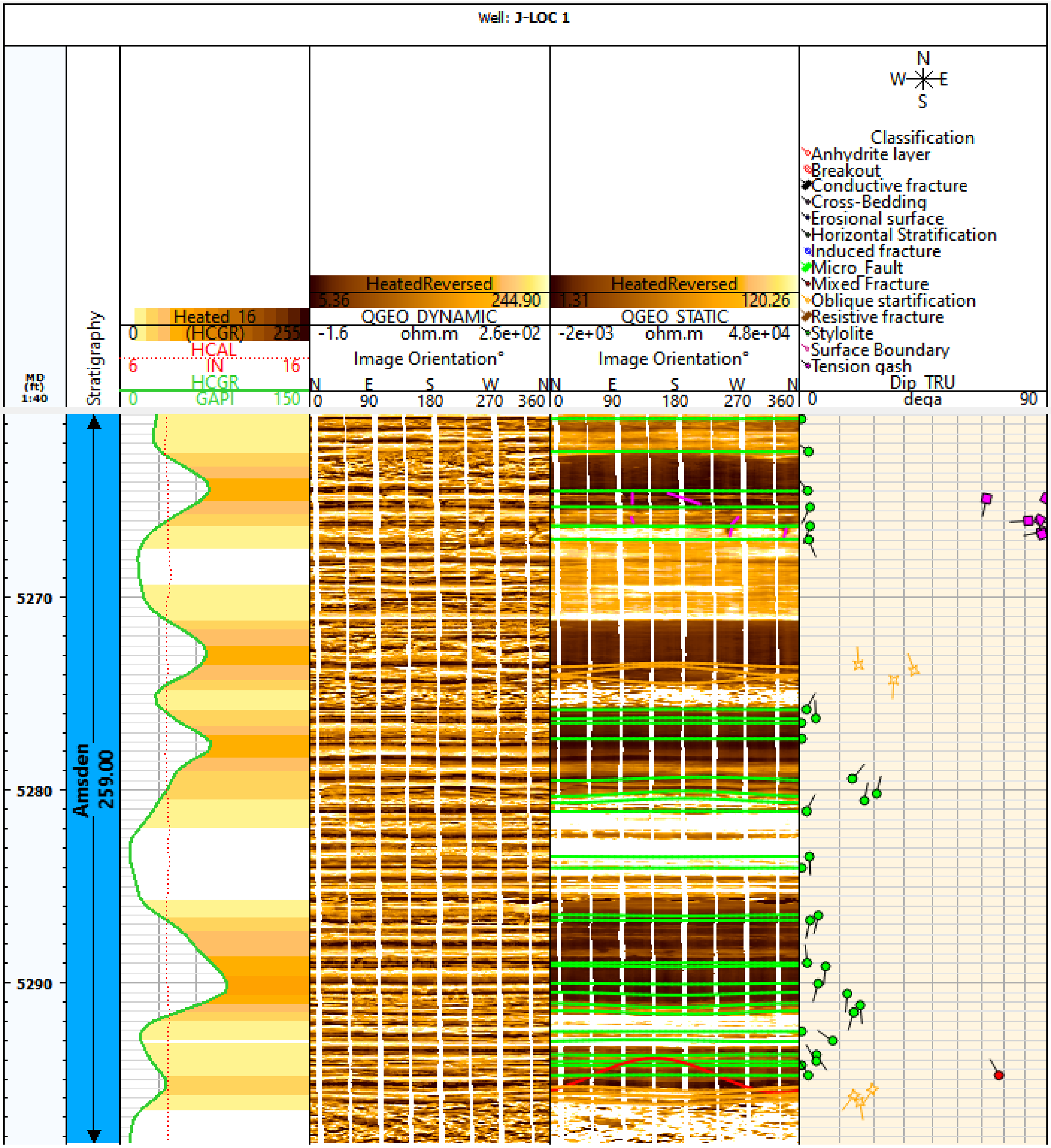


Figure 2-66. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The figure shows; Track 1: Gamma-ray (HSGR), Caliper (HCal); Track 2: Borehole dynamic image log; Track 3: Borehole static image log. Track 4: Tectonic and sedimentary tadpoles' orientation. in the interval between 5260.5 and 5298.5 ft.

2.4.4.4 Stress

J-LOC 1 openhole logging data were used to construct a 1D mechanical earth model (1D MEM) to evaluate geomechanical properties of the Opeche/Spearfish Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties, such as Young's modulus, Poisson's ratio, shear modulus, and bulk modulus, were calculated based on the available well logs. The formation strength properties, like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion, were also estimated from the available data (Figure 2-67). Table 2-20 provides the summary of stresses in the Opeche/Spearfish Formation generated using 1D MEM.

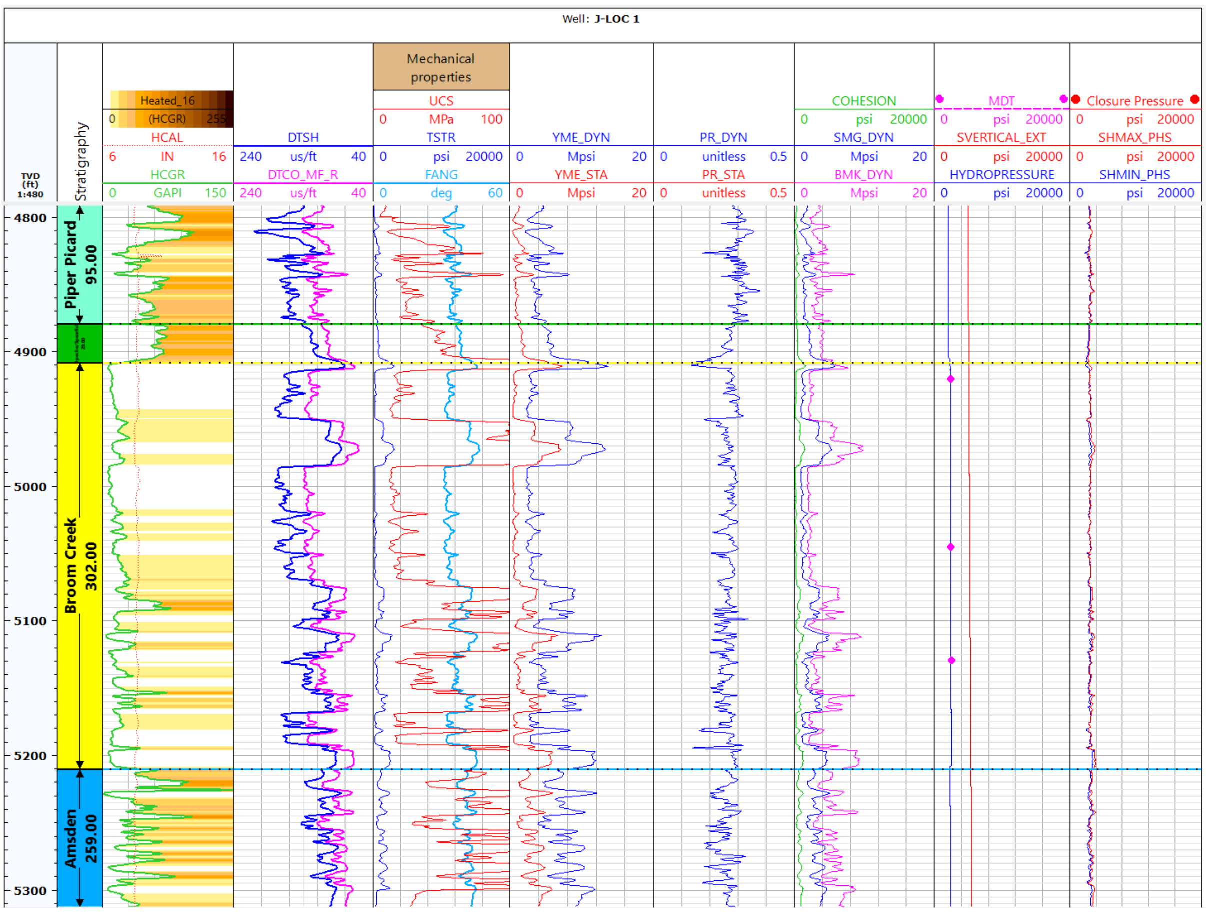


Figure 2-67. J-LOC 1, 1D MEM (Piper Picard, Opeche/Spearfish, Broom Creek, and Amsden Formations). Track1: Gamma-ray (HSGR), caliper (HCal); Track 2: Shear Sonic (DTSH), Compressional Sonic (DTCO); Track 3: Uniaxial Confining Stress (UCS), Tensile Strength (TSTR), Friction angle (FANG); Track 4: Static Young's modulus (YME_Sta) and Dynamic Young's modulus (YME_Dyn); Track 5: Static Poisson's ratio (PR_Sta) and Dynamic Poisson's ratio (PR_Dyn); Track 6: Dynamic Shear Modulus (SMG_Dyn), Dynamic Bulk Modulus (BMK_Dyn), Cohesion.; Track 7: Pore pressure (Hydropressure), MDT, Vertical stress (Svertical); Track 8: Maximum horizontal stress (SHmax_PHS), Minimum horizontal stress (Shmin_PHS), and closure pressure.

Table 2-20. Summary of Stresses Generated Using 1D MEM in Opeche/Spearfish Formation

Depth, ft	Hydrostatic Pressure, psi	Vertical Stress, psi	Minimum Stress, psi
4800	2064	4957	2922
4904	2108	5073	2623

2.4.4.5 *Ductility and Rock Strength*

Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Opeche/Spearfish Formation core in the J-LOC 1 well. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5800 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material. Because of the low porosity and anhydrite mineralogy, the sample was not saturated for testing. Table 2-21 shows the parameters of the sample tested, and Table 2-22 shows the elastic parameters obtained.

Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-68, the sample failed at a maximum stress of 113.8 MPa (16,5053 psi). The final stage (Radial Stage 4) of testing, as shown in yellow (Figure 2-68), has significant residual strength postfailure, indicating a high degree of ductility.

Table 2-21. Multistage Triaxial Test Sample Parameters for the Opeche/Spearfish Formation

Sample and Experiment Information			
Depth:	4905.8 ft	**Rock Type:**	Anhydrite
Formation:	Opeche/Spearfish	**Porosity:**	3.53%
Dry Bulk Density:	2.660 g/cm^3	**Pore Fluids:**	None
Diameter:	25.40 mm	**Entered Length:**	62.99 mm

Table 2-22. Elastic Properties Obtained Through Experimentation for the Opeche/Spearfish Formation: E = Young's Modulus, n = Poisson's Ratio, K = Bulk Modulus, G = Shear Modulus, P = Uniaxial Strain Modulus

Elastic Properties Measured at Different Confining Pressures							
Event	**Conf., MPa**	**Diff., MPa**	**E, GPa**	**n**	**K, GPa**	**G, GPa**	**P, GPa**
1	10.2	10.0	55.14	0.140	25.51	24.19	57.76
2	20.3	20.2	58.07	0.150	27.65	25.25	61.32
3	30.2	30.1	60.84	0.161	29.93	26.20	64.86
4	40.3	40.0	60.94	0.195	33.35	25.49	67.34

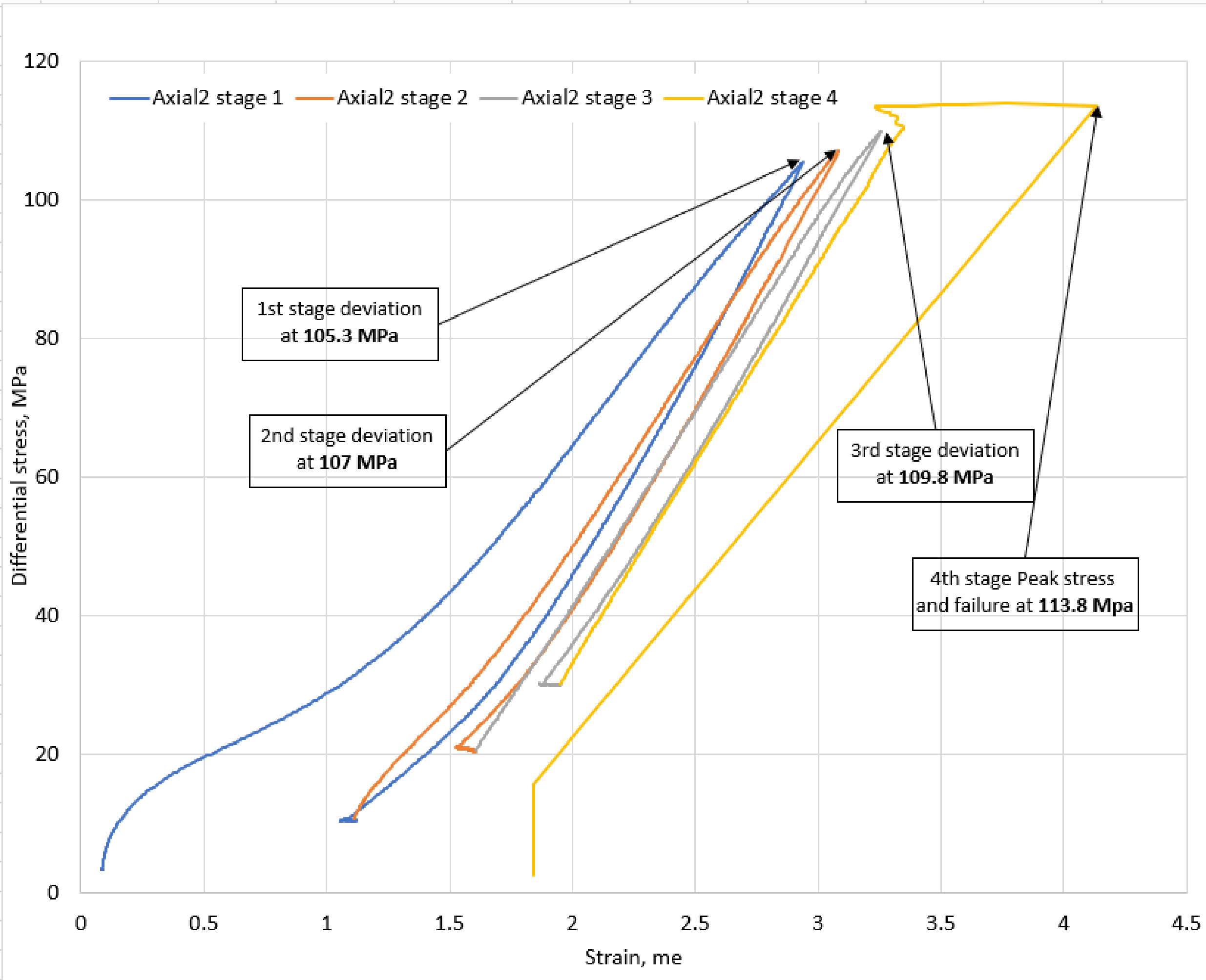


Figure 2-68. J-LOC 1 results of multistage triaxial test performed at confining pressures exceeding 40 MPa (5800 psi), providing information regarding the elastic parameters and peak strength of the anhydrite rock sample. Failure occurred at the Radial Stage 4 peak stress of 113.8 MPa (16,5053 psi).

2.5 Faults, Fractures, and Seismic Activity

2.5.1 Faults and Fractures

In the DCC West SGS area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. A suspected Precambrian basement fault was interpreted in the 3D seismic data set evaluated as part of site characterization (North Dakota Industrial Commission, 2021). This feature is confined to the Precambrian basement which is approximately 4000 feet below the Broom Creek Formation. This suspected fault does not have sufficient vertical extent to allow fluid movement between formations and does not pose a risk for potential induced seismicity.

2.5.2 Seismic Activity

The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that "the Williston Basin as a whole is in an overburden compressive stress regime," which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).

Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 2-23) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The seismic event recorded closest to the DCC West SGS area occurred near Hebron, North Dakota, 35.82 miles from the planned injection wells (Table 2-23). The magnitude of this seismic event is estimated to have been 0.2.

Table 2-23. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)

Date	Magnitude	Depth, mi	Longitude	Latitude	City or Vicinity of Seismic Event	Map Label	Distance to the Injection Wells, mi
Sept. 28, 2012	3.3	0.4*	−103.48	48.01	Southeast of Williston	A	118.89
June 14, 2010	1.4	3.1	−103.96	46.03	Boxelder Creek	B	142.10
March 21, 2010	2.5	3.1	−103.98	47.98	Buford	C	138.32
Aug. 30, 2009	1.9	3.1	−102.38	47.63	Ft. Berthold southwest	D	62.40
Jan. 3, 2009	1.5	8.3	−103.95	48.36	Grenora	E	150.41
Nov. 15, 2008	2.6	11.2	−100.04	47.46	Goodrich	F	68.64
Nov. 11, 1998	3.5	3.1	−104.03	48.55	Grenora	G	161.97
March 9, 1982	3.3	11.2	−104.03	48.51	Grenora	H	159.96
July 8, 1968	4.4	20.5	−100.74	46.59	Huff	I	44.03
May 13, 1947	3.7**	U***	−100.90	46.00	Selfridge	J	75.99
Oct. 26, 1946	3.7**	U***	−103.70	48.20	Williston	K	135.05
April 29, 1927	0.2**	U***	−102.10	46.90	Hebron	L	35.82
Aug. 8, 1915	3.7**	U***	−103.60	48.20	Williston	M	131.19

* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.
*** Unknown depth.

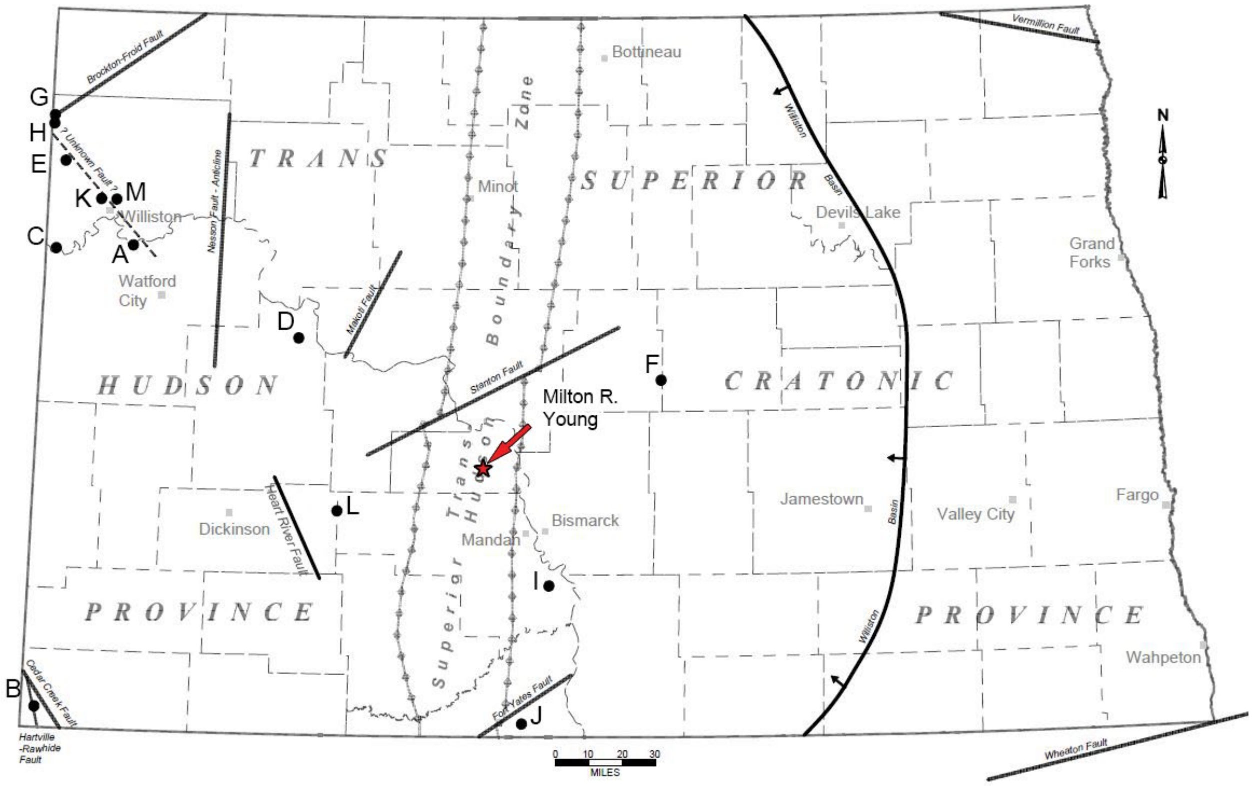


Figure 2-69. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations labeled in Table 2-23.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two damaging seismic events predicted to occur over a 10,000-year time period (Figure 2-70) (U.S. Geological Survey, 2022). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016, determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) state there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic seismic events in North Dakota that could be associated with nearby oil and gas activities. These results indicate relatively stable geologic conditions in the region surrounding the potential injection site. Based upon the review and assessment of 1) the USGS studies, 2) the characteristics of the Broom Creek Formation injection zone and the upper and lower confining zones, 3) the low risk of induced seismicity because of the basin-stress regime, and 4) the history of recorded seismic events, seismic activity will not interfere with containment of the maximum volume of CO_2 proposed to be injected annually over the life of this project.

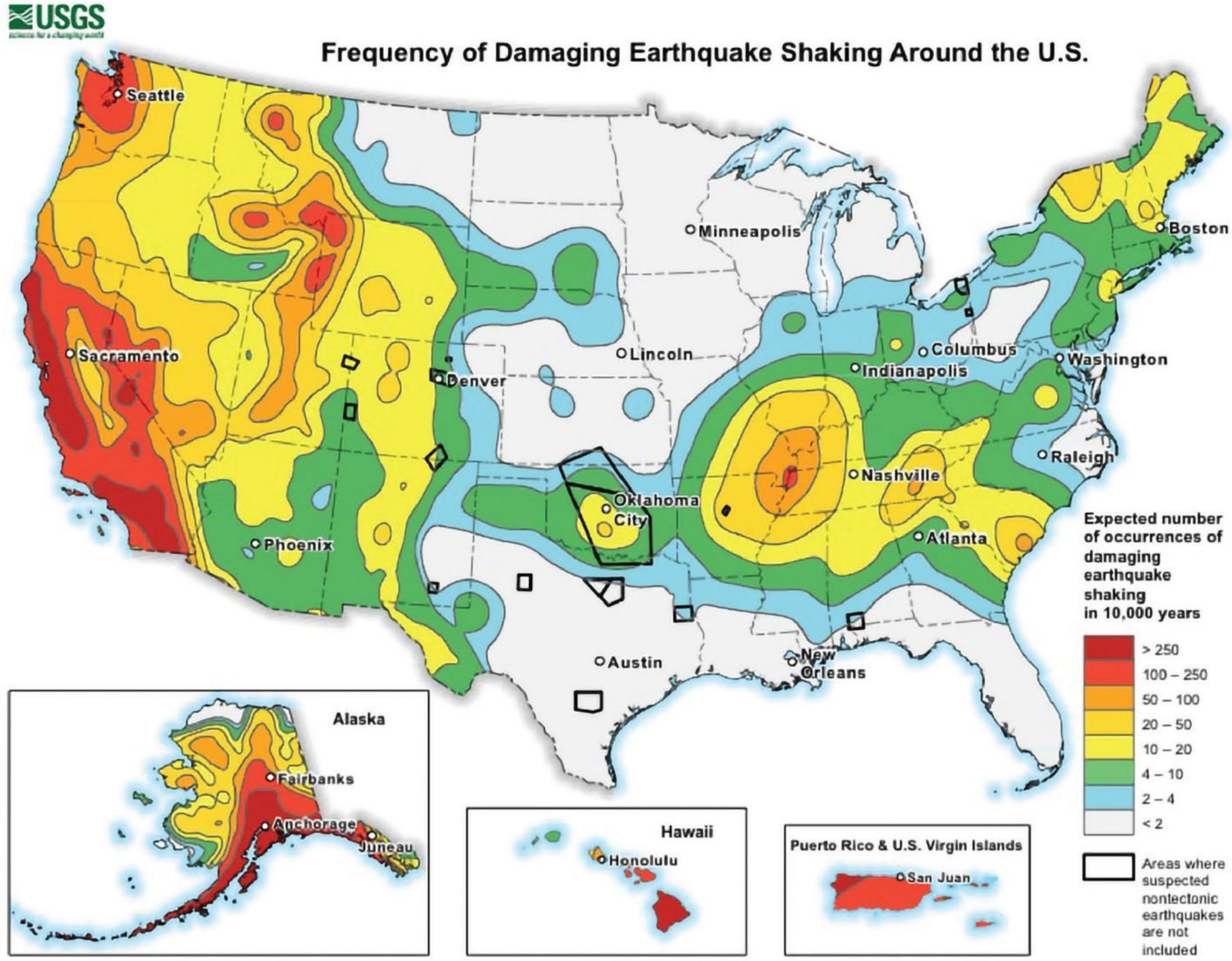


Figure 2-70. Probabilistic map showing how often scientists expect damaging seismic event shaking around the United States (U.S. Geological Survey, 2022). The map shows there is a low probability of damaging seismic events occurring in North Dakota.

2.6 Potential Mineral Zones

The North Dakota Geological Survey recognizes the Spearfish Formation as the only potential oil-bearing formation above the Broom Creek Formation. However, production from the Spearfish Formation is limited to the northern tier of counties in western North Dakota (Figure 2-71). There has been no exploration for, nor development of, hydrocarbon resource from the Spearfish Formation in the DCC West SGS area.

Two of the closest hydrocarbon exploration wells within the storage facility area are the Herbert Dresser 1-34 (NDIC File No. 4937) and the Raymond Henke 1-24 (NDIC File No. 4940) (Figure 2-72). Both wells were drilled in 1970 to explore potential hydrocarbons in the Charles Formation and Red River Formation, respectively. The wells were dry and did not suggest the presence of hydrocarbons. No known producible accumulations of hydrocarbons are in the storage facility area.

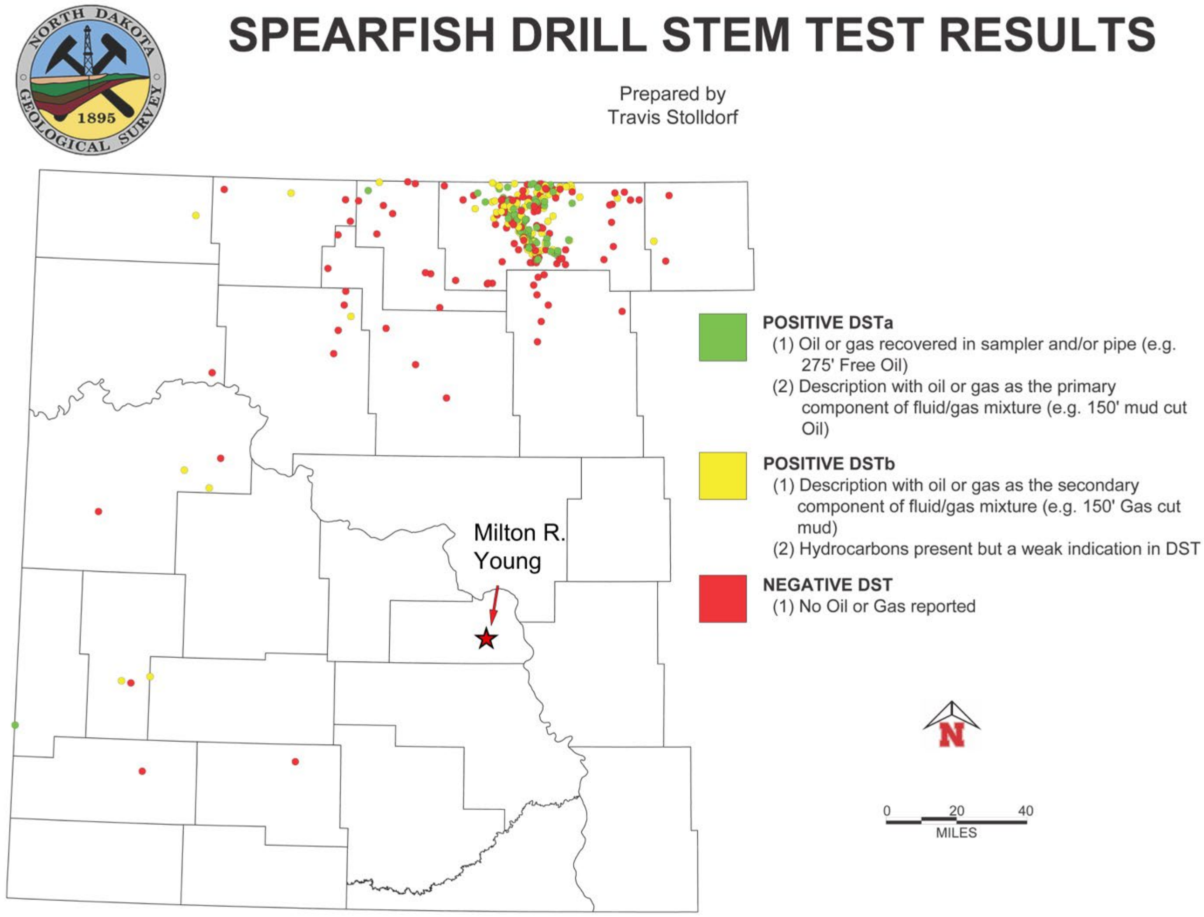


Figure 2-71. Drillstem test (DST) results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020).

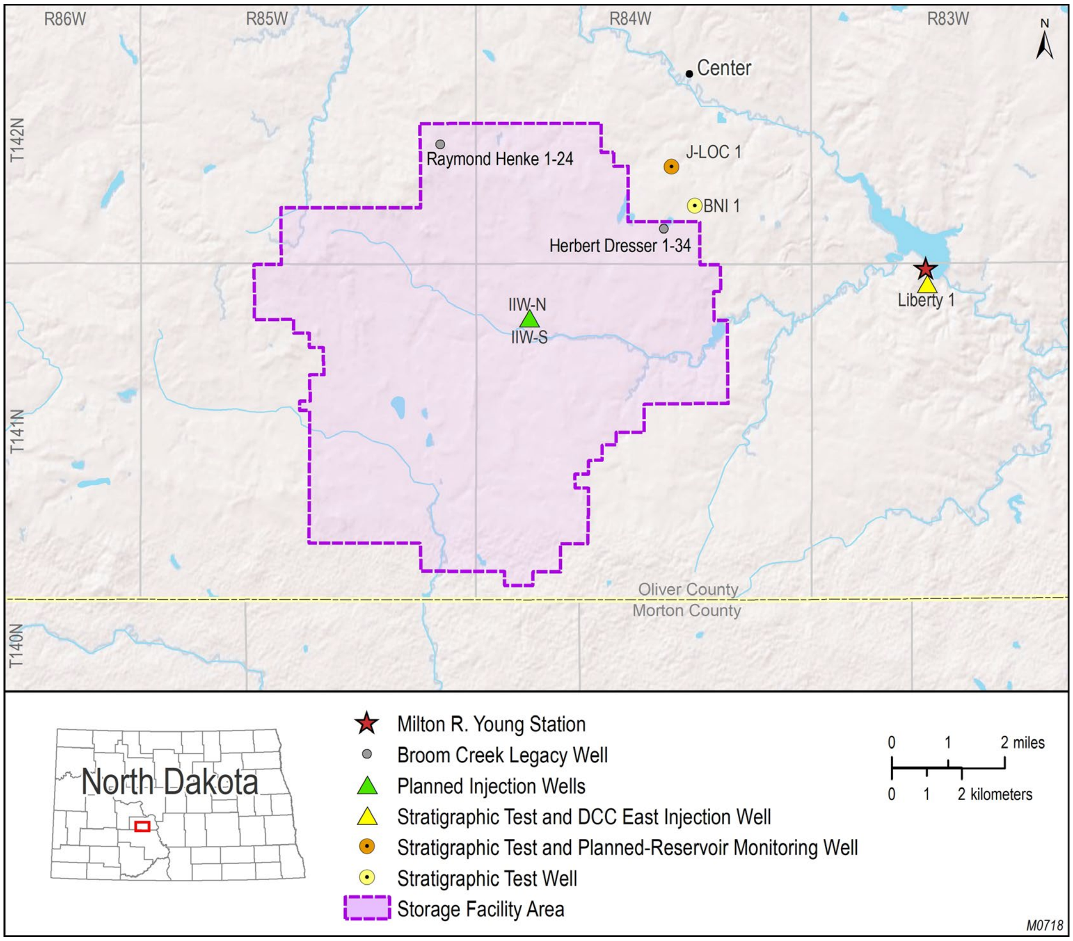


Figure 2-72 Map showing location of Raymond Henke 1-24 (NDIC File No. 4940) and Herbert Dresser 1-34 (NDIC File No. 4937) relative to DCC West SGS.

Shallow gas resources can be found in many areas of North Dakota. NDCC § 57-51-01 defines shallow gas resources as gas produced from a zone that consists of strata or formation, including lignite or coal strata or seam, located above the depth of 5000 feet below the surface, or located more than 5000 feet below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced.

Lignite coal currently is mined in the area of the Center Mine, operated by BNI Coal. The Center Mine currently mines the Hagel coal seam for use as fuel at MRYS. The Hagel coal seam is the lowermost major lignite present in this area of the Sentinel Butte Formation.

Thickness of the Hagel coal seam averages 7.8 ft in the area permitted to be mined but varies, with some areas exceeding 10 ft in thickness (Figure 2-73) (Zygarlicke and others, 2019). Coal seams in the Bullion Creek Formation exist in the area below the Hagel seam, but currently the Hagel is the only economically minable seam with its thickness and overburden of 100 ft or less (Figure 2-74). The Hagel and other coal seams in the Fort Union Group thicken and deepen to the west. The overlying Beulah–Zap coal seam has pinched out farther to the west but is economically minable in the central part of Mercer County. The Hagel seam pinches out to the east, and no other coal seams are mined farther east than the Hagel.

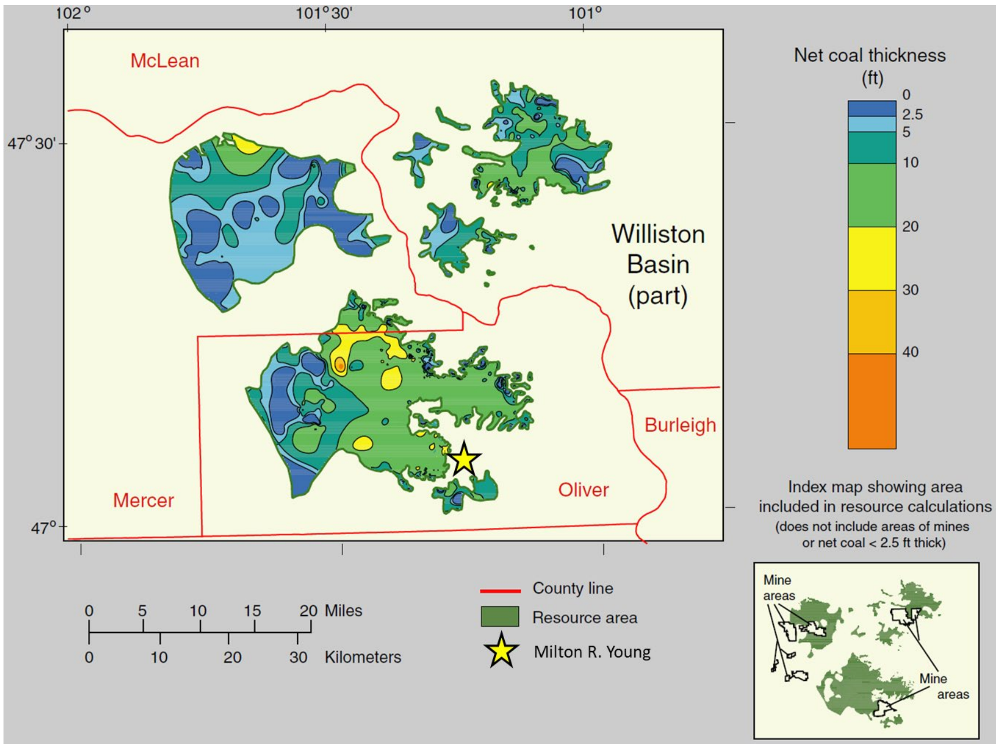


Figure 2-73. Hagel net coal isopach map (modified from Ellis and others, 1999).

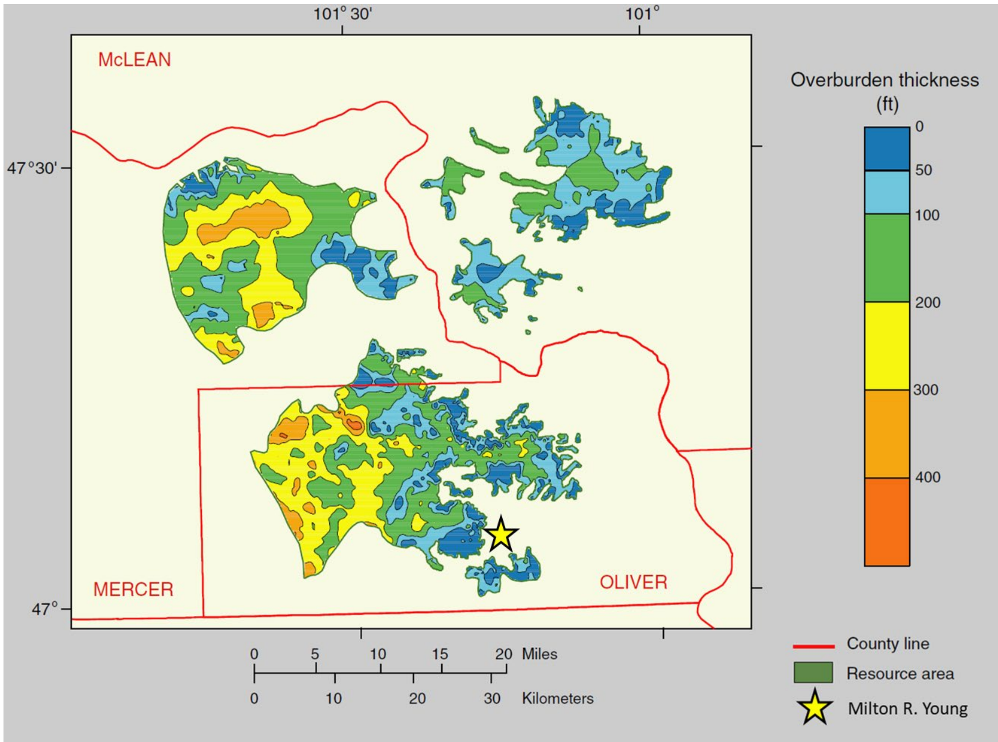


Figure 2-74. Hagel overburden isopach map (modified from Ellis and others, 1999).

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SECTION 3.0

GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

3.1 Introduction

Existing and site-specific subsurface data were analyzed and interpreted (Section 2.2). The data and interpretations were used as inputs to Schlumberger's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone (the Broom Creek Formation), the upper confining zone (the Opeche–Picard interval was divided into two zones: the lower Piper Formation [Picard Member] and the Opeche/Spearfish Formation) and the lower confining zone (the Amsden Formation). The geologic model encompasses a 4070-mi^2 (74-mi × 55-mi) area around the proposed DCC West SGS to characterize the geologic extent, depth, and thickness of the subsurface geologic strata (Figure 2-3). Geologic properties were distributed within the 3D model, including facies, porosity, and permeability.

The geologic model and properties served as inputs for numerical simulations of CO_2 injection using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd., 2019). Numerical simulations of CO_2 injection were conducted to assess potential CO_2 injection rate, disposition of injected CO_2, wellhead pressure (WHP), bottomhole pressure (BHP), and pressure changes in the storage reservoir throughout the expected injection time frame and postinjection period. Results of the numerical simulations were then used to determine the project's area of review (AOR) pursuant to North Dakota's geologic CO_2 storage regulations.

3.2 Overview of Simulation Activities

3.2.1 Modeling of the Injection Zone and Overlying and Underlying Seals

A geologic model was constructed to characterize the injection zone along with the upper and lower confining zones. Activities included data aggregation, structural framework creation, data analysis, and property distribution. Major inputs for the geologic model included geophysical logs from nearby wells and core sample measurements, which acted as control points during the distribution of the geologic properties throughout the modeled area, and seismic survey data. The geologic properties distributed throughout the model include acoustic impedance (AI), total porosity, effective porosity, permeability, and facies.

Three 3D seismic AI volumes (Figure 2-7) were resampled to the geologic model grid (Figure 2-3). The volumes were used to guide the facies and petrophysical property distributions within the 3D geologic model and determine lateral heterogeneity through a variogram assessment. Horizontal variogram directions and structures were determined from the resampled 3D Beulah seismic AI volume because it covered the largest areal extent and captured multiple dune structures, producing the most reliable variogram calculation.

3.2.2 Structural Framework Construction

Schlumberger's Petrel software was used to interpolate structural surfaces for the lower Piper (Picard Member), undifferentiated Opeche/Spearfish, Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) database; core data collected from the Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, Flemmer 1, ANG 1, J-LOC 1, Liberty 1, BNI 1, MAG 1, and Coteau 1 wells (Figure 2-4);

and three 3D seismic surveys and approximately 45 miles of 2D seismic lines (Figure 2-7). The interpolated data were used to constrain the model extent in 3D space.

3.2.3 Data Analysis and Property Distribution

3.2.3.1 Confining Zones (lower Piper, Opeche/Spearfish, and Amsden Formations)

The upper confining zone (lower Piper and Opeche/Spearfish Formations) and the lower confining zone (Amsden Formation) were each assigned a single facies, based on their primary lithology determined by well log analysis to be siltstone for the upper confining zone and dolostone for the lower confining zone. AI, porosity, and permeability logs were upscaled from a well log scale to the scale of the geologic model grid to serve as control points for property distributions. The control points were used in combination with variograms, Gaussian random function simulation algorithms, and secondary trend data to distribute the properties. A 6800-ft major and minor axis length variogram model in the lateral direction and a 160-ft vertical variogram length were used within the lower Piper Formation. An 8200-ft major and 7500-ft minor axis length variogram model along an azimuth of 144° and 90-ft vertical variogram length were used for the Opeche/Spearfish Formation. A major axis length of 6500 ft and a minor axis length of 5300 ft along an azimuth of 180° in the lateral direction and 13-ft vertical length were used for the Amsden Formation. Vertical variogram lengths were determined from the upscaled well logs.

3.2.3.2 Injection Zone (Broom Creek Formation)

Seismic data were resampled to the geologic model grid and used to determine lateral heterogeneity through a variogram assessment. Nonreservoir facies (dolostone, anhydrite) captured a major axis range of 8200 ft and a minor axis range of 6000 ft in the lateral direction. Reservoir facies (sandstone, dolomitic sandstone) captured a major axis range of 5000 ft and a minor axis range of 4500 ft along an azimuth of 45°. Vertical variogram lengths were determined from the upscaled well logs (Table 3-1.)

Table 3-1. Lateral and Vertical Variogram Lengths for Facies Distributions Within the Injection Zone

Facies	Azimuth, degrees	Major Length, ft	Minor Length, ft	Vertical length, ft
Sandstone	45	5000	4500	30
Dolostone	90	8200	6000	35
Dolomitic Sandstone	45	5000	4500	28
Anhydrite	90	8200	6000	17

AI from 3D seismic surveys was upscaled to the resolution of the geologic model grid to serve as control points for facies and petrophysical property distributions. Calculated AI logs, derived from available sonic (ΔT) and bulk density (RHOB) well logs in the project area, were also upscaled to aid in discovering trends between well log data and seismic AI data and serve as additional control points for property distributions. After a trend between the AI data and well logs was identified, an AI property was then distributed throughout the model using the upscaled seismic AI data and upscaled AI logs as control points, the horizontal variogram parameters described above, and Gaussian random function simulation algorithms.

Facies classifications were interpreted from well log data and correlated with descriptions of core taken from the Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, Flemmer 1, ANG 1, J-LOC 1, Liberty 1, BNI 1, MAG 1, and Coteau 1 wells. Four facies were modeled within the Broom Creek Formation: 1) sandstone, 2) dolostone, 3) dolomitic sandstone, and 4) anhydrite (Figure 2-10). Facies logs were generated from gamma ray, density, neutron porosity, sonic, and resistivity logs. Seismic facies probability volumes interpreted from the 3D Beulah seismic area were used to guide the facies distribution. Three probability volumes corresponding to the predominant facies of sandstone, dolostone, and dolomitic sandstone were resampled into the geologic model (Figures 3-1 and 3-2). Upscaled mineral fraction logs were also used to generate a facies trend model, which was guided by the resampled seismic probability, kriging algorithm, and variogram ranges described above. The facies logs were upscaled to the resolution of the 3D model to serve as control points for geostatistical distribution using sequential indicator simulation and guided by the facies trend model (Figure 2-13).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE; total porosity less occupied or isolated pore space), and permeability (K_{int}) well logs were estimated and compared with core porosity and permeability measurements to ensure good agreement with the ten cored wells: Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, Flemmer 1, ANG 1, J-LOC 1, Liberty 1, BNI 1, MAG 1, and Coteau 1. A PHIE property was distributed using calculated PHIE well logs, upscaled to the resolution of the 3D model as control points, variogram structures described previously with Gaussian random function simulation and AI volume cokriging, and conditioned to the distributed facies (Figure 3-3). A K_{int} property was distributed using the same variogram structures and Gaussian random function algorithm but was paired with PHIE volume cokriging.

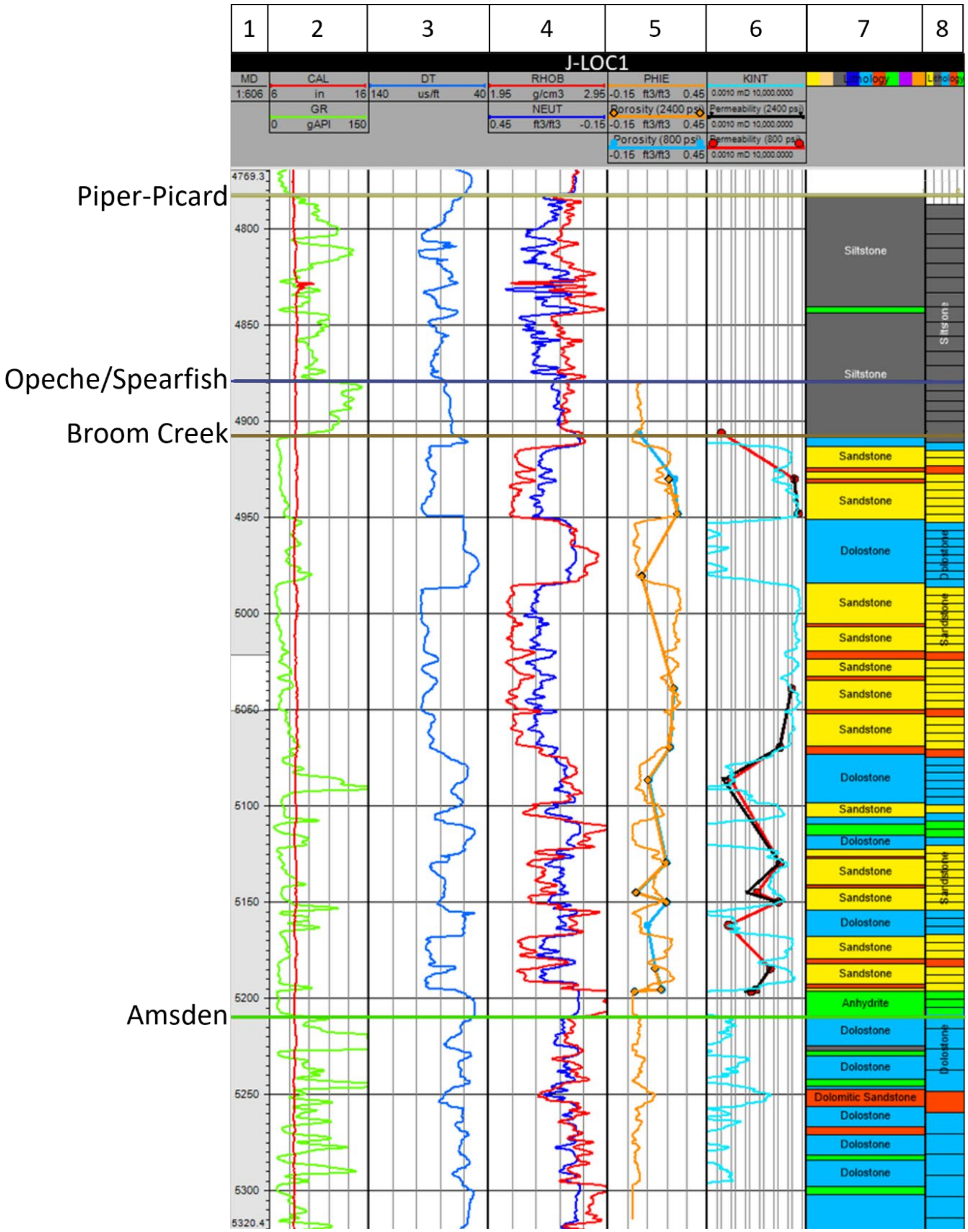


Figure 3-1. Facies classification in wells J-LOC 1. Well logs displayed in tracks from left to right are 2) gamma ray (green) and caliper (red); 3) delta time (blue); 4) neutron porosity (dark blue), density (red); 5) porosity (orange) core porosity (orange and blue dots); 6) permeability (light blue) and core permeability (black and red dots); 7) interpreted facies (lithology) log; and 8) upscaled facies (lithology).

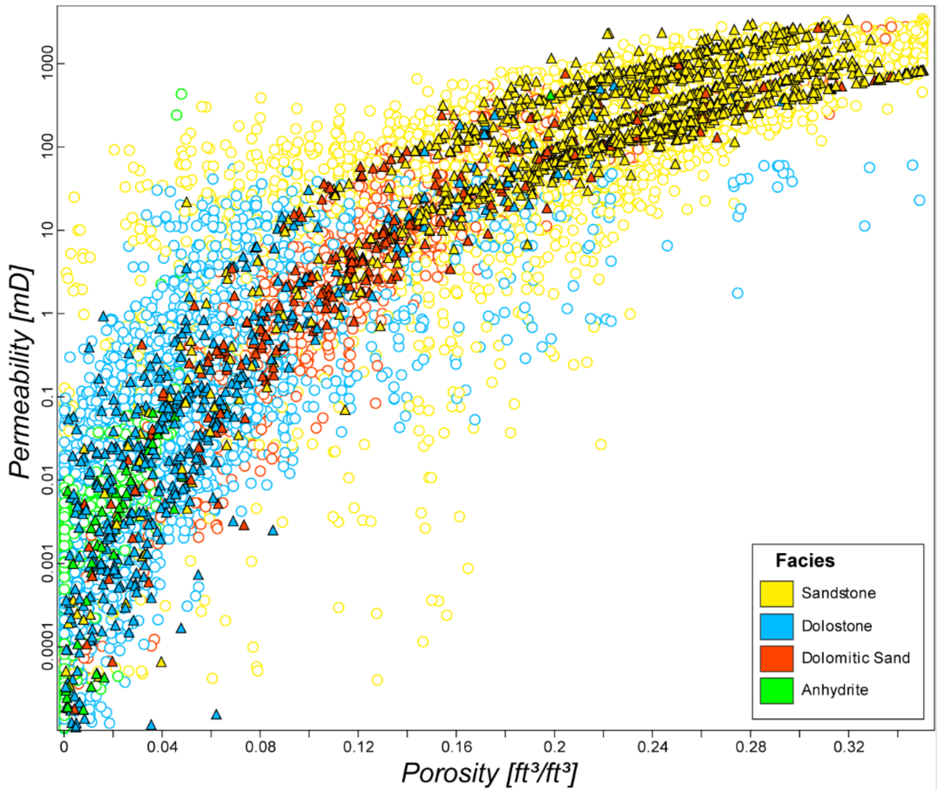


Figure 3-2. Illustration of the relationship between the modeled porosity and permeability. Upscaled well log values are represented by triangles, while circles represent distributed values.

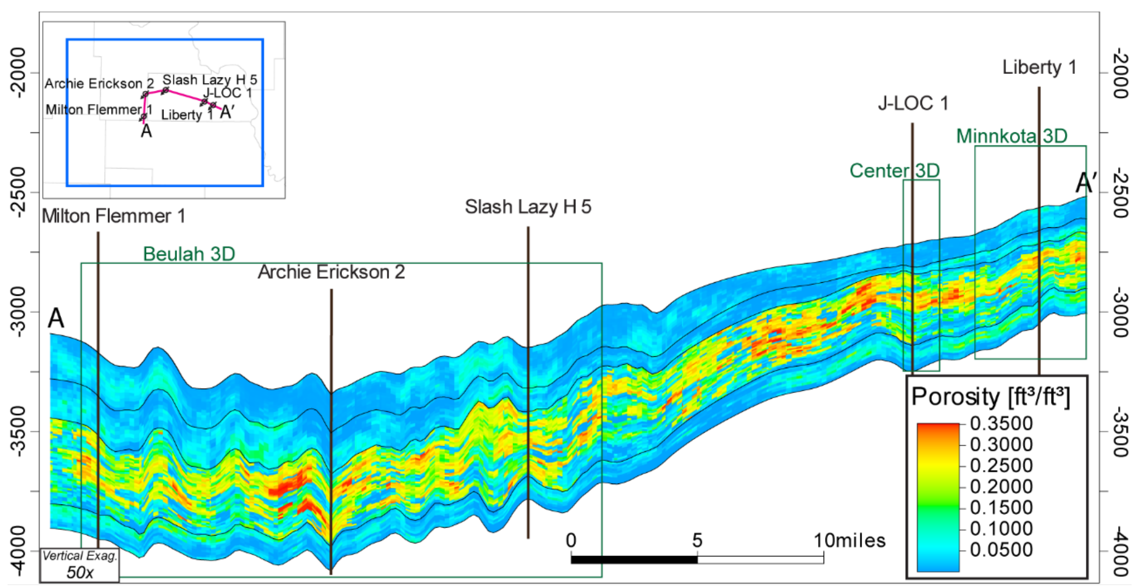


Figure 3-3. Distributed PHIE property along a W–E cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (50× vertical exaggeration shown).

3.3 Numerical Simulation of CO_2 Injection

3.3.1 Simulation Model Development

Numerical simulations of CO_2 injection into the Broom Creek Formation were conducted using the geologic model described above. Simulations were carried out using CMG's GEM, a compositional reservoir simulation module. Both measured temperature and pressure, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figures 3-4a and 3-4b display a 3D and aerial view, respectively, of the simulation model with the permeability property and proposed injection wells (IIW-S and IIW-N) for DCC West SGS. The Liberty 1 and Unity 1 wells were also included to represent the injection site identified for the storage facility created and permitted by NDIC Order No. 31583 (DCC East Center Broom Creek Storage Facility #1).

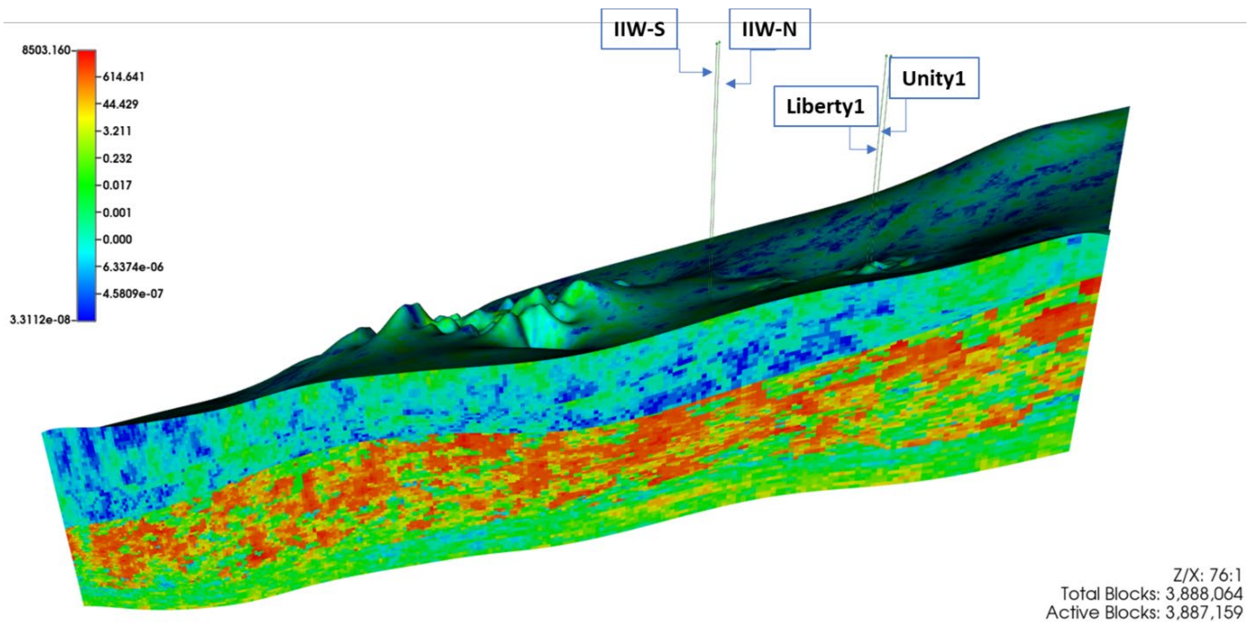


Figure 3-4a. 3D view of the simulation model with the permeability property and injection wells displayed. The low-permeability layers (blue and green) at the top and bottom of the figure should be noted. These layers represent the Opeche–Picard interval (upper confining zone) and the Amsden Formation (lower confining zone). The varied permeability of the Broom Creek Formation is shown between these layers.

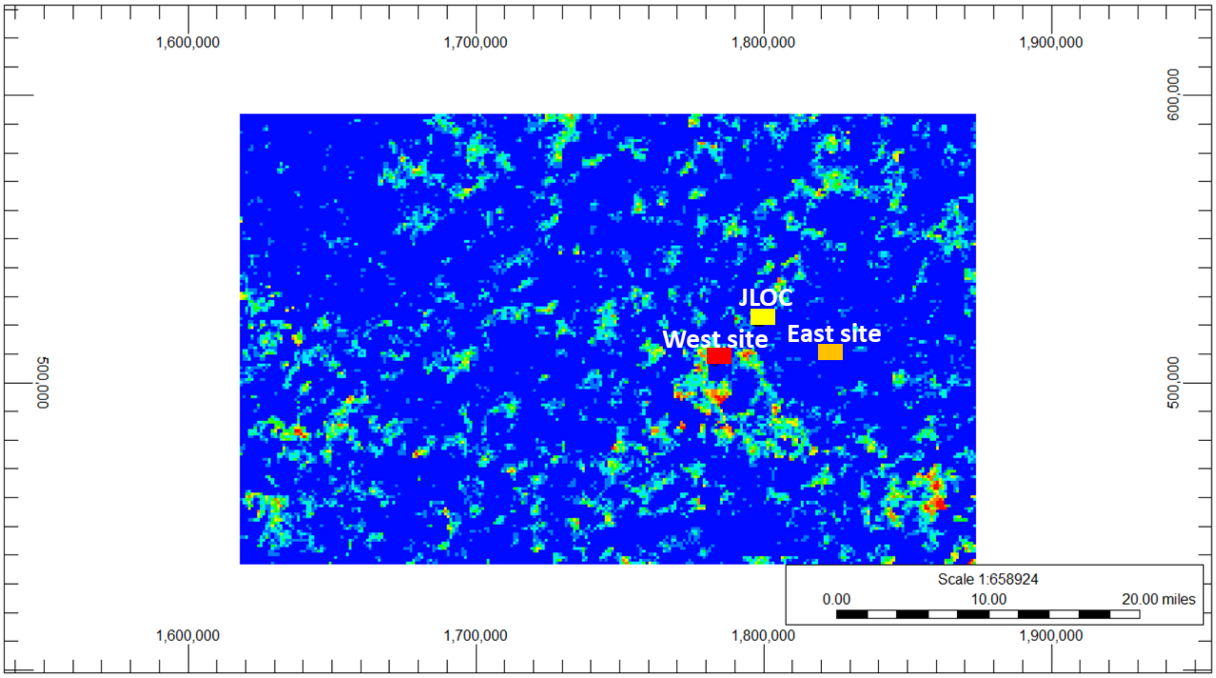


Figure 3-4b. Aerial view of the simulation model with the permeability property, the injection well sites displayed, and the model scale.

The simulation model encompasses an area of 48.5 miles by 29.7 miles. DCC West SGS is located approximately 16.1 miles from the North edge of the model and approximately 31.32 miles from the West edge of the model. The simulation model boundaries were assigned partially closed conditions as the Broom Creek Formation pinches out in the northern and eastern parts of the modeled area but is infinite-acting towards the southern and western boundary. Distances from the edge of the model to the pinch-out are assumed to be 56,500 ft (~10.7 mi) to the east, 19,400 ft (~3.7 mi) to the northeast, and 184,800 ft (35 mi) to the north. The reservoir was assumed to be 100% brine-saturated with an initial formation salinity of 49,000 ppm total dissolved solids (TDS) (Table 3-2).

Table 3-2. Summary of Reservoir Properties in the Simulation Model

Formation	Average Permeability[2], mD	Average Porosity, %[1]	Initial Pressure, P_i, psi	Salinity, ppm	Boundary Condition
Opeche–Picard Interval	0.00525	2.14	2415.8 (at 4920 ft)[3]		Partially closed
Broom Creek	7.225	14.2		49,000	
Amsden	0.0175	2.92			

[1] Porosity values are reported as the arithmetic mean. Permeability values are reported as the geometric mean.
[2] Permeability averages calculated after 2.5 multiplier was applied.
[3] Measured depth, below KB.

Numerical simulations of CO_2 injection performed allowed CO_2 to dissolve into the native formation brine. Mercury injection capillary pressure (MICP) data for the Opeche/Spearfish, Broom Creek, and Amsden Formations were used to generate relative permeability and the capillary pressure curves for the five representative facies in the simulation model (sandstone, siltstone, dolostone, dolomitic sandstone, and anhydrite) (Figures 3-5–3-8). MICP samples tested within the Opeche–Picard interval, Broom Creek, and Amsden Formations included siltstone, sandstone, dolomitic sandstone, and dolostone lithologies. The siltstone (Opeche–Picard interval) relative permeability curve was assigned to anhydrite facies, as no anhydrite samples were available from the MICP calculations. The main reason for this assignment is that both siltstone and anhydrite represent low permeability facies.

Capillary pressure curves calculated from MICP data were modified to the model scale based on the permeability and porosity values of the simulation model for the five representative lithofacies and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-5–3-8. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples from MICP data and modeled properties to scale the capillary entry pressure value derived from core testing (Table 3-3). The capillary pressure curves for siltstone and anhydrite were also modified based on the simulation model, resulting in two different ratios derived from MICP data (same MICP sample for both facies) and the porosity and permeability properties for each of these facies in the model, showing two different capillary pressure curves for siltstone and anhydrite facies, Figure 3-6.

Temperature and pressure data recorded in the J-LOC 1 wellbore (Tables 2-2 and 2-3) were used to derive a temperature and pressure gradient to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.02°F/ft was used to calculate subsurface temperatures throughout the study area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.49 psi/ft (Table 2-3).

The simulation model permeability was tuned globally by applying a multiplier to match reservoir properties estimated from Broom Creek Formation step rate test. The permeability multiplier was calculated based on the area of study during the injectivity test and the permeability and thickness (transmissibility) values from the numerical transient analysis. The value obtained from this calculation resulted in a permeability multiplier of 5.0. Ultimately, a global multiplier of 2.5 was applied before numerical simulations to provide a more conservative input for simulation.

A fluid sample from the Broom Creek Formation collected from the J-LOC 1 wellbore was analyzed by Minnesota Valley Testing Laboratories (MVTL) and confirmed by the EERC, and the TDS results of 49,000 ppm were used as input for the reservoir simulation. Table 3-2 shows the general reservoir properties for numerical simulation analysis in this study.

The CO_2 stream used to conduct numerical simulations of CO_2 injection was composed of 98.25% CO_2 and 2% trace quantities of other constituents, including 1.44% nitrogen, 0.31% oxygen, and 10 ppm hydrogen sulfide. This is a likely CO_2 injection stream based on compositional studies of CO_2 from potential third-party sources. Other constituents such as sulfur, hydrocarbons, glycol, amine, aldehydes, NO_x, and NH_3 may also be present but in a negligible amount that would have no impact on geochemical reactions in the storage formation and were not included.

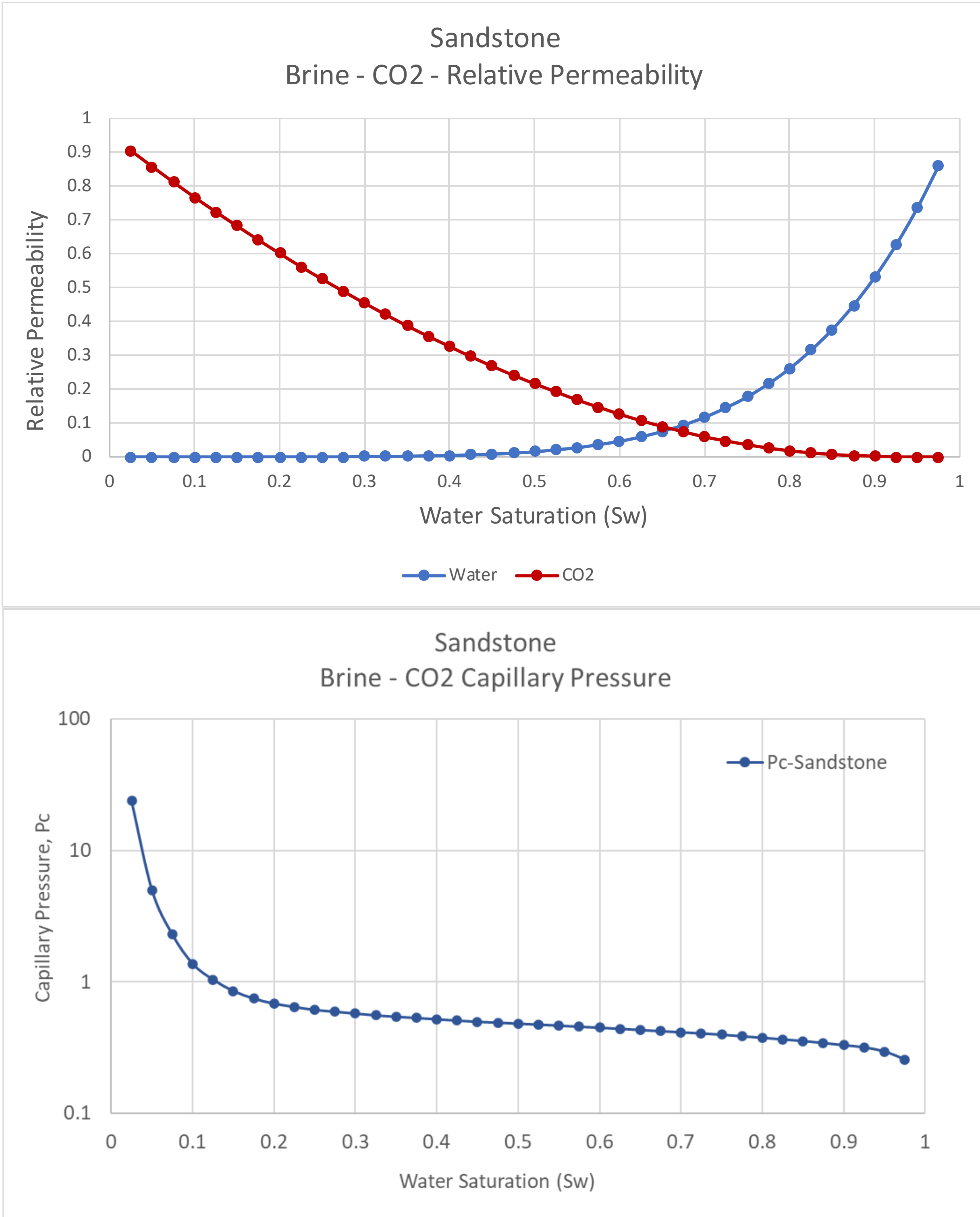
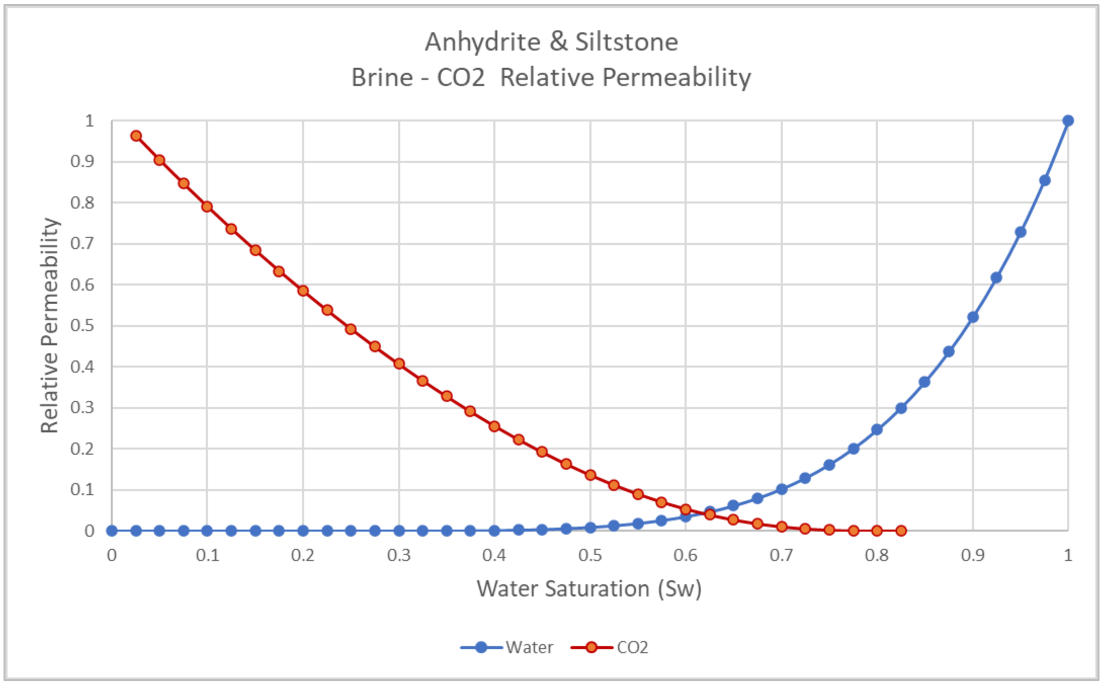


Figure 3-5. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone rock type in the Broom Creek Formation.



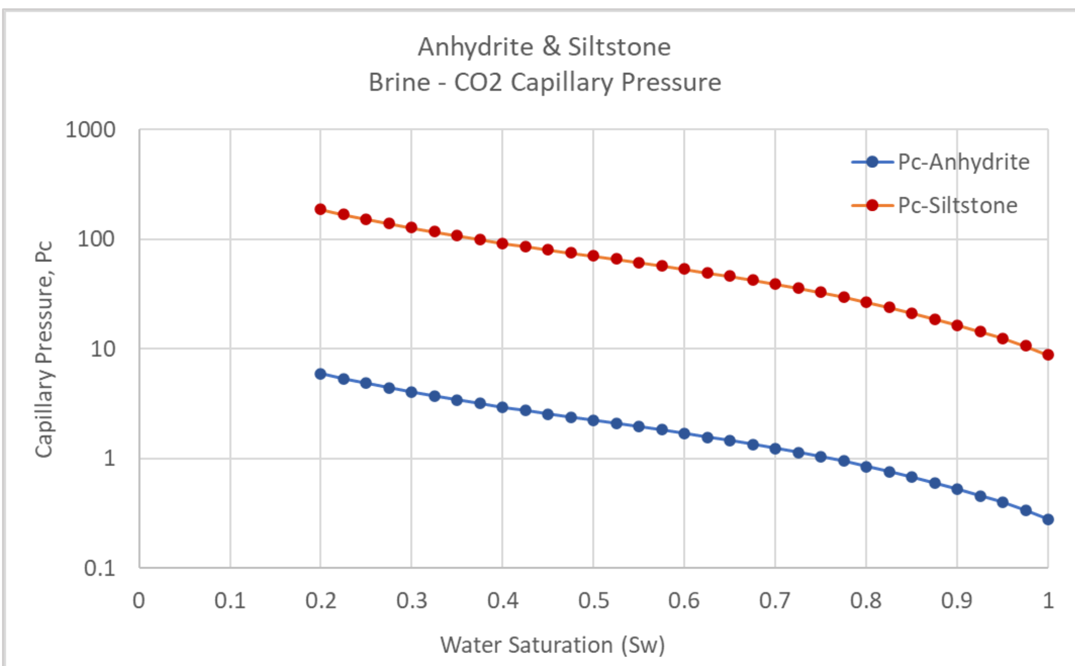


Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone rock type in the Opeche–Picard interval and anhydrite rock type in the Broom Creek Formation.

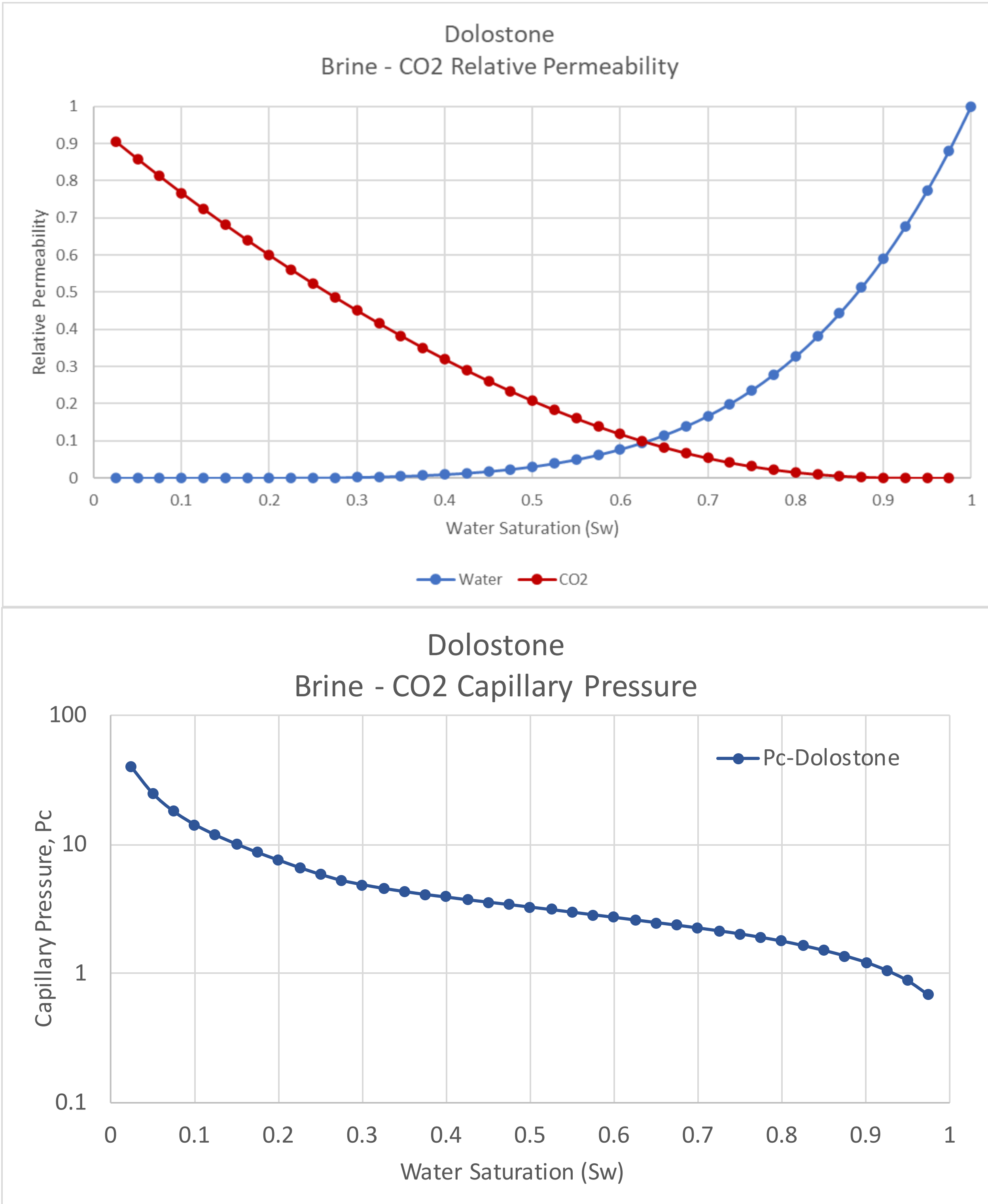
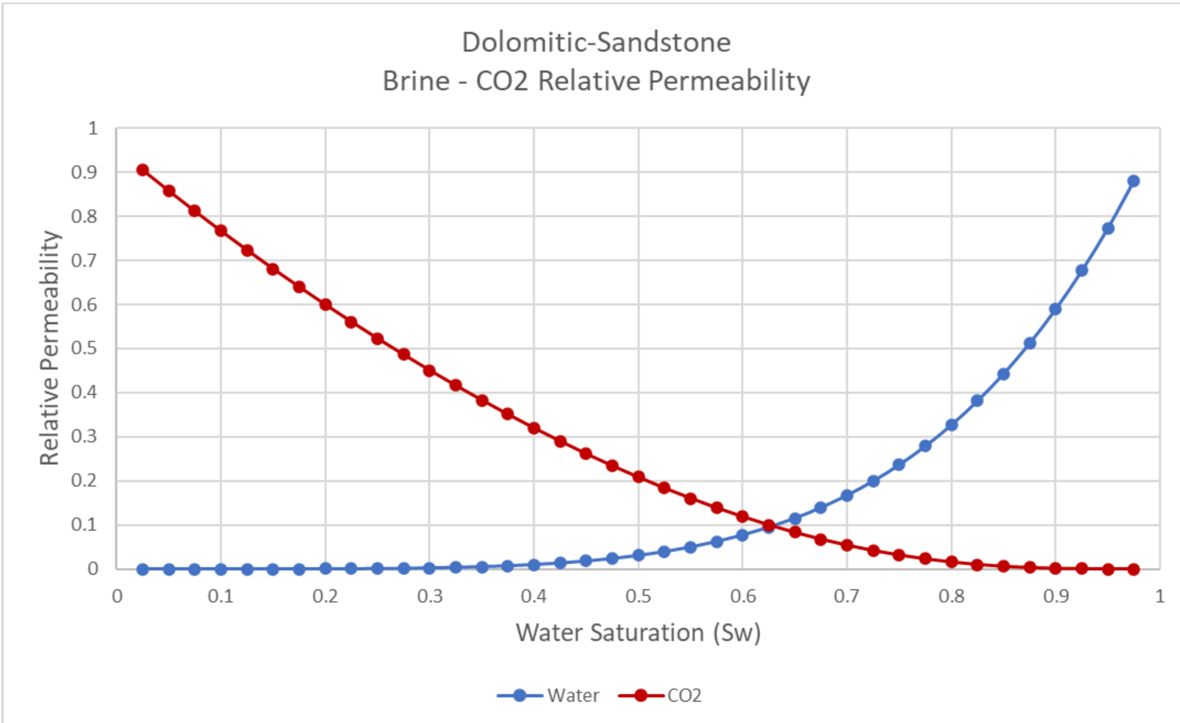


Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone rock types in the Broom Creek and Amsden Formations.



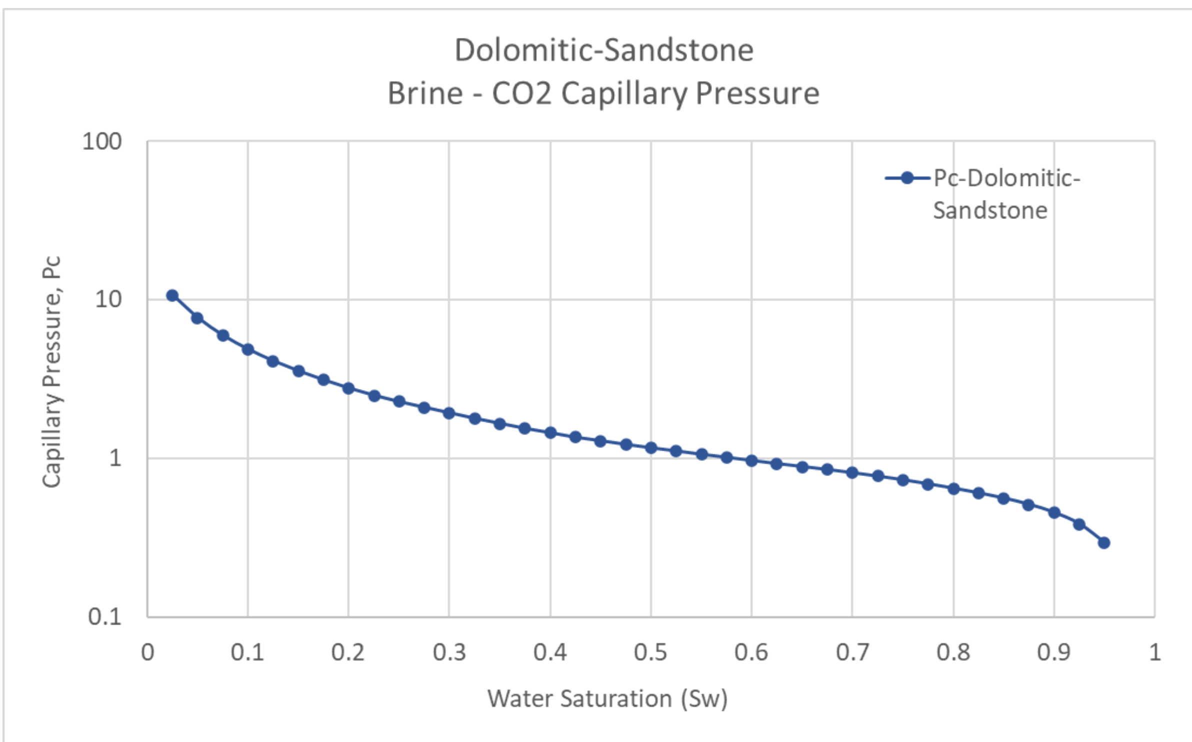


Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone rock type in the Broom Creek Formation.

Table 3-3. Core and Model Properties Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure Used in the Simulation Model

	Core					Model				
	Porosity, fraction	**Permeability, mD**	**Capillary Entry Pressure, A/Hg, psi**	**Capillary Entry Pressure Brine/CO_2, psi**	**Reservoir Quality Index**	**Porosity, fraction**	**Permeability, mD**	**Capillary Entry Pressure B/CO_2, psi**	**Reservoir Quality Index**	**Multiplication Factor**
Sandstone	0.267	1147	3.04	0.2006	65.543	0.2375	1375.07	0.2567	76.094	0.8613
Siltstone	0.017	0.000020	2630	168.1031	0.0343	0.049392	0.017239	8.7949	0.59078	0.05806
Dolostone	0.048	0.00478	274	18.078	0.31557	0.08645	13.5536	0.6807	12.521	0.0252
Dolomitic-Sandstone	0.087	0.00683	400	25.567	0.2802	0.15517	277.86	0.2942	42.3157	0.006621
Anhydrite	0.017	0.00002	2630	168.1031	0.0343	0.02802	9.6866	0.2795	18.5926	0.001845

Approximately 7 miles east from DCC West SGS is the injection site identified for the DCC East SGS Project, as shown in Figures 2-3 and 2-4. The DCC East SGS Project is included in the numerical model and simulated injecting simultaneously with DCC West SGS. The DCC East SGS Project consists of two Broom Creek injection wells (Liberty 1 and Unity 1), which are proposed to inject with an annual average gas rate of 4 MMt/yr for the first 15 years and 3.5 MMt/yr for the last 5 years for a total 20-year CO_2 injection period. The DCC West SGS well pad, with two proposed deviated wells, IIW-N and IIW-S, was simulated as perforated across the Broom Creek Formation interval. The well constraints and wellbore model inputs for the simulation model are shown in Table 3-4. An additional simulation case with a smaller tubing size of 6⅝ inches was conducted under the same conditions as shown in Table 3-4. Results using the 7-inch tubing simulation case are presented in this section and used for purposes of boundary delineations (storage facility area, AOR), as the resulting areal extent of these boundaries was greater and, therefore, represents a more conservative scenario.

Table 3-4. Well Constraints and Wellbore Model in the Simulation Model

Primary Group Constraint, injection rate	Primary Well Constraint, maximum BHP	Secondary Well Constraint, WHP	Tubing Size	Wellhead Temperature	Downhole Temperature
DCC East Injecting 4.0 MMt/yr for Initial 15 years and 3.5 MMt/yr for the last 5 years	3039.1 psi for Liberty-1; 3032.3 psi for Unity-1	1700 psi	7 in.	90°F	136°F
DCC West Injecting with Max. BHP	3233.12 psi for IIW-N; 3242.0 for IIW-S	2100 psi	7 in.	90°F	136°F

3.3.2 Sensitivity Analysis

Because the availability of data for this study included well logs, core sample data, and rock–fluid properties, the need for typical sensitivity studies of influential reservoir parameters has been reduced. A preliminary sensitivity analysis suggested that, at the given injection volume, the wellhead temperature (WHT) played a prominent role in determining WHP response. Sensitivity simulations of different WHTs indicated that injection at a higher WHT would require a higher WHP. To evaluate the expected injection design, a WHT value of 90°F was chosen to most closely represent the expected operational temperature.

3.4 Simulation Results

Numerical simulations of CO_2 injection for DCC West SGS were assumed to be operating at the same time as the DCC East SGS Project, with the given well and group constraints listed in Table 3-4. This section discusses the injection constraints for IIW-S and IIW-N and the resulting simulation results. The predicted injection WHP of both wells, IIW-S and IIW-N, in DCC West SGS would not exceed 2100 psi during injection. The BHPs are reaching the maximum values of 3233 and 3242 psi for IIW-N and IIW-S wells, respectively (Figure 3-9). An average injection rate of 6.11 MMt/yr, with 1.768 MMt/yr for well IIW-N, and 4.342 MMt/yr for well IIW-S, was achievable over the 20 years of injection. A total of 122.9 MMt of CO_2 was injected into the Broom Creek Formation with the two wells at the end of 20 years of simulated injection (Figure 3-10). The injected volume was 35.7 MMt and 87.2 MMt for the IIW-N and IIW-S wells, respectively.

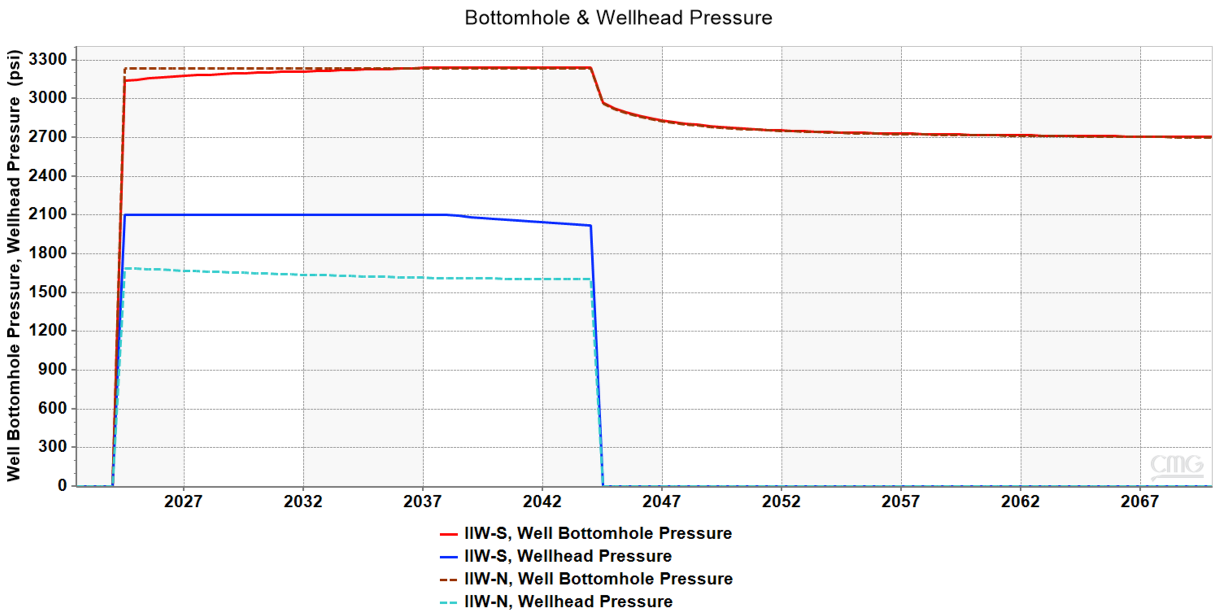


Figure 3-9. WHP and BHP response with the expected injection rate.

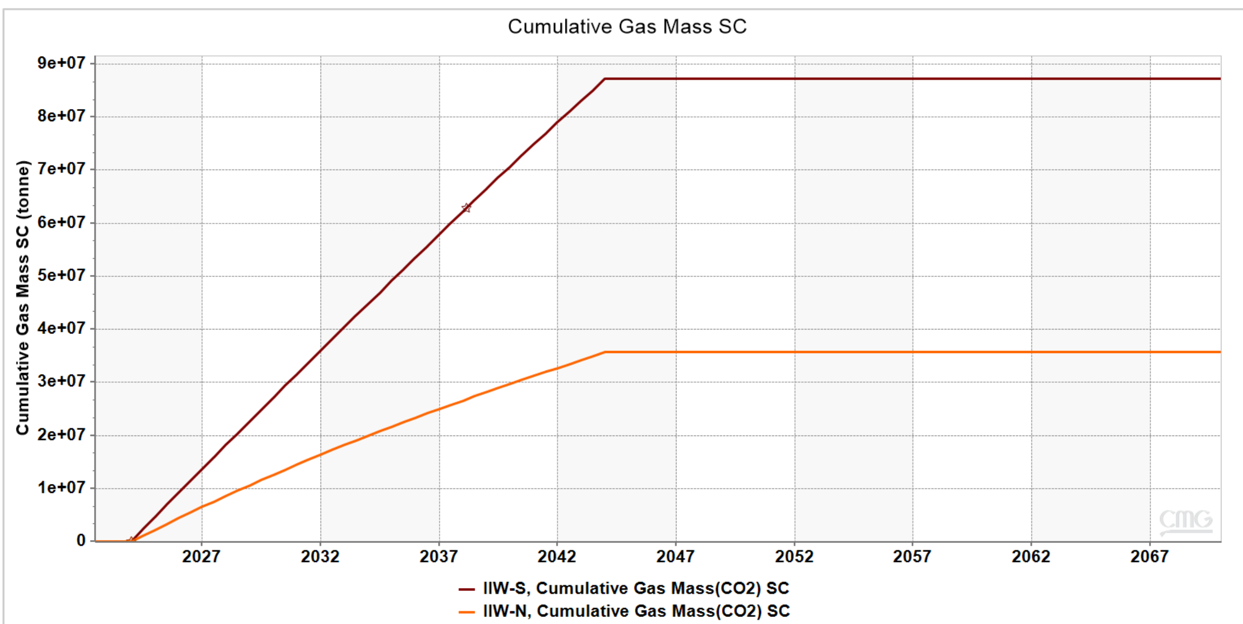


Figure 3-10. Cumulative injected gas mass over 20 years of injection.

During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of the CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO_2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-11).

The pressure front (Figure 3-12) shows the distribution of pressure increase throughout the Broom Creek Formation at 1, 10, and 20 years of injection and 10 years postinjection. A maximum increase of 677 psi is estimated in the near wellbore area after the 20 year injection period.

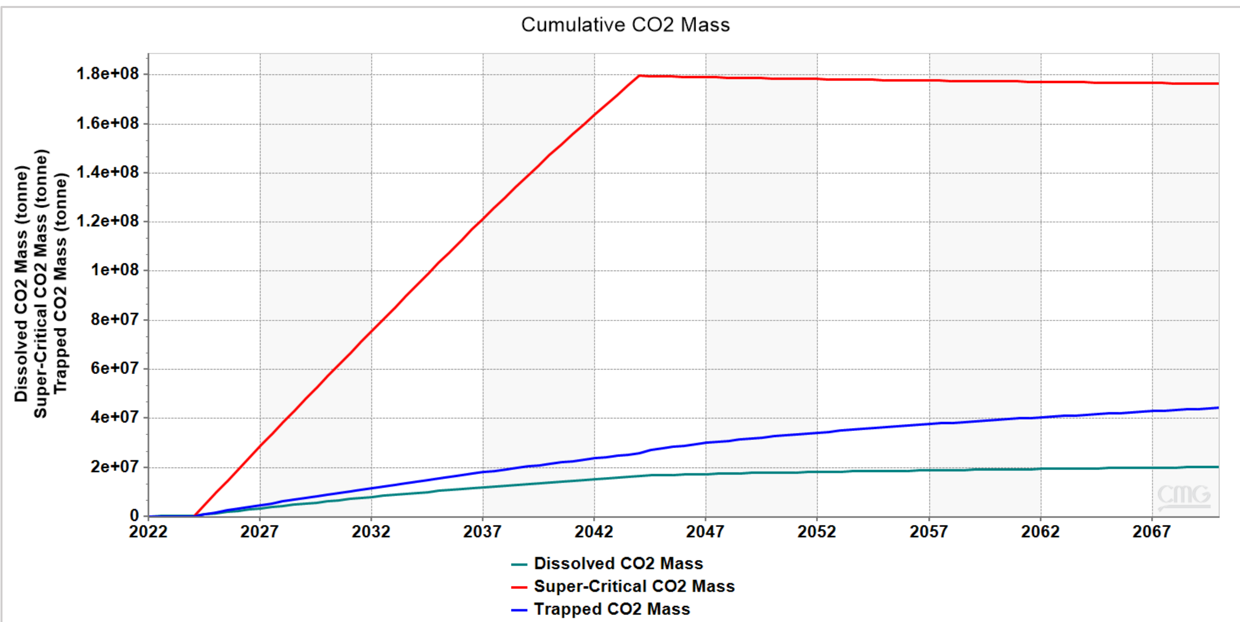


Figure 3-11. Simulated total supercritical-phase CO_2, trapped CO_2, and dissolved CO_2 in brine.

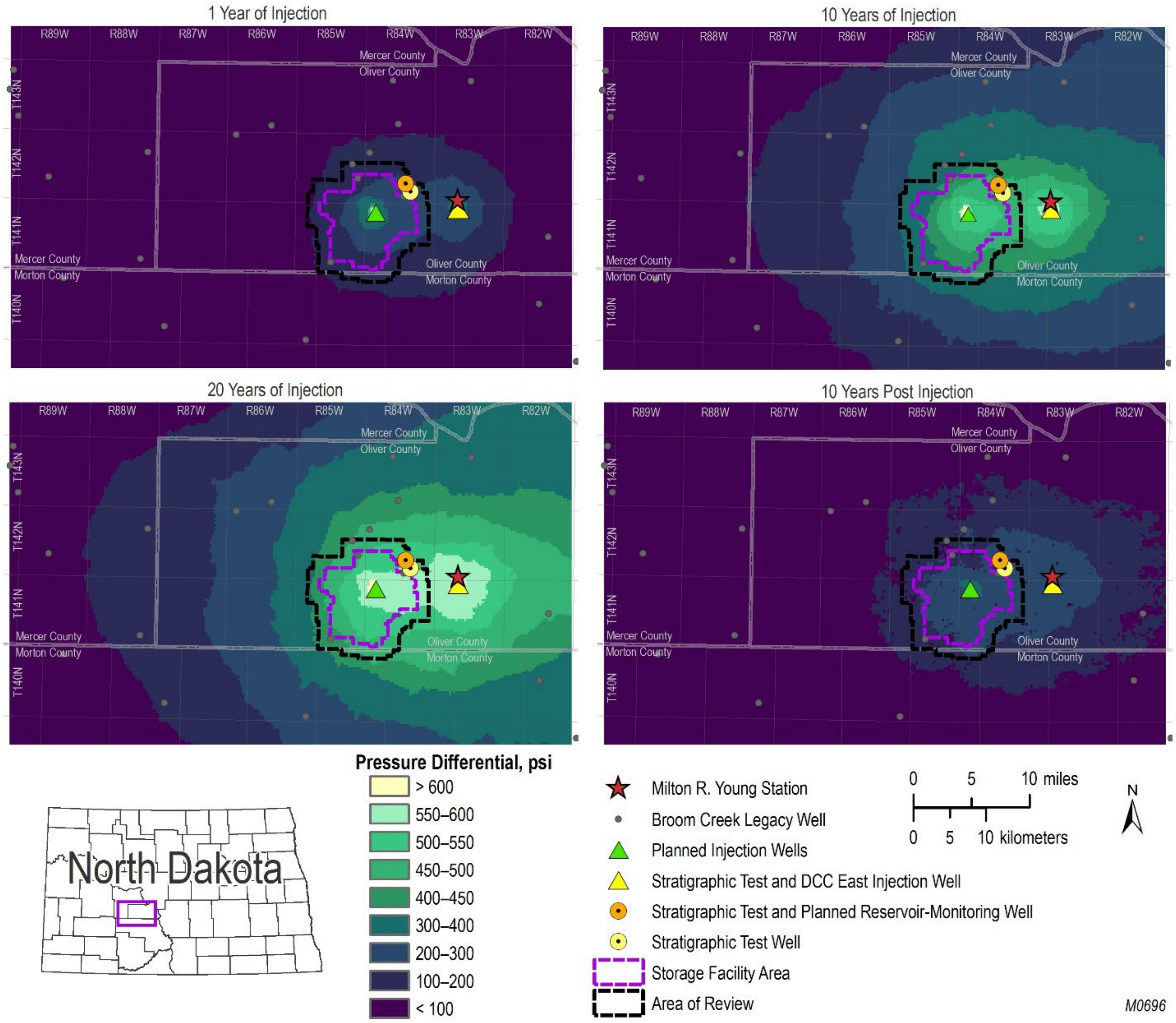


Figure 3-12. Average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of injection, and 10 years of postinjection. Simulated injection at both DCC East SGS and DCC West SGS begin at the same time.

Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the cap rock or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-13 and 3-14 show the gas saturation at the end of injection in north-to-south and east-to-west cross-sectional views, respectively.

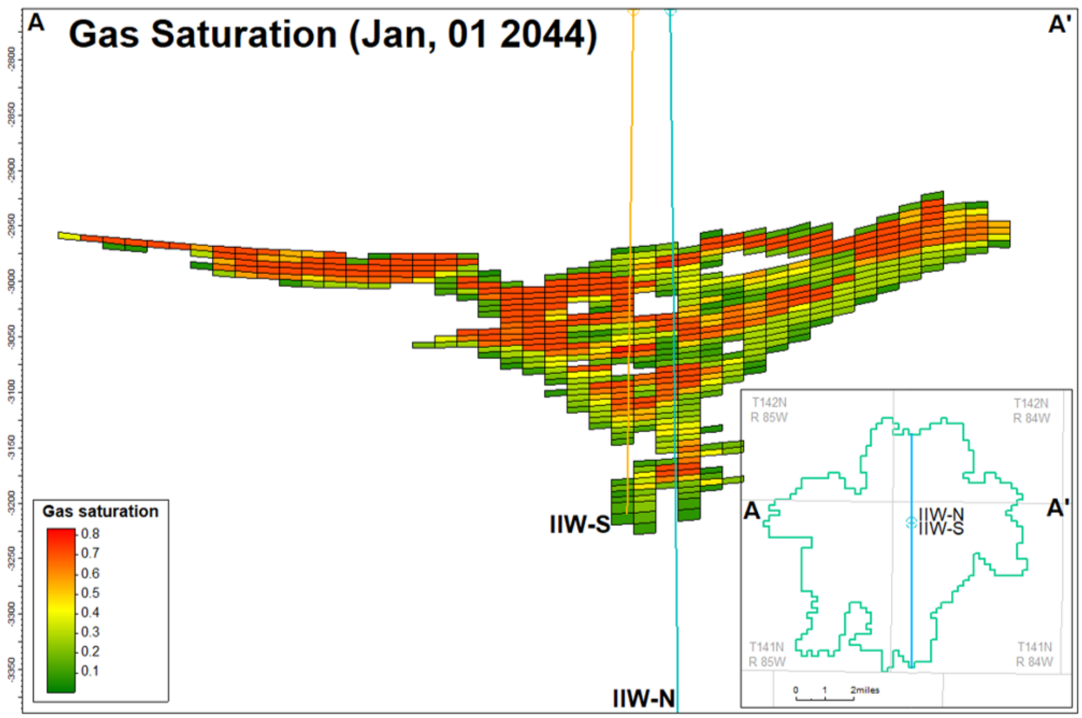


Figure 3-13. CO_2 plume boundary and cross section at the end of injection displayed south to north through the IIW-N and IIW-S wells. White cells or "empty" intervals do not contain CO_2 saturation. 50× vertical exaggeration shown**.**

3.4.1 Maximum Injection Pressures and Rates

An additional case was run to determine if the wells would ultimately be limited by the maximum WHP of 2100 psi or maximum calculated downhole pressures of 3233 and 3242 psi for the IIW-N and IIW-S wells, respectively. Results of a stress test performed at the J-LOC 1 well within the Broom Creek Formation, over an interval from 5043 to 5047 ft, indicated an average fracture propagation pressure of 3593 psi, resulting in an estimated fracture propagation pressure gradient of 0.712 psi/ft. The propagation pressure gradient was used to calculate maximum BHP constraints, based upon 90% of the fracture propagation pressure.

In this scenario, the maximum WHP of 2100 psi was removed, and the wells IIW-N and IIW-S in the DCC West project area were injecting one well at a time and with only maximum BHP as a constraint. The site identified for the DCC East SGS Project located approximately 7 miles to the east, was assumed shut-in for this simulation case. Other parameters were kept the same for the additional tests.

The maximum BHPs for the individual wells were reached in the simulation. At the maximum BHP of 3233 and 3242 psi, the corresponding predicted maximum wellhead injection pressure responses with only one well injecting at a time were 1997 and 2459 psi for the IIW-N and IIW-S wells, respectively (Figure 3-15). In this scenario, the IIW-N and IIW-S wells were able to inject at daily average maximum injection rates of 10,834 and 19,503 tonnes/day of CO_2, respectively, with the planned 7-inch-diameter tubing.

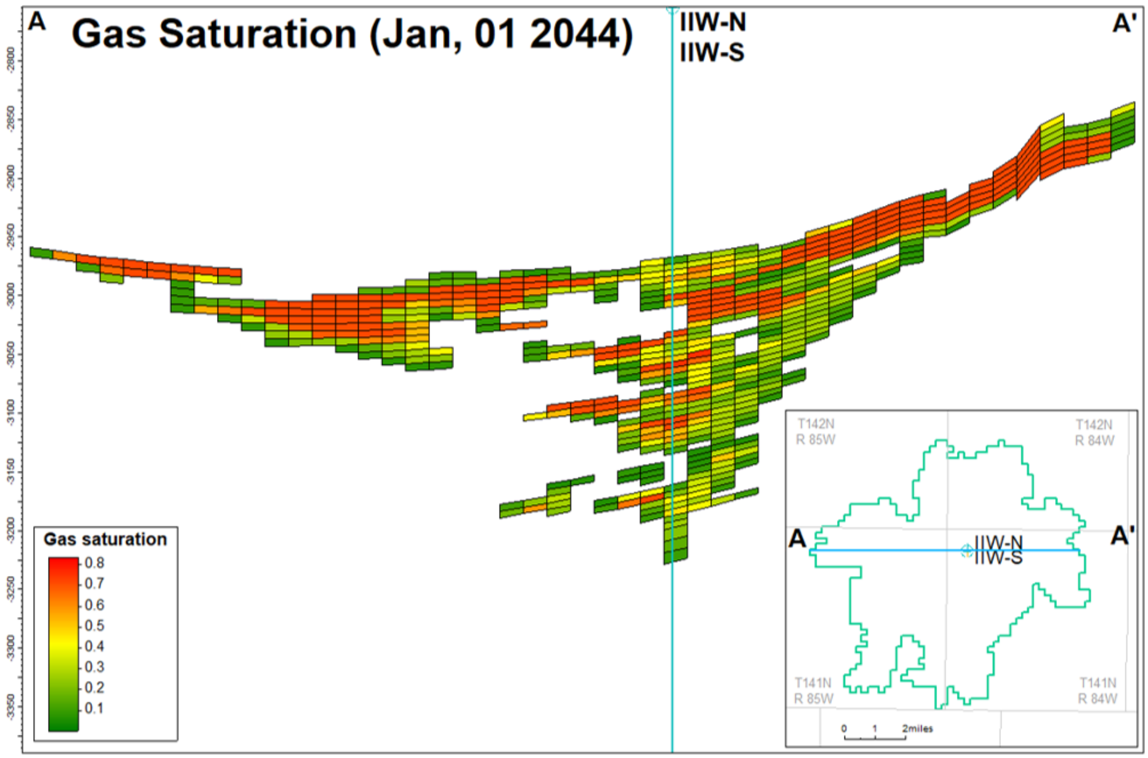
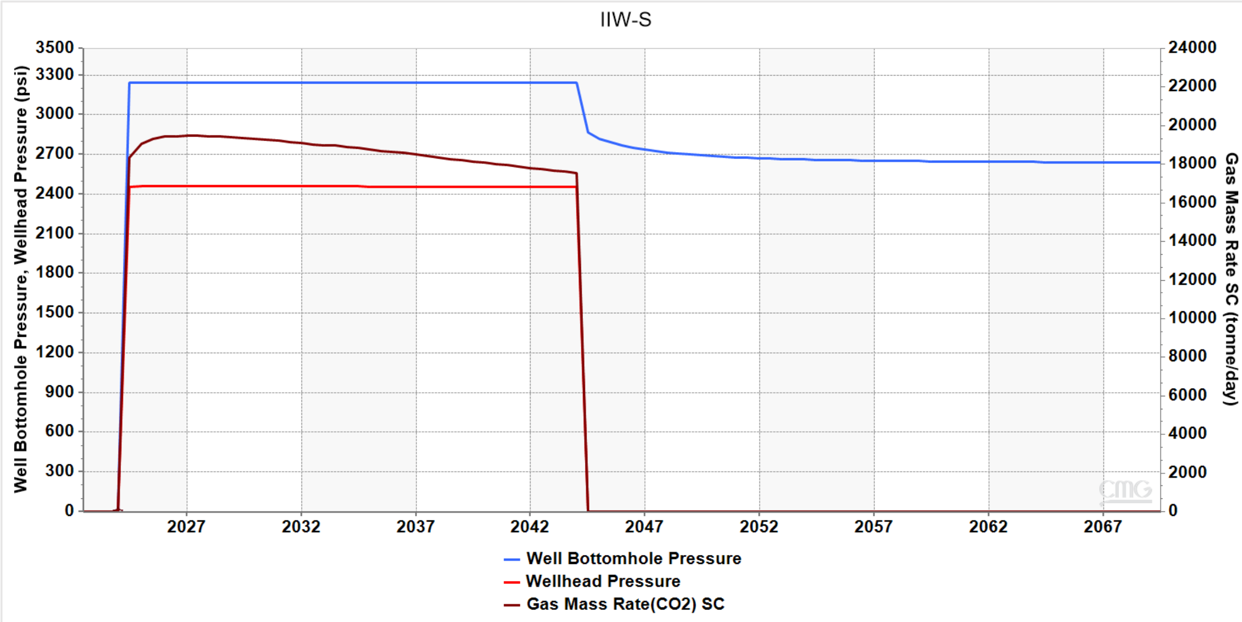


Figure 3-14. CO_2 plume boundary (green inset polygon) and cross section at the end of injection displayed west to east through the IIW-N and IIW-S wells. White cells or "empty" intervals do not contain CO_2 saturation. 50× vertical exaggeration shown.



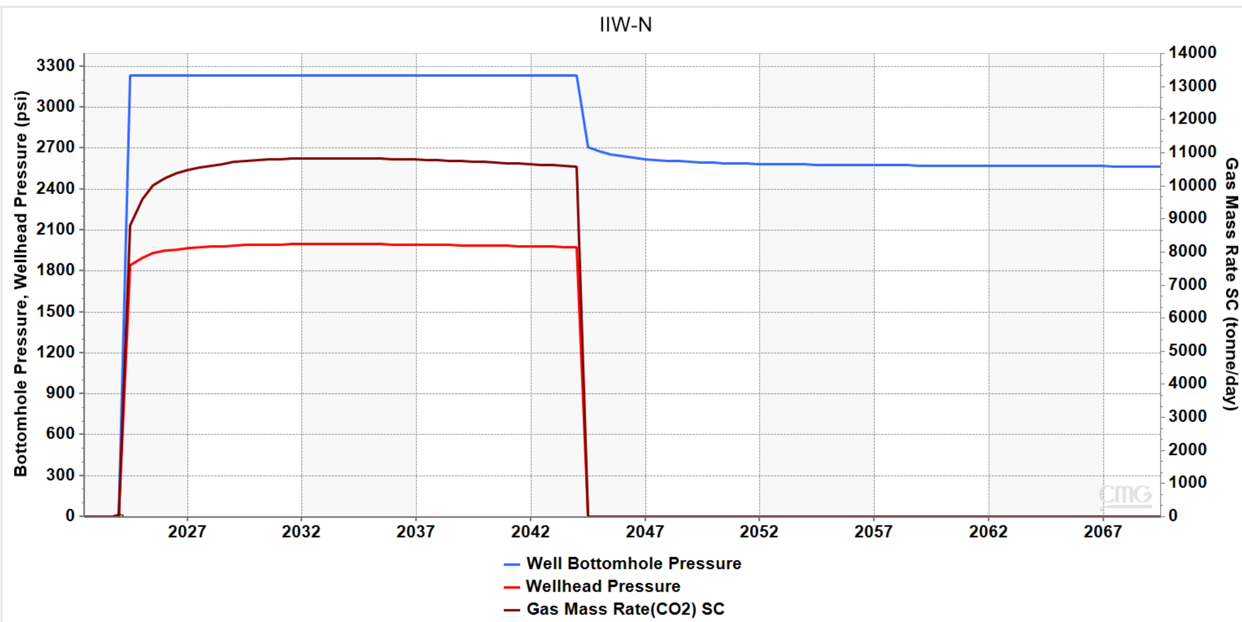


Figure 3-15. Maximum pressure and gas rate response when the wells were operated without any WHP limits: IIW-S well (top) and IIW-N well (bottom).

3.4.2 Stabilized Plume and Storage Facility Area

Movement of the injected CO_2 plume is driven by the potential energy found in the buoyant force of the injected CO_2. As the plume spreads out within the reservoir and CO_2 is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO_2 is gradually lost. Eventually, the buoyant force of the CO_2 is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO_2 plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project's storage facility area and the scale and scope of the project's monitoring plans.

Plume stabilization can be visualized at the microscale as CO_2 being unable to exit its current pore space and enter the neighboring pore space, but at the macroscale, these interactions cannot be measured. Instead, plume stabilization may be estimated using the tools available to predict the CO_2 plume's extent.

For DCC West SGS, the CO_2 plume was simulated in 5-year time steps to observe that the rate of total areal extent change slows after injection ceases. This information was used to inform the storage facility area. The simulation model will be regularly updated during the CO_2 storage operation as data collected from the site will inform predictions of injected CO_2 movement.

3.5 Delineation of the Area of Review

The AOR encompasses both the areal extent of the CO_2 plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into an underground source of drinking water (USDW), assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical threshold pressure.

3.5.1 EPA Methods 1 and 2

U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure (U.S. Environmental Protection Agency, 2013). The EPA methods, Methods 1 and 2, were evaluated for determining the AOR for DCC West SGS. Additional information about Methods 1 and 2 can be found in Appendix C.

EPA Method 1 (pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013).

Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (kg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_I is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f} = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW.

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids (ρ_i), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the J-LOC 1 stratigraphic test well. Application of EPA Method 1 (Equation 1) using site-specific data from the J-LOC 1 well shows that the injection zone in the project area is overpressurized with respect to the lowest USDW (i.e., Method 1 $\Delta P_{i,f} < 0$). An example of the EPA Method 1 application showing negative $\Delta P_{i,f}$ (relative overpressure) is given in Table 3-5, with similar results when applied to each column of the grid cells in the Broom Creek Formation simulation model.

Table 3-5. EPA Method 1 Critical Threshold Pressure Increase Calculated at the J-LOC 1 Wellbore Location

Depth,* ft	Depth,* m	P_i Injection Zone Pressure, MPa	P_u USDW Base Pressure, MPa	ρ_i Injection Zone Density, kg/m^3	Z_u USDW Base Elevation, m amsl	Z_i Reservoir Elevation, m amsl	$\Delta P_{i,f}$ Threshold Pressure Increase, MPa	$\Delta P_{i,f}$ Threshold Pressure Increase, psi
5046	1538	17.12	3.74	1023	379	−788	−1.66	−241

* Ground surface elevation is 750 m, above mean sea level (amsl). Depth provided is the midpoint of the Broom Creek formation in feet below ground surface.

Calculations using EPA Method 1 resulted in a negative threshold pressure increase across the project area, with a value of -241 psi calculated using data from the J-LOC 1 well. The negative threshold pressure increase value indicates the storage formation is overpressured relative to the USDW and the use of Method 1 would result in an unreasonably large AOR on the order of thousands of square miles. The lack of evidence for hydrostatic equilibrium between the reservoir and the USDW renders Method 2 unapplicable for the site; therefore, a risk-based approach to AOR delineation was pursued. In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

3.5.2 Risk-Based AOR

As an alternative to the EPA AOR delineation methods, the EERC developed a risk-based AOR delineation method that can be applied to overpressured reservoirs (Burton-Kelly and others, 2021). The risk-based AOR method leverages ASLMA (Analytical Solution for Leakage in Multilayered Aquifers), a FORTRAN program used to estimate formation fluid leakage through hypothetical leaky wellbores. The risk-based method has been peer-reviewed, published, and accepted as the method for AOR determination in previous North Dakota storage facility permit applications such as DCC East Center Broom Creek Storage Facility #1 and DGC Beulah Broom Creek Storage Facility #1. Additional details of the risk-based AOR model can be found in Appendix C.

The risk-based method uses ASLMA to derive a relationship between storage unit pressure buildup and potential incremental formation fluid migration into overlying aquifers. Incremental fluid migration is flow that is attributable to storage unit pressure increase and ignores flow that would occur along leakage pathways that existed before injection began A macro-enabled Microsoft Excel file was used to define the inputs, including aquifer characteristics to represent the storage unit, storage USDW, and intermediate aquifers, as well as calculations that were employed in the method. For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-6 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3.

Intermediate aquifers between the storage unit and the lowest USDW may act as thief zones where present and divert upward fluid flow away from the USDW. ASLMA allows for the use of multiple layers to act as aquifers or potential thief zones (e.g., Aquifer 1, Aquifer 2). Pressure buildup estimates derived from numerical simulations of CO_2 injection were used with ASLMA to generate potential incremental leakage maps within the areal extent of the simulation model. These potential leakage maps indicate the areas hypothetical leakage is more likely to occur and were used to inform the AOR delineation.

Table 3-6 Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Brine Density, kg/m^3	Porosity, %	Permeability, mD	Permeability, m^2	HCON, m/d	Specific Storage, m^{-1}	Total Head, m
Overlying Units to Ground Surface (not directly modeled)	0	298										
Aquifer 3 (USDW – Fox Hills Fm)	298	73	3.4	15.9	1563	1001	35	280	2.76E-13	2.10E-01	5.60E-06	760
Aquitard 2 (Pierre Fm–Inyan Kara Fm)	372	804	7.3	57.8	2500		1	0.02	1.97E-17	3.40E-05	8.77E-06	732
Aquifer 2 (Thief Zone – Inyan Kara Fm)	1175	54	11.3	51.3	3360	944	13.45	7.9	7.75E-15	1.21E-02	4.90E-06	710
Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal)	1229	259	15.1	62.2	24,675		2.14	0.11	1.08E-16	1.92E-04	8.95E-06	927
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1488	100	17.1	59.0	49,350	1023	14.2	7.5	7.40E-15	1.22E-02	5.06E-06	917

* Ground surface elevation, 750 m amsl.

3.5.2.1 Relating Pressure Buildup to Incremental Leakage with ASLMA Model and Compositional Simulation

In the proposed scenario, Aquifer 1 (stratigraphically, the lowest aquifer in the ASLMA model) represents the Broom Creek Formation; Aquifer 2 represents the Inyan Kara Formation (a potential thief zone); and Aquifer 3 represents the USDW. All stratigraphic units between these aquifers are assumed to be low-porosity and low-permeability aquitards. Figure 3-16 shows the ASLMA-derived relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for the case without the leaky wellbore open to Aquifer 2 (thief zone). In the case where the leaky wellbore is closed to Aquifer 2, there is no incremental leakage to Aquifer 2. The curvilinear relationship between pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 is used to predict the incremental leakage from the pressure buildup map produced by the compositional simulation of the geocellular model. The average simulated pressure buildup in the reservoir is represented by a raster (grid) map of pressure buildup values. For each raster value (grid cell map location), the relationship between pressure buildup and incremental leakage (Figure 3-16) is used to predict incremental leakage using a linear interpolation between the points making up the curve.

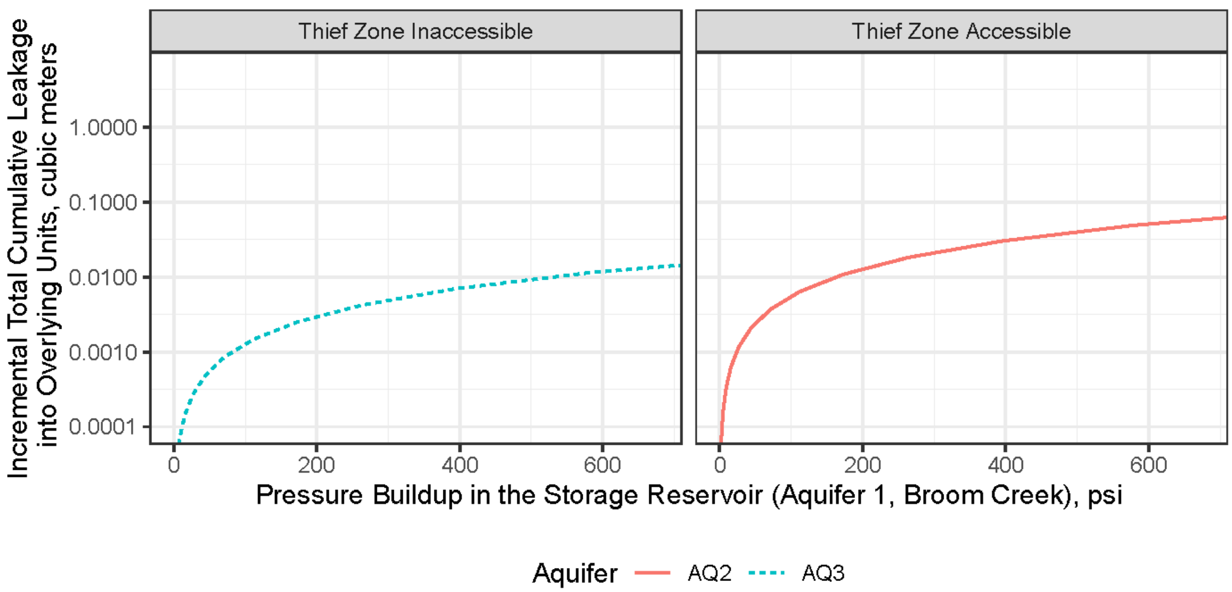


Figure 3-16. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m^3) into overlying reservoirs denoted AQ2 (Inyan Kara) in orange and AQ3 (Fox Hills, USDW) in blue. In this scenario, shown on the left, the leaky wellbore is closed to Aquifer 2 (Inyan Kara).

3.5.2.2 Incremental Leakage Maps and AOR Delineation

The assumptions and calculations used to determine the risk-based AOR at DCC West SGS incorporate at least four safety factors for the protection of groundwater resources. If the ASLMA model has resulted in an underestimation of the amount of potential leakage over the injection period, such underestimation is likely to be mitigated by:

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—a more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.

- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—a real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.

- The low density of known legacy wellbores in the DCC West SGS area—CO_2 injection is proposed to occur in an area with few available leakage pathways.

- The continued overpressured nature of the Broom Creek Formation with respect to overlying saline aquifers—over relatively short (e.g., 50-year) timescales, overpressured aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

The application of the pressure buildup–incremental leakage relationship, shown in Figure 3-16, to results of simulated pressure buildup, produces a potential incremental leakage map shown in Figure 3-17. The map shows the estimated total cumulative incremental leakage potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire 20-year period.

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental leakage maps to delineate a risk-based AOR. For the Broom Creek Formation injection at DCC West SGS, a threshold of 1 m^3 of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the 20-year injection period is established. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the pressure buildup–incremental leakage relationship curve in Figure 3-16. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period, shown in Table 3-7, was 677 psi in the raster cell intersected by

Table 3-7 Summary Results from the Risk-Based AOR Method of Estimated Total Potential Cumulative Leakage after 20 years of Injection and No Thief Zone

Maximum Vertically Averaged Change in Reservoir Pressure, psi	677.0
Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Without* Injection, m^3	0.012
Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore *Attributable to* Injection, m^3	0.033

the injection well, which corresponds to less than 0.033 m^3 of flow over 20 years. This pressure is below the potential incremental flow threshold of 1 m^3. Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

Results of the risk-based method detailed above generate a minimum AOR extent which is equivalent to the storage facility area plus a 1-mile buffer. Within the AOR, the pressure increase is not expected to be large enough to cause incremental flow of more than 1 m^3 into the USDW over the injection period (Figure 3-17). As shown, the AOR is depicted by black dotted line, which includes the storage facility area. Figures 3-18 and 3-19 illustrate legacy wellbores and the land use within the AOR, respectively.

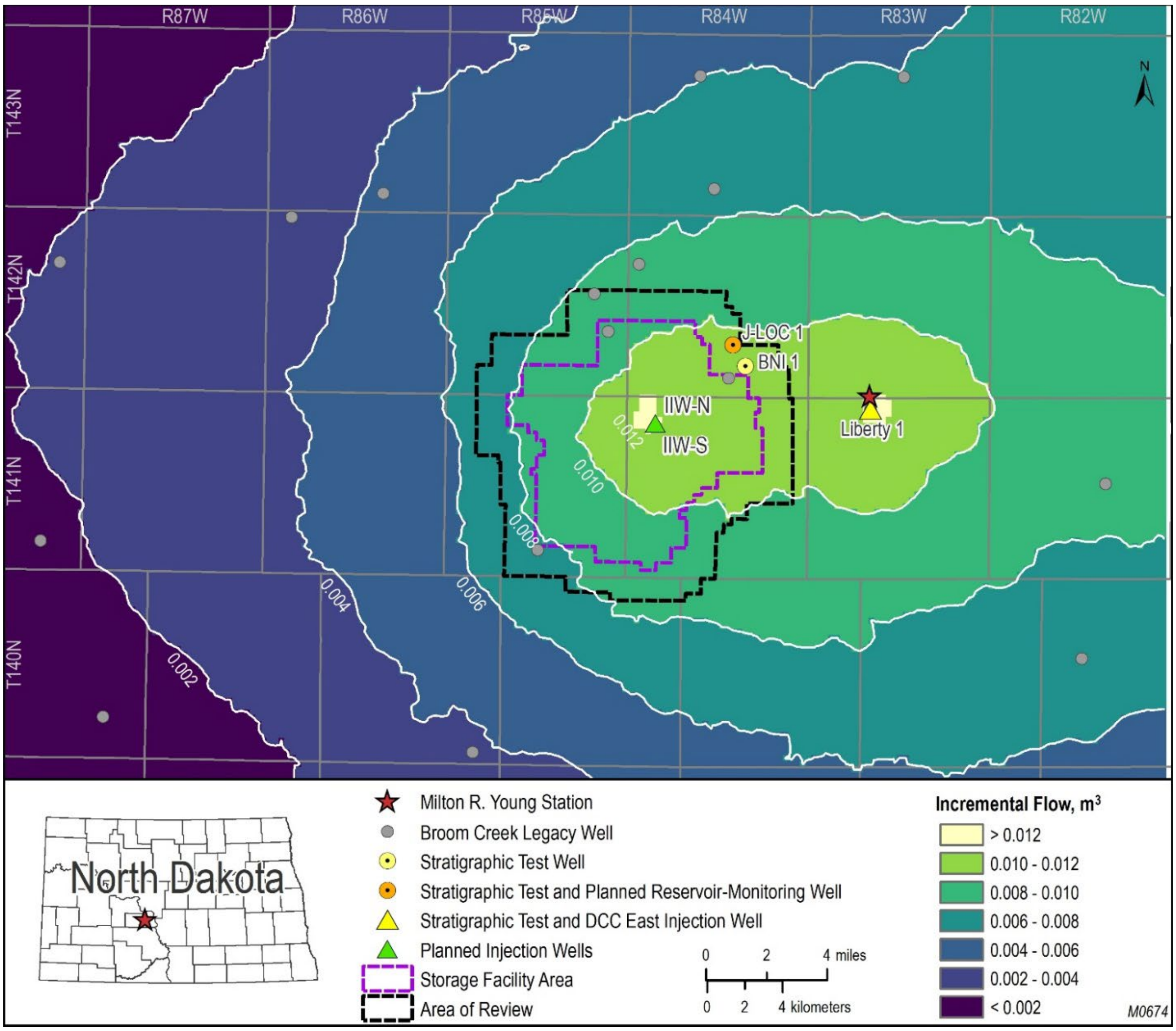


Figure 3-17. Potential incremental leakage map at the end of 20 years of CO_2 injection for the scenario where the leaky wellbore is closed to Aquifer 2 (thief zone). The dotted black polygon denotes the areal extent of the storage facility area plus 1-mile buffer at the end of 20 years of CO_2 injection as determined using a compositional simulator and the site-specific geologic model.

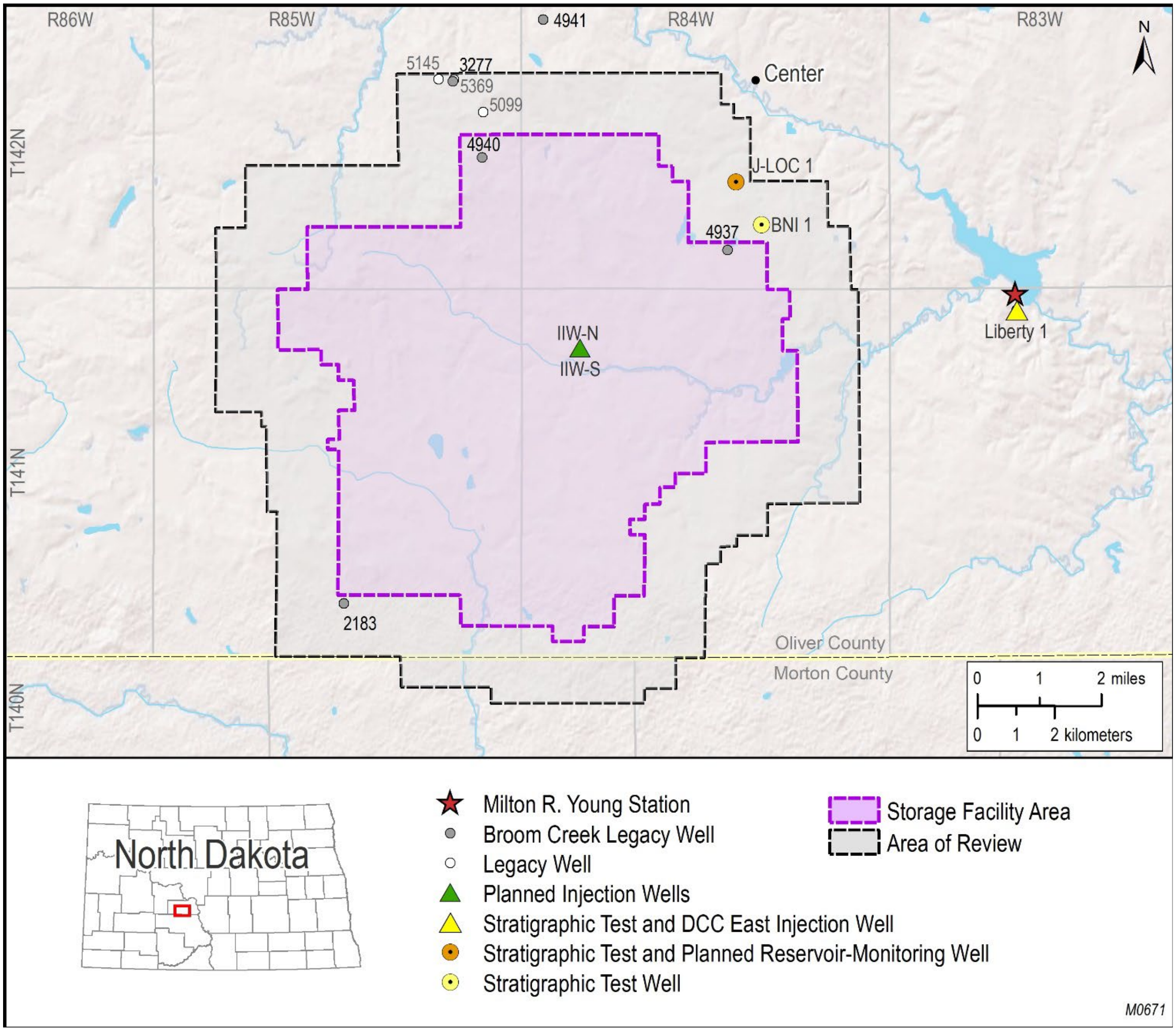


Figure 3-18. Final AOR estimations of DCC West SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), AOR (gray boundary and shaded area), and city of Center. Gray and white circles represent nearby legacy wells in or near the storage facility area.

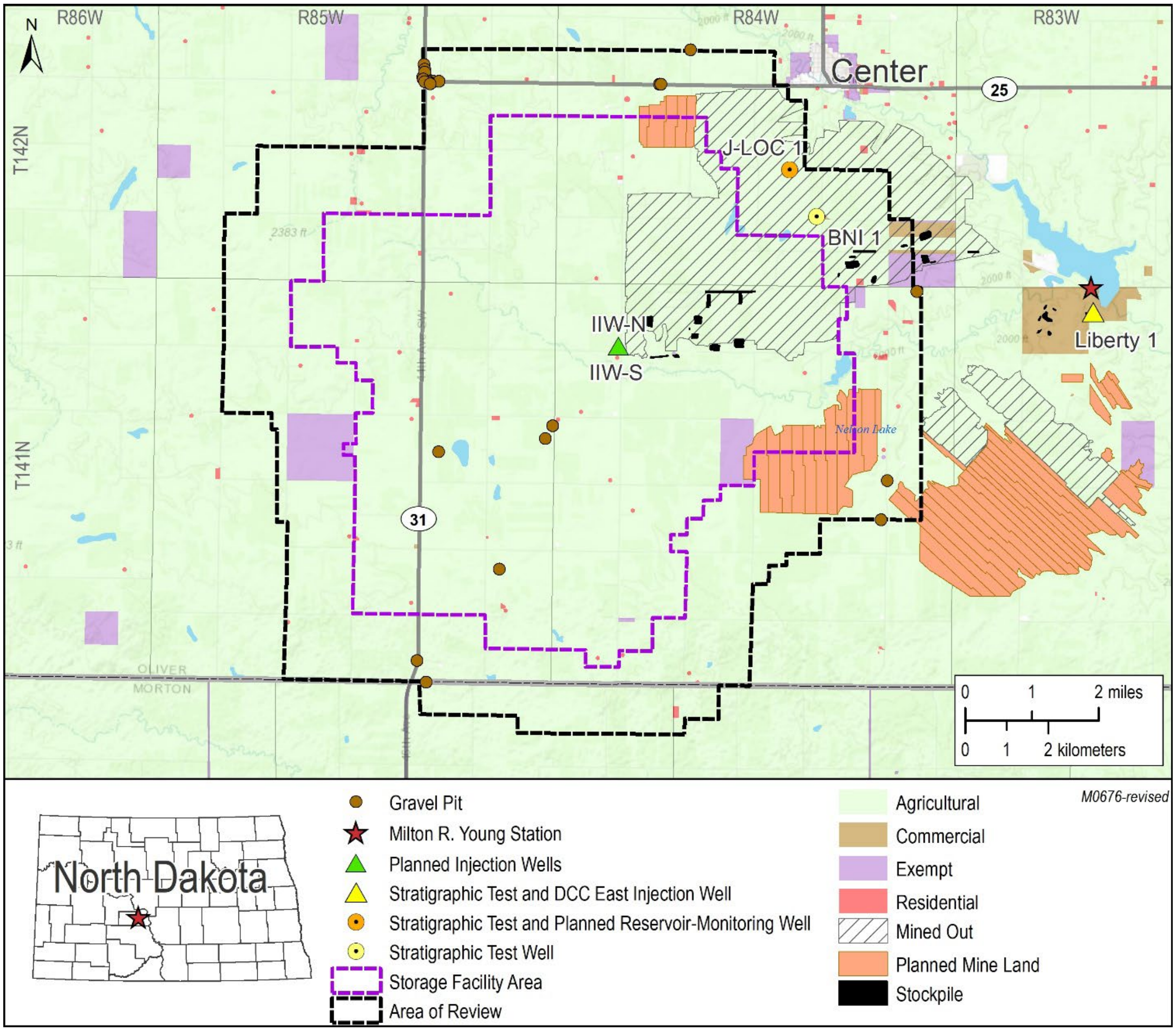


Figure 3-19. Land use in and around the AOR of the DCC West storage facility.

3.6 References

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SECTION 4.0

AREA OF REVIEW

4.0 AREA OF REVIEW

4.1 Area of Review (AOR) Delineation

4.1.1 Written Description

North Dakota regulations for geologic storage of carbon dioxide (CO_2) require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the J-LOC 1 well shows that the storage reservoir in the project area is overpressured with respect to the deepest USDW (i.e., the allowable increase in pressure is less than zero). The storage reservoir is calculated to be overpressured, with a value of −241 psi calculated using data from the J-LOC 1 well. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 677 psi in the raster cell intersected by the injection well, which corresponds to less than 0.033 m^3 of flow over 20 years (Section 3.5 Delineation of the Area of Review).

NDAC § 43-05-01-05(1)(b)(3) requires "a review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.

All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-4, Table 4-1) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action was required and included a review of all available well records (Table 4-2). The evaluation determined that all abandoned wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-3 through 4-12 and Figures 4-5 through 4-11).

An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement.

Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (1)(b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

4.1.2 Supporting Maps

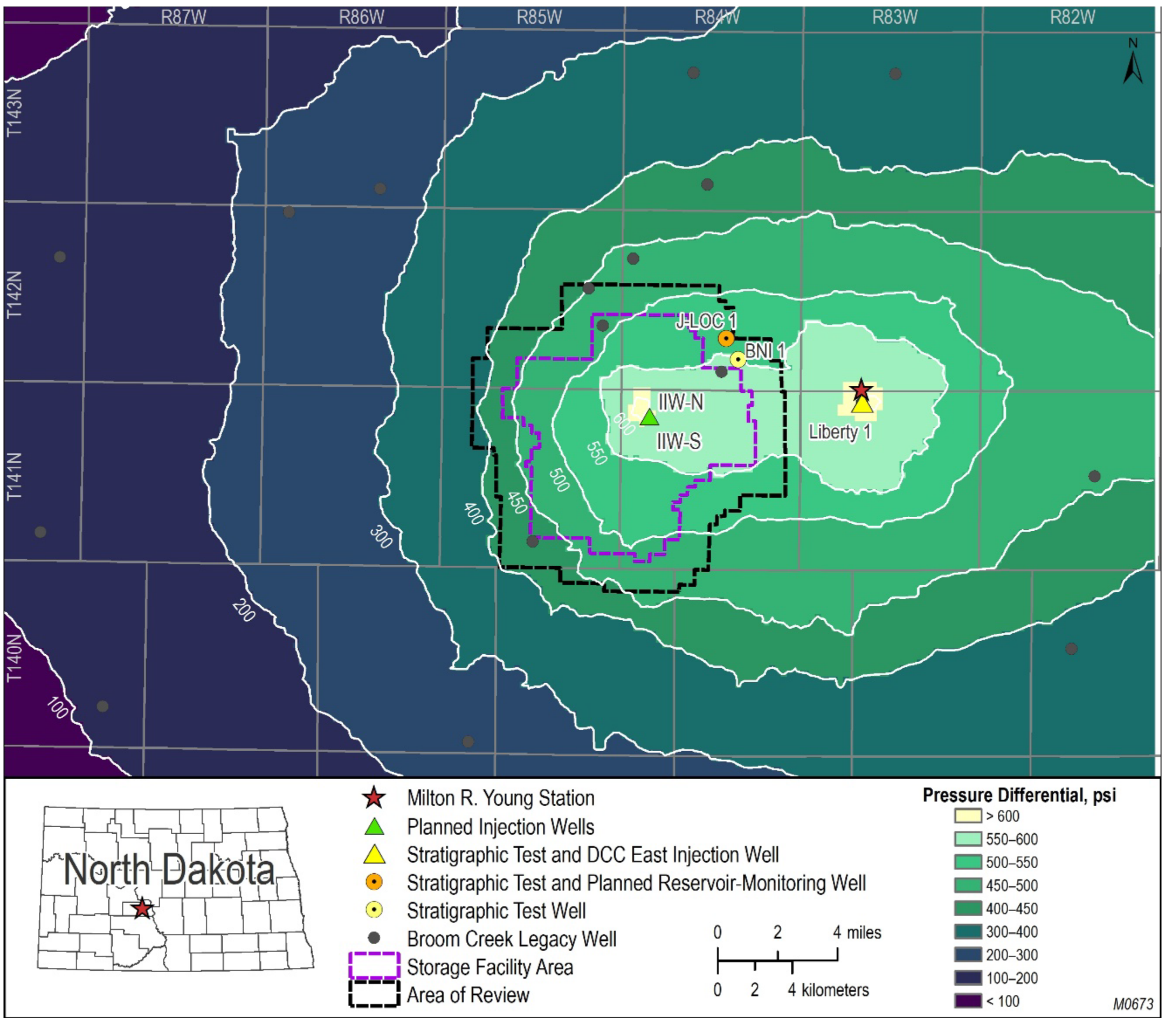

Figure 4-1. Pressure map showing the subsurface pressure influence associated with CO_2 injection in the Broom Creek Formation at both the DCC West SGS and DCC East SGS Project sites. Shown are the storage facility area and AOR boundary in relation to the predicted maximum subsurface pressure influence. Subsurface pressure subsides at the cessation of injection.

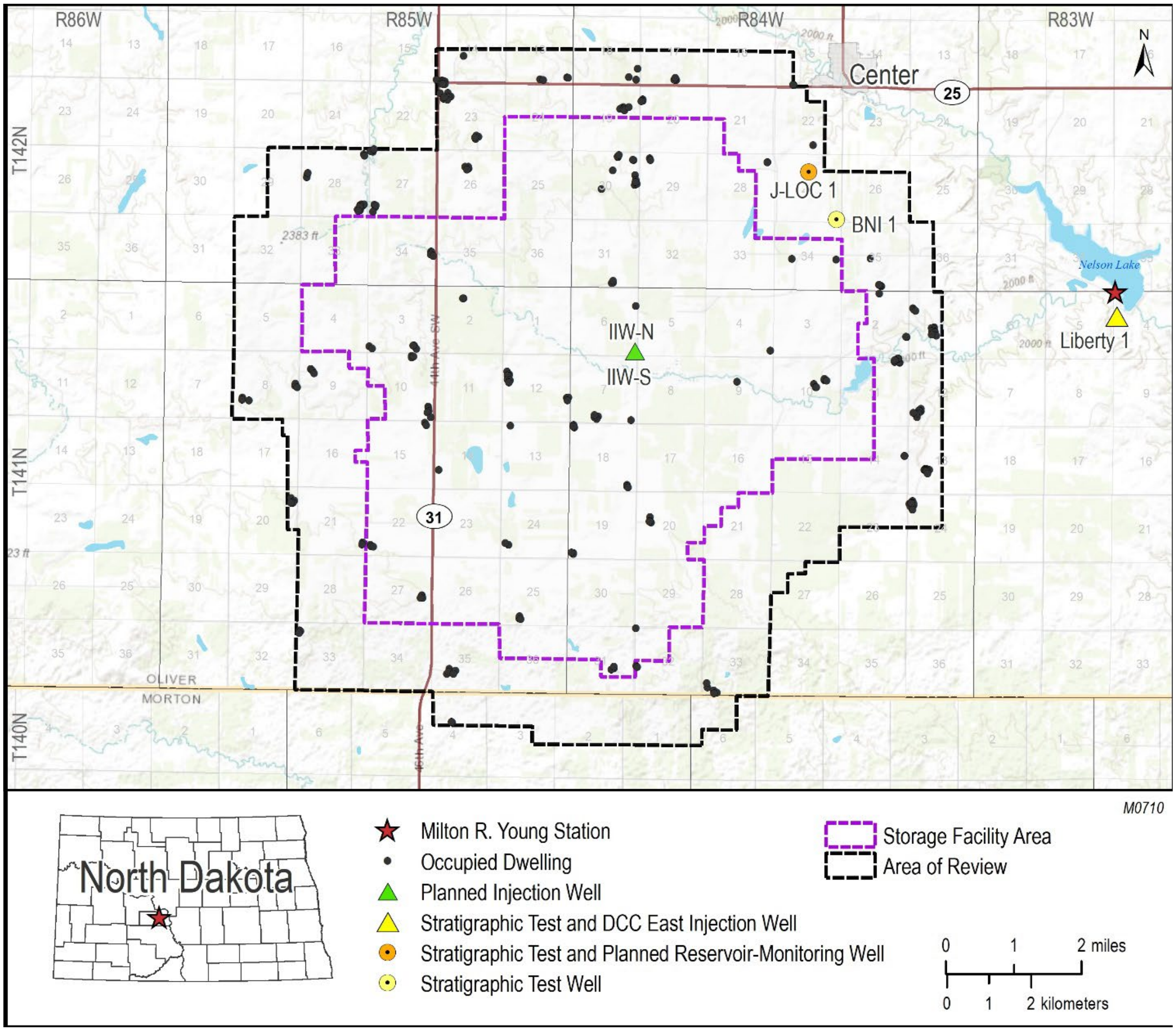

Figure 4-2. AOR map showing the storage facility area and AOR boundaries. The black circles represent occupied dwellings.

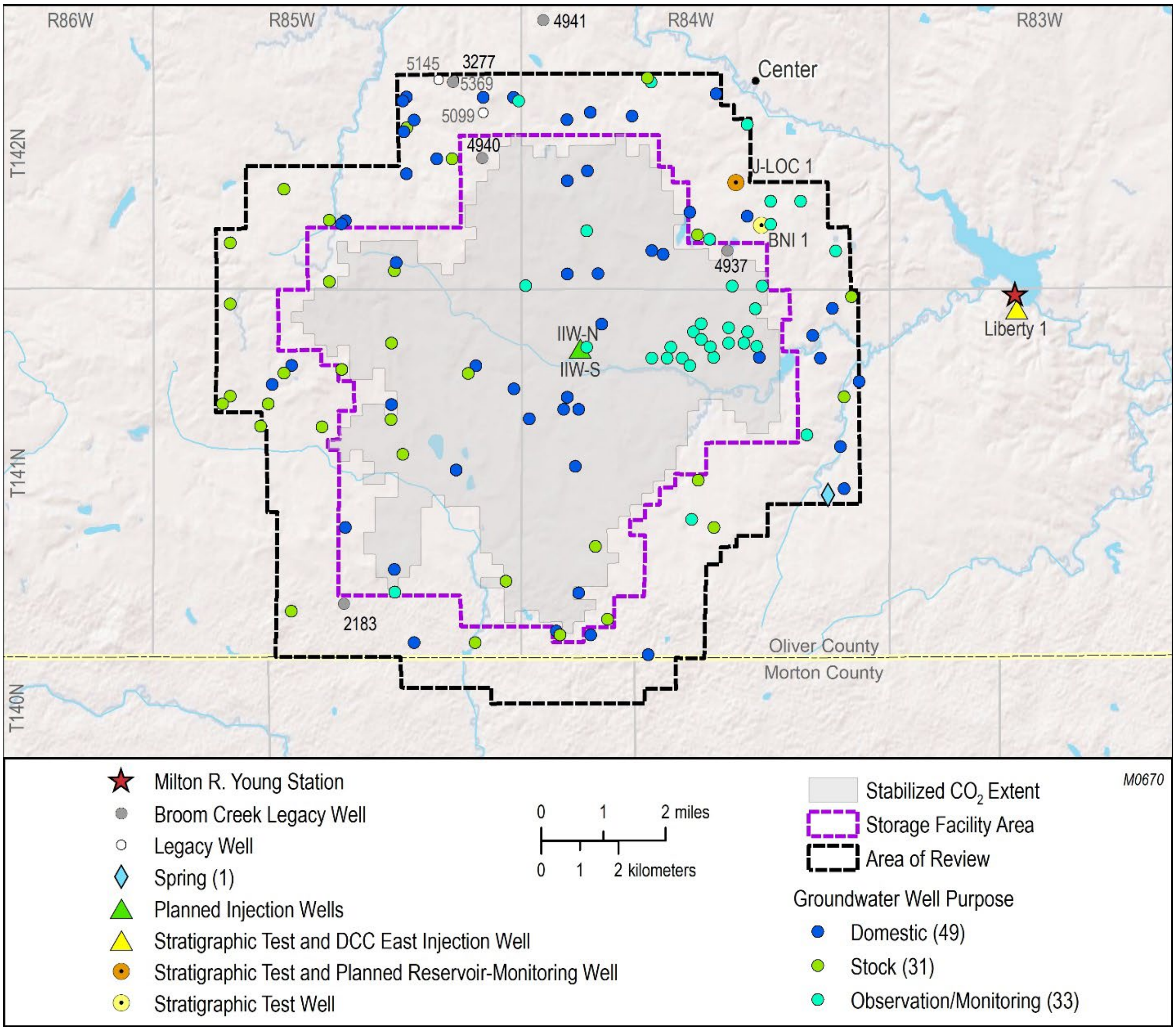

Figure 4-3. AOR map in relation to nearby legacy wells (wells that penetrate the Broom Creek as gray circles and wells that do not penetrate the Broom Creek as white circles) and groundwater wells. Shown are the storage facility area (dashed purple boundary) and 1-mi AOR boundary (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. One spring is present in the AOR.

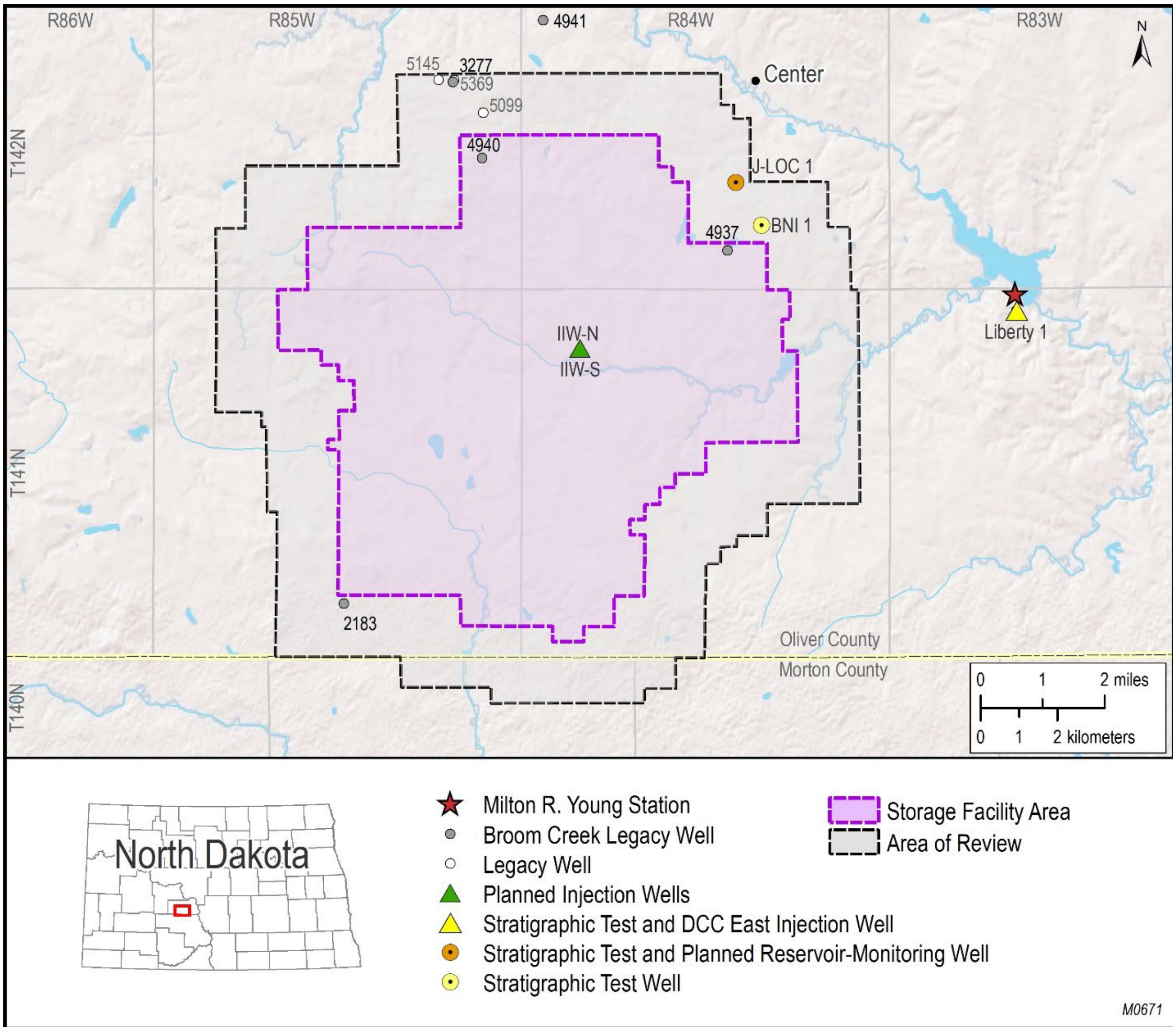

Figure 4-4. The AOR map in relation to nearby legacy wells that penetrate the Broom Creek Formation. Shown are the storage facility area (purple boundary), city of Center, and AOR (gray boundary). Gray circles represent nearby legacy wells penetrating the Broom Creek Formation while the white circles represent other legacy wells that do not reach the Broom Creek Formation.

Table 4-1. Investigated and Identified Surface and Subsurface Features (Figures 4-1 through 4-4)

Surface and Subsurface Features	Investigated and Identified (Figures 4-1 through 4-4)	Investigated But Not Found in AOR
Injection Wells		X
Producing (active) Wells		X
Abandoned Wells	X	
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs	X	
Water Wells	X	
Mines (surface and subsurface)	X	
Quarries		X
Subsurface Structures (e.g., coal mines)	X	
Location of Proposed Wells	X	
Location of Proposed Cathodic Protection Boreholes*		X
Any Existing Aboveground Facilities	X	
Structures Intended for Human Occupancy	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines	X	
Indian Country Boundary Lines		X
Other Pertinent Surface Features**	X	

* Cathodic protection planned with location TBD.
** Center, North Dakota, city limit boundary.

4.2 Corrective Action Evaluation

Table 4-2. Wells in AOR Evaluated for Corrective Action

NDIC[1] Well File No.	Operator	Well Name	Spud Date	Surface Casing OD, in.	Surface Casing Seat, ft	Long-String Casing, in.	Hole Direction	TD,[2] ft	TVD,[3] ft	Status	Plug Date	TWN	RNG	Section	Qtr/Qtr	County	Area	Corrective Action Needed
2183	Signal Drilling & Exploration, Inc.	Paul Bueligen 1	3/22/1959	8.625	666	Openhole	Vertical	6894	6894	P&A[4]	4/18/1959	141 N	85 W	34	NW/NW	Oliver	AOR	No
4940	General American Oil Company of Texas	Raymond Henke 1-24	8/29/1970	8.625	643	Openhole	Vertical	9604	9604	P&A	10/4/1970	142 N	85 W	24	SE/SW	Oliver	SFA	No
3277	Sunray DX Oil CO.	Ervin V. Henke 1	11/18/1962	9.625	673	Openhole	Vertical	8000	8000	P&A	12/13/1962	142 N	85 W	14	NE/SE	Oliver	AOR	No
4937	General American Oil Company of Texas	Herbert Dresser 1-34	8/25/1970	8.625	300	Openhole	Vertical	6042	6042	P&A	9/8/1970	142 N	84 W	34	SE/NW	Oliver	SFA	No
34244	University of North Dakota EERC	BNI 1	1/17/2018	9.625	1386	Openhole	Vertical	5316	5315	P&A	2/6/2018	142 N	84 W	27	SE/SE	Oliver	AOR	No
37380	Minnkota Power Cooperative, Inc.	J-LOC 1	5/14/2020	9.625	1654	5.5	Vertical	10470	10470	TA[5]	N/A	142 N	84 W	27	SW/NE	Oliver	AOR	No
4941	General American Oil Company of Texas	Kenneth Henke 1-7	7/22/1970	8.625	296	Openhole	Vertical	6218	6218	P&A	25785	142 N	84 W	7	NE/SW	Oliver	Outside	No
5099	W. H. Hunt Trust Estate	Henke 1	8/28/1971	8.625	318	Openhole	Vertical	4315	4315	Dry	26181	142 N	85 W	24	NE/NW	Oliver	AOR	No
5145	Calvert Drilling & R. K. Petroleum Corp.	Albert Albers 1	12/4/1971	8.625	330	Openhole	Vertical	3920	3920	Dry	26276	142 N	85 W	14	NW/SE	Oliver	AOR	No
5369	Cardinal Petroleum Co. &R.K. Petroleum	Henke 9-14	11/14/1973	8.625	289	Openhole	Vertical	3814	3814	Dry	26987	142 N	85 W	14	NE/SE	Oliver	AOR	No

[1] North Dakota Industrial Commission.
[2] Total depth.
[3] True vertical depth.
[4] Plugged and abandoned.
[5] Temporarily abandoned.

Table 4-3. Paul Bueligen 1 (NDIC File No. 2183) Well Evaluation

Well Name: Paul Bueligen 1 (NDIC File No. 2183)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	6491	6560	69	15
2	5821	5890	69	15
3	5191	5260	69	15
4	3981	4050	69	15
5	586	666	80	25
6	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	666	Cement Plug 5 isolates bottom of surface casing.
Pierre	1340	
Mowry	–	
Inyan Kara	4010	Cement Plug 4 isolates top of Inyan Kara Formation.
Swift	–	
Opeche	4988	
Broom Creek	5140	Cement Plug 3 within Broom Creek Formation, uppermost 51 ft may be exposed to openhole.
Kibbey Lime	5874	Cement Plug 2 isolates top of Kibbey Lime Formation.

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.3ppg mud weight gypsum mud.

Spud Date: 11/18/1968
Total Depth: 6894 ft (Mission Canyon Formation)

Surface Casing:
8⅝" casing set at 666 ft

P&A

Corrective Action: No corrective action necessary. Cement Plug 4 isolates the top of the Inyan Kara Formation and prevents fluid from reaching the Fox Hills Formation. Cement Plug 3 is within Broom Creek Formation. Upper 51 ft of Broom Creek Formation is exposed to previously drilled openhole.

Table 4-4. Raymond Henke 1-24 (NDIC File No. 4940) Well Evaluation

Well Name: Raymond Henke 1-24 (NDIC File No. 4940)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	9221	9306	85	25
2	5997	6082	85	25
3	4209	4294	85	25
4	4008	4093	85	25
5	541	620	79	25
6	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	643	Cement Plug 5 isolates bottom of surface casing.
Pierre	1470	
Mowry	3794	
Inyan Kara	4080	Cement Plug 4 isolates upper section of Inyan Kara Formation and prevents upward movement. Cement Plug 3 isolates lower portion of Inyan Kara Formation.
Swift	4371	
Spearfish/Opeche	–	
Broom Creek	5212	
Charles	6082	Cement Plug 2 isolates the top of the Charles Formation.

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.5ppg mud weight salt mud.

Spud Date: 8/29/1970
Total Depth: 9604 ft (Red River Formation)

Surface Casing:
8⅝" casing set at 643 ft

P&A

Corrective Action: No corrective action necessary. Cement Plug 4 at the top of the Inyan Kara Formation isolates and prevents movement of fluid to the Fox Hills Formation. Cement Plug 3 set at lower Inyan Kara Formation provides additional barrier between Broom Creek Formation and Fox Hills Formation. Broom Creek Formation is exposed to openhole. Lowest 77 ft section of Inyan Kara Formation may be exposed to openhole.

Table 4-5. Ervin V. Henke 1 (NDIC File No. 3277) Well Evaluation

Well Name: Ervin V. Henke 1 (NDIC File No. 3277)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	7653	7738	85	25
2	6278	6363	85	25
3	4915	5000	85	25
4	3939	4024	85	25
5	607	673	66	25
6	0	27	27	10

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
9⅝" Casing Shoe	673	Cement Plug 5 isolates bottom of surface casing.
Pierre	1413	
Mowry	3703	
Inyan Kara	3983	Cement Plug 4 isolates top of Inyan Kara Formation.
Swift	4295	
Spearfish/Opeche	–	Cement Plug 3 isolates above the Broom Creek Formation preventing upward movement
Broom Creek	5162	
Mission Canyon	6552	Cement Plug 2 above the Mission Canyon Formation.

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.1ppg mud weight low solids with diesel mud.

Spud Date: 11/18/1968
Total Depth: 8000 ft (Duperow Formation)

Surface Casing:
9⅝" casing set at 673 ft

P&A

Corrective Action: No corrective action necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs. Cement Plug 3 prevents fluid movement from the Broom Creek Formation past the Opeche/Spearfish Formation. Cement Plug 4 prevents movement to the Fox Hills Formation.

Table 4-6. Herbert Dresser 1-34 (NDIC File No. 4937) Well Evaluation

Well Name: Herbert Dresser 1-34 (NDIC File No. 4937)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	5738	5823	85	25
2	4874	4959	85	25
3	3975	4060	85	25
4	3809	3894	85	25
5	260	343	83	25
6	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	300	Cement Plug 5 isolates the 8⅝" casing shoe with 43 and 40 ft cement below and above the casing shoe, respectively.
Pierre	1282	
Greenhorn	3223	
Mowry	3593	Cement Plug 4 isolated across the top of the Inyan Kara Formation. Cement Plug 3 isolates lower section of Inyan Kara Formation.
Inyan Kara	3890	
Swift	4105	
Broom Creek	4940	Cement Plug 2 isolates 19 ft of the Broom Creek Formation and its upper-confining layer with a total cement plug thickness of 85 ft.

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.4ppg mud weight chem gel.

Corrective Action: No corrective action is necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs and is within the estimated AOR.

Spud Date: 8/25/1970
Total Depth: 6042 ft (Charles Formation)
Surface Casing:
8⅝" 36# K-55 casing set at 300 ft, cement to surface with 225 sacks of Class G cement.

Openhole P&A

Table 4-7. BNI 1 (NDIC File No. 34244) Well Evaluation

Well Name: BNI 1 (NDIC File No. 34244)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	4739	5199	460	170
2	3466	3623	157	60
3	1277	1447	170	75
4	68	125	57	25

All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
Pierre	1225	Cement Plug 3 isolates the 9⅝" casing shoe with 61 ft and 109 ft cement below and above the casing shoe, respectively.
9⅝" Casing Shoe	1386	
Greenhorn	3170	
Mowry	3568	
Newcastle	3628	
Inyan Kara	3840	Cement Plug 2 isolates above the Inyan Kara Formation.
Swift	4104	
Rierdon	4522	
Broom Creek	4900	Cement Plug 1 isolates 161 ft above and completely across the Broom Creek Formation, respectively.

Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.4ppg mud weight water based

Spud Date: 1/17/2018
Total Depth: 5316 ft (Amsden Formation)

Surface Casing:
9⅝" 36# J-55 casing set at 1386 ft, cement to surface with 465 sacks of Class G cement.

Openhole P&A

Corrective Action: No corrective action is necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs and is located near the outside edge of the AOR. Monitoring at this location may be necessary depending on actual plume growth.

Table 4-8. J-LOC 1 (NDIC File No. 37380) Well Evaluation

Well Name: J-LOC 1 (NDIC File No. 37380)

Casing Program				
Section	Casing Outside Diameter (in.)	Weight, (lb/ft)	Casing Seat (ft)	Grade
Surface	9⅝	40	1654	K-55
Production	5½	23	10,450	L-80 13Cr-95

Cementing Program				
Casing (in.)	Cement Type	TOC[1] (ft)	Excess (%)	Volume, sacks
9⅝	Class C	Surface	100	728
5½	Class G	2920	100	1160
	CO_2-resistant	4592		

Completion/Plugging Program

Item	Description	Length (ft)	Top Depth (ft)
1	Wireline bailed cement	50	3929
2	2AA CICR[2]	1.73	3979
3	Perforation	10	4015
4	2AA CIBP[3]	1.5	4069
5	Wireline bailed cement	50	4846
6	2AA CICR	1.73	4896
7	Perforation	10	4912
8	Wireline bailed cement	50	9782
9	2AA CICR	1.73	9832
10	Perforation	10	9880

Spud Date: 5/14/2020
Total Depth: 10,470 ft (Precambrian basement)
Cased hole TA

Formation		Remarks
Name	Estimated Top (ft)	
Pierre	1250	Dual casing and cement isolate the surface section.
9⅝" Casing Shoe	1654	
Mowry	3585	Production casing, cement, CIBP, CICR, and cement above isolate the Inyan Kara Formation.
Inyan Kara	3888	
Swift	4057	
Opeche/Spearfish	4879	Production casing, CO_2-resistant cement, CICR, and cement above isolate the Broom Creek Formation.
Broom Creek	4908	
Amsden	5210	
Icebox	9662	Production casing, CO_2-resistant cement, CICR and cement above isolate the Deadwood and Black Island Formations.
Black Island	9783	
Deadwood	9821	
Precambrian	10,298	

Corrective Action: No corrective action is necessary. The Deadwood Formation is isolated mechanically by conventional and CO_2-resistant casing and cement. Perforations in the Deadwood, Broom Creek, and Inyan Kara Formations have been isolated by cement, CICRs, and cement on top. A mechanical integrity test (MIT) was witnessed and approved by the North Dakota State Inspector on December 21, 2020.

[1] Top of cement.
[2] Cast iron cement retainers.
[3] Cast iron bridge plug.

Table 4.9. Kenneth Henke 1-7 (NDIC File No. 4941) Well Evaluation

Well Name: Kenneth Henke 1-7 (NDIC File No. 4941)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	5921	6006	85	25
2	4915	5000	85	25
3	4115	4200	85	25
4	3915	4000	85	25
5	220	300	80	25
6	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	296	Cement Plug 5 isolates bottom of surface casing.
Pierre	1375	
Mowry	3694	
Inyan Kara	3990	Cement Plug 4 isolates top of Inyan Kara Formation.
Swift	4183	Cement Plug 3 across top of Swift Formation.
Spearfish/Opeche	–	Cement Plug 2 isolates Broom Creek Formation.
Broom Creek	5093	Cement Plug 1 across Charles Formation.

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 9.7ppg mud chem gel

Spud Date: 7/22/1970
Total Depth: 6218 ft (Charles Formation)

Surface Casing:
8⅝" casing set at 296 ft

P&A

Corrective Action: No corrective action necessary. The Broom Creek Formation is isolated mechanically by a series of balanced cement plugs. Cement Plug 2 prevents fluid movement from the Broom Creek Formation.

Table 4-10. Henke 1 (NDIC File No. 5099) Well Evaluation

Well Name: Henke 1 (NDIC File No. 5099)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	4115	4200	85	25
2	3405	3490	85	25
3	2806	360	80	25
4	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation	Cement Plug Remarks	
Name	Wireline Top (ft)	
8⅝" Casing Shoe	318	Cement Plug 3 isolates bottom of surface casing
Pierre	1470	
Greenhorn	3407	Cement Plug 2 isolates across the Greenhorn Formation
Mowry	3795	
Inyan Kara	4096	Cement Plug 1 within the Inyan Kara Formation

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 10.1ppg mud

Spud Date: 08/28/1971
Total Depth: 4315 ft (Morrison Formation)

Surface Casing:
8⅝" casing set at 318 ft

P&A

Corrective Action: No corrective action necessary. The well has not penetrated the Broom Creek Formation. Cement Plug 1 prevents any fluid movement from Inyan Kara

Table 4-11. Albert Albers 1 (NDIC File No. 5145) Well Evaluation

Well Name: Albert Albers 1 (NDIC File No. 5145)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	2932	3000	68	20
2	266	330	64	20
3	0	16	16	5

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation		Cement Plug Remarks
Name	Wireline Top (ft)	
8⅝" Casing Shoe	330	Cement Plug 2 isolates bottom of surface casing
Pierre	1444	
Greenhorn	3383	Cement Plug 1 is above the Greenhorn Formation preventing upward fluid movement.
Mowry	3775	

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with drilling mud.

Spud Date: 12/04/1971
Total Depth: 3920 ft (Cretaceous Formation)

Surface Casing:
8⅝" casing set at 330 ft

P&A

Corrective Action: No corrective action necessary. The well has not penetrated the Broom Creek Formation. Cement Plug 1 prevents any fluid movement above the Greenhorn Formation.

Table 4-12. Henke 9-14 (NDIC File No. 5369) Well Evaluation

Well Name: Henke 9-14 (NDIC File No. 5369)

Cement Plugs				
Number	Interval (ft)		Thickness (ft)	Volume (sacks)
1	3670	3755	85	25
2	275	360	85	25
3	0	16	16	5
4				

Note: All cement plugs have been calculated using 1.15 sacks per cubic foot and a gauge hole.

Formation	Cement Plug Remarks	
Name	Wireline Top (ft)	
8⅝" Casing Shoe	289	Cement Plug 3 isolates bottom of surface casing
Pierre	1424	
Greenhorn	3324	
Mowry	3703	Cement Plug 1 across the top of the Mowry Formation.
Inyan Kara	3756	

Note: Data and information are provided from well-plugging report found in NDIC database.

Well was drilled and abandoned with 9.9ppg mud

Spud Date: 11/14/1973
Total Depth: 3814 ft (Formation)

Surface Casing:
8⅝" casing set at 289 ft

P&A

Corrective Action: No corrective action necessary. The well has not penetrated the Broom Creek Formation. Cement Plug 1 prevents any fluid movement from above the Mowry Formation.

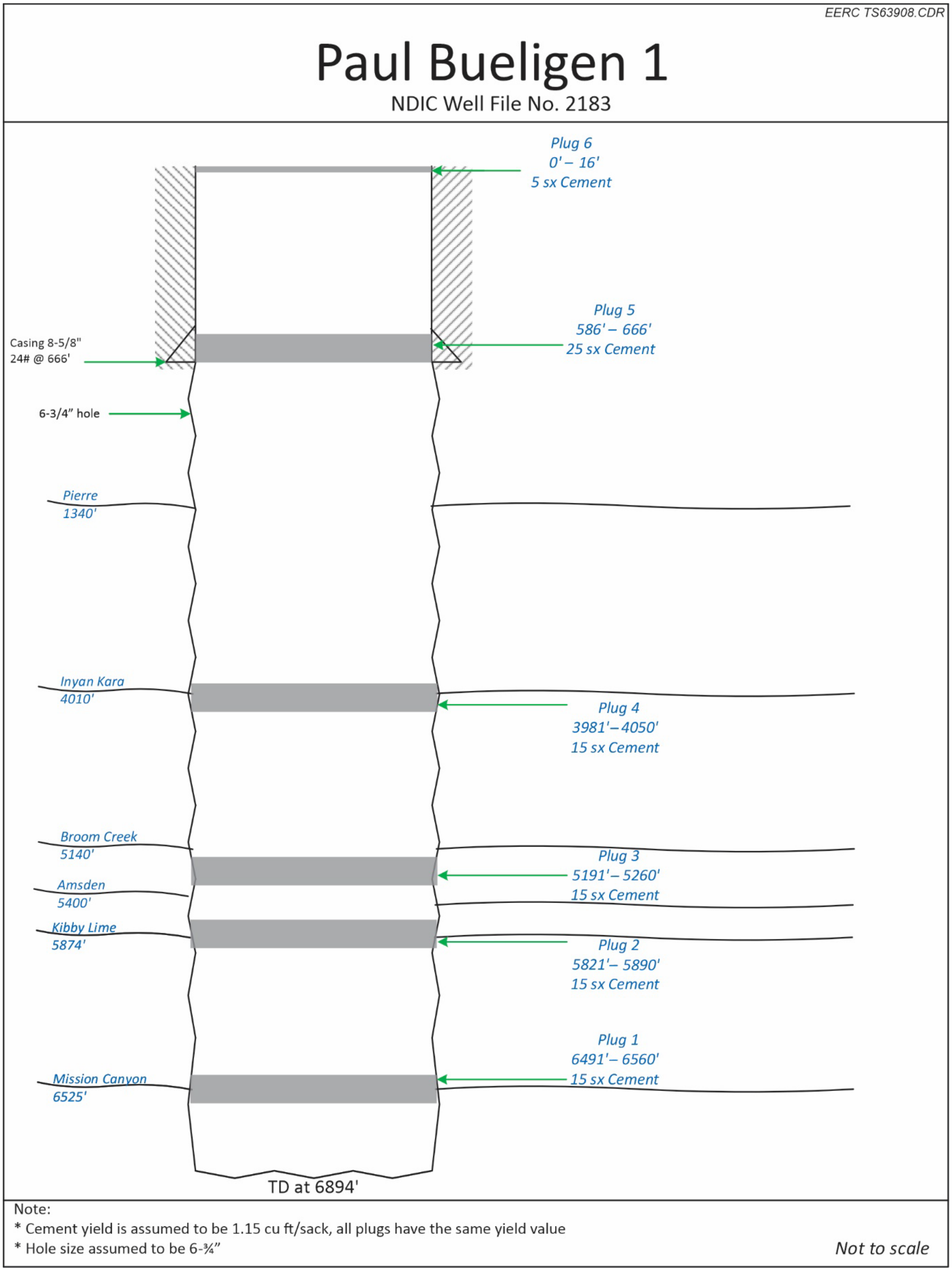

Figure 4-5. Paul Bueligen 1 (NDIC File No. 2183) well schematic showing the location and thickness of cement plugs.

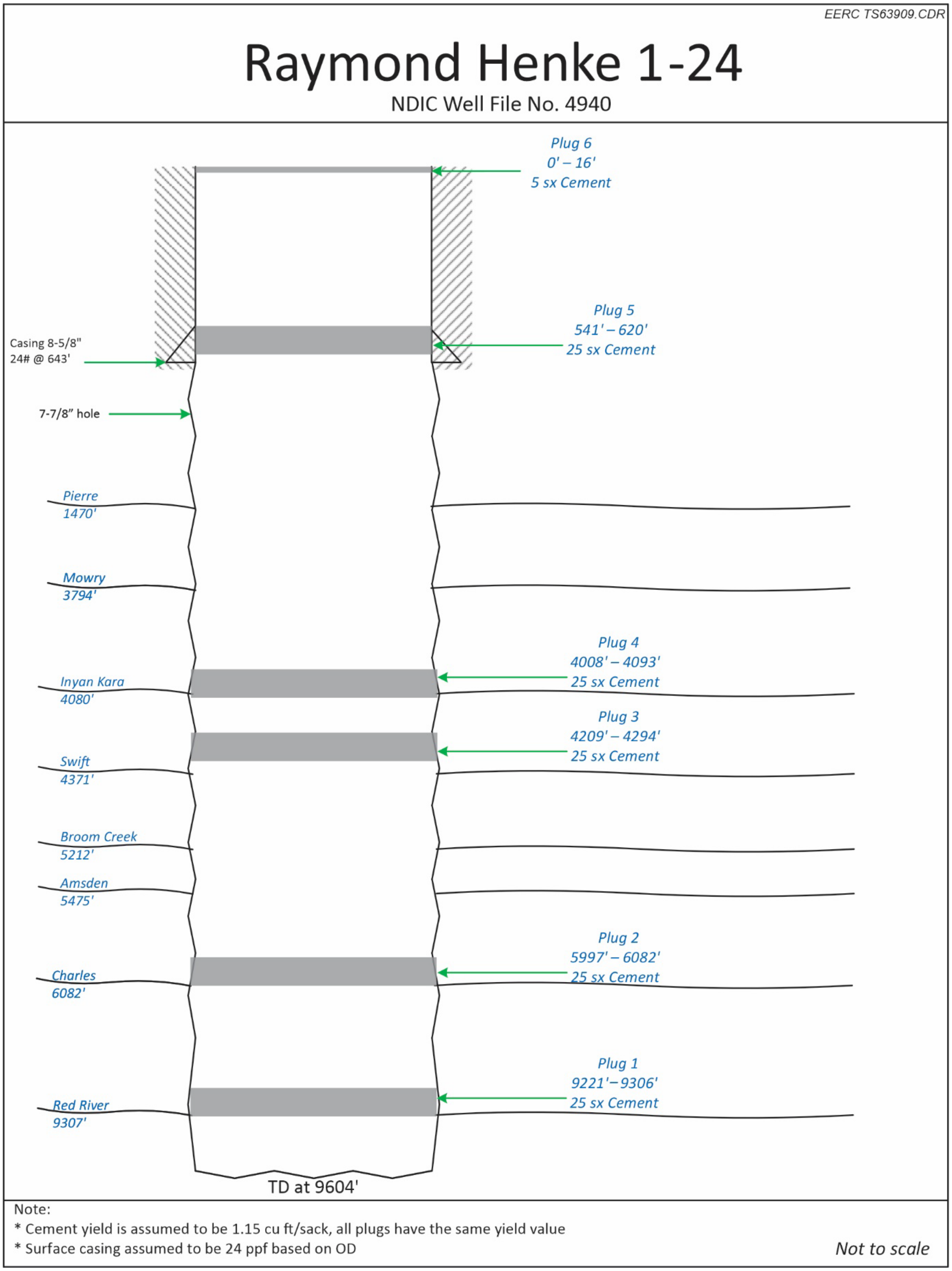

Figure 4-6. Raymond Henke 1-24 (NDIC File No. 4940) well schematic showing the location and thickness of cement plugs.

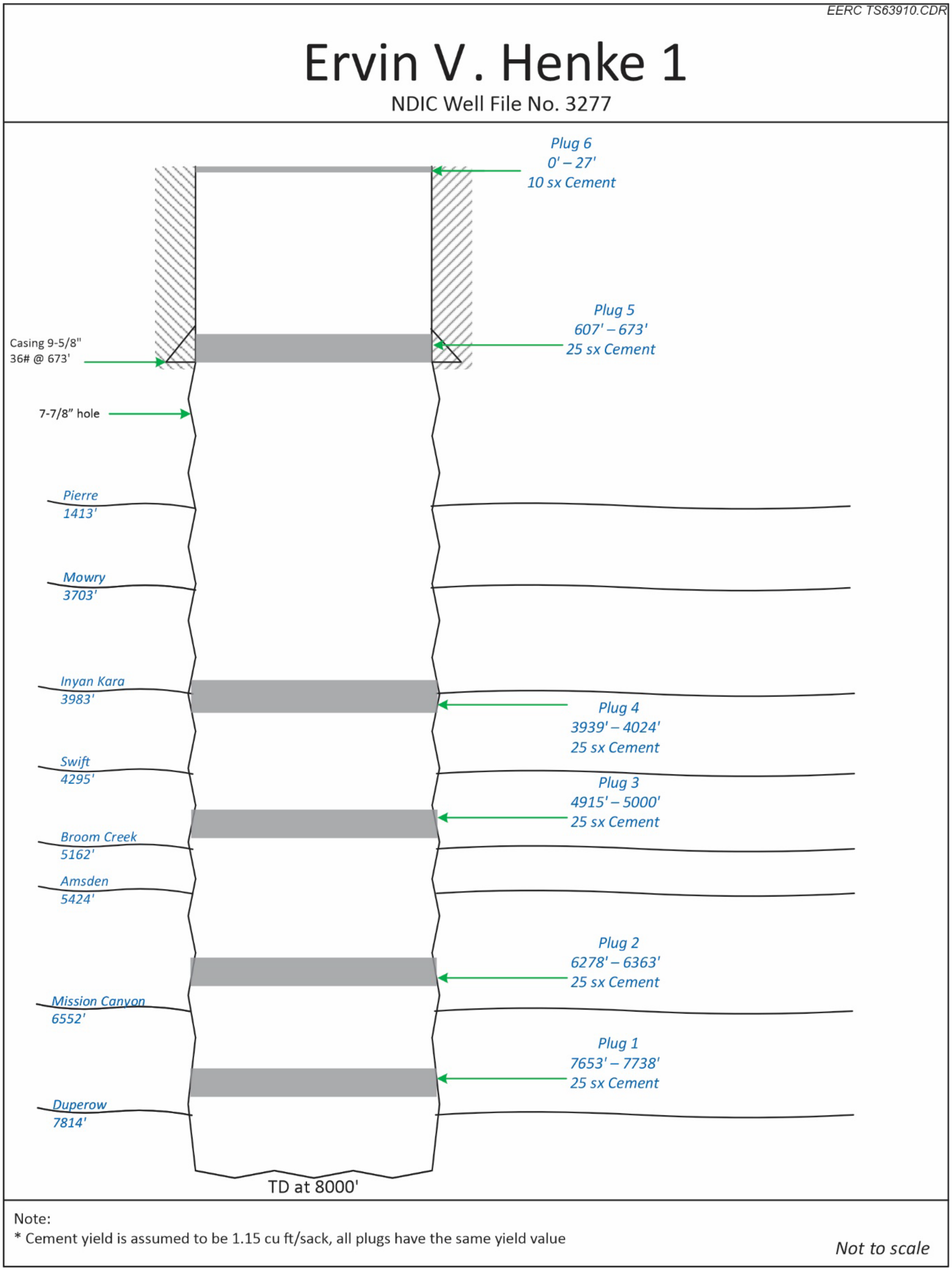

Figure 4-7. Ervin V. Henke 1 (NDIC File No. 3277) well schematic showing the location and thickness of cement plugs.

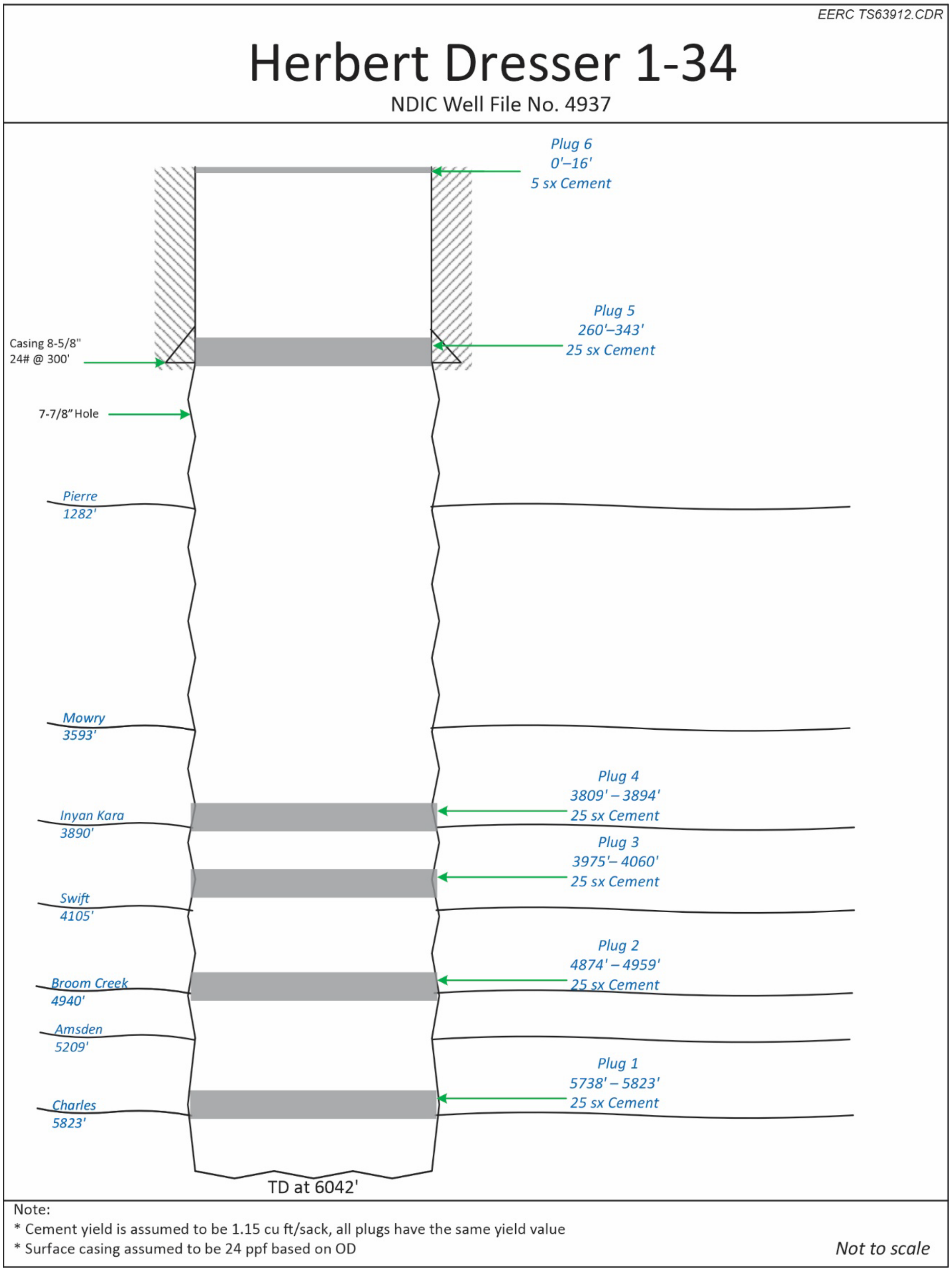

Figure 4-8. Herbert Dresser 1-34 (NDIC File No. 4937) well schematic showing the location and thickness of cement plugs.

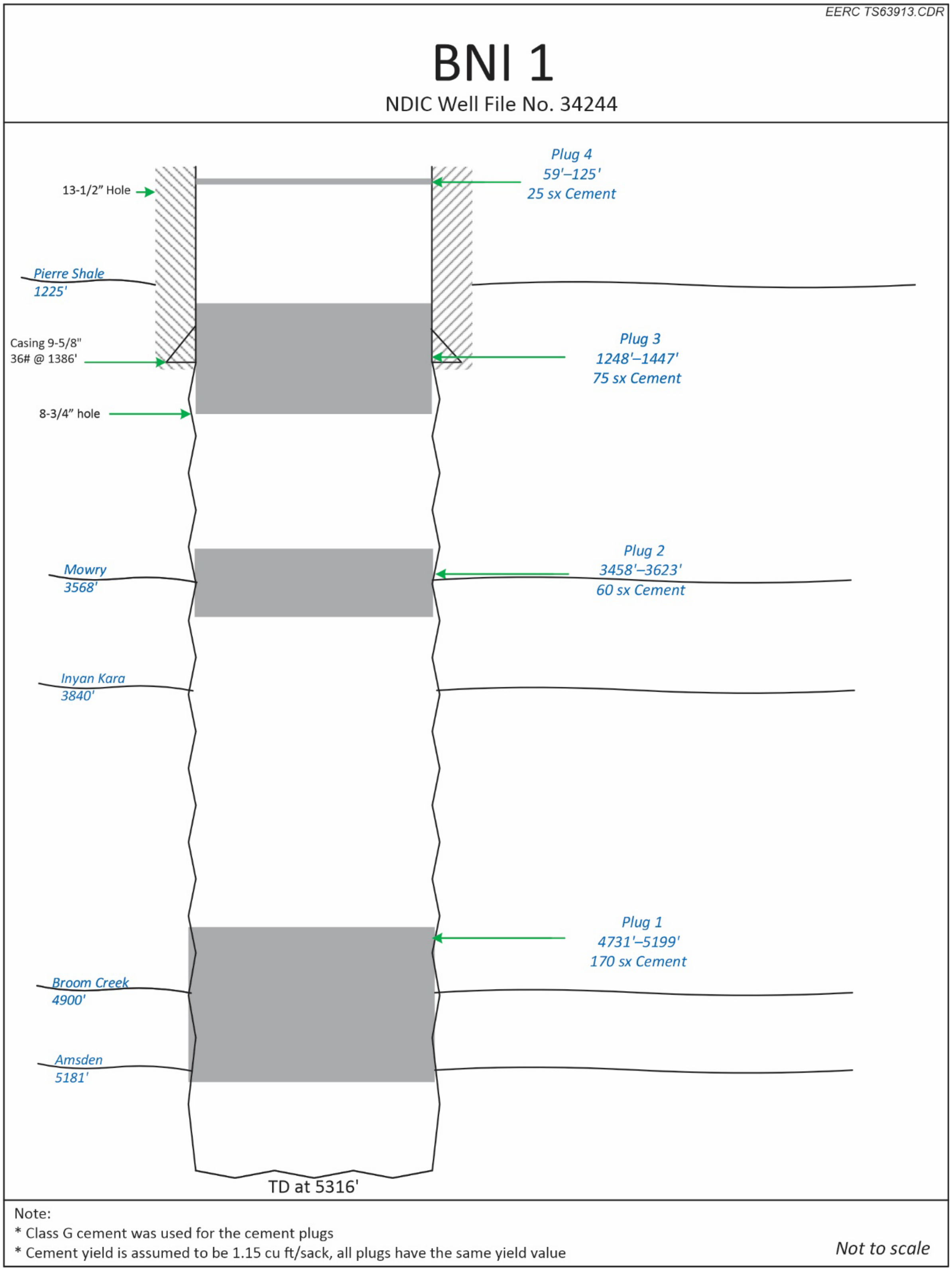

Figure 4-9. BNI 1 (NDIC File No. 34244) well schematic showing the location and thickness of cement plugs.

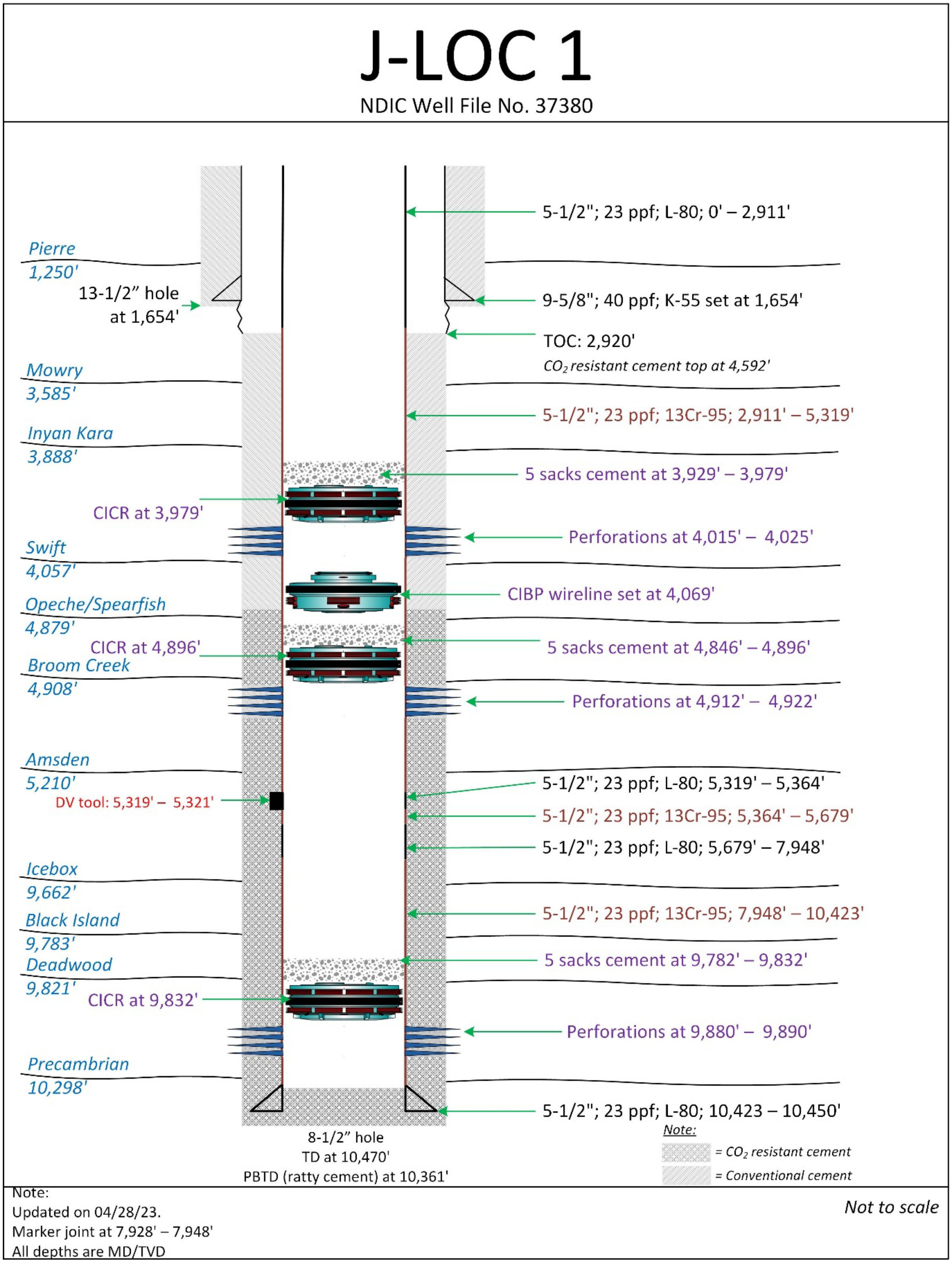

Figure 4-10. J-LOC 1 (NDIC File No. 37380) well schematic showing the location and thickness of cement plugs and cement retainers.

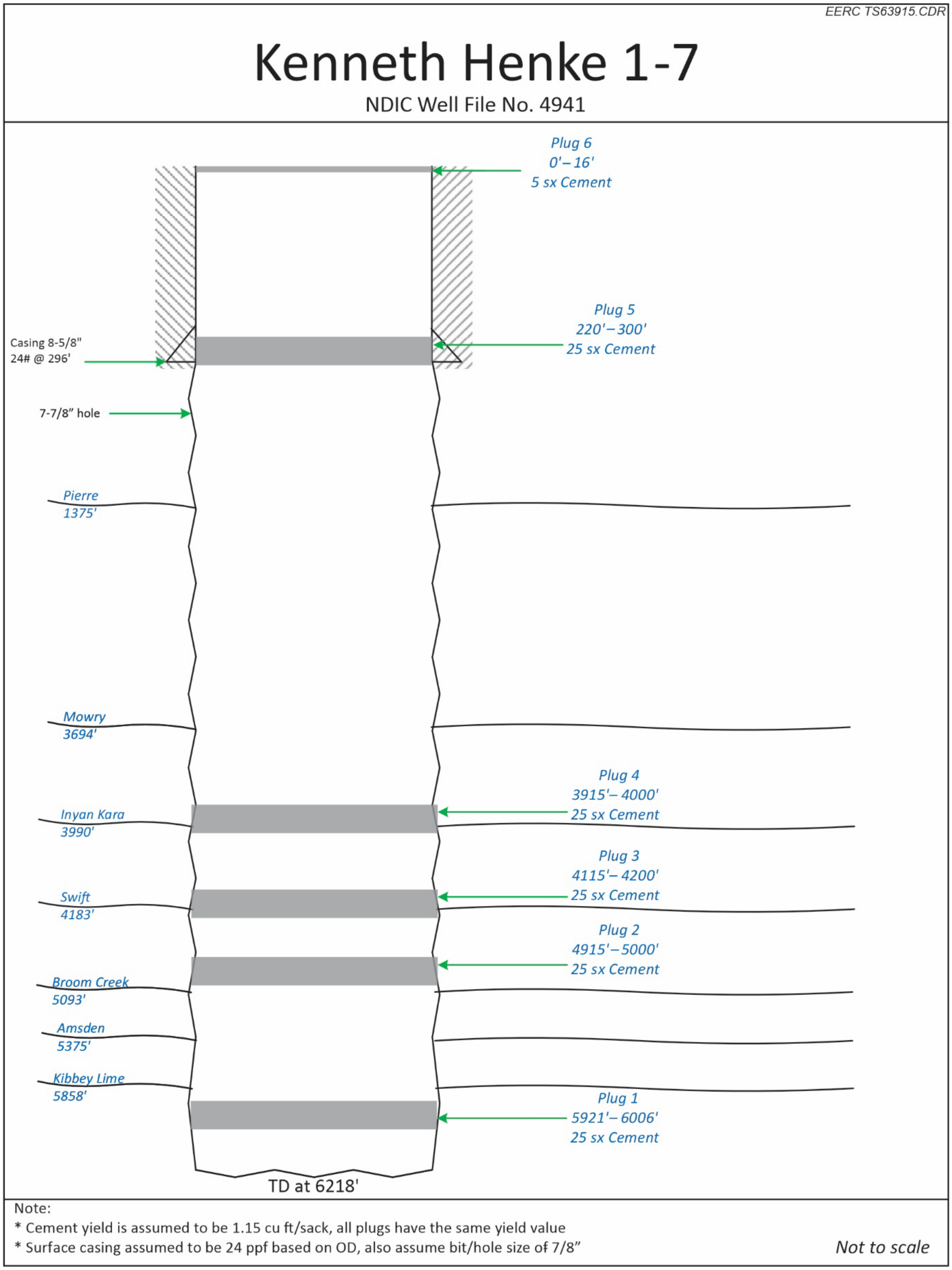

Figure 4-11. Kenneth Henke 1-7 (NDIC File No. 4941) well schematic showing the location and thickness of cement plugs.

4.3 Reevaluation of AOR and Corrective Action Plan

The AOR and corrective action plan will periodically be reevaluated in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each referred to as a Reevaluation Date). The AOR reevaluations will address the following:

- Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date.

- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified.

- The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.

4.4 Protection of USDWs

4.4.1 Introduction of USDW Protection

The primary confining zone and additional overlying confining zones geologically isolate the Fox Hills Formation, the lowest USDW in the AOR, from the underlying injection zone. The Opeche-Picard interval is the primary confining zone, with additional confining layers above, geologically isolating all USDWs from the injection zone. The uppermost confining layer is the Pierre Formation, an impermeable shale in excess of 1000 ft thick, providing an additional seal for all USDWs in the region (Table 4-13 and Figure 4-12).

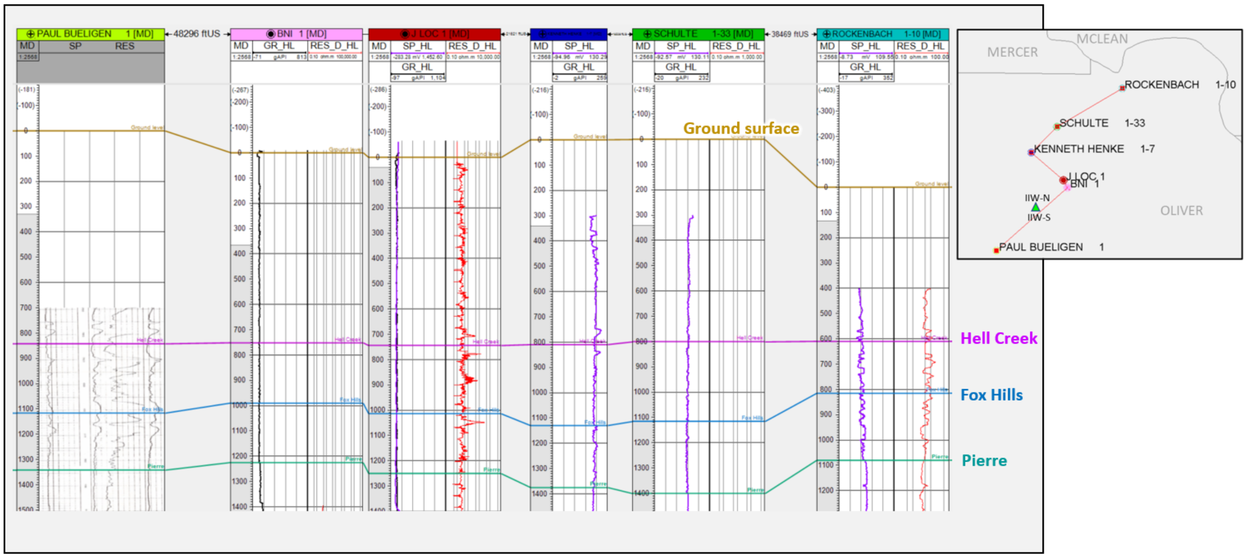

Figure 4-12. South to north cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown in the inset map and labeled with corresponding well names.

Table 4-13. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the J-LOC 1 geologic model formation tops)

Name of Formation	Lithology	Formation Top Depth,* ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Shale	1250	1934	0
Greenhorn	Shale	3184	401	1934
Mowry	Shale	3585	60	2335
Skull Creek	Shale	3655	233	2405
Swift	Shale	4057	47	2807
Rierdon	Shale	4529	146	3279
Piper (Kline Member)	Limestone	4675	109	3425
Piper (Picard)	Shale	4784	95	3534
Opeche/Spearfish	Shale	4879	29	3629

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota comprises several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-13). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 and 1500 ft thick (Thamke and others, 2014).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; overlying Cannonball, Tongue River, and Sentinel Butte Formations of the Tertiary Fort Union Group; and Tertiary Golden Valley Formation (Figure 4-14). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers, which are not necessarily present in all parts of the AOR (Croft, 1973).

The lowest USDW in the AOR is the Fox Hills Formation, which together with the overlying Hell Creek Formation is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit comprising interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all fluvial in origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the AOR is approximately 900 to 1200 ft deep and 200 to 350 ft thick. The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of DCC West SGS (Figure 4-15).

The Pierre Shale is a thick, regionally extensive shale unit, which forms the lower boundary of the Fox Hills–Hell Creek system, also isolating all overlying freshwater aquifers from the deeper saline aquifer systems. The Pierre Shale is a dark gray to black marine shale and is typically 1000-ft thick in the AOR (Thamke and others, 2014).

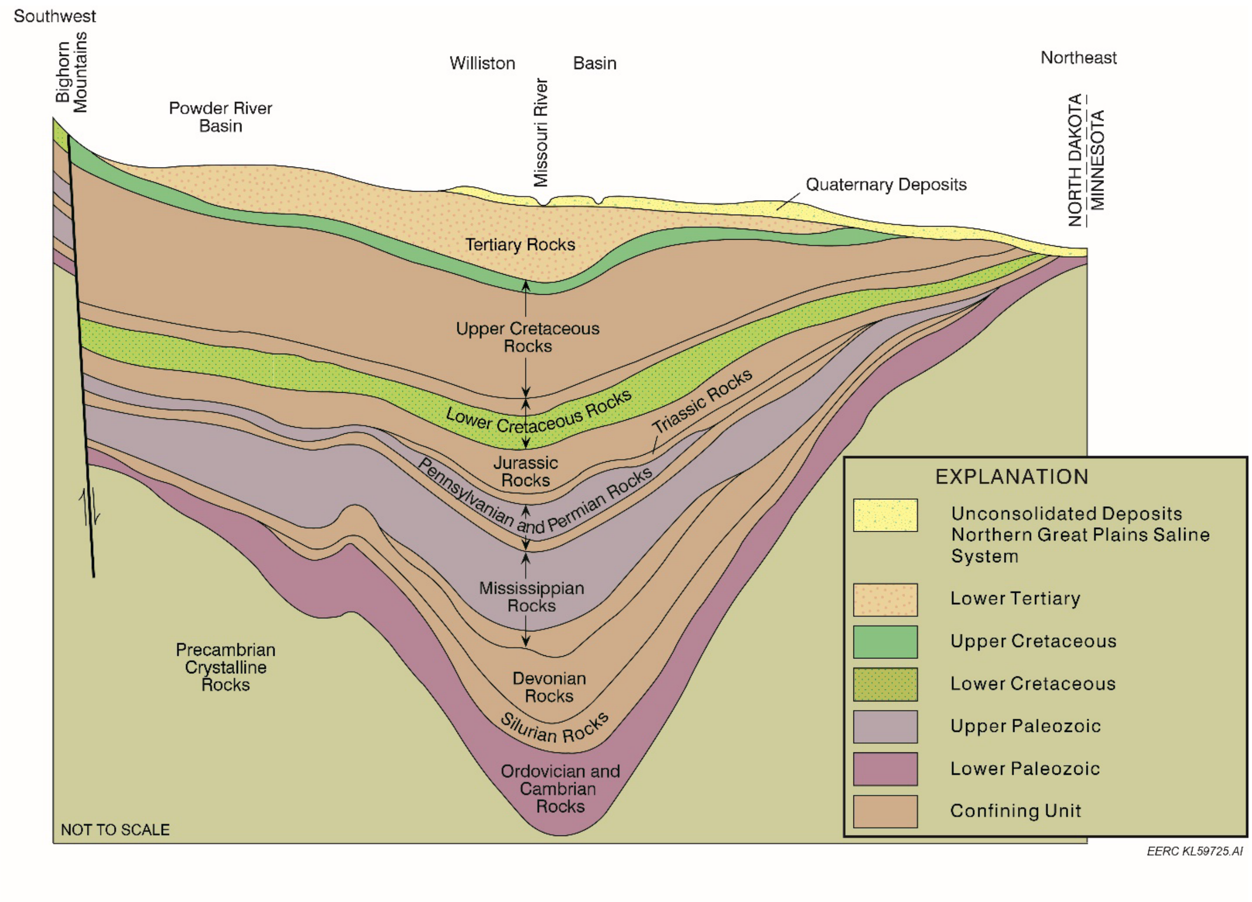

Figure 4-13. Major aquifer systems of the Williston Basin.

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
	Tertiary		Golden Valley	Yes
		Fort Union	Sentinel Butte	Yes
			Tongue River	Yes
			Cannonball	Yes
Mesozoic	Cretaceous		Hell Creek	Yes
			Fox Hills	Yes
			Pierre	No
		Colorado	Niobrara	No
			Carlile	No
			Greenhorn	No
			Belle Fourche	No

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Figure 4-14. Upper stratigraphy of Oliver County showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973).

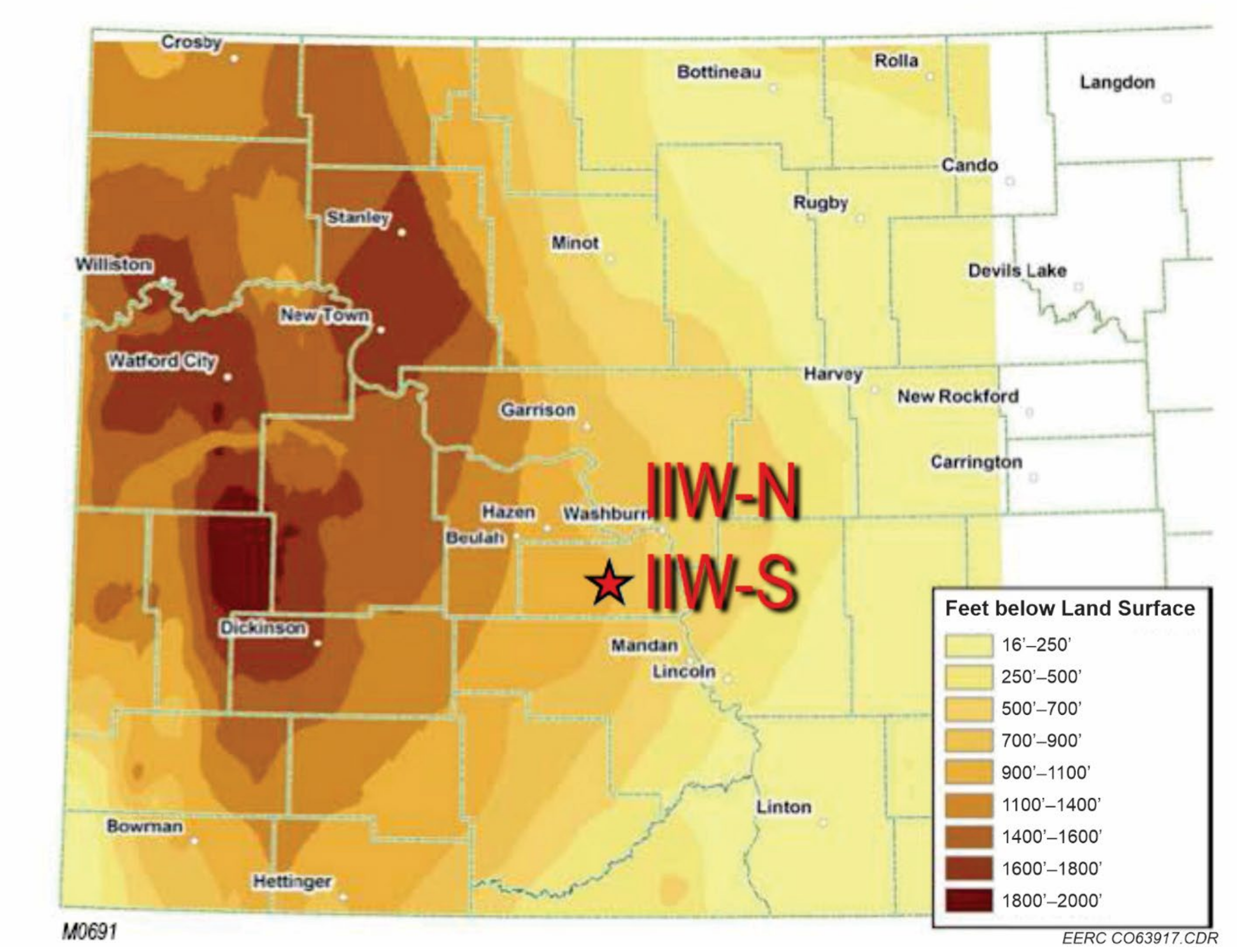

Figure 4-15. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

4.4.3 Hydrology of USDW Formations

The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, which isolates it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AOR is to the east (Figure 4-16). Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a TDS (total dissolved solids) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering.

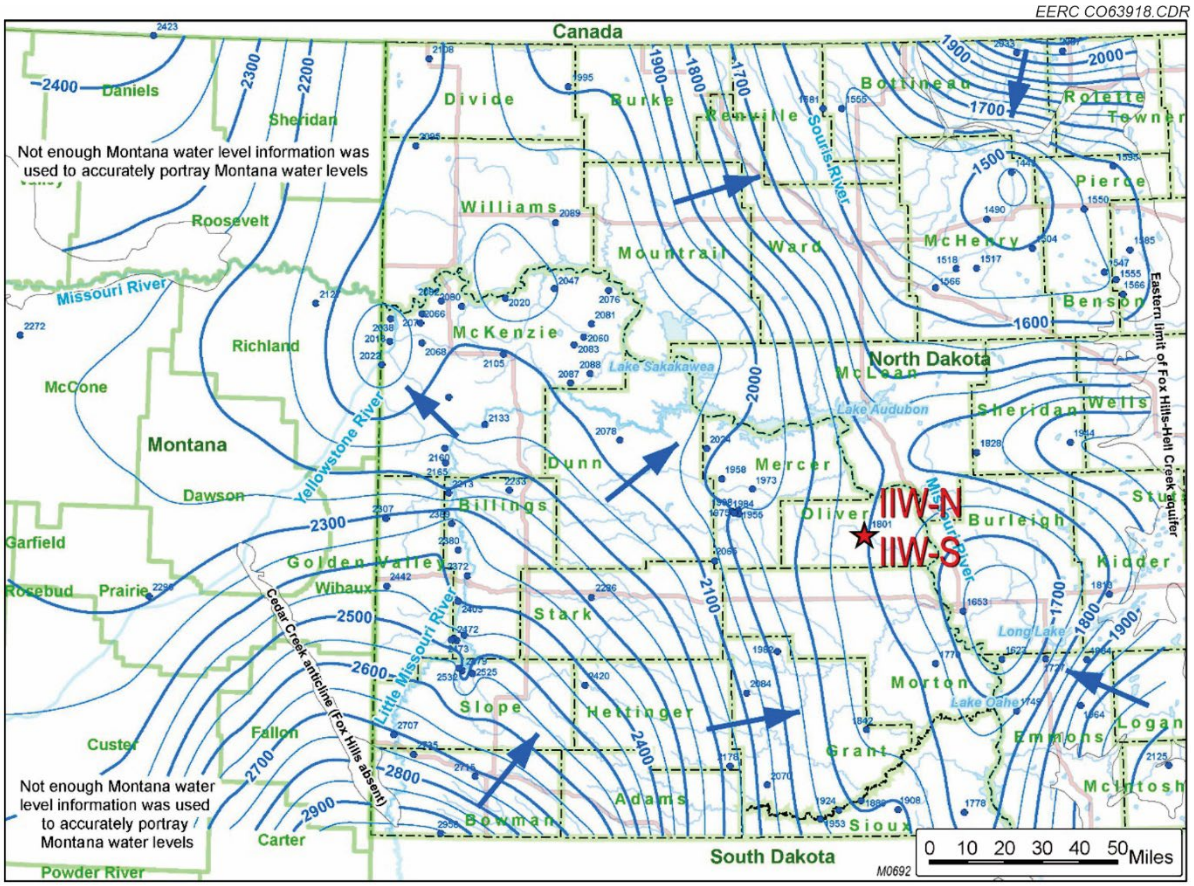

Figure 4-16. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the AOR in central Oliver County (modified from Fischer, 2013).

Seven Broom Creek legacy wells (NDIC File No. 2183, 4940, 4937, 3277, 5149, 5369, 5099), one stratigraphic test well, BNI 1 (NDIC File No. 34244), and one stratigraphic test and planned reservoir-monitoring well J-LOC 1, (NDIC File No. 37380), penetrate through the Fox Hills within the AOR (Table 4-2). Based on the North Dakota State Water Commission (SWC) database, two water wells (W295 and W395) penetrate the Fox Hills Formation in the AOR (Figure 6-3 in Section 6). An additional 11 wells are deeper than 400 feet within the AOR but shallower than the Fox Hills Formation. These are made up of one observation well (Well Index 9432), six domestic wells, and four stock wells.

Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR. A cross section of these formations is presented in Figure 4-17. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional

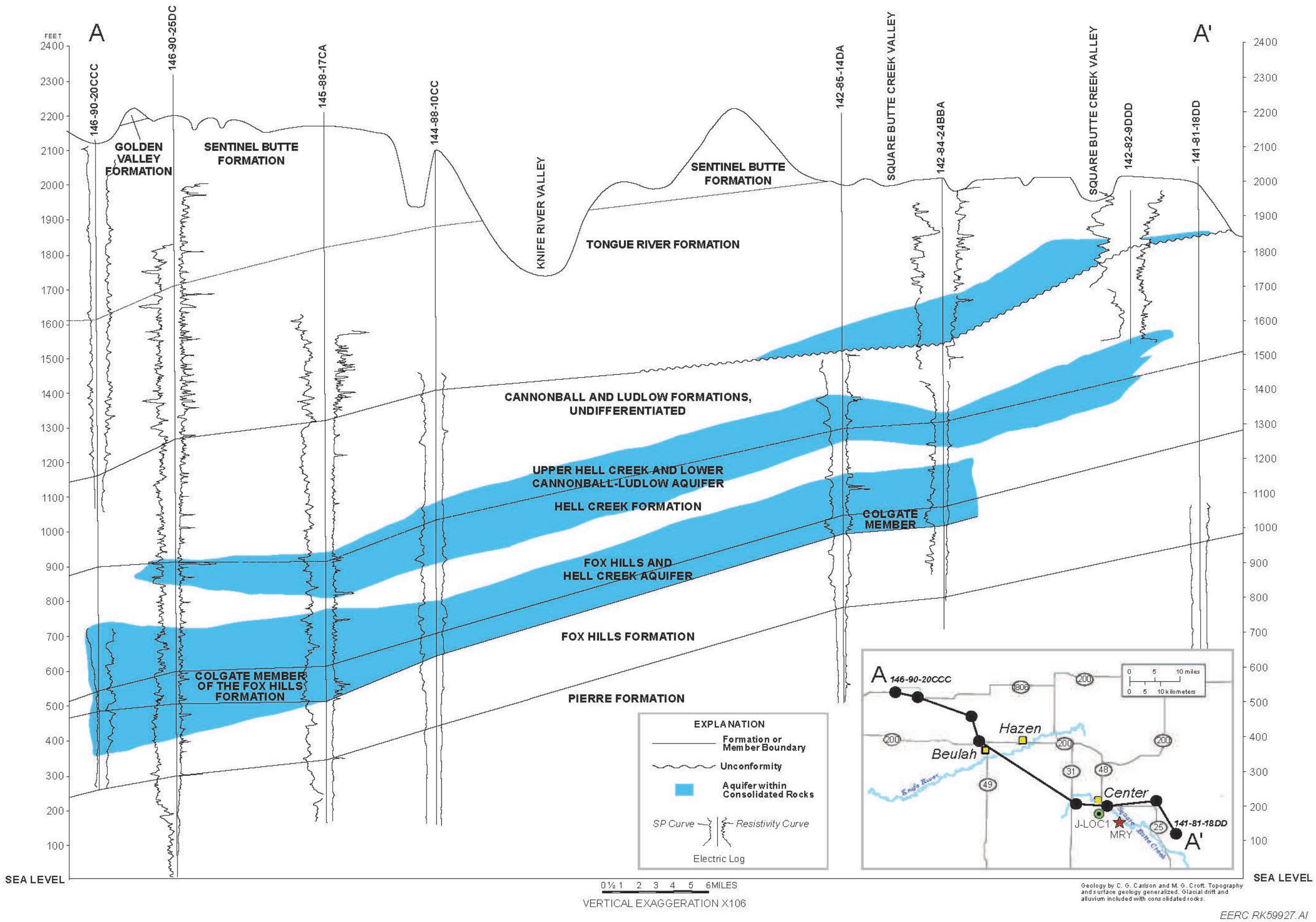

Figure 4-17. West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section.

carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the AOR. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1000 ppm (Croft, 1973).

In the far western portion of the AOR, the Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation ranges from approximately 400–1000 ppm (Croft, 1973).

4.4.4 Protection for USDWs

The Fox Hills–Hell Creek aquifer system is the lowest USDW in the AOR. The injection zone (Broom Creek Formation) and lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations of Permian, Jurassic, and Cretaceous age (Figure 2-2). The primary seal of the injection zone is the Permian-aged Opeche/Spearfish Formation with the shales of the Permian-aged Spearfish, Jurassic-aged Piper (Picard), Rierdon, and Swift Formations, all of which overlie the Opeche Formation. Above the Swift is the confined saltwater aquifer system of the Inyan Kara Formation, which extends across much of the Williston Basin. Above the Inyan Kara Formation are the Cretaceous-aged shale formations, which are named the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations. The Pierre Formation is the thickest shale formation in the AOR and primary geologic barrier between the USDWs and injection zone. The geologic strata overlying the injection zone consist of multiple impermeable rock layers that are free of transmissive faults or fractures and provide adequate isolation of the USDWs from CO_2 injection activities in the AOR.

4.5 References

Croft, M.G., 1973, Ground-water resources of Mercer and Oliver Counties, North Dakota: U.S. Geological Survey, County Ground Water Studies – 15.

Fischer, K., 2013, Groundwater flow model inversion to assess water availability in the Fox Hills–Hell Creek Aquifer: North Dakota State Water Commission Water Resources Investigation No. 54.

Thamke, J.N., LeCain, G.D., Ryter, D.W., Sando, R., and Long, A.J., 2014, Hydrogeologic framework of the uppermost principal aquifer systems in the Williston and Powder River structural basins, United States and Canada: U.S. Geological Survey Groundwater Resources Program Scientific Investigations Report 2014-5047.

Trapp, H., and Croft, M.G., 1975, Geology and ground water resources of Hettinger and Stark Counties North Dakota: U.S. Geological Survey, County Ground Water Studies – 16.

SECTION 5.0

TESTING AND MONITORING PLAN

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5.0 TESTING AND MONITORING PLAN

This testing and monitoring plan includes: 1) a plan for analyzing the captured CO_2 stream; 2) leak detection and corrosion-monitoring plans for surface facilities and all wells associated with the project; 3) a well logging and testing plan; 4) an environmental monitoring plan to verify the injected CO_2 is contained in the storage reservoir; and 5) a quality assurance and surveillance plan (QASP). Table 5-1 provides an overview of the planned testing and monitoring activities.

Table 5-1. Overview of the Major Components of the Testing and Monitoring Plan

	Monitoring Activity	Equipment/Testing	Target Area
SURFACE	Continuous CO_2 Injection Pressure, Rate, and Volume Measurements	Surface P/T[a] gauge and a flowmeter installed near each injection wellhead for continuous monitoring	Surface-to-reservoir (CO_2 injection wells)
SURFACE	CO_2 Stream Analysis	Compositional and isotopic testing	Near the flowmeter placed downstream of the point of transfer
SURFACE	Surface Facilities Leak Detection	Gas detection stations on flowline risers and injection wellheads, surface P/T gauges, acoustic detectors, and flowmeters with shutoff alarms spliced to SCADA[b] system for continuous monitoring	Flowline from the point of transfer to the CO_2 injection wellheads
SURFACE	CO_2 Flowline Corrosion Detection	Flow-through corrosion coupon testing	Flowline from the point of transfer to the CO_2 injection wellheads
WELLBORE	External Mechanical Integrity	Casing-conveyed DTS[c] (fiber optic) for continuous monitoring, with temperature or oxygen activation logging as backup methods	Well infrastructure
WELLBORE	Internal Mechanical Integrity	Surface digital gauges on tubing and annulus and tubing-conveyed P/T gauges for continuous monitoring; tubing-casing annulus pressure testing	Well infrastructure
WELLBORE	Downhole Corrosion Detection	Flow-through corrosion coupon testing and PNLs,[d] with ultrasonic logging or other approved CIL[e] as backup methods	Well materials
ENVIRONMENTAL	Near-Surface (soil gas and groundwater) Monitoring	Sampling and analysis of soil gas profile stations, selected shallow groundwater wells, and dedicated Fox Hills monitoring wells	Vadose zone and USDWs
ENVIRONMENTAL	Above-Zone Monitoring Interval (Inyan Kara Formation)	DTS for continuous monitoring and PNLs	CO_2 injection wellbores
ENVIRONMENTAL	Direct Storage Reservoir Monitoring	Continuous monitoring with DTS and tubing-conveyed P/T gauge, PNLs, and pressure falloff testing	Storage reservoir and primary confining zone
ENVIRONMENTAL	Indirect Storage Reservoir Monitoring	Continuous monitoring with seismicity stations and time-lapse VSPs[f] and seismic surveys	Entire storage complex

[a] Pressure/temperature.
[b] Supervisory control data and acquisition.
[c] Distributed temperature sensing.
[d] Pulsed-neutron log.
[e] Casing inspection log.
[f] Vertical seismic profile.

Pursuant to NDAC § 43-05-01-11.4, the combination of the foregoing efforts is used to verify that the project is operating as permitted and is not endangering USDWs. Another purpose of this testing and monitoring plan is to establish baseline (preinjection) conditions for the surface facilities, CO_2 injection and reservoir-monitoring wellbores, soil gas, groundwaters down to the lowest USDW (Fox Hills Aquifer), and the storage reservoir complex associated with the project.

DCC West will review this testing and monitoring plan at a minimum of every 5 years to ensure the technologies and strategies deployed remain appropriate for demonstrating containment of CO_2 in the storage reservoir and conformance with predictive modeling and simulations.

A detailed testing and monitoring plan for the baseline and operational phases of the project is provided in the remainder of this section. Section 6.0 (Postinjection Site Care and Facility Closure Plan) details the testing and monitoring activities planned for the postinjection phase. A comprehensive summary of the testing and monitoring plan from baseline through postinjection site care is provided in Appendix E (Testing and Monitoring Summary Table).

5.1 CO_2 Stream Analysis

The captured CO_2 stream will be continuously monitored during injection operations to accurately measure CO_2 volumes transported from the custody transfer station at the Liberty 1 CO_2 injection site near the Milton R. Young Station (MRYS) (i.e., point of transfer) to the injection wellheads. A P/T gauge and flowmeter installed on the CO_2 flowline near each of the CO_2 injection wellheads (IIW-N and IIW-S) will provide continuous, real-time measurements of the injection volume, rate, pressure, and temperature of the CO_2 stream during operations. The monitoring equipment will be spliced to a SCADA system and have automated shutoff alarms for notifying the operations center in the event of an anomalous reading.

Another goal of monitoring the captured CO_2 stream is to protect the materials and equipment that will come into contact with the stream. DCC West calculated a CO_2 stream specification from the MRYS, as shown in Table 5-2. In accordance with NDAC § 43-05-01-11.4(1)(a), the captured CO_2 stream will be sampled at least once prior to injection and at least quarterly throughout the operational phase of the project. CO_2 stream sample ports will be placed downstream of the point of transfer and the main metering stations near each injection wellhead. The CO_2 stream will be sampled and analyzed using methods and standards generally accepted by industry to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density.

Table 5-2. Calculated MRYS CO_2 Stream Specification

Component	Composition	Volume %
CO_2	≥ 96%	≥ 96.0%
N_2	< 37,000 ppmv*	< 3.7%
H_2	0 ppmv	0.000%
O_2	< 100 ppmv	< 0.0100%
H_2S	< 10 ppmv	< 0.0010%

Continued…

Table 5-2. Calculated MRYS CO_2 Stream Specification (continued)

Component	Composition	Volume %
Total Sulfur	< 1.25 ppmv	< 0.000125%
Moisture – No Free Water	< 642 ppmv	< 0.0642%
Hydrocarbons	< 1800 ppmv	< 0.18%
Glycol	< 7 ppmv	< 0.0007%
Amine	< 1.25 ppmv	< 0.000125%
Aldehydes	< 5 ppmv	< 0.0005%
NO_x	< 50 ppmv	< 0.005%
NH_3	< 1 ppmv	< 0.0001%
	TOTAL	100.0%

* Parts per million by volume.

5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to specify the monitoring strategies DCC West will use to quantify any losses of CO_2 during operations from the surface facilities. Surface facilities include the CO_2 injection wellheads (IIW-N and IIW-S), the reservoir-monitoring wellhead (J-LOC 1), and the CO_2 flowline from the point of transfer to the injection wellheads. Figure 5-1 is a site map showing the locations of the surface facilities and a generalized injection wellsite layout. Figure 5-2 is a generalized flow diagram from the point of transfer to the injection wellheads, illustrating key surface connections and monitoring equipment.

The CO_2 flowline will be monitored with a P/T gauge and flowmeter located downstream of the point of transfer and near each of the injection wellheads for performing mass balance calculations. The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Acoustic detectors, further described in Attachment A-1 of Appendix D, will be installed at strategic locations along the flowline path to help detect any auditory anomalies. Gas detection stations will also be placed at the injection wellheads and key wellsite locations (e.g., flowline risers and inside enclosures). The gas detection stations, further described in Attachment A-2 in Appendix D, will have an integrated alarm system to monitor for multiple gases, including but not limited to CO_2 and H_2S. The leak detection equipment will be spliced to a SCADA system for continuous, real-time monitoring and integrated with automated warning systems to notify the operations center, giving DCC West the ability to remotely close the valves in the event of an emergency. The SCADA system is briefly described in Attachment A-3 of Appendix D.

Each of the injection and reservoir-monitoring wellheads will be equipped with a gas detection station. Gas detection stations will also be placed inside the wellhead enclosures. The stations will be integrated with the SCADA system for continuous, real-time monitoring.

Field personnel will have multigas detectors with them for all visits to the wellsite or during flowline inspections. The multigas detectors, which will primarily monitor CO_2 levels in workspace atmospheres, are described in Attachment A-4 in Appendix D. The multigas detectors will be inspected prior to every field visit and be maintained according to the manufacturer's

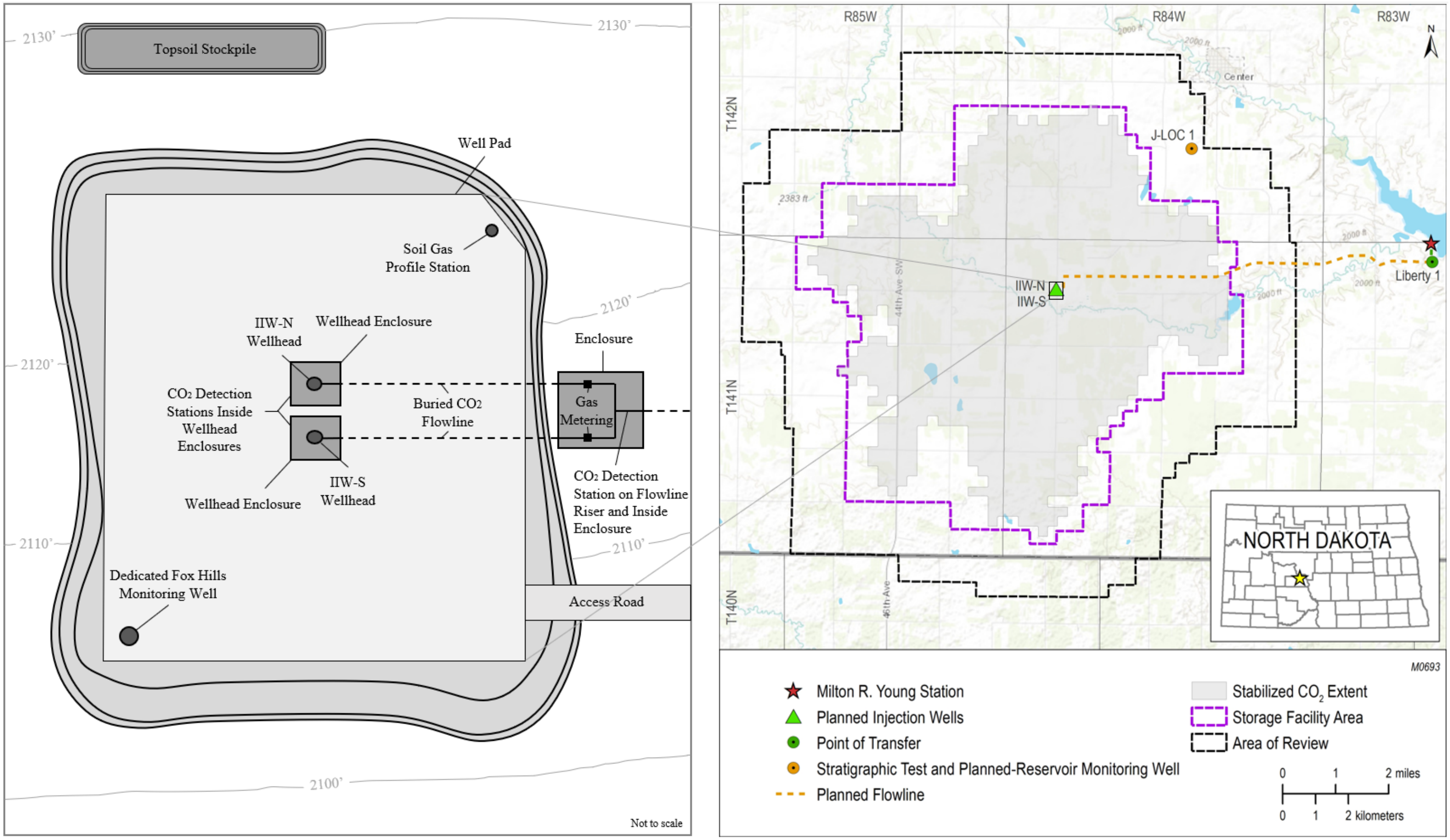

Figure 5-1. Site map detailing the surface facilities layout. Inset map illustrates a generalized injection wellsite layout with monitoring equipment identified.

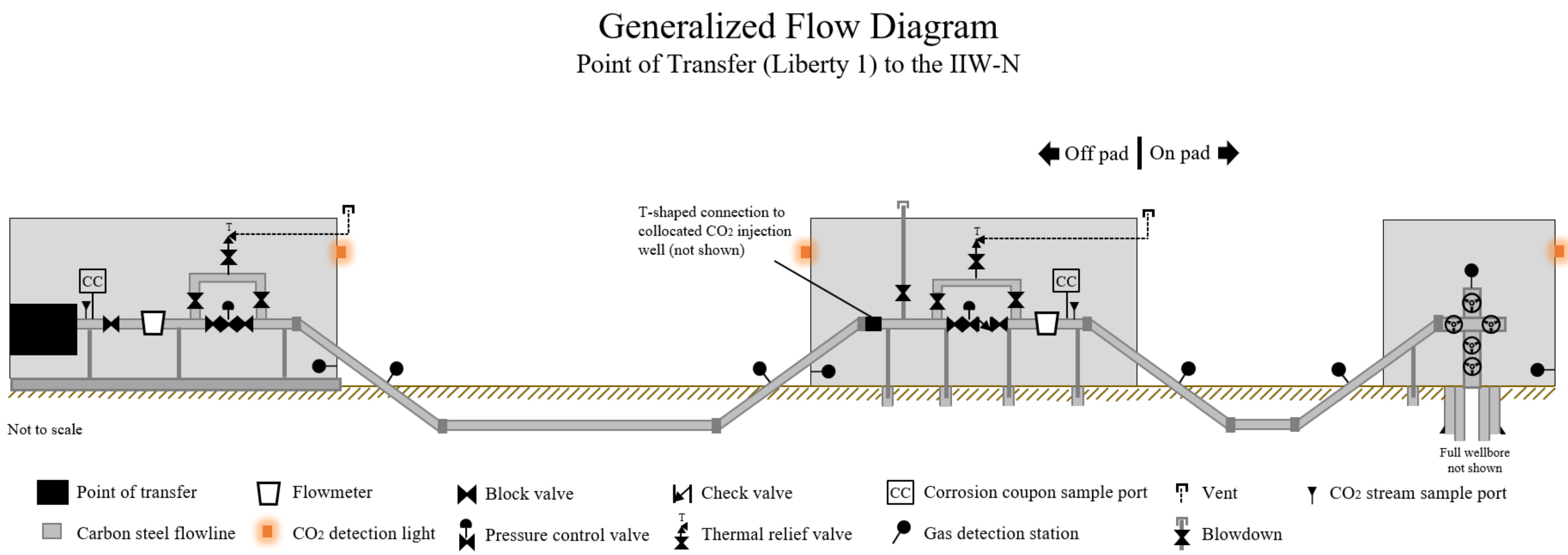

Figure 5-2. Generalized flow diagram from the point of transfer to the IIW-N injection well illustrating key surface connections and monitoring equipment. This flow diagram is identical for the IIW-S injection well (not shown).

recommendations. In addition, CO_2 detection safety lights (part of the integrated alarm system) will be placed outside of all enclosures to warn field personnel of potential indoor air quality threats.

Pursuant to NDAC § 43-05-01-14, leak detection equipment will be inspected and tested on at least a semiannual basis. Any defective equipment will be repaired or replaced and retested. A record of each inspection result will be kept by the site operator, maintained for at least 10 years, and made available to the NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC.

5.2.1 Data Sharing

The CO_2 flowline from the capture facility (MRYS) to injection wellsites associated with DCC East's permitted geologic CO_2 storage project and DCC West (this application) will be operated as one integrated SCADA system with data flowing to a single operations center, which will allow DCC East and West to share operational data and controls in real-time and ensure operational parameters (e.g., flowline pressures) are safely maintained between the two sites at all times.

5.3 CO_2 Flowline Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance.

5.3.1 Corrosion Prevention

The CO_2 stream concentration is highly pure (at least 96% by volume; Table 5-2). The high-purity CO_2 stream helps to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be in accordance with American Petroleum Institute (API) 5L X-65 PSL 2 (2018) requirements, which includes applying external coatings to the pipe (e.g., fusion-bonded epoxy) and any borings or crossings (e.g., abrasive-resistant overcoats) to prevent corrosion. The flowline will also use a cathodic protection system in accordance with 49 Code of Federal Regulations (CFR) Part 195. DCC West will supply the NDIC with a map of cathodic protection borehole locations to meet NDAC § 43-05-01-05(1)(a) prior to injection.

5.3.2 Corrosion Detection

Pursuant to NDAC § 43-05-01-11.4(1)(c)(3), DCC West will use the corrosion coupon method to monitor for corrosion in the CO_2 flowline throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. Coupon sample ports will be located near the point of transfer and near each injection wellhead (Figure 5-2), and sampling will occur quarterly. At the request of the NDIC, DCC West may also utilize a coupon sample port for conducting longer-term coupon testing (e.g., annually). The process that will be used to conduct each coupon test is described in Appendix D under Section 1.3.2.

5.4 Wellbore Mechanical Integrity Testing

Pursuant to NDAC § 43-05-01-11.1, DCC West will conduct the mechanical integrity testing of the CO_2 injection and reservoir-monitoring wellbores to ensure there is no significant leak in the casing, tubing, or packer and no significant fluid movement into an USDW adjacent to the wellbore. External mechanical integrity in the CO_2 injection wells (IIW-N and IIW-S) and reservoir-monitoring well (J-LOC 1) will be demonstrated with the following:

1) An ultrasonic logging tool (example provided as Attachment A-5 of Appendix D) in combination with variable-density logs (VDLs) and cement bond logs (CBLs) will be used to establish the baseline external mechanical integrity behind the well casing. Repeat ultrasonic logs in the CO_2 injection wells may be run during well workovers in cases where the well tubing must be pulled.

2) A PNL (example provided as Attachment A-6 of Appendix D) will also be run to establish the baseline saturation profile behind casing. During injection operations in the CO_2 injection wells, the PNL (in sigma mode) will be run in Year 1, again at Year 3, and at least once every 3 years thereafter (i.e., Year 6, Year 9, and so on) for confirming external mechanical integrity by assessing signs of vertical migration of CO_2 in the near wellbore environment. If the repeat PNLs detect evidence of vertical migration of CO_2 outside the storage reservoir, then DCC West will notify and work with NDIC to identify and take appropriate action, such as pulling the well tubing and running an ultrasonic logging tool for attributing the source of the suspected out-of-zone migration.

3) DTS fiber-optic cable (described in Attachment A-7 of Appendix D) installed outside of the long-string casing will continuously monitor the temperature profile of the CO_2 injection wellbores from the storage reservoir to surface.

4) A baseline temperature log will be run in case the DTS fiber-optic cable fails and temperature log data are needed in the future. An oxygen activation log may also be collected as a future alternative backup method.

Internal mechanical integrity will be demonstrated with the following:

1) A surface pressure gauge on the casing annulus (between surface and long-string sections) for continuous monitoring.

2) A tubing-casing annulus pressure test prior to injection. Repeat pressure tests will be conducted anytime the well tubing is pulled and reinstalled.

3) The tubing-casing annulus pressure will be continuously monitored with a tubing-conveyed P/T gauge (described in Attachment A-8 of Appendix D) placed above the packer and a surface digital P/T gauge on each wellhead.

4) A N_2 cushion (250 psi minimum) with seal pot system to maintain constant positive pressure on the well annulus in each CO_2 injection well.

5) The tubing pressure will be continuously monitored with a tubing-conveyed P/T gauge (described in Attachment A-8 of Appendix D) in each wellbore and a digital surface pressure gauge on each wellhead.

6) A PNL will be run in Year 1 and at least once every 3 years thereafter (i.e., Year 6, Year 9, and so on) in the CO_2 injection wells to determine well annulus saturations.

Table 5-3 summarizes the foregoing mechanical integrity testing plan. All continuous monitoring devices associated with monitoring mechanical integrity will be connected to the SCADA system for continuous, real-time reporting. Wellbore schematics illustrating the monitoring equipment to be installed in the CO_2 injection wells and reservoir-monitoring well are shown in Figures 5-3 through 5-5.

Table 5-3. Overview of the Mechanical Integrity Testing Plan

Activity/Instrumentation	Baseline Frequency	Operational Frequency (20-year period)
External Mechanical Integrity Testing		
Ultrasonic Logging Tool	Acquire baselines in IIW-N, IIW-S, and J-LOC 1.	May repeat during well workovers in cases when tubing must be pulled in IIW-N and IIW-S.
PNL	Acquire baselines in IIW-N, IIW-S, and J-LOC 1. Run log from the Opeche-Picard Formation to the surface to establish baseline conditions.	Repeat PNL in Year 1, Year 3, and at least once every 3 years thereafter in IIW-N and IIW-S. Run log from the Opeche-Picard Formation to the surface to establish mechanical integrity.
DTS Fiber Optics	Install at completion of IIW-N and IIW-S.	Continuous temperature profile monitoring along the IIW-N and IIW-S wellbores.
Temperature or Oxygen Activation Logging	Acquire baseline(s) in IIW-N, IIW-S, and J-LOC 1.	Perform at least annually in the CO_2 injection wells but only if DTS fails.
Internal Mechanical Integrity Testing		
Surface Pressure Gauge on the Casing Annulus (between surface and long-string sections)	Install gauges in IIW-N, IIW-S, and J-LOC 1.	Gauges will monitor pressures in IIW-N, IIW-S, and J-LOC 1.
Tubing-Casing Annulus Pressure Testing	Perform in IIW-N, IIW-S, and J-LOC 1.	Repeat pressure tests will be conducted anytime the well tubing is pulled and reinstalled.
Tubing-Casing Annulus Pressure Monitoring	Install digital surface and downhole gauges in IIW-N, IIW-S, and J-LOC 1.	Gauges will continuously monitor annulus pressures in IIW-N, IIW-S, and J-LOC 1.
N_2 Cushion to Maintain Positive Pressure on the Well Annulus	Add initial volumes to fill well annulus in IIW-N and IIW-S.	N_2 cushion will be used to maintain a consistent positive pressure (250 psi minimum) in IIW-N and IIW-S.
Surface and Tubing-Conveyed P/T Gauges	Install gauges in IIW-N, IIW-S, and J-LOC 1.	Gauges will monitor temperatures and pressures in the tubing continuously in IIW-N, IIW-S, and J-LOC 1.
PNL	Acquire baseline in IIW-N, IIW-S, and J-LOC 1. Run log from the Opeche-Picard Formation to the surface to establish baseline conditions.	Repeat PNL in Year 1, Year 3, and at least once every 3 years thereafter in IIW-N and IIW-S. Run log from the Opeche-Picard Formation to the surface to establish mechanical integrity.

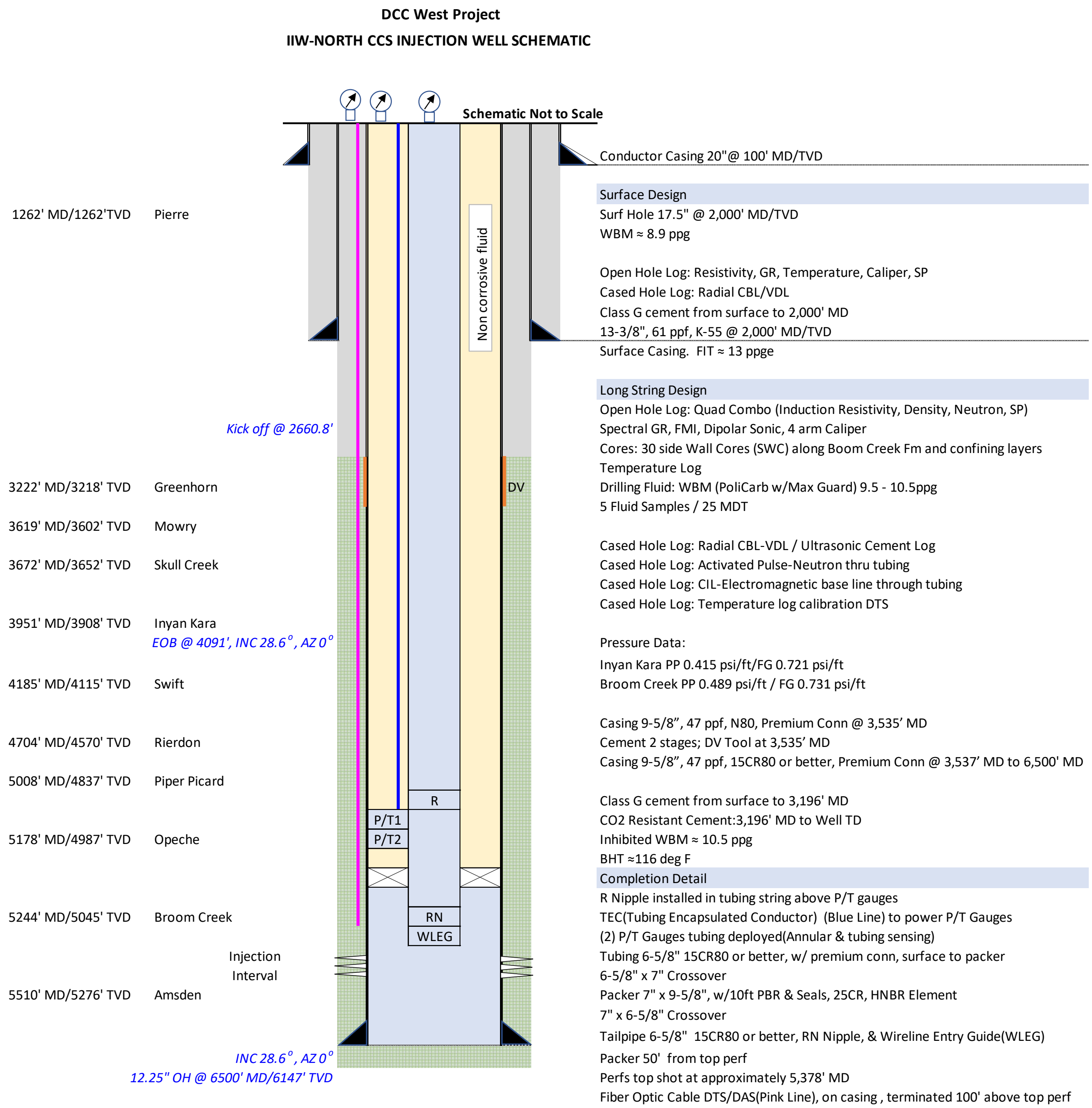

Figure 5-3. Proposed wellbore schematic for the IIW-N CO_2 injection well, illustrating the key corrosion prevention measures and monitoring equipment to be installed. The pink line in the schematic represents the fiber-optic cable installed outside the well casing, while the blue line represents the tubing-encapsulated conductor (TEC) cable for powering the tubing-conveyed P/T gauges. The tubing-conveyed P/T gauge will be housed within a mandrel and ported through the tubing to allow direct, real-time monitoring of the Broom Creek Formation.

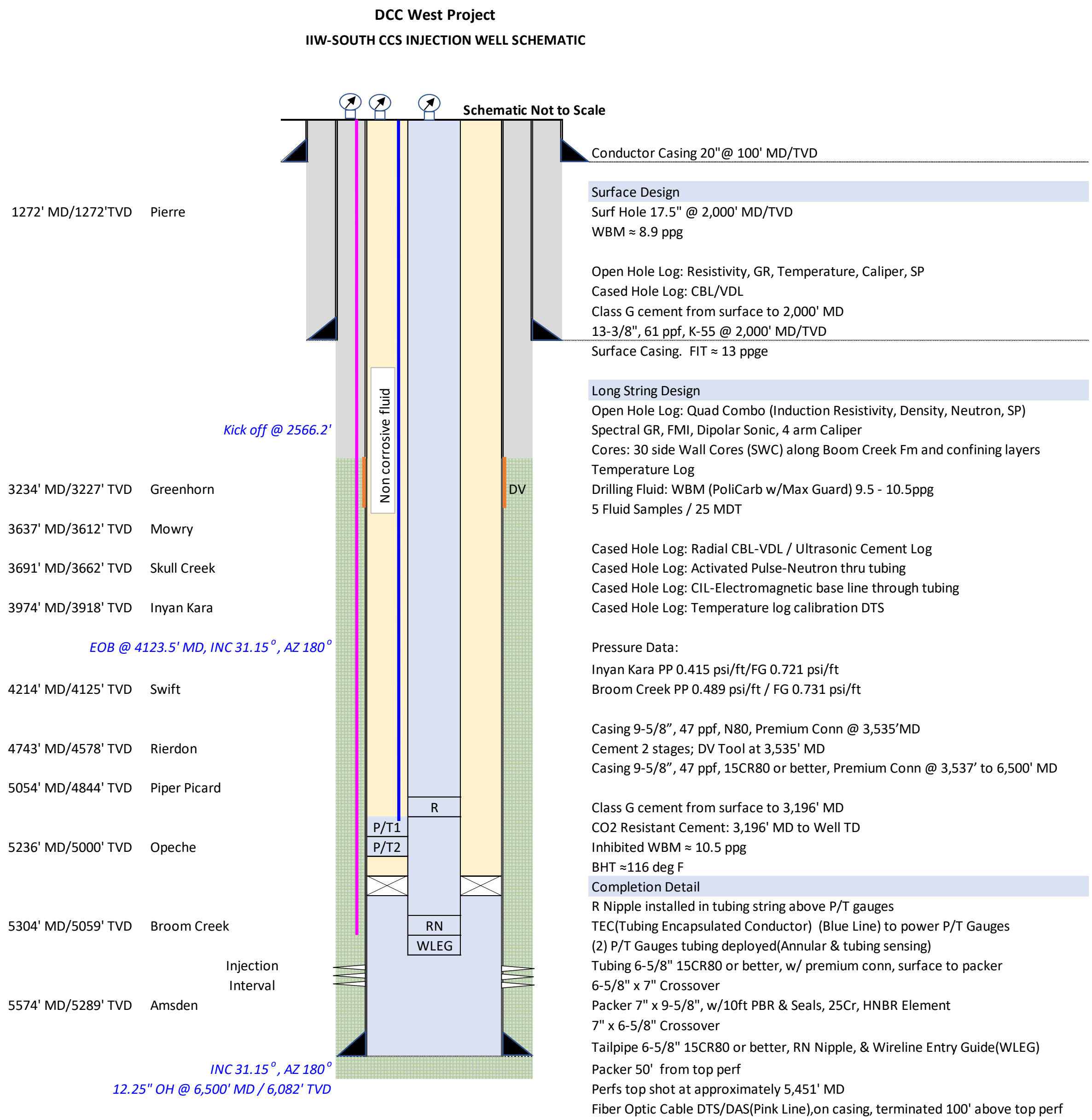

Figure 5-4. Proposed wellbore schematic for the IIW-S CO_2 injection well, illustrating the key corrosion prevention measures and monitoring equipment to be installed. The pink line in the schematic represents the fiber-optic cable installed outside the well casing, while the blue line represents the TEC cable for powering the tubing-conveyed P/T gauges. The tubing-conveyed P/T gauge will be housed within a mandrel and ported through the tubing to allow direct, real-time monitoring of the Broom Creek Formation.

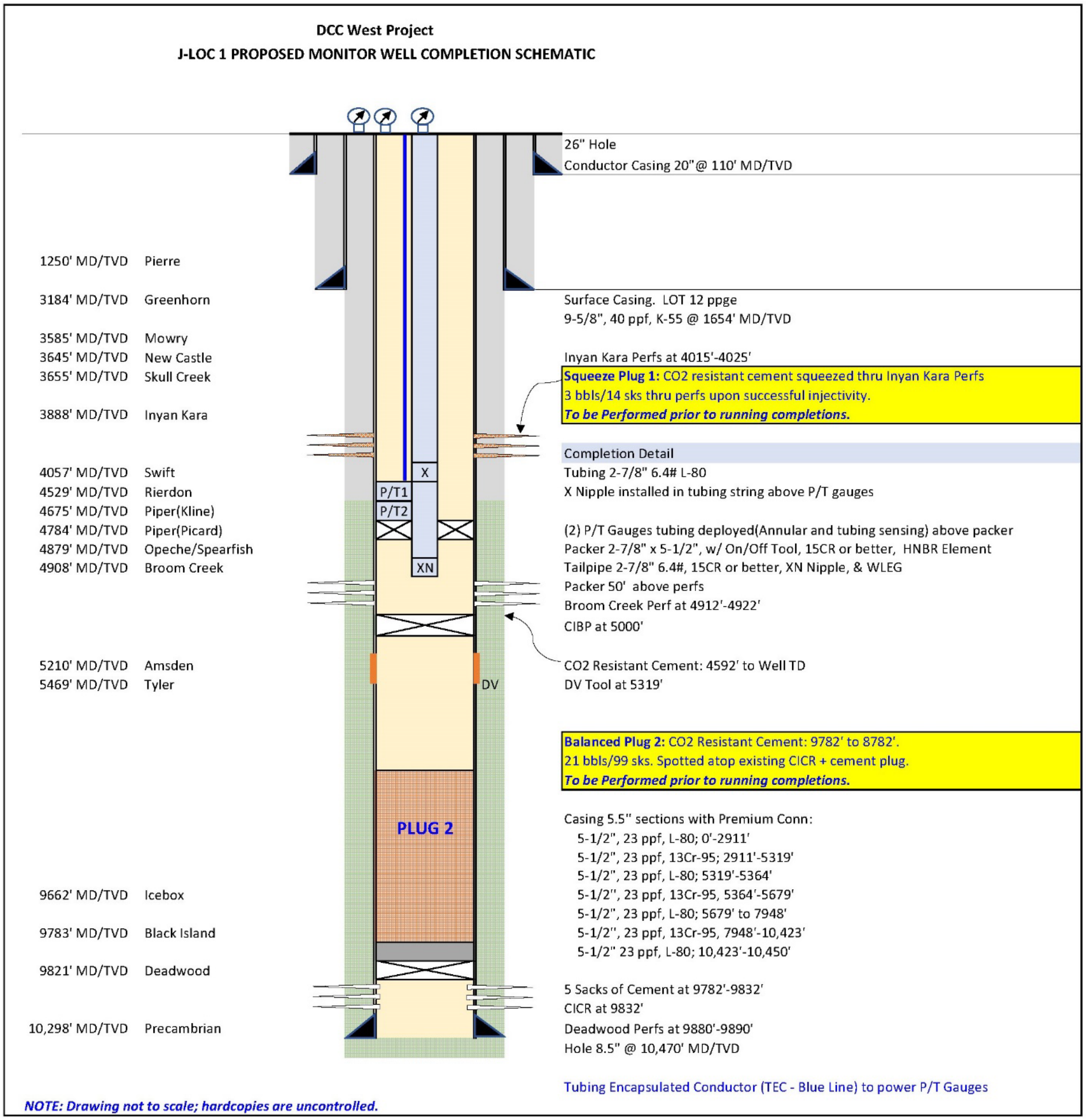

Figure 5-5. Proposed wellbore schematic for the J-LOC 1 reservoir-monitoring well, illustrating the key corrosion prevention measures and monitoring equipment to be installed. The blue line in the schematic represents the TEC cable for powering the tubing-conveyed P/T gauges. The tubing-conveyed P/T gauge will be housed within a mandrel and ported through the tubing to allow direct, real-time monitoring of the Broom Creek Formation.

5.5 Baseline Wellbore Logging and Testing Plan

Pursuant to NDAC § 43-05-01-11.2, DCC West will collect baseline logging and testing measurements from subsurface geologic formations in the CO_2 injection wellbores to: 1) verify the depth, thickness, porosity, permeability, lithology, and salinity of the storage reservoir complex; 2) ensure conformance with the injection well construction requirements; and 3) establish accurate baseline data for making future time-lapse measurements.

Table 5-4 specifies baseline logging and testing activities already completed in the J-LOC 1. Table 5-5 identifies the planned logging and testing activities for the CO_2 injection wells. Coring activities are described separately in Figures 5-3 and 5-4 for IIW-N and IIW-S, respectively, and Section 2.2.2.2 of this SFP for the J-LOC 1. The logging and testing plan for the IIW-S wellbore will be the same as what is presented for the IIW-N but may exclude dipole sonic logging (assuming dipole sonic logging is successful in the IIW-N). Table 5-3 (see Section 5.4) and Table 5-6 (see Section 5.7) specify the logging activities and operational frequencies for demonstrating mechanical integrity and gathering monitoring data, respectively, from project wells.

DCC West will provide NDIC with an opportunity to witness all logging and testing carried out under this section and inform NDIC of logging and testing activities as required. Log and well test files will be submitted to NDIC as required.

Table 5-4. Completed Logging and Testing for the Reservoir-Monitoring Well

	Logging/Testing	Justification
Surface Section	Openhole Logs: Triple Combo (resistivity and neutron and density porosity), Borehole Compensated Sonic, Spontaneous Potential [SP], gamma ray [GR], Caliper, and Temperature	Quantified variability in reservoir properties, such as resistivity and lithology, and measured hole conditions. Identified mechanical properties, including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.
	Cased-Hole Logs: Ultrasonic Imaging Tool (USIT), CBL, VDL, GR, and Temperature	Identified cement bond quality radially, evaluated the cement top and zonal isolation, and established external mechanical integrity. Established baseline temperature profile.
Long-String Section	Openhole Logs: Triple Combo and Spectral GR	Quantified variability in reservoir properties, including resistivity, porosity, and lithology. Provided input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identified mechanical properties, including stress anisotropy. Provided compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.
	Openhole Log: Dipole Sonic	Identified mechanical properties, including stress anisotropy.
	Openhole Log: Fracture Finder Log	Quantified fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.
	Openhole Log: Combinable Magnetic Resonance (CMR)	Interpreted reservoir properties (e.g., permeability and porosity) and determined the best location for pressure test depths, formation fluid sampling depths, and stress testing depths.
	Fluid Sampling (Modular Formation Dynamics Tester)	Collected fluid sample from the Inyan Kara and Broom Creek Formations for analysis. Collected in situ microfracture stress tests in the Broom Creek and Opeche–Picard for formation breakdown pressure, fracture propagation pressure, and fracture closure pressure.

Continued…

Table 5-4. Completed Logging and Testing for the Reservoir-Monitoring Well (continued)

	Logging/Testing	Justification
Long-String Section	Injectivity Test	Performed to define the fracture gradient and maximum allowable injection pressure of the storage reservoir.
	Pressure Falloff Test	Performed to verify hydrogeologic characteristics of the Broom Creek Formation.
	Cased-Hole Logs: Casing Collar Locator (CCL), USIT, VDL, and Temperature	Identified cement bond quality radially, confirmed mechanical integrity, and established baseline temperature profile.

Table 5-5. Proposed Logging and Testing Plan for the CO_2 Injection Wellbores

	Logging/Testing	Justification	NDAC § 43-05-01-11.2
Surface Section	Openhole Logs: Resistivity, SP, Caliper, and Temperature	Quantify variability in reservoir properties, such as resistivity and lithology, and measure hole conditions.	(1)(b)(1)
	Cased-Hole Logs: Ultrasonic Logging Tool, CBL, VDL, GR, and Temperature	Identify cement bond quality radially, evaluate the cement top and zonal isolation, and establish external mechanical integrity. Establish baseline temperature profile for temperature-to-DTS calibration.	(1)(b)(2) and (1)(d)
Long-String Section	Openhole Logs: Quad Combo (triple combo plus dipole sonic), SP, GR, and Caliper	Quantify variability in reservoir properties, including resistivity, porosity, and lithology and measure hole conditions. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identify mechanical properties, including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	(1)(c)(1)
	Openhole Log: Fracture Finder Log	Quantify fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.	(1)(c)(1)
	Openhole Log: Magnetic Resonance Log	Aid in interpreting reservoir permeability and determined the best location for modular dynamics testing (MDT) fluid-sampling depths, packer-setting depths, and stress-testing depths.	(1)(c)(1)
	Fluid Sampling and Testing	Collect fluid sample from the Broom Creek Formation for analysis.	(2) and (3)
	Openhole Log: Spectral GR	Identify clays and lithology that could affect injectivity. Also used for core to log depth correlation.	(4)(b)
	Injectivity Test	Perform to define the fracture gradient and maximum allowable injection pressure of the storage reservoir.	(4)
	Pressure Falloff Test	Perform to verify hydrogeologic characteristics of the Broom Creek Formation.	(5)
	Cased-Hole Log: Pulsed-Neutron Log	Confirm mechanical integrity and establish baseline saturation profile from the Broom Creek to the Skull Creek Formations.	11.4(g)(1)
	Cased-Hole Logs: CCL, Ultrasonic Logging Tool, and VDL	Confirm mechanical integrity and establish baseline temperature profile for temperature-to-DTS calibration.	(1)(c)(2) and (d)

5.6 Wellbore Corrosion Prevention and Detection Plan

The purpose of this corrosion prevention and detection plan is to monitor the well materials to ensure they meet the minimum standards for material strength and performance, pursuant to NDAC § 43-05-01-11.4(1)(c).

5.6.1 Downhole Corrosion Prevention

To prevent corrosion of the well materials from CO_2 exposure, the following preemptive measures will be implemented in the IIW-N and IIW-S wellbores: 1) cement in the injection well opposite the injection interval and extending approximately 1850 feet uphole and above the top of the Mowry Formation (upper confining zone above the Inyan Kara Formation) will be CO_2-resistant; 2) the well casing will also be CO_2-resistant from the bottomhole to a depth just above the Mowry Formation; 3) the well tubing will be CO_2-resistant from the injection interval to surface; 4) the packer will be CO_2-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor. Figures 5-3 and 5-4 summarize the downhole corrosion prevention measures in each of the injection wellbores, and Figure 5-5 illustrates the corrosion prevention measures for the reservoir-monitoring wellbore, even though the reservoir-monitoring wellbore (J-LOC 1) is not anticipated to come into contact with the CO_2 plume.

5.6.2 Downhole Corrosion Detection

PNLs will be acquired in the IIW-N, IIW-S, and J-LOC 1 wellbores prior to injection. Repeat ultrasonic logs in the CO_2 injection wells may be run during well workovers in cases where the well tubing must be pulled. Repeat PNLs acquired in Year 1 of injection, Year 3, and at least once every three years thereafter in the IIW-N and IIW-S wellbores may also be useful for detecting signs of corrosion.

5.7 Environmental Monitoring Plan

To verify the injected CO_2 is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored.

As required by NDAC § 43-05-01-11.4(1)(d and h), the near-surface environment, defined as the region from the surface down to the lowest USDW (Fox Hills Aquifer), will be monitored by sampling three new vadose zone soil gas profile stations, two new dedicated Fox Hills Formation monitoring wells, and up to five existing groundwater wells.

The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the confining zone above the storage reservoir to the confining zone above the next permeable zone above the storage reservoir (i.e., Opeche–Picard Formations to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the IIW-N and IIW-S wellbores as well as periodic PNLs.

Wellbore data collected from the reservoir-monitoring well (J-LOC 1) have been integrated with the geologic model to inform the reservoir simulations used to characterize the initial state of the storage reservoir prior to injection operations (Section 3.0). The simulated CO_2 plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

Pursuant to NDAC § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optic (DTS- and distributed acoustic sensing [DAS]-capable) and downhole P/T measurements. In addition, falloff tests and PNLs will be performed in the IIW-N and IIW-S wellbores. The DAS is further described in Attachment A-9 of Appendix D. Indirect methods include time-lapse VSPs and seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently contained in the storage reservoir. In addition, DCC West will install seismometer stations for passively detecting and locating seismic events.

5.7.1 Near-Surface Monitoring

Figure 5-6 describes the near-surface baseline and operational monitoring plan, which includes sampling from three vadose zone soil gas profile stations, two new dedicated Fox Hills Formation monitoring wells, and up to five existing groundwater wells.

DCC West plans to initiate soil gas sampling to establish baseline conditions at the project site. Soil gas will be sampled at three permanent soil gas profile stations installed on or adjacent to the CO_2 injection well pad, the J-LOC 1 well, and NDIC File No. 4937. Samples will be collected from each station roughly quarterly, or 3–4 times prior to injection, to establish baseline conditions and any seasonal fluctuations. Once injection begins, the sampling frequency will remain the same during the operational phase of the project.

Soil gas analytes will include concentrations of CO_2, O_2, and N_2 (further described in Section 1.7.1 of Appendix D), and the results of the baseline soil gas sampling program will be provided to NDIC prior to injection.

NDIC File No. 4937 was plugged and abandoned with three cement plugs placed between the Broom Creek Formation and the Fox Hills Formation (Figure 4-8). The surface location of NDIC File No. 4937 is just inside the stabilized CO_2 plume boundary by approximately 160 feet, but there is not anticipated to be sufficient pressure increase in the storage reservoir from CO_2 injection to move more than 0.011 m^3 of fluid into the lowest USDW at NDIC File No. 4937 (discussed in Section 3.5.1). A soil gas profile station (i.e., SGPS03) for sampling soil gas throughout the operational phase of the project is proposed at NDIC File No. 4937 as an assurance-monitoring technique, as shown in Figure 5-7.

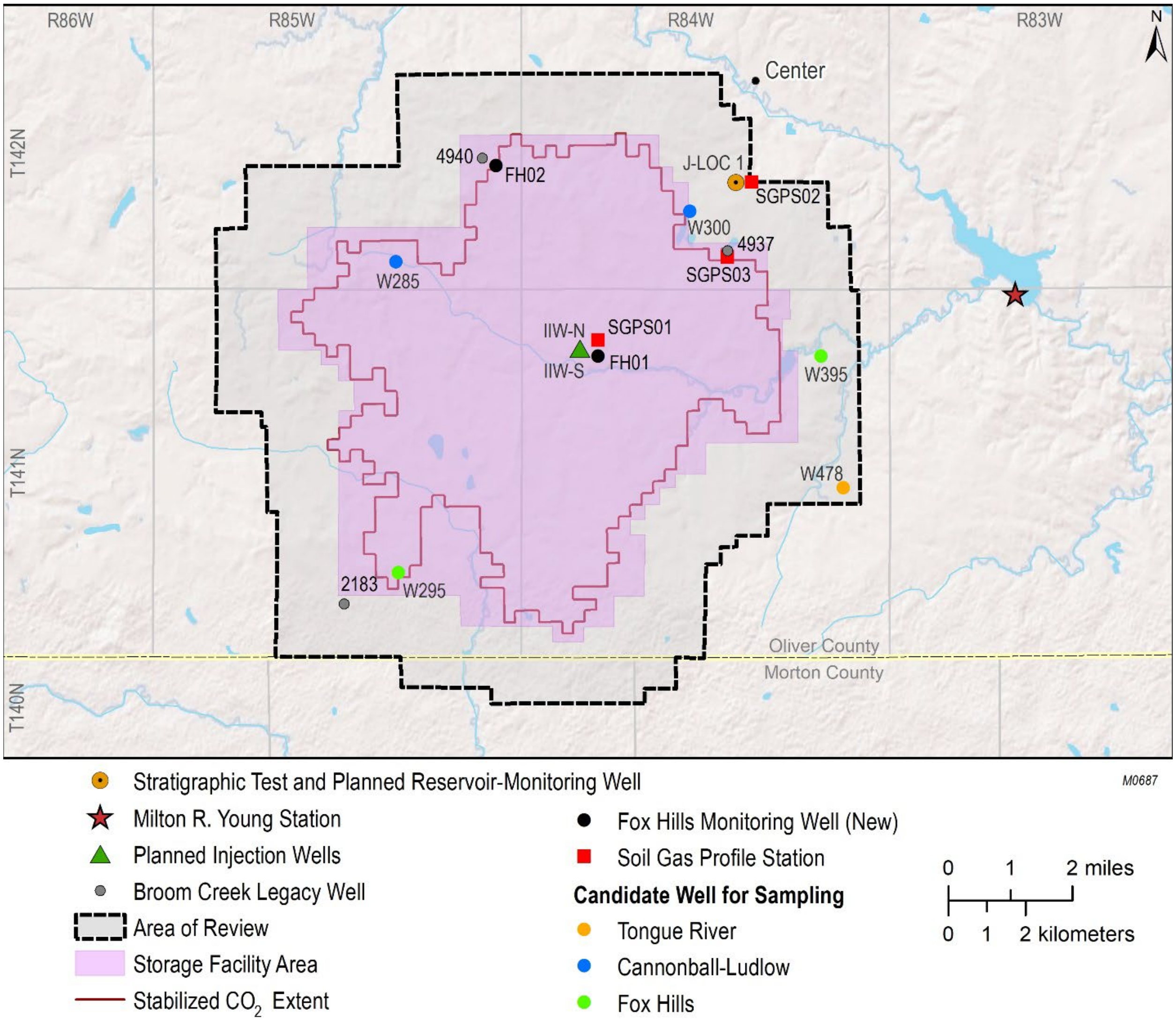

Figure 5-6. DCC West's planned baseline and operational near-surface sampling locations.

DCC West plans to acquire baseline samples in up to five existing groundwater wells within the AOR boundary, collecting 3–4 samples from each well prior to injection. Once injection begins, the groundwater sampling program will shift to a new dedicated Fox Hills monitoring well (FH01) placed near the CO_2 injection well pad that will collect samples 3–4 times in Years 1–4 and reduce sampling frequency to annually thereafter. Additional sampling of wells in the AOR may be phased in for sampling as the CO_2 plume expands and migrates in the storage reservoir.

NDIC File Nos. 2183 and 4940 were plugged and abandoned with two cement plugs placed between the Broom Creek Formation and the Fox Hills Formation (Figures 4-5 and 4-6, respectively). In addition, NDIC File Nos. 2183 and 4940 are outside the stabilized CO_2 plume boundary; therefore, neither wellbore is anticipated to come into contact with CO_2. DCC West plans to monitor both of these legacy wellbores to provide additional assurance of nonendangerment to USDWs near these legacy wells. Once the CO_2 plume comes within 1 mile of NDIC File No. 4940 (projected to occur in Year 9), DCC West plans to drill a second dedicated Fox Hills monitoring well (FH02) near the legacy well. FH02 will be sampled 3–4 times in the first year after drilling, with the sampling frequency decreasing to annually thereafter. The existing Fox Hills well, W295, will also be sampled at least annually once the CO_2 plume comes within 1 mile of NDIC File No. 2183 (projected to occur in Year 17). Figure 5-7 shows the locations of the Fox Hills monitoring wells near each legacy well.

DCC West will employ a proactive monitoring approach to track the CO_2 plume extent and associated pressure front near NDIC File Nos. 2183, 4937, and 4940 (Section 5.7.2) to ensure nonendangerment to the near-surface environment.

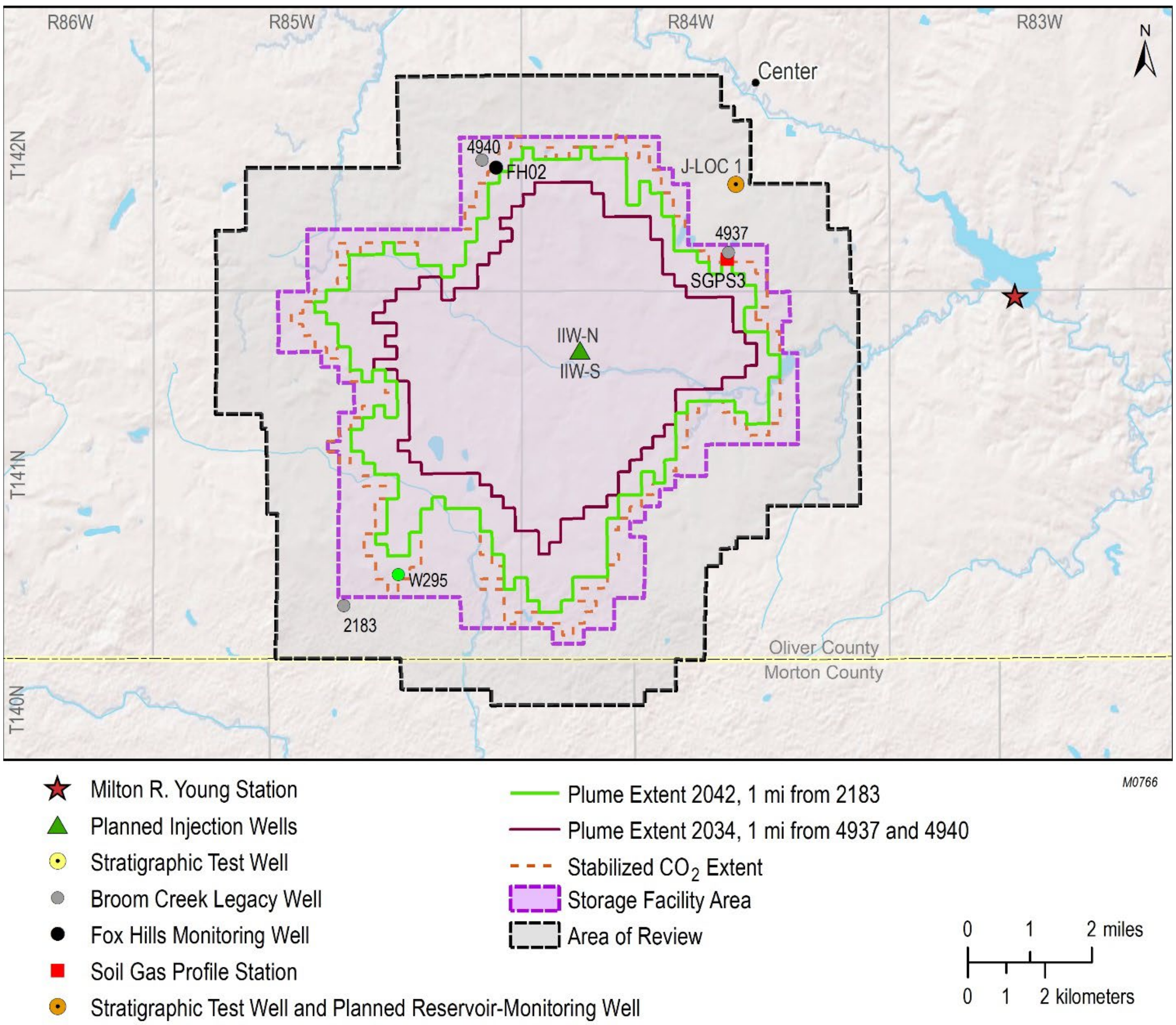

Figure 5-7. Phased monitoring approach for legacy wells NDIC File Nos. 2183 and 4940.

Water analytes for all groundwater well locations will include pH, conductivity, total dissolved solids, and alkalinity as well as major cations/anions and trace metals (further described in Section 1.7.2 of Appendix D). Table 5-6 includes baseline groundwater monitoring results for two of the existing groundwater wells located on the eastern edge of the AOR boundary. State-certified laboratory reports for the baseline data provided in Table 5-6 are available in Appendix B. A state-certified laboratory analysis will be provided to NDIC prior to injection for all baseline groundwater testing.

DCC West will evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO_2 plume extent in the subsurface.

Table 5-7 summarizes the near-surface baseline (preinjection) and operational monitoring plans for the geologic CO_2 storage project.

Table 5-6. Initial Results for DCC West's Baseline Groundwater Monitoring Plan

Well ID (Aquifer)	Sample Event	pH, pH unit	Conductivity, µmhos/cm	Total Alkalinity, mg/L $CaCO_3$	Total Dissolved Solids, mg/L
W395 (Fox Hills)	November 2021	8.2	2904	1030	1740
	March 2022	8.4	2913	902	1870
	May 2022	8.5	2818	1072	1790
	September 2022	8.4	2903	942	1710
W478 (Tongue River)	November 2021	8.2	2167	1230	1370
	March 2022	8.4	2102	1129	1300
	May 2022	8.6	2156	1136	1300
	September 2022	8.1	2177	1234	1390

Table 5-7. Summary of Near-Surface Baseline and Operational Monitoring Plan

Activity	Baseline Frequency	Operational Frequency (20-year period)
Soil Gas		
Soil Gas Sampling (Figure 5-6)	Collect 3–4 seasonal samples per station (i.e., SGPS01–SGPS03) prior to injection and perform concentration and isotopic testing on all samples.	Collect 3–4 seasonal samples annually per station (i.e., SGPS01–SGPS03) and perform concentration analysis on all samples.
Existing Groundwater Wells		
Sampling of Up to 5 Existing Groundwater Wells (Figure 5-6)	Collect 3–4 seasonal samples per well prior to injection and perform water quality and isotopic testing on all samples.	At the start of injection, shift sampling program to the dedicated Fox Hills monitoring well near the CO_2 injection well pad (FH01). Wells may be phased in over time as the CO_2 plume migrates.
Fox Hills Monitoring		
Sampling from FH01 Near CO_2 Injection Pad (Figure 5-6)	Collect 3–4 seasonal samples and perform water quality and isotopic testing on all samples.	Collect 3–4 seasonal samples annually in Years 1–4 and perform water quality analysis on all samples. Reduce sample frequency to annually thereafter.

Continued…

Table 5-7. Summary of Near-Surface Baseline and Operational Monitoring Plan (continued)

Activity	Baseline Frequency	Operational Frequency (20-year period)
Fox Hills Monitoring		
Sampling from FH02 near NDIC File No. 4940 (Figures 5-6 and 5-7)	None.	Drill FH02 when CO_2 plume approaches NDIC File No. 4940 within 1 mile (Year 9). Collect 3–4 seasonal samples in first year after drilling and perform water quality analysis on all samples. Reduce sample frequency to annually thereafter.
Sampling from W295 near NDIC File No. 2183 (Figures 5-6 and 5-7)	Well included as part of the baseline sampling plan for the 5 existing groundwater wells above.	Collect a sample for water quality analysis annually once the CO_2 plume approaches NDIC File No. 2183 within 1 mile (Year 17).

5.7.2 Deep Subsurface Monitoring

DCC West will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The direct and indirect storage reservoir monitoring methods described in Table 5-8 and throughout this section of the permit application will be used to characterize the CO_2 plume's saturation and pressure within the AOR for the baseline and operational phases of the project.

5.7.2.1 AZMI Monitoring

Prior to injection, DCC West will acquire PNL data in the IIW-N and IIW-S wellbores from the storage reservoir (Broom Creek Formation) up through the Opeche–Picard Formations (upper confining zone) and Skull Creek Formation (upper confining zone above the Inyan Kara Formation or dissipation interval). Baseline PNLs will be run in the IIW-N, IIW-S, and J-LOC 1 wellbores. Repeat PNLs will be run in the IIW-N and IIW-S wellbores in Year 1 of injection, Year 3, and at least every 3 years thereafter (Years 6, 9, 12, and so on) until the end of injection. These time-lapse data from the PNLs will be used to ensure CO_2 is not detected in the AZMI as an additional assurance-monitoring technique for evaluating the performance of the storage reservoir complex and protecting USDWs. Repeat PNLs for the J-LOC 1 are not planned because the well is not anticipated to come into contact with the CO_2 plume during the operational phase of the project.

DTS fiber optics installed in the IIW-N and IIW-S wellbores will monitor the temperature profile along the AZMI continuously.

5.7.2.2 Direct Reservoir Monitoring

DTS fiber optics installed in the IIW-N and IIW-S wellbores will directly monitor the temperature in the storage reservoir continuously. P/T readings from a tubing-conveyed bottomhole pressure gauge in each of the CO_2 injection wells and reservoir-monitoring well will also be continuously recorded. Baseline PNLs will be run in the IIW-N, IIW-S, and J-LOC 1 wellbores. Repeat PNLs will be collected over the Broom Creek Formation in the IIW-N and IIW-S wellbores preinjection and in Year 1, Year 3, and at least every 3 years thereafter until the end of CO_2 injection. Falloff testing will be performed prior to injection and once every five years in each of the CO_2 injection wells.

The temperature and saturation profiles collected over the storage reservoir will provide information about the uniformity of CO_2 injectivity within the injection interval. The falloff testing data will confirm projections of the storage capacity and injectivity of the storage reservoir. The pressure data will be used primarily to track the pressure front and ensure the pressure differential in the Broom Creek Formation conforms to numerical simulations.

5.7.2.3 Indirect Reservoir Monitoring

Indirect monitoring will include time-lapse VSPs and 2D seismic surveys. Prior to injection, DCC West plans to acquire a VSP at the CO_2 injection wellsite using the DAS-capable fiber optics installed in each of the CO_2 injection wells. DCC West will also acquire a 2D fence design seismic survey, which is illustrated in Figure 5-8. A repeat VSP survey will be acquired in Year 1 of injection operations to confirm the CO_2 plume is migrating in the subsurface as expected. The VSP will be sourced along the 2D lines shown in Figure 5-8. In Years 2 and 4 of injection operations, repeat 2D seismic surveys will be acquired. DCC West will reevaluate the design and frequency of the repeat 2D seismic surveys but anticipates that repeat seismic surveys will be acquired on at least a 5-year frequency thereafter (e.g., Years 9, 14, and 19).

If necessary, the time-lapse VSP and seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO_2 plume, including extending the 2D lines to capture additional data as the CO_2 plume expands. These time-lapse monitoring efforts will help demonstrate conformance between the reservoir model simulation and site performance and monitor the evolution of the CO_2 plume.

DCC West will install seismometer stations prior to injection. The seismometer stations, combined with the DAS-enabled fiber optics in the CO_2 injection wells, will continuously monitor for and passively detect and locate seismicity events near injection operations. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented in Section 1.7.3.3 of Appendix D.

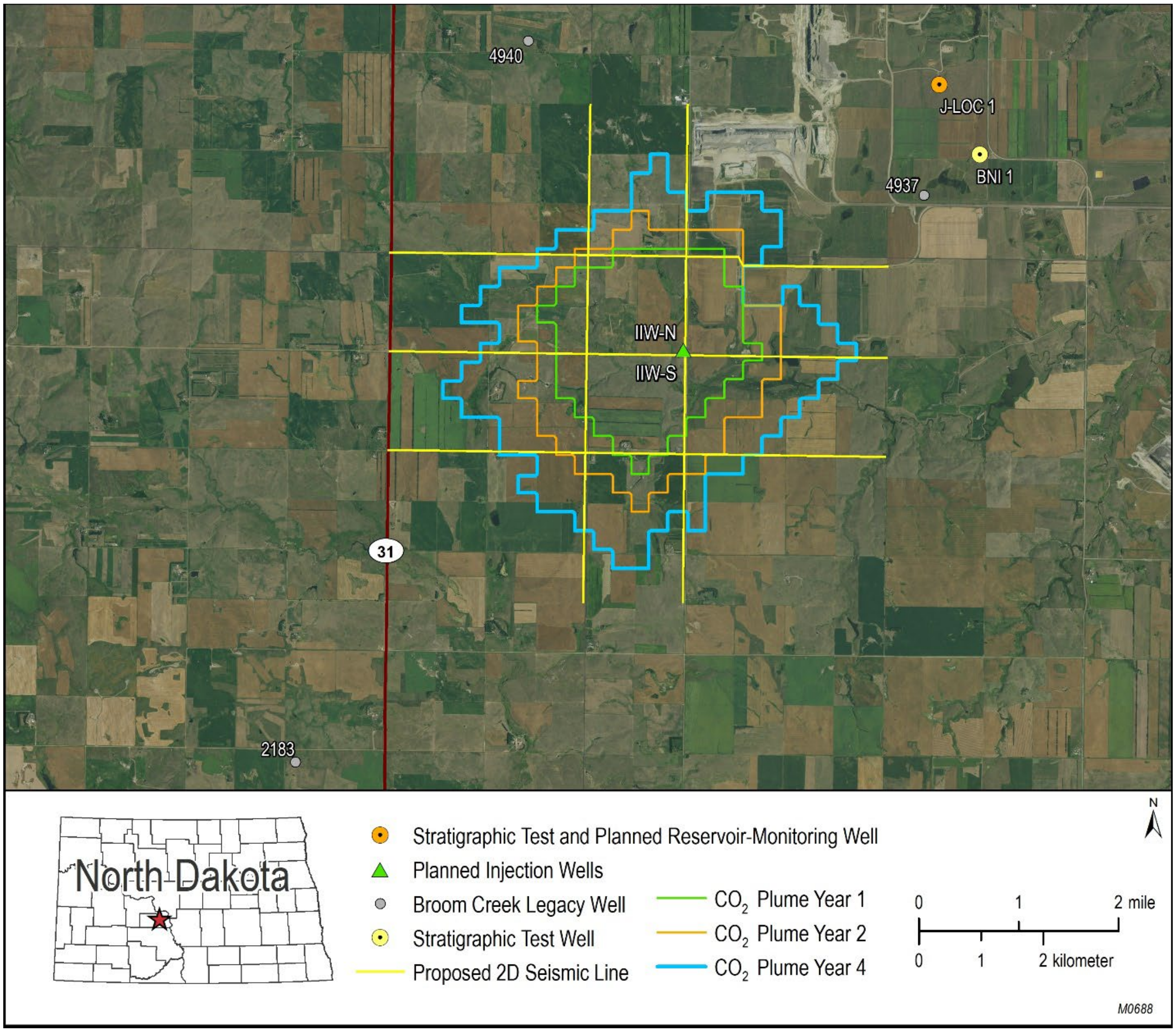

Figure 5-8. Locations of the proposed 2D seismic lines for the fence design centered on the CO_2 injection well pad to establish a baseline and monitoring for the project site during Years 1–4 of injection.

Table 5-8 summarizes the deep subsurface baseline (preinjection) and operational monitoring plans for the geologic CO_2 storage project.

Table 5-8. Summary of Deep Subsurface Baseline and Operational Monitoring Plan

Activity	Baseline Frequency	Operational Frequency (20-year period)
AZMI		
DTS Fiber Optics	Install during completion of the IIW-N and IIW-S.	Monitor temperature changes continuously in the IIW-N and IIW-S.
PNL	Perform in IIW-N, IIW-S, and J-LOC 1 prior to injection. Run log from the Opeche-Picard Formation through the Skull Creek Formation to establish baseline conditions.	Collect PNLs in Year 1, Year 3, and at least once every 3 years thereafter in IIW-N and IIW-S wellbores. Run log from the Opeche–Picard Formation through the Skull Creek Formation to confirm containment in the storage reservoir.
Storage Reservoir (direct)		
DTS Fiber Optics	Install during completion of the IIW-N and IIW-S.	Monitor temperature changes continuously in the IIW-N and IIW-S.
PNL	Perform in IIW-N, IIW-S, and J-LOC 1 prior to injection. Run log from the Amsden through the Opeche–Picard Formations to establish baseline conditions.	Collect PNLs in Year 1, Year 3, and at least once every 3 years thereafter in IIW-N and IIW-S wellbores. Run log from the Amsden Formation through the Opeche–Picard Formation to determine the Broom Creek Formation's saturation profile and provide assurance of containment in the storage reservoir.
P/T Readings	Install P/T gauges over the storage reservoir in IIW-N, IIW-S, and J-LOC 1 prior to injection.	Collect P/T readings continuously from the storage reservoir in IIW-N, IIW-S, and J-LOC 1.
Pressure Falloff Testing	Conduct prior to injection in IIW-N and IIW-S.	Conduct once every 5 years in IIW-N and IIW-S.
Storage Reservoir (indirect)		
Time-Lapse VSPs	Collect baseline VSP.	Collect repeat VSP in Year 1.
Time-Lapse 2D Seismic Surveys (Figure 5-8)	Collect baseline fence 2D seismic survey.	Repeat 2D seismic survey in Years 2 and 4. At Year 4 of injection, reevaluate frequency, line extents, and location based on plume growth and seismic results. DCC West plans to collect repeat seismic surveys on at least a 5-year frequency thereafter (e.g., Year 9, 14, and 19).
Passive Seismicity	Install seismometer stations.	Monitor for seismic events continuously.

5.7.3 Adaptive Management Approach

DCC West will monitor the geologic CO_2 storage project with an adaptive management approach (Ayash and others, 2017). Monitoring data gathered from the testing and monitoring plan will be reported to the NDIC as required under NDAC § 43-05-01-18, which will provide the basis for justifying any updates to an approved testing and monitoring plan, including the 5-year reevaluation of the testing and monitoring plan. During each 5-year review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed, or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.

Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO_2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO_2 within the permitted geologic storage facility.

5.8 Quality Assurance and Surveillance Plan

In accordance with NDAC § 43-05-01-11.4 (1)(k), DCC West has developed a QASP as part of the testing and monitoring plan. The QASP is provided in Appendix D of this permit.

5.9 References

American Petroleum Institute, 2018, Line Pipe: API Specification 5L, Forty-Sixth Ed., April 2018, Errata 1, May 2018, 210 p.

Ayash, S.C., Nakles, D.V., Wildgust, N., Peck, W.D., Sorenson, J.A., Glazewski, K.A., Aulich, T.R., Klapperich, R.J., Azzolina, N.A., and Gorecki, C.D., 2017, Best practice for the commercial deployment of carbon dioxide geologic storage – the adaptive management approach: Plains CO_2 Reduction (PCOR) Partnership Phase III, Task 13 Deliverable D102/Milestone M59 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-05-01, Grand Forks, North Dakota, Energy and Environmental Research Center, August.

SECTION 6.0

POSTINJECTION SITE AND FACILITY CLOSURE PLAN

6.0 POSTINJECTION SITE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that DCC West will perform following the cessation of CO_2 injection to achieve final closure of the site. This plan provides the postinjection monitoring program that will provide evidence that the injected CO_2 plume is stable (i.e., CO_2 migration will be unlikely to move beyond the boundary of the storage facility area).

Based on the current simulations of CO_2 plume movement following the cessation of CO_2 injection, it is projected that the CO_2 plume will stabilize within the storage facility area boundary (see Section 3.0), confirming nonendangerment of USDWs within the AOR. Based on these observations, a minimum postinjection monitoring period of 10 years is planned to confirm these current projections of the CO_2 plume extent and postinjection stabilization. However, monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO_2 plume and nonendangerment of USDWs. The nature and duration of that extension will be determined based upon an update of this plan and NDIC approval.

In addition to DCC West executing the postinjection monitoring program, the CO_2 injection wells will be plugged as described in the plugging plan of this permit application (Section 9.0). All surface equipment not associated with long-term monitoring will be removed, and all surface land associated with the project will be reclaimed to as close as is practicable to its predisturbance condition. Following the plume stability demonstration, a final assessment will be prepared to document the status of the site and be submitted to NDIC as part of a facility closure report.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection in the Broom Creek Formation at an average rate of 6.11 million metric tons per year, followed by a postinjection period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the conclusion of CO_2 injection. At the time that CO_2 injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 677 psi at the location of the CO_2 injection well pad. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of the pressure evaluation are provided as part of the AOR delineation of this permit application (see Section 3.5).

Figure 6-2 illustrates the predicted gradual pressure decrease in the storage reservoir, over a 10-year period following the cessation of CO_2 injection. The pressure at the CO_2 injection well pad at the end of the 10-year period is anticipated to decrease 300–350 psi as compared to the pressure in the storage reservoir at the time CO_2 injection ends. This trend of decreasing pressure is anticipated to continue over time until the pressure of the storage reservoir approaches the original reservoir pressure conditions.

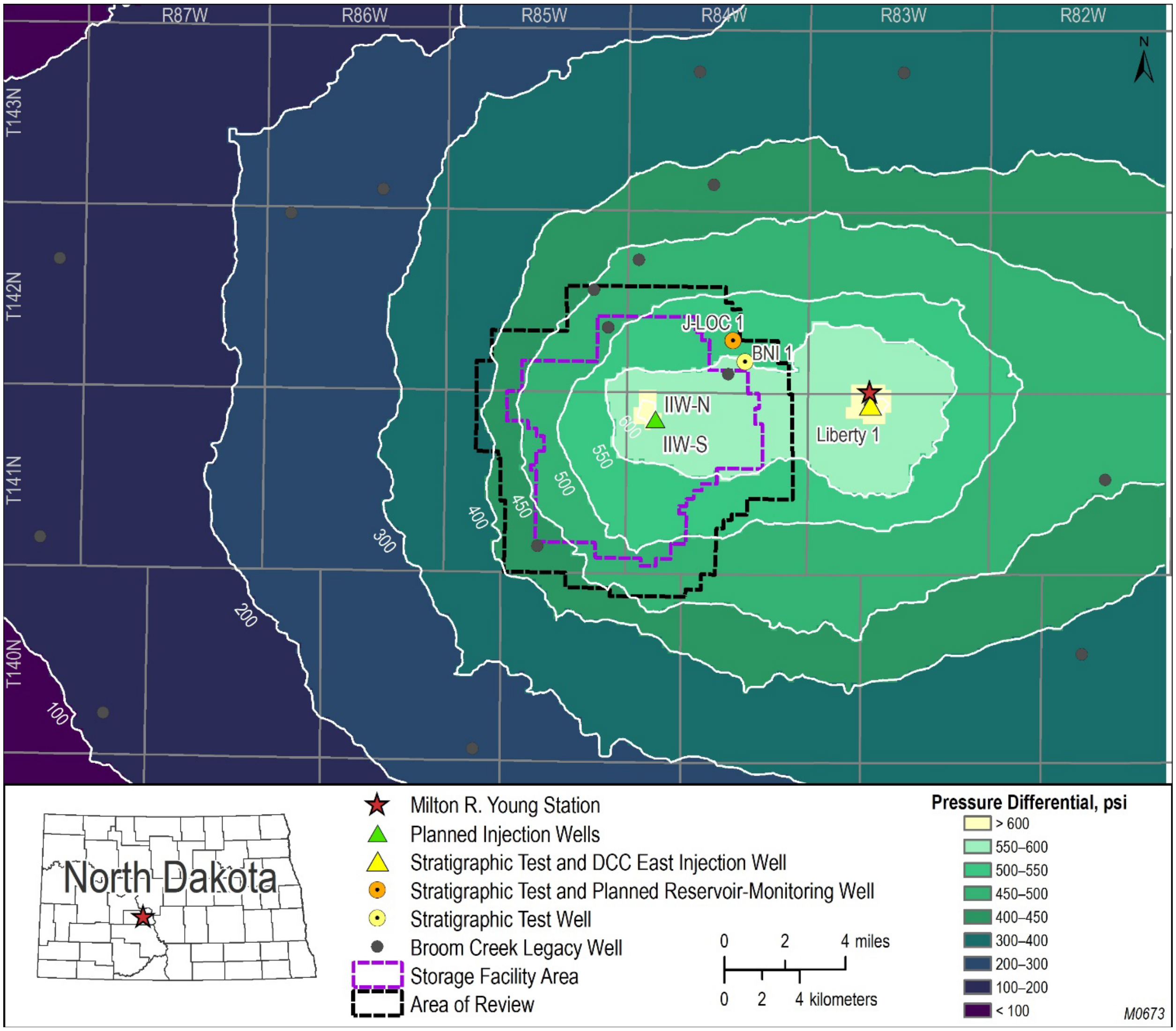

Figure 6-1. Predicted pressure increase in storage reservoir following 20 years of injection of an average 6.11 million metric tons per year of CO_2.

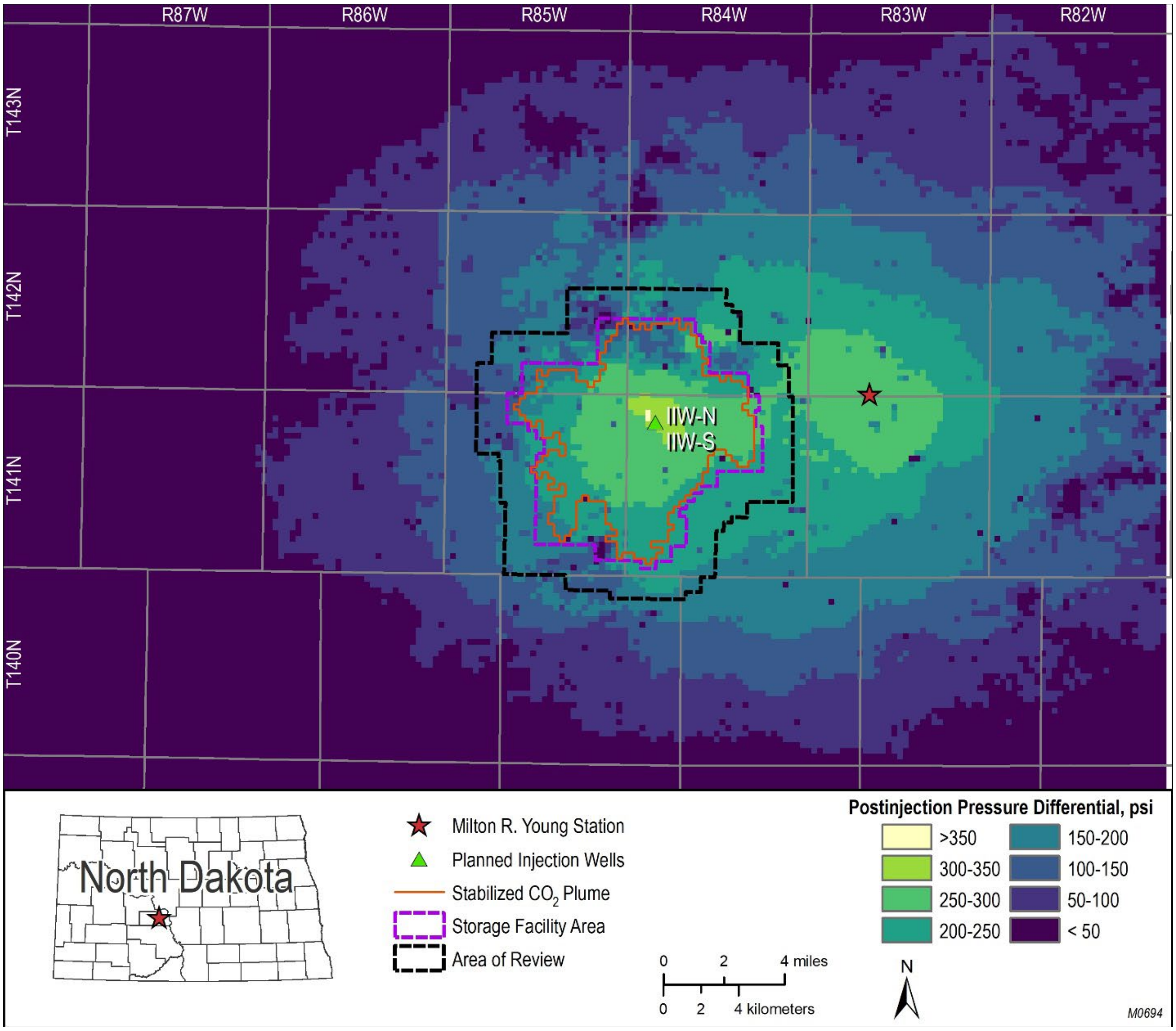

Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection.

6.1.2 Predicted Extent of CO_2 Plume

Figure 6-2 illustrates the extent of the CO_2 plume following the planned 10-year PISC period (also called the stabilized plume), which is based on numerical simulation predictions. The results of these simulations predict that 99% of the separate-phase CO_2 mass would be contained within an area of 35.5 square miles by the end of the 10-year PISC period. Changes in the areal extent of the CO_2 plume over the planned PISC period is not predicted to be measurable.

Additional simulations beyond the 10-year PISC period were also performed and predict that at no time will the boundary of the stabilized plume at the site extend beyond the boundary of the storage facility area. If such a determination can be made following the planned 10-year PISC period, the CO_2 plume will meet the definition of stabilization as presented in NDCC § 38-22-17(5)(d) and qualify the geologic storage site for receipt of a certificate of project completion.

6.2 Postinjection Testing and Monitoring Plan

This postinjection testing and monitoring plan includes: 1) a wellbore mechanical integrity and corrosion detection plan for the reservoir-monitoring wellbore (J-LOC 1); and 2) an environmental monitoring plan for the near-surface and deep subsurface to provide evidence that the injected CO_2 plume has stabilized within the storage reservoir and USDWs are nonendangered. This plan assumes that the CO_2 injection wells will be plugged at cessation of injection.

6.2.1 Wellbore Testing

The wellbore mechanical integrity testing and corrosion detection plan for the J-LOC 1 wellbore during the PISC period is provided in Table 6-1.

Table 6-1. Mechanical Integrity Testing Plan for the J-LOC 1 Wellbore During the PISC Period

Activity	Postinjection Frequency (10 years minimum)
External Mechanical Integrity	
PNL (oxygen activation log) or Temperature Log	Collect at cessation and at least once every 3 years thereafter. Run log from the Opeche-Picard Formation to the surface.
Internal Mechanical Integrity	
Surface Pressure Gauge on the Casing Annulus	Gauge will monitor pressure between the surface casing and long-string casing continuously.
Tubing-Casing Annulus Pressure Testing	Repeat pressure tests will be conducted anytime the well tubing is pulled and reinstalled.
Tubing-Casing Annulus Pressure Monitoring	Digital surface pressure gauges will monitor annulus pressures continuously.
Surface and Tubing-Conveyed P/T Gauges	Gauges will monitor temperatures and pressures in the tubing continuously.
Corrosion Detection	
CIL (e.g., ultrasonic)	May collect during workovers when tubing is pulled.

6.2.2 Soil Gas and Groundwater Monitoring

Figure 6-3 identifies the location of the soil gas profile stations and groundwater wells that will be included in this monitoring effort. The three stations (SGPS01–SGPS03) and two dedicated Fox Hills monitoring wells drilled for this project (FH01 and FH02) will be sampled during the proposed PISC period. Additional sampling of groundwater in the PISC period (e.g., wells sampled during the baseline and operational phases of the project) may occur for select shallow groundwater wells within the AOR still active and accessible.

Analytes for all soil gas and groundwater sampling collected during the PISC period are anticipated to be the same as what is presented in Section 5.7.1 and Appendix C of this permit application; however, it is anticipated that the final target list of analytical parameters will likely be reduced for the PISC period based on an evaluation of the monitoring results that are generated during the 20-year injection period of the storage operations.

Table 6-2 identifies the sampling locations and frequency for soil gas and groundwater monitoring.

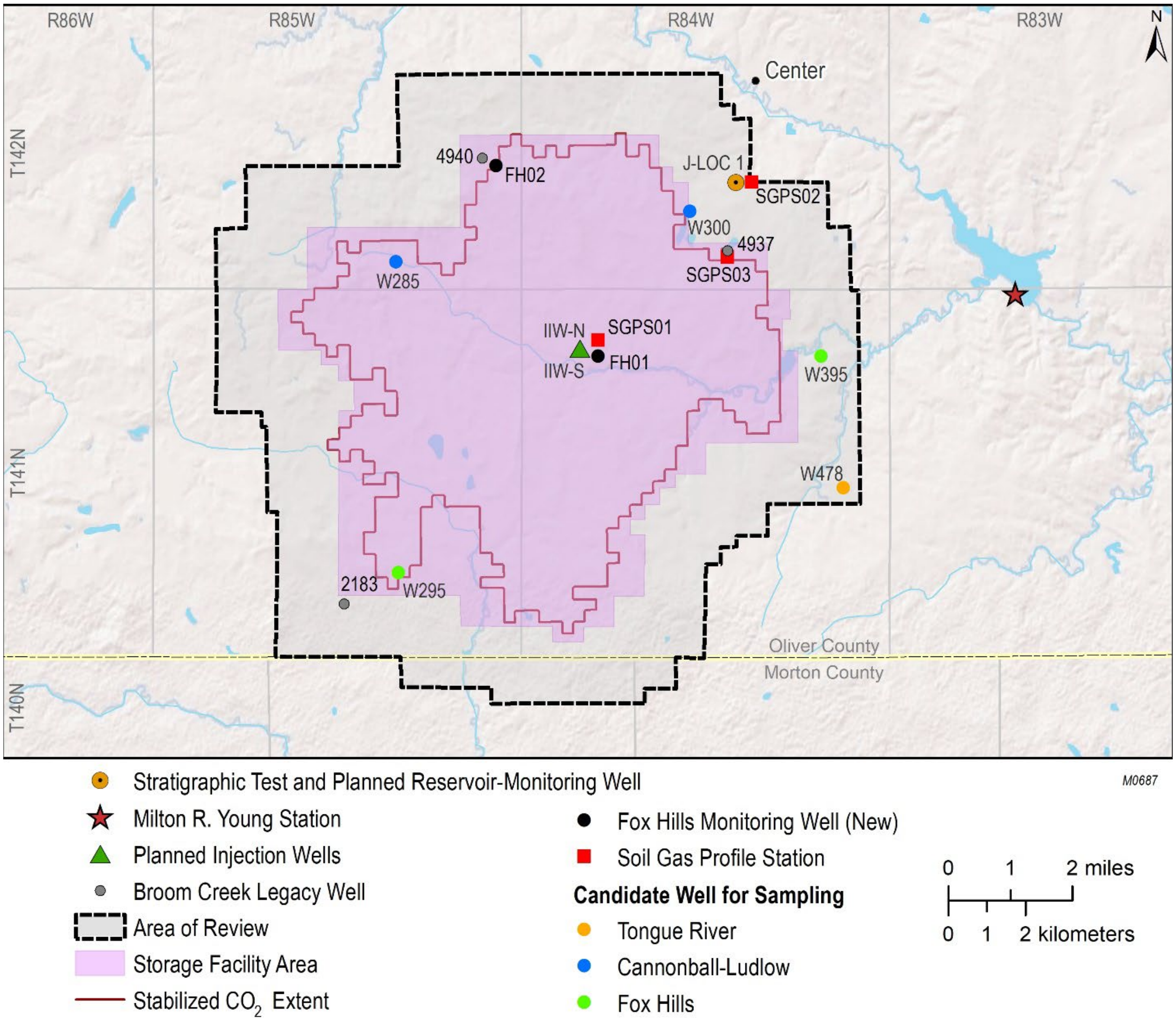

Figure 6-3. Soil gas and groundwater well sampling locations included in the PISC period.

Table 6-2. Soil Gas and Groundwater Monitoring Plan During the PISC Period

Activity	Postinjection Frequency (10 years minimum)
Soil Gas	
SGPS01–SGPS03 Sampling (Figure 6-3)	Collect 3–4 seasonal samples at each station (SGPS01–SGPS03) in Year 21 and every 3 years following the cessation of CO_2 injection.
Groundwater	
W285, W295, W300, W395, and W478 Sampling (if feasible) (Figure 6-3)	Collect 3–4 seasonal samples in Year 21, Year 24, and Year 29 as part of the final facility closure.
Dedicated Fox Hills Monitoring Wells (FH01 and FH02) (Figure 6-3)	Collect 3–4 seasonal samples in Year 21, Year 24, and Year 29 as part of the final facility closure.

6.2.3 Deep Subsurface Monitoring

Table 6-3 identifies the deep subsurface monitoring strategy during the PISC period.

Table 6-3. Deep Subsurface Monitoring Plan During the PISC Period

Activity	Postinjection Frequency (10-year period)
Storage Reservoir, Direct	
Downhole P/T Gauge Readings (J-LOC 1)	Collect P/T readings continuously from the storage reservoir (J-LOC 1).
Storage Reservoir, Indirect	
Time-Lapse Seismic Surveys	Actual design and frequency to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the CO_2 plume over time.

6.2.3.1 CO_2 Plume and Associated Pressure Front Monitoring

Monitoring of the migration of the CO_2 plume and associated pressure front in the storage reservoir during the PISC period will be conducted using the methods summarized in Table 6-3. Monitoring methods include a combination of geophysical monitoring (i.e., time-lapse 2D seismic) and formation-monitoring (i.e., downhole pressure/temperature) for tracking CO_2 saturation and associated pressure, respectively, over the entire storage reservoir complex.

The design and frequency of the 2D time-lapse seismic survey will depend on how the CO_2 plume is migrating during the operational phase of the project and the results of the adaptive management approach (Section 5.7.1). As stated in Table 5-8 and Section 5.7.2.3, the 2D seismic survey design and frequency will be reevaluated and updated as necessary, starting in Year 4 of injection.

6.3 Postinjection Site Care Plan

At the start of the PISC period, any flowlines buried less than 3 feet below final contour will be flushed and removed (e.g., the planned flowline segment at the point of transfer on DCC East property and the aboveground portion of the flowline at the injection wellsite) in accordance with the abandonment of flowlines pursuant to NDAC § 43-02-03-34.1. Associated costs for these activities are outlined in Section 12.0.

As required by NDAC § 43-05-01-19(3) and (5), PISC activities will include the P&A (plugging and abandonment) of the CO_2 injection wells (IIW-N and IIW-S) and reclamation of the injection well pad. Reclamation of the CO_2 injection wells and the injection pad includes wellhead removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, and reclamation of the flowline at the injection pad. Well pad reclamation activities may occur contemporaneously with flowline removal and will work around the soil gas profile station (SGPS01) and dedicated Fox Hills monitoring well (FH01).

The J-LOC 1 wellbore will be used for deep subsurface monitoring during the PISC period. The testing and monitoring activities for the J-LOC 1 and near-surface sampling are described in Section 6.2. Section 12.0 includes cost estimates for performing these proposed testing and monitoring activities.

6.3.1 Schedule for Submitting Postinjection Monitoring Results

All PISC-monitoring data and results will be submitted to NDIC within 60 days following the anniversary date on which CO_2 injection ceased. The annual reports will contain information and data generated during the reporting period, including seismic data acquisition, formation-monitoring data, soil gas and groundwater analytical results, and simulation results from updated geologic models and numerical simulations.

6.4 Facility Closure Plan

DCC West will submit a final facility closure plan and notify NDIC at least 90 days prior to its intent to close the site. The facility closure plan will describe a set of activities that will be performed, following approval by NDIC, at the end of the PISC period. Facility closure activities will include the plugging of all wells that are not planned for continued use in monitoring the closed site; the decommissioning of storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring; and the reclaiming of the surface land of the site to as close as is practicable to its predisturbance condition.

As part of the final assessment, DCC West will work with NDIC to determine which wells and monitoring equipment will remain and transfer to the state for continued postinjection monitoring. Plugging and abandonment of the J-LOC 1 and well pad reclamation are costs factored into Section 12.0, but the NDIC may choose to retain this reservoir-monitoring well into the postclosure period. The dedicated Fox Hills monitoring wells drilled adjacent to the CO_2 injection wells and NDIC File No. 4940 (FH02) and near the injection well pad (FH01), as well as the soil gas profile stations (SGPS01–SGPS03), may also transfer ownership to the state or a third party, pending NDIC review and approval of the PISC plan and final assessment pursuant to NDAC § 43-05-01-19. Cost estimates for the PISC and closure periods can be found in Section 12.0 of this permit application in the scenario such that transfer to the state or a third party does not occur.

6.4.1 Submission of Facility Closure Report, Survey, and Deed

A facility closure report will be prepared and submitted to NDIC within 90 days following the execution of the PISC and facility closure plan. This report will provide NDIC with a final assessment that documents the location of the stored CO_2 in the reservoir, describes its characteristics, and demonstrates the stability of the CO_2 plume in the reservoir over time. The facility closure report will also document the following:

- Plugging records of the CO_2 injection wells and reservoir-monitoring well.
- Location of the sealed CO_2 injection wells and reservoir-monitoring well on a plat survey that has been submitted to the local zoning authority.
- Notifications to state and local authorities as required by NDAC § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO_2.
- Postinjection monitoring records.

At the same time, DCC West will also provide NDIC with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by NDIC. The plat will indicate the location of the injection well relative to permanently surveyed benchmarks pursuant to NDAC § 43-05-01-19.

Lastly, DCC West will record a notation on the deed (or any other title search document) to the property on which the injection well was located pursuant to NDAC § 43-05-01-19.

SECTION 7.0

EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

DCC West, operator of the West Site storage facility, will enter into an agreement whereby DCC West employees, contractors, and agents are required to follow the DCC West facility emergency action plans, including, but not limited to, the DCC West facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks. In addition, the integration of the ERRP with the existing DCC West facility response plan and risk management plan (and incorporated into the DCC West integrated contingency plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the geologic storage facility and the DCC West facility and can be made available upon request.

7.1 Background

CO_2 produced at the Milton R. Young Station (MRYS) will be the primary source of CO_2 geologically stored approximately 7 miles from the MRYS location. DCC West is requesting a commercial permit for the operation of the storage facility to provide flexibility to receive sources so long as any source can meet or exceed 96% CO_2. Stream composition was modeled for the DCC West site for purposes of establishing the storage facility boundary using a 98.25% CO_2 stream composition for the purposes of establishing the storage facility boundary, which represents the projected stream composition (stream may range from minimum composition of 96% CO_2 to 99.9% CO_2). The projected composition of the injected gas is a minimum 96% dry CO_2 (by volume), with trace quantities (4% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C2+, and hydrocarbons. Figure 7-1 identifies the planned capture facility, the CO_2 flowline, the CO_2 injection wells (IIW-N and IIW-S), and monitoring well (J-LOC 1). At time of this application, DCC West has not applied for any other permits with state, federal or local agencies. The well locations, including latitudes and longitudes, are provided below (Table 7-1).

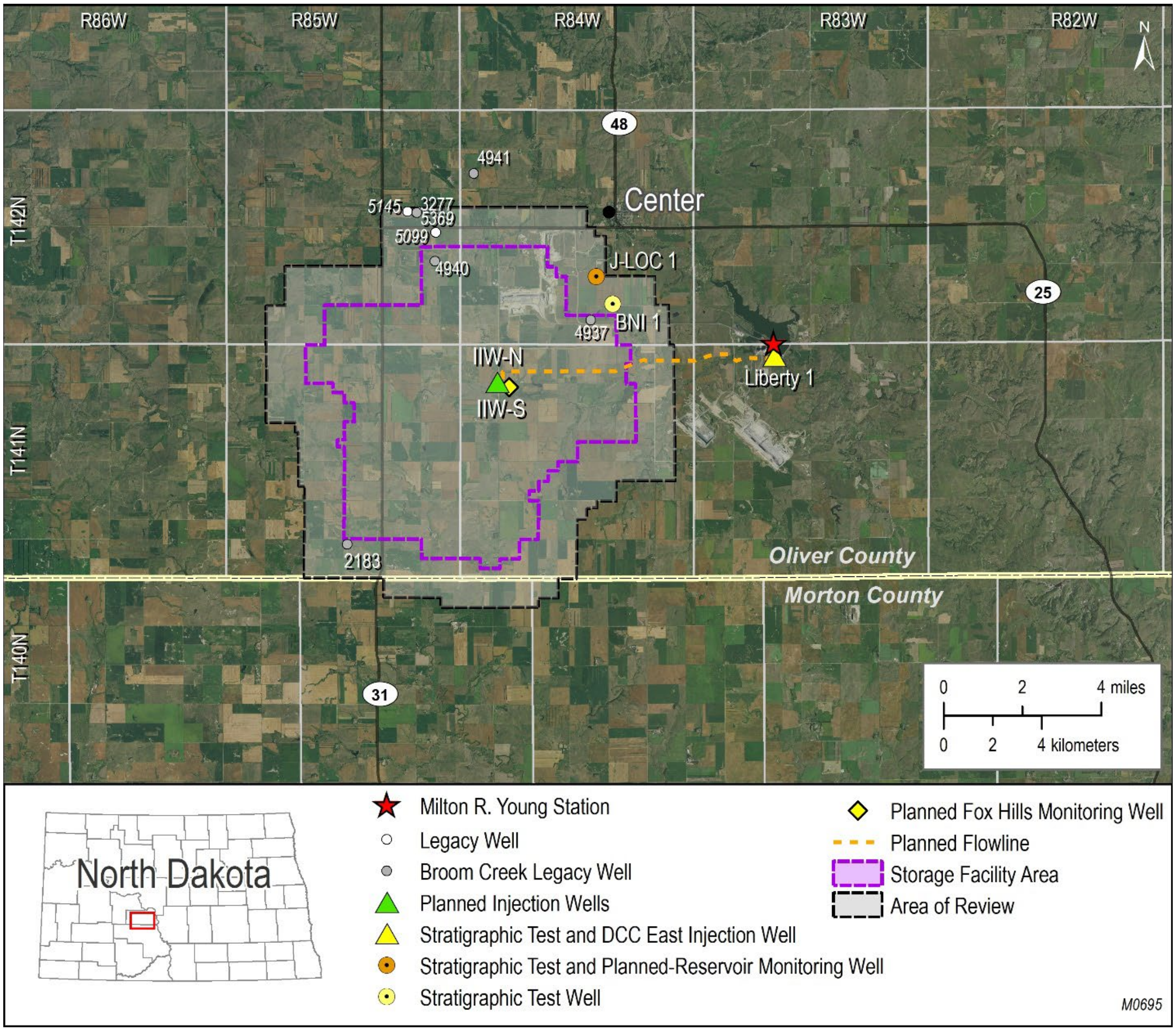

Figure 7-1. Locations of DCC West, CO_2 injection wells (IIW-N and IIW-S), and the planned deep subsurface monitoring well (J-LOC 1). Also shown are the planned capture facility and CO_2 flowline from the transfer shed on the Liberty 1 wellpad to the proposed CO_2 injection wells.

Table 7-1. Well Name and Location Information for the CO_2 Injection Wells (IIW-N and IIW-S) and Monitoring Well (J-LOC 1) of the Geologic Storage Operations

Well Name	Purpose	NDIC* File No.	Quarter/Quarter	Section	Township	Range	Latitude	Longitude
IIW-N	CO_2 injection well	TBD**	SE	6	141	84	TBD	TBD
IIW-S	CO_2 injection well	TBD	SE	6	141	84	TBD	TBD
J-LOC 1	Monitoring well	37380	SWNE	27	142	84	47.092987	–101.309634

* North Dakota Industrial Commission.
** To be determined.

The primary DCC West contacts for the geologic storage project and their contact information are in Table 7-2.

Table 7-2. Primary DCC West Project Contacts

Individual	Title	Contact Information Office Phone Number
Craig Bleth	Vice President of Project Development	(701) 794-7261
Shannon Mikula	Storage Development Lead	(701) 795-4211

Contact names and information for the key local emergency organizations/agencies and specific contractors and equipment vendors able to respond to potential leaks or loss of containment are provided in a separate section of this ERRP (Section 7.6, Emergency Communications Plan).

7.2 Local Resources and Infrastructure

Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include BNI Coal Inc.-leased mine land, including reclaimed mine land.

The infrastructure in the vicinity of the project that may be impacted as a result of an emergency event is shown in Figure 7-1 and includes 1) MRYS and associated facilities and infrastructure; 2) the CO_2 injection wellheads (IIW-N and IIW-S) and the monitoring wellhead (J-LOC 1); 3) nearby commercial and residential structures; and 4) the CO_2 flowline. Figure 7-2 shows land use within the area of review (AOR), including commercial, residential, and public lands, if any, as required in North Dakota Administrative Code (NDAC) § 43-05-01-13.

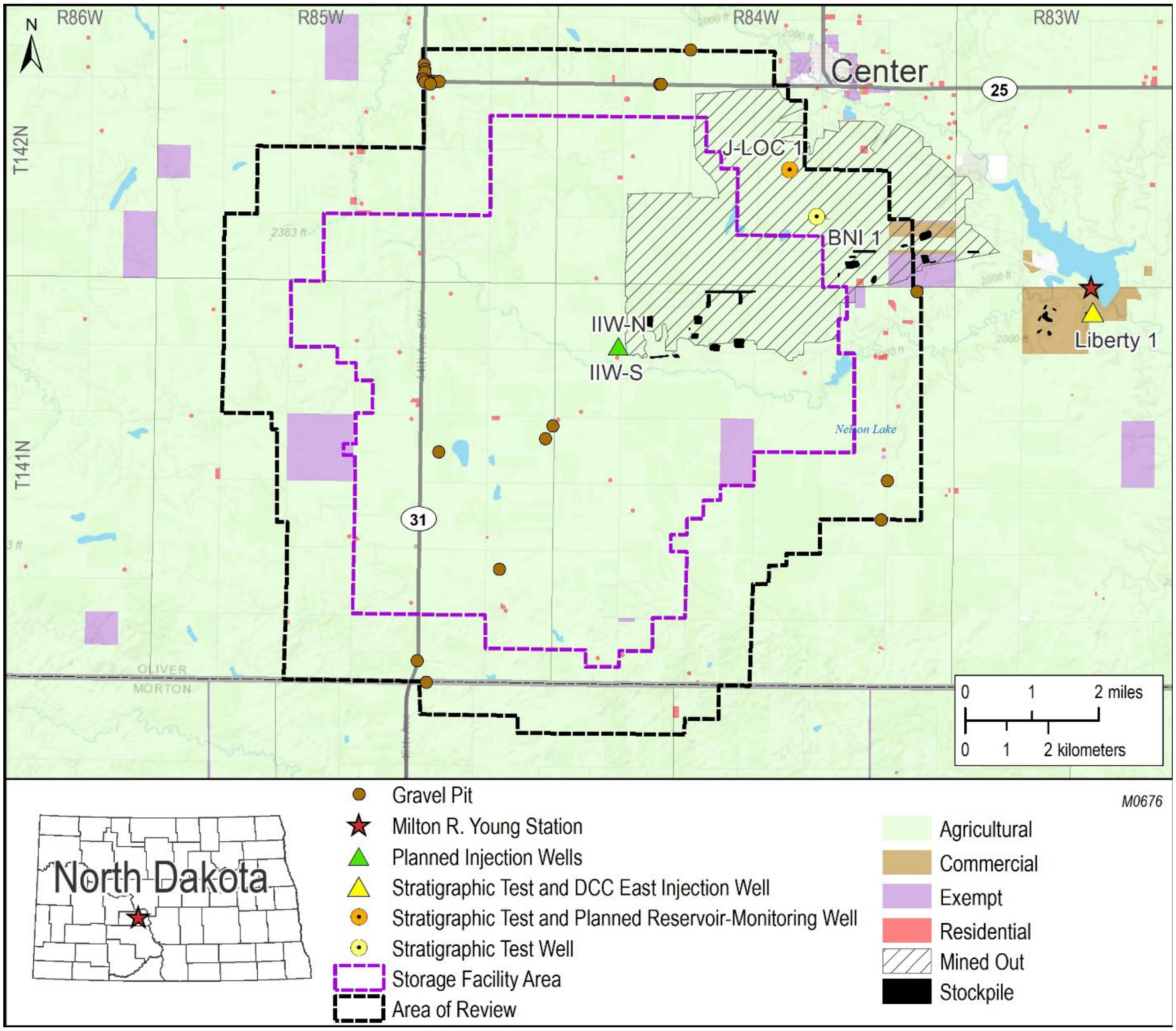

Figure 7-2. Residential, commercial, mined, and agricultural land use within 1 mile of the storage facility area.

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

Several scenarios could activate an emergency response. This ERRP considers any adverse incident involving threat to human health, threat to endangerment of a lowermost USDW, or potential materially damage to property to be an "event." An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. The scope of response, actions, and order of activities will be proportional to the severity and impact of the event and implemented as outlined in this ERRP.

7.3.2 Potential Project Emergency Events and Their Detection

The risk assessment for the project produced a list of potential technical project risks (i.e., a risk register) which were placed into the following three time frames:

1. Preinjection
2. Injection
3. Injection/postinjection

The events identified during technical reviews for the DCC West secure geologic storage site are listed in Table 7-3. Appendix F contains a response protocol for each event identified in Table 7-3. The protocols may be modified and refined based on the specific circumstances and conditions of the event as well as any discussion with governmental authorities having jurisdiction.

Table 7-3. Risk Category Matrix

Construction Period • Well control event while drilling or completing the well with loss of containment • Movement of brine between formations during drilling • Presence of H_2S while drilling or completing the well
Injection Period • Loss of mechanical integrity (flowlines, injection, monitoring wells, disposal well) • Loss of containment (LOC): vertical migration of CO_2/brines via injection wells, monitor wells, Class I wells, plugged and abandoned (P&A) wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in flowlines, wells, and infrastructure • Monitoring equipment failure or malfunction • Induced seismicity • Seismic event • Other natural disaster
Postinjection Site Care Period • Loss of mechanical integrity (monitoring wells) • LOC: vertical migration of CO_2/brines via monitoring wells, Class I wells, P&A wells, and undocumented wells • LOC: lateral migration of CO_2 outside of defined AOR • LOC: vertical migration due to failure in the confining zone, faults, and fractures • External impact in monitoring wells • Monitoring equipment failure or malfunction • Natural seismicity • Other natural disaster

If information from the monitoring network, alarm system, field operators, or external reports evidences a potential leak of CO_2 or formation fluids from any well or surface facility, including any pressure change or monitoring data which indicate the presence of a leak or loss of containment from the storage reservoir or concern for the mechanical integrity of the system, the following actions will be taken:

1. The project will activate the emergency and remediation response protocol consistent with this ERRP and circumstances of the event.

2. The NDIC Department of Mineral Resources (DMR) Underground Injection Control program director (UIC program director) will immediately be notified within 24 hours of discovery.

The UIC program director may allow the operator to resume injection prior to remediation if the storage operator demonstrates that the injection operation will not endanger USDWs.

In addition to the foregoing technical project risks, the occurrence of a natural disaster (e.g., naturally occurring earthquake, tornado, lightning strike, etc.) also represents an event for which an emergency response action may be warranted. For example, an earthquake or weather-related disaster (e.g., tornado or lightning strike) has the potential to result in injection well problems (integrity loss, leakage, or malfunction) and may also disrupt surface and subsurface storage operations. These events are addressed in the DCC West emergency response plans (Appendix F) and will be extended to the geologic storage operations.

7.4 Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-3, as well as potential natural disasters, will follow the same protocol. This protocol consists of the following actions:

- The facility response plan qualified individual (QI) (see Section 7.6, Emergency Communications Plan) will be notified immediately and, as soon as is practicable and within 24 hours of that notification, make an initial assessment of the severity of the event (i.e., does it represent an emergency event?) to ensure all necessary steps have been taken to identify and characterize any release pursuant to NDAC Section 43-05-01-13(2)(b).

- If determined to be an emergency event, the QI or designee shall notify the NDIC DMR UIC program director (see Section 7.6, Emergency Communications Plan) within 24 hours of the emergency event determination (pursuant to NDAC § 43-05-01-13) and implement the emergency communications plan.

- Following these actions, the geologic storage project operator will:

    1. Initiate a project shutdown plan and immediately cease CO_2 injection. However, in some circumstances, the operator may, in consultation with the NDIC DMR UIC program director, determine whether gradual or temporary cessation of injection is more appropriate.
    2. Shut in the CO_2 injection well (close flow valve).

3. Vent CO_2 from surface facilities.
4. Limit access to the wellhead to authorized personnel only, equipped with appropriate personal protective equipment (PPE) and any additional safety equipment, as appropriate.
5. If warranted, initiate the evacuation of the MPC plant and associated geologic storage project facilities in accordance with the facility response plan and communicate with local emergency authorities to initiate evacuation plans of nearby residents.
6. Perform the necessary actions to determine the cause of the event and, in consultation with the NDIC DMR UIC program director, identify and implement appropriate emergency response actions (see Table 7-4, for details regarding the specific actions that will be taken to determine the cause and, if required, mitigation of each of the events listed in Table 7-3).

Table 7-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO_2 Flowline from the CO_2 Capture System to CO_2 Injection Wellhead	• The CO_2 release and its location will be detected by pipeline safety actuation and monitoring equipment, visual inspection, and/or CO_2 wellhead monitors, which will trigger an MPC alarm, alerting plant system operators to take necessary action. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program near the location of failure to monitor the presence of CO_2 and its natural dispersion following the shutdown of the flowline using practices similar to those used to develop the risk management plan. • The flowline failure will be inspected to determine the root cause of the flowline failure. • Repair/replace the damaged flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.
Integrity Failure of Injection or Monitoring Well	• Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure. • Identify and implement appropriate remedial actions to repair damage to the well (in consultation with the NDIC DMR UIC program director). • If subsurface impacts are detected, implement appropriate site investigation activities to determine the nature and extent of these impacts. • If warranted based on the site investigations, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).
Monitoring Equipment Failure of Injection Well	• Monitor well pressure, temperature, and annulus pressure (manually, if necessary) to determine the cause and extent of failure. • Identify and, if necessary, implement appropriate remedial actions (in consultation with the NDIC DMR UIC program director).

Continued . . .

Table 7-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

<table>
<tr><td>Storage Reservoir Unable to Contain the Formation Fluid or Stored CO_2</td><td>

• Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well and soil gas profile station, and analyze the samples for indicator parameters (see Testing and Monitoring Plan in Section 5.0 of the SFP application).
• If the presence of indicator parameters is confirmed, develop (in consultation with the NDIC DMR UIC program director) a case-specific work plan to:
1. Install additional monitoring points near the impacted area to delineate the extent of impact:
a. If a USDW is impacted above drinking water standards, arrange for an alternate potable water supply for all users of that USDW.
b. If a surface release of CO_2 to the atmosphere is confirmed, initiate an evacuation plan, if warranted, in tandem with an appropriate workspace and/or ambient air-monitoring program at the appropriate incident boundary to monitor the presence of CO_2 and its natural dispersion following the termination of CO_2 injection following practices similar to those used to develop the risk management plan.
c. If surface release of CO_2 to surface waters is confirmed, implement appropriate surface water-monitoring program to determine if water quality standards are exceeded.
2. Proceed with efforts, if necessary, to a) remediate the USDW to achieve compliance with drinking water standards (e.g., install system to intercept/extract brine or CO_2 or “pump and treat” the impacted drinking water to mitigate CO_2/brine impacts) and/or b) manage surface waters using natural attenuation (i.e., natural processes, e.g., biological degradation, active in the environment that can reduce contaminant concentrations) or active treatment to achieve compliance with applicable water quality standards.
• Continue all remediation and monitoring at an appropriate frequency (as determined by DCC West management designee and the NDIC DMR UIC program director) until unacceptable adverse impacts have been fully addressed.
</td></tr>
<tr><td>Natural Disasters (seismicity)</td><td>

• Identify when the event occurred and the epicenter and magnitude of the event.
• If magnitude is greater than 2.7:
1. Determine whether there is a connection with injection activities.
2. Demonstrate all project wells have maintained mechanical integrity.
If a loss of CO_2 containment is determined, proceed as described above to evaluate, and if warranted, mitigate the loss of containment.
</td></tr>
</table>

Continued . . .

Table 7-4. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters	• Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • In the case of severe weather, consider a temporary shutdown of injection operations to mitigate risks. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate extent of any impacts. • If impacts or endangerment are detected, identify and implement appropriate response actions in accordance with the facility response plan (in consultation with the NDIC DMR UIC program director).

For each of the listed events, a detailed description of monitoring equipment and control in place is included in Appendix F.

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

All DCC West plant and geologic storage project personnel will have undergone hazardous waste operations and emergency response (HAZWOPER) training in accordance with guidelines produced and maintained by the Occupational Safety and Health Administration (OSHA) (OSHA 29 Code of Federal Regulations [CFR] § 1910.120). In addition, assistance has been secured from local (Center, North Dakota) and Oliver and Burleigh County emergency services to implement this ERRP.

Equipment (including appropriate PPE) needed in the event of an emergency and remedial response will vary, depending on the emergency event. Response actions (e.g., cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. However, when specialized equipment (such as a drilling rig or logging equipment or potable water hauling, etc.) is required, the Director – Regulatory & Technical Services (see Table 7-2) shall be responsible for its procurement, including maintenance of the list of contractors and equipment vendors (see Section 7.6, Emergency Communications Plan).

7.5.2 Staff Training and Exercise Procedures

DCC West will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and plant operations training programs, which are described in the ICP. Periodic training will be provided, not less than annually, to protect all necessary plant and project personnel. The training efforts will be documented in accordance with the requirements of the DCC West plans which, at a minimum, will include a record of the trainee's name, date of training, type of training (e.g., initial or refresher), and instructor name. DCC West will coordinate with Minnkota's Milton R. Young Station staff to participate in emergency response activities. These activities are rooted in regulatory compliance and best practices for rural industrial facilities. Many of the training initiatives established by the Minnkota staff are intended to develop emergency response relationships integrated into safety environmental, and emergency preparedness programs and involve work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events. A few examples of these training activities with local responders include: participation in the Oliver County Local Emergency Planning Committee, MRY Rescue Team, EPA Tier II reporting regarding hazardous materials, annual hazardous materials training. With the addition of carbon sequestration projects adjacent to the Milton R. Young Station these training exercises will expand to include considerations for response to a significant release of CO_2 to the atmosphere.

7.6 Emergency Communications Plan

An incident command system is identified in the facility response plan that specifies the organization of a facility response team and team member roles and responsibilities in the event of an emergency. The DCC West organizational structure is still in development, DCC West will provide updated information to provide specific identification and contact information of each member of the facility response team.

Table 7-5 contains the contact information for the DMR contact.

Table 7-5. NDIC DMR UIC Contact

Company	Service	Location	Phone
NDIC DMR	Class VI/CCUS Supervisor	Bismarck, ND	(701) 328-8020

The QI or designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies provided in Table 7-6. Table 7-7 lists available contractors and service providers.

Table 7-6. Off-Site Emergency Notification Phone List

Oliver County Sheriff Department*	911 or (701) 794-3450
Oliver County Fire Department (primary)*	911 or (701) 794-3210
Oliver County Ambulance	911 or (701) 220-1329
Helicopter Air Care	911 or Sandford AirMed Dispatch (800) 437-6886
North Dakota Highway Patrol	911 or (701) 328-9921
North Dakota Highway Department	(701) 794-3450
North Dakota Poison Control	(800) 222-1222
Sandford Medical Hospital (Bismarck)	(701) 323-6000
Sandford AirMed (Bismarck)	(800) 437-6886
MRYS Emergency Response Team (ERT)	(701) 794-8711
State Emergency Response Commission*	(833) 997-7455

* Those persons/agencies above marked with an asterisk have received a copy of the DCC West emergency response action plan.

Table 7-7. Potential Contractor and Services Providers

Company	Service	Location	Phone
Baranko Brothers	Excavation and dirt work/hauling	Dickinson, ND	(701) 690-7279
Cyclone	Drilling rig	Gillette, WY	(307) 660-2370
Enerstar	Housing and rentals	Bismarck, ND	(701) 934-1557
GeothermEx	Site management/drilling supervisor services	Houston, TX	(281) 769-4517
Schlumberger	Cementing	Denver, CO	(720) 272-5288
	Core analysis	Houston, TX	(801) 232-5799
	Direction and measurements	Denver, CO	(484) 522-8434
	Products and services	Denver, CO	(517) 755-9050
	Bits	Denver, CO/Williston, ND	(303) 518-6135
	Completions	Houston, TX	(440) 391-2711
Cameron Surface Systems	Bits	Minot, ND	(701) 354-9952
Reservoir Group	Coring	Denver, CO/Houston, TX	(832) 350-5292
Rud Oil	Diesel	Center, ND	(701) 794-3165
Go Wireline	Wireline tool/fishing services	Dickinson/Williston, ND	(406) 480-1086
MI SWACO	Drilling fluids		(661) 549-3645
Sunburst Mudlogging	Logging/geologic services	Billings, MT	(406) 860-1228
Innovative Solutions	Solids control	Williston, ND	(701) 770-0359
WellPro, Inc.	Fishing equipment	Dickinson, ND	(701) 227-3737
Creek Oilfield Services	Waste disposal/casing running/supply	Williston/Bismarck, ND	(701) 590-5859 (715) 563-7543
Environmental Solutions	Cuttings disposal	Belfield, ND	(701) 300-1156
Waste Management	Trash	Bismarck, ND	(701) 214-9741
ASK Transportations	Bulk fresh water	Williston, ND	(701) 580-5627
Darby Welding	Welding	Dickinson, ND	(701) 483-5896
Panther PPT	Bop testing	Watford, ND	(701) 227-3737
Wyoming Casing	Casing services	Williston, ND	(701) 290-8522
CCS	Tank farm	Cody, WY	(701) 260-7780
MVTL Lab	Formation fluids collection	Bismarck, ND	(701) 204-5478
Petroleum Services	Casing (float, centralizer)	Williston, ND	(701) 770-1763

Lastly, the facility response plan contact list also includes addresses and contact information for the neighboring facilities and occupied residences located within a 1-mile radius of the geologic storage project. Because indicated local and regional emergency agencies (Table 7-6) are provided a copy of the facility response plan, the QI or designee may rely upon emergency agency assistance when it is necessary and appropriate to alert the applicable neighboring facilities and residents in order to allow the operator to focus time and resources on response measures (see also Section 7.4[5]).

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by NDIC DMR.
- Within 1 year of an AOR reevaluation.
- Within a prescribed period (to be determined by NDIC DMR) following any significant changes to the project, e.g., injection process, the injection rate, etc.
- As required by NDIC DMR.

If the review indicates that no amendments to the ERRP are necessary, MPC will provide the documentation supporting the "no amendment necessary" determination to the UIC program director. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to NDIC DMR as soon as reasonably practicable, but in no event later than 1 year following the commencement of a review.

SECTION 8.0

WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

The Worker Safety Plan (WSP) describes the minimum safety programs, permit activities, and training requirements to deploy during construction, operation, and postinjection site care periods. This document does not limit the application of additional programs and technologies that could improve the safety and performance of the operation.

This WSP incorporates the safety program for the Tundra SGS Site as a whole. It includes monitoring wells, monitoring system, injection well network, and the CO_2 flowline from the capture facility to the storage site.

8.1 Definitions

a. **Confined space** means a space large enough and so configured that an employee can bodily enter and perform assigned work, has limited or restricted means for entry or exit (for example, tanks, vessels, silos, storage bins, hoppers, vaults, and pits or spaces that may have limited means of entry), and is not designed for continuous employee occupancy. This definition could also apply to a trench, bell hole, cellar, or excavation.

   Some confined spaces are designated "permit-required" confined spaces; i.e., entry into the space must be controlled through application of a confined space entry permit. A "Yes" answer to *any one* of the following questions means the space must be designated permit-required:

   - Does the space contain, or have the potential to contain, a hazardous atmosphere?
   - Does the space contain a material that has the potential for engulfing an entrant?
   - Does the space have an internal configuration such that an entrant could be trapped or asphyxiated by inwardly converging walls or a floor, which slopes downward and tapers to a smaller cross-section?
   - Does the space contain any other recognized serious safety or health hazard?

   The Confined Space Entry (CSE) Program is provided to protect authorized employees and contractors that will enter permit-required confined spaces.

b. **Contractor** means a company or person performing work, providing services, or supplying equipment at the work site, including its subcontractors.

c. **Entry supervisor** means the person (such as the employer, site manager/supervisor, or crew chief) responsible for determining if acceptable entry conditions are present at a permit space where entry is planned, for authorizing entry and overseeing entry operations, and for terminating entry as required by this section.

d. **Hazardous energy** means energy sources including electrical, mechanical, hydraulic, pneumatic, chemical, thermal, or other sources in machines and equipment where the unexpected start-up or release of stored energy can result in serious injury or death.

e. **Operator** means DCC West or any DCC West employee.

f. Permitted work activities means activities that require the use of a permit, including, but not limited to, confined space entry, lockout/tagout, trenching and excavation, electrical, and hot work.

g. Site manager/supervisor means operator-designated representative in charge of the work site or work.

h. Work site means physical location under control of the operator where work is being performed on behalf of the operator.

i. Work means task or tasks to be executed by the operator or contractor.

j. Visitor means a person or person(s) present at the work site that is there for observational, not work, purposes.

8.2 Stop Work Authority

Every operator and contractor has the right, obligation, authority, and responsibility to stop any work or action that is unsafe or that, if continued, may result in adverse impact to human health or the environment. No operator employee or contractor will be subject to discipline or sanction for stopping any work or action that they believe in good faith is unsafe or may result in adverse impact to the environment. Work must be stopped in a safe manner and immediately reported to the site manager/supervisor or operator representative. Appropriate actions will be taken to mitigate the hazard before work is allowed to commence. Every contractor will have a stop work authority program that advises their employees of their rights to use stop work authority.

8.3 Incident Notification and Response

Operator employee or contractor shall be required to immediately notify the site manager/supervisor (or designated operator representative) of all incidents involving injury or illness to a contractor; damage to operator or contractor equipment as a result of contractor activities at the work site; and any spill, release, or leak. Prompt investigation is required of all injuries, illnesses, equipment or property damage, environmental spills/releases, and other health, environment, and safety (HES)-related incidents.

Unsafe conditions must be immediately reported to the operator. "Near miss" incidents that could have resulted in injury or damage must be reported by the operator employee or contractor to the site manager/supervisor (or designated operator representative).

8.4 Incident Report and Investigation

An initial preliminary written incident report for all workplace incidents shall be submitted within twenty-four (24) hours of occurrence, with known facts, to the site manager/supervisor (or the designated operator representative).

An investigation will be started as soon as possible following notification into all injuries, illnesses, equipment or property damage, other HES-related incidents, or leak, spill, or release. A written interim incident investigation report for all incidents will be provided every seven (7) calendar days until the final incident report is submitted to the site manager/supervisor (or the designated operator representative). The operator may actively participate in any investigation of incidents at any work site or on any operator-controlled location(s). The operator will be allowed to request any work site HES data (i.e., audits, incident investigations, observation reports, other HES reports) for purposes of identifying trends, root causes, and training opportunities.

The final incident report shall include, at a minimum, description of the incident, date/time, location, immediate actions taken, chronology, injury details, OSHA (Occupational Safety and Health Administration) classification, impact on people, environment and business continuity as applicable, protective equipment performance assessment, review of the process (design, operation, maintenance, and administrative control), identification of root cause, and recommendation for corrective actions.

The operator shall provide timely notification to the site owner of all incidents involving injury or property damage and will provide weekly reports to the site owner that provide a summary of incidents.

All incident reports that result in formal notification to any government entity or authority shall be provided to the operator. Additionally, any investigations, inspections, or penalties assessed on the contractor by any government entity or authority, relating to or in connection with any work performed for operator, shall promptly be provided to the operator.

8.5 Training

The contractor shall receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training shall be conducted by, or under the supervision of, an operator site supervisor/manager or an operator-designated representative. Trainers must be thoroughly familiar with the operations plan and Emergency Remedial Response Plan (ERRP).

The contractor shall conduct a training needs assessment that is representative of the contracted work site assignments. The contractor shall establish the type and frequency of training in a role and responsibility matrix by position ("matrix"). The contractor shall ensure that personnel have been given all core and special training identified in the matrix.

However, the following are minimum requirements regardless of position or work:

- All newly hired personnel shall attend onboarding training for the work site and successfully complete required safety training according to the assigned position prior to starting work.

- All operation employees shall participate in annual training to understand and reinforce how to perform the assigned role/job, equipment functioning, and instrumentation.

- All employees shall participate in annual refresher training for the emergency response procedures contained in the ERRP.

- Monthly briefings shall be provided to operations personnel according to their respective responsibilities and shall highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

- Documentation of all training shall be retained by the contractor and made available for operator inspection upon request.

8.6 Contractor Qualification and Bridging Documents

The Contractor shall have an assurance process in place to ensure that all HES requirements are fully executed and sustained. Corrective actions shall be tracked through closure. The operator shall be provided access to assurance reports upon request. A bridging document shall be created to align the safety program between operator policies and contractor policies, if required.

8.7 General Health, Safety, and Welfare

The work site must be maintained so as not to create or otherwise contribute to an unhealthy working or living environment. In order to accomplish this objective, the operator and contractor shall ensure the following:

Information/posting/signs. All emergency, safety, and operational information/postings/ signs shall be communicated in a format to ensure comprehension by the operator, visitors, or contractors on the work site, as per OSHA 29 CFR (Code of Federal Regulations) 1910.145, country, state/province, local, or international equivalent.

Job safety analysis. The contractor shall complete and review, with all affected parties, a job safety analysis (JSA) prior to performing any task. Anytime the job scope or the conditions change, the contractor shall review and revise (if needed) the JSA with all affected parties.

Prejob meeting. On work sites where simultaneous operations (SIMOPS) shall be conducted, daily prejob planning meeting(s) shall be held involving representatives from all potentially affected parties.

English language proficiency. At least one person per crew or work group assigned to a task is fully capable of communicating in the English language (both in a verbal and written manner) such as that they can perform the work safely. If required, an interpreter shall be provided.

Short service or new hire. Short-service personnel or new hires, defined as individuals with less than 3 years' specific industrial experience shall be formally mentored and supervised by an experienced professional for a minimum of 45 working days and shall be uniquely identified in the field (stickers and unique color hard hat). The employee shall fulfill core training before starting activities on the work site. Documentation of completion of mentoring/training must be retained and available for inspection upon request.

Medical fitness/personal hygiene. Personnel shall be medically fit to safely perform the work they are expected to perform. The operator may audit to ensure that personnel maintain appropriated standards of personal hygiene during performance of the work.

Housekeeping. The contractor shall ensure good housekeeping practices are conducted at the work site by all personnel to provide for a safe and orderly working environment. Aisles, emergency exits, and controls must be always kept free of obstacles.

Machine guarding. The contractor shall ensure that all equipment machine guarding (permanent, temporary, and portable) is properly installed and maintained. Before removing guards to service-guarded equipment, the service-guarded equipment must be isolated, locked out, tagged out, and verified to be nonfunctioning. See lockout/tagout procedure [p. 8-7].

Portable hand tools. All portable hand tools shall have proper insulation, grounding, and guarding as per manufacturer requirements and be protected by GFCI (ground fault circuit interrupter) per OSHA guidelines, as applicable. All portable tools shall be properly maintained and used per manufacturer original design and intended purpose. Tools shall be regularly inspected, and damaged or worn tools shall be taken out of service. No homemade or modified hand tools shall be used on the work site.

Management of change (MOC). The contractor shall have a formal MOC process implemented for all equipment changes (except for "replacement in kind"), process, and procedural changes. The contractor shall ensure no contractor's equipment is used or modified outside of the original equipment manufacturer design specifications.

Clothing and other apparel. Ragged or loose clothing and jewelry (rings, watches without breakaway nonmetallic bands, necklaces, exposed piercings, etc.) are not to be worn when on the work site. Any clothing that becomes saturated with hazardous chemicals should be promptly removed and replaced.

First Aid/CPR. The contractor shall ensure sufficient first aid/CPR (cardiopulmonary resuscitation), defibrillator equipment, and trained personnel (National Safety Council, American Heart Association, Red Cross, etc.) are available at the work site as per OSHA 29 CFR 1910.151 or equivalent country, state/province, or local regulations. First aid/CPR and defibrillator kit(s) containing an appropriate quantity of supplies shall be always maintained on location.

Transportation safety. The contractor shall ensure that all modes of transportation are fit for purpose for travel to/from/within the work site. The contractor shall ensure compliance with all applicable country, state/province, and local regulations.

Industrial hygiene

- The contractor will assess job duties to determine if hazards are present, or are likely to be present, which necessitate the use of engineering controls, administrative controls, or personal protective equipment (PPE).

- The contractor shall document this hazard assessment through a written certification that identifies the work site evaluated, the person certifying that the evaluation has been performed, and the date(s) of the hazard assessment. Documentation shall be retained by the contractor and made available to the operator upon request for inspection.

- Based on the results of this hazard assessment, the contractor may be required to perform an industrial hygiene assessment of the work site to determine the level of exposure to hazards (chemicals, lead, dust, noise, etc.).

- Appropriate measures shall be taken based on these assessments in order to safely manage operator, contractor, and visitor exposures.

8.8 Personal Protective Equipment

All contractors and visitors must wear appropriate PPE for the hazards present at the work site. Actual PPE requirements shall be determined as per hazard/risk assessments and safety data sheets for products that personnel might be exposed to at the work site ("risk assessment").

The following PPE, at a minimum, must be used by all operators or contractors at the work site, along with the appropriate training in the proper use and care of such PPE:

- Hard hats
- Safety glasses with side shields
- Protective footwear (safety-toed boots)
- Personal monitor(s) as needed based on risk assessments for H_2S or other hazardous materials

The following is a list of PPEs that, based on the hazard/risk assessment, might be required for the work site and the applicable standards/certifications that apply:

- Respiratory protection meeting OSHA 29 CFR 1910.134, National Institute of Occupational Safety and Health (NIOSH)-certified

- Head protection meeting American National Standards Institute (ANSI) Z89.1 Class 1 Type E&G

- Eye and face protection appropriate for the work environment and hazards meeting ANSI Z87.1

- Foot protection meeting ASTM F 2413 or international equivalent standard

- Hearing protection meeting ANSI S3.19 standard

- Hand protection (gloves) appropriate for the work environment, exposure, and hazards

- Flame-retardant clothing certified to National Fire Protection Association (NFPA) 2112 (NFPA 70E Arc Flash PPE Category for personnel performing electrical work) (as identified by regulation or local company management including but not limited to 29 CFR 1910.132, 29 CFR 1910.269, 29 CFR 1910.335, ASTM 1506, NFPA 70E, NFPA 2112, and NFPA 2113)

8.9 Fire Protection

The contractor shall, based on a risk assessment, provide and maintain fire protection equipment for the work. Fire protection shall comply with all local regulatory requirements or equivalent NFPA requirements and shall be dedicated for firefighting use only.

8.10 Hand Safety

The contractors shall have a hand safety awareness-training program targeting topics such as pinch points, hold points, soft grips, cutting devices, proper hand tools, hot/cold conditions, chemical handling, etc.

Selection of appropriate hand protection should be based on an evaluation of the performance characteristics of the hand protection relative to the task(s) to be performed, conditions present, duration of use, and the hazards and potential hazards identified.

Contractors are required to use appropriate hand protection when they encounter the following hand hazards:

- Thermal
- Sharp materials
- Electrical current
- Chemical exposure
- Impact
- Abrasive materials

8.11 Permitted Work Activities

The following are considered permitted activities and require a permit to be executed. The site supervisor (such as the employer-designated site manager/supervisor, superintendent, shift manager, or crew chief) shall be responsible for determining if acceptable permit conditions are present for, and that site conditions exist for, permitted work activities as planned; for authorizing and overseeing such permitted activities or operations; and for terminating such activities or operations as required by this section.

Hot work. Any work that may introduce any source of ignition where flammable vapors may be present or will generate sufficient heat to ignite combustible and/or flammable materials, and these materials will support combustion once ignited.

Confined space entry. Any confined space entry conducted on the operator property must be done under a permit-required confined space program, which shall identify methods to comply with the requirements of OSHA Standard 1910.146.

Lockout/tagout procedure. When any hazardous energy scenario is encountered, including, but not limited to, the following during performance of servicing or maintenance of equipment:

a. Removal or bypass of machine guards or other safety devices.
b. Placement or positioning of any part of their body in contact with the point of operation.
c. Placement or positioning of any part of their body in a danger zone associated with a machine's operating cycle.
d. When the release of stored energy that could injure the operator, contractor, visitor, or a member of the public, if the isolated device (e.g., valve, breaker, etc.) were to be operated by mistake.

then the following safe work practices are required:

a. Use of lockout/tagout controls to prevent the release of hazardous energy.
b. The equipment must be de-energized, and locks and tags must be applied to the energy isolating devices.
c. All work involving isolation of hazardous energy must be done in accordance with 29 CFR 1910.147.

Excavation and trenching. The contractor performing trenching and excavation activities on a work site must provide competent personnel capable of identifying existing and predictable hazards in the immediate surroundings. The contractor shall ensure that the competent person must be on-site during all excavation activities where the potential for injury exists. The competent person must also comply with all applicable OSHA construction regulations.

Pre-excavation notification requirements. Injection and plant locations must have a means of receiving a written "ticket locate request" from a state one-call notification center. In addition, each location must have a 24-hour emergency telephone number, such as a plant location or an answering service. Based upon site location and known risks, additional underground reviews or preliminary activities may be required prior to excavation, such as use of GPR (ground-penetrating radar), hand-digging, hydro-vac.

Electrical. The contractor performing electrical work activities shall provide qualified personnel. Qualified persons must be trained and knowledgeable of the construction and operations of the equipment, or a specific work method, and be trained to recognize and avoid the electrical hazards that might be present with respect to that equipment or work method.

Energized equipment to which a qualified or unqualified person might be exposed must be in an electrically safe work condition before an employee works within the limited approach boundary or the arc flash protection boundaries. For cases where it is determined that the equipment cannot be placed in an electrically safe work condition, an energized electrical work permit must be completed and approved prior to the work commencing.

Energized work that is considered routine for diagnostic testing or troubleshooting is exempted from the energized electrical work permit requirements if there is an approved maintenance or operating procedure in place for the task.

Electrical safety program. The contractor shall have an electrical safety program that identifies the levels of all electrical and associated tasks to be performed and the personnel position qualified to perform each of these tasks as per OSHA/NEC (National Electrical Code), API (American Petroleum Institute) 500, NFPA 70E or equivalent country, state/province, or local regulations. Contractor electricians shall be qualified to perform electrical activities on the contractor's or operator's equipment at the work site, as required by local regulations or equivalent OSHA/NEC/NFPA 70E standards.

Contractors working in areas where there are electrical hazards shall be provided with and shall use protective equipment that is designed and constructed for the specific part of the body to be protected and for the work to be performed.

The contractor shall consider all overhead power lines to be energized unless proper measures have been taken for de-energizing. When work is being performed near energized overhead power lines, any part of the crane, boom, mast, gin poles, suspended loads, or machinery shall not be permitted within 10 feet (3 meters) of the power lines. However, this safe working distance can be increased according to the voltage of the power lines (OSHA 29 CFR 1926.550, 1910.181, and 1910.269 or equivalent country, state/province, or local regulations).

The contractor shall ensure that all personnel will use only portable ladders, scaffolding, or other elevating devices, made of nonconductive material, when working around energized electrical equipment.

Precautions shall be taken to ensure that all equipment used is properly grounded and that accidental contact with ungrounded electrical sources is prevented.

The contractor shall ensure all contractor electrical components, tools, and PPE are maintained in a safe working condition.

Temporary electrical power setup for the operation of tools and equipment shall be protected by GFCI circuits.

General light-duty vehicle safety. All workers and visitors on-site must employ a vehicle appropriate for access conditions as some work sites may require 4-wheel or all-wheel drive to access. Vehicles should be maintained in such a way that all vehicle safety measures remain in working order (brakes, safety belts, headlights, etc.) and should be equipped with standard roadside safety equipment, such as radios/phones, traffic flags, flares or cones, and first aid kits.

Drivers of these light-duty vehicles must obey access road and site speed limits and traffic rules. When conditions limit visibility and/or mobility, the drivers must have adequate visibility and access to proper driving routes. Drivers shall operate light-duty vehicles only when they are free of any mental or physical impairment. Drivers shall turn off engine any time the driver exits the vehicle, even if for a moment.

Driving hazards and foot traffic only areas must be clearly marked with safety cones, barrels, barricades, or safety flags. Flaggers or spotters must be used for vehicle reverse/backup driving.

All light-duty vehicles parked on-site must be clear of light- and heavy-duty vehicle traffic.

In the event of an accident, notification is to be provided to the superintendent immediately following any emergency contacts that may be required. Further, the driver of the vehicle will submit to any drug/alcohol-related testing mandated in such instances.

8.12 Chemical, Hazardous, or Flammable Materials

Safety Data Sheets (SDS). The contractor shall ensure that all chemical products/materials supplied to the work site are accompanied by the respective SDS upon delivery. The contractor shall provide operator site supervisor/manager with an inventory of all chemical products/materials to be used along with copies of the related SDS documents 1 week prior to delivery. The operator shall have authority to prohibit any chemical product/material that is deemed unacceptable; this is at the sole discretion of the operator.

The contractor shall instruct all personnel on the safe use of the chemical products/materials in accordance with an appropriate written hazard communication program, as dictated by local/state/federal regulatory requirements.

The contractor shall ensure that SDS for chemicals are reviewed by personnel prior to exposure.

Storage, use, and labeling of chemicals and hazardous/flammable materials. The contractor shall ensure all hazardous and/or flammable materials/products are labeled, handled, dispensed, and stored in accordance with OSHA 29 CFR 1910.106 and 1910.1200, or equivalent country, state/province, or local regulations.

All chemicals, paints, and hazardous/flammable materials shall be kept in appropriate containers, which are clearly labeled as to the respective contents, and stored in fit-for-purpose storage containers (uniquely identified, vented, etc.). Container labeling shall be consistent with OSHA, DOT (the U.S. Department of Transportation), NFPA, or equivalent country, state/province, or local regulation.

Hydrogen sulfide. When the presence of hydrogen sulfide gas may exist at greater than 10 ppm in the wellbore, formation, facilities, or production stream, contractor is responsible for ensuring that the personnel are properly trained and qualified. Personal monitoring equipment shall be used by all personnel, and personal monitoring devices must be set to alarm at 10 ppm so that personnel are alerted to evacuate the area. The H_2S monitors shall be calibrated per the manufacturer's specifications and, at a minimum, be "bump-tested" at least monthly.

Compressed gas and air cylinders. Compressed gas cylinders shall be properly used, maintained, stored, handled, and transported as designated by OSHA 29 CFR 1910.101-106, 1910.252, 1910.253, and 1926.350 or equivalent country, state/province, or local regulations.

Compressed gas and air equipment shall be constructed in accordance with ASME Boiler & Pressure Vessel Code, Section VIII Edition 1968 or equivalent country, state/province, local, or international laws or regulations. Equipment includes but is not limited to safety devices, flame arrestors, regulators, pressure gauges, check valves, pressure relief valves, labeling, etc.

All compressed gas cylinders shall be returned promptly to a suitable/designated storage area when not in use. Compressed gas cylinders shall be stored in the upright position and secured.

Protective caps shall be placed over the cylinder valves when not in use or when being transported.

Compressed gas cylinders shall be stored away from heat, fire, molten metal, or electrical lines.

Compressed gas cylinders shall not be transported by mobile cranes unless a special carrier is used.

Oxygen and flammable gases shall be stored in areas separated by a minimum of 20 feet or by a fire barrier rated for 30 minutes.

Acetylene or liquid compressed gas cylinders shall never be used in a horizontal position, as the liquid may be forced out through the hose, causing a fire hazard or explosion. Oxygen/acetylene cutting torch lines shall include flashback arrestors placed (at least) at the cylinder end. The preference is for the arrestor to be on the torch side.

Compressed air should not be used for cleaning clothing or parts of the body. If compressed air is used for cleaning, the discharge shall not exceed 30 psi (2.07 bar), and eye/face protection shall be worn.

8.13 Overhead/Outside Guarded Area

Lifting and hoisting. When contractor is working overhead, the area below shall be barricaded, or other equivalent measures taken, to protect workers on the work site. No one shall be permitted to pass under any suspended load. If any crane/hoisting operations are planned, contractor must have a competent person designated with minimum of three specific operating years of experience:

a. Each lifting device shall identify the manufacturer, safe working load, service/manufactured date, and serial/identification number.

b. Lifting devices shall be managed in a formal maintenance program (i.e., in service – out of service date, color-coding, rejection criteria, etc.).

c. Tail chains used on rig floor tuggers, winches, cranes, etc., must be attached to a certified lifting point and cannot be wrapped/choked around the load and/or back onto itself.

d. Tail chains are prohibited from use in all employee-riding operations, and contractor must provide an employee-riding risk assessment, which must at a minimum include identified hazards, hazard effects, control methods/mitigations, and recovery measures.

e. All other application of chains shall be consistent with original equipment manufacturer (OEM) ratings, design, and usage.

f. Lever-type load binders are prohibited for use on all work sites.

g. Homemade or modified lifting devices are prohibited for use on all work sites.

h. Tag lines shall be used when moving or lifting equipment.

Powered lifting device safety. All contractors operating a powered lifting device (forklift, cranes, winches, gin pole trucks, etc.) shall maintain current certification/training per OSHA regulations or equivalent country, state/province, or local regulations. All powered lifting devices shall have a preuse inspection as required by local regulation or manufacturer recommendation.

Scaffolds or platforms. All scaffolds or platforms used for installation and maintenance or removal of machinery and equipment shall be erected, maintained, and used in compliance with OSHA or a country, state/province, local, or international equivalent regulation. All scaffolds are to be inspected and tagged by a competent person prior to use and subsequently inspected by a competent person prior to each shift.

Safety harnesses and lifelines. When staff are working outside of properly guarded work platforms, a full body safety harness and lifeline, complete with shock absorbing lanyard(s) or self-retracting lifeline, shall be provided by the contractor and worn by all workers when working above 6 feet (construction) or when walking on working surfaces higher than 4 feet (general industry) without proper guarding. The contractor shall have procedures, trained personnel, and equipment necessary to rescue workers that may be suspended from fall protection equipment following a fall.

8.14 Work Site Conduct

Firearms, weapons, and non-work-related dangerous materials. The possession of firearms, weapons, explosives, or non-work-related dangerous materials at work, or while conducting work, is strictly forbidden.

Drug, alcohol, and controlled substances requirements. The contractor shall have a written Drug and Alcohol Program that conforms to the operator's drug, alcohol, and controlled substances requirements, of which the contractor confirms receipt and understanding. The contractor shall comply with all governmental requirements, including all applicable federal, state, and local drug and alcohol-related laws and regulations, including without limitation, the applicable DOT regulations. The contractor shall have a drug and alcohol policy in place and a functioning drug and alcohol-testing program, which include provisions for preemployment, postaccident, random, reasonable suspicion, return to duty, and follow-up testing as allowable under local, state, and federal law.

At a minimum, testing requirements and procedures, including testing mechanisms, substances, and cutoff levels, must comply with current DOT guidelines under 49 CFR Part 199 and/or 49 CFR Part 40. The contractor might have a non-DOT drug program. The contractor non-DOT Drug and Alcohol program shall include preemployment/preaccess screening and drug testing, postincident testing, for cause/reasonable suspicion testing, and random testing with an annual rate of at least 25% for drug and 10% for alcohol. No alcoholic beverages are to be consumed on the work site. Any contractor determined to be under the influence of, in possession of, or distributing either drugs or alcohol will be discharged for the remainder of the work.

Smoking and lighters/matches. Smoking is not allowed in any facilities or vehicles owned by the operator or within at least 20 feet or more of any facility entrance or exit, windows, or air intake vents. Smoking is not allowed on any roof area. If permitted on the work site, lighters and matches should be stored in safe areas away from flammable or combustible materials. Electronic cigarettes are to be treated in the same manner and shall only be used in designated areas.

Inappropriate behavior. Inappropriate behavior including, but not limited to, horseplay, practical jokes, offensive remarks, offensive gestures, harassment, etc., is prohibited while performing work or while on the work site. The contractors are expected to discharge, for the duration of the work, any personnel engaged in fighting on the job site. If any contractor is caught stealing from the operator or other contractors, those personnel are to be discharged and will be prohibited from returning to the work site.

SECTION 9.0

WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

DCC West plans to construct two CO_2 injection wells (IIW-N and IIW-S) as designed by Baker Hughes in compliance with North Dakota Industrial Commission (NDIC) Class VI underground injection control (UIC) injection well construction requirements. The proposed target injection horizon is the Broom Creek Formation. The project proposes the reentry and conversion of the NDIC-approved stratigraphic test well J-LOC 1 (NDIC File No. 37380) into a monitoring well for observing and reporting real-time pressure and temperature data, microseismic events, and CO_2 saturations as well as data for history-matching the geomodeling and simulations, as required in the testing and monitoring plan.

9.1 CO_2 Injection Well – IIW-N Well Proposed Casing and Cementing Programs

The IIW-N well is proposed to be drilled and completed as a CO_2 injection well in the Broom Creek Formation, with a target trajectory depth of approximately 6500 ft from the surface location. The proposed well trajectory of IIW-N is 28.61° deviation with the bottomhole location to be approximately 1503 ft to the north of the surface location. The IIW-N well trajectory is provided in Figure 9-1, and the proposed injection wellbore schematic is provided in Figure 9-2.

Tables 9-1 through 9-4 and Appendix H provide the proposed casing and cement programs for the IIW-N drilling program, which demonstrate compliance with the well construction program with North Dakota Administrative Code (NDAC) § 43-05-01-11 (Injection Well Construction and Completion Standards).

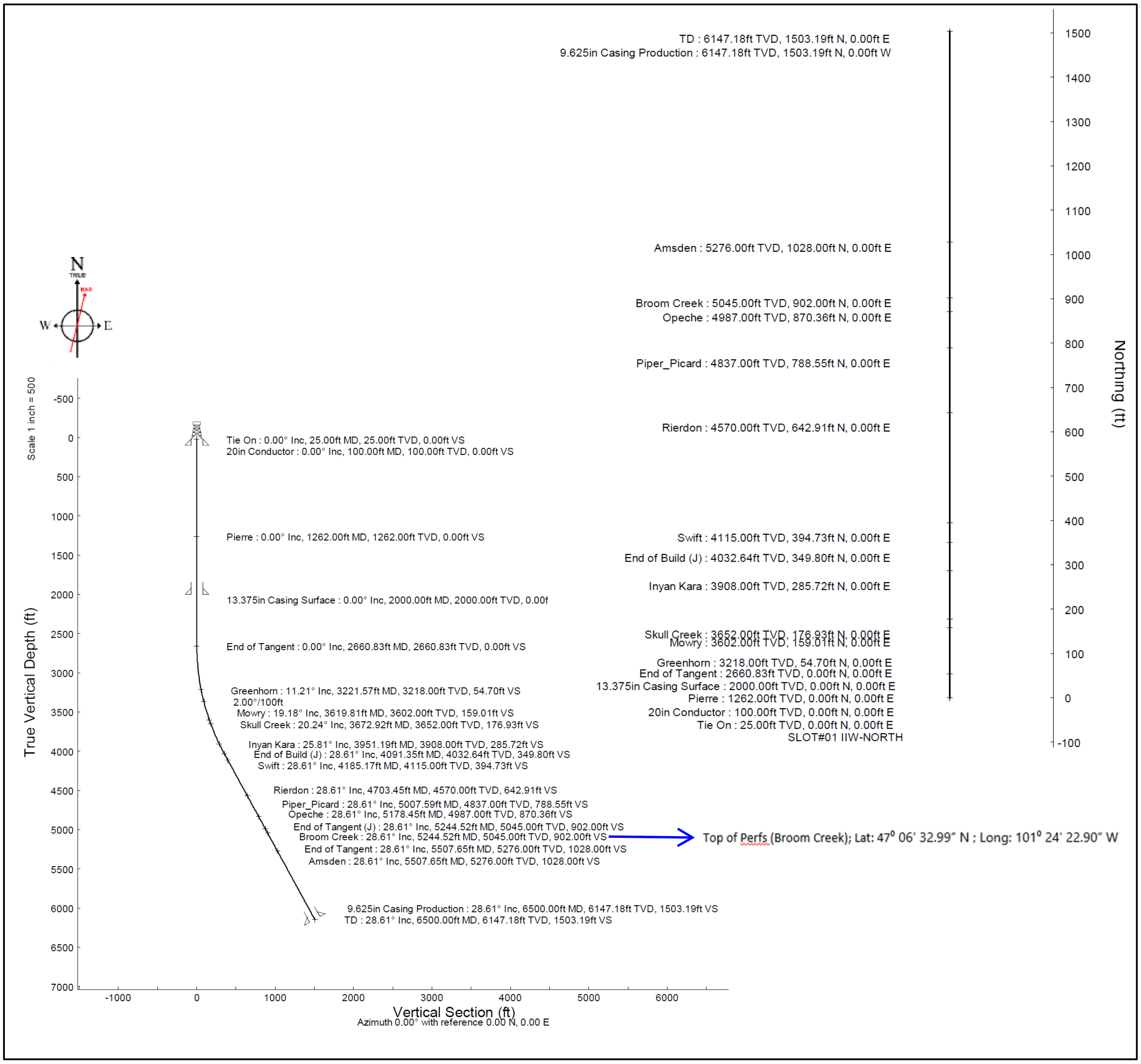

Figure 9-1. IIW-N proposed well trajectory.

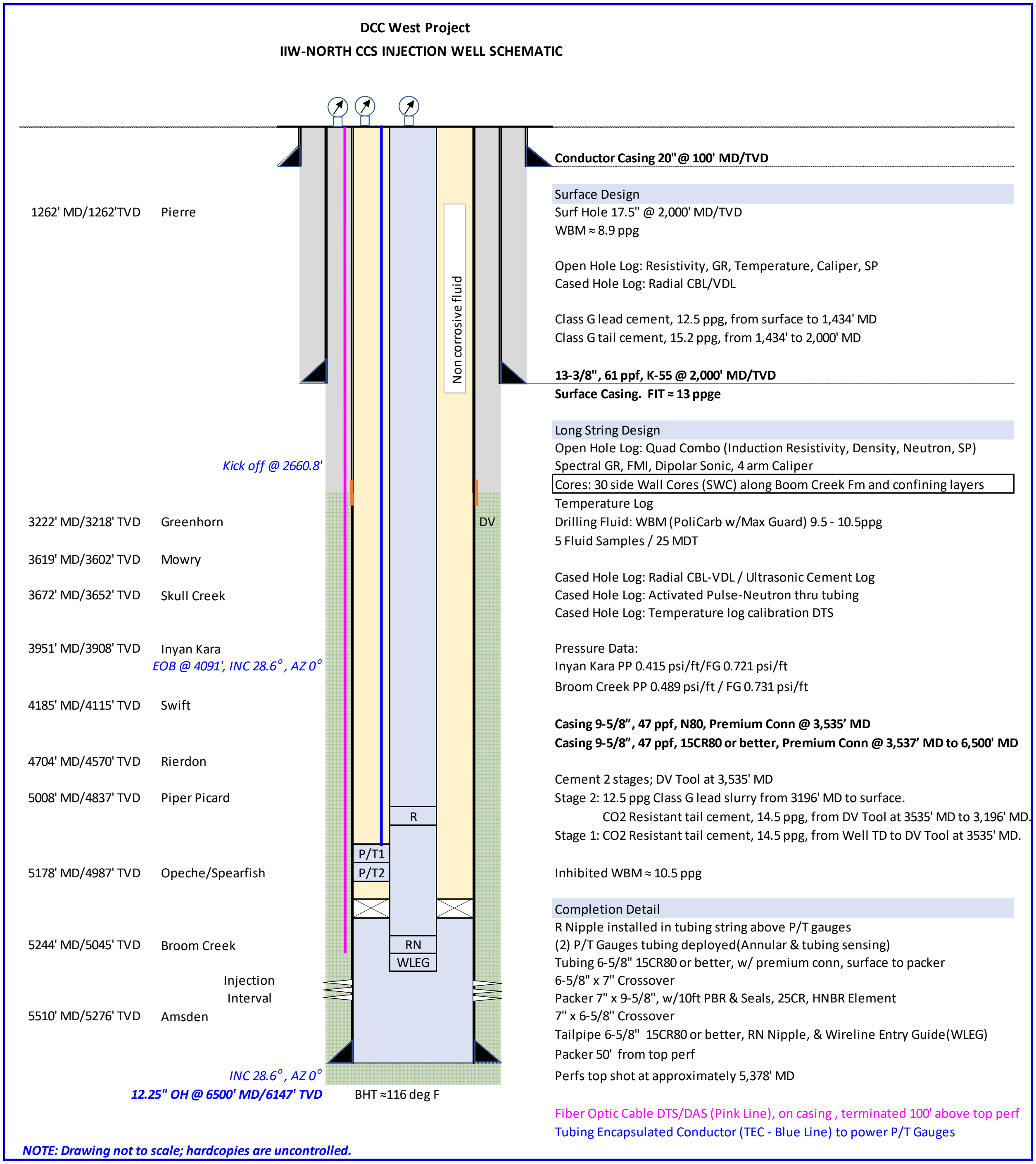

Figure 9-2. IIW-N proposed injection wellbore schematic.

Table 9-1. CO_2 Injection Well IIW-N – Well Information

Well Name:	**IIW-N**	**NDIC No.:**		**API No.:**	
County:	OLIVER	**State:**	ND	**Operator:**	DCC West Project LLC
Location:	Sect. 6, T141N, R84W	**Footages:**	TBD (Lat: 47° 06' 32.99" N; Long: 101° 24' 22.90" W)	**Total Depth:**	6500 ft

FNL: From the north line (TBD [to be determined]).
FWL: From the west line (TBD).

Table 9-2. CO_2 Injection Well IIW-N – Proposed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection*	Top Depth, ft	Bottom Depth, ft	Objective
Conductor	26.0	20	94	H40	API	0	100	Structural support
Surface	17.5	13⅜	61	K-55	API BTC	0	2000	Isolate Pierre
Long String	12.25	9⅝	47	N80	M–M	0	3535	Protect USDWs
Long String	12.25	9⅝	47	15CR80 or better	M–M	3535	6500	Isolate Inyan Kara, isolate injection target

* API: American Petroleum Institute, BTC: buttress, and M–M: premium metal-to-metal connection.

Table 9-3. CO_2 Injection Well IIW-N – Proposed Casing Properties

OD, in.	Grade	Weight, lb/ft	Con-nect.	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, Klb	
								Body	Conn.
20	H-40	94	API	19.124	18.936	1530	520	1077	581
13⅜	K-55	61	API BTC	12.515	12.359	3090	1540	962	1169
9⅝	N80	47	M-M	8.681	8.525	6870	4760	1086	1161
9⅝	15CR80 or better	47	M-M	8.681	8.525	6870	4760	1086	1086

Table 9-4. CO_2 Injection Well IIW-N – Proposed Cement Program

Casing, in.	Tail			Lead		
	Slurry	Interval, ft	Vol, Sacks	Slurry	Interval, ft	Vol, Sacks
13⅜	Class G* 15.2 ppg	2000–1434	500	Class G, 12.5 ppg	1434–0	769
9⅝ Stage 1	No Tail	No Tail	No Tail	PERMASET **14.8 ppg	6500–3535	902
9⅝ Stage 2	PERMASET 14.8 ppg	3535–3196	100	Class G 12.5 ppg	3196–0	581

* Conventional cement slurry plus additives.
** PERMASET is an enhanced cement blend to resist degradation by CO_2 reaction. DV Tool at 3535' MD.
Note: Cement evaluation is planned via radial bond log/variable-density log.

A two-stage cementing job for the long-string casing is proposed and will be specifically designed to accommodate the length of casing, wellbore conditions, and hydraulic pressure simulations of the cementing operation. Communication for approval from the North Dakota Department of Mineral Resources (DMR) will occur prior to installation.

9.2 CO_2 Injection Well – IIW-S Well Proposed Casing and Cementing Programs

The IIW-S well is proposed to be drilled and completed as a CO_2 injection well in the Broom Creek Formation, with a target trajectory depth of approximately 6500 ft from the surface location. The proposed well trajectory of IIW-S is 31.15° deviation with the bottomhole location to be approximately 1642 ft to the south from surface location. The proposed well trajectory of IIW-S is provided in Figure 9-3, and the proposed injection wellbore schematic is provided in Figure 9-4.

Tables 9-5 through 9-8 and Appendix H provide the proposed casing and cement programs for the IIW-S drilling program, which demonstrates compliance with the well construction program with NDAC § 43-05-01-11 (Injection Well Construction and Completion Standards).

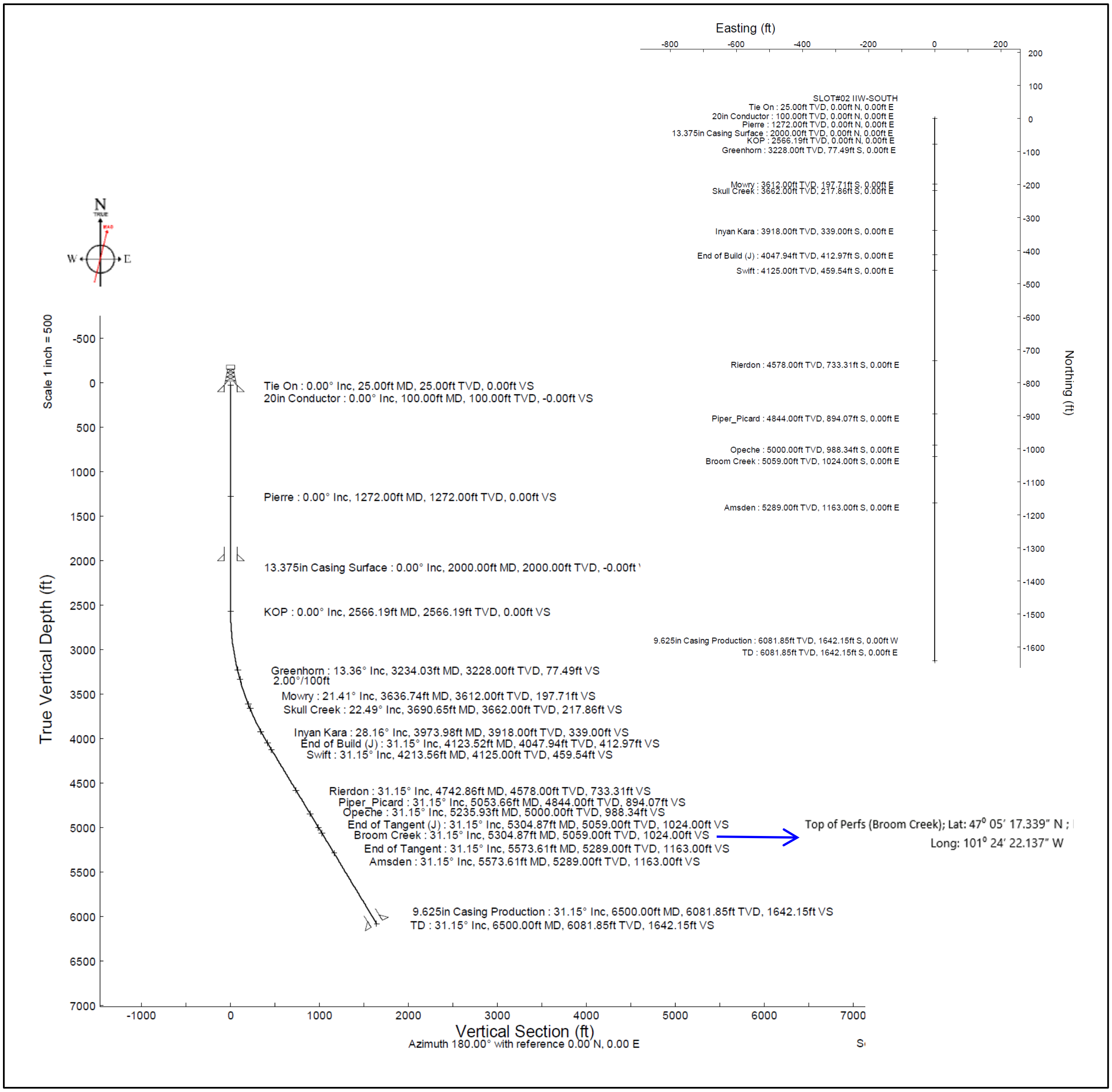

Figure 9-3. IIW-S proposed well trajectory.

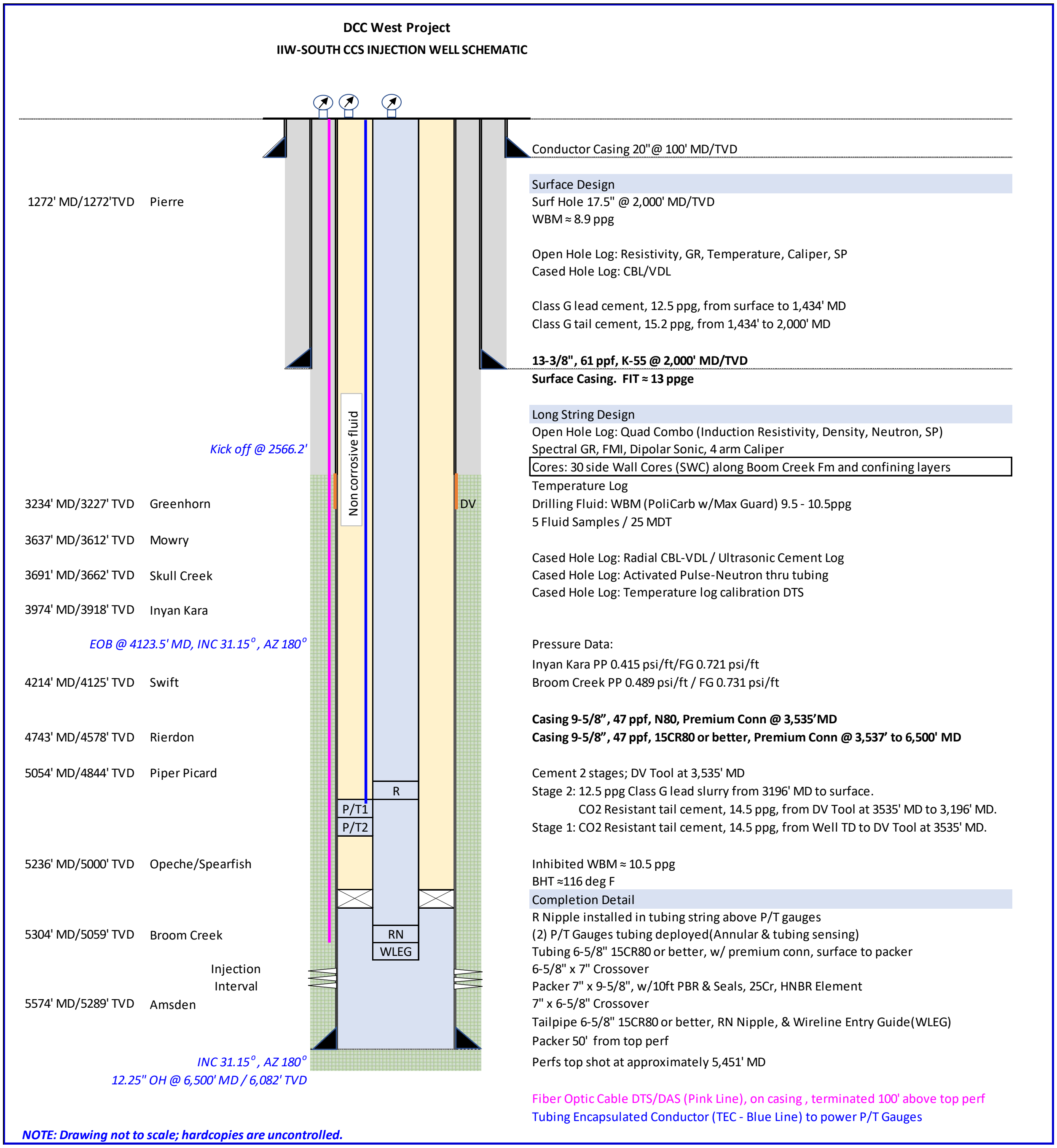

Figure 9-4. IIW-S proposed injection wellbore schematic.

Table 9-5. CO_2 Injection Well IIW-S – Well Information

Well Name:	**IIW-N**	**NDIC No.:**		**API No.:**	
County:	Oliver	**State:**	ND	**Operator:**	DCC West Project LLC
Location:	Sect. 6, T141N, R84W	**Footages:**	TBD Lat: 47º 05’ 17.339” N ; Long: 101º 24’ 22.137” W	**Total Depth:**	6500 ft

Table 9-6. CO_2 Injection Well IIW-S – Proposed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth, ft	Bottom Depth, ft	Objective
Conductor	26	20	94	H40	API	0	100	Structural support
Surface	17.5	13⅜	61	K-55	API BTC	0	2000	Isolate Pierre
Long String	12.25	9⅝	47	N80	M-M	0	3535	Protect USDWs
Long String	12.25	9⅝	47	15CR80 or better	M-M	3535	6500	Isolate Inyan Kara, isolate injection target

Table 9-7. CO_2 Injection Well IIW-S – Proposed Casing Properties

OD, in.	Grade	Weight, lb/ft	Con-nect.	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, Klb	
								Body	Conn.
20	H-40	94	API	19.124	18.936	1530	520	1077	581
13⅜	K-55	61	API BTC	12.515	12.359	3090	1540	962	1169
9⅝	N80	47	M–M	8.681	8.525	6870	4760	1086	1161
9⅝	15CR80 or better	47	M–M	8.681	8.525	6870	4760	1086	1086

Table 9-8. CO_2 Injection Well IIW-S – Proposed Cement Program

Casing, in.	Tail			Lead		
	Slurry	Interval, ft	Vol, Sacks	Slurry	Interval, ft	Vol, Sacks
13⅜	Class G* 15.2 ppg	2000–1434	500	Class G, 12.5 ppg	1434–0	769
9⅝ Stage 1	No Tail	No Tail	No Tail	PERMASET **14.8 ppg	6500–3535	902
9⅝ Stage 2	PERMASET 14.8 ppg	3535–3196	100	Class G 12.5 ppg	3196–0	581

* Conventional cement slurry plus additives.
** PERMASET is an enhanced cement blend to resist degradation by CO_2 reaction. DV Tool at 3535' MD.
Note: Cement evaluation is planned via radial bond log/variable-density log.

A two-stage cementing job for the long-string casing is proposed and will be specifically designed to accommodate the length of casing, wellbore conditions, and hydraulic pressure simulations of the cementing operation. Communication for approval from the North Dakota DMR will occur prior to installation.

9.3 Monitoring Well J-LOC 1 – Actual and Proposed Well Casing and Cementing Programs

The J-LOC 1 was drilled as a stratigraphic test well in May 2020 with plans to be recompleted as a monitoring well. The existing wellbore diagram is shown in Figure 9-5. The proposed completion is provided in Figure 9-6.

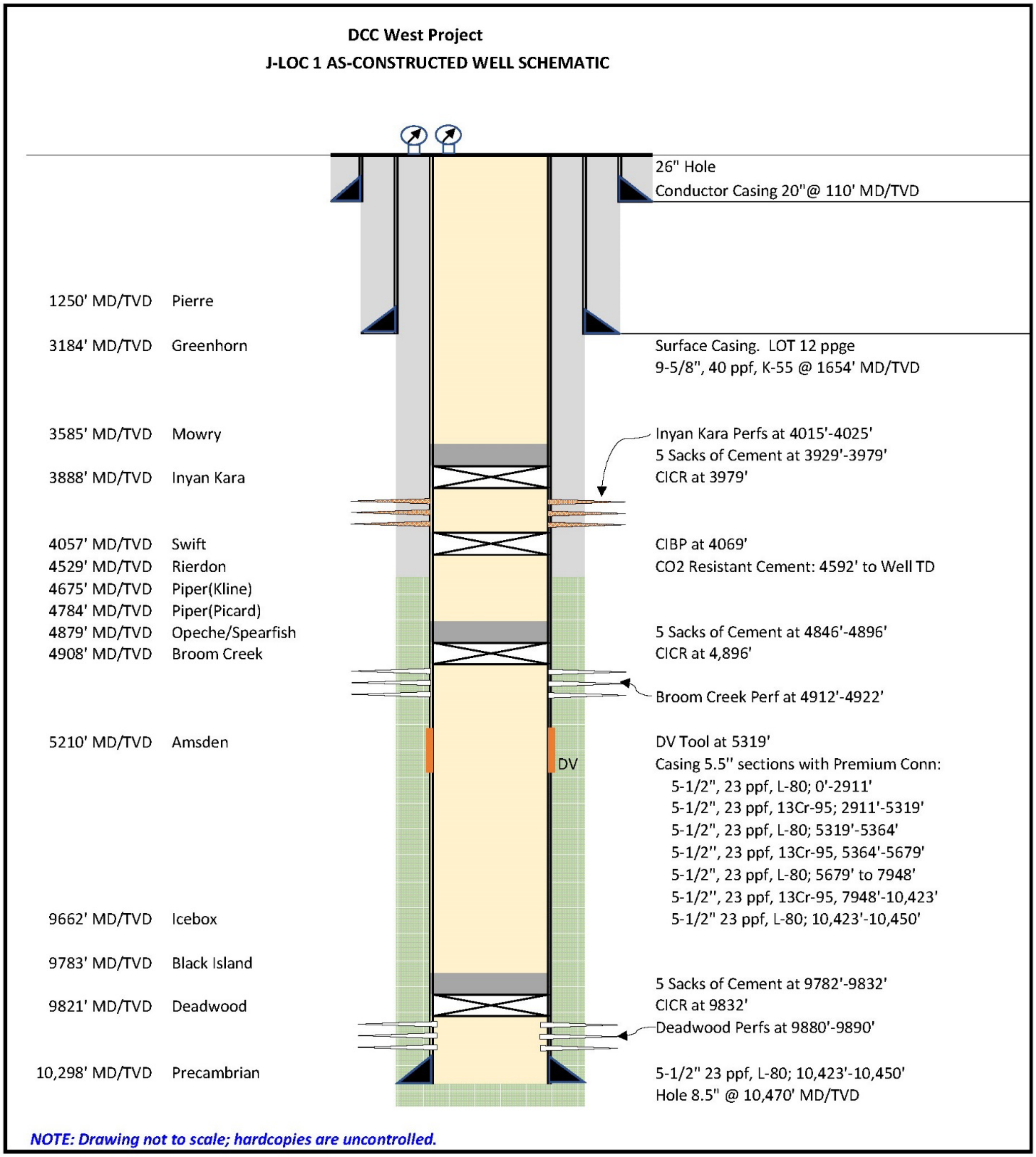

Figure 9-5. J-LOC 1 as-constructed wellbore schematic.

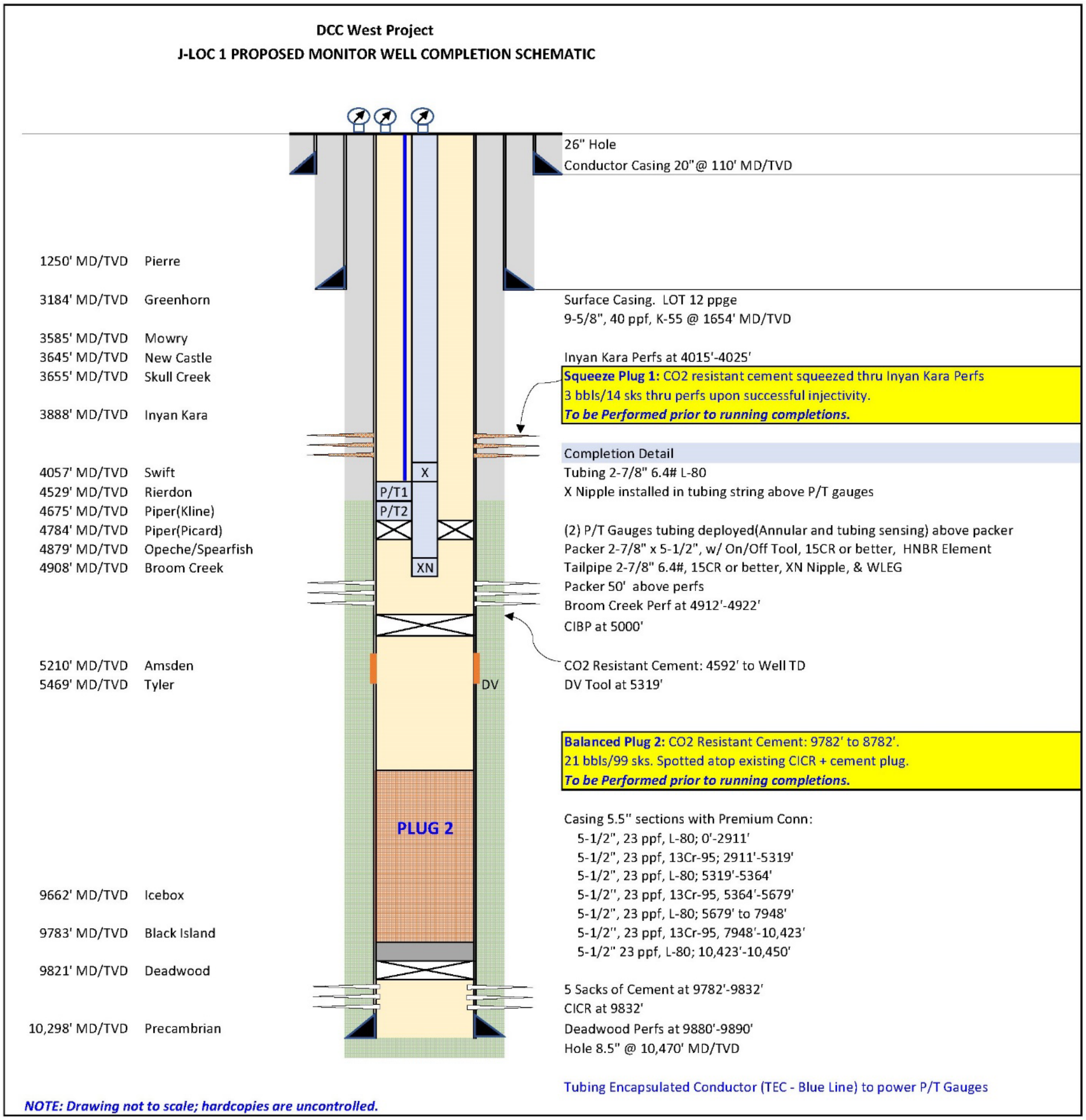

Figure 9-6. Proposed design of the J-LOC1 CO_2-monitoring wellbore schematic.

Tables 9-9 through 9-12 provide the as-constructed casing and cement programs for J-LOC 1, which demonstrates compliance for the well construction program with NDAC § 43-05-01-09(2) for a CO_2 monitoring well.

Table 9-9. Monitor Well J-LOC 1 – Well Information

Well Name:	**J-LOC 1**				
County:	Oliver	**State:**	ND		
Location:	SW NE Sec 27 T142 R84	**Footages:**	1373' FNL 2515' FEL	**Total Depth:**	10,470 ft

Table 9-10. Monitor Well J-LOC 1 – As-Constructed Casing Program

Section	Hole Size, in.	Casing OD in.	Weight, lb/ft	Grade	Conn.	Casing Top Depth, ft	Casing Bottom Depth, ft	Objective
Conductor	26"	20"	94	K55	BTC	0.0	110.0	Well control
Surface Casing	13.5"	9⅝"	40.0	K55	BTC	0.0	1654.0	Isolate Pierre
Prod Casing	8½"	5½"	23	L-80, 13Cr-95	Premium	0.0	10,450.0	Isolate monitoring zone

Table 9-11. Monitor Well J-LOC 1 – As-Constructed Casing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift, in.	Burst, psi	Collapse, psi	Yield Strength, Klb	
								Body	Connection
20	K-55	94	BTC	19.124	18.936	2110	520	1480	1402
9⅝"	K-55	40	BTC	8.835	8.679	3950	2570	630	714
5½"	13Cr-95	23	Premium	4.670	4.545	12,540	12,930	630	482
	L-80	23	Premium	4.670	4.545	10,560	11,160	530	405

Table 9-12. Monitor Well J-LOC 1 –Proposed Cement Plugs Program (Figure 9-6)

Plug	Method	Interval, ft	Slurry Volume, bbl	Slurry Density, ppg	Volume, Sacks	Comments
Plug 1	Squeeze through perforations	4015–4025	3.6	14.8	16	PERMASET* system/cement CO_2-resistant
Plug 2	Spotted plug	9782–8782	21.2	14.8	98	PERMASET* system/cement CO_2-resistant

* See Appendix H

SECTION 10.0

PLUGGING PLAN

10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedures for the IIW-N, IIW-S, and J-LOC 1 wells are designed from the proposed injection well completion status. The proposed plugging procedures do not reflect the current as-constructed state for J-LOC 1. Plugging operations may occur at different times in the life cycle of the injector wells, IIW-N and IIW-S, and the monitor well, J-LOC 1. The IIW-N and IIW-S wells are planned for P&A once the CO_2 injection operation ceases. The CO_2 monitor well, J-LOC 1, is planned for P&A after verification and North Dakota Industrial Commission (NDIC) approval of the CO_2 plume stabilization.

A proposed detailed P&A procedure will be provided to NDIC prior to the procedure being conducted. After approval, advance notification will be given to allow an NDIC representative to be present during the plugging operations. The P&A events will be documented by a workover supervisor during P&A execution. The records of the P&A events shall demonstrate the utilization of CO_2-compatible materials used and complete isolation of the injection zone.

10.1 IIW-N: Proposed Injection Well P&A Program

The proposed IIW-N CO_2 injection well schematic is provided in Figure 10-1.

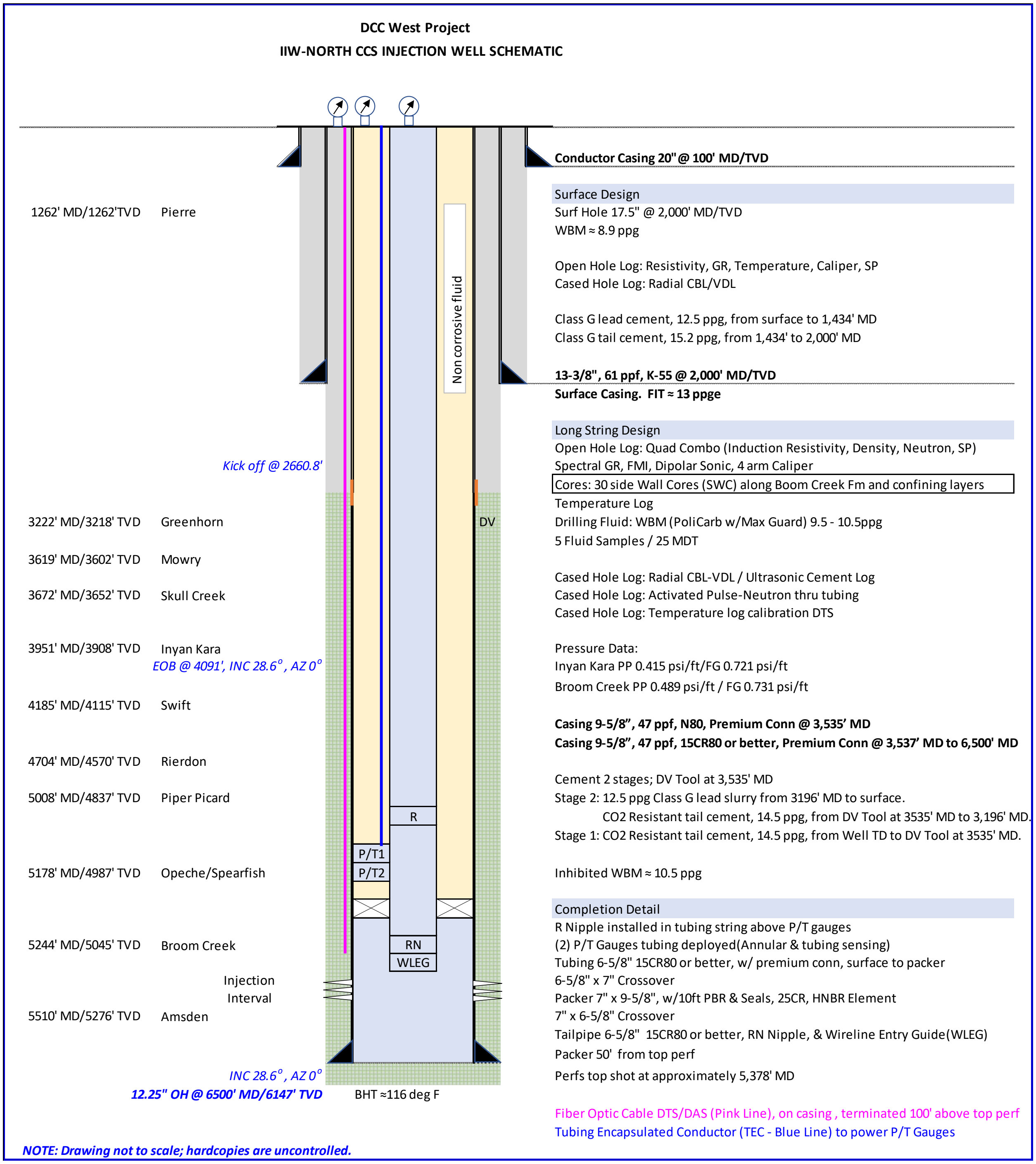

Figure 10-1. Proposed CO_2 injection well schematic for IIW-N.

NDIC will be contacted in advance, and an "intent to plug and abandon" form for IIW-N will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and NDIC field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows:

1. Move in (MI) rig onto IIW-N well and rig up (RU). All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Shut well in and obtain static pressure.

4. Record static bottomhole pressure from downhole gauge, and calculate kill fluid density.

5. Test the cement pump and flowline to 5000 psi.

6. Pump kill fluid (weight determined by bottomhole pressure measurement) volume, and fill injection tubing. Monitor tubing pressure.

7. Make sure tubing-casing annulus is filled to surface with inhibited packer fluid and test to 1500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

Note: If failure of pressure test is identified, the operator will prepare a plan to repair the well prior to P&A.

8. If both casing and tubing are dead, then nipple up blowout preventers (NU BOPs).

   Contingency: If the well is not dead, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill weight fluid until well is static. After well is dead, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

9. Pull out of hole, and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer and if plug is already set in nipple, RU electric line, and prepare to cut tubing string just above packer. Make a cut above the packer at least 5- to 10-ft MD (measured depth), pull the tubing out of hole, and proceed to next step. If problems are noted, update cement remediation plan. The squeeze packer might be used to force cement in case the packer cannot be removed.

10. Pick up work string, and round trip in hole (TIH) with bit and scraper to condition wellbore.

11. Once casing is scrapped and no restrictions with TD (total depth) confirmed. RU slick line unit/wireline (preferred), MU (make up) CIBP (cast iron bridge plug) for 9⅝" casing. Run and set to TD to ensure well integrity. This step can be modified based on the casing condition across the perforation interval.

12. RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options:
    a. Activate neutron log
    b. Noise log
    c. PLT (production logging tool)
    d. Tracers
    e. Temperature log

13. Rig down logging truck.

14. TIH work string with squeeze packer to 5350-ft MD, the top of Plug 1, across the Broom Creek perforations (top of perforations at 5378 ft). Circulate well, set squeeze packer, and pump injection rate to establish cement pump rate. RU equipment for cementing operations.

15. Mix and pump CO_2-resistant 14.8-ppg slurry to squeeze the Broom Creek Formation and isolate it from the Dakota Group in accordance with NDIC regulations. Unlatch from squeeze packer and circulate.

16. Spot 40.5 bbl of CO_2-resistant 14.8-ppg slurry atop squeeze packer; top of Plug 2 is estimated at 5017' MD. Wait on cement (WOC), and run in hole (RIH) to tag top of cement and pressure-test.

17. Set balanced Plug 3 with CO_2-resistant 14.8-ppg slurry in between fresh water as spacer pills of 8.4 ppg to cover the Dakota Group and isolate it from underground source of drinking water (USDW) interval(s). Pull out above the plug and circulate. WOC, tag top of Plug 3, estimated at 3400-ft MD, and pressure-test.

18. Set balanced Plug 4 with Class G 15.2-ppg slurry to cover the shoe of the surface casing. Pull out above Plug 4 and circulate. WOC, tag top of Plug 4, estimated at 1700-ft MD, and pressure-test.

19. Set surface Plug 5 with Class G cement and additives: 14.5 ppg to isolate the top of the surface casing.

20. Lay down work string. Rig down all equipment and move out. Cut casing at 5' below the ground. Clean cellar to where a plate can be welded with well information.

21. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

The proposed P&A plan for IIW-N is summarized in Table 10-1 and provided in Figure 10-2.

Table 10-1. Summary of Proposed Injection Well P&A Plan for IIW-N

Cement Plug Number	Interval Range, ft	Thickness, ft	Volume, sacks	Notes
1	5408–5350	58	320	CO_2-resistant slurry, 14.8 ppg, squeezed cement job to isolate perforations
2	5350–5017	333	113	CO_2-resistant slurry, 14.8 ppg, spotted atop squeeze packer at 5570' MD
3	4300–3400	900	310	CO_2-resistant slurry, 14.8-ppg balanced plug
4	2200–1700	500	172	Conventional Class G cement, 15.2-ppg balanced plug
5	100–0	100	32	Conventional Class G cement, 14.5-ppg balanced plug

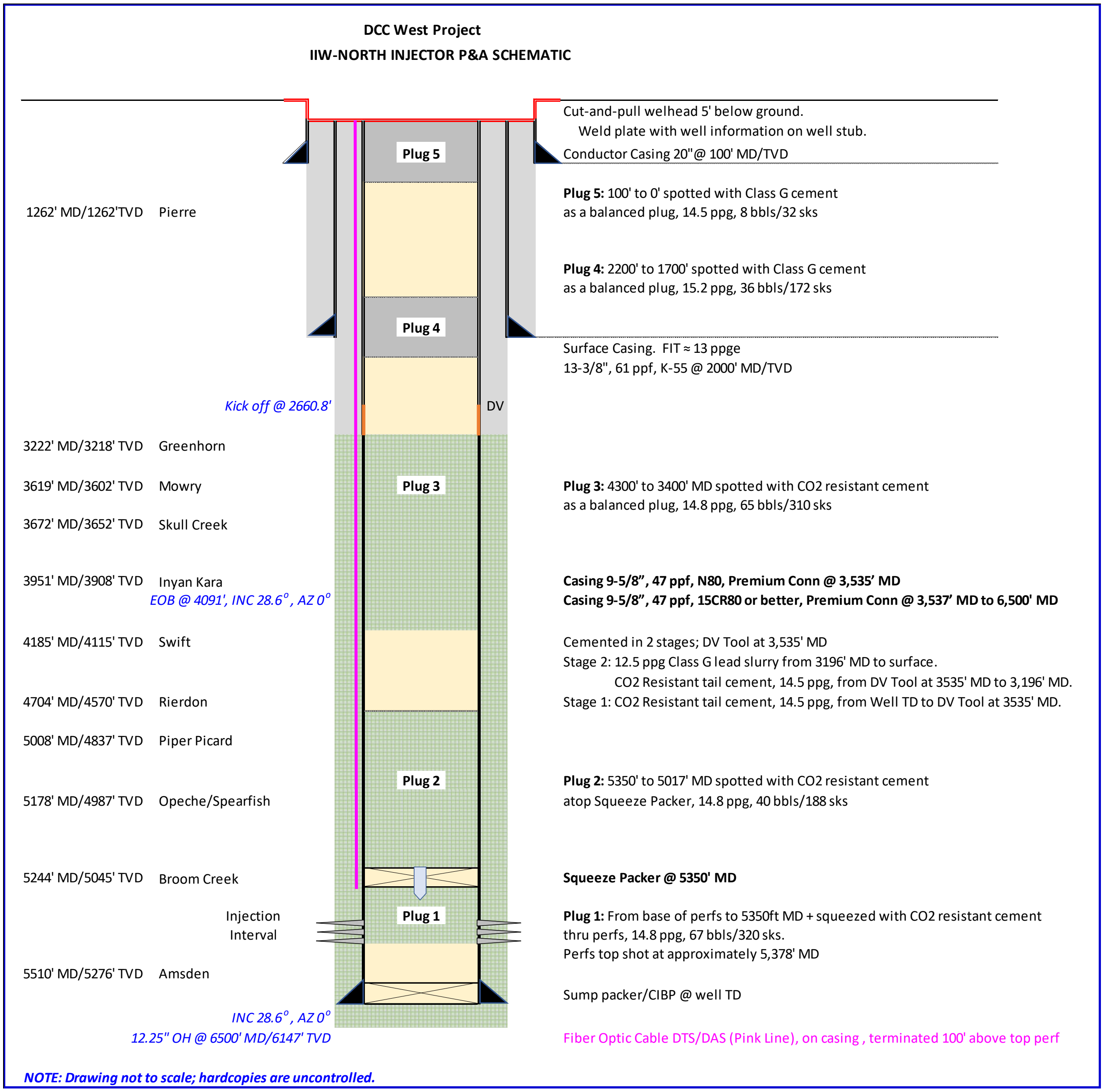

Figure 10-2. Schematic proposed P&A plan for IIW-N.

10.2 IIW-S: Proposed Injection Well P&A Program

The proposed IIW-S CO_2 injection well schematic is provided in Figure 10-3.

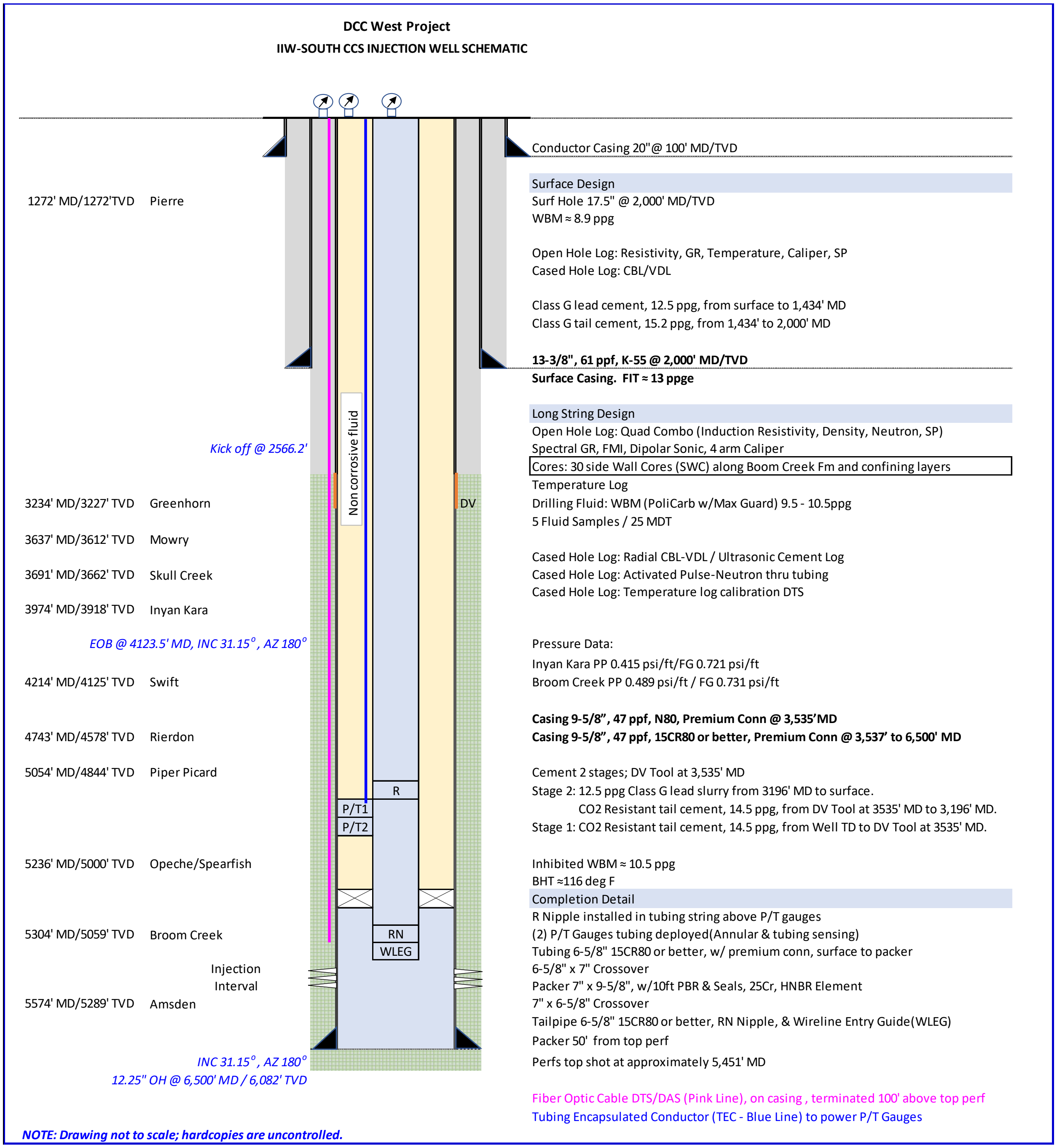

Figure 10-3. Proposed CO_2 injection well schematic for IIW-S.

NDIC will be contacted, and an intent to plug and abandon form for IIW-S will be filed for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and NDIC field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows:

1. MI rig onto IIW-S well, and RU. All CO_2 pipelines will be marked and noted with rig supervisor prior to MI.

2. Conduct and document a safety meeting.

3. Shut well in, and obtain static pressure.

4. Record bottomhole pressure from downhole gauge, and calculate the kill fluid density.

5. Test the pump and line to 5000 psi.

6. Pump kill fluid (weight determined by bottomhole pressure measurement) volume, and fill injection tubing. Monitor tubing pressure.

7. Make sure tubing-casing annulus is filled to surface with inhibited packer fluid and test to 1500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

   Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

8. If both casing and tubing are dead, then NU BOPs.

   Contingency: If the well is not dead or pressure cannot be bled off the tubing, RU slickline, and set plug in lower-profile nipple below the packer. Circulate tubing and annulus with kill weight fluid until well is dead. After well is dead, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

9. Pull out of hole, and lay down tubing, packer, cable, and sensors.

   Contingency: If unable to release tubing and retrieve packer, RU electric line, and prepare to cut tubing string just above packer. Make a cut above the packer at least 5- to 10-ft MD, pull the work string out of hole, and proceed to next step. If problems are noted, update cement remediation plan. The squeeze packer might be used to force cement in case the packer cannot be removed.

10. Pick up work string, and TIH with bit to condition wellbore.

11. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.
    a) Activate neutron log
    b) Noise log
    c) PLT
    d) Tracers
    e) Temperature log

12. Once casing is scrapped and no restrictions with TD are confirmed, RU slick line unit/wireline (preferred), MU CIBP for 9⅝" casing, run and set to TD to ensure well integrity. This step can be modified based on the casing condition across the perforation interval.

13. TIH work string with squeeze packer to 5430-ft MD, the top of Plug 1 across the Broom Creek perforations (top of perforations at 5451-ft MD). Circulate well, set squeeze packer, and pump injection rate to establish cement pump rate. RU equipment for cementing operations.

14. Mix and pump CO_2-resistant 14.8-ppg slurry to cover the Broom Creek Formation and isolate it from the Dakota Group in accordance with program. Unlatch from squeeze packer and circulate. Spot 8 bbl of CO_2-resistant 14.8-ppg slurry atop squeeze packer. Pump in between a freshwater pill of 8.4 ppg as spacer to avoid contamination; top of Plug 2 is estimated at 5017-ft MD.

15. Set balanced Plug 3 with CO_2-resistant 14.8-ppg slurry in between fresh water as spacer pills of 8.4 ppg to cover the Dakota Group and isolate it from USDW interval(s). Pull out above the plug and circulate. WOC, tag top of Plug 3, estimated at 3400-ft MD, and pressure-test.

16. Set balanced Plug 4 with Class G 15.2-ppg slurry to cover the shoe of the surface casing. Pull out above Plug 4 and circulate. WOC, tag top of Plug 4, estimated at 1700-ft MD, and pressure-test.

17. Set surface Plug 5 with Class G cement and additives: 14.5 ppg to isolate the top of surface casing.

18. Lay down work string. Rig down all equipment and move out. Cut the casing at 5' below the ground. Clean cellar to where a plate can be welded with well information.

19. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

The proposed P&A plan for IIW-S is summarized in Table 10-2 and provided in Figure 10-4.

Table 10-2. Summary of Proposed Injection Well P&A Plan for IIW-S

Cement Plug Number	Interval Range, ft	Thickness, ft	Volume, sacks	Notes
1	5481–5430	51	320	CO_2-resistant slurry, 14.8 ppg, squeezed cement job to isolate perforations
2	5430–5017	413	188	CO_2-resistant slurry, 14.8 ppg, spotted atop squeeze packer at 5570' MD
3	4300–3400	900	310	CO_2-resistant slurry, 14.8-ppg balanced plug
4	2200–1700	500	172	Conventional Class G cement, 15.2-ppg balanced plug
5	100–0	100	32	Conventional Class G cement, 14.5-ppg balanced plug

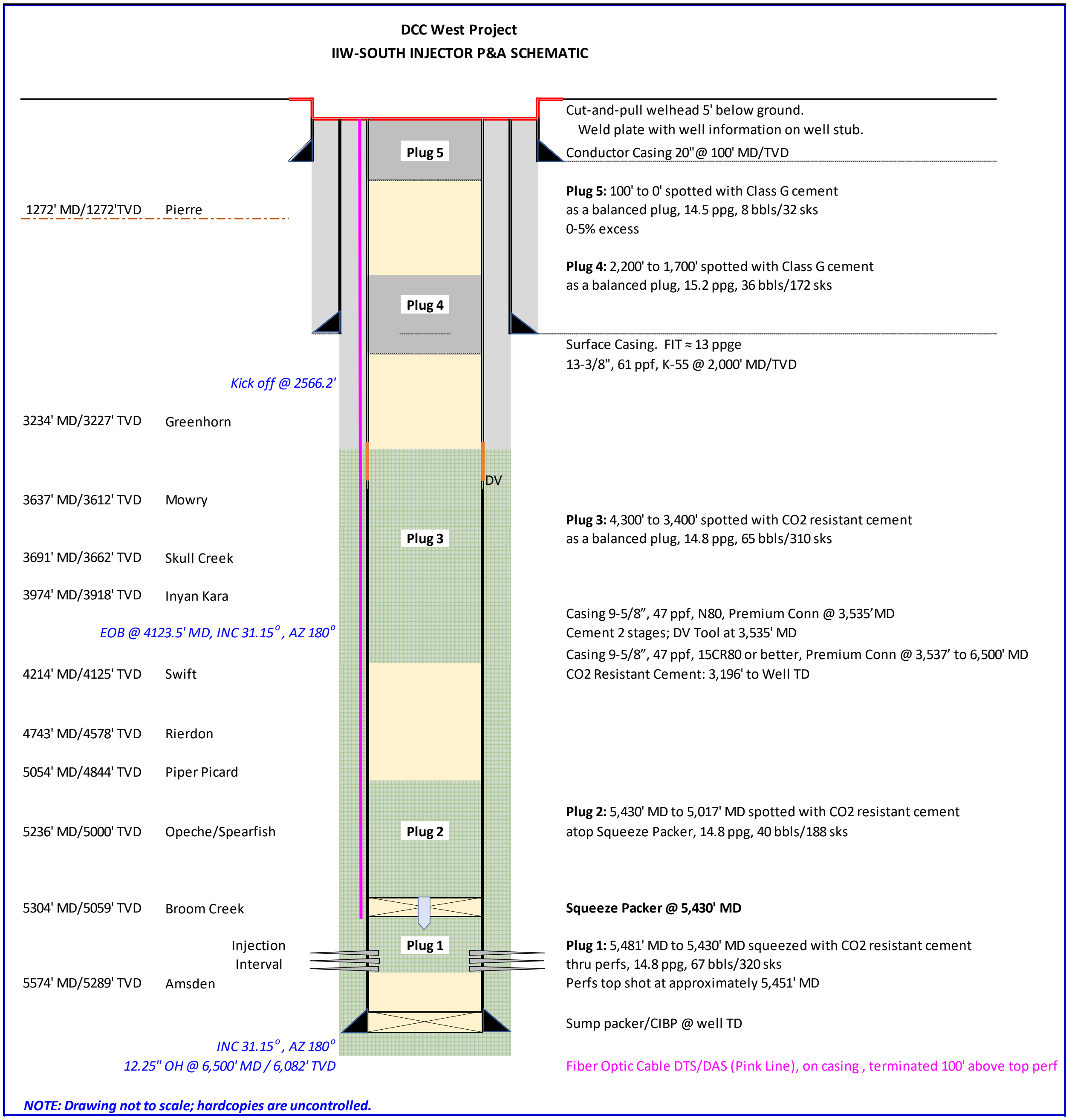

Figure 10-4. Schematic of proposed P&A plan for IIW-S.

10.3 J-LOC 1 Proposed Monitoring Well P&A Program

The J-LOC 1 wellbore shall be P&A upon CO_2 plume stabilization with validation and approval from NDIC that monitoring of the plume extent is no longer required. The as-planned CO_2-monitoring well schematic of J-LOC 1 is provided in Figure 10-5.

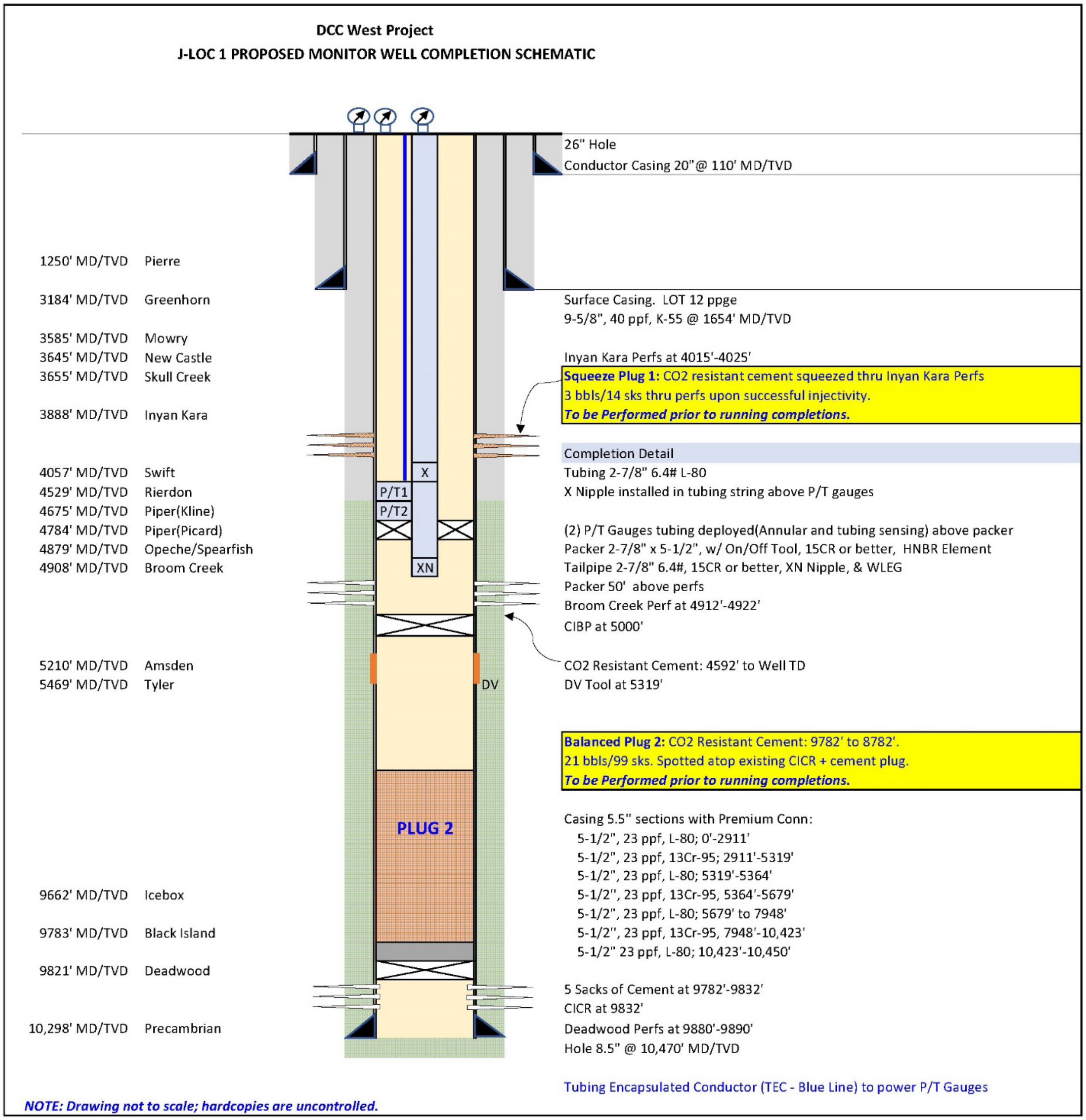

Figure 10-5. As-planned wellbore schematic for J-LOC 1.

The proposed procedure for P&A of the J-LOC 1 well will be performed as follows:

1. MI, and RU workover rig onto J-LOC1.

2. Conduct and document a safety meeting.

3. Record bottomhole pressure. Test the pump and line to 5000 psi. Fill tubing with kill fluid. If there is pressure on the well, calculate kill fluid weight by bottomhole pressure. Monitor tubing pressure.

   Make sure tubing-casing annulus is filled to surface with inhibited packer fluid and test to 1500 psi, or NDIC-approved test pressure, and monitor for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and connections, and repeat test. Release pressure.

Note: If failure in long-string casing is identified, the operator will prepare a plan to repair the well prior to P&A.

4. If both casing and tubing are dead, then NU BOPs.

Contingency: If the well is not dead or slight pressure cannot be bled off, RU slickline, and set plug in lower-profile nipple below first packer. Circulate tubing and annulus with kill weight fluid until well is static. After well is dead, nipple down tree, NU BOPs, and perform a function test. Prepare to recover packer with work string.

5. Pull out of hole, and lay down tubing, packer, cable, and sensors.

Contingency: If unable to release tubing and retrieve packers because of:

   a) Top Packer Stuck: Prepare plan to cut tubing above the top packer, 5 to 10 ft of MD. Mill/wash over the seals and OD of the top packer to release the string, until the bottom packer. Run fishing equipment, and work fish out.

   b) Bottom Packer Stuck: If bottom packer is stuck, proceed to RU electric line, and prepare to cut tubing string just above bottom packer, pull the work string out of hole, and proceed to next step. If problems are noted, update cement remediation plan.

6. Pick up work string, and TIH with bit to condition wellbore.

7. Pull out of the hole, and RU logging unit. Confirm external mechanical integrity by running one of the tests listed as options. Rig down logging truck.
   a) Activate neutron log
   b) Noise log
   c) PLT
   d) Tracers
   e) Temperature log

NOTE:

a. Squeeze Plug 1 through Inyan Kara Formation perforations established prior to start of completion operations.

Inyan Kara Formation Perforations Squeeze Plug 1 Planning:

- TIH with work string and squeeze packer, set packer at 3915', and attempt to establish injectivity through Inyan Kara Formation perforations. On successful injectivity, RU equipment for cementing operations.
- Squeeze CO_2-resistant slurry to isolate Inyan Kara Formation perforations from upper formations. Unset squeeze packer, circulate, and pull out of hole (POOH). Pressure-test Inyan Kara Formation perforation squeeze plug.

b. Spot Plug 2 prior to start of completion operations, with an estimated TOC (top of cement) of 8782', atop existing cement retainer and cement plug at TOC at 9782' MD. Trip in work string and mule shoe, tag existing plug TOC. Circulate and rig up for cementing. Spot CO_2-resistant cement with estimated TOC 8782' MD.

8. TIH with work string, and set CIBP at ~5000' within the Broom Creek Formation interval.
9. Trip out of hole (TOOH), pick up squeeze packer, and set at ~ 4900' (~12 ft above top of perforations) to squeeze perforations for Plug 3. Establish injection rate to determine cement squeeze pump rate into Broom Creek perforations. RU equipment for cementing operations.
10. Squeeze CO_2-resistant slurry to isolate the Broom Creek Formation perforations from the upper formations. Unlatch from the squeeze packer.
11. Spot CO_2-resistant 14.8-ppg slurry atop squeeze packer; top of Plug 4 is estimated at 3000' MD. This additionally isolates Inyan Kara Formation perforations that were previously squeezed as Plug 1, prior to start of completion operations. Pull up hole, WOC, tag plug, and pressure-test.
12. Set balanced Plug 5 with Class G 15.2-ppg slurry to cover the shoe of the surface casing. Pull out above the Plug 5 and circulate. WOC, tag top of the Plug 5, estimated at 1400' MD, and pressure-test.
13. Spot surface Plug 6 with Class G cement and additives: 14.5 ppg to isolate the top of surface casing.
14. Lay down work string. Rig down all equipment and move out. Cut the casing at 5' below the ground. Clean cellar to where a plate can be welded with well information.

15. The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

The proposed P&A plan for J-LOC 1 is summarized in Table 10-3 and provided in Figure 10-6.

Table 10-3. Summary of P&A Plan for J-LOC 1

Cement Plug Number	Interval Range, ft	Thickness, ft	Volume, sacks	Notes
1	4025–4015	10	14	**Performed prior to running completions.** Squeeze Plug 1 through Inyan Kara perforations upon establishing injectivity.
2	9782–8782	1000	99	**Performed prior to running completions.** CO_2-resistant slurry, 14.8 ppg, spotted atop existing cast iron cement retainer (CICR) at 9832' and existing cement plug.
3	5000–4900	100	28	CO_2-resistant slurry, 14.8 ppg, squeeze cement job through squeeze packer at 4900' upon establishing injectivity. Isolates Broom Creek perforations.
4	4900–3000	1900	192	CO_2-resistant slurry, 14.8-ppg plug spotted atop squeeze packer. Isolates Inyan Kara interval.
5	1900–1400	500	50	Conventional Class G cement, 15.2-ppg balanced plug.
6	200–0	200	20	Conventional Class G cement, 14.5-ppg balanced plug.

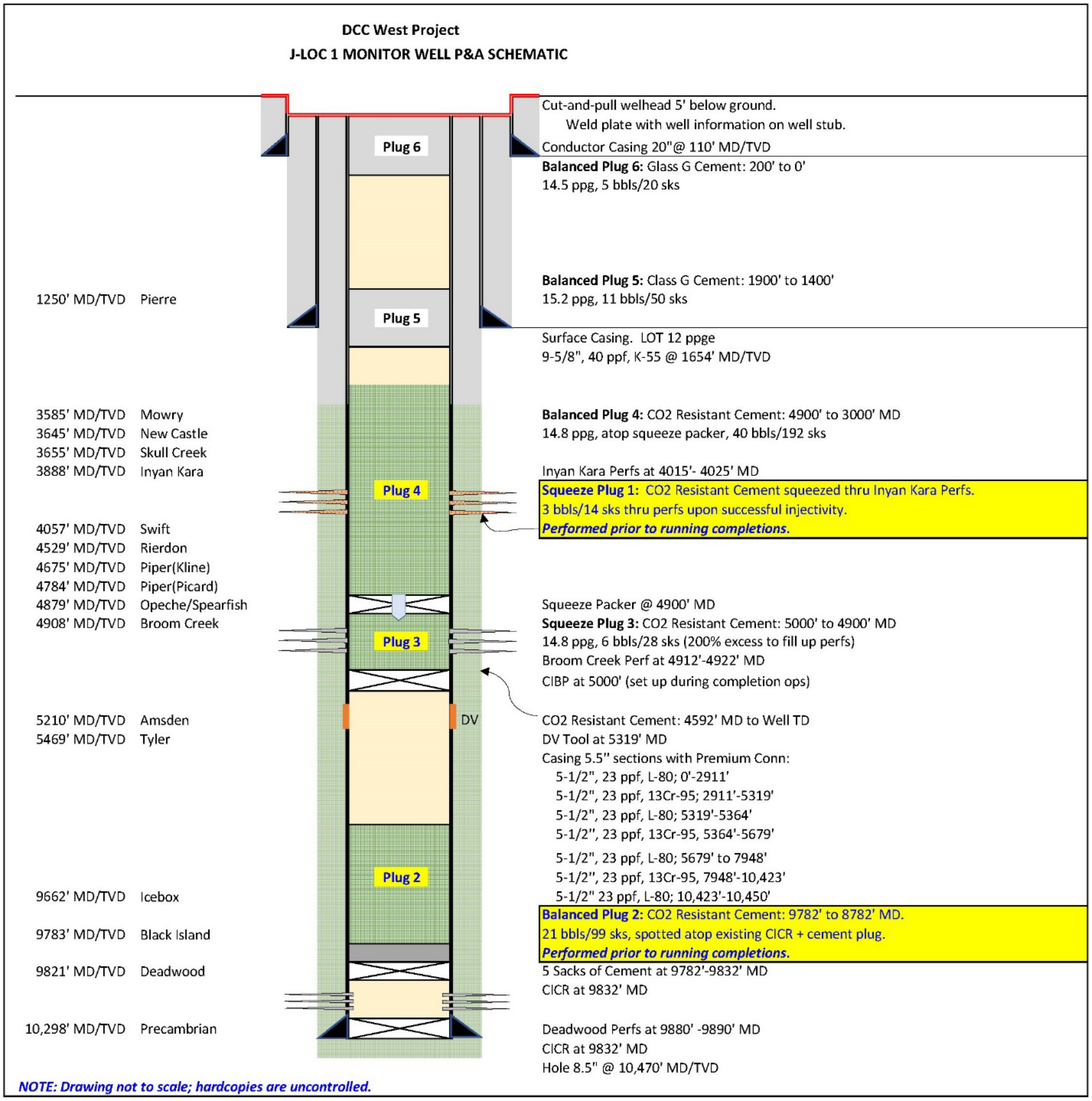

Figure 10-6. Schematic of proposed abandonment plan for monitoring well J-LOC 1.

SECTION 11.0

INJECTION WELL AND STORAGE OPERATIONS

11.0 INJECTION WELL AND STORAGE OPERATIONS

This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDW). The information that is presented in Table 11-1 meets the permit requirements for injection well and storage operations as documented in North Dakota Administrative Code (NDAC) § 43-05-01-05.1(b)(4) & (5) and § 43-05-01-11.3.

Table 11-1. DCC West SGS Proposed Injection Well Operating Parameters

Item	Values	Description/Comments	
Injected Volume			
Total Injected Volume	122.9 MMt 2,363,160.5 MMCF	Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint	
Injection Rates	**IIW-N**	**IIW-S**	**Description/Comments**
Average Injection Rate	4844 tonnes/day (94 MMscf/day) 1.768 MMt/yr 686,353.6 MMCF 35.686 MMt	11,897 tonnes/day (230 MMscf/day) 4.342 MMt/yr 1,676,806.8 MMCF 87.183 MMt	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Average Maximum Daily Injection Rate	10,834 tonnes/day (208.3 Mscf/day) 3.954 MMt/yr 1,484,680.4 MMCF 77.193 MMt	19,503 tonnes/day (374.7 Mscf/day) 7.118 MM tonnes/year 2,622,375.5 MMCF 136.346 MMt	Based on maximum BHP with only one well injecting at a time: IIW-N: 3233 psi and IIW-S: 3242 psi
Pressures	**IIW-N**	**IIW-S**	**Description/Comments**
Formation Fracture Pressure at Top Perforation	3592 psi	3602 psi	Based on geomechanical analysis of formation fracture gradient as 0.712 psi/ft
Average Surface Injection Pressure	1633 psi	2085 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Surface Maximum Injection Pressure	1997 psi	2459psi	Based on maximum BHP with only one well injecting at a time: IIW-N: 3233 psi and IIW-S: 3242 psi (using the designed 7-inch tubing)
Average BHP	3233 psi	3216 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Calculated Maximum BHP	3233 psi	3242 psi	Based on 90% of the formation fracture pressure of 3592.4 psi for IIW-N and 3602.1 psi for IIW-S

11.1 IIW-N Well – Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1 of this SFP, the IIW-N well will be drilled and completed as a Class VI CO_2 injection well (Figures 11-1 and 11-2 and Tables 11-2 through 11-4).

Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber optic will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations. Perforating should occur at a minimum of 40' below the end of the fiber cable.

The following proposed completion procedure outlines the general steps necessary to complete and test the well:

1. Rig up workover rig.
2. Nipple up BOP (blowout preventer).
3. Test BOP.
4. Pick up work string and bit and scraper to clean out wellbore from the installation of the long-string casing.
5. Run in the hole and tag the stage tool.
6. Establish circulation with 10-ppg brine.
7. Drill out the stage tool and continue running the bit and scraper to the top of the float collar. Tag plug back depth.
8. Circulate wellbore volume with 10-ppg brine to remove solids and ensure consistent wellbore fluid for pressure test.
9. Close backside valve (work string-casing annulus), and pressure up wellbore to 1500 psi or as required by the North Dakota Industrial Commission (NDIC). Hold pressure, and test casing for 30 minutes. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator may require assessing the root cause and correcting it.
10. Trip out of hole (TOOH) and lay down BHA (bottomhole assembly).
11. Perform safety meeting to discuss logging and perforating operations.
12. Rig up wireline truck.
13. Run cased-hole logs by program. Note: run CBL/VDL (cement bond log/variable-density log) and ultrasonic tool logs without pressure as a first pass, and run them with 1000-psi pressure as a second pass.

    Note: If cementing logs show poor bonding from the cementing job, the results shall be communicated to NDIC, and an action plan will need to be prepared.

14. Pick up and run cast iron bridge plug (CIBP) and wireline setting tool to plug back total depth (PBTD) and set CIBP.
15. TOOH with wireline setting tool
16. Trip in hole (TIH) with perforating guns, and perforate designated injection intervals. Ensure top perforation is a minimum of 40 ft below end of the casing-conveyed fiber-optic cable.

17. Perforate the Broom Creek Formation, minimum 4 spf (shots per foot). The depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation.
18. TOOH with perforating guns.
19. Rig down logging truck.
20. Pick up retrievable service packer and run in the hole with work string.
21. Circulate wellbore with 10-ppg brine.
22. Set service packer above the top perforation in a good cement bond zone of the long-string casing.
23. Rig up acid trucks and equipment.
24. Pump designed matrix acid treatment to clean the perforations, not to exceed formation fracture pressure. Adjust acid formulation and volumes with water samples and compatibility test.
25. Rig down acid trucks and equipment.
26. Rig up service pump company.
27. Perform an injectivity test/step rate test as specifically designed.
28. Rig down service pump company after injectivity tests.
29. Unset packer and circulate hole with inhibited packer fluid.
30. TOOH and lay down packer and work string.
31. Rig up P/T (pressure/temperature) gauge spooling unit, and prepare rig floor to run completion assembly.
32. Run completion assembly per program.
33. Space out packer approximately 50 ft above the top perforations; a variance request/approval will be required from NDIC if packer is set more than 50 ft above the top perforation.
34. Install tubing assembly, cable connector, and tubing hanger at wellhead.
35. Hydraulically actuate packer by pressuring up the tubing string against blanking plug preinstalled in packer tailpipe assembly.
36. Rig up logging truck.
37. Run in hole to blanking plug at bottom of packer.
38. TOOH with blanking plug.
39. Top off annulus with inhibited packer fluid.
40. Perform annular pressure test of 1000 psi for 30 minutes.
41. Run cased-hole logs through tubing by program.
42. Rig down logging truck.
43. Nipple down BOP.
44. Rig down workover rig.
45. Install injection tree.
    Note: Figure 5-4 illustrates the proposed wellhead schematic.
46. Rig down equipment.

Table 11-2. IIW-N Proposed Upper Completion

Description	OD, in.	Depth, ft	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.
6⅝" Tubing	6⅝	0–5600	15CR80* or better	28	Premium*	5.79	5.66
Dual P/T Gauges, Annulus, and Tubing Sensing:							
6⅝" Tubing	6⅝	5600–5640	15CR80* or better	28	Premium*	5.79	5.66
6⅝" 28# × 7" 29# Crossover	7	5640–5642	15CR80* or better	28	Premium	5.79	5.66
831-600 Premier Packer with Polished Bore Receptacle, 25Cr85, HNBR* Element:							
6⅝" Pup Joint	6⅝	5660–5670	15CR80* or better	28	Premium*	5.79	5.66
R Nipple	6⅝	5670–5674	25CR85	28	Premium*	5.63	NA
6⅝" Pup Joint	6⅝	5674–5684	15CR80* or better	28	Premium*	5.79	5.66
Wireline Entry Guide	6⅝	5684–5690	15CR80* or better	28	Premium*	5.79	5.66

15CR80 – 15% chrome alloy-grade 80 ksi (kilopound per square inch) material yield strength.
25CR85 – 25% chrome alloy-grade 85 ksi material yield strength.
Premium – M–M (metal-to-metal connection).
HNBR* – hydrogenated nitrile.

Table 11-3. IIW-N Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, Klb
6⅝	15CR80 or better	28	Premium	5.79	5.66	8170	8810	651,000

Table 11-4. IIW-N Cased-Hole Logging

Description	Depth, ft	Comments
CBL/VDL – CCL (casing collar locator) – Ultrasonic Imaging Tool	From 6500' to surface	Cement/casing log; 30-ft shoe track in 9⅝" casing before tubing is installed.
Pulsed Activated Neutron	From 6500' to surface	Baseline; run through tubing – log both 9⅝" and through 6⅝" tubing after tubing is installed.
Temperature Log	From 6500' to surface	Baseline; run through tubing – log both 9⅝" and through 6⅝" tubing after tubing is installed.

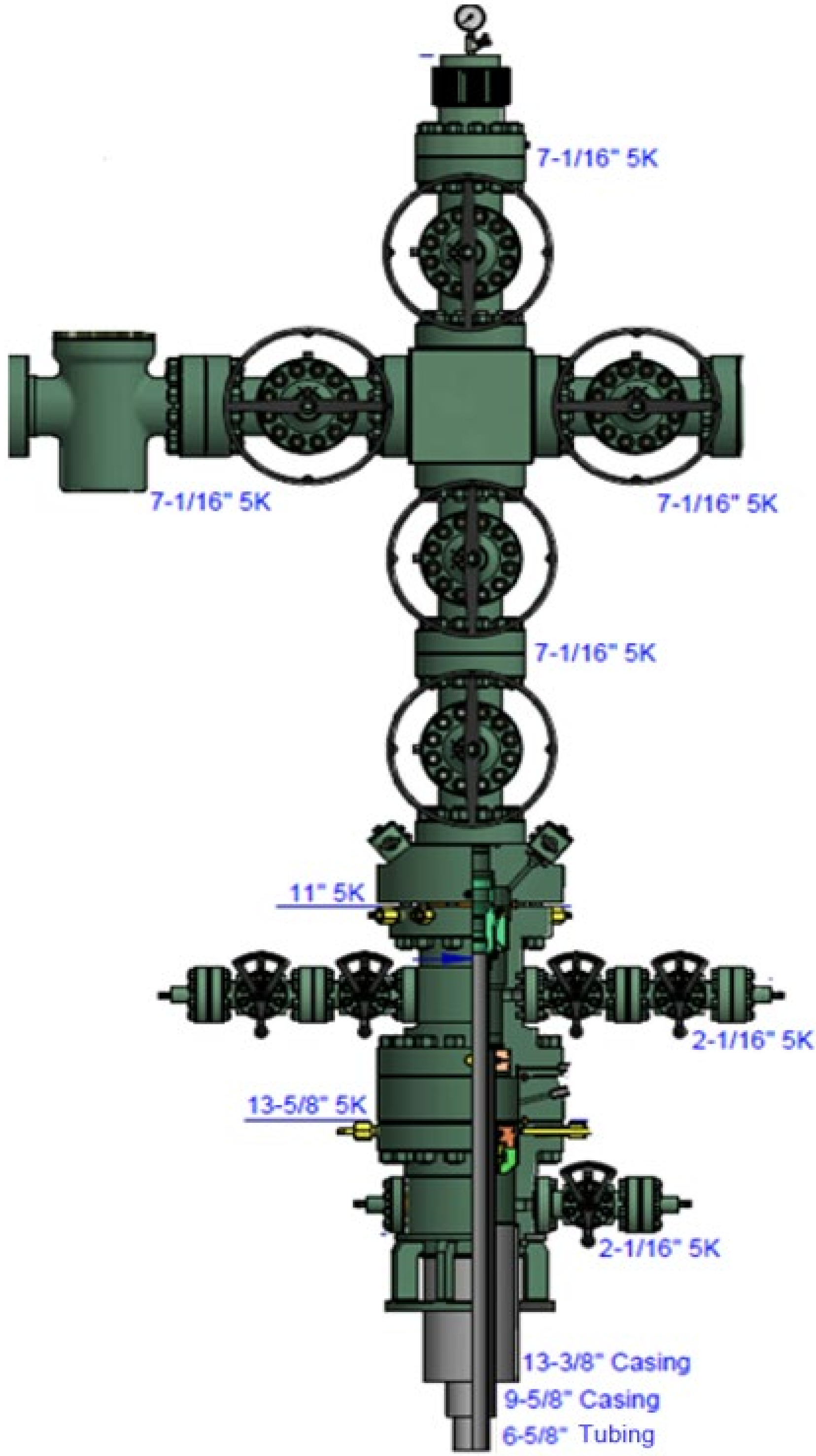

Figure 11-1. IIW-N proposed CO_2-resistant wellhead schematic.

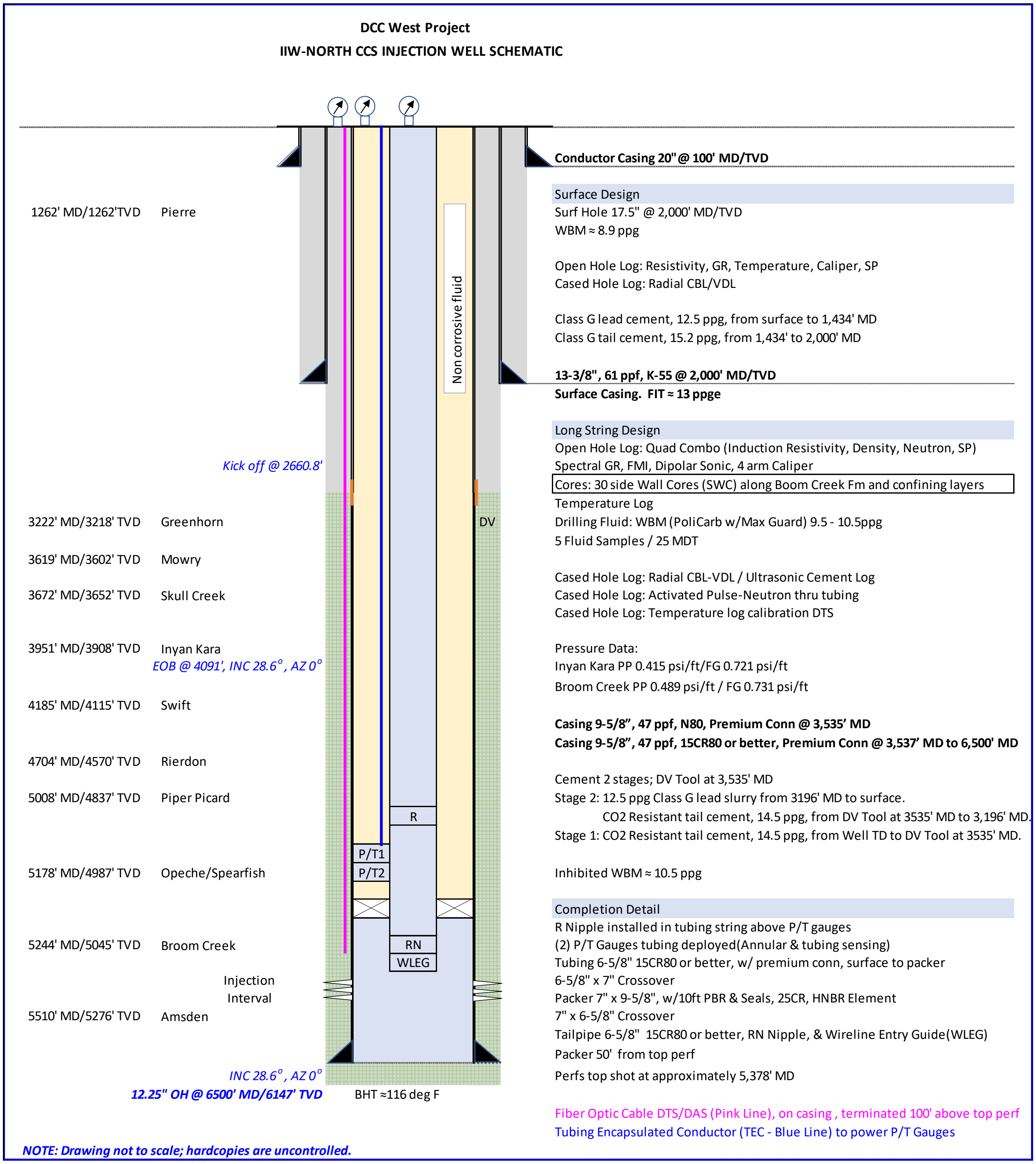

Figure 11-2. IIW-N proposed completed wellbore schematic.

11.2 IIW-S Well – Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1 of this SFP, the IIW-S well will be drilled and completed as a Class VI CO_2 injection well (Figures 11-3 and 11-4 and Tables 11-5 through 11-7). The following proposed completion procedure outlines the general steps necessary to complete and test the well:

1. Nipple up BOP.
2. Test BOP.
3. Pick up work string and bit to clean out cement.
4. Run in the hole, and tag the stage tool.
5. Circulate with brine, 10 ppg.
6. Drill out the stage tool, and clean the casing until the top of the float collar.
7. Circulate with brine, 10 ppg.
8. Test casing for 30 minutes with 1500 psi. If the pressure decreases more than 10% in 30 minutes, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator may require assessing the root cause and correcting it.
9. Pull BHA out of the hole.
10. Perform safety meeting to discuss logging and perforating operations.
11. Rig up logging truck.
12. Run cased-hole logs by program. Note: run CBL/VDL and ultrasonic tool logs without pressure as a first pass, and run them with 1000-psi pressure as a second pass.

    Note: In case cementing logs show poor bonding in the cementing job, the results will be communicated to NDIC, and an action plan will be prepared.

13. Run CIBP and wireline setting tool to well TD and set CIBP.
14. Pull wireline setting tool out of hole.
15. Run perforating guns to the injection target and below end of fiber-optic cable installed on casing.
16. Perforate the Broom Creek Formation, minimum 4 spf. The depth will be defined with the final log. Gas gun technology or high-performance guns should be evaluated to provide deeper penetration into the formation.
17. Pull guns out of the hole.
18. Rig down logging truck.
19. Pick up service packer, and run in the hole with work string.
20. Circulate with brine, 10 ppg.
21. Set service packer above the perforations.
22. Rig up acid trucks and equipment.
23. Perform cleaning of the perforations with acid. Adjust acid formulation and volumes with water samples and compatibility test.
24. Rig down acid trucks and equipment.
25. Perform an injectivity test/step rate test.
26. Unset packer and circulate hole with inhibited packer fluid.
27. Pull service packer and work string out of the hole.
28. Rig up P/T gauge spooling unit, and prepare rig floor to run upper completion.
29. Run completion assembly per program.
30. Space out packer approximately 50 ft above the top perforations.
31. Install tubing sections, cable connector, and tubing hanger.
32. Hydraulically actuate packer by pressuring up the tubing string against blanking plug preinstalled in packer tailpipe assembly.
33. Rig up logging truck.

34. Run in hole to blanking plug below packer.
35. Pull blanking plug below packer out of hole.
36. Perform annular pressure test of 1000 psi for 30 minutes.
37. Run cased-hole logs through tubing by program.
38. Rig down logging truck.
39. Nipple down BOP.
40. Install injection tree.

    Note: Figure 5-4 illustrates the proposed wellhead schematic.

41. Rig down equipment.

    Note: DTS/DAS fiber-optic cable will be run along the exterior of the long-string casing. Special clamps, bands, and centralizers are installed to protect the fiber and provide a marker for wireline operations. Perforating should occur a minimum of 40' below the end of the fiber-optic cable.

Table 11-5. IIW-S Proposed Upper Completion

Description	OD, in.	Depth, ft	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.
6⅝" Tubing	6⅝	0–5600	15CR80 or better	28	Premium	5.79	5.66
Dual P/T Gauges, Annulus and Tubing Sensing							
6⅝" Tubing	6⅝	5600–5640	15CR80 or better	28	Premium	5.79	5.66
6⅝" 28# × 7" 29# Crossover	7	5640–5642	15CR80* or better	28	Premium	5.79	5.66
831-600 Premier Packer with Polished Bore Receptacle, 25Cr85, HNBR Element							
6⅝" Pup Joint	6⅝	5660–5670	15CR80 or better	28	Premium	5.79	5.66
R Nipple	6⅝	5670–5674	25Cr85	28	Premium	5.63	NA
6⅝" Pup Joint	6⅝	5674–5684	15CR80 or better	28	Premium	5.79	5.66
Wireline Entry Guide	6⅝	5684–5690	15CR80 or better	28	Premium	5.79	5.66

15CR80 – 15% chrome alloy-grade 80 ksi material yield strength.
25CR85 – 25% chrome alloy-grade 85 ksi material yield strength.

Table 11-6. IIW-S Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, Klb
6⅝	15CR80 or better	28	Premium	5.79	5.66	8170	8810	651,000

Table 11-7. IIW-S Cased-Hole Logging

Description	Depth, ft	Comments
CBL/VDL – CCL – ultrasonic imaging tool	From 6500' to surface	Cement/casing log; 30-ft shoe track in 9⅝" casing before tubing is installed.
Pulsed Activated Neutron	From 6500' to surface	Baseline; run through tubing – log both 9⅝" and through 6⅝" tubing after tubing is installed.
Temperature Log	From 6500' to surface	Baseline; run through tubing – log both 9⅝" and through 6⅝ tubing after tubing is installed.

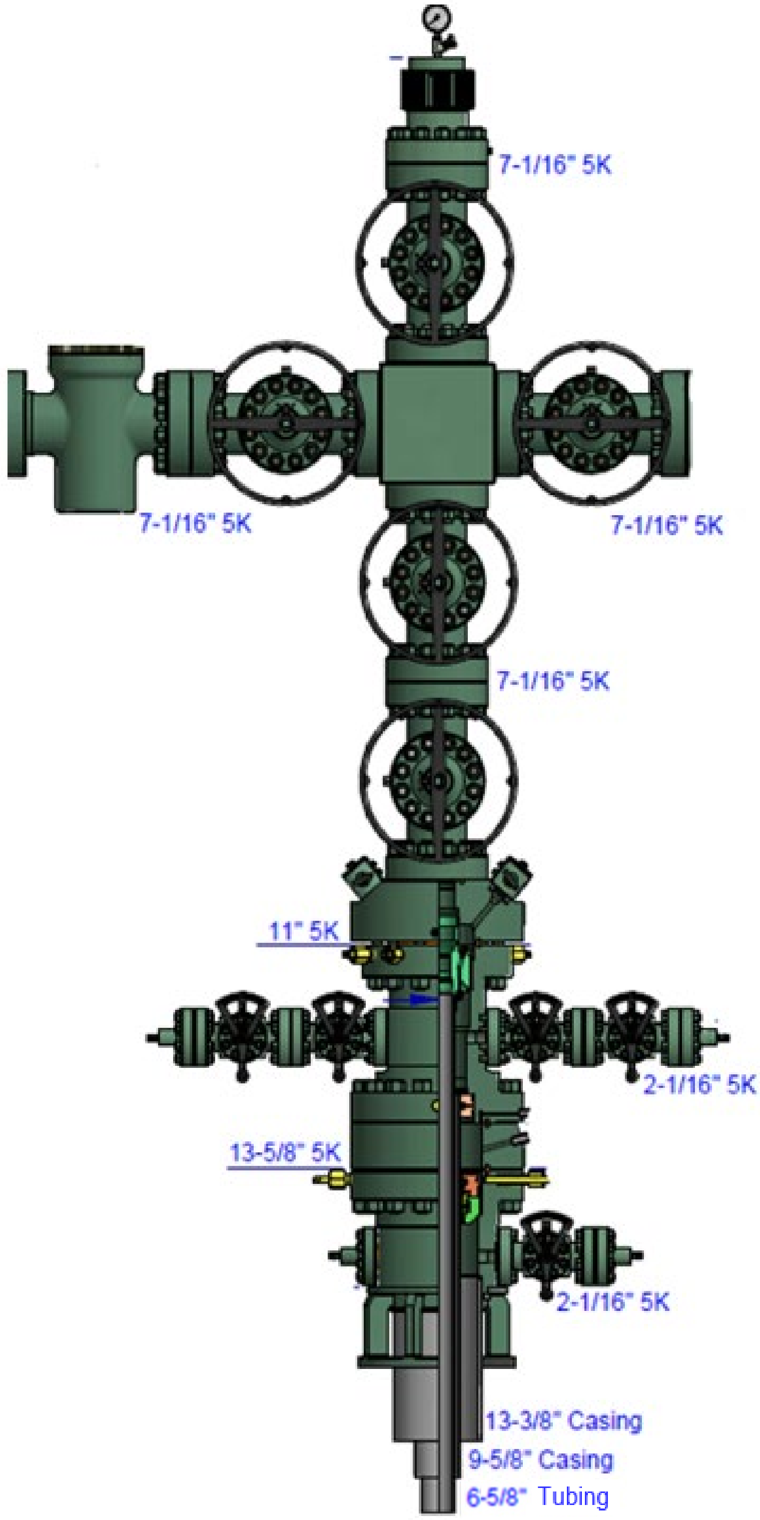

Figure 11-3. IIW-S proposed CO_2-resistant wellhead schematic.

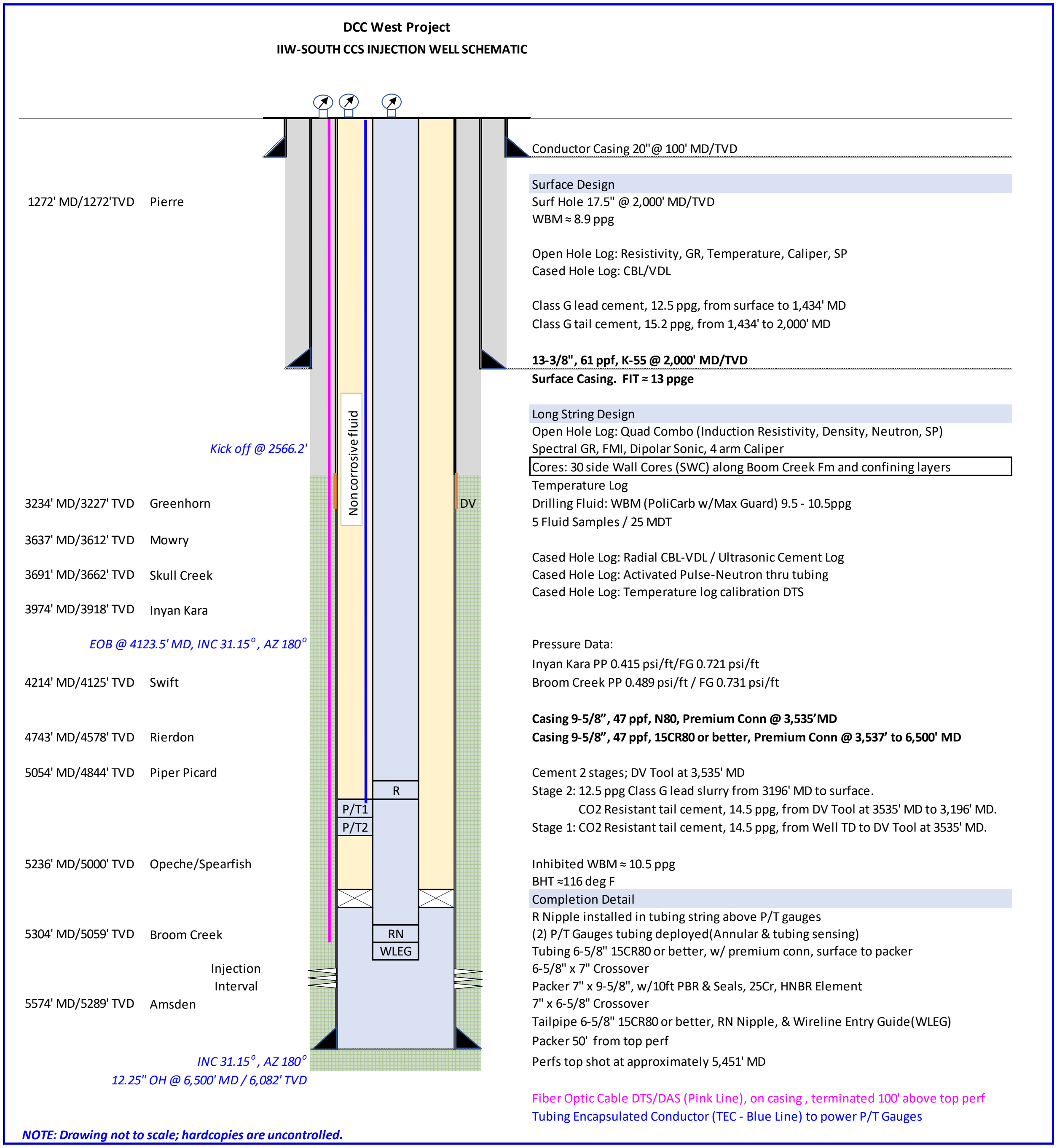

Figure 11-4. IIW-S proposed completed wellbore schematic.

11.3 J-LOC 1 Proposed Procedure for Monitoring Well Operations

J-LOC 1 will be recompleted as a CO_2-monitoring well (Figures 11-5 through 11-7 and Tables 11-8 through 11-10) to support deep subsurface monitoring of IIW-N and IIW-S, the proposed injection wells. Monitoring of the CO_2 plume extent and the storage reservoir pressure will be conducted continuously through the use of the P/T gauges deployed along the outside of the tubing. Monitoring will be conducted during injection operations as well as during the postinjection site closure (PISC), which are discussed in more detail in the Testing and Monitoring Plan (Section 5.0) of this permit application. Monitoring methods will include a combination of formation-monitoring methods (e.g., downhole pressure, downhole temperature, and pulsed-neutron capture/reservoir saturation tool logs) to verify mechanical integrity and support CO_2 plume stabilization evaluations.

The following proposed completion procedure outlines the general steps necessary to complete and test the well:

1. Rig up workover rig.
2. Nipple up BOP.
3. Test BOP.
4. Pick up work string and bit and scraper to clean out cement.
5. Run in the hole to first cement plug at 3929', and tag top of plug.
6. Establish circulation with brine, 10 ppg.
7. Drill out 50' cement plug at 3929' and cast iron cement retainer (CICR) at 3979'.
8. Continue cleaning out well to depth of approximately 4025'.
9. Pull out of hole with drill bit assembly.
10. Rig up cement trucks and equipment.
11. Pick up test/squeeze packer assembly.
12. Run in hole, and set at a depth of approximately 3915'.
13. Perform cement squeeze with CO_2-resistant cement into Inyan Kara Formation perforations 4015'–4025'.
14. Perform pressure test on cement squeeze.
15. Pull out of hole with test/squeeze packer assembly. Wait on cement curing time.
16. Pick up bit assembly.
17. Run in hole, and tag cement squeeze ~4015'.
18. Continue drilling cement and drill CIBP at ~ 4096'
19. Continue to depth of approximately 4846' and drill out 50' of cement and CICR at 4896'.
20. Continue cleaning out well to approximately 9782', and tag lowermost cement plug.
21. TOOH and lay down bit assembly.
22. ***Optional wireline logging run of wellbore.***
23. TIH with work string to tagged depth at approximately 9782'.
24. Establish circulation.
25. Pump a cement plug from tagged depth to ~ 8782' (1000-foot cement plug) with CO_2-resistant cement on top of the existing cement plug.
26. TOOH with work string.
27. Pick up mechanical set CIBP.
28. Run in hole to 5000', set CIBP, and top with cement.
29. Rig down cement trucks and equipment.

30. TOOH with mechanical setting tool.
31. Rig up P/T gauge spooling unit and prepare rig floor to run completion assembly.
32. Run completion assembly to approximately 50 ft above the top perforations.
33. Circulate well with inhibited packer fluid.
34. Set packer in well cement bond interval of the long-string casing.
35. Perform annular pressure test for 15 minutes, following procedures above for injection wells.
36. Install tubing sections, cable connector, and tubing hanger in wellhead.
37. Nipple down BOP.
38. Rig down workover rig.
39. Install injection tree.

    Note: Figure 11-4 illustrates the proposed wellhead schematic.

40. Rig down equipment.

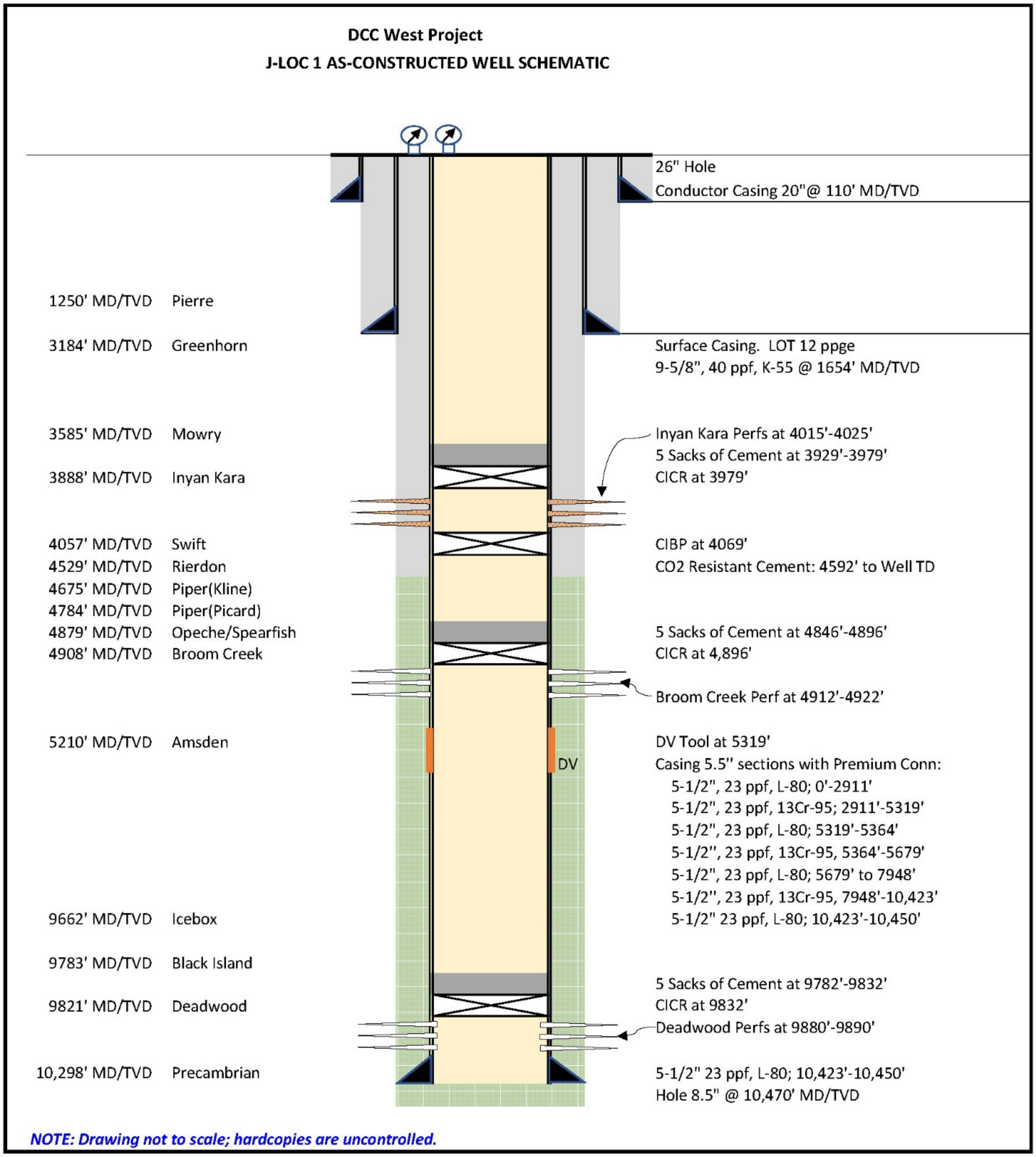

Figure 11-5. J-LOC 1 as-constructed wellbore schematic.

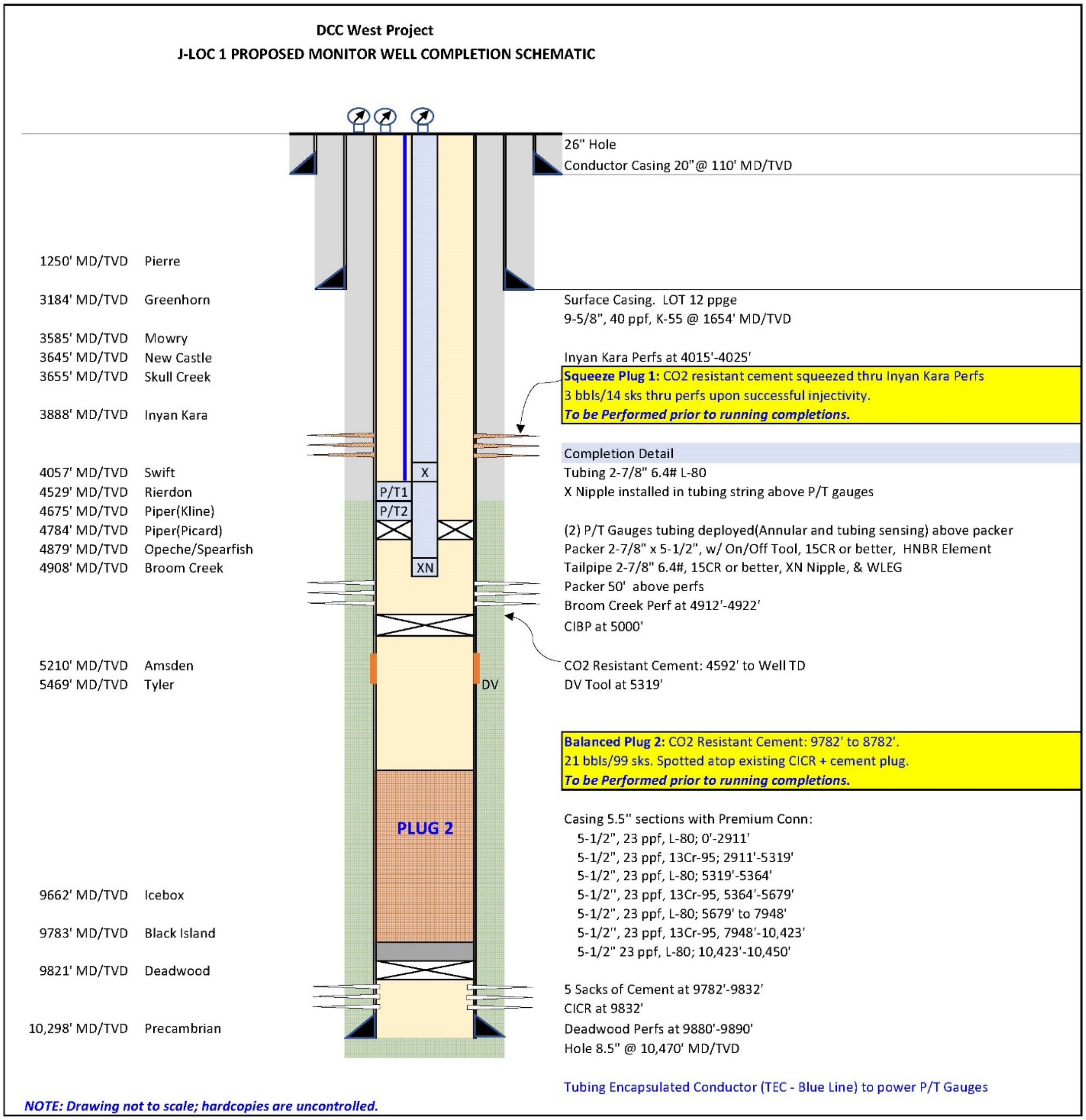

Figure 11-6. J-LOC 1 proposed completed wellbore schematic.

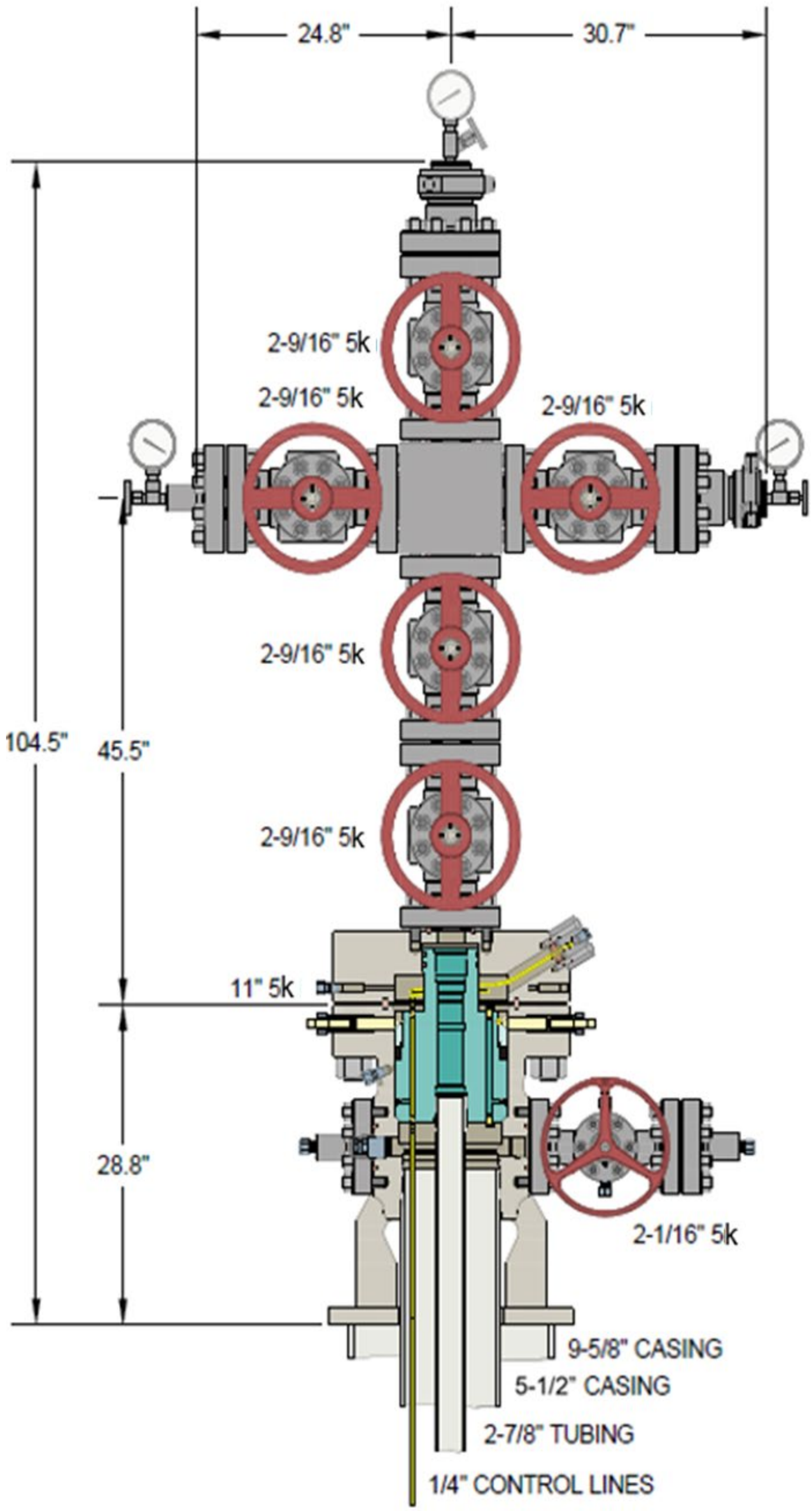

Figure 11-7. J-LOC 1 proposed wellhead schematic.

Table 11-8. J-LOC 1 Proposed Completion

Description	OD, in.	Depth, ft	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.
Tubing	2⅞	0–4861	L-80	6.4	Premium	2.441	2.374
X Nipple	2⅞	4861–4862	15Cr80 or better		Premium	2.313	N/A
Dual P/T Gauges, Annulus and Tubing Sensing Packer 5½" × 2⅞" 15Cr80 or Better with On/Off Tool						2.313	
Pup Joint	2⅞	4872–4876	15Cr80 or better	6.4	Premium	2.441	2.374
XN Nipple	2⅞	4878–4879	15Cr80 or better		Premium	2.205	N/A
Pup Joint	2⅞	4879–4880	15Cr80 or better	6.4	Premium	2.441	2.374

Table 11-9. J-LOC 1 Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, Klb
2⅞	L-80	6.4	Premium	2.441	2.347	11,170	10,570	105,600

Table 11-10. J-LOC 1 Cased-Hole Logging

Description	Depth, ft	Comments
CBL/VDL – CCL – Ultrasonic Imaging Tool	From 9782 to surface	Cement/casing log; 30-ft shoe track in 5.5" casing before tubing is installed.
Temperature Log	From 9782 to surface	Baseline; run through casing only before installing tubing. 5.5" casing
Pulsed Activated Neutron	From 9782 to surface	Baseline; run through casing only before installing tubing. 5.5" casing
Temperature Log	From 5000 to surface	Baseline; run through tubing – log both 5.5" and through 2⅞" tubing after tubing is installed.
Pulsed Activated Neutron	From 5000 to surface	Baseline; run through tubing – log both 5.5" and through 2⅞" tubing after tubing is installed.

* Estimated; will be adjusted with actual tally.

SECTION 12.0

FINANCIAL ASSURANCE DEMONSTRATION PLAN

12.0 FINANCIAL ASSURANCE DEMONSTRATION PLAN

This financial assurance demonstration plan (FADP) is provided to meet the regulatory requirements for the geologic storage of CO_2 as prescribed by the state of North Dakota in North Dakota Administrative Code (NDAC) § 43-05-01-09.1. The storage facility permit (SFP) application must demonstrate that a financial instrument is in place that is sufficient to cover the costs associated with corrective actions and monitoring and reporting.

The FADP describes actions the operator of DCC West SGS has taken and shall take to assure state and federal regulators that sufficient financial support is in place to:

a) Cover the cost of any corrective action (NDAC § 43-05-01-05.1) that may be required at the geologic storage facility during any of its phases of operation, including injection well plugging (NDAC § 43-05-01-11.5), postinjection site care (PISC) and facility closure (NDAC § 43-05-01-19), emergency and remedial response (ERR) (NDAC § 43-05-01-13), and endangerment to underground sources of drinking water (USDWs).

b) Provide funds for routine monitoring and reporting activities by DCC West during injection operations, the PISC period, and closure activities as determined by regulatory agencies.

This FADP provides cost estimates for each of the above actions (Section 12.2) based on the information that is provided in the SFP application and describes the financial instruments that will be established (Section 12.3). The FADP was prepared to account for the entire operation of the DCC West storage facility.

As the FADP was prepared, U.S. Environmental Protection Agency (EPA) guidance was also considered to assess the effectiveness of multiple qualifying financial instruments in the context of DCC West SGS, e.g., key aspects of long-term public confidence, optimization of stakeholder interests, and practicality of implementation. Further, because of the structure of entity ownership, both DCC West SGS and the DCC East SGS Project are controlled by Minnkota, the FADP financial instruments were considered in evaluating the assurance approach during each of the operational periods. There are distinct operator/owner entities (i.e., DCC West SGS and DCC East SGS) for the two storage facilities and these storage sites will be jointly operated as dedicated storage sites for the primary purpose of providing carbon sequestration services to Minnkota. The FADP was prepared to account for the entire operation of the DCC West.

Based on review and consideration of the available financial instruments contained in NDAC § 43-05-01-09.1, applicant proposes to use a combination of commercial insurance and combination of additional funds to pour over into a separate account under the established standby trust approved by the DCC West SGS Project to fulfill the FADP requirements of the project Class VI permit. The details contained in this FADP along with supporting documentation establish the approach the applicant proposes to use to meet the financial responsibility requirements and that each of these instruments sufficiently addresses the activities and costs associated with the corrective action plan, injection well-plugging program, PISC and facility closure, emergency and remedial response plan (ERRP), and endangerment of USDWs.

Each of these instruments is described in full in subsequent subsections of this FADP and in Appendix G. If there are any changes, updated information related to the financial instruments will be provided on an annual basis to NDIC for review and evaluation as required under NDAC § 43-05-01-09.1.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name:	DCC West
Facility Contact:	Shannon Mikula
Injection Well Locations:	IIW-N: Section 6, T141N, R84W
	IIW-S: Section 6, T141N, R84W

12.2 Approach to Financial Responsibility Cost Estimates

In accordance with the requirements contained in NDAC § 43-05-01-09.1, the FADP provides financial assurance sufficient to cover the activities identified in the corrective action plan, injection well-plugging program, PISC and facility closure, ERR, and endangerment of USDWs (Table 12-6). The following provides a summary description of the considerations and assessment approach for each activity.

12.2.1 Corrective Action

According to NDAC § 43-05-01-05.1, corrective action involves inventorying and characterizing existing wells in the proposed AOR (area of review). The objective of corrective action assessment is to describe the actions DCC West will take, prior to and over the course of the project operation, on existing wells to proactively prevent the movement of fluid into or between USDWs. A detailed description of how the AOR was delineated can be found in Section 3.0 of this SFP application. DCC West implemented the following workflow to estimate costs associated with corrective action activities: 1) delineate the AOR and 2) identify and evaluate active and abandoned legacy wells within the AOR to ensure they meet the minimum completion standards for geologic storage of CO_2 and require no corrective action.

DCC West has determined there are no wells in the proposed AOR to which corrective action would be required prior to or during the project operation, PISC, or postclosure period (Section 4.2. All legacy wellbores within the AOR boundary are located outside the projected stabilized CO_2 plume boundary.) DCC West will employ a proactive monitoring approach to track the CO_2 plume extent and associated pressure front throughout the life of the project to ensure nonendangerment of USDWs, which includes acquiring time-lapse seismic and continuously monitoring reservoir pressure in the Broom Creek Formation at the CO_2 injection wells and reservoir-monitoring well (Section 5.7.2). For the avoidance of doubt, if injection or monitoring wells proposed as part of the DCC West site operation require corrective action, such associated activities and costs relating thereto would be accounted for as part of the project's operating budget.

12.2.2 Plugging of Injection Wells

The plugging of injection wells as part of site program closure and as required by NDAC § 43-05-01-11.5 is included within the project cost and is covered within this FADP and proposed instruments. The injection wells will be plugged at cessation of the injection operation as discussed in Section 6.0 of this SFP application and in Subsection 12.2.3 of this FADP. The specifics of the plugging program can be found in Section 10.0 of this SFP application. These costs shall be disbursed through the trust as described herein, while the amount associated with well plugging funded following commencement of the operation of the wells. The estimate covers the aggregated P&A cost of two injector wells (IIW-N and IIW-S), including rig mobilization, rig rentals, cementing, logging, and haulage (Table 12-3). Reservoir-monitoring well plugging is separately accounted for as part of facility closure (Table 12-4). To ensure a conservative estimate, a 20% contingency was added, and no deductions were made for salvage value of materials.

12.2.3 Implementation of the Postinjection Site Care Plan and Facility Closure Activities

PISC and facility closure cost estimates include site monitoring and periodic reevaluation of the AOR, facilities maintenance and power costs, and overhead and support costs during the 10-year PISC period. Details of the activities and actions contained in the PISC and facility closure plan can be found Section 6.0 of this SFP application.

The total combined cost for the implementation of the PISC and facility closure activities is estimated to be $13,617,000, including $11,239,000 for implementing the PISC and $2,378,000 for facility closure activities, as provided in Table 12-1, and which includes the following: a) formation monitoring (i.e., downhole pressure and temperature surveys, pulsed-neutron logs), b) near-surface monitoring (i.e., soil gas and Fox Hills Formation testing) and mechanical integrity well tests (i.e., injection well annulus pressure, ultrasonic logging), and c) coordinated repeat time-lapse seismic. The largest element of the PISC cost estimate relates to seismic studies, which are required to be carried out at 5-year intervals to validate models, which are expected to cover an area up to 25 mi^2. Additionally, at the start of the PISC period, determined by cessation of injection operations, DCC West will plug and abandon the two injection wells and abandon in place the flowline, if no other beneficial use is determined at that time. DCC West would leave intact for the period of the PISC the reservoir-monitoring well and the dedicated Fox Hills monitoring wells (FH01 and FH02). These costs for plugging and surface facilities reclamation are included in Table 12-4.

Table 12-1. Cost Estimate for PISC Activities, Assuming a 10-year PISC Period

Activity		Cost*
Monitoring and AOR Reevaluation (see Table 12-3)		$7,811,000
Overhead and Support		$1,540,000
Facilities Maintenance and Power		$1,888,000
	Total	**$11,239,000**

* Costs are based on estimates of current contract day rates and materials.

Table 12-2. Monitoring and AOR Reevaluation (part of the PISC)

Activity		Cost*
Soil Gas Sampling		$794,000
Time-Lapse Seismic Surveys		$5,250,000
Water Sampling		$200,000
Saturation Log Monitoring Wells		$845,000
Annular Pressure Testing**		$111,000
AOR Reevaluation		$96,000
Casing Inspection Log Monitoring Wells		$300,000
Optical Gas Imaging		$144,000
Visual Inspection of Wellheads		$71,000
	Total	**$7,811,000**

* Costs are based on estimates of current contract day rates and materials.
** Reservoir-monitoring well.

DCC West will prepare and submit an application for facility closure to the NDIC and, upon authorization from the NDIC will proceed with plugging the reservoir-monitoring wells. The specifics of the plugging program can be found in Section 10.0 In addition to the P&A of the reservoir-monitoring wells, the facility closure activities cost estimates include electrical removal, surface facilities removal, and site restoration for the wellsite and assumed impacted areas of the aboveground surface facilities (Table 12-4). Fox Hills monitoring wells (FH01 and FH02) are assumed to remain in place, as the groundwater monitoring locations may be wanted by NDIC or DCC West for some future use. To ensure a conservative estimate, a 20% contingency was added, and no deductions were made for salvage value of materials.

Table 12-3. Plugging CO_2 Injection Wells and CO_2 Flowline

Activity	Cost*
Mobilization and Location	$161,000
Rig Rates and Daily Cost	$301,000
Hauling and Disposal	$43,000
Balance of Plant	$
Hydrostatic Testing and Scanning	$
Pipe Rental	$
Bit and Scrapers	$
Logging	$300,000
Casing Crew and Torque	$34,000
DST Service and Manifold	$
Sensors and Fiber Optic	$45,000
Cementing	$400,000
Perforating Cost	$
Pumping Truck and Acid	$
Wellhead Service	$60,000
Tangibles	$
Flowline/Surface Facilities Decommission**	$400,000
Subtotal	**$1,744,000**
Contingency	**20%**
Tax	**7%**
Total Cost* **	**$2,215,000**

* Costs are based on estimates of current contract day rates and materials and P&A of two injector wells.
** Costs include abandonment of flowlines.
*** Dollar amount rounded.

Table 12-4. Cost Estimate for Facility Closure Activities

Activity	Cost*
Reservoir-Monitoring Well P&A**	$1,361,000
Facilities Closure	$1,017,000
Total Facility Closure	**$2,378,000**

* Costs are based on estimates of current contract day rates and materials.
** Costs are based on P&A of two reservoir-monitoring wells.

12.2.4 Implementation of Emergency and Remedial Response Actions

12.2.4.1 Emergency Response Actions

The ERRP and associated detailed assessment can be found in Section 7.0 and Appendix F of this SFP application. The ERRP assessment supports a determination that the likelihood of release of significant volumes of CO_2 from underground storage into the soil or the atmosphere or significant volumes of saltwater into the environment are considered remote. Multiple factors were considered in the development of the ERRP, including:

a) Extensive and independently verified analysis of the integrity of the storage mechanism.
b) Selection of qualified and experienced storage facility operator.
c) Selection of qualified and experienced drilling contractor.

Risk mitigation measures include:

a) Location of injection facilities away from urban population and in an industrial-zoned, brownfield property.
b) Continuous monitoring of transportation and injection systems.
c) Routine measurement and reporting of CO_2 volumes.
d) Physical security, barriers, and signage around injection facilities.
e) Primary and secondary containment for leaked fluids at injection well pads.

A review of the ERRP technical risk categories for DCC West SGS identified a list of events that could potentially result in the movement of injected CO_2 or formation fluids in a manner that may endanger a USDW and require an emergency response. These events are as follows:

a) Loss of injectivity
b) Lower storage capacity than modeled
c) Containment loss – lateral migration of CO_2
d) Containment loss – pressure propagation
e) Containment loss – vertical migration of CO_2 or formation water brine via injection wells, other wells, or inadequate confining zones
f) Natural disasters

If it is determined that one or more of these events have occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7.0) and Appendix F of this SFP application. DCC West's planned response actions are summarized in Table 7-4.

12.2.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 7-4 is challenging since remediation measures specifically dedicated to CO_2 storage impacts are poorly documented, with one of the more important data gaps being the lack of precise knowledge of the leakage mechanisms and associated impacts (Manceau and others, 2014). Furthermore, to date, no remediation action following CO_2 leakage after geologic storage has ever been implemented mainly because of the absence of established impacts (Manceau and others, 2014). Consequently, the degree of maturity of remediation measures in the carbon capture and storage (CCS) field is low, making it necessary to rely on literature that is primarily based on modeling or hypotheticals with other release and loss containment events, e.g., the analogy between CO_2 and volatile organic compounds, the latter having been addressed extensively in the literature. Additionally, for the remedial measures, costs and time for adequate removal are generally site-dependent, and no information is specifically available in this area in the CCS field.

Based on this current situation, two key technical manuscripts were relied upon to identify and estimate the costs of mitigation/remediation technologies to address undesired migration of CO_2 from a geologic storage reservoir (Manceau and others, 2014; Bielicki and others, 2014).

12.2.4.2.1 Identification of Remediation Technologies

Manceau and others (2014) identified several remediation technologies/strategies that are available to address the potential impacted media that may result from an emergency event. These impacted media and remediation measures are listed in Table 12-5. The impacted media in Table 12-5 include surface and groundwater/USDWs, vadose zone, indoor settings, and atmosphere; the remedial measures include a combination of active (e.g., air sparging) and passive (e.g., dispersion, natural attenuation) systems. However, it is important to note that, at this time, no methodology is widely accepted for designing intervention and remediation plans for CO_2 geologic storage projects. Consequently, there remains a need for establishing the best field-applied and test practices for mitigating an undesired CO_2 migration. This effort will be based on a combination of available literature and experience that is gained over time in existing CO_2 storage projects.

Table 12-5. Proposed Technologies/Strategies for Remediation of Potential Impacted Media

Impacted Media	Potential Remedial Measures
Groundwater/USDW	Monitored natural attenuation
	Pump-and-treat
	Air sparging
	Permeable reactive barrier
	Extraction/injection
	Biological remediation
Vadose Zone (soil gas)	Monitored natural attenuation
	Soil vapor extraction
	pH adjustment (via spreading of alkaline supplements, irrigation, and drainage)
Surface Water	Passive systems, e.g., natural attenuation
	Active treatment systems
Atmosphere	Passive systems, e.g., natural mixing, dispersion
Indoor/Workplace Settings	Sealing of leak points
	Depressurization
	Ventilation

12.2.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

Given the lack of a site-specific estimate of implementing the emergency event responses at DCC West SGS, and in the interest of providing sufficient financial assurance, DCC West has compiled cost estimates associated with a conservative hypothetical scenario. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP.

Emergency Remedial Response Scenarios

The applicant started with the DCC East SGS Project Risk Assessment ERR matrix and formed a task force (TF) to reevaluate and quantify project risks based upon the DCC West SGS-specific site characteristics. The TF consisted of members with relevant professional qualifications and experience in subsurface analysis, facilities engineering, drilling engineering, operations, finance, environmental protection, or risk engineering. Multiple working sessions were conducted, and the TF reached consensus on the identification of risks underlying various aspects of the project. The findings of the TF (Appendix F) support the understanding of financial risks and the approach to FADP described in this document.

Following the identification of financial risks, the applicant compiled cost estimates associated with a conservative hypothetical scenario wherein a significant volume of briny water migrates to the surface during injection operations through one of the injection wells. The scenario contemplates a reactive response approach, e.g., mobilization of response personnel and equipment upon discovery of such an event. This approach is considered appropriate because of the remoteness of the residual risk. Specific postoccurrence action is not determinable until occurrence; thus actual response to such an event would be based on its severity. Because of the remote likelihood, this single conservative scenario was compiled to account for the outer-limit cost estimate to satisfy event response. The scenario used for cost estimating assumed the optimal operating conditions (10 years of operation) requiring outer-limit response and remediation costs. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP.

Endangerment of Drinking Water Sources
As discussed in the ERRP section, the risk of endangerment to USDWs is considered remote. However, as part of the reactive response scenario contemplated in the ERR cost estimate, the applicant assessed the specific response actions and cost data to represent the likely impact of such an event on sources of drinking water. Because of precautions taken in the design for spill control and pollution prevention, the well pad design incorporates two liners and a berm that, in combination with the response strategy, would minimize this portion of environmental repair. Thus the applicant assessed the second reactive scenario, which contemplates a subsurface leak scenario. This subsurface leak scenario has primary costs related to groundwater delineation and an extended period (10 years) of quarterly monitoring and reporting after emergency remedial actions are taken.

Selected Elements of Analysis of Inherent Risks
The projected AOR includes mostly land associated with the coal-mining operations of BNI, the area where MRYS is located, and land primarily used for agriculture activities. Residents and man-made structures are scattered across the surface. The closest highly populated area is the town of Center, North Dakota, with a population of 588 (2020 census), located approximately 5.1 miles northeast of the DCC West SGS injection site.

From the surface to the lowermost USDW—the Fox Hills Aquifer—the groundwater is considered a protected aquifer with <10,000 ppm TDS (total dissolved solids). The Fox Hills base is estimated at a depth of approximately 1000 ft and is followed by a thick section of clays with a thickness of approximately 2600 ft. These clays act as a seal until the next major permeable zone, the Inyan Kara. The Inyan Kara is an underpressured formation that is classified as an exempt aquifer under NDCC § 43-02-05-03 west of the 83W range line, and this formation is mostly targeted for water disposal wells in those areas. Approximately 900 ft of cap rock acts as a main seal between the Inyan Kara zone and the Broom Creek.

Inside the AOR, 80 water wells are located in shallow aquifers, providing water for the associated farms' livestock, irrigation, and localized consumption (Figure 4-3). Two existing wells that penetrate the Fox Hills Formation will be used as tools for monitoring the USDW (ID W295, 14108527DAA and ID W395, 14108411AA on Figure 5-6). The project will install one additional USDW well, as described in the monitoring plan (Section 5.0), to periodically sample the lowest USDW.

No producible minerals, oil, natural gas, or other reserves are reported in the AOR for the Broom Creek Formation or overlying formations. As described in the AOR and corrective action section (Section 4) for the DCC West storage reservoir, seven deep wells penetrate the storage complex (five oil and gas exploration, two stratigraphic) within or in proximity to the plume boundaries and the identified pressure front. These wells are identified in Section 4.2 as Paul Bueligen 1 (NDIC File No. 2183), Raymond Henke 1-24 (NDIC File No. 4940), Ervin V. Henke 1 (NDIC File No. 3277), Kenneth Henke 1-7 (NDIC File No. 4941), BNI 1 (NDIC File No. 34244), Herbert Dresser 1-34 (NDIC File No. 4937), and J-LOC 1 (NDIC File No. 37380). J-LOC 1 will be converted to a reservoir-monitoring well for DCC West, and the other six wells were analyzed and included in the risk assessment as well as in the corrective action evaluation.

Cost Estimates

Tables in this section provide a detailed estimate, in current dollars, of the cost for performing corrective actions on wells in the AOR, plugging the injection well, PISC and facility closure, and ERR. Table 12-6 is a summary of the cost estimates underlying the FADP, identifying proposed financial instrument(s) that will provide the appropriate assurance to regulatory agencies of the applicant's intent and ability to fulfill its responsibilities.

Table 12-6. Potential Future Costs Covered by Financial Assurance in $K*

Activity	Total Cost	Covered by Special-Purpose Trust	Covered by Commercial Insurance	Details in Supporting Table
Corrective Action on Wells in AOR	$0	$0	$0	NA
Plugging Injection Wells and Flowline/Surface Facilities Decommissioning	$2,215	$2,215	$0	Table 12-3
PISC	$11,239	$11,239	$0	Table 12-1
Facility Closure	$2,378	$2,378	$0	Table 12-4
ERR	$11,782	$0	$11,782	Table 12-7
Endangerment of USDWs	$2,487	$0	$2,487	Table 12-8
Total	**$30,101**	**$15,832**	**$14,269**	

* Insurance policies will cover events occurring on or involving DCC West or DCC East SGS Project assets, sites, or operations. All other amounts identified will be funded to separate accounts for DCC West SGS and DCC East SGS Project.

Cost estimates assume that these costs would be incurred if a third party were contracted to perform these activities. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the postinjection period, e.g., the use of postinjection seismic surveys.

The values included in the FADP are based on cost estimates provided during the permit application development process and are based on the hiring of a third party to perform the services or procurement of goods associated with performance. The cost estimates are based upon initial work performed by Oxy Low Carbon Ventures (OLCV) and were updated for inflation and with additional historical price data from other projects managed by Baker Hughes in North Dakota, cost quotes from third-party companies, regulatory guidance documents, and professional judgment about the level of effort required to complete an activity. These values are subject to change during the course of the project to account for inflation of costs and any changes to the project that affect the cost of the covered activities. If the cost estimates change, the applicant will adjust the value of the financial instruments, and any adjustment will be submitted for approval by NDIC as required under NDAC § 43-05-01-09.1(3).

Tables 12-7 and 12-8 provide additional information for the future cost estimates provided in Table 12-6.

Table 12-7. Emergency and Remedial Response*

Activity/Item	Cost
Pump Trucks (twin pump)	$126,000
Frac Tanks	$53,000
Vacuum Truck	$40,000
Dozer	$20,600
Excavator	$22,600
Dump Truck	$36,000
Brine Disposal (no Class I)	$1,100
Trucking Water	$12,200
Water Transfer Pump and Personnel Package	$12,900
Light Towers, Trailers, Generator, Heaters, Communications, etc.	$8,500
Heater Packages	$40,000
Fuel Tank Storage	$3,800
Drill and P&A Relief Well in Broom Creek	$9,530,000
Special Well Control Team – (e.g., wild well/boots & coats)	$1,875,000
Total	**$11,781,700**

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence. A significant portion of these costs, should they be incurred, would be covered by commercial insurance which is an industry standard control of well (COW) coverage. Costs are based on estimates of current contract rates.

Table 12-8. Endangerment of USDWs*

Description	Total Estimated Amount
General Response Actions	$6,700
Groundwater Delineation	$1,432,000
Irrigation/Domestic Well Sampling and Replacement	$145,000
Quarterly Groundwater Monitoring (10 years) and Reporting	$844,000
P&A of Groundwater-Monitoring Wells	$59,000
Total	**$2,486,700**

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence. Costs are based on estimates of current contract rates.

12.3 Financial Instruments

DCC West is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments:

- DCC West will establish a separate special purpose trust account and deposit funds for plugging of injection wells in accordance with NDAC § 43-05-01-11.5, with separate accounts for amounts estimated for implementation of PISC activities and closure costs in accordance with NDAC § 43-05-01-19.

- A third-party pollution liability insurance policy with an aggregate limit of $14,269,000 will be secured to cover the costs of implementing ERR actions, if warranted, in accordance with NDAC § 43-05-01-13. Additional information about deductions, exceptions, and the premium to be paid is also provided in the attached Appendix G Market Assessment.

The estimated total costs of these activities and breakdown apportionment across proposed financial instruments are presented in Table 12-6. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity.

The company providing insurance will meet all the following criteria:

1. The company is authorized to transact business in North Dakota.

2. The company has either passed the specified financial strength requirements based on credit ratings or has met a minimum rating, minimum capitalization, and ability to pass the rating, when applicable.

3. The third-party insurance can be maintained until such a time that NDIC determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies DCC West as the covered party, will be provided by one or a combination of the companies meeting the creditworthiness and other requirements of section 43-05-01-09.1. The applicant has procured indicated terms for commercial environmental impairment liability (EIL) insurance coverage to fund covered emergency and remedial response actions to protect USDW arising out of sequestration operations. However, the greatest exposure would be an acute upward migration through the CO_2 injection well, which would have an estimated cost of $14,269,000 for emergency and remedial response actions, and such coverage would be an amount sufficient to cover the amounts identified in the endangerment of USDWs. The coverage limit will not be lower than the estimated amount to be covered by commercial insurance, $14,269,000, as found in Table 12-6, and may be acquired at a higher limit based upon assessment of available insurance products and market capacity.

12.4 References

Bielicki, J.M., Pollak, M.F., Fitts, J.P., Peters, C.A., and Wilson, E.J., 2014, Causes and financial consequences of geologic CO_2 storage reservoir leakage and interference with other subsurface resources: International Journal of Greenhouse Gas Control, v. 20, p. 272–284.

Manceau, J.C., Hatzignatiou, D.G., Latour, L.L, Jensen, N.B., and Réveillére, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO_2 from a geological storage unit—current status: International Journal of Greenhouse Gas Control, v. 22, p. 272–290.

APPENDIX A

WELL AND WELL FORMATION FLUID-SAMPLING LABORATORY ANALYSIS

EERC
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ANALYTICAL RESEARCH LAB - Final Results

Set Number: 54654
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020

July 24, 2020

Sample	Parameter	Result	
54654-03	**Broom Creek 6/13/20**		
	Alkalinity, as Bicarbonate (HCO3-)	83.4	mg/L
	Alkalinity, as Carbonate (CO3=)	0	mg/L
	Alkalinity, as Hydroxide (OH-)	0	mg/L
	Alkalinity, Total as CaCO3	68.4	mg/L
	Aluminum	263	µg/L
	Antimony	< 5	µg/L
	Arsenic	< 5	µg/L
	Barium	187	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 5	µg/L
	Boron	11.7	mg/L
	Bromide	< 20	mg/L
	Cadmium	< 2	µg/L
	Calcium	2030	mg/L
	Chloride	26400	mg/L
	Chromium	< 40	µg/L
	Cobalt	109	µg/L
	Conductivity at 25°C	68800	µS/cm
	Copper	< 200	µg/L
	Dissolved Inorganic Carbon	15.5	mg/L
	Dissolved Organic Carbon	1130	mg/L
	Fluoride	< 1	mg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	8.2	mg/L
	Magnesium	404	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	936	µg/L
	Nickel	213	µg/L
	Phosphorus	< 1	mg/L

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

July 24, 2020

Set Number: 54654
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020

Sample	Parameter	Result
54654-03	**Broom Creek 6/13/20**	
	Potassium	202 mg/L
	Selenium	88.0 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L
	Sodium	16900 mg/L
	Strontium	49.0 mg/L
	Sulfate	3060 mg/L
	Thallium	< 5 µg/L
	Thorium	< 3 µg/L
	Total Dissolved Solids	49000 mg/L
	Total Inorganic Carbon	17.0 mg/L
	Total Organic Carbon	1160 mg/L
	Uranium	23 µg/L
	Vanadium	95.4 µg/L
	Zinc	< 0.1 mg/L
54654-04	**Broom Creek 6/13/20 duplicate**	
	Alkalinity, as Bicarbonate (HCO3-)	84.0 mg/L
	Alkalinity, as Carbonate (CO3=)	0 mg/L
	Alkalinity, as Hydroxide (OH-)	0 mg/L
	Alkalinity, Total as CaCO3	68.9 mg/L
	Aluminum	248 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	188 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	11.2 mg/L
	Bromide	< 20 mg/L
	Cadmium	< 2 µg/L
	Calcium	2000 mg/L
	Chloride	27000 mg/L
	Chromium	< 40 µg/L

Distribution ________________________ Date ___________

ANALYTICAL RESEARCH LAB - Final Results

July 24, 2020

Set Number: 54654
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020

Sample	Parameter	Result	
54654-04	**Broom Creek 6/13/20 duplicate**		
	Cobalt	108	µg/L
	Conductivity at 25°C	69900	µS/cm
	Copper	< 200	µg/L
	Dissolved Inorganic Carbon	15.5	mg/L
	Dissolved Organic Carbon	1120	mg/L
	Fluoride	< 1	mg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	9.4	mg/L
	Magnesium	399	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	946	µg/L
	Nickel	219	µg/L
	Phosphorus	< 1	mg/L
	Potassium	202	mg/L
	Selenium	87.6	µg/L
	Silicon	< 1	mg/L
	Silver	< 5	µg/L
	Sodium	16900	mg/L
	Strontium	48.1	mg/L
	Sulfate	3070	mg/L
	Thallium	< 5	µg/L
	Thorium	< 3	µg/L
	Total Dissolved Solids	49700	mg/L
	Total Inorganic Carbon	16.8	mg/L
	Total Organic Carbon	1190	mg/L
	Uranium	24	µg/L
	Vanadium	103	µg/L
	Zinc	< 0.1	mg/L

Distribution ________________________ Date ___________

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ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result	
54655-03	**Broom Creek 6/13/20 (Total Metals)**		
	Aluminum	311	µg/L
	Antimony	< 5	µg/L
	Arsenic	< 5	µg/L
	Barium	259	µg/L
	Beryllium	< 4	µg/L
	Bismuth	< 5	µg/L
	Boron	11.0	mg/L
	Cadmium	< 2	µg/L
	Calcium	2000	mg/L
	Chromium	< 40	µg/L
	Cobalt	109	µg/L
	Copper	< 200	µg/L
	Iron	< 1	mg/L
	Lead	< 5	µg/L
	Lithium	8.2	mg/L
	Magnesium	381	mg/L
	Manganese	26	µg/L
	Mercury	< 0.1	µg/L
	Molybdenum	973	µg/L
	Nickel	224	µg/L
	Phosphorus	< 1	mg/L
	Potassium	194	mg/L
	Selenium	92.4	µg/L
	Silicon	< 1	mg/L
	Silver	< 5	µg/L
	Sodium	16200	mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ____________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result
54655-03	**Broom Creek 6/13/20 (Total Metals)**	
	Strontium	46.5 mg/L
	Thallium	< 5 µg/L
	Thorium	< 3 µg/L
	Uranium	25 µg/L
	Vanadium	107 µg/L
	Zinc	< 0.1 mg/L
54655-04	**Broom Creek 6/13/20 duplicate (Total Metals)**	
	Aluminum	289 µg/L
	Antimony	< 5 µg/L
	Arsenic	< 5 µg/L
	Barium	246 µg/L
	Beryllium	< 4 µg/L
	Bismuth	< 5 µg/L
	Boron	11.3 mg/L
	Cadmium	< 2 µg/L
	Calcium	1940 mg/L
	Chromium	< 40 µg/L
	Cobalt	112 µg/L
	Copper	< 200 µg/L
	Iron	< 1 mg/L
	Lead	< 5 µg/L
	Lithium	7.9 mg/L
	Magnesium	398 mg/L
	Manganese	26 µg/L
	Mercury	< 0.1 µg/L
	Molybdenum	980 µg/L
	Nickel	220 µg/L
	Phosphorus	< 1 mg/L
	Potassium	197 mg/L
	Selenium	90.8 µg/L
	Silicon	< 1 mg/L
	Silver	< 5 µg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ______________________ Date __________

ANALYTICAL RESEARCH LAB - Final Results

July 23, 2020

Set Number: 54655
Fund#: 25089
PI: Lonny Jacobson
Contact Person: Lonny Jacobson

Request Date: Thursday, June 18, 2020
Due Date: Thursday, July 2, 2020
Set Description: Minnkota JLOC 1 Well-MDT Fluid Sampling June 2020 (Total Metals)

Sample	Parameter	Result	
54655-04	**Broom Creek 6/13/20 duplicate (Total Metals)**		
	Sodium	16300	mg/L
	Strontium	46.9	mg/L
	Thallium	< 5	µg/L
	Thorium	< 3	µg/L
	Uranium	25	µg/L
	Vanadium	110	µg/L
	Zinc	< 0.1	mg/L

Note: Results are reported on a dry basis, unless otherwise noted.

Distribution ______________________ Date __________

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1769
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:18
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Inyan Kara

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	15 Jun 20	JD
pH	* 8.6	units	N/A	SM4500 H+ B	15 Jun 20 17:00	HT
Conductivity (EC)	4774	umhos/cm	N/A	SM2510-B	15 Jun 20 17:00	HT
pH - Field	8.63	units	NA	SM 4500 H+ B	13 Jun 20 10:18	JSM
Temperature - Field	20.8	Degrees C	NA	SM 2550B	13 Jun 20 10:18	JSM
Total Alkalinity	544	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Phenolphthalein Alk	22	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Bicarbonate	501	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Carbonate	43	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Conductivity - Field	5347	umhos/cm	1	EPA 120.1	13 Jun 20 10:18	JSM
Total Organic Carbon	1340	mg/l	0.5	SM5310-C	23 Jun 20 17:34	NAS
Sulfate	2450	mg/l	5.00	ASTM D516-11	17 Jun 20 11:38	EV
Chloride	554	mg/l	1.0	SM4500-Cl-E	17 Jun 20 9:50	EV
Nitrate-Nitrite as N	0.16	mg/l	0.10	EPA 353.2	18 Jun 20 8:56	EV
Ammonia-Nitrogen as N	1.11	mg/l	0.20	EPA 350.1	16 Jun 20 11:40	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Jun 20 12:37	MDE
Total Dissolved Solids	3450	mg/l	10	I1750-85	17 Jun 20 15:53	HT
Calcium - Total	17.2	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Magnesium - Total	< 5 @	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Sodium - Total	1120	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Potassium - Total	5.7	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Iron - Total	0.33	mg/l	0.10	6010D	24 Jun 20 11:07	MDE
Manganese - Total	< 0.05	mg/l	0.05	6010D	24 Jun 20 11:07	MDE
Barium - Dissolved	0.26	mg/l	0.10	6010D	23 Jun 20 12:02	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1769
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:18
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Inyan Kara

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 0.05	mg/l	0.05	6010D	23 Jun 20 12:02	SZ
Molybdenum - Dissolved	< 0.1	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Strontium - Dissolved	0.32	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	26 Jun 20 14:33	CC
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Jun 20 14:33	CC
Chromium - Dissolved	0.0304	mg/l	0.0020	6020B	26 Jun 20 14:33	CC
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Jun 20 14:33	CC
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	26 Jun 20 14:33	CC
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	26 Jun 20 14:33	CC

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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51 W. Lincoln Way ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885

MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1768
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:10
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Broom Creek

Temp at Receipt: 4.2C

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	15 Jun 20	JD
pH	* 7.3	units	N/A	SM4500 H+ B	15 Jun 20 17:00	HT
Conductivity (EC)	66249	umhos/cm	N/A	SM2510-B	15 Jun 20 17:00	HT
pH - Field	7.21	units	NA	SM 4500 H+ B	13 Jun 20 10:10	JSM
Temperature - Field	20.9	Degrees C	NA	SM 2550B	13 Jun 20 10:10	JSM
Total Alkalinity	67	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Bicarbonate	67	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Carbonate	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Hydroxide	< 20	mg/l CaCO3	20	SM2320-B	15 Jun 20 17:00	HT
Conductivity - Field	65006	umhos/cm	1	EPA 120.1	13 Jun 20 10:10	JSM
Total Organic Carbon	1360	mg/l	0.5	SM5310-C	26 Jun 20 12:37	NAS
Sulfate	2620	mg/l	5.00	ASTM D516-11	17 Jun 20 11:38	EV
Chloride	29900	mg/l	1.0	SM4500-Cl-E	17 Jun 20 9:50	EV
Nitrate-Nitrite as N	25.1	mg/l	0.10	EPA 353.2	18 Jun 20 8:37	EV
Ammonia-Nitrogen as N	0.36	mg/l	0.20	EPA 350.1	16 Jun 20 11:40	EV
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Jun 20 12:37	MDE
Total Dissolved Solids	49000	mg/l	10	I1750-85	17 Jun 20 15:53	HT
Calcium - Total	1990	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Magnesium - Total	376	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Sodium - Total	16300	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Potassium - Total	226	mg/l	1.0	6010D	16 Jun 20 14:25	MDE
Iron - Total	< 2 @	mg/l	0.10	6010D	24 Jun 20 11:07	MDE
Manganese - Total	< 1 @	mg/l	0.05	6010D	24 Jun 20 11:07	MDE
Barium - Dissolved	< 2 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

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MEMBER
ACIL

Report Date: 30 Jun 20
Lab Number: 20-W1768
Work Order #: 82-1477
Account #: 007048
Date Sampled: 13 Jun 20 10:10
Date Received: 15 Jun 20 8:00
Sampled By: MVTL Field Services
PO #: 203046

Temp at Receipt: 4.2C

Jennifer Altendorf
Minnkota Power Cooperative
3401 24th St SW
Center ND 58530

Sample Description: Broom Creek

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Copper - Dissolved	< 1 @	mg/l	0.05	6010D	23 Jun 20 12:02	SZ
Molybdenum - Dissolved	< 2 @	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Strontium - Dissolved	45.2	mg/l	0.10	6010D	23 Jun 20 12:02	SZ
Arsenic - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Cadmium - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE
Chromium - Dissolved	< 0.04 @	mg/l	0.0020	6020B	15 Jun 20 16:05	MDE
Lead - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE
Selenium - Dissolved	0.1204	mg/l	0.0050	6020B	15 Jun 20 16:05	MDE
Silver - Dissolved	< 0.01 @	mg/l	0.0005	6020B	15 Jun 20 16:05	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

APPENDIX B

FRESHWATER WELL FLUID SAMPLING

W395 (Fox Hills) – November 2021

MINNESOTA VALLEY TESTING LABORATORIES, INC.

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MEMBER ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W395

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	10 Nov 21	AC
pH	* 8.2	units	N/A	SM4500-H+-B-11	10 Nov 21 17:00	AC
Conductivity (EC)	2904	umhos/cm	N/A	SM2510B-11	10 Nov 21 17:00	AC
Total Alkalinity	1030	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Bicarbonate	1030	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	10 Nov 21 17:00	AC
Tot Dis Solids(Summation)	1740	mg/l	12.5	SM1030-F	18 Nov 21 14:34	Calculated
Cation Summation	28.7	meq/L	NA	SM1030-F	15 Nov 21 10:55	Calculated
Anion Summation	33.1	meq/L	NA	SM1030-F	18 Nov 21 14:34	Calculated
Percent Error	-7.12	%	NA	SM1030-F	18 Nov 21 14:34	Calculated
Bromide	3.20	mg/l	0.100	EPA 300.0	15 Nov 21 21:03	RMV
Total Organic Carbon	1.2	mg/l	0.5	SM5310C-11	16 Nov 21 21:44	NAS
Dissolved Organic Carbon	1.2	mg/l	0.5	SM5310C-96	16 Nov 21 21:44	NAS
Fluoride	2.31	mg/l	0.10	SM4500-F-C	10 Nov 21 17:00	AC
Sulfate	< 5	mg/l	5.00	ASTM D516-11	15 Nov 21 14:26	SD
Chloride	442	mg/l	2.0	SM4500-Cl-E-11	10 Nov 21 10:55	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 14:34	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	10 Nov 21 14:18	SD
Phosphorus as P - Total	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	< 0.2	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 13:07	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	11 Nov 21 14:29	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

Continued…

W395 (Fox Hills) – November 2021 (continued)

MINNESOTA VALLEY TESTING LABORATORIES, INC.

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MEMBER ACIL

Report Date: 26 Nov 21
Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

PO #: 25411

Temp at Receipt: 0.4C ROI

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: NDCS

Sample Description: NDCS-W395

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Total Dissolved Solids	1760	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA
Calcium - Total	4.9	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Magnesium - Total	1.8	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Sodium - Total	668	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Potassium - Total	3.1	mg/l	1.0	6010D	11 Nov 21 14:00	SZ
Lithium - Total	0.099	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Iron - Total	1.86	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Silicon - Total	5.20	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.23	mg/l	0.10	6010D	12 Nov 21 11:33	MDE
Zinc - Total	0.60	mg/l	0.05	6010D	12 Nov 21 11:33	MDE
Boron - Total	2.79	mg/l	0.10	6010D	17 Nov 21 9:08	SZ
Calcium - Dissolved	4.9	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Magnesium - Dissolved	1.7	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Sodium - Dissolved	647	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Potassium - Dissolved	3.4	mg/l	1.0	6010D	11 Nov 21 16:00	SZ
Lithium - Dissolved	0.106	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Iron - Dissolved	0.35	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Silicon - Dissolved	5.25	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.25	mg/l	0.10	6010D	15 Nov 21 10:55	MDE
Zinc - Dissolved	0.09	mg/l	0.05	6010D	15 Nov 21 10:55	MDE
Boron - Dissolved	2.87	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 11:07	MDE

RL = Method Reporting Limit

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CERTIFICATION: ND # ND-00016

Continued…

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MEMBER ACIL

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 26 Nov 21
Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W395

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Barium - Total	0.1742	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Copper - Total	0.0075	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Lead - Total	0.0049	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Manganese - Total	0.0167	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Molybdenum - Total	0.0045	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 11:07	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 11:07	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 11:07	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.1580	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
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! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

Continued…

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MEMBER ACIL

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Report Date: 26 Nov 21
Lab Number: 21-W4373
Work Order #: 82-3114
Account #: 007033
Date Sampled: 9 Nov 21 16:30
Date Received: 10 Nov 21 7:24
Sampled By: Client

Project Name: NDCS

PO #: 25411

Sample Description: NDCS-W395

Temp at Receipt: 0.4C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Manganese - Dissolved	0.0094	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Molybdenum - Dissolved	0.0043	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

Bromide was analyzed at MVTL, New Ulm, MN.
ND Certification #:R-040

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

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@ = Due to sample matrix
! = Due to sample quantity
= Due to concentration of other analytes
+ = Due to internal standard response

CERTIFICATION: ND # ND-00016

W478 (Tongue River) – November 2021

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MEMBER
ACIL

Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Metal Digestion				EPA 200.2	11 Nov 21	RAA
pH	* 8.2	units	N/A	SM4500-H+-B-11	11 Nov 21 18:00	RAA
Conductivity (EC)	2167	umhos/cm	N/A	SM2510B-11	11 Nov 21 18:00	RAA
Total Alkalinity	1230	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Phenolphthalein Alk	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Bicarbonate	1230	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Carbonate	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Hydroxide	< 20	mg/l CaCO3	20	SM2320B-11	11 Nov 21 18:00	RAA
Tot Dis Solids(Summation)	1370	mg/l	12.5	SM1030-F	19 Nov 21 15:13	Calculated
Cation Summation	25.1	meq/L	NA	SM1030-F	16 Nov 21 12:36	Calculated
Anion Summation	25.9	meq/L	NA	SM1030-F	19 Nov 21 15:13	Calculated
Percent Error	-1.66	%	NA	SM1030-F	19 Nov 21 15:13	Calculated
Bromide	< 0.5 @	mg/l	0.100	EPA 300.0	16 Nov 21 0:11	RMV
Total Organic Carbon	7.1	mg/l	0.5	SM5310C-11	16 Nov 21 23:56	NAS
Dissolved Organic Carbon	7.2	mg/l	0.5	SM5310C-96	16 Nov 21 23:56	NAS
Fluoride	1.62	mg/l	0.10	SM4500-F-C	11 Nov 21 18:00	RAA
Sulfate	34.3	mg/l	5.00	ASTM D516-11	19 Nov 21 15:13	SD
Chloride	20.9	mg/l	2.0	SM4500-Cl-E-11	17 Nov 21 13:30	SD
Nitrate-Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	18 Nov 21 15:33	SD
Nitrite as N	< 0.2	mg/l	0.20	EPA 353.2	11 Nov 21 15:01	SD
Phosphorus as P - Total	0.23	mg/l	0.20	EPA 365.1	19 Nov 21 8:56	SD
Phosphorus as P-Dissolved	0.24	mg/l	0.20	EPA 365.1	19 Nov 21 10:05	SD
Mercury - Total	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Mercury - Dissolved	< 0.0002	mg/l	0.0002	EPA 245.1	18 Nov 21 12:33	MDE
Total Dissolved Solids	1420	mg/l	10	USGS I1750-85	12 Nov 21 9:25	RAA

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The reporting limit was elevated for any analyte requiring a dilution as coded below:
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CERTIFICATION: ND # ND-00016

Continued…

W478 (Tongue River) – November 2021 (continued)

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MEMBER ACIL

Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Calcium - Total	2.8	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Magnesium - Total	1.5	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Sodium - Total	572	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Potassium - Total	3.0	mg/l	1.0	6010D	16 Nov 21 12:36	MDE
Lithium - Total	0.076	mg/l	0.020	6010D	16 Nov 21 9:32	SZ
Aluminum - Total	< 0.1	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Iron - Total	0.43	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Silicon - Total	4.12	mg/l	0.10	6010D	16 Nov 21 14:55	SZ
Strontium - Total	0.14	mg/l	0.10	6010D	12 Nov 21 15:33	MDE
Zinc - Total	0.06	mg/l	0.05	6010D	12 Nov 21 15:33	MDE
Boron - Total	0.56	mg/l	0.10	6010D	17 Nov 21 12:08	SZ
Calcium - Dissolved	2.7	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Magnesium - Dissolved	1.5	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Sodium - Dissolved	568	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Potassium - Dissolved	3.5	mg/l	1.0	6010D	16 Nov 21 10:36	MDE
Lithium - Dissolved	0.076	mg/l	0.020	6010D	16 Nov 21 11:32	SZ
Aluminum - Dissolved	< 0.1	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Iron - Dissolved	0.48	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Silicon - Dissolved	4.23	mg/l	0.10	6010D	16 Nov 21 15:55	SZ
Strontium - Dissolved	0.14	mg/l	0.10	6010D	15 Nov 21 12:55	MDE
Zinc - Dissolved	0.06	mg/l	0.05	6010D	15 Nov 21 12:55	MDE
Boron - Dissolved	0.58	mg/l	0.10	6010D	17 Nov 21 14:08	SZ
Antimony - Total	< 0.001	mg/l	0.0010	6020B	16 Nov 21 13:21	MDE
Arsenic - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Barium - Total	0.0912	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE

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CERTIFICATION: ND # ND-00016

Continued…

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MEMBER ACIL

Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Beryllium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Cadmium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Chromium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Cobalt - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Copper - Total	0.0053	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Lead - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Manganese - Total	0.0048	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Molybdenum - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Nickel - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Selenium - Total	< 0.005	mg/l	0.0050	6020B	16 Nov 21 13:21	MDE
Silver - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Thallium - Total	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 13:21	MDE
Vanadium - Total	< 0.002	mg/l	0.0020	6020B	16 Nov 21 13:21	MDE
Antimony - Dissolved	< 0.001	mg/l	0.0010	6020B	16 Nov 21 14:31	MDE
Arsenic - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Barium - Dissolved	0.0913	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Beryllium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 16:48	MDE
Cadmium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Chromium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Cobalt - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Copper - Dissolved	0.0044	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Lead - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Manganese - Dissolved	0.0053	mg/l	0.0020	6020B	17 Nov 21 15:06	MDE
Molybdenum - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE
Nickel - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix # = Due to concentration of other analytes
! = Due to sample quantity + = Due to internal standard response

CERTIFICATION: ND # ND-00016

Continued…

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Report Date: 7 Dec 21
Lab Number: 21-W4441
Work Order #: 82-3150
Account #: 007033
Date Sampled: 10 Nov 21 11:00
Date Received: 11 Nov 21 7:18
Sampled By: Client

Barry Botnen
UND-Energy & Environmental
15 N. 23rd St.
Grand Forks ND 58201

Project Name: North Dakota Carbon Safe
Sample Description: NDCS-W478

Temp at Receipt: 1.2C ROI

	As Received Result		Method RL	Method Reference	Date Analyzed	Analyst
Selenium - Dissolved	< 0.005	mg/l	0.0050	6020B	16 Nov 21 14:31	MDE
Silver - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Thallium - Dissolved	< 0.0005	mg/l	0.0005	6020B	16 Nov 21 14:31	MDE
Vanadium - Dissolved	< 0.002	mg/l	0.0020	6020B	16 Nov 21 14:31	MDE

* Holding time exceeded

Approved by: Claudette K. Carroll

Claudette K. Carroll, Laboratory Manager, Bismarck, ND

RL = Method Reporting Limit

The reporting limit was elevated for any analyte requiring a dilution as coded below:
@ = Due to sample matrix   # = Due to concentration of other analytes
! = Due to sample quantity   + = Due to internal standard response

CERTIFICATION: ND # ND-00016

W395 (Fox Hills) – March 2022

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	456004	**Date Collected:**	03/30/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	03/31/2022 07:18	**Collector:**	Client
Temp @ Receipt (C):	1.4	**Received on Ice:**	Yes		

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**32.9**	meq/L		1	05/16/2022 14:13	05/16/2022 14:13	CW		
TDS - Summation	**1870**	mg/L	12.5	1	05/16/2022 14:13	05/16/2022 14:13	CW		
Anion Summation	**32.2**	meq/L		1	05/16/2022 14:13	05/16/2022 14:13	CW		
Percent Difference	**1.0**	%		1	05/16/2022 14:13	05/16/2022 14:13	CW		

Inorganic Chemistry

Method: ASTM D516-11

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	<5	mg/L	5	1	04/06/2022 13:31	04/06/2022 13:31	SRD	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	**3.82**	mg/L	0.500	5	04/12/2022 12:39	04/12/2022 12:39	RMV	MA,NDA	*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	03/31/2022 12:19	03/31/2022 12:19	SRD	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	03/31/2022 11:29	03/31/2022 11:29	SRD	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	<0.2	mg/L	0.2	1	03/31/2022 12:15	03/31/2022 15:10	SRD	MA,NDA	
Phosphorus as P, Dissolved	<0.2	mg/L	0.2	1	03/31/2022 12:15	03/31/2022 15:19	SRD		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**1.3**	mg/L	1	1	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	
Total Organic Carbon	**1.2**	mg/L	0.5	1	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	456004	**Date Collected:**	03/30/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	03/31/2022 07:18	**Collector:**	Client
Temp @ Receipt (C):	1.4	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**902**	mg/L as CaCO3	20.5	1	03/31/2022 19:58	03/31/2022 19:58	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 19:58	03/31/2022 19:58	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 19:58	03/31/2022 19:58	RAA		
Bicarbonate	**902**	mg/L as CaCO3	20.5	1	03/31/2022 19:58	03/31/2022 19:58	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 19:58	03/31/2022 19:58	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2913**	umhos/cm	1	1	03/31/2022 19:58	03/31/2022 19:58	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.4**	units	0.1	1	03/31/2022 19:58	03/31/2022 19:58	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**501**	mg/L	10.0	5	04/05/2022 10:30	04/05/2022 10:30	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**2.47**	mg/L	0.1	1	03/31/2022 19:58	03/31/2022 19:58	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1780**	mg/L	10	1	04/01/2022 09:11	04/01/2022 09:11	RAA	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA, SDA	
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID: 456004 **Date Collected:** 03/30/2022 12:00 **Matrix:** Groundwater
Sample ID: NDCS-W395 **Date Received:** 03/31/2022 07:18 **Collector:** Client

Temp @ Receipt (C): 1.4 **Received on Ice:** Yes

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 10:46	SLZ	MA,NDA	
Boron	**3.10**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 10:53	MDE	MA,NDA	
Calcium	**4.68**	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:26	MDE	MA,NDA	
Magnesium	**1.15**	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:26	MDE	MA,NDA	
Sodium	**815**	mg/L	5	5	03/31/2022 17:20	04/06/2022 14:17	MDE	MA,NDA	
Potassium	**3.29**	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:26	MDE	MA,NDA	
Iron	**0.19**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 10:46	SLZ	MA,NDA	
Calcium, Dissolved	**4.68**	mg/L	1	1	04/05/2022 08:37	04/06/2022 13:43	MDE	MA,NDA	
Magnesium, Dissolved	**1.16**	mg/L	1	1	04/05/2022 08:37	04/06/2022 13:43	MDE	MA,NDA	
Sodium, Dissolved	**747**	mg/L	5	5	04/05/2022 08:37	04/06/2022 15:30	MDE	MA,NDA	
Potassium, Dissolved	**3.59**	mg/L	1	1	04/05/2022 08:37	04/06/2022 13:43	MDE	MA,NDA	
Strontium	**0.17**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 10:46	SLZ	MA,NDA	
Zinc	**0.17**	mg/L	0.05	1	03/31/2022 17:20	04/05/2022 10:46	SLZ	MA,NDA	
Lithium	**0.0964**	mg/L	0.02	1	03/31/2022 17:20	04/07/2022 09:20	SLZ	NDA	
Silicon	**5.60**	mg/L	0.1	1	03/31/2022 17:20	04/07/2022 15:00	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 13:13	SLZ	MA,NDA	
Boron, Dissolved	**3.07**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 12:15	MDE	MA,NDA	
Iron, Dissolved	**0.16**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 13:13	SLZ	MA,NDA	
Strontium, Dissolved	**0.16**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 13:13	SLZ	MA,NDA	
Zinc, Dissolved	**0.126**	mg/L	0.05	1	04/05/2022 08:37	04/05/2022 13:13	SLZ	MA,NDA	
Lithium, Dissolved	**0.0979**	mg/L	0.02	1	04/05/2022 08:37	04/07/2022 11:28	SLZ	NDA	
Silicon, Dissolved	**5.24**	mg/L	0.1	1	04/05/2022 08:37	04/07/2022 15:53	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Silver, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	05/11/2022 12:53	CC	MA,NDA	

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	456004	**Date Collected:**	03/30/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	03/31/2022 07:18	**Collector:**	Client
Temp @ Receipt (C):	1.4	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Antimony, Dissolved	<0.001	mg/L	0.001	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Barium	**0.1166**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Barium, Dissolved	**0.1073**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Beryllium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/07/2022 10:39	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Copper	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Copper, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Lead	**0.0005**	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Lead, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Manganese	**0.0030**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Manganese, Dissolved	**0.0022**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Molybdenum	**0.0041**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	

Report Date: Tuesday, May 17, 2022 2:11:28 PM

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	456004	**Date Collected:**	03/30/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	03/31/2022 07:18	**Collector:**	Client
Temp @ Receipt (C):	1.4	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Molybdenum, Dissolved	**0.0041**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Nickel	**0.0028**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 16:34	MDE	MA,NDA	
Selenium	<0.005	mg/L	0.005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	
Vanadium	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 11:28	MDE	MA,NDA	

Report Date: Tuesday, May 17, 2022 2:11:28 PM

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W478 (Tongue River) – March 2022

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	474003	**Date Collected:**	03/31/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-478	**Date Received:**	03/31/2022 15:09	**Collector:**	Client

Temp @ Receipt (C): 5.8 **Received on Ice:** Yes

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**25.6**	meq/L		1	05/17/2022 12:51	05/17/2022 12:51	CW		
TDS - Summation	**1300**	mg/L	12.5	1	05/17/2022 12:51	05/17/2022 12:51	CW		
Anion Summation	**23.8**	meq/L		1	05/17/2022 12:51	05/17/2022 12:51	CW		
Percent Difference	**3.7**	%		1	05/17/2022 12:51	05/17/2022 12:51	CW		

Inorganic Chemistry

Method: ASTM D516-11

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	**31.0**	mg/L	5	1	04/06/2022 13:54	04/06/2022 13:54	SRD	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	<0.500	mg/L	0.500	5	04/13/2022 08:20	04/13/2022 08:20	RMV	MA,NDA	*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	03/31/2022 16:35	03/31/2022 16:35	SRD	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	04/07/2022 10:51	04/07/2022 10:51	SRD	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	**0.22**	mg/L	0.2	1	04/07/2022 10:38	04/08/2022 09:52	SRD	MA,NDA	
Phosphorus as P, Dissolved	**0.22**	mg/L	0.2	1	04/07/2022 10:38	04/08/2022 11:40	SRD		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**10.1**	mg/L	1	2	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	
Total Organic Carbon	**9.7**	mg/L	0.5	2	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	474003	**Date Collected:**	03/31/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-478	**Date Received:**	03/31/2022 15:09	**Collector:**	Client
Temp @ Receipt (C):	5.8	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**1129**	mg/L as CaCO3	20.5	1	04/01/2022 01:25	04/01/2022 01:25	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	04/01/2022 01:25	04/01/2022 01:25	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	04/01/2022 01:25	04/01/2022 01:25	RAA		
Bicarbonate	**1129**	mg/L as CaCO3	20.5	1	04/01/2022 01:25	04/01/2022 01:25	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	04/01/2022 01:25	04/01/2022 01:25	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2102**	umhos/cm	1	1	04/01/2022 01:25	04/01/2022 01:25	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.4**	units	0.1	1	04/01/2022 01:25	04/01/2022 01:25	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**20.1**	mg/L	2.00	1	04/05/2022 10:45	04/05/2022 10:45	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**1.72**	mg/L	0.1	1	04/01/2022 01:25	04/01/2022 01:25	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1390**	mg/L	10	1	04/01/2022 09:12	04/01/2022 09:12	RAA	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA, SDA	
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA	

Report Date: Thursday, May 19, 2022 2:41:48 PM

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	474003	**Date Collected:**	03/31/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-478	**Date Received:**	03/31/2022 15:09	**Collector:**	Client
Temp @ Receipt (C):	5.8	**Received on Ice:**	Yes		

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 11:27	SLZ	MA,NDA	
Boron	**0.55**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 11:17	MDE	MA,NDA	
Calcium	**2.68**	mg/L	1	1	03/31/2022 17:20	04/06/2022 11:06	MDE	MA,NDA	
Magnesium	**1.53**	mg/L	1	1	03/31/2022 17:20	04/06/2022 11:06	MDE	MA,NDA	
Sodium	**564**	mg/L	1	1	03/31/2022 17:20	04/06/2022 11:06	MDE	MA,NDA	
Potassium	**3.22**	mg/L	1	1	03/31/2022 17:20	04/06/2022 11:06	MDE	MA,NDA	
Iron	**0.34**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 11:27	SLZ	MA,NDA	
Calcium, Dissolved	**2.86**	mg/L	1	1	04/05/2022 08:37	04/06/2022 12:04	MDE	MA,NDA	
Magnesium, Dissolved	**1.59**	mg/L	1	1	04/05/2022 08:37	04/06/2022 12:04	MDE	MA,NDA	
Sodium, Dissolved	**580**	mg/L	1	1	04/05/2022 08:37	04/06/2022 12:04	MDE	MA,NDA	
Potassium, Dissolved	**3.83**	mg/L	1	1	04/05/2022 08:37	04/06/2022 12:04	MDE	MA,NDA	
Strontium	**0.12**	mg/L	0.1	1	03/31/2022 17:20	04/05/2022 11:27	SLZ	MA,NDA	
Zinc	**0.06**	mg/L	0.05	1	03/31/2022 17:20	04/05/2022 11:27	SLZ	MA,NDA	
Lithium	**0.0608**	mg/L	0.02	1	03/31/2022 17:20	04/07/2022 09:43	SLZ	NDA	
Silicon	**3.83**	mg/L	0.1	1	03/31/2022 17:20	04/07/2022 15:23	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 12:48	SLZ	MA,NDA	
Boron, Dissolved	**0.56**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 11:56	MDE	MA,NDA	
Iron, Dissolved	**0.33**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 12:48	SLZ	MA,NDA	
Strontium, Dissolved	**0.12**	mg/L	0.1	1	04/05/2022 08:37	04/05/2022 12:48	SLZ	MA,NDA	
Zinc, Dissolved	**0.0617**	mg/L	0.05	1	04/05/2022 08:37	04/05/2022 12:48	SLZ	MA,NDA	
Lithium, Dissolved	**0.0576**	mg/L	0.02	1	04/05/2022 08:37	04/07/2022 11:08	SLZ	NDA	
Silicon, Dissolved	**3.89**	mg/L	0.1	1	04/05/2022 08:37	04/07/2022 16:13	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Lead, Dissolved	**0.0008**	mg/L	0.0005	5	04/05/2022 08:37	05/11/2022 13:00	CC	MA,NDA	

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www.MVTL.com

Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	474003	Date Collected:	03/31/2022 10:00	Matrix:	Groundwater
Sample ID:	NDCS-478	Date Received:	03/31/2022 15:09	Collector:	Client
Temp @ Receipt (C):	5.8	Received on Ice:	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Antimony, Dissolved	<0.001	mg/L	0.001	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Silver, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Barium	**0.0874**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Barium, Dissolved	**0.0896**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Beryllium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/07/2022 16:20	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Copper	**0.0253**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Copper, Dissolved	**0.0020**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Lead	**0.0008**	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Manganese	**0.0054**	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Manganese, Dissolved	**0.0050**	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Molybdenum	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	

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www.MVTL.com

Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	474003	**Date Collected:**	03/31/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-478	**Date Received:**	03/31/2022 15:09	**Collector:**	Client
Temp @ Receipt (C):	5.8	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Molybdenum, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Nickel	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	04/05/2022 08:37	04/06/2022 17:29	MDE	MA,NDA	
Selenium	<0.005	mg/L	0.005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	
Vanadium	<0.002	mg/L	0.002	5	03/31/2022 17:20	04/19/2022 12:30	MDE	MA,NDA	

Report Date: Thursday, May 19, 2022 2:41:48 PM

W395 (Fox Hills) – May 2022

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1304002	**Date Collected:**	05/26/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	05/27/2022 07:30	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	2.8	**Received on Ice:**	Yes		

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**29.6**	meq/L		1	07/01/2022 08:42	07/01/2022 08:42	CW		
TDS - Summation	**1790**	mg/L	12.5	1	07/01/2022 08:42	07/01/2022 08:42	CW		
Anion Summation	**32.1**	meq/L		1	07/01/2022 08:42	07/01/2022 08:42	CW		
Percent Difference	**-4.11**	%		1	07/01/2022 08:42	07/01/2022 08:42	CW		

Inorganic Chemistry

Method: ASTM D516-11

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	<5	mg/L	5	1	06/01/2022 15:27	06/01/2022 15:27	EJV	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	**2.74**	mg/L	0.500	5	06/02/2022 12:10	06/02/2022 12:10	MDH	MA,NDA	*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	05/27/2022 14:56	05/27/2022 14:56	EMS	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	06/02/2022 08:34	06/02/2022 08:34	EJV	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	<0.2	mg/L	0.2	1	06/02/2022 11:46	06/03/2022 10:09	EJV	MA,NDA	*
Phosphorus as P, Dissolved	<0.2	mg/L	0.2	1	06/02/2022 14:03	06/03/2022 10:28	EJV		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**1.5**	mg/L	1	1	05/27/2022 09:30	05/27/2022 09:30	NS	MA,NDA	
Total Organic Carbon	**1.5**	mg/L	0.5	1	05/27/2022 09:30	05/27/2022 09:30	NS	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1304002	**Date Collected:**	05/26/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	05/27/2022 07:30	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	2.8	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**1072**	mg/L as CaCO3	20.5	1	06/01/2022 01:03	06/01/2022 01:03	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	06/01/2022 01:03	06/01/2022 01:03	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	06/01/2022 01:03	06/01/2022 01:03	RAA		
Bicarbonate	**1072**	mg/L as CaCO3	20.5	1	06/01/2022 01:03	06/01/2022 01:03	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	06/01/2022 01:03	06/01/2022 01:03	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2818**	umhos/cm	1	1	06/01/2022 01:03	06/01/2022 01:03	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.5**	units	0.1	1	06/01/2022 10:10	06/01/2022 10:10	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**378**	mg/L	10	5	05/31/2022 11:56	05/31/2022 11:56	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**1.88**	mg/L	0.1	1	06/01/2022 01:03	06/01/2022 01:03	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1730**	mg/L	10	1	05/27/2022 16:31	05/27/2022 16:31	AMC	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	06/13/2022 14:15	06/14/2022 13:02	AMC	MA,NDA, SDA	
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	06/04/2022 09:15	06/07/2022 09:48	AMC	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1304002	Date Collected:	05/26/2022 10:00	Matrix:	Groundwater
Sample ID:	NDCS-W395	Date Received:	05/27/2022 07:30	Collector:	MVTL Field Service
Temp @ Receipt (C):	2.8	Received on Ice:	Yes		

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 12:14	MDE	MA,NDA	
Boron	**2.60**	mg/L	0.1	1	05/27/2022 17:01	06/20/2022 14:26	SLZ	MA,NDA	
Calcium	**4.27**	mg/L	1	1	05/27/2022 17:01	06/10/2022 10:41	MDE	MA,NDA	
Magnesium	**1.31**	mg/L	1	1	05/27/2022 17:01	06/10/2022 10:41	MDE	MA,NDA	
Sodium	**763**	mg/L	5	5	05/27/2022 17:01	06/10/2022 11:47	MDE	MA,NDA	
Potassium	**2.90**	mg/L	1	1	05/27/2022 17:01	06/10/2022 10:41	MDE	MA,NDA	
Iron	**0.29**	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 12:14	MDE	MA,NDA	
Calcium, Dissolved	**4.19**	mg/L	1	1	06/01/2022 18:20	06/17/2022 13:57	SLZ	MA,NDA	
Magnesium, Dissolved	**1.26**	mg/L	1	1	06/01/2022 18:20	06/17/2022 13:57	SLZ	MA,NDA	
Sodium, Dissolved	**671**	mg/L	1	1	06/01/2022 18:20	06/17/2022 13:57	SLZ	MA,NDA	
Potassium, Dissolved	**2.91**	mg/L	1	1	06/01/2022 18:20	06/17/2022 13:57	SLZ	MA,NDA	
Strontium	**0.15**	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 12:14	MDE	MA,NDA	
Zinc	**0.39**	mg/L	0.05	1	05/27/2022 17:01	06/02/2022 12:14	MDE	MA,NDA	
Lithium	**0.0871**	mg/L	0.02	1	05/27/2022 17:01	06/15/2022 09:45	SLZ	NDA	
Silicon	**4.90**	mg/L	0.1	1	05/27/2022 17:01	06/16/2022 10:00	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:26	MDE	MA,NDA	
Boron, Dissolved	**2.52**	mg/L	0.1	1	06/01/2022 18:20	06/20/2022 17:17	SLZ	MA,NDA	
Iron, Dissolved	**0.16**	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:26	MDE	MA,NDA	
Strontium, Dissolved	**0.14**	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:26	MDE	MA,NDA	
Zinc, Dissolved	**0.09**	mg/L	0.05	1	06/01/2022 18:20	06/02/2022 09:26	MDE	MA,NDA	
Lithium, Dissolved	**0.0854**	mg/L	0.02	1	06/01/2022 18:20	06/15/2022 11:14	SLZ	NDA	
Silicon, Dissolved	**4.78**	mg/L	0.1	1	06/01/2022 18:20	06/16/2022 12:39	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony	<0.001	mg/L	0.001	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	1304002	**Date Collected:**	05/26/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	05/27/2022 07:30	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	2.8	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony, Dissolved	<0.001	mg/L	0.001	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Barium	**0.1034**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Barium, Dissolved	**0.0910**	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Beryllium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/28/2022 14:41	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Copper	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Copper, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Lead	**0.0016**	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Lead, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Manganese	**0.0039**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Manganese, Dissolved	**0.0028**	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Molybdenum	**0.0034**	mg/L	0.002	5	05/27/2022 17:01	06/03/2022 12:01	MDE	MA,NDA	
Molybdenum, Dissolved	<0.005	mg/L	0.005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Nickel	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Silver, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1304002	**Date Collected:**	05/26/2022 10:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	05/27/2022 07:30	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	2.8	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Selenium	<0.005	mg/L	0.005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	
Vanadium	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 18:33	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 18:52	MDE	MA,NDA	

Report Date: Saturday, July 9, 2022 12:55:24 PM

W478 (Tongue River) – May 2022

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1318005	**Date Collected:**	05/27/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	05/27/2022 13:45	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.3	**Received on Ice:**	Yes		

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**23.7**	meq/L		1	07/13/2022 09:58	07/13/2022 09:58	CW		
TDS - Summation	**1300**	mg/L	12.5	1	07/13/2022 09:58	07/13/2022 09:58	CW		
Anion Summation	**24.0**	meq/L		1	07/13/2022 09:58	07/13/2022 09:58	CW		
Percent Difference	**-0.47**	%		1	07/13/2022 09:58	07/13/2022 09:58	CW		

Inorganic Chemistry

Method: ASTM D516-11

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	**30.3**	mg/L	5	1	06/08/2022 12:13	06/08/2022 12:13	EJV	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	**0.279**	mg/L	0.100	1	06/02/2022 17:03	06/02/2022 17:03	MDH	MA,NDA	

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	05/27/2022 15:29	05/27/2022 15:29	EMS	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	06/02/2022 08:51	06/02/2022 08:51	EJV	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	**0.24**	mg/L	0.2	1	06/02/2022 11:46	06/03/2022 10:19	EJV	MA,NDA	
Phosphorus as P, Dissolved	**0.24**	mg/L	0.2	1	06/02/2022 14:03	06/03/2022 10:28	EJV		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**7.2**	mg/L	1	1	06/02/2022 09:30	06/02/2022 09:30	NS	MA,NDA	
Total Organic Carbon	**7.4**	mg/L	0.5	1	06/02/2022 09:30	06/02/2022 09:30	NS	MA,NDA	

Report Date: Wednesday, July 13, 2022 10:24:16 AM

Corrected 1318 - 671075

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1318005	**Date Collected:**	05/27/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	05/27/2022 13:45	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.3	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**1136**	mg/L as CaCO3	20.5	1	06/01/2022 23:50	06/01/2022 23:50	RAA	MA,NDA	*
Alkalinity, Phenolphthalein	**29**	mg/L as CaCO3	20.5	1	06/01/2022 23:50	06/01/2022 23:50	RAA		
Carbonate	**59**	mg/L as CaCO3	20.5	1	06/01/2022 23:50	06/01/2022 23:50	RAA		
Bicarbonate	**1078**	mg/L as CaCO3	20.5	1	06/01/2022 23:50	06/01/2022 23:50	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	06/01/2022 23:50	06/01/2022 23:50	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2156**	umhos/cm	1	1	06/01/2022 23:50	06/01/2022 23:50	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.6**	units	0.1	1	06/01/2022 23:50	06/01/2022 23:50	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**21.0**	mg/L	2	1	05/31/2022 12:22	05/31/2022 12:22	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**1.81**	mg/L	0.1	1	06/01/2022 23:50	06/01/2022 23:50	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1350**	mg/L	10	1	06/02/2022 14:00	06/02/2022 14:00	AMC	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	06/13/2022 14:15	06/14/2022 13:02	AMC	MA,NDA, SDA	
Mercury, Dissolved	**0.0005**	mg/L	0.0002	1	07/06/2022 14:40	07/07/2022 09:01	AMC	MA,NDA	

Report Date: Wednesday, July 13, 2022 10:24:16 AM Corrected 1318 - 671075

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1318005	**Date Collected:**	05/27/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	05/27/2022 13:45	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.3	**Received on Ice:**	Yes		

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 13:36	MDE	MA,NDA	
Boron	**0.53**	mg/L	0.1	1	05/27/2022 17:01	06/20/2022 15:21	SLZ	MA,NDA	
Calcium	**2.40**	mg/L	1	1	05/27/2022 17:01	06/10/2022 11:44	MDE	MA,NDA	
Magnesium	**1.49**	mg/L	1	1	05/27/2022 17:01	06/10/2022 11:44	MDE	MA,NDA	
Sodium	**561**	mg/L	1	1	05/27/2022 17:01	06/10/2022 11:44	MDE	MA,NDA	
Potassium	**3.12**	mg/L	1	1	05/27/2022 17:01	06/10/2022 11:44	MDE	MA,NDA	
Iron	**0.57**	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 13:36	MDE	MA,NDA	
Calcium, Dissolved	**2.69**	mg/L	1	1	06/01/2022 18:20	06/17/2022 14:21	SLZ	MA,NDA	
Magnesium, Dissolved	**1.67**	mg/L	1	1	06/01/2022 18:20	06/17/2022 14:21	SLZ	MA,NDA	
Sodium, Dissolved	**537**	mg/L	1	1	06/01/2022 18:20	06/17/2022 14:21	SLZ	MA,NDA	
Potassium, Dissolved	**3.10**	mg/L	1	1	06/01/2022 18:20	06/17/2022 14:21	SLZ	MA,NDA	
Strontium	**0.11**	mg/L	0.1	1	05/27/2022 17:01	06/02/2022 13:36	MDE	MA,NDA	
Zinc	**0.11**	mg/L	0.05	1	05/27/2022 17:01	06/02/2022 13:36	MDE	MA,NDA	
Lithium	**0.0594**	mg/L	0.02	1	05/27/2022 17:01	06/15/2022 10:28	SLZ	NDA	
Silicon	**3.38**	mg/L	0.1	1	05/27/2022 17:01	06/16/2022 10:33	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:40	MDE	MA,NDA	
Boron, Dissolved	**0.55**	mg/L	0.1	1	06/01/2022 18:20	06/20/2022 17:53	SLZ	MA,NDA	
Iron, Dissolved	**0.71**	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:40	MDE	MA,NDA	
Strontium, Dissolved	**0.12**	mg/L	0.1	1	06/01/2022 18:20	06/02/2022 09:40	MDE	MA,NDA	
Zinc, Dissolved	**0.09**	mg/L	0.05	1	06/01/2022 18:20	06/02/2022 09:40	MDE	MA,NDA	
Lithium, Dissolved	**0.0603**	mg/L	0.02	1	06/01/2022 18:20	06/15/2022 11:29	SLZ	NDA	
Silicon, Dissolved	**3.49**	mg/L	0.1	1	06/01/2022 18:20	06/16/2022 13:00	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony	<0.001	mg/L	0.001	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	

Report Date: Wednesday, July 13, 2022 10:24:16 AM Corrected 1318 - 671075

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1318005	**Date Collected:**	05/27/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	05/27/2022 13:45	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.3	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony, Dissolved	<0.001	mg/L	0.001	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Barium	**0.0880**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Barium, Dissolved	**0.0871**	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Beryllium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/28/2022 16:02	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Copper	**0.0104**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Copper, Dissolved	**0.0024**	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Lead	**0.0020**	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Lead, Dissolved	**0.0009**	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Manganese	**0.0091**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Manganese, Dissolved	**0.0093**	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Molybdenum	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/03/2022 14:54	MDE	MA,NDA	
Molybdenum, Dissolved	<0.005	mg/L	0.005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Nickel	<0.002	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Silver, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	

Report Date: Wednesday, July 13, 2022 10:24:16 AM   Corrected 1318 - 671075

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	1318005	**Date Collected:**	05/27/2022 12:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	05/27/2022 13:45	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.3	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Selenium	<0.005	mg/L	0.005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	
Vanadium	**0.0022**	mg/L	0.002	5	05/27/2022 17:01	06/01/2022 20:19	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	06/01/2022 18:20	06/13/2022 19:11	MDE	MA,NDA	

W395 (Fox Hills) – September 2022

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID: 3578001 **Date Collected:** 09/29/2022 10:30 **Matrix:** Groundwater
Sample ID: NDCS-W395 **Date Received:** 09/30/2022 08:00 **Collector:** MVTL Field Service

Temp @ Receipt (C): 1.2 **Received on Ice:** Yes

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**32.6**	meq/L		1	10/19/2022 15:59	10/19/2022 15:59	CW		
TDS - Summation	**1710**	mg/L	12.5	1	10/19/2022 15:59	10/19/2022 15:59	CW		
Anion Summation	**31.5**	meq/L		1	10/19/2022 15:59	10/19/2022 15:59	CW		
Percent Difference	**1.82**	%		1	10/19/2022 15:59	10/19/2022 15:59	CW		

Inorganic Chemistry

Method: ASTM D516-16

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	<5	mg/L	5	1	10/05/2022 12:28	10/05/2022 12:28	EJV	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	**3.34**	mg/L	0.500	5	10/19/2022 00:37	10/19/2022 00:37	RMV	MA,NDA	*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	09/30/2022 15:38	09/30/2022 15:38	EJV	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	10/06/2022 12:24	10/06/2022 12:24	EJV	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	**0.12**	mg/L	0.1	1	10/06/2022 15:39	10/10/2022 09:01	EJV	MA,NDA	
Phosphorus as P, Dissolved	**0.11**	mg/L	0.1	1	10/06/2022 15:40	10/10/2022 10:19	EJV		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**1.1**	mg/L	1	1	10/07/2022 09:36	10/07/2022 09:36	NS	MA,NDA	
Total Organic Carbon	**1.0**	mg/L	0.5	1	10/07/2022 09:36	10/07/2022 09:36	NS	MA,NDA	

Report Date: Saturday, October 29, 2022 1:13:12 PM

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	3578001	**Date Collected:**	09/29/2022 10:30	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	09/30/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**942**	mg/L as CaCO3	20.5	1	09/30/2022 19:46	09/30/2022 19:46	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	09/30/2022 19:46	09/30/2022 19:46	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	09/30/2022 19:46	09/30/2022 19:46	RAA		
Bicarbonate	**942**	mg/L as CaCO3	20.5	1	09/30/2022 19:46	09/30/2022 19:46	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	09/30/2022 19:46	09/30/2022 19:46	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2903**	umhos/cm	1	1	09/30/2022 19:46	09/30/2022 19:46	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.4**	units	0.1	1	09/30/2022 19:46	09/30/2022 19:46	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**446**	mg/L	10.0	5	10/03/2022 12:19	10/03/2022 12:19	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**2.29**	mg/L	0.1	1	09/30/2022 19:46	09/30/2022 19:46	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1720**	mg/L	10	1	10/03/2022 16:00	10/03/2022 16:00	RAA	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	10/18/2022 09:55	10/19/2022 09:00	AMC	MA,NDA, SDA	
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	10/06/2022 09:20	10/06/2022 12:13	AMC	MA,NDA	

Report Date: Saturday, October 29, 2022 1:13:12 PM

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www.MVTL.com

Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	3578001	**Date Collected:**	09/29/2022 10:30	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	09/30/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	09/30/2022 17:00	10/05/2022 10:56	SLZ	MA,NDA	
Boron	**3.20**	mg/L	0.1	1	09/30/2022 17:00	10/07/2022 11:11	MDE	MA,NDA	
Calcium	**4.41**	mg/L	1	1	09/30/2022 17:00	10/10/2022 12:26	SLZ	MA,NDA	
Iron	**0.30**	mg/L	0.1	1	09/30/2022 17:00	10/05/2022 10:56	SLZ	MA,NDA	
Potassium	**2.59**	mg/L	1	1	09/30/2022 17:00	10/10/2022 12:26	SLZ	MA,NDA	
Magnesium	**1.24**	mg/L	1	1	09/30/2022 17:00	10/10/2022 12:26	SLZ	MA,NDA	
Sodium	**686**	mg/L	1	1	09/30/2022 17:00	10/10/2022 12:26	SLZ	MA,NDA	
Strontium	**0.16**	mg/L	0.1	1	09/30/2022 17:00	10/05/2022 10:56	SLZ	MA,NDA	
Zinc	**0.28**	mg/L	0.05	1	09/30/2022 17:00	10/05/2022 10:56	SLZ	MA,NDA	
Lithium	**0.0801**	mg/L	0.02	1	09/30/2022 17:00	10/06/2022 10:36	SLZ	NDA	
Silicon	**4.71**	mg/L	0.1	1	09/30/2022 17:00	10/06/2022 15:10	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	10/03/2022 08:07	10/05/2022 11:53	SLZ	MA,NDA	
Boron, Dissolved	**3.00**	mg/L	1	10	10/03/2022 08:07	10/07/2022 15:49	MDE	MA,NDA	
Calcium, Dissolved	**4.40**	mg/L	1	1	10/03/2022 08:07	10/03/2022 13:32	SLZ	MA,NDA	
Iron, Dissolved	**0.23**	mg/L	0.1	1	10/03/2022 08:07	10/05/2022 11:53	SLZ	MA,NDA	
Potassium, Dissolved	**2.84**	mg/L	1	1	10/03/2022 08:07	10/03/2022 13:32	SLZ	MA,NDA	
Magnesium, Dissolved	**1.24**	mg/L	1	1	10/03/2022 08:07	10/03/2022 13:32	SLZ	MA,NDA	
Sodium, Dissolved	**742**	mg/L	10	5	10/03/2022 08:07	10/03/2022 14:51	SLZ	MA,NDA	
Strontium, Dissolved	**0.16**	mg/L	0.1	1	10/03/2022 08:07	10/05/2022 11:53	SLZ	MA,NDA	
Zinc, Dissolved	**0.10**	mg/L	0.05	1	10/03/2022 08:07	10/05/2022 11:53	SLZ	MA,NDA	
Lithium, Dissolved	**0.0815**	mg/L	0.02	1	10/03/2022 08:07	10/06/2022 10:56	SLZ	NDA	
Silicon, Dissolved	**4.63**	mg/L	0.1	1	10/03/2022 08:07	10/06/2022 15:33	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Beryllium	<0.0005	mg/L	0.0005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	3578001	**Date Collected:**	09/29/2022 10:30	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	09/30/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	10/03/2022 08:07	10/14/2022 12:19	MDE	MA,NDA	
Vanadium	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Manganese	**0.0036**	mg/L	0.002	5	09/30/2022 17:00	10/18/2022 10:21	CC	MA,NDA	
Manganese, Dissolved	**0.0042**	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Nickel	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Copper	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/18/2022 10:21	CC	MA,NDA	*
Copper, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	09/30/2022 17:00	10/18/2022 10:21	CC	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Selenium	<0.005	mg/L	0.005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Molybdenum	**0.0040**	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Molybdenum, Dissolved	**0.0042**	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Silver, Dissolved	<0.0005	mg/L	0.0005	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Antimony	<0.001	mg/L	0.001	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	3578001	**Date Collected:**	09/29/2022 10:30	**Matrix:**	Groundwater
Sample ID:	NDCS-W395	**Date Received:**	09/30/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony, Dissolved	<0.001	mg/L	0.001	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Barium	**0.1185**	mg/L	0.002	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Barium, Dissolved	**0.1058**	mg/L	0.002	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	
Lead	**0.0011**	mg/L	0.0005	5	09/30/2022 17:00	10/14/2022 17:27	MDE	MA,NDA	
Lead, Dissolved	<0.0005	mg/L	0.0005	5	10/03/2022 08:07	10/04/2022 11:09	MDE	MA,NDA	

Report Date: Saturday, October 29, 2022 1:13:12 PM

W478 (Tongue River) – September 2022

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	3561006	**Date Collected:**	09/28/2022 17:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	09/29/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Calculated

Method: SM1030F

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	**25.4**	meq/L		1	10/19/2022 16:28	10/19/2022 16:28	CW		
TDS - Summation	**1390**	mg/L	12.5	1	10/19/2022 16:28	10/19/2022 16:28	CW		
Anion Summation	**26.0**	meq/L		1	10/19/2022 16:28	10/19/2022 16:28	CW		
Percent Difference	**-1.04**	%		1	10/19/2022 16:28	10/19/2022 16:28	CW		

Inorganic Chemistry

Method: ASTM D516-16

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	**34.0**	mg/L	5	1	10/05/2022 11:01	10/05/2022 11:01	EJV	MA,NDA	

Method: EPA 300.0

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Bromide	<0.500	mg/L	0.500	5	10/18/2022 22:52	10/18/2022 22:52	RMV	MA,NDA	*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrite as N	<0.2	mg/L	0.2	1	09/29/2022 16:32	09/29/2022 16:32	EJV	MA,NDA, SDA	
Nitrate + Nitrite as N	<0.2	mg/L	0.2	1	10/06/2022 12:06	10/06/2022 12:06	EJV	MA,NDA	

Method: EPA 365.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Phosphorus as P	**0.22**	mg/L	0.1	1	10/06/2022 15:39	10/10/2022 08:47	EJV	MA,NDA	
Phosphorus as P, Dissolved	**0.21**	mg/L	0.1	1	10/06/2022 15:40	10/10/2022 10:18	EJV		

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Dissolved Organic Carbon	**7.0**	mg/L	2	2	10/07/2022 09:36	10/07/2022 09:36	NS	MA,NDA	
Total Organic Carbon	**7.1**	mg/L	1	2	10/07/2022 09:36	10/07/2022 09:36	NS	MA,NDA	

Report Date: Saturday, October 29, 2022 12:10:07 PM

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	3561006	**Date Collected:**	09/28/2022 17:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	09/29/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Inorganic Chemistry

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	**1234**	mg/L as CaCO3	20.5	1	09/29/2022 23:55	09/29/2022 23:55	RAA	MA,NDA	*
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	09/29/2022 23:55	09/29/2022 23:55	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	09/29/2022 23:55	09/29/2022 23:55	RAA		
Bicarbonate	**1234**	mg/L as CaCO3	20.5	1	09/29/2022 23:55	09/29/2022 23:55	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	09/29/2022 23:55	09/29/2022 23:55	RAA		

Method: SM2510 B-2011 EC

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	**2177**	umhos/cm	1	1	09/29/2022 23:55	09/29/2022 23:55	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	**8.1**	units	0.1	1	09/29/2022 23:55	09/29/2022 23:55	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	**21.4**	mg/L	2.0	1	10/03/2022 11:10	10/03/2022 11:10	EJV	MA,NDA	

Method: SM4500-F-C-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Fluoride	**1.65**	mg/L	0.1	1	09/29/2022 23:55	09/29/2022 23:55	RAA		

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	**1400**	mg/L	10	1	09/30/2022 17:00	09/30/2022 17:00	RAA	MA,NDA	

Metals

Method: EPA 245.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury	<0.0002	mg/L	0.0002	1	10/06/2022 09:20	10/06/2022 12:13	AMC	MA,NDA, SDA	
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	10/06/2022 09:20	10/06/2022 12:13	AMC	MA,NDA	

Report Date: Saturday, October 29, 2022 12:10:07 PM

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Member ACIL

Account #: 7033 **Client:** University of North Dakota - EERC

Analytical Results

Lab ID:	3561006	**Date Collected:**	09/28/2022 17:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	09/29/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Metals

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Aluminum	<0.1	mg/L	0.1	1	09/29/2022 17:11	10/05/2022 10:38	SLZ	MA,NDA	
Boron	**0.58**	mg/L	0.1	1	09/29/2022 17:11	10/07/2022 11:02	MDE	MA,NDA	
Calcium	**2.73**	mg/L	1	1	09/29/2022 17:11	10/03/2022 12:52	SLZ	MA,NDA	
Iron	**0.40**	mg/L	0.1	1	09/29/2022 17:11	10/05/2022 10:38	SLZ	MA,NDA	
Potassium	**2.78**	mg/L	1	1	09/29/2022 17:11	10/03/2022 12:52	SLZ	MA,NDA	
Magnesium	**1.54**	mg/L	1	1	09/29/2022 17:11	10/03/2022 12:52	SLZ	MA,NDA	
Sodium	**587**	mg/L	2	1	09/29/2022 17:11	10/03/2022 12:52	SLZ	MA,NDA	
Strontium	**0.13**	mg/L	0.1	1	09/29/2022 17:11	10/05/2022 10:38	SLZ	MA,NDA	
Zinc	<0.05	mg/L	0.05	1	09/29/2022 17:11	10/05/2022 10:38	SLZ	MA,NDA	
Lithium	**0.0569**	mg/L	0.02	1	09/29/2022 17:11	10/06/2022 10:30	SLZ	NDA	
Silicon	**3.60**	mg/L	0.1	1	09/29/2022 17:11	10/06/2022 15:07	SLZ	MA,NDA	
Aluminum, Dissolved	<0.1	mg/L	0.1	1	09/30/2022 08:24	10/05/2022 11:43	SLZ	MA,NDA	
Boron, Dissolved	**0.55**	mg/L	0.1	1	09/30/2022 08:24	10/07/2022 15:48	MDE	MA,NDA	
Calcium, Dissolved	**2.61**	mg/L	1	1	09/30/2022 08:24	10/03/2022 13:27	SLZ	MA,NDA	
Iron, Dissolved	**0.44**	mg/L	0.1	1	09/30/2022 08:24	10/05/2022 11:43	SLZ	MA,NDA	
Potassium, Dissolved	**2.68**	mg/L	1	1	09/30/2022 08:24	10/03/2022 13:27	SLZ	MA,NDA	
Magnesium, Dissolved	**1.50**	mg/L	1	1	09/30/2022 08:24	10/03/2022 13:27	SLZ	MA,NDA	
Sodium, Dissolved	**577**	mg/L	2	1	09/30/2022 08:24	10/03/2022 13:27	SLZ	MA,NDA	
Strontium, Dissolved	**0.13**	mg/L	0.1	1	09/30/2022 08:24	10/05/2022 11:43	SLZ	MA,NDA	
Zinc, Dissolved	<0.05	mg/L	0.05	1	09/30/2022 08:24	10/05/2022 11:43	SLZ	MA,NDA	
Lithium, Dissolved	**0.0589**	mg/L	0.02	1	09/30/2022 08:24	10/06/2022 10:55	SLZ	NDA	
Silicon, Dissolved	**3.62**	mg/L	0.1	1	09/30/2022 08:24	10/06/2022 15:33	SLZ	MA,NDA	

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Beryllium	<0.0005	mg/L	0.0005	5	09/29/2022 17:11	10/14/2022 11:47	MDE	MA,NDA	

Report Date: Saturday, October 29, 2022 12:10:07 PM

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Member ACIL

Account #: 7033 Client: University of North Dakota - EERC

Analytical Results

Lab ID:	3561006	**Date Collected:**	09/28/2022 17:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	09/29/2022 08:00	**Collector:**	MVTL Field Service

Temp @ Receipt (C): 1.2 **Received on Ice:** Yes

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Beryllium, Dissolved	<0.0005	mg/L	0.0005	5	09/30/2022 08:24	10/14/2022 12:16	MDE	MA,NDA	
Vanadium	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Vanadium, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Chromium	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Chromium, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Manganese	**0.0050**	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Manganese, Dissolved	**0.0044**	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Cobalt	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Cobalt, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Nickel	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Nickel, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Copper	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Copper, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Arsenic	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Arsenic, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Selenium	<0.005	mg/L	0.005	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Selenium, Dissolved	<0.005	mg/L	0.005	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Molybdenum	<0.002	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Molybdenum, Dissolved	<0.002	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Silver	<0.0005	mg/L	0.0005	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Silver, Dissolved	<0.0005	mg/L	0.0005	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Cadmium	<0.0005	mg/L	0.0005	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Cadmium, Dissolved	<0.0005	mg/L	0.0005	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Antimony	<0.001	mg/L	0.001	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	

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Continued…

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Analytical Results

Lab ID:	3561006	**Date Collected:**	09/28/2022 17:00	**Matrix:**	Groundwater
Sample ID:	NDCS-W478	**Date Received:**	09/29/2022 08:00	**Collector:**	MVTL Field Service
Temp @ Receipt (C):	1.2	**Received on Ice:**	Yes		

Metals

Method: EPA 6020B

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Antimony, Dissolved	<0.001	mg/L	0.001	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Barium	**0.0923**	mg/L	0.002	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Barium, Dissolved	**0.0885**	mg/L	0.002	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Thallium	<0.0005	mg/L	0.0005	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Thallium, Dissolved	<0.0005	mg/L	0.0005	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	
Lead	<0.0005	mg/L	0.0005	5	09/29/2022 17:11	10/04/2022 14:44	MDE	MA,NDA	
Lead, Dissolved	<0.0005	mg/L	0.0005	5	09/30/2022 08:24	10/04/2022 11:05	MDE	MA,NDA	

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APPENDIX C

EPA- AND RISK-BASED AREA OF REVIEW METHODS

EPA- AND RISK-BASED AREA OF REVIEW METHODS

EPA METHODS 1 AND 2: AOR DELINEATION FOR CLASS VI WELLS

U.S. Environmental Protection Agency (EPA) guidance for area of review (AOR) evaluation includes several computational methods for estimating pressure buildup in the storage reservoir in response to CO_2 injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest underground source of drinking water (USDW) (U.S. Environmental Protection Agency, 2013). The following equation and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location (e.g., the JLOC-1 stratigraphic well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between the storage reservoir and the lowest USDW.

EPA Method 1 (*pressure front based on bringing the injection zone and USDW to equivalent hydraulic heads*) is presented as a method for determining whether a storage reservoir is in hydrostatic equilibrium with the lowest USDW (U.S. Environmental Protection Agency, 2013). Under Method 1, the maximum pressure increase that may be sustained in the injection zone (critical threshold pressure increase) is given by Equation 1:

$$\Delta P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) - P_I \qquad \text{[Eq. 1]}$$

Where:

P_u is the initial fluid pressure in the USDW (Pa).
ρ_i is the storage reservoir fluid density (kg/m^3).
g is the acceleration due to gravity (m/s^2).
z_u is the representative elevation of the USDW (m amsl).
z_i is the representative elevation of the injection zone (m amsl).
P_I is the initial pressure in the injection zone (Pa).
$\Delta P_{i,f}$ is the critical threshold pressure increase (Pa).

Equation 1 assumes that the hypothetical open borehole is perforated exclusively within the injection zone and USDW. If $\Delta P_{i,f} = 0$, then the reservoir and USDW are in hydrostatic equilibrium; if $\Delta P_{i,f} > 0$, then the reservoir is underpressurized relative to the USDW, and if $\Delta P_{i,f} < 0$, then the reservoir is overpressurized relative to the USDW.

In scenarios where the storage reservoir and USDW are in hydrostatic equilibrium ($\Delta P_{i,f} = 0$), EPA Method 2 (*pressure front based on displacing fluid initially present in the borehole*) can be used to calculate the critical pressure threshold. Method 2 was originally presented by Nicot and others (2008) and Bandilla and others (2012). Method 2 calculates the critical threshold pressure increase (ΔP_c), which is the fluid pressure increase sufficient to drive formation fluids into the lowermost USDW. This ΔP_c is determined using Equations 2 and 3, assuming 1) hydrostatic conditions, 2) initially linear densities in the borehole, and 3) constant density once the injection zone fluid is lifted to the top of the borehole (i.e., uniform density approach):

$$\Delta P_C = \frac{1}{2}\, g\, \xi\, (Z_u - Z_i)^2 \qquad \text{[Eq. 2]}$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{Z_u - Z_i} \qquad \text{[Eq. 3]}$$

Where:

ΔP_c is the critical threshold pressure increase (Pa).
g is the acceleration of gravity (m/s^2).
z_u is the elevation of the base of the lowermost USDW (m amsl).
z_i is the elevation of the top of the injections zone (m amsl).
P_i is the fluid density in the injection zone (kg/m^3).
P_u is the fluid density in the USDW (kg/m^3).

RISK-BASED AOR DELINEATION

The methods described by EPA (2013) for estimating the AOR under the Class VI rule (40 U.S. Code of Federal Regulations [CFR] 146.81 et seq.) were developed assuming that the storage reservoirs would be in hydrostatic equilibrium with overlying aquifers. However, in the state of North Dakota, and potentially elsewhere around the United States, candidate storage reservoirs are already overpressurized relative to overlying aquifers and thus subject to potential vertical formation fluid migration from the storage reservoir to the lowermost USDW, even prior to the planned storage project. Consequently, applying EPA (2013) methods to these geologic situations essentially results in an infinite AOR, which makes regulatory compliance infeasible.

Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressurized relative to overlying aquifers. For example, Birkholzer and others (2014) described the unnecessary conservatism in EPA's definition of critical pressure, which could lead to a heavy burden on storage facility permit (SFP) applicants. As an alternative, Burton-Kelly and others (2021) proposed a risk-based reinterpretation of this framework that would allow for a reduction in the AOR while ensuring protection of drinking water resources.

A computational framework for estimating a risk-based AOR was proposed by Oldenburg and others (2014, 2016), who compared formation fluid leakage through a hypothetical open flow path in the baseline scenario (no CO_2 injection) to the incrementally larger leakage that would occur in the CO_2 injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir pressurization and vertical migration through leaky wells. These semianalytical solutions were extensions of earlier work for formation fluid leakage through abandoned wellbores by Raven and others (1990) and Avci (1994), which were creatively solved, coded, and compiled in FORTRAN under the name ASLMA (Analytical Solution for Leakage in Multilayered Aquifers) and extensively described by Cihan and others (2011, 2012) (hereafter "ASLMA Model").

Recently, White and others (2020) outlined a similar risk-based approach for evaluating the AOR using the National Risk Assessment Partnership (NRAP) Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS). However, NRAP-IAM-CS and the subsequent open-sourced version (NRAP-Open-IAM) are constrained to the assumption that the storage reservoir is in hydrostatic equilibrium with overlying aquifers and, therefore, may not accurately estimate the AOR for storage projects located in regions where the storage reservoir is overpressurized relative to overlying aquifers.

Building a geologic model in a commercial-grade software platform (like Petrel; Schlumberger, 2020) and running fluid flow simulations using numerical reservoir simulation in a commercial-grade software platform (like CMG's [Computer Modelling Group's] compositional simulator, GEM) provide the "gold standard" for estimating pressure buildup in response to CO_2 injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storage reservoir and primary seal formation (cap rock) and do not include the geologic units overlying the cap rock because of the computational burden of conducting such a complex simulation. In addition, geologic modeling of the overlying units may add a substantial amount of time and effort during prefeasibility-phase projects that are unwarranted given the amount of uncertainty that may be present if only a few nearby wells can be used for characterization activities. Earlier studies (e.g., Nicot and others, 2008; Birkholzer and others, 2009; Bandilla and others, 2012; Cihan and others, 2011, 2012) have shown that far-field fluid pressure changes outside of the CO_2 plume domain can be reasonably described by a single-phase flow calculation by representing CO_2 injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).

The semianalytical solutions embedded within the ASLMA Model have been shown to compare with the numerical model, TOUGH2-ECO2-N, and provided accurate results for pressures beyond the CO_2 plume zone (Birkholzer and others, 2009; Cihan and others, 2011, 2012). Therefore, the proposed workflow for delineating a risk-based AOR uses the ASLMA Model to examine pressure buildup in the storage reservoir and resultant effects of this buildup on the vertical migration of formation fluid via (single) hypothetical leaky wellbores located at progressively greater distances from the injection well (Figure C-1).

An important distinction between EPA Methods 1 and 2, which both calculate a critical pressure threshold (either $\Delta P_{i,f}$ for Method 1 or ΔP_c for Method 2) and the risk-based AOR approach is that the risk-based approach 1) calculates and maps the potential incremental flow of formation fluids from the storage reservoir to the USDW that could occur and then 2) delineates the areal extent beyond which no significant leakage would occur. Therefore, the region beyond which no significant leakage would occur does not present an endangerment to the USDW; hence, the region inside of this areal extent is the risk-based AOR.

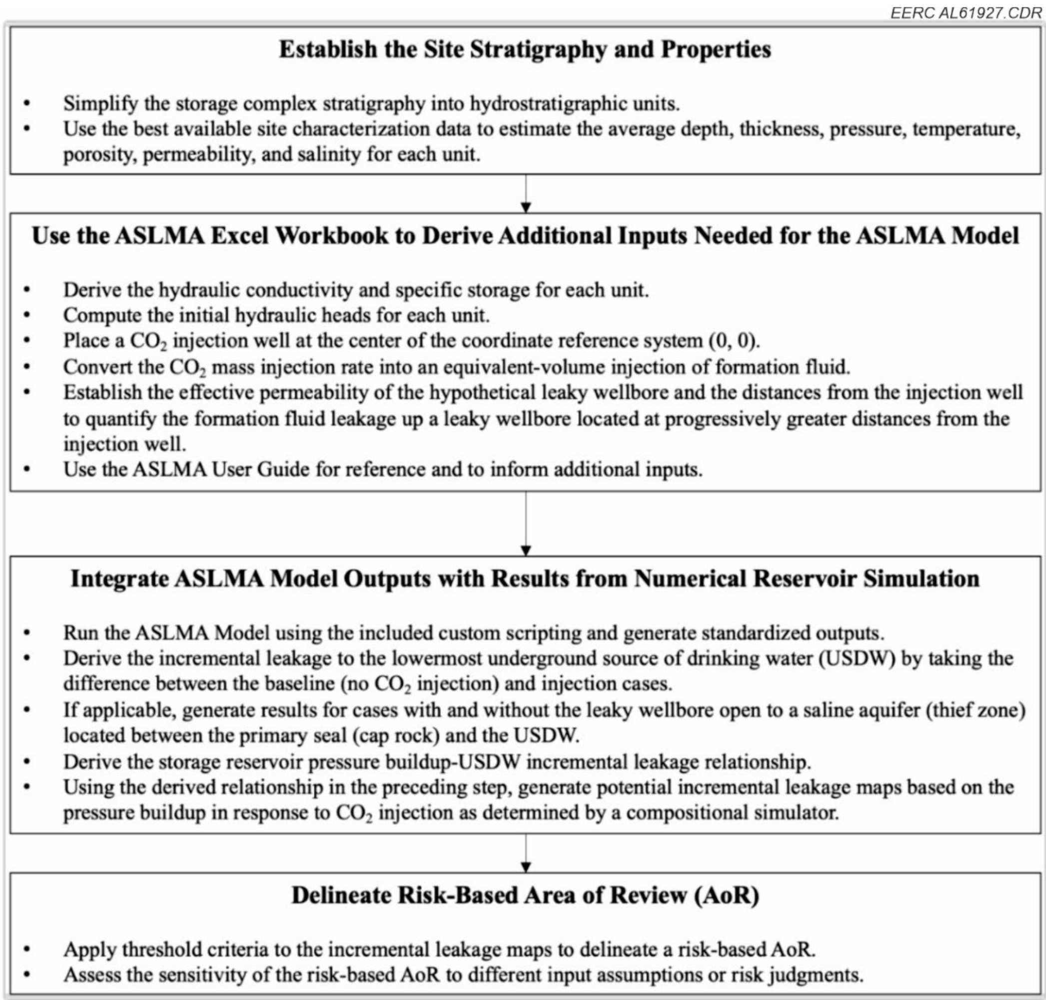

Figure C-1. Workflow for delineating a risk-based AOR for an SFP (modified from Burton-Kelly and others, 2021).

CRITICAL THRESHOLD PRESSURE INCREASE ESTIMATION

For the purposes of delineating AOR for the project study area, constant fluid densities for the lowermost USDW (Fox Hills Formation) and injection zone (Broom Creek Formation) were used in the calculations. Respective fluid densities were used to represent the injection zone fluids (ρ_i), which are estimated based on the in situ estimated brine salinity, temperature, and pressure at the JLOC-1 stratigraphic test well.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value across the project area and b) lack of evidence for hydrostatic equilibrium between the reservoir and the USDW (i.e., Method 2 does not apply) indicates that a risk-based approach to AOR delineation may be pursued.

RISK-BASED AOR CALCULATIONS

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The following discussion expands upon the description of inputs and assumptions in Section 3 of the application. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter "ASLMA Workbook").

Initial Hydraulic Heads

The original ASLMA Model (Cihan and others, 2011) initially assumed hydrostatic pressure distributions in the entire system. The current work uses a modified version of the ASLMA Model to simulate pressure perturbations and leakage rates when there are initial head differences in the aquifers (Oldenburg and others, 2014). The initial hydraulic heads are calculated assuming a total head based on the unit-specific elevations and pressures. The total heads are entered into the ASLMA Model and establish the initial pressure conditions for the storage complex prior to CO_2 injection.

For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table C-1 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Therefore, the storage complex requires different treatment than the default AOR calculations described by EPA (2013). Details on the calculations of initial hydraulic head are provided in Burton-Kelly and others (2021).

CO_2 Injection Parameters

The ASLMA Model for the project used a Broom Creek CO_2 injection rate that matched the simulation scenario. A single injector is placed at the center of the ASLMA Model grid at an x,y-location of (0,0) in the coordinate reference system. The ASLMA Model requires the CO_2 injection rate to be converted into an equivalent-volume injection of formation fluid in units of cubic meters per day. Microsoft Excel Visual Basic for Applications (VBA) functions were used to estimate the CO_2 density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table C-2. The CO_2 mass injection rate and CO_2 density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-6 in Section 3.5.6.

Hypothetical Leaky Wellbore

In the project area, few wellbores are known to exist that penetrate the primary seal of the Broom Creek storage reservoir. However, for heuristic, "what-if" scenario modeling, which is needed to generate the data for delineating a risk-based AOR, a single hypothetical leaky wellbore is inserted into the ASLMA Model at 1, 2, …, 100 km from the CO_2 injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 12-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure C-2) have included an "open wellbore" with an effective permeability as high as 10^{-5} m^2 (10^{10} mD) to values more representative of leakage through a wellbore annulus of 10^{-12} to 10^{-10} m^2 (10^3 to 10^5 mD)

Table C-1. Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex

Hydrostratigraphic Unit	Depth to Top,* m	Thickness, m	Pressure, MPa	Temperature, °C	Salinity, ppm	Brine Density, kg/m^3	Porosity, %	Permeability, mD	Permeability, m^2	HCON, m/d	Specific Storage, m^{-1}	Total Head, m
Overlying Units to Ground Surface (not directly modeled)	0	298										
Aquifer 3 (USDW – Fox Hills Fm)	298	73	3.4	15.9	1563	1001	35	280	2.76E-13	2.10E-01	5.60E-06	760
Aquitard 2 (Pierre Fm–Inyan Kara Fm)	372	804	7.3	57.8	2500		1	0.02	1.97E-17	3.40E-05	8.77E-06	732
Aquifer 2 (Thief Zone – Inyan Kara Fm)	1175	54	11.3	51.3	3360	944	13.45	7.9	7.75E-15	1.21E-02	4.90E-06	710
Aquitard 1 (Swift–Broom Creek Fm) (primary upper seal)	1229	259	15.1	62.2	24,675		2.14	0.11	1.08E-16	1.92E-04	8.95E-06	927
Aquifer 1 (Storage Reservoir – Broom Creek Fm)	1488	100	17.1	59.0	49,350	1023	14.2	7.5	7.40E-15	1.22E-02	5.06E-06	917

* Ground surface elevation is 750 m amsl.

Table C-2. CO_2 Density and Injection Parameters Used for the ASLMA Model

CO_2 Density, Reservoir Conditions, kg/m³	Injection Period	Injection Rate, m³ per day	Injection Period, years
678	1	16,200	20

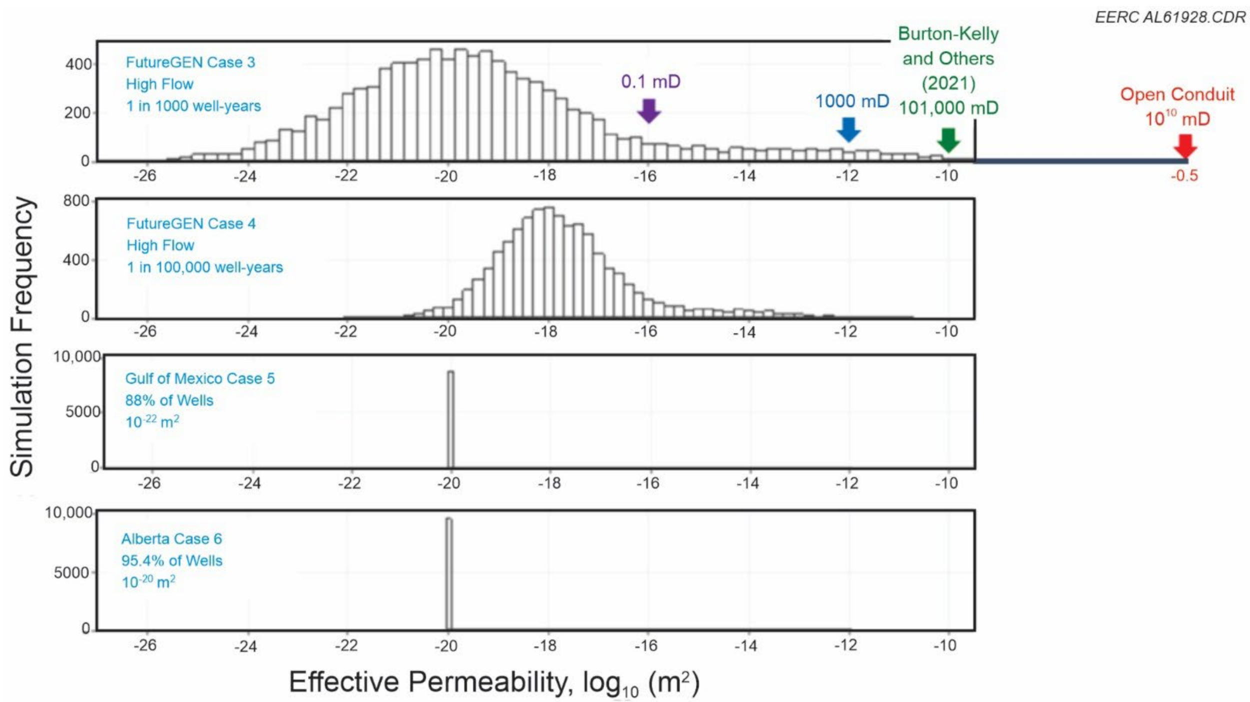

Figure C-2. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

(Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO_2 storage sites and estimated a wide range from 10^{-20} to 10^{-10} m² (10^{-5} to 10^{5} mD). For the project Broom Creek ASLMA Model, the effective permeability of the leaky wellbore is set to 10^{-16} m² (0.1 mD), which is a conservative (highly permeable) value near the top of the published range for the effective permeability of potentially leaking wells at CO_2 storage sites (Figure C-2).

The current work uses the ASLMA Model Type 1 feature (focused leakage only) for the nominal model response, which makes the conservative assumption that the aquitards are impermeable. This assumption prevents the pressure from diffusing into the overlying aquitards, resulting in a greater pressure buildup in the storage reservoir and a commensurately greater amount of formation fluid vertically migrating from the storage reservoir through the leaky wellbore. The conservative assumption of Model Type 1 rather than Model Type 3 (coupled focused and diffuse leakage) provides an added level of protection to the delineation of a risk-based AOR by projecting a larger pressure buildup in the storage reservoir than a scenario in which pressure is allowed to dissipate through the upper seal and, therefore, a greater leakage of formation fluid up the leaky wellbore.

Saline Aquifer Thief Zone

As shown in Table C-1, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the primary seal above the storage reservoir and USDW (Aquifer 3, Fox Hills Formation). Formation fluid migrating up a leaky wellbore that is open to Aquifer 2 will preferentially flow into Aquifer 2, and the continued flow up the wellbore and into the USDW will be reduced. Therefore, the presence of Aquifer 2 may act as a thief zone and reduce the potential for formation fluid impacts to the groundwater.

The thief zone phenomenon was described by Nordbotten and others (2004) as an “elevator model” by analogy with an elevator full of people on the main floor, who then get off at various floors as the elevator moves up, such that only very few people ride all the way to the top floor. The term “thief zone” is also used in the oil and gas industry to describe a formation encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 (Inyan Kara Formation) were run and evaluated to quantify the effect of a thief zone on the risk-based AOR.

Aquifer- and Aquitard-Derived Properties

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table C-1). For each unit shown in Table C-1, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: hydraulic conductivity (HCON) and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek and Inyan Kara from distributed properties in the geologic model and Fox Hills from regional well log data. Porosity is represented as an arithmetic mean and permeability as a geometric mean value within each hydrostratigraphic unit (excluding nonsandstone rock types).

VBA functions included in the ASLMA Workbook are used to estimate the formation fluid density and viscosity from the aquifer or aquitard pressure, temperature, and salinity inputs, which are then used to estimate HCON and SS. The estimated reference case HCON for the storage reservoir (Aquifer 1), thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table C-1. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).

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APPENDIX D

QUALITY ASSURANCE SURVEILLANCE PLAN

1.0 QUALITY ASSURANCE AND SURVEILLANCE PLAN

Pursuant to NDAC § 43-05-01-11.4(1)(k), this QASP was developed and is being provided as part of the testing and monitoring plan (Section 5.0). The purpose of the QASP is to specify monitoring tools/equipment performance standards and data collection and processing procedures.

1.1 CO_2 Stream Analysis

NDAC § 43-05-01-11.4(1)(a) requires analysis of the CO_2 stream in compliance with applicable analytical methods and standards generally accepted by industry and with sufficient frequency to yield data representative of its chemical and physical characteristics. DCC West will collect samples of the injected CO_2 stream at least quarterly and analyze the CO_2 stream to determine its chemical and physical characteristics, including composition, corrosiveness, temperature, and density. The compositional analyses will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used in the industry.

1.2 Surface Facilities Leak Detection Plan

The surface leak detection plan is outlined in Section 5.2 of this permit application. The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Leak detection equipment will be connected to a SCADA system for continuous, real-time monitoring and be integrated with automated warning systems to notify the operations center, giving DCC West the ability to remotely close the valves in the event of an emergency. Specification sheets for the equipment are provided in this appendix and include: 1) acoustic detectors (Attachment A-1); gas detection stations (Attachment A-2); the SCADA system (Attachment A-3); and multigas detectors for personnel (Attachment A-4).

1.3 CO_2 Flowline Corrosion Prevention and Detection Plan

1.3.1 Corrosion Prevention

The corrosion prevention plan for the CO_2 flowline is described in Section 5.3.1 of this permit application. The flowline construction materials will be in accordance with API 5L X-65 PSL 2 (2018) requirements, which includes applying external coatings to the pipe (e.g., fusion-bonded epoxy) and any borings or crossings (e.g., abrasive-resistant overcoats) to prevent corrosion. The flowline will also use a cathodic protection system in accordance with 49 CFR Part 195 and will be pressure-tested prior to CO_2 injection operations.

1.3.2 Corrosion Detection

DCC West will use the corrosion coupon method to monitor for corrosion in the CO_2 flowline and injection well materials throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. Coupon sample ports will be located near the point of transfer and near each injection wellhead (Figure 5-2), and sampling will occur quarterly. At the request of the NDIC, DCC West may also utilize a coupon sample port for conducting longer-term coupon testing (e.g., annually).

The process that will be used to conduct each coupon test is described below in Sections 1.3.2.1 through 1.3.2.3.

1.3.2.1 Sample Description

Corrosion coupons that are representative of the construction materials of the flowline and injection well that contact the CO_2 stream will be tested. Materials from these process components and/or conventional corrosion coupons of similar composition and specifications will be weighed, measured, and photographed prior to initial exposure.

1.3.2.2 Sample Exposure

Each sample will be suspended in a flow-through apparatus, which will be located downstream of all processes (i.e., downstream of the point of transfer and near the injection wellheads as shown in Figure 5-2). A parallel stream of high-pressure CO_2 will be withdrawn from the flowline, passed through the flow-through apparatus, and then routed back into a lower-pressure point upstream in the compression system. This loop will operate any time injection is occurring. The operation of this system will provide exposure of the samples to CO_2 that is representative of the composition, temperature, and pressures that will be present along the flowline, at the wellhead, and in the injection tubing.

1.3.2.3 Sample Handling and Monitoring

The exposed materials/coupons will be handled and assessed for corrosion in accordance with either the National Association of Colleges and Employers (NACE) Standard SP0775, Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations (2018) or the ASTM International (ASTM) Method G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (2017) to determine and document corrosion rates based on mass loss. The coupons will be photographed, visually inspected for cracking and pitting with a minimum of 10× power, dimensionally measured (to within 25.4 micrometers), and weighed (to within 0.0001 gram). Exposed coupons will be replaced with new coupons after each assessment.

1.4 Wellbore Mechanical Integrity Testing

The plan for mechanical integrity testing of the CO_2 injection wells and reservoir-monitoring well can be found in Section 5.4 of this permit application. Examples of ultrasonic and pulsed-neutron logging tools that can be used for confirming mechanical integrity in the project wellbores based on their designs are provided in Attachments A-5 and A-6, respectively. The DTS fiber-optic cable is described in Attachment A-7, and the tubing-conveyed P/T gauges are described in Attachment A-8. For all downhole logging tools, DCC West will ensure that third-party contractors follow industry standard QA/QC protocols and that monitoring equipment (e.g., downhole P/T gauges) are maintained in accordance with manufacturer recommendations.

Regarding the PNL strategy discussed in Section 5.4 of the permit application, DCC West will contract a third-party to conduct a feasibility study that quantifies the CO_2 detection capabilities and limitations based on the design of the CO_2 injection and reservoir-monitoring wellbores. Results of the feasibility study will be submitted to the NDIC prior to injection for approval.

1.5 Baseline Wellbore Logging and Testing Plan

The plan for baseline logging and testing of the CO_2 injection wells and reservoir-monitoring well can be found in Section 5.5 of this permit application. For all planned logging and well testing activities, DCC West will ensure that third-party contractors follow industry standard QA/QC protocols.

1.6 Wellbore Corrosion Prevention and Detection Plan

1.6.1 Downhole Corrosion Prevention

The plan to prevent corrosion in the CO_2 injection and reservoir-monitoring wellbores is outlined in Section 5.6.1 of this permit application. DCC West will ensure that third-party contractors follow industry standard QA/QC protocols when drilling and completing each of the wells and that the selected well materials at a minimum meets the standards selected and presented in Sections 9.0, 10.0, and 11.0 of this permit application.

1.6.2 Downhole Corrosion Detection

To detect possible signs of corrosion in the IIW-N and IIW-S wellbores, PNL (and potentially ultrasonic log) data will be acquired to monitor for signs of out-of-zone migration. For any logging activities related to corrosion detection, DCC West will ensure that third-party contractors follow industry standard QA/QC protocols.

1.7 Environmental Monitoring Plan

The environmental monitoring plan is summarized in Section 5.7 and Tables 5-6 and 5-8 of Sections 5.7.1 and 5.7.2 of this permit application, respectively.

1.7.1 Soil Gas Monitoring

Vadose zone soil gas monitoring directly measures the characteristics of the air space between soil components and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of three soil gas sites (profile stations) will be installed within the storage facility area and sampled, as shown in Figure 5-6. Figure D-1 is an example wellbore schematic of a soil gas profile station.

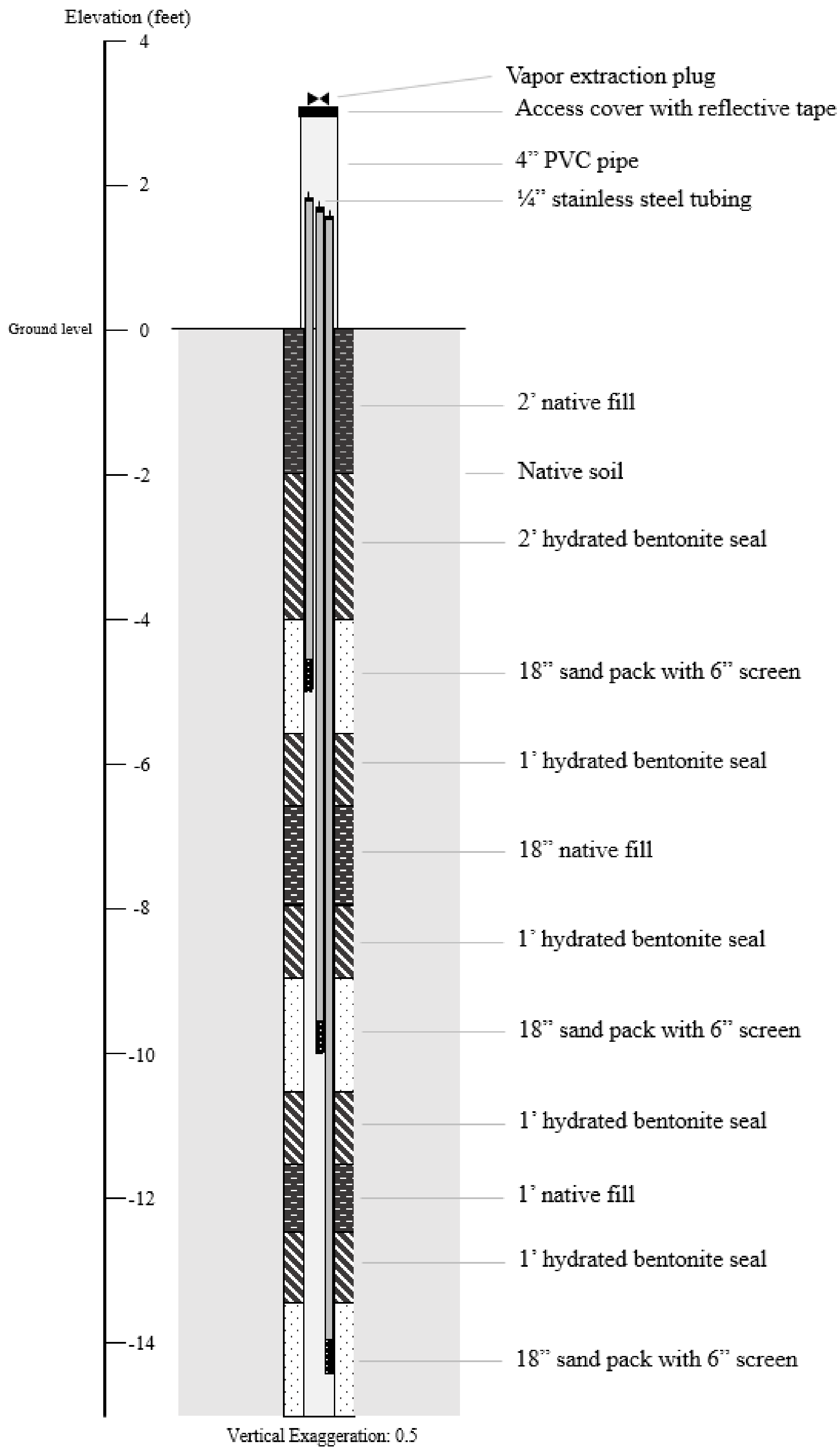

Figure D-1. Example wellbore schematic of a soil gas profile station.

1.7.1.1 Soil Gas Sampling and Analysis Protocol

Section 5.7.1 of this application outlines the sampling plan for soil gas. Tables D-1 and D-2 indicate a minimum set of analytes that will be included for the soil gas analysis.

Table D-1. Soil Gas Analytes Identified with Field and Laboratory Instruments

Analyte	Units
N_2	vol%
O_2	vol%
CO_2	vol%
H_2S	vol%
$CH_4 + H_2O$	vol%

Table D-2. Stable and Radiocarbon Isotope Measurements of Soil Gas Samples

Isotope	Units
$\delta^{13}C$ of CO_2 and CH_4*	‰ (per mil)
$\delta^{14}C$ of CO_2 and CH_4*	‰ (per mil)
δD of CH_4*	‰ (per mil)

* Only measured if high enough concentration detected.

At minimum, DCC West will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below.

Example Soil Gas Profile Station Sampling Procedure

Prior to the collection of each sample, a minimum of three probe casing volumes will be removed, and the representativeness of the gas flow will be determined by analyzing the soil gas over time for CO_2, total VOCs, H_2S, and O_2 using a handheld multigas meter. The handheld meter will be calibrated daily based on manufacturer instructions. After these measurements of the soil gas composition stabilize, two soil gas samples will be collected for characterization at each location using an air sampling bag and labeled with the appropriate sample number and site information. The samples will be sent to third-party laboratories for compositional and isotopic analysis.

1.7.1.2 QA/QC Procedures

DCC West will ensure that third-party service providers selected for soil gas sampling and analysis follow industry standard sampling and analytical QA/QC protocols, including collection of field blanks and duplicate (replicate) samples to identify environmental contamination and evaluate repeatability in sampling and analytical methods, respectively.

1.7.2 Groundwater Monitoring

Groundwater monitoring directly measures the chemical constituents of the water in the pore space between grains of subsurface geologic formations (aquifers) and is an indirect indicator of both chemical and biological processes occurring in and below a sampling horizon. A total of two new dedicated Fox Hills monitoring wells and up to five existing groundwater wells will be sampled in the AOR (as shown in Figure 5-6).

1.7.2.1 Groundwater Sampling and Analysis Protocol

Section 5.7.1 of this application describes the plan for monitoring groundwater (to the lowest USDW). DCC West will select third-party service providers to collect groundwater samples and ensure that standard industry QA/QC procedures are followed. At minimum, DCC West will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below.

<u>Example Groundwater Well Sampling Procedure</u>

Groundwater samples will be collected by a third party from the dedicated Fox Hills monitoring wells as well as other shallower groundwater wells specified by DCC West with landowner approval using the wells' submersible pumps. The standard procedure for sampling the wells is provided below:

1. Comply with any landowner or regulator requests and agreements to sample shallow groundwater wells, such as additional measurements (e.g., nitrate levels) and record keeping.

2. Purge the well using a measured bucket to determine the pumping rate when the valve is fully open.
   a. The longer the well has not been in use, the longer the well will need to be purged before sample collection. Purge time will also depend on the total depth of the well.
   b. For wells used daily, purge the well for 1–2 minutes. For wells used on a seasonal basis, such as livestock or irrigation, purge the well for 15 minutes, or longer if the well is over 100 feet deep. If the well has not been in use in the past year, three well volumes may need to be removed to ensure a freshwater sample can be collected.
   c. For wells used continuously, samples may be collected without purging.

3. Collect the sample.
   a. Once the well has been sufficiently purged, sample collection can proceed.
   b. Record the location of the sample point.
   c. Collect field readings: temperature, conductivity, and pH.
   d. Fill appropriate sample containers for analysis with minimum headspace and refrigeration/cooling to reduce microbial activity.

4. Collect a duplicate sample for QA/QC purposes.

State-certified commercial laboratories will be identified by DCC West to analyze the water samples for the analytes described in Tables D-3 and D-4.

Table D-3. General Analytes for Groundwater Samples

Analyte	Cation (total and dissolved)	Anion (total)
pH	Aluminum	Bromide
Conductivity	Antimony	Chloride
Alkalinity	Arsenic	Fluoride
Total Dissolved Solids (TDS)	Barium	Nitrate
Total Organic Carbon (TOC)	Beryllium	Nitrite
Dissolved Organic Carbon (DOC)	Boron	Sulfate
	Cadmium	
	Calcium	
	Chromium	
	Cobalt	
	Copper	
	Iron	
	Lead	
	Lithium	
	Magnesium	
	Manganese	
	Mercury	
	Molybdenum	
	Nickel	
	Potassium	
	Selenium	
	Silicon	
	Silver	
	Sodium	
	Strontium	
	Thallium	
	Phosphorus	
	Vanadium	
	Zinc	

Table D-4. Stable and Radiocarbon Isotope Measurements in Groundwater

Isotope	Units
$\delta D\ H_2O$	‰ (per mil)
$\delta^{18}O\ H_2O$	‰ (per mil)
$\delta^{13}C$ DIC	‰ (per mil)
$^{3}H\ H_2O$	‰ (per mil)
$\delta^{14}C$ DIC	‰ (per mil)

1.7.2.2 QA/QC Procedures

DCC West will ensure that third-party service providers selected for groundwater sampling and analysis follow industry standard sampling and analytical QA/QC protocols, including collection of field blanks and duplicate (replicate) samples to identify environmental contamination and evaluate repeatability in sampling and analytical methods, respectively.

1.7.3 Deep Subsurface Monitoring

DCC West will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO_2 plume and associated pressure relative to the permitted storage reservoir. The direct and indirect storage reservoir monitoring methods described in Table 5-8 and throughout this subsection of the permit application will be used to characterize the CO_2 plume's saturation and pressure within the AOR for the baseline and operational phases of the project.

1.7.3.1 Above-Zone Monitoring Interval and Direct Storage Reservoir Monitoring

Monitoring of the storage reservoir during the injection operation includes monitoring of the injection flow rates and volumes, wellhead injection temperatures and pressures, bottomhole injection pressures, temperature, and saturation profiles from the storage reservoir to the AZMI, and the tubing-casing annulus pressure or casing pressure. Baseline PNLs will be acquired in the CO_2 injection wells and reservoir-monitoring well. Repeat PNLs will then be acquired in the CO_2 injection wells. DCC West will ensure that all continuous monitoring devices are inspected and maintained in accordance with the manufacturer's recommendations. For any logging activities, DCC West will ensure that third-party contractors follow industry standard QA/QC protocols.

1.7.3.2 Time-Lapse Seismic Surveys

The geophysical monitoring that is planned for the project includes time-lapse seismic surveys. The time-lapse methods (i.e., VSPs and 2D seismic surveys) may utilize the DAS fiber-optic cable installed in the CO_2 injection wellbores. The DAS fiber is described in Attachment A-9. Time-lapse seismic surveys provide a measurement of the change in acoustic properties of the storage formation as injected CO_2 saturates the storage interval.

Application of time-lapse seismic surveys for monitoring changes in acoustic properties requires a quality preoperational seismic survey for baseline conditions. The monitor survey should be repeated as closely to the baseline conditions and parameters as possible. The seismic monitor data should be reprocessed simultaneously with the original baseline data or processed with the same steps and workflow to ensure repeatability. Repeatability is a measure of seismic quality (Lumley and others, 1997, 2000) that can be quantified once the processed data are analyzed by an experienced seismic interpreter.

1.7.3.3 Passive Seismicity Monitoring

The Williston Basin is a tectonically stable region of the North American Craton. A total of 13 events have been detected in North Dakota since 1870 (see Section 2.5.2). The closest recorded seismic event relative to the CO_2 injection wells was approximately 60 miles away (see Table 2-26). While few seismic events have been recorded in the region, DCC West plans to maintain a surface array during injection to ensure the safe operation of both the storage facility and associated infrastructure. This seismic monitoring will be conducted with a surface array of seismometer stations deployed to ensure detection of larger magnitude events (e.g., >2.7) and locate epicenters within 5 kilometers (km) of the injection well. DCC West will work with all third-party contractors to ensure proper design and installation of the passive seismicity monitoring array.

DCC West will follow a traffic light system (described next) if a seismic event is recorded by either the local or public national array during injection operations.

<u>Traffic Light System</u>
If an event is recorded by either the local private array or the public national array to have occurred within 5 km of the injection well, DCC West would implement its emergency remedial and response plan (Appendix F) subject to detected earthquake magnitude limits defined below:

- For events >2.7 located within 5 km of injection, DCC West will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity. If the event is not related to the storage facility operation, the operator will resume normal injection rates.

- For events >4.0 located within 5 km of injection, DCC West will stop injection and perform an inspection in surface facilities and wells. If there is no damage, the operator will reduce the injection rate by not less than 50% and perform a detailed analysis to determine if a causal relationship exists. If the event is not related to the storage facility operation, the operator will resume normal injection rates. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

- For events >4.5 located within 5 km of injection, the operator will stop injection. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. The operator will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis is conducted to determine if a causal relationship exists between injection operations and observed seismic activity. If the event is not related to the storage facility operation, and previously approved by the regulators, the operator will resume normal injection rates in steps, increasing the surveillance Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include but not be limited to:
  - Pausing operations until reservoir pressures fall below a critical limit.
  - Continuing operations at a reduced rate and/or below a revised maximum operation pressure.

1.8 References

American Petroleum Institute, 2018, Line pipe: API Specification 5L, Forty-Sixth Ed., April 2018, Errata 1, May 2018, 210 p.

ASTM International, 2017, ASTM G1-03(2017)e1, Standard practice for preparing, cleaning, and evaluating corrosion specimens: West Conshohocken, Pennsylvania, ASTM International, www.astm.org/g0001-03r17e01.html (accessed April 2022).

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Lumley, D.E., Cole, S., Meadows, M.A., Tura, A., Hottman, B., Cornish, B., Curtis, M., and Maerefat, N., 2000, A risk analysis spreadsheet for both time-lapse VSP and 4D seismic reservoir monitoring: 70th Annual International Meeting, SEG, Expanded Abstracts, p. 1647–1650.

National Association of Colleges and Employers, 2018, NACE SP0775, Preparation, installation, preparation, and interpretation of corrosion coupons in oilfield operations: https://standards.globalspec.com/std/10401680/nace-sp0775 (accessed April 2022).

Attachment A-1 – Acoustic Detector for CO_2 Flowline Specifications

DET-TRONICS®

SPECIFICATION DATA

FlexSonic™ Acoustic Detector AC100 Sensor ATX10 Transmitter

DESCRIPTION

The FlexSonic™ Acoustic Detector is designed to recognize the unique ultrasonic frequency content of events such as gas leaks. When a pressurized gas leak occurs, the frequency content of the sound being generated extends beyond the audible portion of the spectrum into the ultrasonic region (above 20 kHz). The intensity of the sound generated by a leak is determined by several factors including pressure, leak rate, gas viscosity, and distance from the leak source. Acoustic detection is less susceptible to environmental factors (such as high winds) that can degrade the ability of traditional sensing technology based on gas concentration to detect the presence of a leak. When combined with line of sight and/or point gas detectors, the additional layer of protection provided by the FlexSonic Acoustic Detector offers the ultimate solution for gas leak detection.

The FlexSonic Acoustic Detector is comprised of two main components: the AC100 Acoustic Sensor, and the ATX10 Acoustic Transmitter.

The AC100 Acoustic Sensor employs a high performance microphone and digital signal processing (DSP) technology to continuously monitor the acoustic signal. The wide dynamic range and spectral resolution enable the sensor to provide both superior sensitivity and false alarm discrimination.

The ATX10 Transmitter evaluates the incoming acoustic power spectrum data from the AC100 Acoustic Sensor and makes a determination of alarm condition.

FEATURES AND BENEFITS

- Analyzes 24 discrete ultrasonic bands
- Large detection coverage area
- Nearly instantaneous response
- Non-contact gas leak detection
- Adjustable detection range
- Superior false alarm discrimination with patented technology
- Suitable for harsh outdoor applications
- Stand alone capability with the ATX10 Transmitter
- Globally approved explosion-proof stainless steel housing
- Wide acoustic dynamic range
- Integrated Acoustic Integrity Check (AIC)
- 4-20 mA output combined with HART
- Can detect small gas leaks at or below 6 bar (87 psi)
- Extensive data logging with removable storage
- Ideally suited for locations where traditional technologies are challenged, such as outdoor and unmanned operations
- Minimum maintenance required
- No routine calibration required
- Not affected by poisoning
- Functions with all gas types
- Fail-safe operation
- Certified SIL 2 Capable

Continued…

Attachment A-1 – Acoustic Detector for CO_2 Flowline Specifications (continued)

SPECIFICATIONS

ATX10 AND AC100	
Operating Voltage	24 Vdc nominal; Operating range is 9 to 30 Vdc. Um=250 V (Intrinsic Safety Rating).
Power Consumption	AC100: 1.25 watts @ 9 Vdc 1.25 watts @ 24 Vdc 1.25 watts @ 30 Vdc. ATX10: 0.75 watts @ 9 Vdc 1.25 watts @ 24 Vdc 1.75 watts @ 30 Vdc
Temperature Range	Operating: –55°C to +75°C (–67°F to +167°F) Storage: –55°C to +85°C (–67°F to +185°F).
Humidity	5 to 95% RH, non-condensing (Det-Tronics verified).
Ingress Protection	IP66, NEMA/Type 4X.
Electro-Magnetic Compatibility	EMC Directive 2014/30/EU
Emmissions	EN61000-6.3 EN61000-6.4
Immunity	EN61000-6.1 EN61000-6.2
Conduit Entries	3/4" NPT or M25.
Enclosure Material	316 stainless steel, electropolished.
Shipping Weight	AC100: 6.2 pounds (2.8 kilograms). ATX10: 11.5 pounds (5.2 kilograms).
Warranty	3 years.
AC100 only	
Detection Coverage Performance	Leak Source = 0.004 kg/Sec (6 Bar (87 psi), 2 mm round orifice). Basic Mode, 50 db setting = 12 meters (40 feet) Profile Mode (4 db above background) = 20 meters (66 feet)
Acoustic	Dynamic range: Greater than 100 db
Self-Diagnostic Test (AIC)	Automatic acoustic integrity check performed once every 10 (factory default) minutes.
ATX10 only	
Current Output	4-20 mA with HART (non-isolated, sourcing*) 20 mA indicates Alarm condition 16 mA indicates Pre-Alarm condition 4 mA indicates Normal condition 2 mA or less indicates a Fault condition. *Isolated or sinking operation requires the use of a FlexVu® Model UD10 Display. ** UD30 output is a Non-Isolated Sourcing Output.
Maximum Loop Resistance	300 ohms at 18 Vdc; 600 ohms at 24 Vdc
Wiring Terminals	Rated for 14 to 18 AWG (2.5 to 0.75 mm²) wire.

CERTIFICATION—	
FM/CSA	**AC100** Class I, Div1, Groups B, C & D Class II/III, Div1/Div2, Groups E, F & G Class I, Div2, Groups A, B, C & D Temperature code T4 Tamb: –55°C to +75°C NEMA/Type 4X **ATX10** Class I, Div1, Groups B, C & D Class II/III, Div1/Div2, Groups E, F & G Temperature code T5 Class I, Div2, Groups A, B, C & D Temperature code T4 Tamb: –55°C to +75°C NEMA/Type 4X
ATEX	**AC100** DEMKO 12 ATEX 1263479X CE 0539 Ex II 2 G II 2 D Ex d ib IIC T4 Gb Ex tb IIIC T80°C Db Tamb: –55°C to +75°C IP66 **ATX10** DEMKO 12 ATEX 1263925X CE 0539 Ex II 2 G II 2 D Ex d IIC T6 Gb Ex tb IIIC T80°C Db Tamb: –55°C to +75°C IP66
IECEx	**AC100** IECEx ULD13.0002X Ex d ib T4 Gb Ex tb IIIC T80°C Db Tamb: –55°C to +75°C IP66 **ATX10** IECEx ULD13.0003X Ex d IIC T6 Gb Ex tb IIIC T80°C Db Tamb: –55°C to +75°C IP66
DNV	Type Approval Certificate No. A-11023.
SIL Approval	IEC 61508 Certified SIL 2 Capable.

Specifications subject to change without notice.

Det-Tronics manufacturing system is certified to ISO 9001—the world's most recognized quality management standard.

DET-TRONICS

Corporate Office
6901 West 110th Street
Minneapolis, MN 55438 USA
www.det-tronics.com

Phone: +1 952.941.5665
Toll-free: +1 800.765.3473
Fax: 952.829.8750
det-tronics@carrier.com

Attachment A-2a – Gas Detection Station Specifications for CO_2

DET-TRONICS

SPECIFICATION DATA

Infrared Carbon Dioxide Gas Detector
PointWatch Eclipse®
Model PIRECL

DESCRIPTION

YEAR 5 WARRANTY

The PointWatch Eclipse® Model PIRECL Carbon Dioxide (CO_2) Detector is a diffusion-based, point-type infrared gas detector that provides continuous monitoring of CO_2 gas concentrations in the range of 0-2%/volume (0-20000 ppm).

All units are powered from 24 Vdc, and are furnished with an onboard "status indication" LED, an internal magnetic calibration switch and an external calibration line for use with the optional PIRTB remote calibration termination box.

The Eclipse CO_2 detector is ideal for use in harsh outdoor environments and is certified for use in Class I, Division 1 (CSA), and Zone 1 (ATEX/IECEx) hazardous areas. It can be used as a stand-alone detector, or as part of a larger facility protection system.

Two basic configurations are available:
- 4-20 mA output with HART communication protocol and RS-485 MODBUS communications.
- 4-20 mA output with HART communication protocol and RS-485 MODBUS communications, with two alarm relays and one fault relay.

FEATURES AND BENEFITS

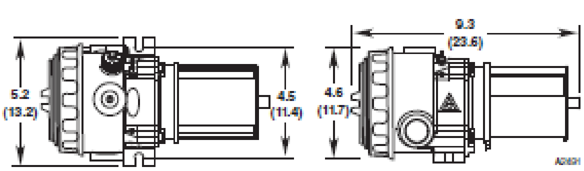
- Superior optics protection system.
- No undisclosed failure modes.
- Routine calibration not required.
- Explosion-proof, stainless steel housing with tethered weather protection baffle.
- Integral wiring compartment eliminates need for external junction boxes.
- On-board tri-color LED eliminates need for alarm and fault indication.
- Built-in optional relay package eliminates need for external relay output module.
- Non-interfering HART communication capability.
- Optional hand-held HART communicator enables field configuration and calibration.
- Heated sapphire optics deliver long-lasting, high performance detection capability.
- Immune to damage from exposure to constant background gases or to high gas concentrations.

Continued…

Attachment A-2a – Gas Detection Station Specifications for CO_2 (continued)

SPECIFICATIONS

Input Voltage	24 Vdc nominal. Operating range is 18 to 32 Vdc. Ripple cannot exceed 0.5 volts Peak-to-Peak.
Power Consumption (Detector with relays)	4.0 (5.5) watts nominal @ 24 Vdc 7.5 (8.0) watts peak @ 24 Vdc 10.0 (10.0) watts peak @ 32 Vdc.
Warm-up Time	Two minutes from cold power-up to normal mode; 1 hour minimum recommended.
Current Output	Linear 4-20 mA (current source/sink, isolated/non-isolated) rated at 600 ohms maximum loop resistance @ 24 Vdc operating voltage.
Detection Range	0-2%/vol or 0-20000 ppm.
Detectable Gas	Carbon Dioxide (CO_2).
Calibration	All units are calibrated at the factory.
Device Configuration	Configuration parameters include tag number, measurement range, alarm levels, and other selectable parameters.
Response Time	T50 = 6 sec (Det-Tronics verified).
Accuracy	0-20000 ppm or 0-2%/vol: ±10% Full Scale @ 25°C. (Det-Tronics verified).
Temperature Range	Operating: See CSA, ATEX, and IECEx Certifications. Storage: –55°C to +85°C (–67°F to +185°F).
Humidity (Non-Condensing)	0 to 99% R.H. (Det-Tronics verified).
Self-Diagnostic Test	All critical tests performed once per second.
Ingress Protection	IP66/IP67 (DEMKO Verified).
Detector Housing Material	316 stainless steel (CF8M).
Surface Preparation	Electropolish.
Conduit Entry Options	Two entries, 3/4 inch NPT or M25.
HART Communicator Port (Optional)	Intrinsically safe output.
Optics Protection	Weather guard with hydrophobic filter, static dissipating plastic.
Wiring Terminals	Field wiring screw terminals are UL/CSA rated for up to 14 AWG wire, and DIN/VDE rated for 2.5 mm² wire.
Shipping Weight	11.5 lbs. (5.2 kg).
Dimensions	Inches (cm).



Certifications

CSA:
Class I, Div. 1, Groups B, C & D (T4) with optional intrinsically safe output for HART communication in accordance with control drawing 011975-001.
Class I, Div. 2, Groups A, B, C & D (T3C)
Tamb = –40°C to +75°C
Acidic atmospheres excluded
Conduit seal not required.

ATEX/CE:
CE 0539 Ex II 2 G
Ex de IIC T4-T5 Gb
-- OR --
Ex de [ib] IIC T4-T5 Gb
(with HART communication port)
DEMKO 01 ATEX 129485X.
T5 (Tamb –50°C to +40°C)
T4 (Tamb –50°C to +75°C)
IP66/IP67.
-- OR --
CE 0539 Ex II 2 G
Ex d IIC T4-T5 Gb
-- OR --
Ex d [ib] IIC T4-T5 Gb
(with HART communication port)
DEMKO 01 ATEX 129485X.
T5 (Tamb –55°C to +40°C)
T4 (Tamb –55°C to +75°C)
IP66/IP67.

IECEx:
IECEx ULD 04.0002X
Ex de IIC T4-T5 Gb
– OR –
Ex de [ib] IIC T4-T5 Gb
(with HART communication port)
T5 (Tamb –50°C to +40°C)
T4 (Tamb –50°C to +75°C)
IP66/IP67.
– OR –
IECEx ULD 04.0002X
Ex d IIC T4-T5 Gb
– OR –
Ex d [ib] IIC T4-T5 Gb
(with HART communication port)
T5 (Tamb –55°C to +40°C)
T4 (Tamb –55°C to +75°C)
IP66/IP67.

INMETRO:
CEPEL 02.0078X
Ex d e [ib] IIC T4-T5 Gb IP66/IP67
T5 (Tamb –50°C to +40°C)
T4 (Tamb –50°C to +75°C)
– OR –
Ex d [ib] IIC T4-T5 Gb IP66/IP67
T5 (Tamb –55°C to +40°C)
T4 (Tamb –55°C to +75°C).

DET-TRONICS

Corporate Office
6901 West 110th Street
Minneapolis, MN 55438 USA
www.det-tronics.com

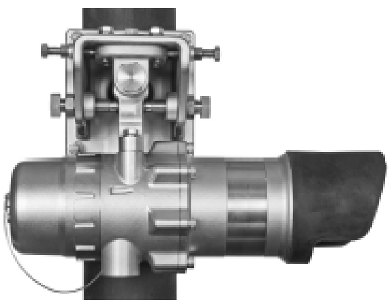
Phone: +1 952.941.6665
Toll-free: +1 800.765.3473
Fax: 952.829.8750
det-tronics@carrier.com

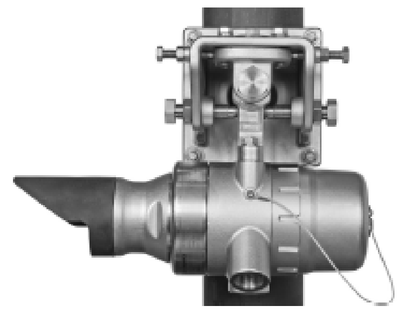
Attachment A-2b – Gas Detection Station Specifications for Hydrocarbons

DET-TRONICS

SPECIFICATION DATA

FlexSight™ LS2000 Line-of-Sight Infrared Hydrocarbon Gas Detector





DESCRIPTION

YEAR 5 WARRANTY

The FlexSight™ Line-of-Sight Infrared Hydrocarbon Gas Detector model LS2000 is a gas detection system that provides continuous monitoring of combustible hydrocarbon gas concentrations in the range of 0–5 LFL-meters, over a distance of 5–120 meters. Standard system outputs include an electrically isolated/non-isolated 4-20 mA DC current output, with HART communication and RS-485 Modbus communication. Alarm and fault relays are available as an option.

The system consists of two stainless steel modules — a transmitter and a receiver, along with mounting fixture hardware. Both modules are powered from an external 24 volt DC supply. The receiver provides the measurement signal outputs, and is furnished with onboard "status indication" LEDs and an internal magnetic calibration switch. The transmitter houses a high quality xenon flash lamp.

The LS2000 is certified explosion-proof for use in Class I, Division 1 and 2; Class II, Division 1; Class I, Zone 1; and Zone 1, Zone 2 hazardous areas and holds third party performance certification for methane, butane, and propane gas detection. It can be used as a stand-alone detector, or as part of a larger facility protection system using other Det-Tronics equipment.

By connecting the transmitter and receiver via a three-wire shielded cable, an optional "communication link" can be created between the two devices to enable: single point system diagnostics, dynamic lamp power optimization, synchronized LEDs, transmitter configuration via connection to the receiver, and calibration initiation from either device.

FEATURES AND BENEFITS

- ± 0.8 degree misalignment tolerance (~±56cm @ 40m; ~±168cm @ 120m)
- IR source: High performance, long lasting xenon flashlamp - **10 year warranty on IR source**
- Large detection coverage area (detection range 5–120 meters)
- Maximum distances and proper operation verified with 95% signal obscuration
- Global compliance to FM6325, ISA-12.13.04, EN 60079-29-4, and IEC 60079-29-4 performance standards
- Certified SIL 2 capable
- Third party performance certified and factory calibrated to Methane, Butane, and Propane
- Microprocessor controlled heated optics for increased resistance to moisture and ice
- Standard 4–20 mA output (configurable), HART communication, RS-485 Modbus
- Optional alarm relays (Ex d only)
- Mounting hardware and alignment brackets included
- Mounts to pole (4.5" nominal OD) or flat surface
- Built-in locking adjusters deliver fine control of alignment angles
- Telescope is the only tool needed for optimal alignment
- Multi-color LEDs are provided on both modules for detailed visual indication of operating status
- Non-intrusive zero calibration options: on-board magnetic switch, Modbus communication, HART communication, or external switch
- Optional 475 field communicator unit for communication, diagnostic, and set up from point to point
- Modular design for ease of maintenance
- EQP compatible version available.

Continued…

Attachment A-2b – Gas Detection Station Specifications for Hydrocarbons (continued)

SPECIFICATIONS

Operating Voltage (Both Modules): 24 Vdc nominal. Operating range is 18 to 30 Vdc. Ripple cannot exceed 0.5 volts P-P.

Power Consumption

Power Consumption (Watts)			
		TX Max	RX Max
@ 24VDC	Total Unit, No Heaters or Relays	6.5	2.6
	30% Heater Only	1.4	1.1
	50% Heater Only	2.5	2.0
	70% Heater Only	3.5	2.7
	100% Heater Only	4.2	3.3
	Relay Only	N/A	1.2
	Total Unit, Max	10.7	7.2
@ 33VDC*	Total Unit, Max	16.0	10.0

*Per regulatory approval requirements, the unit power consumption was measured at 33 VDC input voltage (10% above claimed range) and results listed on the product label.

Inrush Current: 1 amp typical incrush current at 24 Vdc.

Transmitter Lamp: Xenon flashlamp, field-replaceable module.

Warmup Time: 15 seconds minimum, 150 seconds maximum from power-up, depending upon alignment accuracy.

Current Output: Linear 0-20 mA (isolated/non-isolated) rated at 600 ohms maximum loop resistance @ 24 Vdc operating voltage. Levels below 4 mA indicate a fault condition. Fault output levels are user configurable.

Relay Outputs (Optional): Available on Ex d approved models only. Two alarm, one fault relay. Form C Type (NO/NC).
Contact Rating: 3 amperes at 30 Vdc.

Alarm Relay Setpoint Range: Low Alarm: 0.5 to 4.5 LFL-meters (default = 1)
High Alarm: 0.5 to 4.5 LFL-meters (default = 3).

Visual Status Indicator: Multi-color LED on each module indicates operating status.

Available Gases: Third party performance approved to methane, butane, and propane.

Detection Range: Short Range: 5-60 meters.
Long Range: 30-120 meters.

Misalignment Tolerance: ±0.8 degree minimum (~±56cm @ 40m; ~±168cm @ 120m).

Calibration: LS2000 systems are span calibrated for methane, propane, or butane at the factory. Span calibration in the field is not required.
Zero calibration can be accomplished in the field using the on-board magnetic reed switch.

Response Time: T90: 2 seconds (5.0 LFL-meters applied).

Accuracy/Linearity: ±5% of full scale gas concentration or ±10% of applied gas concentration, whichever is greater.

Repeatability: ±5%.

Temperature Range: Operating: –55°C to +75°C (–67°F to +167°F)
Storage: –55°C to +85°C (–67°F to +185°F).

Humidity: 5 to 99% relative humidity; designed for outdoor applications.

Fog Performance: FM 6325 performance req. 4.18

Vibration: FM6325 and DNV Standard for Cert No. 2.4, Type B (DNV testing includes operation of alignment mounts during 4G vibration).

Measurement Range: 0-5 LFL-meters.

Interference Resistance: Immune to sun and flare radiation, tested to 800 ±50 W/m² at ≥ 3° to optical axis and common contaminants.

Self-Diagnostic Test: Fail-Safe operation ensured by performing all critical tests once per second.

Module Housing Material: 316 stainless steel (CF8M).

Conduit Entry Options: 3/4 inch NPT or M25, with two entries for transmitter and four entries for receiver.

Optics Protection: Microprocessor controlled heated optics mitigate against ice and dew formation.

Ingress Protection: IP66/67; NEMA Type 4X

Tropicalization / PCBD Protection: Conformal coated printed circuit boards: CTI Rating of 600V, maximum allowed by standard.
Third party tested per ASTM-D-3638-07.

Wiring: Field wiring screw terminals are UL/CSA rated for up to 14 AWG shielded wire, and are DIN/VDE rated for 2.5 mm² wire.

Shipping Weight: Transmitter and receiver with mounting hardware: 85 pounds (38 kg).

Warranty: 5 year limited warranty from date of manufacture.
10 year warranty on IR source.

Certification

APPROVED

Receiver with or without Relays
Class I, Div. 1, Groups B, C & D (T4).
Class I, Div. 2, Groups A, B, C & D (T4).
Class II/III, Div. 1 & 2, Groups E, F & G (T4).
Tamb = –50°C to +65°C.
Class I, Zone 1, AEx db IIC T4 IP66/67.
Tamb = –50°C to +65°C.
Type 4X, IP66/67.

Receiver without Relays
Class I, Div. 1, Groups B, C & D (T4).
Class I, Div. 2, Groups A, B, C & D (T3C).
Class II/III, Div. 1, Groups E, F & G (T4).
Class II/III, Div. 2, Groups E, F & G (T3C).
Tamb = –50°C to +75°C.
Class I, Zone 1, AEx db eb IIC T4 IP66/67.
Tamb = –50°C to +75°C.
Type 4X, IP66/67.

Transmitter
Class I, Div. 1, Groups B, C & D (T4).
Class I, Div. 2, Groups A, B, C & D (T3C).
Class II/III, Div. 1, Groups E, F & G (T4).
Class II/III, Div. 2, Groups E, F & G (T3C).
Tamb = –50°C to +75°C.
Class I, Zone 1, AEx db IIC T4 IP66/67.
Class I, Zone 1, AEx db eb IIC T4 IP66/67.
Tamb = –50°C to +75°C.
Type 4X, IP66/67.

Receiver with Relays
Class I, Div. 1, Groups B, C & D (T4).
Tamb = –55°C to +75°C.
Class I, Div. 2, Groups A, B, C & D (T4).
Class II/III, Div. 1 & 2, Groups E, F & G (T4).
Tamb = –55°C to +65°C.
Class I, Zone 1, Ex db IIC T4 IEC 60079-29-4 IP66/67.
Tamb = –55°C to +75°C.
Type 4X, IP66/67.

Receiver without Relays
Class I, Div. 1, Groups B, C & D (T4).
Class I, Div. 2, Groups A, B, C & D (T3C).
Class II/III, Div. 1, Groups E, F & G (T4).
Class II/III, Div. 2, Groups E, F & G (T3C).
Tamb = –55°C to +75°C.
Class I, Zone 1, Ex db eb IIC T4 IEC 60079-29-4 IP66/67.
Tamb = –50°C to +75°C.
Class I, Zone 1, Ex db IIC T4 IEC 60079-29-4 IP66/67.
Tamb = –55°C to +75°C.
Type 4X, IP66/67.

Transmitter
Class I, Div. 1, Groups B, C & D (T4).
Class I, Div. 2, Groups A, B, C & D (T3C).
Class II/III, Div. 1, Groups E, F & G (T4).
Class II/III, Div. 2, Groups E, F & G (T3C).
Tamb = –55°C to +75°C.
Class I, Zone 1, Ex db IIC T4 IEC 60079-29-4 IP66/67.
Tamb = –55°C to +75°C.
Class I, Zone 1, Ex db eb IIC T4 IEC 60079-29-4 IP66/67.
Tamb = –50°C to +75°C.
Type 4X, IP66/67.

Receiver
CE 0539 Ex II 2 G
DEMKO 15 ATEX 1386X
Ex db eb IIC T4 EN 60079-29-4 IP66/67
T4 (Tamb –50°C to +75°C)
(Receiver without relays)
–OR–
Ex db IIC T4 EN 60079-29-4 IP66/67
T4 (Tamb –55°C to +75°C)
(Receiver with or without relays)

Transmitter
CE 0539 Ex II 2 G
DEMKO 15 ATEX 1386X
Ex db eb IIC T4 EN 60079-29-4 IP66/67
T4 (Tamb –50°C to +75°C)
–OR–
Ex db IIC T4 EN 60079-29-4 IP66/67
T4 (Tamb –55°C to +75°C)

Performance verified with Methane, Butane, and Propane in accordance with EN 60079-29-4.

Receiver
IECEx ULD 05.0001X
Ex db eb IIC T4 IEC 60079-29-4 IP66/67
T4 (Tamb –50°C to +75°C)
(Receiver without relays)
–OR–
Ex db IIC T4 IEC 60079-29-4 IP66/67
T4 (Tamb –55°C to +75°C)
(Receiver with or without relays)

Transmitter
IECEx ULD 05.0001X
Ex db eb IIC T4 IEC 60079-29-4 IP66/67
T4 (Tamb –50°C to +75°C)
–OR–
Ex db IIC T4 IEC 60079-29-4 IP66/67
T4 (Tamb –55°C to +75°C)

Performance verified with Methane, Butane, and Propane in accordance with IEC 60079-29-4.

IEC 61508: 2010 Parts 1-7
Certified SIL 2 Capable.

INMETRO
UL-BR 15.0742X
Ex db eb IIC T4
Ex db IIC T4
IP66/67
–50°C ≤ Tamb ≤ +75°C (for Ex db eb version)
–55°C ≤ Tamb ≤ +75°C (for Ex db version)

DNV
Certificate No. TAA000002M

90-1215

Specifications subject to change without notice.

Det-Tronics manufacturing system is certified to ISO 9001 — the world's most recognized quality management standard.

Corporate Office
6901 West 110th Street
Minneapolis, MN 55438 USA
www.det-tronics.com

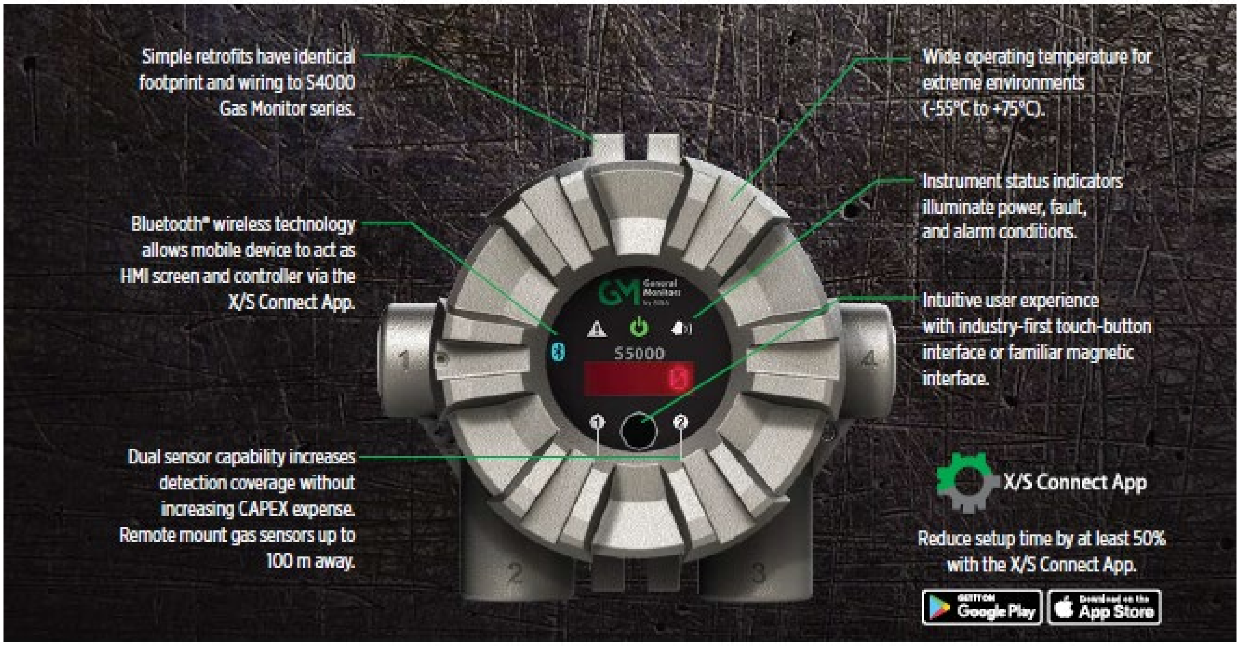
Phone: +1 952.941.5665
Toll-free: +1 800.765.3473
Fax: 952.829.8750
det-tronics@carrier.com

Attachment A-2c – Gas Detection Station Specifications for Toxic Gases

S5000 Gas Monitor

Extreme Durability. Anytime. Anywhere.

General Monitors



Advanced Sensor Technology

POWERED BY XCell® SENSORS WITH TruCal® TECHNOLOGY

- Patented XCell H_2S and CO Sensors with TruCal technology extend calibration cycles for as long as 2 years, actively monitor sensor integrity, and compensate for environmental factors and electrochemical sensor drift.
  - **Diffusion Supervision** sends acoustic signal every 6 hours to check that sensor inlet isn't obstructed so gas can reach the sensor.
  - Worry-free operation—automatically self-checks four times per day.
- Three-year warranty and five-year expected life for XCell Sensors.
- **SafeSwap** enables safe and quick XCell Sensor replacement without powering off gas detector.

Applications

- Compressor stations
- CNG maintenance facilities
- Drilling and production platforms
- Fuel loading facilities
- LNG/LPG processing and storage
- Oil well logging
- Petrochemical
- Refineries

MSA The Safety Company

WE KNOW WHAT'S AT STAKE.

Continued…

Attachment A-2c – Gas Detection Station Specifications for Toxic Gases (continued)

S5000 **Gas Monitor**

Specifications

General Monitors by MSA

Product Specifications		
COMBUSTIBLE GAS SENSOR TYPE	Catalytic bead (Passive comb., XCell comb.) Infrared (IR400)	
TOXIC GAS & OXYGEN SENSOR TYPE	**XCell Toxic**	Ammonia (NH_3), Carbon Monoxide (CO), Carbon Monoxide (CO) H_2-resistant, Chlorine (Cl_2), Sulfur Dioxide (SO_2)
	Passive MOS, Echem, XCell Toxic	Hydrogen Sulfide (H_2S)
	XCell O_2	Oxygen (O_2)
	Infrared	Carbon Dioxide (CO_2)
	Electrochem	Ammonia (NH_3), Hydrogen (H_2), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Nitric Oxide (NO), Nitrogen Dioxide (NO_2)
SENSOR MEASURING RANGES	**Combustible**	0-100% LEL (CB, IR)
	Cl_2	0-5, 0-10, 0-20 ppm
	CO	0-100, 0-500, 0-1000 ppm
	CO, H_2-resistant	0-100 ppm
	CO_2	0-2000, 0-5000, 0-10000, 0-30000, 0-50000 ppm
	H_2	0-1000 ppm
	HCl	0-50 ppm
	HCN	0-50 ppm
	H_2S	0-10, 0-20, 0-50, 0-100, 0-500 ppm
	NH_3	0-100 ppm, 0-1000 ppm
	NO	0–100 ppm
	NO_2	0-10 ppm
	O_2	0-25%
	SO_2	0-25, 0–100 ppm
APPROVALS CLASSIFICATION	*See manual for complete CSA listings.*	
DIVISIONS (US/CAN)	Class I, Div/Zone 1&2, Groups A, B, C & D T5/T4; Class II, Div/Zone 1&2, Groups E, F & G, T6; Class III Type 4X, IP66	
US ZONES	Class I, Zone 1 AEx db IIC T5 Gb Class I, Zone 2 AEx nA nC IIC T4 Gc Zone 21 AEx tb IIIC T85°C Db	
CANADIAN ZONES/ ATEX/ IECEx	Ex db IIC T5 Gb Ex nA nC IIC T4 Gc Ex tb IIIC T85°C Db	
CE MARKING DIRECTIVES	Complies with EMC, RED, ATEX	
WARRANTY	**S5000 transmitter**	2 years
	XCell Sensors	3 years
	Passive comb., MOS, IR400, IR700	2 years
	Echem Sensors	Varies by gas
APPROVALS	CSA, FM**, ATEX, IECEx,INMETRO, ABS, DNV-GL Marine, CE Marking. Complies with C22.2 No. 152, FM 6320, ANSI/ISA/CSA/IEC/EN 60079-29-1, ANSI/ ISA 12.13.01. Suitable for SIL 2.	

Dimensions	
HOUSING (W x H x D)	6.37" x 5.38" x 4.25" (162 x 137 x 108 mm)
W/PASSIVE SENSOR	6.37" x 7.62" x 4.25" (162 x 193 x 108 mm)
W/DIGITAL SENSOR	6.37" x 10.4" x 4.25" (162 x 265 x 108 mm)
W/IR400 IR SENSOR	14.8" x 6.0" x 4.25" (375 x 152 x 108 mm)
WEIGHT	8 lb. (3.6 kg), 316 SS

Environmental Specifications		
OPERATING TEMPERATURE RANGE	**Transmitter**	-55°C to +75°C
	CB (sintered, Zones)	-40°C to +70°C
	CB (screened, Div)	-40°C to +75°C
	MOS (sintered, Zones)	-40°C to +70°C
	MOS (screened, Div)	-40°C to +75°C
	IR (CSA)	-40°C to +75°C
	IR (ATEX/IECEx)	-60°C to +75°C
	XCell (Comb)	-55°C to +60°C
	XCell (Toxic/O_2)	-40°C to +60°C
STORAGE TEMPERATURE RANGE	**Housing, IR400, IR700, passive sensors**	-50°C to +85°C
	XCell sensors	-40°C to +60°C
RELATIVE HUMIDITY (NON-CONDENSING)	**XCell sensors, IR400, IR700**	10-95%
	Passive combustible	0-95%
	Passive H_2S	15-95%

Mechanical Specifications			
INPUT POWER	24 VDC nominal, 12 to 30 VDC		
SIGNAL OUTPUT	Dual 4-20 mA current source or sink, HART, Modbus, Bluetooth. *Optional: w/o Bluetooth*		
RELAY RATINGS	5A @ 30VDC; 5A @ 220 VAC (3X) SPDT – fault, warn, alarm		
RELAY MODES	Common, discrete, horn		
NORMAL MAX POWER		**Without Relays**	**With Relays**
	Passive comb.	5.0 W	6.0 W
	Passive MOS	9.8 W	10.8 W
	IR400/IR700	7.9 W	8.9 W
	XCell comb.	5.0 W	6.0 W
	XCell toxic & O_2	2.6 W	3.6 W
	IR400/IR700 + XCell comb.	10.8 W	11.8 W
	IR400/IR700 + XCell toxic or O_2	8.6 W	9.6 W
	Dual XCell toxic or O_2	3.3 W	4.3 W
	Dual XCell comb.	7.4 W	8.4 W
	XCell comb. + XCell toxic or O_2	5.7 W	6.7 W
STATUS INDICATORS	4-digit scrolling LED, icons depicting fault, warn, alarm, Bluetooth, 1 and 2 to indicate sensor reading displayed		
RS-485 OUTPUT	Modbus RTU, suitable for linking up to 128 units or up to 247 units with repeaters		
BAUD RATE	2400, 4800, 9600, 19200, 38400, 115200		
HART	HART 7, Device Description (DD) and Device Type Manager (DTM) available		
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, calibration faults, analog output mismatch fault		
CABLE REQUIREMENTS	3-wire shielded cable for single sensor and 4-wire shielded cable for dual sensor configurations. Accommodates up to 12 AWG or 4 mm2 *Refer to manual for mounting distances.*		

*** See manual for FM-approved sensors*

Specifications subject to change without notice.

MSA operates in over 40 countries worldwide. To find an MSA office near you, please visit ***MSAsafety.com/offices***.

Attachment A-3 – SCADA System Description

The SCADA system is a computer-based system or systems used by personnel in a control room that aims to collect and display information about the CO_2 storage injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using DCC West operator process control selections, the SCADA will have the ability to send commands and control the storage injection network (i.e., start or stop pumps, open or close valves, control process equipment remotely, etc.).

In addition to monitoring and control ability, the SCADA system will include warnings, both audible and visual, to alert the DCC West control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Attachment A-4 – Personnel Multigas Detector Specifications

IBRID MX6

An easy and flexible way to do gas detection

Get ready to see hazardous levels of oxygen, toxic and combustible gas, and volatile organic compounds (VOCs) like never before.

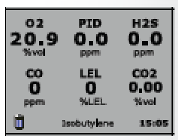
The MX6 iBrid™ is more than an intelligent hybrid of Industrial Scientific's best monitoring technologies. It's the first gas monitor to feature a full-color LCD display screen.

The display improves safety with clear readings in low-light, bright-light or anywhere in between. Whether the work is outside, inside or underground, it's easy to see what gas hazards lurk in the immediate work environment.

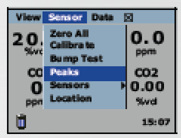
And a color display is more than eye-catching. It allows the user to step through instrument settings and functions with an intuitive menu and the instrument's five-way navigation button. It even supports the option of on-board graphing for easily interpreted direct readings and recorded data.

Plus, the MX6 iBrid is our most rugged instrument ever. It is compatible with our DSX™ Docking Station and iNet

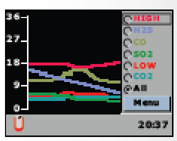
MX6 IBRID COLOUR SCREEN



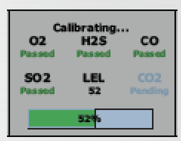
The MX6 clearly shows real-time readings in PPM or % by volume.



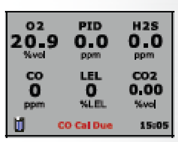
An intuitive menu provides easy access to features and setup.



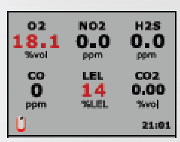
Datalog trends and direct readings can be viewed graphically.



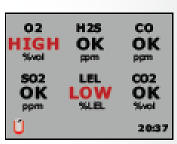
Calibration progress and results are shown for each sensor.



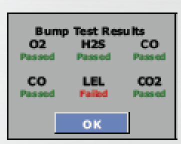
A "calibration due" warning appears for each relevant sensor.



Bright red numerals and a flashing backlight show alarm conditions.



Alarms shown with "Go/No Go" text and flashing backlight.



Color-coded text shows test or calibration results at a glance.

KEY FEATURES

- 24 "Plug-and-Play" fieldreplaceable sensors including PID and Infrared options
- Up to 6 gases monitored simultaneously
- Simple, user-friendly, customizable menudriven navigation
- Five-way navigation button
- Durable, concussionproof overmold
- Optional integral sampling pump with strong 30.5 meter (100 feet) sample draw
- Full-color graphic LCD is highly visible in a variety of lighting conditions
- Powerful, 95 dB audible alarm

iNet READY

Continued…

Attachment A-4 – Personnel Multigas Detector Specifications (continued)

TYPICAL RANGE OF GASES DETECTED

SENSOR	RANGE	RESOLUTION
CATALYTIC BEAD		
Combustible Gas	0-100% LEL	1%
Methane	0-5% vol	0.01%
ELECTROCHEMICAL		
Ammonia	0-500 ppm	1
Carbon Monoxide	0-1,500 ppm	1
Carbon Monoxide (High Range)	0-9,999 ppm	1
Carbon Monoxide/ Hydrogen low	0-1,000 ppm	1
Chlorine	0-50 ppm	0.1
Chlorine Dioxide	0-1 ppm	0.01
Carbon Monoxide/	CO: 0-1,500 ppm	1
Hydrogen Sulfide (COSH)	H2S: 0-500 ppm	0.1
Hydrogen	0-2,000 ppm	1
Hydrogen Chloride	0-30 ppm	0.1
Hydrogen Cyanide	0-30 ppm	0.1
Hydrogen Sulfide	0-500 ppm	0.1
Nitric Oxide	0-1,000 ppm	1
Nitrogen Dioxide	0-150 ppm	0.1
Oxygen	0-30% vol	0.1%
Phosphine	0-5 ppm	0.01
Phosphine (High Range)	0-1,000 ppm	1
Sulfur Dioxide	0-150 ppm	0.1
INFRARED		
Hydrocarbons	0-100% LEL	1%
Methane (% vol)	0-100% vol	1%
Methane (% LEL)	0-100% LEL	1%
Carbon Dioxide	0-5% vol	0.01%
PHOTOIONIZATION		
VOC	0-2,000 ppm	0.1

SPECIFICATIONS

Specifications subject to change without notice

INSTRUMENT WARRANTY:	Warranted for as long as the instrument is supported by Industrial Scientific Corporation
CASE MATERIAL:	Lexan/ABS/Stainless Steel w/ protective rubber overmold
DIMENSIONS:	135 mm x 77 mm x 43 mm (5.3" x 3.05" x 1.7") – without pump 167 mm x 77 mm x 56 mm (6.6" x 3.1" x 2.2") – with pump
WEIGHT:	409 g (14.4 oz) typical – without pump 511 g (18.0 oz) typical – with pump
DISPLAY/READOUT:	Color Graphic Liquid Crystal Display
POWER SOURCE/ RUN TIMES:	Rechargeable Lithium-ion (Li-ion) Battery Pack (24 hours) – without pump Rechargeable, Extended-Range Lithium-ion (Li-ion) Battery Pack (36 hours) – without pump Replaceable AA Alkaline Battery Pack (10.5 hours) – without pump
OPERATING TEMPERATURE RANGE:	-20ºC to 55ºC (-4ºF to 131ºF)
OPERATING HUMIDITY RANGE:	15% to 95% non-condensing (continuous)

Attachment A-5 – Ultrasonic Tool Example

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Ultrasonic Pulse Echo tool

High-resolution simultaneous cement evaluation and casing inspection

The primary goal of cement placement is to provide zonal isolation while at the same time protect the casing from corrosive fluids. However, the cement sheath can be stressed by well activity or a poor cementing job to the point where it is no longer effective. The casing is the first barrier for well integrity and it endures significant wear and corrosive conditions throughout the lifecycle of the well. Compromised casing can lead to catastrophic failure impacting safety, the environment and production.

Regulatory compliance requires evaluation of the casing and cement to ensure well integrity is maintained over the lifecycle of the well.

The **Ultrasonic™ Pulse Echo tool** from Sondex provides ultrasonic pulse echo mapping of the casing and cement with one logging run to gain maximum understanding of wellbore zonal isolation. The Ultrasonic Pulse Echo tool employs a rotating transducer to provide high resolution, 360-degree assessment of both the casing integrity and the cement bond. The transducer uses varying frequencies from 250 to 450 kHz to transmit and measure ultrasonic waveforms reflected from the casing and the cement to assess annular integrity. It provides high-resolution circumferential casing and cement coverage data – detecting defects or channels as narrow as 1.2-in. (30.5 mm) The Ultrasonic Pulse Echo tool can also identify casing integrity problems by inspecting the casing for drill wear, ovality and corrosion.

The Ultrasonic Pulse Echo tool simultaneously acquires measurements for casing and cement in one run. Post processing of the logs is integrated with the acquisition software. The evaluation logs are available immediately after the run reducing non-productive time and significantly shortening the time to make critical decisions to maintain well integrity.

To learn more about how the Ultrasonic Pulse Echo tool will provide maximum understanding of your wellbore zonal isolation in one run, contact your Sondex representative or visit sondex.com.

Applications

- Cement top determination and mapping of cement placement
- Deepwater wells with a variety of cement or fluid conditions
- Drilling wear and corrosion evaluation
- Primary or remedial cement job quality check
- Locating internal and external casing defects
- Heavy wellbore fluid environments

Benefits

- Compliance with well integrity regulations
- Operational efficiency
- Reduce risk of zonal communication
- Reduce risk of casing failure
- Reduce Non-productive time

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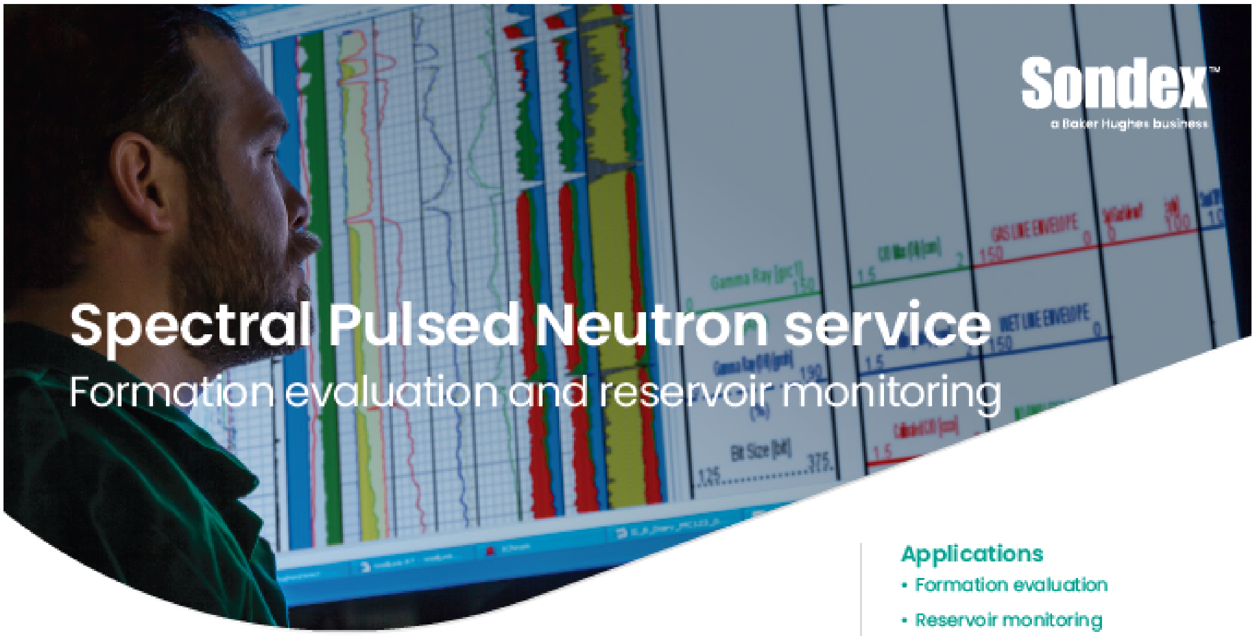
Continued…

Attachment A-5 – Ultrasonic Tool Example (continued)

Ultrasonic Pulse Echo tool specifications	
Answer Products	Acoustic impedance, cement bond data, casing thickness, internal radius, external radius, ovality, internal rugosity, burst pressure
Range of measurement	0 - 10 Mrayl
Accuracy	
Cement impedance	0 - 3.3 Mrayl +/- 0.50 Mrayl; > 3.3 Mrayl +/- 15%
Casing thickness	+/- 2%
Maximum operating pressure	20,000 psi (138 kPa)
Maximum operating temperature	347° F (175 °C) for 4 hr
Maximum casing size (OD)	20.0-in. (508 mm)
Minimum casing size (OD)	4.5-in.* (114.3 mm)
Mud type or weight limitations	
Maximum water-base mud weight	Any weight
Maximum oil-base mud weight	13.3 ppg (1.6 g/cc) [attenuation: 12 db/cm per MHz]
Tool OD	3-⅝-in. (92 mm)
Length	12.86 ft (3.92 m)
Weight (in air)	216 lb (98 kg)
Maximum logging speed	40 ft/min (13 m/min)
Combinability	INTeX, DAL

* Minimum ID of 4.00-in.

Attachment A-6 – Pulsed-Neutron Logging Tool Example



Spectral Pulsed Neutron service

Formation evaluation and reservoir monitoring

The **Spectral Pulsed Neutron (SPN) service** can undertake a broad scope of reservoir evaluation and management applications, including reservoir saturation and produced fluids monitoring, formation evaluation, production profiling, workover and well abandonment evaluation, borehole diagnostics, location of bypassed oil, gas detection and quantification, and identification of water production.

The service uses an advanced, slim-hole, multifunction, pulsed neutron reservoir monitoring tool and is ideally suited for acquiring data through tubing. The tool is flexible with multiple operating modes that are selectable by surface commands. The tool is also very efficient with multiple sensors that enable faster tool movement while performing data acquisition. The SPN service combines multiple acquisition modes, reducing multiple passes down to one pass, without compromising data quality, resulting in logging times reduced by up to 66%.

The Spectral Pulsed Neutron tool employs three high-density high-resolution gamma ray detectors and an advanced digital downhole acquisition system. The reliable high output neutron generator produces gamma ray counts up to 3 times higher than conventional instrumentation providing the most accurate and efficient measurements in the industry. The enhanced detectors and electronics measure both the arrival time and energy of detected gamma rays. The generator is pulsed at distinct frequencies, and the data acquisition system operates in various timing modes to obtain the different gamma ray measurements.

Data acquisition through casing is enabled by the high energy neutrons emitted from the non-chemical pulsed neutron source, even in complicated well completions utilizing multiple tubing and casing strings and sizes. The instrumentation combines multiple nuclear measurements in one system with industry-leading accuracy and precision. Carbon/Oxygen (C/O) and Pulsed Neutron Capture (PNC) measurements acquired with the SPN tool provide formation fluid saturations, porosity, three-phase holdup determination, and oxygen activation measurements for the detection of water flow in annuli and channels.

Extensive physical characterization of the SPN tool is conducted at our Houston Technology Center. The characterization provides forward-

Applications

- Formation evaluation
- Reservoir monitoring and management
- Borehole diagnostics
- Workover applications

Features and benefits

- Higher count rates and improved signal-to-noise ratio significantly reduces logging times
- Innovative mixed acquisition mode provides a complete pulsed neutron data set all in the same pass
- Multiple modes for operating versatility
- Flexible deployment on e-line
- Pre-job MCNP modelling to provide accurate quantitative fluid saturation

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Continued…

Attachment A-6 – Pulsed-Neutron Logging Tool Example (continued)

looking pulsed neutron measurement response predictions for well candidate evaluation and data analysis. The tool's measurements are interpreted using Monte Carlo N-Particle (MCNP) transport mode modelling to provide accurate saturation profiles in a wide range of borehole, casing, formation, and fluid conditions.

The Spectral Pulsed Neutron service includes modelling of unique downhole conditions to ensure that the analysis of the reservoir is as accurate as possible. Extensive pre-job planning tools are available for the design of a data acquisition program that optimizes the answers provided by the service.

Spectral Pulsed Neutron Service data can be matched with previous-generation **RPM™ reservoir performance monitor service** measurements for easy comparison in mature fields. For remedial work and time-lapse monitoring, the data can be overlaid with existing log measurements in real time, allowing rapid workover planning.

The SPN hardware is combinable with other production logging instruments. It is constructed in short, modular sections to facilitate shipping and handling.

Applications description

Formation evaluation

- Salinity-independent quantitative measurement with the **GasView™ gas saturation service**
- Salinity-independent quantitative measurement with the **OmniView™ three-phase fluid saturation service**
- Salinity-independent quantitative measurement in light oil reservoirs with the **OilView™ two-phase fluid saturation service**
- Quantitative measurement in light oil or high salinity reservoirs with the **FluidView™ multiphase saturation service**
- Formation resistivity, neutron porosity, and density data with **NEO™ openhole log emulation**
- Porosity evaluation

Reservoir monitoring and management

- Reservoir management base logs
- Monitoring fluid contacts
- Time-lapse fluid saturation monitoring
- Production and reservoir depletion
- Identification of pressure-depleted sands
- Monitoring wells with air or gas filled boreholes
- Gas flood monitoring for steam, CO_2 sequestration and EOR projects
- Steam envelope build up in steam-assisted gravity drainage (SAGD) wells

Borehole diagnostics

- Production and hold-up monitoring in horizontal wellbores
- Identification of water channeling
- Annular injection profiling in multiple-string completions

Workover applications

- Location of bypassed and irreducible hydrocarbons, residual oil saturation independent of water salinities
- Re-evaluation of marginal fields
- Gravel pack evaluation and monitoring

Tool specification

Description	Specification
Tool diameter	1.80 in. (w/ Boron coating)
Tool length	19 ft
	29.75 ft (w/ telemetry, GR and CCL)
Temperature	350°F
Pressure	20,000 psi
Minimum restriction	1.90 in.
Maximum hole size	12.25 in.
Tool compressive strength	570 lb
Tool tensile strength	22,000 lb
Maximum bend rate	30°/100 ft
Crystals	BrilLance 380

Logging speed

Mode	Speed
PNC	30 fpm
C/O	2 to 6 fpm
PNC3D	20 fpm
PNHI	20 fpm
Hydrolog	2 to 150 fpm
Mixed mode	2 to 6 fpm

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Attachment A-7 – DTS Fiber-Optic Cable Specifications

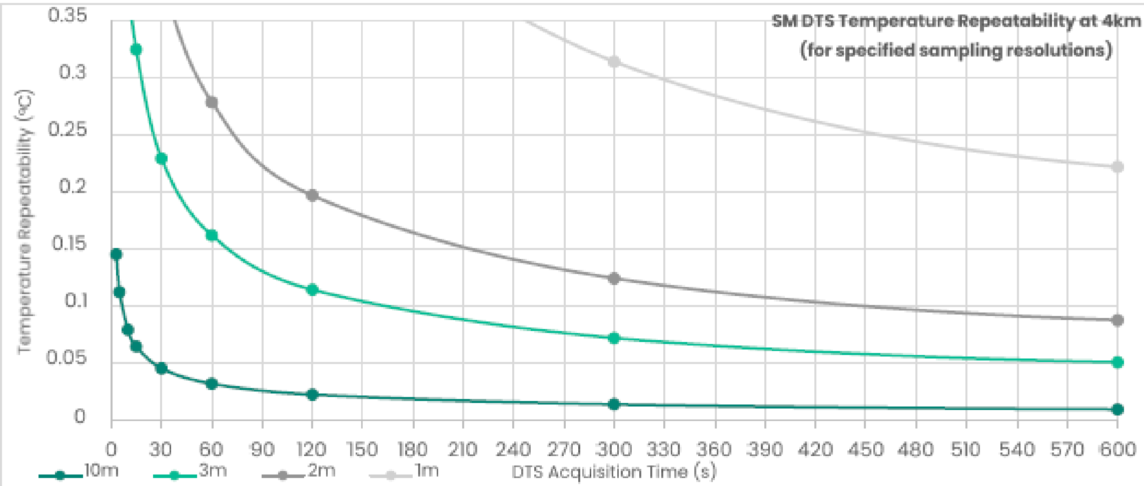
The SureVIEW™ DTS fiber optic interrogator provides convenient multi-well performance monitoring with continuous, rapidly updating temperature profiles along the length of the completion. The interrogator is designed to provide highly accurate temperature data from a single SM fiber, which reduces cost by eliminating the need for dual-ended fibre configurations.

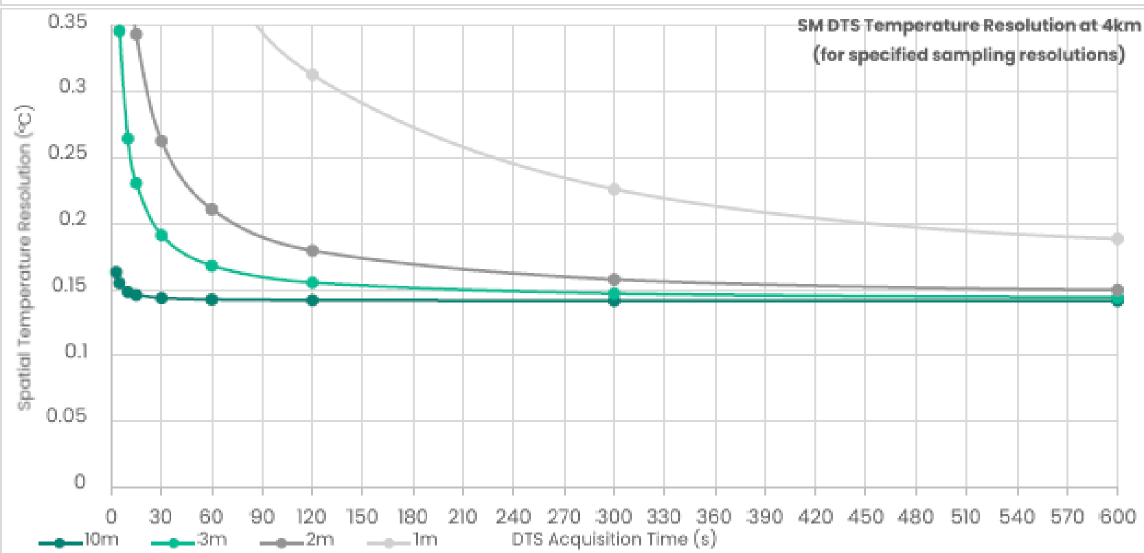
SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Form Factor	19 in. Rack
Height	2U
Depth (in.)	19.8
Certifications	TUV (US, Can), CE
Public Software Interfaces	OPC/UA, Modbus
Maximum Distance Range (km)	20+
Minimum Spatial Resolution (m)	1.0
Minimum Sampling Interval (m)	0.33
Fastest Acquisition Rate (sec)	3.3
Number of Channels	8 or 16
Internal Data Storage Capability	250 GB
Fiber Types	9/125 μm SMF CoreBright™
Optical Connectors	Fiber Pigtails
Computer Interfaces	Ethernet, DPI, USB
Power Consumption (W)	100 W maximum

Continued…

Attachment A-7 – DTS Fiber-Optic Cable Specifications (continued)

SureVIEW™ DTS Surface Interrogator Specifications	
Description	**Value**
Voltage Input	22-27 VDC
Differential Attenuation Compensation	Yes
Fiber Configuration	Single-Ended or J-Type
Absolute Temperature Accuracy (°C)	±2 (worst-case, rapid cycling over full operating range)
Operating temperature (°C)	0 to 40
Storage temperature (°C)	-40 to 80
Operating relative humidity (%)	5 to 95
Sensing temperature Range (°C)	0 to 300





Call your local Baker Hughes representative today to learn more about how SureVIEW monitoring systems can reliably enhance your production operations.

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Attachment A-8 – Tubing-Conveyed P/T Gauge Specifications

Obtain reliable, fault-tolerant data in HP/HT environments

The **SureSENS™ QPT ELITE gauge for permanent installations,** from Baker Hughes, measures static and dynamic pressures and temperatures while introducing a step change in reliability and accuracy. The gauge is qualified for operation at pressures up to 35,000 psi (2414 bar) and temperatures up to 225°C (437°F).

The static pressure information obtained can be used to determine production performance, calculate reserves, and provide input to reservoir simulations. The dynamic pressure data can help determine reservoir characteristics and optimize production rates.

The SureSENS QPT ELITE gauge includes the new ELITE electronics package, built upon our industry leading STAR hybrid electronic package design. The ELITE electronics package incorporates an application-specific integrated circuit (ASIC), providing a new level of reliability to the industry.

Baker Hughes provides three configuration options - a single, dual, and triple gauge.

• The single-gauge configuration is an economical option that will also permit the smallest possible running diameter for a streamlined, slim-hole gauge carrier.

• A dual-gauge configuration provides isolated operational redundancy of the electronics and transducer at any given installation point. Each gauge in a dual package operates individually, providing independent measurements for data redundancy and integrity verification.

• The triple gauge option can offer redundancy or be ported to record three independent pressure measurements. The shorter carrier for a side-by-side triple-gauge assembly also retains a slim hole running outside diameter.

Applications

- Single or multiple gauge systems
- Bottomhole pressure less than 35,000 psi and bottomhole temperatures up to 225°C

Features and Benefits

- Provides superior reliability in demanding HP/HT conditions
- Deploys multiple gauge combinations on a single standardized carrier
- Eliminates the need for additional splices, increases reliability, and reduces installation time through unique construction configurations with fewer connections
- Deploys multiple gauges, flowmeters, anad valve positions to provide redundant readings
- Serves as platform for future developments
- Derives finest P/T measurement resolution attainable

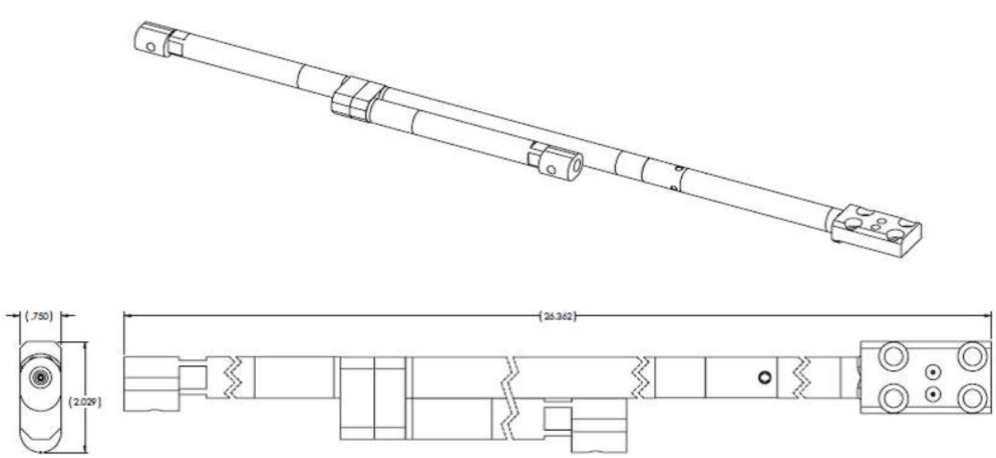
Continued…

Attachment A-8 – Tubing-Conveyed P/T Gauge Specifications (continued)

Length	25.5 in. to 26.5 in. (64.77 cm to 67.31 cm)					
Height/Width	0.750 in. (19.05 mm) / 1.318 in. to 2.50 in. (33.50 mm to 63.50 mm)					
Seals	Metallic seals and EB welds					
Transducer	Shear mode quartz					
Transducer options	10,000 psi (689.5 bar)	16,000 psi (1103.2 bar)	20,000 psi (1379.0 bar)	25,000 psi (1723.6 bar)	30,000 psi (2068.4 bar)	35,000 psi (2413.7 bar)
Material	Inconel 718	MP35N				
Pressure range	15 psi to 11,000 psi (1 bar to 758.4 bar)	15 psi to 18,000 psi (1 bar to 1241.1 bar)	15 psi to 23,000 psi (1 bar to 1620.3 bar)	15 psi to 28,000 psi (1 bar to 1930.5 bar)	15 psi to 33,000 psi (1 bar to 2275.3 bar)	15 psi to 37,500 psi (1 bar to 2585.5 bar)
Temperature rating (operating)	-99.4°F to 302°F (-73°C to 150°C)	-99.4 to 437°F (-73°C to 225°C)				
Storage temperature	-40°F to 302°F (-40°C to 150°C)					
Temperature shock	5.4°F (3°C) per minute					
Vibration	>10 G, 10 Hz-2 kHz					
Shock	500 G					
Pressure measurement range (calibrated)	200 psi to 10,000 psi (13.8 bar to 689.5 bar)	200 psi to 16,000 psi (13.8bar to 1103.2 bar)	200 psi to 20,000 psi (13.8 bar to 1379.0 bar)	200 psi to 25,000 psi (13.8 bar to 1723.6 bar)	200 psi to 30,000 psi (13.8 bar to 2068.4 bar)	200 psi to 35,000 psi (13.8 bar to 2413.7 bar)
Pressure accuracy	+-0.015% 1.5 psi at full scale	+-0.02% 3.2 psi at full scale	+-0.02% 4.0 psi at full scale	+-0.02% 5.0 psi at full scale	+-0.025% 7.5 psi at full scale	+ -0.03% 10.5 psi at full scale
Pressure resolution	0.0001 psi					
Pressure stability	0.02% full scale, 2.0 psi/year	+-0.02% full scale, 3.2 psi/year	+-0.02% full scale, 4.0 psi/year	+-0.02% full scale, 5.0 psi/year	+-0.02% full scale, 7.5 psi/year	+ -0.03% full scale, 10.5 psi/year
Temperature measurement range (calibrated)	77°F to 302°F (25°C to 150°C)	77°F to 437°F (25°C to 225°C)				
Temperature accuracy	0.27°F (0.15°C)					
Temperature resolution	0.0001°F					
Temperature stability	0.018°F (<0.01°C) per year					
Maximum sample rate/second	>16					
Number of gauges support/TEC	32					
Cable distance transmission	50,000 ft (15,240 m)					

SureSENS QPT ELITE Downhole Pressure Temperature Gauge

Figure 4: Assembly Drawing J06-526-00 (tubing with feedthrough)



Attachment A-9 – DAS Fiber-Optic Cable Specifications

SureVIEW sDAS

Fiber optic acoustic monitoring for subsea wells

The **SureVIEW™ seismic distributed acoustic sensing (sDAS) interrogator** offers all of the benefits of fiber optic acoustic monitoring—from flow monitoring and optimization, sand detection and stimulation optimization, to seismic and microseismic monitoring—combined in a single interrogator unit.

Unlike other DAS interrogators, SureVIEW sDAS utilizes Baker Hughes SureVIEW **CoreBright™ optical fiber**, a proprietary fiber specifically designed for durable oil and gas deployments. This allows operators to monitor high value assets through the life of the well, from well-centric to reservoir focused scales.

The combination of SureVIEW sDAS with **CoreBright™ enhanced backscatter fiber (EBF)** permits the acquisition of data in subsea wells located long distances from the data acquisition unit. Testing shows that a vertical seismic profile (VSP) can be acquired from the shore, or host facility up to 50 miles (80 km) away.

The SureVIEW sDAS interrogator can output various formats, suitable for various applications, and has the ability to break down the raw data, as well as compute attributes on-the-fly (frequency-band energy, individual spectra). It can also record data either in continuous or trigger mode, and is equipped with an independent global positioning system (GPS)–thus permitting clock synchronization and clock drift control.

SureVIEW sDAS delivers high fidelity data readily available to processing and answer solution teams. The system may also be remotely operated through a connection to the Baker Hughes cloud services, and is compliant with HDF5 data format.

From seismic processing, reservoir characterization, data visualization and advanced modelling and interpretation, we deliver answers, not just data.

Contact a Baker Hughes representative today to learn how we can help you take energy forward.

Applications

- Subsea and land wells
- Permanent reservoir monitoring
  - Flow monitoring
  - Sand detection
  - Leak detection
  - Stimulation optimization
  - Microseismic monitoring
  - Vertical seismic profiling (VSP)

Benefits

- Delivers an integrated solution from subsurface equipment to remote visualization and analytics that saves time and cost
- Simplifies handling and management of data reducing IT integration time
- Offers a better understanding of the wellbore/reservoir enabling sustained and/or incremental production of your asset
- Enables understanding of the entire completion when coupled with Baker Hughes SureCONNECT™ downhole intelligent wet-connect system
- Provides a long-term well and reservoir monitoring solution while reducing operating costs by minimizing/eliminating unnecessary interventions

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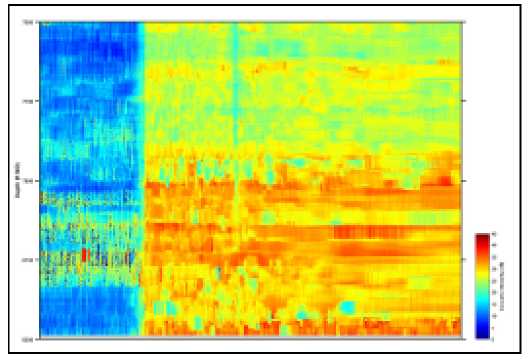
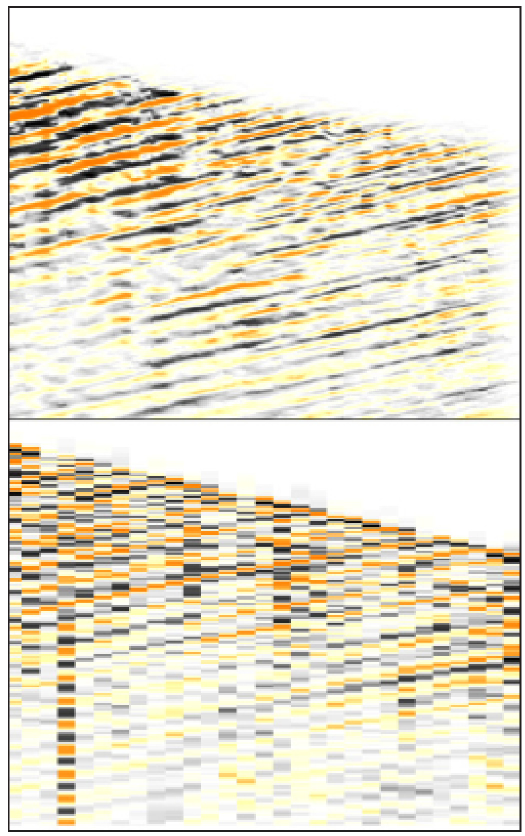
Continued…

Attachment A-9 – DAS Fiber-Optic Cable Specifications (continued)

Technical Specifications	
Technology Supported	SureVIEW DAS VSP
Type	Rackmount
Number of Channels	8
Rack Unit Dimensions	6U
Certifications	CE, TUV
Supply Voltage	110-240 Volts AC, 50 or 60Hz
Typical Power Consumption	Up to 400W
Operating Temperature Range	0°C to +40°C / 32°F to +104°F
Optical Connectors	F3000/APC
Interface Connections	Ethernet, GPS, USB (Geophones) DC Trigger Pulse (GPS Synced)
File Formats	PRODML/HDF5/SEG-Y
Data Storage	960GB (Internal) 8TB (NAS)
Maximum Distance Range	Up to 12 miles (20 km) with CoreBright fiber Up to 50 miles (80 km) with CoreBright EBF
Fiber Type	Single Mode
Spatial Resolution	1.5 meter
Minimum Sampling Interval	0.33 meter
Gauge Length	Selectable 3, 7, 15, 31 meters
Maximum Pulse Rate	10 kHz
Dynamic Range	0.24 nε (over full bandwidth) 1.5pε (narrowband) Up to 1 με



This Distributed Acoustic Sensing (DAS) Frequency Band Energy (FBE) shows acoustic energy acquired in a multi-zone injection well. This information was used to estimate zonal flow allocation.



This comparison shows the upgoing wavefield of a vertical seismic profile (VSP) acquired above the well with a wireline tool (bottom) versus 43 miles (69 km) away from the wellhead (top) with sDAS, and CoreBright™ as lead-in fiber, a 3dB attenuation and a subsea amplifier, and CoreBright™ EBF inside the well.

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APPENDIX E

TESTING AND MONITORING SUMMARY TABLE

Table E-1. Summary of DCC West's Testing and Monitoring Plan

SFP Reference	Monitoring Type	Parameter	Activity Description	Sampling Location/Equipment	Sampling Frequency: Preinjection	Sampling Frequency: Injection (20 years)	Sampling Frequency: Postinjection (10 years minimum)	Primary Purpose(s) of Activity
5.1	CO_2 Stream Analysis	Volume/Mass	Real-time, continuous data recording via SCADA system	Volumetric flowmeters near each injection wellhead	None	Continuous	None	CO_2 accounting and operational safety assurance
		Flow rate						
		Pressure		Surface P/T gauges				
		Temperature						
		Composition	CO_2 stream sampling	Sample ports near each injection wellhead	At least once	At least quarterly	None	CO_2 accounting and ensures stream compatibility with project materials in contact with CO_2
5.2	Surface Facilities Leak Detection Plan	Mass balance	Real-time, continuous data recording via SCADA system and remote-controlled shutoff devices	Dual P/T gauges and flowmeters placed downstream of the point of transfer and near each injection wellhead	None	Continuous	None	CO_2 accounting, leak detection, and operational safety assurance
		Noise	Real-time, continuous data recording via SCADA system	Acoustic detectors installed along the flowline	None	Continuous	None	
		Gas concentrations (e.g., CO_2, CH_4, and H_2S)	Real-time, continuous data recording via SCADA system	Gas detection stations placed at injection wellheads and key wellsite locations	None	Continuous	None	
5.3.2 and 5.6.2	CO_2 Flowline and Downhole Corrosion Detection Plan	Mass/Thickness	Corrosion coupon testing	Corrosion coupon sample ports near CO_2 injection wellbores (IIW-N and IIW-S)	None	Quarterly	None	Corrosion detection of project materials in contact with CO_2 and operational safety assurance
		Pitting						
		Cracking						
5.4 and Table 5-3 6.2.1 and Table 6-1	Wellbore Mechanical Integrity Testing (external)	Material wall thickness	Ultrasonic logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	May repeat during workovers when tubing must be pulled	May repeat during workovers when tubing is pulled (J-LOC 1 only)	Mechanical integrity confirmation and operational safety assurance
		Radial cement bond						
		Saturation profile near the wellbore (outside casing)	Pulsed-neutron logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	Year 1, Year 3, and every 3 years thereafter in the CO_2 injection wells	None	
		Temperature profile	Real-time, continuous data recording via SCADA system	DTS fiber-optic cable installed in CO_2 injection wells	Install at well completion	Continuous	None	
		Temperature or oxygen activation profile	Temperature or oxygen activation logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Acquire once per well	Annually in CO_2 injection wells (only if DTS fails)	At cessation and at least every 3 years thereafter (J-LOC 1 only)	
	Wellbore Mechanical Integrity Testing (internal)	Pressure/temperature	Real-time, continuous data recording via SCADA system	Surface Pressure Gauge on the Casing Annulus (between surface and long-string sections)	Install at well completion	Continuous	Continuous (J-LOC 1 only)	
			Tubing-casing annulus pressure testing	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	Repeat pressure tests will be conducted anytime the well tubing is pulled and reinstalled	Repeat pressure tests will be conducted anytime the well tubing is pulled and reinstalled (J-LOC 1 only)	
			Real-time, continuous data recording via SCADA system	Surface and tubing-conveyed P/T gauges in project wellbores (IIW-N, IIW-S, and J-LOC 1)	Install at well completion	Continuous	Continuous (J-LOC 1 only)	
			Real-time, continuous data recording via SCADA system	N_2 cushion with seal pot system at each CO_2 injection well	Install prior to injection	Continuous	None	
		Saturation profile near the wellbore (well annulus)	Pulsed-neutron logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	Year 1, Year 3, and every 3 years thereafter in the CO_2 injection wells	None	
5.7.1 and Table 5-7	Near-Surface Monitoring – Soil Gas	Soil gas composition (e.g., CO_2, N_2, and O_2)	Soil gas sampling	Permanent stations (SGPS01 through SGPS03)	3–4 seasonal samples per station (with isotopes	3–4 seasonal samples per station (no isotopes)	3–4 seasonal samples per station in Year 21 and every 3 years thereafter (no isotopes)	Protection of near-surface environments
		Soil gas isotopes						Source attribution

Continued…

Table E-1. Summary of DCC West's Testing and Monitoring Plan (continued)

SFP Reference	Monitoring Type		Parameter	Activity Description	Sampling Location/Equipment	Sampling Frequency: Preinjection	Sampling Frequency: Injection (20 years)	Sampling Frequency: Postinjection (10 years minimum)	Primary Purpose(s) of Activity
5.7.1 and Table 5-7 6.2.2 and Table 6-2	Near-Surface Monitoring	Groundwater	Water composition (e.g., pH, TDS, conductivity, major cations/anions, and trace metals)	Existing shallow groundwater well sampling	Up to 5 groundwater well locations (shown in Figure 5-6)	3–4 seasonal samples per well (with isotopes	At start of injection, shift sampling program to FH01 location. Wells may be phased in over time as the CO_2 plume migrates.	Collect 3–4 seasonal samples in Year 21, Year 24, and Year 29 as part of the final facility closure.	Protection of USDWs
			Water isotopes						Source attribution
			Water composition (e.g., pH, TDS, conductivity, major cations/anions, and trace metals)	Fox Hills Aquifer sampling	FH01 near CO_2 injection well pad	3–4 seasonal samples per well (with isotopes	3–4 seasonal samples per well in Years 1–4 and reduce to annually thereafter (no isotopes)		Protection of USDWs
			Water isotopes						Source attribution
			Water composition (e.g., pH, TDS, conductivity, major cations/anions, and trace metals)	Fox Hills Aquifer sampling	FH02 near NDIC File No. 4940	None	Drill FH02 when CO_2 plume approaches NDIC File No. 4940 within 1 mile (Year 9). Collect 3–4 seasonal samples in first year after drilling and reduce sample frequency to annually thereafter		Protection of USDWs
			Water composition (e.g., pH, TDS, conductivity, major cations/anions, and trace metals)	Fox Hills Aquifer sampling	W295 near NDIC File No. 2183	Included in 5 existing shallow groundwater well sampling	Collect a sample for water quality analysis annually once the CO2 plume approaches NDIC File No. 2183 within 1 mile (Year 17).		
5.7.2 and Table 5-8 6.2.3 and Table 6-3	Deep Subsurface Monitoring	Above-Zone Monitoring Interval	Temperature profile (from Opeche-Picard through Skull Creek)	Real-time, continuous data recording via SCADA system	DTS fiber-optic cable installed in CO_2 injection wells	Install at well completion	Continuous	None	Assurance of containment in the storage reservoir
			Saturation profile (from Opeche-Picard through Skull Creek)	Pulsed-neutron logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	Year 1, Year 3, and every 3 years thereafter in the CO_2 injection wells	None	
		Storage Reservoir (direct)	Temperature profile (from Amsden through Opeche-Picard)	Real-time, continuous data recording via SCADA system	DTS fiber-optic cable installed in CO_2 injection wells	Install at well completion	Continuous	None	Determination of storage reservoir performance
			Saturation profile (from Amsden through Opeche-Picard)	Pulsed-neutron logging	Project wellbores (IIW-N, IIW-S, and J-LOC 1)	Once per well	Year 1, Year 3, and every 3 years thereafter in the CO_2 injection wells	None	
			Pressure/temperature	Real-time, continuous data recording via SCADA system	Tubing-conveyed P/T gauge with sensor ported through the tubing in project wellbores (IIW-N, IIW-S, and J-LOC 1) to monitor the Broom Creek	Install at well completion	Continuous	Continuous (J-LOC 1 only)	CO_2 pressure front tracking to ensure conformance with model and simulation projections
			Injectivity	Pressure falloff testing	CO_2 injection wellbores (IIW-N and IIW-S)	Once per well	Once every 5 years per well	None	Assurance of storage reservoir performance
		Storage Reservoir (indirect)	CO_2 saturation	Vertical seismic profiles	CO_2 plume extents (see Figure 5-8)	Collect baseline	Collect repeat in Year 1	None	CO_2 plume tracking to ensure conformance with model and simulation projections
				Time-lapse 2D seismic surveys	CO_2 plume extents (see Figure 5-8)	Collect baseline	Repeat in Years 2 and 4. At Year 4, reevaluate frequency. DCC West plans to collect repeat seismic surveys on at least a 5-year frequency thereafter (e.g., Year 9, 14, and 19).	To be determined	
			Seismicity	Real-time, continuous data recording	Multiple seismometer stations installed within AOR	Install stations	Continuous	None	Seismic event detection and operational safety assurance

APPENDIX F

EMERGENCY AND REMEDIAL RESPONSE PLAN SCENARIOS

Table F-1. Risk Scenario Identification and Emergency Remedial and Response

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
1	Preinjection	***Leakage – drilling operations:*** Hydrostatic column controlling the well decreases below the formation pressure, resulting in a sudden influx of fluid, causing a well control event with loss of containment.	• Flow sensor • Pressure sensor • Tank level indicator • Tripping displacement practices • Mud weight control	• Blowout prevent (BOP) equipment • Kill fluid • Well control training •BOP drills • BOP testing protocol • Kick drill • Lubricators for wireline operations	<u>Drilling:</u> • Stop operation. • Close BOP. • Clear floor and secure area. • Execute well control procedure. • Evaluate drilling parameters to identify root cause. • Notify regulator and propose an action plan based on the finding. • Continue operations. <u>Completion:</u> • Stop operations. • Close BOP. • Clear floor and secure area. • Execute well control procedure. • Notify regulator and propose an action plan based on the finding • Continue operations.	• Rig crew • Rig manager • Field superintendent • Project manager
2	Preinjection	***Leakage – Drilling operations:*** Failure of surface casing completion to protect underground source of drinking water (USDW) while drilling resulting in cross flow of brine between formations resulting in fluid losses into the USDW.	• Pressure sensors • Cement bond log (CBL)	• Pressure sensors • USDW will be covered with the surface casing and set in Pierre Formation. • Casing test after cementing surface casing to check integrity • Formation integrity test (FIT) to verify shoe integrity • CBL to check cement bonding	• In case of influx, control the well without compromising the shoe integrity. • In the case of the shoe leaking, squeeze to regain integrity. • In the case of the surface casing leaking, squeeze or install a casing patch. • Notify regulator and propose remediation plans.	• Rig crew • Rig manager • Field superintendent

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
4	Injection	*Leakage – Project Wellbores* A loss of mechanical integrity in the injection well causing a tubing/packer to leak due to corrosion damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause communication of formation fluids with the annular casing tubing as well as sustained casing pressure. There is no loss of containment (LOC) in this scenario.	* Pressure and temperature gauges on surface and downhole real time * Pulsed-neutron logs (PNLs) *Annular pressure test * CO_2 leak sensors on the wellhead	* Tubing at 15CR or better * Inhibited packer fluid in annulus * Corrosion-monitoring plan * Dry CO_2 injected * 25CR packers * FF trim tubing hanger and tree * CR tubing tailpipes below packers * CR or Inconel carrier for the sensors * New tubing	* Trigger SCADA (supervisory control and data acquisition) alarms/beacons by the system, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * If tubing leak is detected, notify regulator and propose an action plan based on the finding. * Schedule well service to repair tubing.	* Operation engineer * Field superintendent * Project manager
5	Injection/ Postinjection	***Leakage – Project Wellbores*** A loss of mechanical integrity in the monitoring well causing a tubing/packer to leak due to corrosion damage in the tubulars during installation, fatigue, higher load profiles, and others and could cause a communication of the formation fluids with the annular casing tubing as well as sustained casing pressure. There is no LOC in this scenario.	* Pressure and temperature gauges on surface and downhole real time * PNLs * Annular pressure test. * CO_2 leak sensors on the wellhead	* Tubing at 15CR or better * Inhibited packer fluid in annulus * Corrosion-monitoring plan * 25CR packers * CR tubing below/between packers * CR or Inconel carrier for the sensors * New tubing * Cased hole logging program * Monitoring wells are designed to be outside of the projected plume for the majority of the project which reduces the risk of contact with CO_2.	* Trigger SCADA alarms/beacons by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Notify regulator and propose an action plan for well service. * Schedule well service to repair tubing or abandon the well.	* Operation engineer * Field superintendent * Project manager * Rig crew and well contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
6	Injection	***Leakage – Project Wellbores:*** A loss of mechanical integrity in the injection wells causing a casing leak due to corrosion, damage in the tubulars during installation, fatigue, higher load profiles, or others. This event could cause migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	* Pressure and temperature gauges on surface and downhole real time * CO_2 leak sensors on the wellhead * Distributed temperature-sensing (DTS) fiber real time alongside the casing * Flow rate monitoring * Soil gas probes * PNLs * CBL/ultrasonic logging * USDW water monitoring	* CO_2-resistant cement and metallurgic across injection zone * Injection through tubing and packer * Nickel-plated packers * CR or Inconel carrier sensors * Inhibited packer fluid in the annular * Cement to surface * Corrosion-monitoring plan * Cased hole logging program * New casing and tubing installed	* Trigger SCADA alarms/beacons by the system in place, monitoring personnel, or operations engineer. * Follow protocol to stop operation, vent, or deviate CO_2. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * Notify regulator and propose an action plan based on the finding and location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and well contractors * Remediation contractors
7	Injection/ Postinjection	***Leakage – Project Wellbores:*** A loss of mechanical integrity in the monitoring well causing a casing leak due to corrosion, damage in the tubulars during installation, fatigue, higher load profiles, and others. This event could cause a migration of CO_2 and brines through the casing, the cement sheet, and into different formations of the injection target or into USDW.	* Pressure and temperature gauges on surface and downhole real time * CO_2 leak sensors on the wellhead * Soil gas probes * PNLs * CBL/ultrasonic logging * USDW water monitoring	* CO_2-resistant cement across injection zone * 25CR packers * CR or Inconel carrier sensors * Inhibited packer fluid in the annular * Cement to surface * Corrosion-monitoring plan * Cased hole logging program * New casing and tubing installed *Monitoring wells are designed to be outside of the projected plume for most of the project's life cycle which minimizes the risk of contact with CO_2.	* Trigger SCADA alarms/beacons by the system, monitoring personnel, or operations engineer. * Troubleshoot the well. * Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency. * Notify regulator and propose an action plan based on the findings and the location of the leak. * Schedule well service to repair the casing.	* Operation engineer * Field superintendent * Project manager * Rig crew and well contractors * Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
8	Injection/ Postinjection	***Leakage – Legacy Wellbores:*** Brines and CO_2 could migrate through poor cement bonding, cement degradation, or cracking in the cement of plugged and abandoned (P&A) wells.	* Soil gas probes * Time-lapse seismic survey *USDW water sampling	* Legacy wells are properly abandoned for brine movement because of pressurization of injection zone * Injectors will be abandoned as soon as CO_2 injection in the hub ends, except if they are left as monitoring wells	* Evaluate if it is a positive CO_2 release because of a leak in the legacy/P&A well. * Notify regulator and propose plan to repair the well, delineate the area, and identify potential resources affected. * Discuss specific remediation actions and monitoring plans. * Execute program, monitor, and evaluate efficacy.	* Operation engineer * Field superintendent * Project manager * Rig crew and well contractors * Remediation contractors
9	Injection	***Leakage – Faults and Fractures:*** During injection, the pressurization of the injection zone exceeds the sealing capacity of the cap rock/seal above or if there are features such as fault or fractures that are reactivated, creating a leakage pathway for CO_2 and brine to migrate to a shallower formation, including a USDW.	* USDW sampling * Time-lapse seismic survey * PNLs in injector and monitoring wells * Gas soil monitoring	* Seismic survey in the area shows no faults crossing the storage formation or the seal. * Injection is limited to 90% of frac gradient. * Extensive characterization of the rocks shows good sealing capacity. * In case cap rock above Broom Creek fails, Inyan Kara underpressure zone will act as a buffer formation before CO_2 or brines reaching USDW.	* Assess root cause by reviewing monitoring data. * Notify regulators. * If required, follow protocol to stop injection. * If required, conduct geophysical survey to delineate potential leak path. * Evaluate if there is a movement of CO_2 or brines to USDW. If USDW gets affected, discuss with regulatory agency remediation options, action plan, and monitoring program. * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with regulator.	* Monitoring staff * Geologist * Reservoir engineer * Project manager * Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
10	Injection	***Leakage – Geomechanical Seal Failure*** Elevated well bottomhole pressure (BHP) either exceeds the permitted maximum injection pressure or the estimated maximum injection pressure is inaccurate (i.e., the true fracture pressure is lower than the estimated maximum pressure) in the injection zone, resulting in the failure of the confining system and leading to vertical migration of CO_2 or brine to a USDW, the surface or atmosphere (CO_2 only).	* Pressure gauges on surface and downhole real time * USDW sampling * Time-lapse seismic survey * PNL in injector and monitoring wells * Soil gas monitoring	* Seismic survey in the area shows no faults crossing the storage formation or the seal. * Injection is limited to 90% of the fracture gradient. * Core and geomechanical testing and geochemical modeling of the upper confining zone show good sealing capacity and fluid compatibility, respectively. * In the event that the cap rock above the Broom Creek fails, the Inyan Kara underpressured zone will act as a buffer formation before CO_2 or brines are able to reach the USDW. *Microfracture test prior to receiving authorization to operate, confirm formation breakdown pressure.	* Trigger SCADA alarms/beacons by the system, monitoring personnel, or operations engineer. * Follow protocol to stop injection. * Designate an exclusion zone, and provide appropriate personal protective equipment (PPE) for protection of on-site personnel. * Assess root cause by reviewing monitoring data. * If required, conduct geophysical survey to delineate potential leakage pathway. * Evaluate if there is a movement of CO_2 or brines to USDW. * Notify regulatory and propose remediation options, action plan, and monitoring program. * Actions to restore injection will depend on the nature of the leak path and the extent. Operator needs to reevaluate model and discuss action plan with regulator.	*Operation engineer *Monitoring staff * Geologist * Reservoir engineer * Project manager * Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
11	Injection	***Leakage – Natural Disaster:*** A natural disaster event – e.g., snowstorm, tornadoes, floods – impacts the wellhead for the project injection well, forcing the release of CO_2 at the surface (venting).	N/A	* Emergency shutdown (ESD) valve installed near the wellhead * Weather monitoring *Regular safety training for operations personnel, including operator shut-in procedures and emergency response scenarios	* Trigger SCADA alarms/beacons by the system or operations staff. * Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional. * If there are injured personnel, call emergency team and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location and secure the perimeter. If possible, install containment devices around the location. * Contact well control special team to execute blowout emergency plan that may include but is not limited to capping the well, secure location, drill relief well to kill injector, properly repair or abandon injection well. This plan would be discussed with the regulatory agency. * Evaluate environmental impact (soil, water, fauna, vegetation). * Notify regulator and propose action plan. * Execute remediation, and install monitoring system as needed.	* Operation engineer * Field superintendent * Project manager * Rig crew and well contractors * Remediation contractors * Well control specialist

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
12	Injection	***Leakage – Surface Infrastructure:*** Vehicle strikes other surface equipment (e.g., tank battery pumps/compressors, etc.), causing the release of CO_2 at the surface.	* Use of protective equipment, such as bollards * Use of appropriate fencing and signage	* Temperature-controlled building and/or containment, as required by regulation or law, will be proposed to protect the surface equipment and other instrumentation (i.e., interrogator, gauges, meters, etc.).	*Trigger SCADA alarms/beacons by the system or operations staff. * Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. * Follow protocol to shut down CO_2 delivery. *If there are injured personnel, call emergency team and execute evacuation protocol. *Contact field superintendent to activate emergency plan. *Clear location and secure the perimeter. If possible, install containment devices around the location. *Evaluate environmental impact (soil, water, fauna, vegetation). *Assess mechanical integrity of the system. * Notify regulator and propose repair actions. *Repair or replace equipment.	*Operation engineer *Field superintendent *Project manager *Plant manager *Remediation contractors
13	Injection	***Leakage – Surface Infrastructure:*** Failure of a valve results in leakage of CO_2 with potential impacts to health, safety, and the environment, particularly if the leak is not detected and corrected.	* Routine field inspections *Routine inspection of emergency alert systems, monitoring systems and controls	* Equipment upstream or downstream of the failed valve can be used to isolate the problem as necessary. * Preventive maintenance. * Periodic inspections.	*Trigger SCADA alarms/beacons by the system or operations staff. *If there are injured personnel, call emergency team and execute evacuation protocol. *Contact field superintendent to activate emergency plan. *Clear location and secure the perimeter. If possible, install containment devices around the location. *Evaluate environmental impact. *Assess mechanical integrity of the system. *Notify regulator and propose repair actions. *Repair or replace equipment.	*Operation engineer *Field superintendent *Plant manager *Remediation contractors *Emergency teams

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
14	Injection	***Leakage – Surface Infrastructure:*** The CO_2 stream is blocked between valves on the surface, heated (e.g., by the sun), and expands to rupture the line or flowline on the site is plugged and the pressure sensor fails to detect the change, resulting in a CO_2 leak.	*Pressure, temperature and flowmeter sensors in real time *Field inspections	*Relief valves (e.g., pressure safety valves) in areas where this is a risk as part of the design process. * Equipment upstream or downstream of the failed valve can be used to isolate the problem as necessary. *Cleaning protocols: – Wiping the lines – Testing with water – Performing cleaning runs to remove any debris *Witches hat (cone strainer) filters can be used to filter out large pieces of debris on start-up.	*Trigger SCADA alarms/beacons by the system or operations staff. * Follow protocol to shut down CO_2 delivery. *If there are injured personnel, call emergency team and execute evacuation protocol. *Contact field superintendent to activate emergency plan, reverse 9-1-1 protocol for residents or occupants in proximity to occurrence. *Clear location and secure the perimeter. If possible, install containment devices around the location. *Evaluate environmental impact (soil, water, fauna, vegetation). *Assess mechanical integrity of the system. *Notify regulator and propose repair actions. *Repair or replace equipment.	*Operation engineer *Field superintendent *Plant manager *Remediation contractors
15	Injection	***Leakage – Natural Disaster:*** A natural disaster event – e.g., snowstorm, lightning, tornadoes, floods, landslides – impacts the pipelines or flowlines at the storage location, forcing the release of CO_2 at the surface.	*Pressure and flowmeter sensors in real time *Field inspections * Gas detection and soil gas monitoring on or near injection well pad	*Hazard and operability (HAZOP) review. * ESD valve installed near the wellhead so it will cease injection whenever any leak occurs downstream or upstream of the ESD. * Weather monitoring.	* Trigger SCADA alarms/beacons by the system or operations staff. * Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional. * If there are injured personnel, call emergency team, and execute evacuation protocol. * Contact the field superintendent to activate emergency plan. * Clear the location and secure the perimeter. If possible, install containment devices around the location. *Assess mechanical integrity of the pipelines or flowlines. * Notify regulator and propose action plan. * Evaluate environmental impact (soil, water, fauna, vegetation), and present remediation plan to the Commission for approval. * Execute remediation, and install additional monitoring system as needed.	* Operation engineer * Project manager *Remediation contractors *Emergency teams

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
16	Injection	***Leakage – Surface Infrastructure:*** Failure of surface infrastructure results in leakage of H_2S present in the injection stream, impacting health, safety, or the environment.	• Controlled CO_2 injection stream • Leak detection system (LDS) • Wellsite pressure gauges • Field personnel with personal multigas-monitoring devices, including H_2S.	• ESD valve installed near the wellhead so it will cease injection whenever any leak occurs downstream or upstream of the ESD.	• Trigger SCADA alarms/beacons by the system or operations staff. • Follow protocol to shut down CO2 delivery. • Initiate evacuation plan. • Detect H2S leak and its location by interrogator system. • Surface infrastructure will be inspected to determine the root cause of the failure. • Notify regulator and propose action plan. • Repair/replace the infrastructure, and if warranted, put in place the measures necessary to eliminate such events in the future.	• Operation engineer • Field superintendent • Remediation contractors • Emergency teams • Plant manager/ contact
17	Injection	***Leakage - Surface Infrastructure***: Long-distance pipeline that runs through reclaimed mine land and private parcels.	• Satellite imagery • Aerial photography • Optical gas imaging (OGI) cameras • Soil gas monitoring	• Buried pipeline installation specifications and inspection. • Bollards and/or concrete barriers installed to protect aboveground piping at valve stations. • One-call 811 program. • Monitoring in place to detect any anomalous change from remote sensing.	• Trigger SCADA alarms/beacons by the system or operations staff. • Follow protocol to shut down CO2 delivery. • If there are injured personnel, call emergency team, and execute evacuation protocol. • Contact the field superintendent to activate emergency plan, reverse 9-1-1 protocol for residents or occupants in proximity to occurrence. • Clear the location and secure the perimeter. If possible, install containment devices around the location. • Evaluate environmental impact (soil, water, fauna, vegetation). • Notify regulator and propose action plan. • Repair/replace the infrastructure. • Execute remediation, and install necessary measures to eliminate such events happening in the future.	• Operation engineer • Field superintendent • Remediation contractors • Emergency teams • Plant manager/ contact

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
18	Injection	***Leakage – Surface Infrastructure:*** Failure of CO_2 transport flowlines from the Milton R. Young Station (MRYS) SGS (secure geologic storage) Project site CO_2 capture system to Dakota Carbon Center (DCC) west CO_2 injection wellhead.	• Surface pressure/temperature (P/T) gauges and flowmeters at inlet and delivery point	• Preventive maintenance • Periodic inspections • Monitoring devices at both ends of the transmission pipeline and flowline	• Trigger SCADA alarms/beacons by the system or operations staff. • Follow protocol to shut down CO_2 delivery. • Detect CO_2 stream release and its location by interrogator system. • Initiate evacuation plan. • Transmission line and/or flowline failure will be inspected to determine the root cause of the failure. • Notify regulator and propose action plan. • Repair/replace the damaged transmission line or flowline, and if warranted, put in place the measures necessary to eliminate such events in the future.	• Operation engineer • Field superintendent • Remediation contractors • Emergency teams • Plant manager/ contact
19	Injection	***Containment – Vertical Migration via injection well:*** During the life of the injector wells, there are induced stresses and chemical reactions on the tubulars and cement exposed to the CO_2 pressure and plume. Changes in temperature and injection pressure create stresses in the tubulars trying to expand or contract, and it can lead to microannulus effects. The combination of the dry CO_2 injected and the formation brines creates carbonic acid that reacts with the components of the cement to degrade properties such as permeability, strength, porosity, etc., weakening the matrix.	• CO_2 leak sensors on the wellhead • DTS fiber real time alongside the casing • Soil gas probes • USDW water monitoring • PNLs to be run for external mechanical integrity (MI) • CBL/ultrasonic logging • Pressure gauges at surface • Flow rate monitoring	• CO_2-resistant cement and metallurgic across injection zone • Injection through tubing and packer, 15CR or better tubing and 25CR packers • Cement to surface • Cased hole logging program • USDW covered as second barrier with surface casing and surface cement sheet • New casing installed, 15CR or better	• Trigger SCADA alarms/beacons by the system, monitoring personnel, or operations engineer. • Follow protocol to stop operation, vent, or deviate CO_2. • Troubleshoot the well. • Evaluate if there is a movement of CO_2 or brines to USDW. • Notify regulator and propose action plan.* Discuss with regulator the action plan to repair the well or P&A based on the findings of the assessment.	• Operation engineer • Field superintendent • Project manager • Rig crew and well contractors • Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
19 (continued)		These mechanics could lead to cracks, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2.				
20	Injection/ Postinjection	***Containment – Vertical Migration via monitoring well:*** During the life of the monitoring well, there are induced stresses and chemical reactions on the tubulars and cement-exposed brines, pressure plume and, eventually, CO_2. These mechanics could lead to cracks, cement deterioration, channels, or simply permeable paths inside the cement that could connect the injection zone with those above the storage complex, causing migration of brines/CO_2.	• CO_2 leak sensors on the wellhead • Soil gas probes • USDW monitoring • PNLs to be run for external MI • CBL/ultrasonic logging • Pressure gauges at surface	• CO_2-resistant cement across injection zone • Cement to surface • Cased hole logging program • USDW covered as second barrier with surface casing and surface cement sheet • New casing installed, 15CR or better • Monitoring wells are designed to be outside of the plume for most of the injection period.	• Trigger SCADA alarms/beacons by the system, monitoring personnel, or operations engineer. • Troubleshoot the well. • Evaluate if there is a movement of CO_2 or brines to USDW. • Notify regulator and propose action plan. • Discuss with regulator action plan to repair the well or P&A based on the findings of the assessment.	• Operation engineer • Field superintendent • Project manager • Rig crew and well contractors • Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
21	Injection/ Postinjection	***Containment – Lateral Migration of CO_2 Outside Defined AOR:*** The CO_2 plume moves faster or in an unexpected pattern and expands beyond the secured pore space for the project and the area of review (AOR).	• Time-lapse seismic • PNLs in monitoring wells • Pressure and temperature gauges real time in monitoring wells	• Detailed geologic model with stratigraphic wells as calibration • Seismic survey integrated in the model • Extensive characterization of the rocks and formation • AOR review and calibration at least every 5 years • Monitor the plume until stabilization (min. 10 years)	<u>Injection period:</u> • Trigger SCADA alarms/beacons (if unanticipated pressure spike or detection in monitoring well) or identified by monitoring staff. • Review monitoring data and trends and compare with the simulation. • Notify regulator, propose action plan, and request to keep injection process while AOR is reviewed, if the data show that CO_2 will stay in the secured pore space. • Perform logging in monitoring wells. • Conduct geophysical survey as required to evaluate AOR. • Recalibrate model and simulate new AOR. • Assess if additional corrective actions are needed and if it is required to secure additional pore space. • Assess if any remediation is needed, and discuss action plan with regulatory agency. • Present AOR review to regulatory agency for approval and adjust monitoring plan. <u>Postinjection period:</u> • Trigger SCADA alarms/beacons (if unanticipated pressure spike or detection in monitoring well) or identified by monitoring staff. • Review monitoring data and trends, compare with the simulation. • Notify regulator and propose action plan. • Conduct geophysical survey as required to evaluate AOR. • Recalibrate model, and simulate new AOR. • Assess if additional corrective actions are needed and if it is required to secure additional pore space. • Assess if any remediation is needed, and discuss action plan with regulatory agency.	• Monitoring staff • Geologist • Reservoir engineers • Project manager

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
22	Injection/ Postinjection	***Containment – Pressure Propagation:*** A "pressure front" that exceeds the minimum pressure necessary to cause fluid flow from the injection zone into a USDW through a hypothetical conduit (i.e., an artificial penetration that is perforated in both intervals).	• PNLs • Pressure gauges on surface and downhole real time • USDW monitoring • Flow rate monitoring • Time-lapse seismic survey (AOR review periods) • Incremental leakage modeling to validate a lack of potential for fluid movement into the USDW	• Detailed geologic model with stratigraphic wells as calibration • Seismic survey integrated in the model • Extensive characterization of the rocks and formation • AOR review and calibration at least every 5 years • Monitor the plume until stabilization (min 10 years) • USDW covered as second barrier with surface casing and surface cement sheet • Cased hole logging program	<u>Injection period:</u> • Identification by monitoring staff. • Review monitoring data and trends and compare with the simulation. • If endangerment to USDW is suspected, follow shut down procedure. • Notify regulator, propose action plan, and request to keep injection process while AOR is reviewed, if the data show that the CO_2 will stay in the secured pore space. • Perform logging in monitoring wells. • Conduct geophysical survey as required to evaluate AOR. • Recalibrate model and simulate new AOR. • Assess if additional corrective actions are needed and if it is required to secure additional pore space. • Assess if any remediation is needed, and discuss action plan with regulatory agency. • Present AOR review to regulatory agency for approval and adjust monitoring plan. <u>Postinjection period:</u> • Identification by monitoring staff. • Review monitoring data and trends and compare with simulations. • Notify regulator and propose action plan. • Conduct geophysical survey as required to evaluate AOR. • Recalibrate model, and simulate new AOR. • Assess if additional corrective actions are needed and if it is required to secure additional pore space. • Evaluate if there is a movement of CO_2 or brines to USDW. In the remote event that USDW gets affected, discuss remediation options with the regulatory agency.	• Operation engineer • Monitoring staff • Geologist • Reservoir engineers • Project manager • Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
23	Injection	***External impact – Injector Well:*** During injection, the wellhead is hit by a massive object that causes major damages to the equipment. The well gets disconnected from the pipeline and from the shutoff system and leads to a loss of containment of CO_2 and brine.	• Pressure, temperature, and flow sensors in real time • Field inspections • OGI cameras • Bollards and/or concrete barriers installed to protect installation	• Fence location and block direct access to the wellhead • No populated area • Doubled lined pads • Location is able to contain approximately 70,000 bbl	• Trigger SCADA alarms/beacons by the system or operations staff. • Follow protocol to shut down CO_2 delivery if the automatic shutoff device is not functional. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • If there are injured personnel, call emergency team, and execute evacuation protocol. • Contact the field superintendent to activate emergency plan. • Clear the location and secure the perimeter. If possible, install containment devices around the location. • Contact well control special team to execute blowout emergency plan that may include but is not limited to capping the well, secure location, drill relief well to kill injector, properly repair or abandon injection well. This plan would be discussed with the regulatory agency. • Evaluate environmental impact (soil, water, fauna, vegetation). • Notify regulator and propose action plan. • Execute remediation, and install monitoring system as needed.	• Operation engineer • Field superintendent • Project manager • Rig crew and well contractors • Remediation contractors • Well control specialist
24	Injection/ Postinjection	***External impact – Monitoring Well:*** The wellhead of the deep monitoring well is hit by a massive object that causes major damages leading to a LOC. Since the well is open to the formation pressure at the injection zone, formation fluids have the potential to flow and spill on the location.	• Pressure, temperature, and flow sensors in real time • Field inspections • OGI cameras • Bollards and/or concrete barriers installed to protect installation • Incremental leakage modeling to validate a lack of potential for fluid movement into the USDW.	• Fence location and block direct access to the wellhead • No populated area • Lined pads • Reduced pressure in the monitoring well compared with the injector well on bottom	• Trigger SCADA alarms/beacons by the system or operations staff. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • If there are injured personnel, call emergency team and execute evacuation protocol. • Contact the field superintendent to activate emergency plan. • Clear the location and secure the perimeter. If possible, install containment devices around the location.	• Operation engineer • Field superintendent • Project manager • Rig crew and well contractors • Remediation contractors • Well control specialist

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
24 (continued)					• Contact well control special team to execute blowout emergency plan that may include, but is not limited to, capping the well, securing the location, drilling relief well to kill the injector, properly repairing, or abandoning the injection well. • Evaluate environmental impact (soil, water, fauna, vegetation). • Notify regulator and propose action plan. • Execute remediation, and install monitoring system as needed.	
25	Injection	***External impact – Pipeline:*** During injection, the CO_2 pipeline is hit causing major damages and LOC of the CO_2.	• Pressure, temperature, and flowmeter sensors in real time • Field inspections • OGI cameras • Bollards and/or concrete barriers installed to protect aboveground piping at valve stations • Appropriate warning signage/painting • Appropriate fencing	• Buried pipe • Bollards and/or concrete barriers installed to protect aboveground piping at valve stations • Painting for visibility in varied weather conditions • Signage along right of way as needed • One-call 811 program	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel, call emergency team, and execute evacuation protocol. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Verify CO_2 flow was shut off by the system or start protocol to stop flow. • Contact the field superintendent to activate emergency plan. • Clear the location and secure the perimeter. If possible, install containment devices around the location. • Evaluate environmental impact (soil, water, fauna, vegetation). • Notify regulator and propose action plan. • Execute remediation, and install monitoring system as needed.	• Operation engineer • Field superintendent • Remediation contractors • Emergency teams • Plant manager/contact

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
26	Injection	***Monitoring Equipment Failure or Malfunction:*** Failure on the monitoring system/ alarm devices that lead to overpressurization of the system or reservoir beyond the design limits, causing fracturing of the reservoir, leaks or failure on equipment and tubulars, and damage of the facilities.	• Real-time pressure monitoring system and redundancy • Field inspections	• Preventive maintenance • Periodic inspections	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Assess mechanical integrity of the system, and propose repair actions if needed. • Assess any potential environmental impact. • Notify regulator and propose action plan. • Repair or replace instrumentation. Calibrate equipment. • Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir.	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff
27	Injection/ Postinjection	***Injection or Monitoring Equipment Failure:*** Failure of surface injection or monitoring equipment including injection pumps, valves, gauges, meters, sensors, electrical, or other equipment results in potentially unsafe operating conditions and requires an emergency response at the site.	• Real-time monitoring system and redundancy • Field inspections • OGI cameras • Routine inspection/testing of emergency alert systems, monitoring systems, and control systems.	• Preventive maintenance • Periodic inspections	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Assess mechanical integrity of the system, and propose repair actions if needed. • Assess any potential environmental impact. • Notify regulator and propose action plan. • Perform lockout/tagout (LOTO) for defective equipment until it is properly replaced. • Repair or replace instrumentation. Calibrate equipment. • If the assessment allows resuming injection safely, discuss plan with the Commission, and get approval.	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
28	Injection/ Postinjection	***Injection or Monitoring Equipment Failure:*** Malfunction of subsurface injection/monitoring well subsurface equipment including gauges, fiber, cables, or capillary string, requiring an emergency response at the site.	• Real-time monitoring system and redundancy • Field inspections • Routine inspection/testing of emergency alert systems, monitoring systems and controls systems	• Preventive maintenance • Periodic inspections	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Assess mechanical integrity of the system, and propose repair actions if needed. • Assess any potential environmental impact. • Notify regulator and propose action plan. • If the assessment allows resuming injection safely, discuss plan with the Commission, and get approval. • Repair or replace instrumentation. Calibrate equipment. • Review monitoring records, and if needed, perform an injectivity test or falloff test to evaluate reservoir.	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff
29	Injection	***Injection or Monitoring Equipment Failure:*** A large pressure drop in the CO_2 stream results in low temperatures that could cause harm to personnel or damage/brittleness in materials (e.g., carbon steel and elastomers).	• Real-time monitoring system of the CO_2 injection stream	• Use of materials that are rated for low temperatures • Controlled CO_2 stream composition	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Assess mechanical integrity of the system, and propose repair actions if needed . • Assess any potential environmental impact, and propose remedial action with the Commission, if needed. • If the assessment allows resuming injection safely, discuss plan with the Commission and obtain approval. • Repair or replace any damaged equipment and recalibrate. • Review monitoring records and if needed, adjust CO_2 accordingly.	• Operation engineer • Field superintendent • Plant manager • Emergency teams

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
30	Injection	***Induced Seismicity:*** Pressurization of the reservoir, during injection of CO_2, activates preexisting fault planes and creates a displacement that causes a seismic event. If it's a major event (>2.7 Richter), it could compromise the integrity of the wells, facilities, or pipeline.	• Geophones array in surface to monitor induced seismicity • DAS fiber • PNLs • CBL/ultrasonic logging	• Seismic survey of the storage complex shows no faults that could be reactivated. • A detailed geomechanical model was created to evaluate the storage complex. • The region is seismically stable. • Cased hole logging program.	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damages, contact the field superintendent to activate emergency evacuation and secure location. • Follow the traffic light system described in Appendix C, Section 1.7.3.3. • Assess any potential environmental impact. • Notify regulator and propose action plan, if needed. • Define new injection parameters, and get approval from the Commission. • If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff
31	Injection/ Postinjection	***Induced Seismicity:*** Other subsurface injection (e.g., saltwater disposal) causes pressure changes and induced seismicity at the project site or induced seismicity occurs at a nearby site that impacts the project site.	• Geophones array in surface to monitor induced seismicity • Distributed acoustic sensing (DAS) fiber • Pressure gauges at surface • PNLs • CBL/ultrasonic logging	• The Williston Basin is a tectonically stable region (see Section 2.5.2 of the SFP). • Seismic survey of the storage complex shows no faults that could be reactivated. • Detailed geomechanical model was created to evaluate the storage complex. • Cased hole logging program.	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Follow protocol to stop injection (injection period). • Assess any potential environmental impact. • Notify regulator and propose action plan, if needed. • Review regional information as well as monitoring records to determine the origin of the event (natural or induced). • If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period).	• Operation engineer • Field superintendent • Project manager • Geologist • Monitoring staff • Remediation contractors

Continued . . .

Table F-1. Risk Scenario Identification and Emergency Remedial and Response (continued)

	PROJECT PHASE	RISK SCENARIO	MONITORING EQUIPMENT	CONTROL IN PLACE	RESPONSE ACTION	RESPONSE PERSONNEL
32	Injection/ Postinjection	***Major seismic event*** Natural seismicity causes LOC by opening transmissive features in the confining zone, resulting in release of CO_2 to a USDW, surface, or atmosphere.	• Geophones array in surface to monitor induced seismicity • DAS fiber • PNLs • CBL/ultrasonic logging	• The region is seismically stable. • Cased hole logging program.	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Follow the traffic light system described in Appendix C, section 1.7.3.3. • Assess any potential environmental impact. • Notify regulator and propose action plan, if needed. • If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions (injection period).	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff
33	Injection/ Postinjection	***Other Major Natural Disaster*** Natural disaster that limits or endangers the normal operation of the hub.	• Emergency shutdown valves • Weather monitoring	• Project safety program. • Condition/atmospheric monitoring.	• Trigger SCADA alarms/beacons by the system or operations staff. • If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure location. • Follow protocol to stop injection. • Assess mechanical integrity of the system. • Assess any potential environmental impact. • Notify regulator and propose repair actions based on findings. • If the assessment allows resuming injection safely, increase surveillance to validate effectiveness of the actions.	• Operation engineer • Field superintendent • Project manager • Remediation contractors • Emergency teams • Geologist • Reservoir engineers • Monitoring staff
34	Injection	***Accidents or Unplanned Event:*** Loss of electricity causing injection to cease.	• Field inspections	• Programmable logic controller (PLC) with uninterrupted power supply (UPS). • Fail-closed" shutdown valves. • Consider backfeed to redundant generation sources or generation sources. • Install industry-standard weather mitigation on distribution lines.	• Trigger SCADA alarm by the system or operations staff. • PLC/UPS programmed to initiate a closure of shutdown valves in fail safe position (fail-closed). • PLC/UPS will continue to monitor the shutdown and report back to the SCADA system for personnel. • Designate an exclusion zone, and provide appropriate PPE for protection of on-site personnel. • Verify CO_2 flow was shut off by the system or start manual protocol to stop flow, visual inspection and manually close valves. • Notify regulator within 24 hours of shut-in. • Notify regulator of start-up procedure.	• Operation engineer • Field superintendent • Project manager

APPENDIX G

FINANCIAL ASSURANCE DEMONSTATION – MARKET ASSESSMENT

APPENDIX G-1

SAMPLE TRUST AGREEMENT

Marsh

Project Tundra – DCC West

Use of Insurance in the FADP

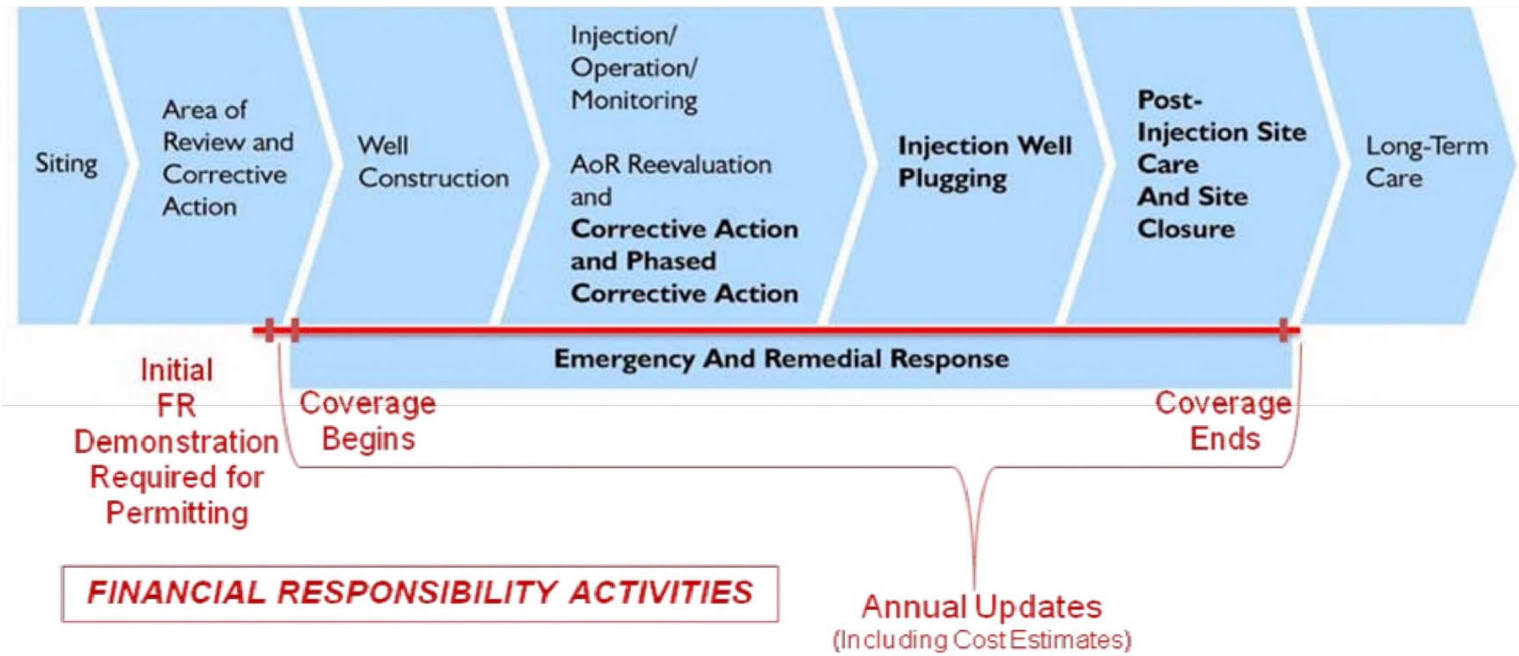
February 16, 2023

Contents

Section One

Executive Summary

This document provides analysis of pollution liability insurance options over the course of the operating lifetime of the CO_2 sequestration company, "DCC West", including the 10 year, post-injection site care period prior to transfer of liability to the State of North Dakota. The following graphic is a helpful summary of the lifecycle of the project and the intended coverage periods.



The market review was requested to outline the applicable environmental insurance products, expected policy terms and conditions, exclusions, costs and deductibles to support applicant to the North Dakota Industrial Commission for necessary UIC Class VI well injection permit financial responsibility requirements as required by section 43-05-01-09.1. The analysis provides a conservative review of traditional insurance programs utilized to provide coverage for Emergency and Remedial Response activities for the DCC West geologic sequestration project, which could respond following a liability claim arising from contamination of an Underground Source of Drinking Water(USDW), including Contractors Pollution Liability, Pollution Liability and Operators Extra Expense/Control of Well. First party/property insurances as well as the extended family of 3rd party liability insurance (such as, but not limited to, general liability, auto liability, employer's liability, cyber liability, professional liability and all measure of executive liability coverages), while generally critical to the greater project and highly recommended, are not under consideration in this analysis. All coverage descriptions, options and estimates provided herein are non- binding estimates based on project data provided. Over the 20+ year of life of the project these estimates will change, as such no guarantee is possible as to the future fitness of the program details provided in this report.

The insurance landscape is evolving to meet the needs of the growing number of Carbon Capture and Storage (CCS) projects in development around the world. Insurers and risk financiers are looking more closely at the unique risks of these projects and developing new forms and methods to address risk that depart from the traditional programs. Bespoke insurance programs designed to address the unique risk profile of CCS and alternative risk financing programs are rapidly entering the marketplace and providing enticing alternatives to traditional programs. All financial responsibility instruments should be explored and evaluated to ensure that the optimal fit of coverage and cost is placed for the project.

Approved methods (in order of EPA preference) for Geological Sequestration (GS) activities:

Table 4: Recommended financial responsibility instruments for GS activities (relative ranking)[10]

Corrective Action	Injection Well Plugging	Post-injection Site Care and Site Closure	Emergency and Remedial Response
1. Trust Fund 2. Letter of Credit 3. Surety Bond 4. Escrow Account 5. Financial Test and Corporate Guarantee* 6. Insurance	1. Trust Fund 2. Letter of Credit 3. Surety Bond 4. Insurance 5. Financial Test and Corporate Guarantee* 6. Escrow Account	1. Trust Fund 2. Insurance 3. Financial Test and Corporate Guarantee* 4. Surety Bond 5. Escrow Account 6. Letter of Credit	1. Insurance 2. Letter of Credit** 3. Surety Bond** 4. Financial Test and Corporate Guarantee* 5. Trust Fund 6. Escrow Account

*Financial tests and corporate guarantees present the lowest direct costs to owners or operators, but the highest risk to the public.
**Letters of credit and surety bonds are likely most appropriate for emergency and remedial response during operation phases.

Source: Underground Injection Control (UIC) Class VI Program Financial Responsibility Guidance July 2011 (epa.gov)

Marsh & McLennan Companies Introduction

Marsh & McLennan Companies (MMC) is the world's leading professional services firm in the areas of risk, strategy and people. The company's 83,000 colleagues advise clients in over 130 countries. With annual revenue of over $20 billion, MMC helps clients navigate an increasingly dynamic and complex environment through four market-leading businesses.

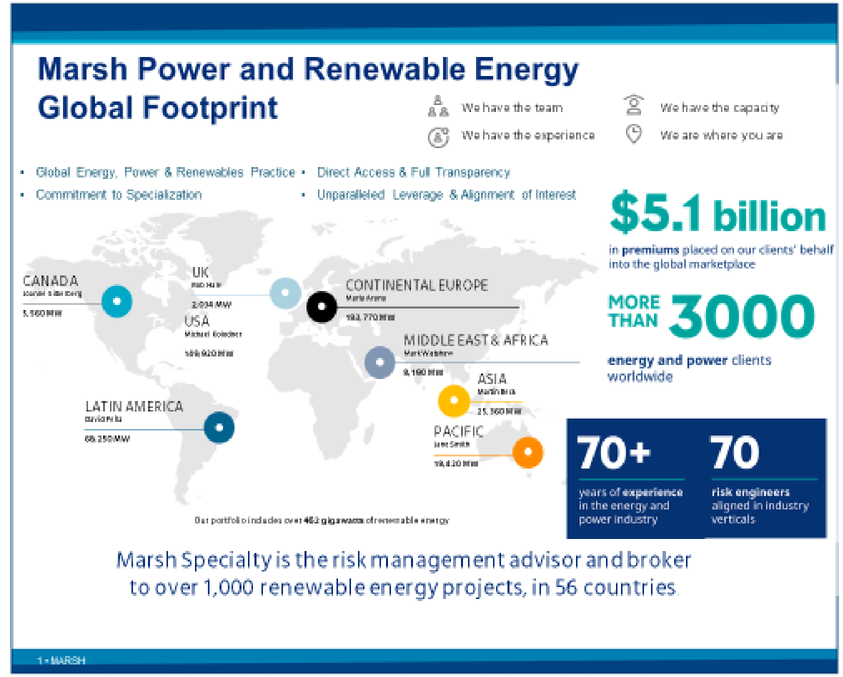
We are four companies, with one purpose: helping our clients to meet the challenges of our time.

About Marsh

Marsh is the world's leading insurance broker and risk advisor. We were founded after the Great Chicago Fire in 1871 and have been in business for 150+ years. We serve commercial and individual clients with data driven risk solutions and advisory services.

Power Industry Expertise

With more than 270 utility clients in the United States, the Marsh Power and Renewable team remains at the forefront of helping utilities manage the many risks they face. We annually place over $5.1 billion of insurance premium on behalf of our utility clients into the global insurance market. We are recognized as the leading broker in the power and utility industry sector and have deep relationships with all the major insurers actively underwriting power and utilities business, including AEGIS, EIM, AIG, ANI, Everest, Liberty International, and FM Global. We have extensive knowledge and deliver results for clients owning all forms of power generation, including natural gas, coal, nuclear, hydro, biomass, geothermal, wind, solar, and energy storage.



Contacts

Pete Nadel, ARM-E
Senior Vice President, Client Executive
Marsh Specialty Energy & Power
M1 +1 216 548 6531   M2 +1 330 309 3655
Peter.Nadel@marsh.com

Matthew Kern
Senior Vice President, Client Leader
Marsh Specialty Energy & Power
M +1 (312) 5604343
Matthew.Kern@marsh.com

Section Two

Coverage Assessment by Project Phase

This section outlines the certain types of insurance that may respond to a pollution event during certain phases of the project life.

Project Phase	General Risks Associated	Types of Insurance	Assumptions/Questions
Construction phase Pollution event	1. Pollution event during construction 2. Well control event during drilling or completion	1. Contractors Pollution Liability (CPL) for Contractor. Separate CPL policy for Owner interest. 2. Operators Extra Expense (OEE) for either owner or contractor as assigned in the drilling contract	1. CPL required by contract with contractor. Owners CPL operates as a difference in limits/difference in conditions to contractors policy 2. Party responsible to provide OEE is established by contract
Operations phase pollution event	1. Pollution during operations 2. Well control event during Operations	1. Pollution Liability (PL) Coverage for Owner 2. Operators Extra Expense (OEE) for Owner or operator	1. Multi-year policy could be desirable. Combined GL/PL may also be available 2. Responsibility to carry OEE can be transferred to the contract operator and can include operator of record via Contract Operator Endorsement.
Injection Well Plugging phase pollution event	Well control event during plugging	OEE for either owner or contractor as per contract	Party responsible to provide OEE is established by contract. Owner's operating pollution liability coverage remains in force until DCC West Operations are discontinued
Post Injection Site Care pollution event	Gradual migration of CO_2 into USDWs	Pollution Liability	Following injection well plugging, pollution policies adjusted to maximum terms and renewed as necessary until liabilities assumed by State of North Dakota

Section Three

Contractors Pollution Liability Coverage Details

Summary

Contractors Pollution Liability (CPL) covers third party damages for bodily, injury property damage or cleanup related to pollution events which occur during construction operations. Unlike other pollution coverage, CPL does not have reporting windows for discovery or reporting of an occurrence. The following coverage sections can be included in a CPL policy:

Coverage A: Contractors Pollution Liability
Coverage B: Transportation Pollution Liability
Coverage C: Emergency and Crisis Management Costs
Coverage D: Non-Owned Site Pollution Liability

Refer to Specimen Policy Form in Appendix A

Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate and are elected at time of binding.

Pollution Liability (PL) policies (discussed in the following section) prefer not to extend coverage to construction operations, including those events occurring during the operations period but arising directly from construction. Accordingly, in order to keep PL market selection as broad as possible, we recommend a separate CPL to cover construction operations.

Review of Coverage

Coverage Limits

Benchmarking reveals an average Contractors Pollution Liability purchase of $20M for multi-year policies. Drilling contractors often carry lower than average CPL limits due to the historical experience of pollution events at contractor risk, which occur during drilling operations, the rural location of their work and general reliance on the pollution coverage grants within other policies that can cover sudden and accidental pollution events. Selection of CPL limits is often driven by broader contract negotiations as well as the aggregate nature of the limit provided over the term of the construction period and completed operations period.

CPL coverage can be structured in many ways, as owner or contractor controlled for the project, owner's or contractor's interest separately or in a combination. The owner's basic objective should be to cover a target limit for pollution events arising from construction activities both during the actual construction and completed operations coverage for 10-years following construction. The simplest approach would be to require the contractor via the construction contract to carry the entire desired limit. While most contractors already carry CPL, the limit may not be large enough and is usually shared across the contractor's entire portfolio of projects. Given smaller usual limits and the shared aggregate, requiring the contractor to cover the entire desired limit can restrict contractor selection and distort available bids.

For this project, we recommend that part of the desired CPL limit be stipulated by contract as a Contractor required insurance, along with others such as General Liability, Auto Liability, Excess, etc. All contractors and subcontractors engaged to perform work at the site should carry the required CPL. We further recommend the owner carry the balance of the desired limit in a CPL Owner's Interest policy to protect against contractor CPL policy deficiencies and termination of coverage or exhaustion of limit over the completed operations period. The owner's CPL policy would operate, as Difference in Conditions/Difference in Limit to the Contractors so would only be accessed in the event the limit was exhausted or not maintained in accordance with the contract requirements. We recommend that both CPL and CPL Owner's interest policies be purchased during the construction period. For the contractor's CPL, a project specific policy is recommended, but not required in this case as the Owner's CPL can supplement. If contractor needs more flexible terms (such as lower limit and not project specific), the owner's CPL can be adjusted to make up the balance of the target pollution policy limit.

Market capacity for CPL is estimated at $450M.

Deductible

Standard deductibles vary from $100,000 to $250,000 for Owner's Interest CPL policies

Exclusions

Exclusions – Refer to Specimen Policy Form in Appendix A

Some of the basic exclusions in a pollution legal liability policy are outlined below; however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in agreement
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Drilling and Specialty Equipment
- Identified Underground Storage Tank (unless scheduled)
- Closure/Post Closure and Reclamation Costs
- Divested Property

Renewal

The policies would not renew. The recommended Contractor's CPL and owner's interest CPL would both run the course of construction and carry a 10 year completed operations extension.

Cancellation

Policy cancellation as per Section IV. Conditions clause 2. Cancellation on page 13 of the sample wording in Appendix A

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

CPL Limit: Contractor premiums are difficult to estimate without detailed knowledge of contractor revenues, operations and loss history.

CPL Owner's interest Limit Option: Construction Period plus 10 Years Completed Operations, Limit of $25M – at $100,000 Deductible = $35,000 to $50,000 annually ($350,000 to $500,000 for a 10-year term), not including applicable taxes and fees.

Pollution Liability Coverage Details

Summary

Pollution Liability is an insurance policy that protects business organizations against liability claims for bodily injury (BI), property damage (PD) and Cleanup (CU) arising out of premises and operations at scheduled locations. Coverage may include various extensions, including first party discovery, non-owned disposal sites, contingent transportation, emergency response, image restoration, and Natural Resource Damages. Additionally, as this coverage does not have reporting windows for events, it can be coordinated with other liability policies that may offer sudden & accidental pollution coverage, such as General Liability and Excess and Operators Extra Expense.

Pollution Liability (PL) coverage can be provided on an annual or multi-year policy term covering property assets. Coverage is offered on claims-made policy form for specifically scheduled assets. Coverage terms and conditions are governed by the complete terms and conditions of the policy, including restrictions and exclusions. Defense is included within the limit of liability, with possibility for additional defense outside. Limits are structured as per incident and aggregate. *Most often, those limits are the same; however, some Insured's choose a split aggregate limit. A split aggregate makes it challenging to build a significant tower of* limits.

Coverage A: Covered Location Pollution Liability
Coverage B: Miscellaneous Pollution Liability
Coverage C: Emergency and Crisis Management Costs

Review of Coverage

Coverage Limits

Benchmarking reveals an average Pollution Liability (PL) purchase of $10M for annual and 2-3 year policies. Longer-term policies (such as 10 years) have larger limits to accommodate the possibility of erosion of the aggregate limit. At first glance, the average PL limit purchase of $10M would appear lower than necessary to respond to recent pollution events. Pollution Liability is often purchased as an excess and difference in conditions coverage to sudden and accidental pollution coverage grants within the main liability program. Operational liability programs normally have much larger limits and serve as a natural downward influence on PL limits purchased. It is almost impossible to say how insurance programs covering CO_2 sequestration compare to the benchmark, as there are so few working examples with pollution policies. Considering the nature of sequestration operations, contamination of an underground source of drinking water is likely to occur gradually and not be discovered until well after the event which caused it. Typical sudden & accidental pollution liability with discovery and reporting windows generally around 21 and 45-days respectively (and shorter) may not reasonably be expected to provide much coverage. Due to the novel nature of CO_2 sequestration operations and lack of an ability to rely on the sudden and accidental pollution grants within the operational liability, it is likely that the selection of Pollution

Liability limits by CO_2 sequestration operations will trend well above benchmarked limits.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the PL policy such as Coverages A and C. Generally, the policy would respond to efforts to measure the extent of the contamination and compensate any users of the drinking water for property damage and/or bodily injury arising from the contamination. Costs to control the breach and restore the well to production would be covered under the OEE policy discussed in the following section.

Market capacity for PL for this risk is estimated at $150M. A combined General Liability and Pollution Liability product is often preferred by other waste disposal operations as it tends to be more cost efficient than standalone liability and pollution towers. Given the novel nature of standalone CO2 sequestration, this is certainly the desired option but may not be available until the market gains more comfort with sequestration operations.

Deductible

The minimum deductible for this risk will likely be $250,000. Small credits are available for incremental increases in deductible but are generally not efficient. A deductible is usually established by market preference and premium for the overall account and limit. The preferred maximum deductible would be $1,000,000, as very small discounts are provided above that amount. The deductible will be a self-insured retention versus a true deductible. Environmental markets do not typically analyze individual financial performance or require collateral for support.

Exclusions

Refer to Specimen Policy Form in Appendix B

Some of the basic exclusions in a PL policy are outlined below; however please note that this is not a complete listing of all exclusions or restrictions contained within the policy.

Applicable to All Insuring Agreements, Except as Indicated

- Criminal Fines, Penalties, and Assessments
- Contractual Liability – except where noted in JOAs
- Prior Waste Disposal Activities
- Intentional Noncompliance
- Internal Expenses
- Insured vs. Insured
- Asbestos and Lead
- Employer Liability
- Prior Knowledge/Non-Disclosure
- Identified Underground Storage Tank (unless scheduled)
- Drilling and Specialty Equipment
- Divested Property
- Damage to Insured's Products and Work
- Insured's Professional Services
- Products Liability
- Property Damage to Conveyances
- Costs to Cleanup Pits or Ponds
- Closure/Post Closure and Reclamation Costs

Renewal

Operations: If PL is purchased on a standalone basis, then we recommend a multi-year period for premium efficiency. The longest available multi-year period for operating assets is usually three years. A combined GL/PL form may be available in the near future as Insurers become more comfortable with risk, technology and appetite. A combined form renews annually.
Post Injection Site Closure: After plugging of the injection well, it would be desirable (if possible) to purchase a 10-year policy to match the post injection site closure period.

Cancellation

Policy cancellation as per Section IV. Conditions clause 2. on page 12 of the sample wording in Appendix B

Many of these risks are written at 100% minimum earned. However, the minimum premium will continue to climb on a multi-year policy so that outpaces the earning. Rule of thumb would be that the policy is 100% fully earned at least two–thirds through a multi-year policy. Refer to policy language. Additionally, sample manuscript endorsements available.

Premium

Pollution Legal Limit Options

PL Limit Option 1: Annual Limit of $25M = $150,000

PL Limit Option 2: Three-year Limit of $25M = $450,000

PL Limit Option 3: Three-year Limit of $50M = $800,000

All premiums are non-adjustable

Section Five

Operators Extra Expense Coverage Details

Operators Extra Expense (OEE), also known as Control of Well (COW), indemnifies owners against costs associated with a well out of control. The base coverage is divided into 3 coverage grants:

A. Control of Well,
B. Expense of re-drilling/recompletion, and
C. Seepage and Pollution, clean up and contamination

Coverage C. grant is of interest to this analysis but can only be triggered by a well out of control event per policy definition. Limits are also supplemented by various extensions (see below).

Review of Coverage

Coverage Limits

OEE policy limits are combined single limits of liability across all coverage sections and extensions for any one occurrence (including defense costs). Therefore, it is prudent to be conservative with limit selection. Conventional wisdom for OEE limit selection for exploration and production accounts holds that the OEE limit should be 3-5 times the dry hole cost of the well insured. While this approach tends to breakdown for uncommon well types and operations, it is considered the general benchmark in selecting limits. A comparison of five times the projected dry hole cost ($6.9MM * 5 = $34.5MM) and the sum of estimated Emergency and Remedial Response expenses from the FADP report ($19.7MM) reveals that a limit of $35,000,000(100%) any one occurrence appears reasonable for both drilling and producing wells.

OEE and PL limits can be coordinated by the insured but the OEE limit is generally not viewed as substitute for PL coverage for the following reasons:

- The priority of payments clause on the OEE policy allows the Insured to direct the limit to whichever sections he chooses
- Operators prefer to reserve OEE limits for Control of Well or Re-drill. These activities have been known to be very expensive in large or difficult claims and could leave little for pollution clean-up.
- Given the broader nature of PL coverage, insureds prefer to reserve PL limits for claims arising from an occurrence that would not be covered by either the OEE or Operational Liability program.

For example, a leak in the well casing causing contamination of a source of underground drinking water could trigger various sections of the OEE policy such as Coverages A, B and C. We recommend that DCC West direct costs to control and restore the well to production first to the OEE policy and deploy any remaining limit to clean-up pollution. The PL policy referenced above should be used to respond to all other remaining clean-up costs that are covered by the policy.

The coverage form should be as broad as possible and include such coverage extensions as: Making Wells Safe, Underground Control of Well, Care Custody and Control, Unlimited Re-Drill, Extended Re-Drill, Extended Pollution, and Removal of Wreck.

The load or credit associated with increased or diminished limits is discussed in the premium section.

Deductible

Often referred to as a retention or excess, the OEE policy carries a single deductible over all coverage sections. The Project should expect a deductible of between $250,000(100%) and $500,000(100%) any one occurrence for drilling and producing wells. Due to the small schedule and Minnkota's minimal well operating record, Insurers may be reluctant to offer lower deductibles.

The credit associated with increased deductibles is discussed in the premium section

Exclusions

A sample copy of the wording is provided in the Appendix C. Exclusions of note are:

- Fines or Penalties
- Breach of Warranties Clause and breach of Due Diligence Clause
- Delay or loss of use (adding Loss of Production Insurance would serve to add back coverage)
- Costs arising out of a well which flow can be promptly controlled by use of onsite equipment or by increasing the weight of drilling fluid
- Exclusion for claim recoverable under the policy solely by reason of the addition or attachment to Section A of the Underground Control of Well Endorsement. This exclusion should be amended or removed to better fit CO_2 Sequestration operations.

Renewal

Most OEE policies renew annually.

Cancellation

As per clause 14. Cancellation on page 7 of the sample policy wording in Appendix C

Premium

All premiums are annual minimum and deposit premiums that are adjustable for drilling wells and flat at inception for producing wells. Based on current market feedback, the $100,000 minimum premium drives the premium during the operating phase due to the small schedule of wells and Minnkota' s minimal well operating record. A contract operator could possibly leverage their experience and existing premium base to provide lower OEE premiums. Additionally, we may be able to negotiate lower premiums for the operating period once injection operations are established and the market is more comfortable with the risk.

Type of Well	Combined Single Limit	Est. Annual Premium
2 Broom Creek Wells (drilling phase)	$35,000,000	Rate of 1.8% times Completed Well Cost (CWC), minimum annual premium $100,000. E.g. CWC est. $6.9M for each Broom Creek well Est. Annual Premium for 2 wells is $248,400
2 Broom Creek Wells (operating phase)	$35,000,000	Rate of 10% of drilling rate subject to a minimum annual premium $100,000. Est. Annual Premium is $100,000

APPENDIX G-2

SAMPLE TRUST AGREEMENT

APPENDIX G-2
STANDBY TRUST AGREEMENT

THIS TRUST AGREEMENT (the “Agreement”) is entered into as of _______________ by and between DCC West Project LLC owner or operator, a limited liability company formed under the laws of the State of Delaware(the “Grantor”), and Bank of North Dakota (the “Trustee”), a bank duly organized and existing under the laws of the State of North Dakota.

WHEREAS, the North Dakota Industrial Commission (Commission), an agency of the State of North Dakota, has established authority to administer certain regulations pursuant to the US Environmental Protection Agency’s Class VI Underground Injection Control Program (UIC). The Commission’s regulations, applicable to the Grantor, require that an owner or operator of an injection well shall provide assurance that funds will be available when needed for corrective actions, injection well plugging, post-injection site care and site closure, and emergency and remedial response during the operation of carbon dioxide (CO_2) geologic sequestration injection wells;

WHEREAS, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facility or facilities identified herein, and;

WHEREAS, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this Agreement, and the Trustee is willing to act as trustee.

NOW THEREFORE, the Grantor and the Trustee agree as follows:

Section 1. Definitions. As used in this Agreement:

A. The term “Grantor” means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor.
B. The term “Trustee” means the Trustee who enters into this Agreement and any successor Trustee.
C. Facility or activity means any “underground injection well” or any other facility or activity that is subject to regulation under the Underground Injection Control Program.
D. “Commission” means the North Dakota Industrial Commission or an authorized representative.
E. “ERR” means emergency and remedial response plan, associated cost estimate and the funded trust property and income apportioned to cover these costs.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A.

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a CO_2 Storage Trust Fund (the “Fund”) to satisfy the financial responsibility demonstration and storage facility fees under the Class VI Underground Injection Control (“UIC”) regulations (N.D.A.C. § 43-05-01-09.1 and N.D.A.C. § 43-05-01-17). This Fund shall remain dormant until funded with the proceeds listed on Schedule C. The Trustee shall have no duties or responsibilities beyond safekeeping this Agreement. Upon funding, this Fund shall become active and be administered pursuant to the terms of this instrument. The Grantor and the Trustee acknowledge that the purpose of the Fund is to fulfill the Grantor's corrective action, injection well plugging, post-injection site care, site closure, emergency and remedial response, and storage facility fee obligations described at N.D.A.C. § 43-05-01-05.1 (Area of review and corrective action), N.D.A.C. § 43-05-01-11.5 (Injection well plugging), N.D.A.C. § 43-05-01-19 (Post-injection site care and site closure), N.D.A.C. § 43-05-01-13 (Emergency and remedial response), and N.D.A.C. § 43-05-01-17 (Storage Facility Fees) respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission or any other state agency. The Grantor and the Trustee intend that no third party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN TRUST, as hereinafter provided. The Trustee shall not be responsible, nor shall it undertake any responsibility, for the amount or adequacy of any additional payments necessary to discharge any liabilities of the Grantor established by the Commission.

<u>Section 4. Payment for Corrective Action, Injection Well Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response</u>. The Trustee shall make payments from the Fund only as the Commission shall direct, in writing, to provide for the payment of the costs of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response of the injection wells covered by this Agreement. The Trustee shall use the Fund to direct-pay or reimburse the Grantor, other persons selected by the Grantor to perform work, or as otherwise directed by the Commission when the Commission advises in writing that the work will be or was necessary for the fulfillment of the Grantor's corrective action, injection well plugging, post-injection site care and site closure, or emergency and remedial response obligations described in N.D.A.C. §§ 43-05-01-05.1, 43-05-01-11.5, 43-05-01-19 and 43-05-01-13, respectively. All expenditures from the Fund shall be to fulfill the legal obligations of the Grantor under such regulations, and not any obligation of the Commission, as the Commission is not a beneficiary of the Trust. The Commission may advise the Trustee that amounts in the Fund are no longer necessary to fulfill the Grantor's obligations under N.D.A.C. § 43-05-01-09.1 and that the Trustee may refund all or a portion of the remaining funds to the Grantor. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

<u>Section 5. Payments Comprising the Fund</u>. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee. Schedule C provides the amounts and timing of the <u>seven (7)</u> payments (i.e., the pay-in schedule).

<u>Section 6. Trustee Management and Investment</u>. Trustee shall manage, invest, and reinvest all of the Trust assets, made up of the principal and income of the Fund, in accordance with the North Dakota Prudent Investor Standards, Chapter 59-17, *et seq.* of the North Dakota Century Code, as amended ("Act"). The Trustee shall invest and reinvest the principal and income, without distinction, according to the investment instructions included within the attached Exhibit B (referred to as "Permitted Investments"), *provided* the Permitted Investments may be revised at any time upon notice from the Grantor. To the extent not inconsistent with the Act and Permitted

Investments, Trustee shall hold the Fund assets thereon subject to the terms and conditions of this Agreement and is empowered and directed to invest and reinvest the Fund assets and any accumulated income in such certificates of deposit, obligations to the United States of America, demand deposits, commercial paper or other securities or accounts as the Grantor shall direct. In the absence of instructions from the Grantor, Trustee shall invest and reinvest the Fund assets in money market funds available upon demand or short notice. All interest earned on the Fund principal shall become part of the Fund assets. Notwithstanding the foregoing, none of the Fund assets may be held in any investment that cannot be sold, redeemed or otherwise liquidated at the holders' option in ninety (90) days or less without loss of interest or discount. All amounts and investments (other than bearer instruments) comprising the Fund assets shall be registered and held in the name of the Trustee.

Section 7. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

A. To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;
B. To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;
C. To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund;
D. To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the Federal or State government; and,
E. To compromise or otherwise adjust all claims in favor of or against the Fund, including claims in favor of the Trust as a loss payee under applicable insurance policies.

Section 8. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other charges and disbursements of the Trustee permitted under this Agreement shall be paid from the Fund.

<u>Section 9. Annual Valuation</u>. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the Commission a statement confirming the value of the Fund. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund.

<u>Section 10. Advice of Counsel</u>. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement or any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

<u>Section 11. Trustee Compensation</u>. Trustee shall be entitled to reasonable compensation for its services provided hereunder in accordance with the Trustee's fee schedule as in effect during the course of this Agreement, *provided* that any change or revision to the fee schedule shall be effective only upon Trustee providing Grantor with thirty (30) days written notice, or another mutually agreed to period of time, which notice shall include effective date(s) of any change or revision. Trustee's current fee schedule is attached as Exhibit C, with such fees identified therein being each and together "Trustee Fees." Additionally, Trustee shall be reimbursed for all expenses reasonably incurred by Trustee in connection with the performance of its duties and enforcement of its rights hereunder and otherwise in connection with the preparation, operation, administration and enforcement of this Agreement, including, without limitation, attorneys' fees, brokerage costs and related expenses incurred by Trustee ("Trustee Expenses"). Grantor shall pay the Trustee Fees and Trust Expenses within thirty (30) days following receipt of an invoice from Trustee.

<u>Section 12. Successor Trustee</u>. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment, and the Commission consents to the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance and receipt of Commission consent of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the Commission, and the present Trustee by certified mail ten (10) days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

<u>Section 13. Instructions to the Trustee</u>. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the Commission to the Trustee shall be in writing, signed by the Commission or its duly constituted delegate(s), and the Trustee may rely on these instructions to the extent permissible by law. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or Commission hereunder has

occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or the Commission, except as provided for herein.

Section 14. Notice of Nonpayment. The Trustee shall notify the Grantor and the Commission, by certified mail within ten (10) days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period.

Section 15. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Provided, however, that the Commission may not be named as a beneficiary of the Trust, receive funds from the Trust, or direct that Trust funds be paid to a particular entity selected by the Commission.

Section 16. Cancellation, Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 15, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor and the Trustee, with the concurrence of the Commission, or by the Trustee and the Commission if the Grantor ceases to exist. Upon termination of the Trust, all remaining Fund property, less final trust administration expenses, and excluding the principal and income contained in the ERR fund account, shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission. At termination of the Trust or upon early written direction by the Grantor, with concurrence of the Commission, Trustee must distribute ERR principal in an amount calculated in accordance with N.D.A.C. § 43-05-01-17 plus a pro rata portion of the income accrued. Following the distribution of the ERR principal and income in accordance with the foregoing clause, any remaining Fund property shall be delivered to the Grantor, or if the Grantor is no longer in existence, at the written direction of the Commission.

Section 17. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense. The Commission does not indemnify either the Grantor or the Trustee. Rather, any claims against the Commission are subject to Chapter 32-12.2, *et seq*.

Section 18. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of North Dakota with regard to claims by the Grantor or Trustee. Claims involving the Commission are subject to North Dakota State law.

Section 19. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

{*Signature Page to Follow*}

IN WITNESS WHEREOF the parties below have caused this Agreement to be executed by their respective representatives duly authorized and their seals to be hereunto affixed and attested as of the date first above written.

Signature of Grantor's Authorized Representative: ________________________________
Name of Grantor's Authorized Representative: _______________________
Title: ____________________

Attest:

Signature: ___________________________________
Name of Attester: ______________________
Title of Attester: _______________________

Certification of Acknowledgement of Notary:

Signature of Trustee's Authorized Representative: _________________________________
Name of Trustee's Authorized Representative: _______________________
Title: ____________________

Attest:

Signature: ___________________________________
Name of Attester: ______________________
Title of Attester: _______________________

Certification of Acknowledgement of Notary:

Schedule A: Facilities and Cost Estimates to which the Trust Agreement Applies

Because the two injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the two wells will form one co-mingled and overlapping CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to both injection wells as one integrated facility.

Facility	Corrective Action ($)	Injection Well Plugging ($)	Post-injection Site Care ($)	Site Closure ($)	Emergency and Remedial Response ($)
IIW-S IIW-N J-LOC 1 (Monitoring Well)	$0.00	$2,215,000.00	$11,239,000.00	$2,378,000.00	$0.00

Schedule B: Trust Fund Property

Because the two injection wells covered by this Agreement will be similarly constructed and drilled from a single well pad and under a combined project plan, the CO_2 injected through the two wells will form one co-mingled and overlapping CO_2 plume in a contractual and legal context. Therefore, funds noted in the table below apply to all two injection wells as one integrated facility.

Facility	Funding Value for Activities
IIW-S	$15,832,000.00
IIW-N	
RDT(Monitoring Well)	

Schedule C: Pay-in Periods/Schedule

The Fund will be funded according to when the financial risks are incurred in three (3) distinct Periods of activity.

- **Pre-Injection**: Once an injection or monitoring well is drilled, plugging costs will need to be accounted for prior to cessation of injection operations. Therefore, the trust account will need to account for the cost of plugging injection and monitoring wells prior to the Post-Injection period. Grantor provides for plugging of the injection wells in the pre-injection period with monitoring plugging costs to be paid in with site closure costs during the Injection period, as further described below. Grantor's estimated cost of this plugging activity is $2,215,000.00. Grantor shall initially fund the Fund account in an amount equal to the total injection well plugging cost and expenses.

- **Injection**:

    - Grantor will fund the Fund account for post-injection site care, monitoring and site closure making seven (7) equal annual installments of $1,945,286.00. Grantor's estimated cost of post-injection site care and monitoring is $11,239,00.00 and site closure activities is $2,378,000.00. The first installment to be made in the Injection period prior to the one-year anniversary of the Commission's issuance of authorization to operate a Class VI injection well and the remaining installments to be made individually on the successive anniversary until fully funding the principal amount of $13,617,000.00.

    - The seven (7) installments are to be made individually prior to the successive anniversary of the Commission's issuance of authorization to operate a Class VI injection well until fully funding the principal amount of $15,832,000.00.

- **Post-Injection and Closure**: All costs associated with post-injection and closure activities must be funded before or at the start of the post-injection phase. However, the Fund may phase out these costs as associated Pre-Injection and Injection Period activities are completed (with approval from the Commission). For example, once wells have been plugged, their corresponding plugging costs may be subtracted from the total value of the Fund account.

Pay-in Schedule
Within seven (7) calendar days after the issuance of final Class VI authorization to operate for the two injection wells, Grantor will ensure that $2,215,000.00 is in the Fund to cover the cost of Injection Period activities (Emergency and Remedial Response Plan). The total value of the trust at the beginning of the Injection Period will be $2,215,000.00.

On or before the seven-year anniversary of the issuance of the final Class VI permit to operate for the three injection wells, Grantor will ensure that an additional $13,617,000.00 is in the Fund to cover the remaining costs of the Pre-Injection, Injection, Post-Injection, and Closure Periods. An additional $1,945,286.00 will be added on or before the one-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. An additional $1,945,286.00 will be added on or before the two-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. An additional $1,945,286.00 will be added on or before the three-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. An additional $1,945,286.00 will be added on or before the four-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. An additional $1,945,286.00 will be added on or before the five-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. An additional $1,945,286.00 will be added on or before the six-year anniversary of the issuance of the final Class VI permit to operate for the two injection wells. A final installment of $1,945,286.00 will be added on or before the seven-year anniversary for the permit to operate for the two injection wells, completing the phase-in of financial responsibility payments for the Pre-Injection, Post-Injection, and Closure Periods. Grantor may also elect to substitute another mechanism to demonstrate financial responsibility for emergency and remedial response for the injection and post-injection phases. If Commission approves such a substitution, this Agreement will be amended accordingly.

These amounts are based on the third-party cost estimate submitted by Grantor in its *Supporting Documentation: Underground Injection Control Class VI Injection Well Permit Applications for DCC West _______________ Wells _,_,_ and _,* dated ___________ (Appendix _) and on the Commission's independent evaluation of the cost estimates. These costs are subject to review and approval by the Commission and may be adjusted for inflation or any change to the cost estimate in accordance with N.D.C.C. § 43-05-01-09.1.

Table 1 shows the activities and estimated costs according to when the payments would be required (i.e., at the start of the "Pre-Injection") phase or at the start of the "Injection and Post-Injection Phase").

Table 1: Trust Funding Schedule

Funding Phase	**Activities**	**Total Activities' Costs Prior to Funding Phase ($000)**	**Amount to be Added Before End of Phase ($000)**
Pre-Injection (within 7 days of operating permit issuance)	Plugging Injection	$2,215	$2,215
	AoR and Corrective Action	$0	
Injection (seven (7) equal installments prior to successive anniversaries of operating permit issuance)	Emergency and Remedial Response	$0	$13,617
	Post-Injection Site Care (Includes Monitoring)	$11,239	
	Closure (including plugging Monitoring Well(s))	$2,378	
		Total Fund	$15,832

Exhibit A: [Grantor] Designee Authorized to Instruct Trustee

[Name]
[Title]
[Grantor name or company if different]
[Address 1]
[Address 2]
[Phone]

[Grantor], as Grantor, may designate other designees by amendment to this Exhibit.

Exhibit B

Permitted Investments

(i) Direct obligations of the United States of America or any agency or instrumentality thereof or obligations backed by the full faith and credit of the United States of America maturing in twelve (12) months or less from the date of acquisition:

(ii) Commercial paper maturing in 180 days of less rated not lower than A-1, by Standard & Poor's or P-1 by Moody's Investors Service, Inc. on the date of acquisition.

(iii) Demand deposits, time deposits or certificates of deposit maturing within one year in commercial banks whose obligations are rated A-1, A or the equivalent or better by Standard & Poor's on the date of acquisition;

(iv) Money market or mutual funds whose investments are limited to those types of investments described in clauses (i) and (iii) above; and

(v) Deposits of the Bank of North Dakota, to the extent guaranteed by the State of North Dakota under North Dakota Century Code Section 6-09-10, or a successor statute.

Exhibit C

Compensation and Reimbursement of Expenses
Trustees Fee Schedule

Outlined below are the initial and ongoing fees for the Bank of North Dakota to provide Trustee services:

One Time Initial Fee:	$1,250.00
Annual fee for Administration:	$1,250.00
Legal Review of Documents:	$400 - $600 estimated
Contact:	Carrie Willits (701) 328-5612 cwillits@nd.gov

The Annual Fee for Administration is subject to change upon a 30 day notification.

APPENDIX H

PERMASET CEMENT LAB ANALYSIS

Baker Hughes

PermaSet cement system

Applications

Conventional Primary and remedial cementing operations in CO_2 and H_2S environments

Features and Benefits

- Improves the cement's resistance to attacks from CO_2, H_2S, magnesium, and sulfate
- Provides minimal permeability and improved mechanical properties
- Offers fit-for-purpose designs for specific applications
- Zero Portlandite content eliminates weak points and reduces carbonation (see Fig. 1)
- Lower heat evolution during setting (less shrinkage and cracking)
- Good mechanical properties
- Real-time well conditions determine the final slurry composition
- Compatible with virtually all API and ASTM cements and most Baker Hughes cement additives

The Baker Hughes **PermaSet™ cement slurries** are fit-for-purpose, carbon dioxide (CO_2)- and hydrogen sulphide (H_2S)-resistant cement systems for use in virtually any well condition around the world. These blends have excellent free fluid control and are compatible with most Baker Hughes additives.

Baker Hughes prides itself on solving potential problems at the wellhead, understanding that a single slurry does not fit all applications. This approach allows unlimited design flexibility and takes CO_2- and H_2S-resistant cement systems out of the lab and into the real world. Our cementing philosophy utilizes state-of-the-art cement pumping equipment, such as the Baker Hughes **Seahawk™ cement unit**, to help ensure a quality cement job.

PermaSet cement slurries are part of the Baker Hughes **Set for Life™ family of cement systems**, which are designed to isolate and protect the targeted zone for the life of the well. These slurries can be blended with other systems in this family to help ensure long-term zonal isolation.

Safety Precautions

Refer to system component material safety data sheets (MSDS) for handling, transport, environmental information, and first aid.

References

- MSDS
- Set for Life systems brochure
- Set for Life cement systems overview

Set API Class G

PermaSet System

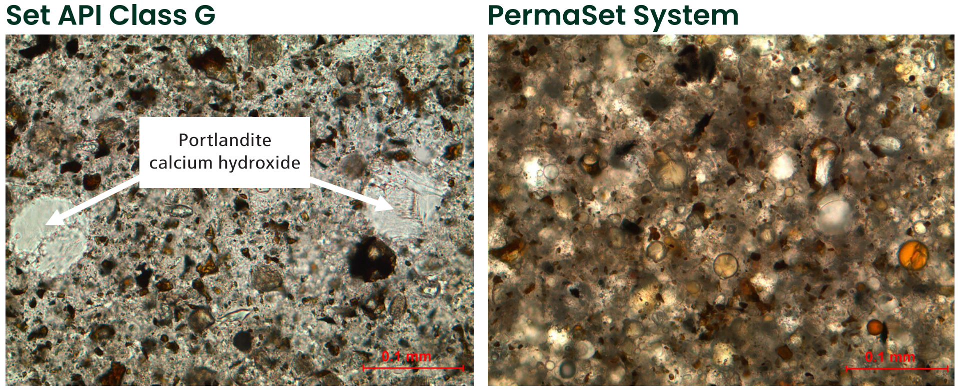


Fig. 1: Thin sections of set samples at 15.8 ppg (1893 kg/m^3) under a light microscope.

Technical data

Typical Properties	
Typical temperature range	70 to 450°F (21 to 232°C) BHCT
Typical slurry density range	9 to 20 ppg (1078 to 2397 kg/m^3)

API Class G versus PermaSet cement slurries	Slurry density		Water permeability** (microdarcy)	$Ca(OH)^2$ Portlandite Content*** (%)	Compressive strength		Tensile strength	
	ppg	kg/m^3			psi	MPa	psi	MPa
Set API Class G*	15.8	1893	2.1	9.5	4,807	33.14	378	2.61
PermaSet system*	15.8	1893	0.002	Not detectable	4,674	32.23	459	3.16
Set API Class G* extended with 4% bwoc bentonite	14.0	1678	10.8	9.2	1,633	11.26	170	1.17
PermaSet system* extended	14.0	1678	0.15	Not detectable	2,529	17.44	272	1.88

* Cement slurries were prepared according to API specification 10B using fresh water. Cement specimens were cured at 200°F (93°C) and 3,000 psi (20.68 MPa) for 72 hrs.

** Water permeabilities were measured under a confining pressure of 4,500 psi (31.03 MPa) with a water injection pressure of 3,000 psi (20.68 MPa) at 200°F (93°C).

*** Quantities were determined by X-ray powder diffraction using the reference intensity ratio method.

Case study: Offshore Angola

PermaSet cement system and SealBond successfully deployed in exploration pre-salt well

An operator, drilling in the Angola offshore environment, expected to face several short- and long-term issues during the drilling of a pre-salt exploration well on one of their fields. These challenges were due to low fracture gradients and the presence of H_2S and CO_2 in the reservoir, which challenged the cement slurry designs and threatened the integrity of the wellbore.

The operator expected the presence of H_2S and CO_2 based on data from offset wells with similar reservoir characteristics. Baker Hughes was asked to evaluate the challenging conditions and design a cementing solution that would address the non- conventional conditions.

Using the **CemFACTS™** and **CemVision™ cement design software**, Baker Hughes engineers ran an analysis of the well data to evaluate the well conditions, and determined an optimal cement design and fluid placement for the operation.

The Baker Hughes **WellTemp™ temperature modeling software** was used in tandem with the proposed pumping schedule to determine the optimal bottomhole circulating temperature required for cement slurries in laboratory testing.

The solution for the challenging well conditions was a combination of our **PermaSet™ cementing system**, a fit-for-purpose, corrosion-resistant cement system, and the **SealBond™ cement spacer system**, designed to create a protective barrier to strengthen the wellbore. Together, these systems mitigated the gas migration in the wellbore and helped avoid losses during and after the cement operation—entrained gas > 5% and mud losses > 800 bbls/hr.

Cement additives and bulk cement were tested and isolated to achieve the slurry requirements. 35% of silica flour was required due to the bottomhole static temperature. It was dry-blended with class G cement, while BA-58L and BA-10L were combined to reduce permeability and restrict the flow in the matrix. The FL-67L fluid loss controller and CD-33L were used to disperse the slurry so as to prevent early gelation. The R-21L retarder was added to the mixing seawater that was prepared in a dedicated clean pit tank, in addition to the additives required to meet the customer requirements and well conditions.

Challenges

- Gas-tight cement slurry for CO_2 and H_2S environment
- Stop gas flow during and after the cement job
- Avoid losses during and after the cement job

Results

- Delivered a PermaSet slurry and SealBond spacer during the two jobs
- Mixed on-the-fly and pumped PermaSet at 16.00 ppg (1.92 sg) with an accuracy of 99.81% of the target density in the first job and 100% premixed in the second job.
- Incurred no gas flow or losses during and after the cement operation
- Achieved successful passing of the PermaSet slurry with static gel strength (from 100 to 500 lbf/100 sq ft in less than 10 minutes) and gas flow tests

APPENDIX I

STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
Pore Space Amalgamation	NDCC §§ 38-22-06(3) and (4) NDAC §§ 43-05-01-08(1) and (2)	**NDCC § 38-22-06** 3. Notice of the hearing must be given to each mineral lessee, mineral owner, and pore space owner within the storage reservoir and within one-half mile of the storage reservoir's boundaries. 4. Notice of the hearing must be given to each surface owner of land overlying the storage reservoir and within one-half mile of the reservoir's boundaries. **NDAC § 43-05-01-08** 1. The commission shall hold a public hearing before issuing a storage facility permit. At least forty-five days prior to the hearing, the applicant shall give notice of the hearing to the following: a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary; b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary; c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary;	a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir boundary and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project;	**1.0 PORE SPACE ACCESS** (p. 1-4) DCC West will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made.	The affidavit has not yet been prepared.
			b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;	**1.0 PORE SPACE ACCESS** (p. 1-1) North Dakota law explicitly grants title of the pore space in all strata underlying the surface of lands and waters to the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [NDCC] Chapter 47-31, Subsurface Pore Space Policy). Prior to issuance of the storage facility permit (SFP), the storage operator is required, in good faith, to attempt to obtain the consent of all persons who own pore space within the storage reservoir. The North Dakota Industrial Commission (NDIC) can amalgamate the nonconsenting owners' pore space into the storage reservoir if the operator can show that 1) after making a good faith effort, they were able to obtain consent of persons who own at least 60% of the pore space in the storage reservoir and 2) NDIC finds that the nonconsenting owners will be equitably compensated for the use of pore space. Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of this SFP application (NDCC § 38-22-06[3] and [4]) and North Dakota Administrative Code (NDAC) § 43-05-01-08[1] and [2]).	**Figure 1-1.** Map showing the proposed flowline location, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing notification area (HNA) for DCC West SGS.
			c. A map showing the storage reservoir boundary and one-half mile outside of the storage reservoir boundary with a description of pore space ownership;	(p. 1-4) DCC West will identify the owners of record (surface and mineral), pore space and mineral lessees of record, and operators of mineral extraction activities within the facility area and within 0.5 miles of its outside boundary. DCC West will notify in accordance with NDAC § 43-05-01-08 of the SFP hearing at least 45 days prior to the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made. (p. 1-1) All owners, lessees, and operators that require notification have been identified in accordance with North Dakota law, which vests the title to the pore space in all strata underlying the surface of lands and water to the owner of the overlying surface estate (NDCC § 47-31-03). The identification of pore space owners indicates there was no severance of pore space or leasing of pore space to a third party from the surface estate prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record.	**Figure 1-1.** Map showing the proposed flowline location, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing notification area (HNA) for DCC West SGS.
			d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each operator of mineral extraction activities;	(p. 1-2) The proposed horizontal boundary of the storage reservoir, including an adequate buffer area, is defined by the simulated migration of the CO_2 plume, using the maximum rate of injection, from the start of injection until the end of injection. DCC West modeled a 98.25% CO_2 stream composition for purposes of establishing the storage facility boundary, which represents the averaged stream composition (stream may range from a minimum composition of 96% CO_2 to 99.9% CO_2). Additionally, by defining the storage reservoir boundary based on the maximum rate rather than the actual operating rate, the project has a built-in storage contingency in the proposed boundary. Further, the horizontal storage reservoir boundary is proposed using a 20-year injection period and was benchmarked off of a maximum design life of the surface equipment. The simulated horizontal storage reservoir boundary results are identified in Figure 1-1.	**Figure 1-1.** Map showing the proposed flowline location, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing notification area (HNA) for DCC West SGS.
			e. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each mineral lessee of record;		
			f. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each surface owner of record;		**Figure 1-1.** Map showing the proposed flowline location, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary; e. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile [.80 kilometer] of the reservoir's boundary; and f. Any other persons as required by the commission. 2. The notice given by the applicant must contain: a. A legal description of the land within the facility area. b. The date, time, and place that the commission will hold a hearing on the permit application. c. A statement that a copy of the permit application and draft permit may be obtained from the commission.	g. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each owner of record of minerals.		notification area (HNA) for DCC West SGS. **Figure 1-1.** Map showing the proposed flowline location, tract numbers, simulated storage reservoir boundary results (storage facility area) and hearing notification area (HNA) for DCC West SGS.
Geologic Exhibits	NDAC § 43-05-01-05 (1)(b)(1)	**NDAC § 43-05-01-05 (1)(b)** (1) The name, description, and average depth of the storage reservoirs;	a. Geologic description of the storage reservoir: Name Lithology Average thickness Average depth	**2.1 Overview of Project Area Geology** (p. 2-1) The proposed Dakota Carbon Center West SGS (secure geologic storage) injection site (DCC West SGS) will be situated approximately 7 miles to the west of the Milton R. Young Station (MRYS) located southeast of Center, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin. Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted via the EERC-led Plains CO_2 Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for permanent CO_2 storage because of, in part, the thick sequence of clastic and carbonate sedimentary rocks and the basin's subtle structural character and tectonic stability (Peck and others, 2014; Glazewski and others, 2015). The target CO_2 storage reservoir for DCC West SGS is the Broom Creek Formation, a predominantly sandstone horizon lying 4908 ft below the surface at the J-LOC 1 stratigraphic test well (NDIC File No. 37380). Unconformably overlying the Broom Creek Formation is 29 ft of the undifferentiated Opeche and Spearfish Formations (hereafter "Opeche/Spearfish Formation"), comprising predominantly siltstone with interbedded dolostone and anhydrite. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish (above) and Opeche (below); since the Minnekahta is absent at the J-LOC 1 location, and due to the similarity in lithology between the two units, the Opeche and Spearfish are undifferentiated here. Overlying the Opeche/Spearfish Formation is 95 ft of the lower portion of the Piper Formation from the top of the Picard	**Figure 2-1.** Topographic map of the DCC West SGS area showing well locations and MRYS in relation to the city of Center. (p. 2-2) **Figure 2-2.** Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue). (p. 2-3)

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>Member to the undifferentiated Opeche/Spearfish, comprising siltstone, dolostone, and interbedded evaporites. Together, the Opeche/Spearfish and lower Piper Formations (hereafter “Opeche–Picard interval”) serve as the primary confining zone (Figure 2-2). The Amsden Formation (dolostone, sandstone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche–Picard interval and the Broom Creek and Amsden Formations comprise the storage complex for DCC West SGS (Table 2-1).
Including the Opeche–Picard interval, there is 851 ft (thickness at the J-LOC 1 well) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2638 ft (thickness at the J-LOC 1 well) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

Table 2-1. Formations Comprising the DCC West SGS CO_2 Storage Complex (average values calculated from the simulation model shown in Figure 2-3)
<table>
<tr><th></th><th>Formation</th><th>Purpose</th><th>Thickness at J-LOC 1, ft</th><th>Depth at J-LOC 1, MD,* ft</th><th>Average Thickness, ft</th><th>Average Depth, MD,* ft</th><th>Lithology</th></tr>
<tr><td rowspan="3">Storage Complex</td><td>Opeche–Picard</td><td>Upper confining zone</td><td>124</td><td>4784</td><td>234</td><td>5010</td><td>Siltstone, dolostone evaporites</td></tr>
<tr><td>Broom Creek</td><td>Storage reservoir (i.e., injection zone)</td><td>302</td><td>4908</td><td>280</td><td>5244</td><td>Sandstone, dolostone, anhydrite</td></tr>
<tr><td>Amsden</td><td>Lower confining zone</td><td>259</td><td>5210</td><td>257</td><td>5524</td><td>Dolostone, sandstone, anhydrite</td></tr>
</table>
* Measured depth.</td><td>Table 2-1. Formations Comprising the DCC West SGS CO2 Storage Complex (average values calculated from the simulation model shown in Figure 2-3) (p. 2-4)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(k)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(k) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;</td><td>b. Data on the injection zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure
Facies changes</td><td>SOURCE OF THE DATA:
2.2.1 Existing Data (p. 2-4)
The existing data used to characterize the geology beneath the DCC West SGS area included publicly available well logs and formation top depths acquired from the North Dakota Industrial Commission’s (NDIC’s) online database and purchased digitized well logs. Well log data and interpreted formation top depths were acquired for 115 wellbores within a 4070-mi2 (74-mi × 55-mi) area covered by the geologic model of the proposed storage site (Figure 2-3). Well data were used to characterize the depth, thickness, and extent of the subsurface geologic formations. Existing 2D and 3D seismic data were also used to characterize the subsurface geology.

Existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were evaluated. Existing wells with core data include the Flemmer 1 (NDIC File No. 34243), BNI 1 well (NDIC File No. 34244), Liberty 1 (NDIC File No. 37672), MAG 1 (NDIC File No. 37833), Coteau 1 (NDIC File No. 38379), Milton Flemmer 1 (NDIC File No. 38594), Archie Erickson 2 (NDIC File No. 38622), Slash Lazy H 5 (NDIC File No. 38701), and ANG 1 (ND-UIC-101) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and integrated with site-specific data.

2.2.2 Site-Specific Data (p. 2-4, and 2-6)
Site-specific efforts to characterize the storage complex generated multiple data sets, including geophysical well logs, petrophysical data, fluid analyses, whole core, and 2D and 3D seismic data. In 2020, the J-LOC 1 well was drilled specifically to gather subsurface geologic data to support development of a storage facility. The J-LOC 1 well was drilled to a depth of 10,470 ft. The downhole sampling and measurement program focused on the proposed storage complex (i.e., the Opeche–Picard interval and the Broom Creek and Amsden Formations) (Figure 2-5).
Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of CO_2. Site-specific and existing data were also used as inputs for geologic model construction (Section 3.2), numerical simulations of CO_2 injection (Section 3.3), geochemical simulation (Sections 2.3.4, 2.4.1.2, and 2.4.3.2), and geomechanical analysis</td><td>Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones. (p. 2-5)

Figure 2-4. Map showing the spatial relationship between the wells where core samples were collected from the formations comprising the storage complex. (p. 2-6)

Figure 2-8. Broom Creek Formation in North</td></tr>
</table>

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td>
(Section 2.4.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency of collecting monitoring data, and interpretation of monitoring data with respect to potential subsurface risks. Furthermore, these data guided and influenced the design and operation of site equipment and infrastructure.

DATA ON THE INJECTION ZONE:
2.3 Storage Reservoir (injection zone) (p. 2-13)
Regionally, the Broom Creek Formation is laterally extensive in the project area (Figure 2-8). Broom Creek Formation core comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with anhydrite layers. The Broom Creek Formation unconformably overlies the Amsden Formation and is unconformably overlain by the Opeche/Spearfish Formation (Figure 2-2) (Murphy and others, 2009).

2.3.2 Mineralogy (p. 2-24)
The combined interpretation of core, well logs, and thin sections shows that the Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with anhydrite layers. Seventeen (17) depth intervals from the Broom Creek Formation from the J-LOC 1 were sampled for thin-section creation, XRD mineralogical determination, and XRF bulk chemical analysis. Thin sections and XRD provide independent confirmation of the mineralogical constituents of the Broom Creek Formation.

Thin-section analysis of the sandstone intervals shows that quartz (~85%) is the dominant mineral. Throughout these intervals are minor occurrences of feldspar (~4%), dolomite (~5%), and anhydrite as cement (~6%). Where present, anhydrite is crystallized between quartz grains and obstructs the intercrystalline porosity. The contact between grains is long (straight) to tangential.

Two distinct carbonate intervals are notable in the Broom Creek Formation cored interval of the J-LOC 1 well. The first is the presence of a very fine- to fine-grained dolostone (75%), with quartz (~16%) and feldspar (~9%) present. The porosity is intercrystalline and not well-developed, averaging 5.5%. Diagenesis is expressed by dolomitization of the original calcite grains. The second carbonate interval comprises fine-grained dolomite (~78%), quartz (10%), feldspar (8%), and clay (4%). Diagenesis is expressed by the dissolution of dolomite, resulting in vuggy porosity. The porosity averages 9%. The anhydrite intervals are expressed as thin beds that separate different sand bodies. The porosity ranges from 1.5% to 2.5%.

XRD data from the samples supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek Formation core primarily comprises quartz, dolomite, anhydrite, feldspar, clay, and iron oxides (Figure 2-18 and Table 2-8). XRD data show illite is the most prominent type of clay within the formation.

XRF data are shown in Figure 2-19 for the Broom Creek Formation. As shown, the majority of the sandstone and dolomite intervals are confirmed through the high percentages of SiO2 (70%–80%), CaO (0%–30%), and MgO (0%–20%). High percentages of CaO and SO_3 indicate the presence of thin layers of anhydrite. The formation shows very little clay, with a range of 0% to 6% observed.

Table 2-6. Description of CO_2 Storage Reservoir (injection zone) at the J-LOC 1 Well
<table>
<tr><th colspan="4">Injection Zone Properties</th></tr>
<tr><th>Property</th><th colspan="3">Description</th></tr>
<tr><td>Formation Name</td><td colspan="3">Broom Creek</td></tr>
<tr><td>Lithology</td><td colspan="3">Sandstone, dolostone, dolomitic sandstone, anhydrite</td></tr>
<tr><td>Formation Top Depth*, ft</td><td colspan="3">4908</td></tr>
<tr><td>Thickness, ft</td><td colspan="3">Sandstone, 169
Dolostone, 89
Dolomitic sandstone, 27
Anhydrite, 17</td></tr>
<tr><td>Capillary Entry Pressure (CO_2/brine), psi</td><td colspan="3">0.20</td></tr>
<tr><th colspan="4">Geologic Properties</th></tr>
<tr><th>Facies</th><th>Property</th><th>Laboratory Core Analysis</th><th>Simulation Model Property Distribution</th></tr>
<tr><td>Broom Creek (sandstone)</td><td>Porosity, %**</td><td>19.51</td><td>21.96</td></tr>
</table>
</td><td>
Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green line has been modified based on new well control. (p. 2-13)

Figure 2-9. Isopach map of the Broom Creek Formation in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-14)

Figure 2-10. Well log display of the interpreted lithologies of the Opeche–Picard interval and Broom Creek and Amsden Formations in J-LOC 1 well. Well logs displayed in tracks from left to right are 2) GR (green) and caliper (red), 3) delta time (light blue), 4) neutron porosity (blue) and density (red), 5) resistivity deep (black) and resistivity shallow (light blue), and 6) facies (lithology). (p. 2-15)

Figure 2-11a. Regional well log stratigraphic cross sections of the Opeche–Picard interval and the Broom Creek Formation flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Cross-
</td></tr>
</table>

<table>
<thead>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application (Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
</thead>
<tbody>
<tr><td></td><td></td><td></td><td></td><td>
<table>
<tr><td></td><td></td><td>(2.46–27.38)</td><td>(0.0005–35.30)</td></tr>
<tr><td></td><td>Permeability, mD***</td><td>69.28
(0.06–2690)</td><td>136.96
(0.0–3401.2)</td></tr>
<tr><td rowspan="2">Broom Creek (dolostone)</td><td>Porosity, %</td><td>8.11
(5.48–8.97)</td><td>4.39
(0.0–34.93)</td></tr>
<tr><td>Permeability, mD</td><td>0.03
(0.02–0.05)</td><td>2.07
(0.0–919.6)</td></tr>
</table>
* Measured Depth
** Porosity values are reported as the arithmetic mean measured at 800 psi followed by the range of values in parentheses.
*** Permeability values are reported as the geometric mean measured at 800 psi followed by the range of values in parentheses.

2.3.4 Geochemical Information of Injection Zone (p. 2-27)
Geochemical simulation has been performed to calculate the effects of introducing the CO_2 stream to the injection zone. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in the Computer Modelling Group Ltd. (CMG) compositional simulation software package GEM. GEM is also the primary simulation software used for evaluating the reservoir's dynamic behavior resulting from the expected CO_2 injection. For this geochemical modeling study, the injection scenario consisted of one injection well injecting for a 20-year period with maximum BHP and maximum wellhead pressure (WHP) of 2100 psi as it was simulated during the evaluation of CO_2 injection. A postinjection period of 25 years was run in the model to evaluate dynamic behavior and/or geochemical reaction after the CO_2 injection is stopped.

The composition of the injected gas will be to a minimum standard consisting of at least 96% dry CO_2 (by volume), with trace quantities (4% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C2+, and hydrocarbons. The CO_2 stream, shown in Table 2-9, that was used for geochemical modeling, contains a higher amount of O_2 than the anticipated injection stream. This stream containing ~95% CO_2 and 2% O_2 was used to represent a conservative scenario with the higher oxygen concentration, because oxygen is the most reactive constituent in the anticipated CO_2 stream. This geochemical scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared.

The scenario with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (87% of bulk reservoir volume) and average formation brine composition (13% of bulk reservoir volume). XRD data from core samples from the J-LOC 1 well with depths from 4910 to 5196.5 ft were averaged and used for calculating the mineralogical composition of the Broom Creek Formation (Table 2-10). Reported ionic composition of the Broom Creek Formation water from the J-LOC 1 well is listed in Table 2-11 and used as input for the aqueous phase for the for the geochemical modeling. The geochemistry case was run for the 20-year injection period followed by 25 years of postinjection monitoring. For computational efficiency, only the most representative minerals from the XRD test and water ions with higher concentration were included in the model to reduce the number of geochemical reactions, Table 2-10. Therefore, only anhydrite, illite, K-feldspar, albite, dolomite, chlorite, and quartz were included as minerals from the XRD report.

Figure 2-20 shows that reservoir performance results for the case with and without geochemical modeling are nearly identical. As a result of geochemical reactions in the reservoir, cumulative injection rate has no observable difference. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.

Figure 2-20 shows that reservoir performance results for the case with and without geochemical modeling are nearly identical. As a result of geochemical reactions in the reservoir, cumulative injection rate has no observable difference. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.

Figure 2-21a shows the cross section for the concentration of CO_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model scenario, and Figure 2-21b shows the same information for the nongeochemistry simulation case for comparisons. The results do not show an evident difference in the CO_2 gas molality fraction between both cases, as seen in Figure 2-20 for the rates injected and injection pressure simulation results.

For the geochemistry case, the pH of the reservoir brine changes in the vicinity of the CO_2 accumulation, as shown in Figure 2-22a. The initial pH of the Broom Creek Formation native brine prior to injection is 7.4. The pH declines to approximately 4.2 to 4.9, in the CO_2-flooded areas near
</td><td>
sections scaled in SSTVD (SubSea True Vertical Depth). (p. 2-16)

Figure 2-11b. Regional well log structural cross sections of the Opeche–Picard interval and the Broom Creek and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is. Cross-sections scaled in SSTVD. (p. 2-17)

Figure 2-12. Structure map of the Broom Creek Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-18)

Figure 2-13. Cross section from A-A' of the DCC West SGS area from the geologic model showing facies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. Geologic model extent is displayed by dark blue box in the upper-left corner. (p. 2-19)
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				the well, during the first 3 years of injection as a result of CO_2 dissolution in the native brine (Figure 2-22b). However, the pH increases to a maximum value of 5.5 because of mineral reactions during the rest of the injection and postinjection periods. Figures 2-23a and 2-23b show the cross section for O_2 molality in the Broom Creek Formation. Figure 2-23a shows the cross section for the concentration of O_2, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model scenario, and Figure 2-23b shows the same information for the nongeochemistry simulation case for comparisons. The results do not show an evident difference in the O_2 gas molality fraction between both cases. After being injected, the oxygen (O_2, 2%) in the CO_2 stream is dissolved in the brine and likely to cause oxidative reactions of the minerals which may induce dissolution/precipitation of reactive minerals and formation of secondary minerals in the reservoir. The simulation results showed no significant precipitation caused by the high concentration of O_2 that would affect the CO_2 injection volume as demonstrated by the comparison in injection rates between the case with and without geochemical modeling shown in Figure 2-20.	**Table 2-6.** Description of CO_2 Storage Reservoir (injection zone) at the J-LOC 1 Well (p. 2-21) **Figure 2-14.** Vertical distribution of core-derived porosity and permeability values in the J-LOC-1 well. Well logs displayed in tracks from left to right are 2) GR (green) and caliper (red), 3) core porosity (800 psi) (blue) and core porosity (2400 psi) (orange), 4) core permeability (800 psi) (red) and core permeability (2400 psi) (black), and 5) facies (lithology). (p. 2-20) **Figure 2-18** XRD data displaying mineralogic characteristics of the Broom Creek Formation in the J-LOC 1 well. (p. 2-25) **Figure 2-19**. XRF data from the Broom Creek Formation in the J-LOC 1. (p. 2-26) **Table 2-9**. CO_2 Stream Composition Used For Geochemical Modeling (p. 2-28) **Table 2-10.** XRD Core Sample Results for J-LOC 1 in Broom Creek Formation (p. 2-28) **Figure 2-20**. Upper graph shows cumulative injection and gas mass rate vs. time. There is no observable difference in injection due to

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					geochemical reactions. The lower graph shows the wellhead injection pressure for the two cases is the same: 2100 psi. The solid line represents the geochemical modeling case, and the dashed line represents the case without geochemical interactions. There is no observable difference in gas rate injection and pressures due to geochemical reactions. (p. 2-30) **Table 2-11** Broom Creek Formation Water Ionic Composition, expressed as molality (p. 2-28) **Figure 2-21a.** CO_2 molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection, showing the distribution of CO_2 molality in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD). (p. 2-31) **Figure 2-21b.** CO_2 molality for the nongeochemistry simulation results after 20 years of injection + 25 years postinjection, showing the distribution of CO_2 molality in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar

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					view of simulation Layer 28 at 2980.8 ft (SSTVD). (p. 2-32) **Figure 2-22a.** Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD). (p. 2-33) **Figure 2-22b.** Geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the pH of formation brine at the wellbore vs. time for layers 28 at 2980.8 ft (SSTVD), layer 42 at 3053.8 ft, and layer 60 at 3147.8 ft.(p. 2-34) **Figure 2-23a.** Cross section for O2 molality for the geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of O2 in gas phase in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD) (p. 2-35)

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					Figure 2-23b. Cross section for O_2 molality for the non-geochemistry case simulation results after 20 years of injection + 25 years postinjection showing the distribution of O2 in gas phase in a log scale. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD). (p. 2-36) **Figure 2-24a**. Dissolution and precipitation quantities of reservoir minerals because of CO_2 injection. Dissolution of illite, anhydrite, chlorite, albite, and K-feldspar with precipitation of quartz, dolomite, and siderite was observed. Ankerite, hematite and ferric hydroxide are showing very small values and account as net zero in this figure due to the scale. (p. 2-38) **Figure 2-24b**. Dissolution of ferric hydroxide and hematite with precipitation of ankerite was observed. These secondary minerals can be formed but in a small volume in the Broom Creek Formation. There is not enough Chlorite minerals present in the injection area to cause the precipitation of ferric hydroxide. (p. 2-38) **Figure 2-25.** Mineral mass changes, in metric

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					tons (tonnes), for the different CO_2-trapping mechanisms present during CO_2 injection with geochemical modeling in the injection zone for the Broom Creek Formation. (p. 2-39) **Figure 2-26.** Mineral mass changes, in metric tons (tonnes), for the different CO_2-trapping mechanisms present during CO_2 injection with geochemical modeling in the injection zone for the Broom Creek Formation. (p.2-40) **Figure 2-27.** Change in molar distribution of anhydrite mineral in dissolution at the end of the injection + 25 years postinjection period in the injection zone of Broom Creek Formation. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD). (p.2-41) **Figure 2-28.** Change in molar distribution of dolomite, the most prominent precipitated mineral, at the end of the injection + 25 years postinjection period in the injection zone of Broom Creek Formation. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
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<tr><td></td><td></td><td></td><td></td><td></td><td>28 at 2980.8 ft (SSTVD) (p.2-42)

Figure 2-29. Change in porosity due to net geochemical dissolution after the 20-year injection + 25 years postinjection period. Maximum porosity change is less than 0.1%. The top-left image is west–east, and the top-right image is a south–north cross section. The bottom image is a planar view of simulation Layer 28 at 2980.8 ft (SSTVD) (p. 2-43)</td></tr>
<tr><td></td><td></td><td></td><td>c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:
Depth
Areal extent
Thickness
Mineralogy
Porosity
Permeability
Capillary pressure
Facies changes</td><td>SOURCE OF THE DATA:
See discussion above under 2.2.1 Existing Data (p. 2-4)

AND

2.4 Confining Zones (p. 2-44)
The confining zones for the Broom Creek Formation are the Opeche–Picard interval and underlying Amsden Formation (Figure 2-2, Table 2-12). Both the Amsden Formation and Opeche–Picard interval consist of impermeable rock layers..

Table 2-12. Properties of Upper and Lower Confining Zones at the J-LOC 1 Well
<table>
<tr><th>Confining Zone Properties</th><th></th><th>Upper Confining Zone</th><th>Lower Confining Zone</th></tr>
<tr><td>Stratigraphic Unit</td><td></td><td>Opeche–Picard</td><td>Amsden</td></tr>
<tr><td>Lithology</td><td></td><td>Siltstone/evaporites/ dolostone</td><td>Dolostone/ anhydrite/sandstone</td></tr>
<tr><td>Formation Top Depth (MD), ft</td><td></td><td>4784</td><td>5210</td></tr>
<tr><td>Thickness, ft</td><td></td><td>124</td><td>259</td></tr>
<tr><td>Capillary Entry Pressure (brine/CO_2), psi</td><td></td><td>20.59</td><td>69.03</td></tr>
<tr><td>Depth below Lowest Identified USDW, ft</td><td></td><td>3534</td><td>3960</td></tr>
<tr><th>Formation</th><th>Property</th><th>Laboratory Analysis*</th><th>Simulation Model Property Distribution**</th></tr>
<tr><td>Opeche/Spearfish</td><td>Porosity, %</td><td>3.53</td><td>2.14 (0.00–14.64)</td></tr>
<tr><td></td><td>Permeability, mD</td><td>0.0104</td><td>0.0021 (0.00–6.37</td></tr>
<tr><td>Amsden</td><td>Porosity, %</td><td>5.4, 7.3</td><td>2.92 (0.00–35.05)</td></tr>
<tr><td></td><td>Permeability, mD</td><td>0.0053, 0.0062</td><td>0.0070 (0.00–156.05)</td></tr>
</table>
* Porosity values recorded at 800-psi confining pressure from the J-LOC 1 well. Permeability values are recorded at 800-psi confining pressure from the J-LOC 1 well. Values measured from Opeche/Spearfish zone for the upper confining zone
** Porosity values from the model are reported as the arithmetic mean (sum of values divided by number of values) followed by the range of values in parentheses. Permeability values from the model are reported as the geometric mean (product of values raised to the inverse series length of the series) followed by the range of values in parentheses.</td><td>Table 2-12. Properties of Upper and Lower Confining Zones at the J-LOC 1 Well (p. 2-44)

Figure 2-30. Areal extent of the Piper Picard Formation in western North Dakota (modified from Carlson, 1993). (p. 2-45)

Figure 2-31. Structure map of the Opeche/Spearfish Formation of the upper confining zone across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-46)

Figure 2-32. Structure map of the lower Piper of the upper confining zone across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation</td></tr>
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<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application (Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description (Page Number)</th></tr>
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2.4.1 Upper Confining Zone (p. 2-44)

In the DCC West SGS area, the lower Piper Formation (Picard Member and lower) consists of siltstone, dolostone, and interbedded evaporates and the Opeche/Spearfish Formation consists of predominantly siltstone with interbedded dolostone and anhydrite. The upper confining zone (Opeche–Picard interval) is laterally extensive across the DCC West SGS area (Figure 2-30). The upper confining zone has sufficient areal extent and integrity to contain the injected CO_2. The upper confining zone is free of transmissive faults and fractures (Section 2.5). The Opeche–Picard interval is 4784 ft below the land surface and 124 ft thick as measured at the J-LOC 1 well (Table 2-12 and Figures 2-31 through 2-34). The contact between the upper confining zone and underlying Broom Creek Formation sandstone is an unconformity that can be correlated across the formation's extent where the resistivity and GR logs show a significant change across the contact (Figure 2-10).

2.4.1.1 Mineralogy (p.2-51)

Thin-section investigation shows that the Opeche/Spearfish Formation comprises predominantly siltstone with interbedded dolostone and anhydrite. Thin sections were created from the base of the Opeche/Spearfish and the transition zone present at the top of the Broom Creek which comprises clay-rich siltstone. The transition zone has similar characteristics as the Opeche/Spearfish Formation and will also act as a seal. The mineral components present in these samples are anhydrite, quartz, feldspar, dolomite, clay, and iron oxides. The grains are typically surrounded by anhydrite or clay as cement or matrix. The rare porosity is due to the dissolution of quartz and feldspar. Log interpretations and visual inspection of the collected core validate consistent mineral assemblage within the Opeche/Spearfish Formation.

XRD data from samples in the J-LOC 1 well core supported facies interpretations from core descriptions and thin-section analysis. The Opeche/Spearfish Formation mainly comprises anhydrite, quartz, clay, and dolomite.

XRF analysis of the Opeche/Spearfish Formation identifies the major chemical constituents to be dominated by SiO2 (~47%), SO3 (~18%), CaO (~16%), Al2O3 (~4%), and MgO (~2%) correlating well with the silicate-, carbonate-, and aluminum-rich mineralogy determined by the XRD (Table 2-13). These results correlate with XRD, core description, and thin-section analysis.

Table 2-13. XRF Data for the Opeche/Spearfish Formation from J-LOC 1

Component	Percentage
	4906* ft
SiO_2	47.41
Al_2O_3	3.78
CaO	16.58
MgO	2.17
SO_3	18.26
Others	11.8

* Sample depth correspond to cored depth. A depth shift must be applied to align the values with log depth.

2.4.1.2 Geochemical Interaction (p.2-52)

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of injected CO_2 stream on the Opeche/Spearfish Formation. Note: PHREEQC's unit of measure is metric. A vertically oriented 1D simulation was created using a stack of 1-meter grid cells, where the formation was exposed to CO_2 at the bottom boundary of the simulation and allowed to enter the system by molecular diffusion processes. Direct fluid flow into the Opeche/Spearfish Formation by free-phase saturation from the injection stream is not expected to occur because of the low permeability of the confining zone. Results were calculated at the grid cell centers: 0.5, 1.5, and 2.5 meters above the cap rock–CO_2 exposure boundary. The mineralogical composition of the Opeche/Spearfish Formation was honored (Table 2-14). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table 2-15). The composition of the injected gas will be to a standard consisting of at least 96% dry CO_2 (by volume), with trace quantities (4% by volume) of water, nitrogen, oxygen, hydrogen sulfide, C2+, and hydrocarbons. The CO_2 stream, shown in Table 2-16 that was used for geochemical modeling contains a higher amount of O_2 (2%) than the anticipated injection stream. This stream containing ~95% CO_2 and 2% O2 was used to represent a conservative scenario, as oxygen is the most reactive constituent among all others. The exposure level, expressed in moles per year, of the CO_2 stream to the cap rock used was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/yr (Espinoza and Santamarina, 2017). This overestimate was used to ensure that the degree and pace of geochemical change would not be underestimated. This

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tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-47)

Figure 2-33. Isopach map of the Opeche/Spearfish Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-48)

Figure 2-34. Isopach map of the lower Piper Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-49)

Table 2-13. XRF Data for the Opeche/Spearfish Formation from J-LOC 1 (p. 2-52)

Table 2-14. Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of J-LOC 1 Core Samples (p. 2-53)

Table 2-15. Formation Water Chemistry from Broom Creek Fluid Samples from J-LOC 1 (p. 2-53)

Table 2-16. Modeled Composition of the Injection Stream. (p. 2-53)

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				geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection. The simulation was performed at elevated reservoir pressure and temperature conditions. Results showed geochemical processes at work. Figures 2-37 through 2-41 show results from geochemical modeling. Figure 2-37 shows change in fluid pH over time as CO_2 enters the system. For the cell at the CO_2 interface, Cell 1 (C1), the pH starts declining from the initial pH of 7.3 and begins to stabilize to a level of 5.3 after 10 years of injection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH only begins to change after Year 24. Lastly, the pH is unaffected in C3, indicating CO_2 does not penetrate this cell within the first 45 years. Figure 2-38 shows the change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. The net change due to precipitation or dissolution in C2 is less than 10 kg per cubic meter per year during active injection, with little to no precipitation or dissolution taking place after injection ceases in Year 2044. Any effects in C3 are not significant to represent at this scale of C1 mineral dissolution and precipitation. Figure 2-39 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table 2-14. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1, albite, anhydrite, K-feldspar, and dolomite are the primary minerals that dissolve. In C2, albite is the primary mineral that dissolves, but it is too small to be seen (0.02%) in Figure 2-39. Figure 2-40 represents expected minerals to be precipitated in weight (%) shown for C1 and C2 of the model. In C1, illite, quartz, and calcite are the minerals to be precipitated. In C2, illite is the primary mineral to be precipitated (<1.0 wt%). Figure 2-41 shows change in porosity of the cap rock for C1–C3. C1 experiences an initial increase in porosity as it is first exposed to CO_2 because of dissolution. The porosity decreases to nearly its initial condition after Year 13 because of precipitation. As dissolution occurs in C1, reaction products move into C2, where they precipitate, causing the porosity to slightly decrease. The net porosity changes from dissolution and precipitation represented in Figure 2-41 are miniscule and, in later years, are unchanging. These results suggest that geochemical change from exposure to CO_2 is minor and will not cause substantive deterioration of the Opeche/Spearfish cap rock. ***2.4.2 Additional Overlying Confining Zones*** (p. 2-59) Several other formations provide additional confinement above the Opeche–Picard interval. Impermeable rocks above the primary seal include the Piper (Kline Member), Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-17). Together with the Opeche–Picard interval, these formations are 851 ft thick (thickness at the J-LOC 1 well) and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-42, Broom Creek to Swift). Above the Inyan Kara Formation, 2638 ft (thickness at the J-LOC 1 well) of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-43, Inyan Kara to Pierre). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-17). **Table 2-17. Description of Zones of Confinement above the Immediate Upper Confining Zone, Opeche–Picard Interval (data based on the J-LOC 1 well)** Name of Formation | Lithology | Formation Top Depth, ft | Thickness, ft | Depth below Lowest Identified USDW, ft Pierre | Mudstone | 1250 | 1934 | 0 Greenhorn | Mudstone | 3184 | 401 | 1934 Mowry | Mudstone | 3585 | 60 | 2335 Skull Creek | Mudstone | 3655 | 233 | 2405 Swift | Mudstone | 4057 | 472 | 2807 Rierdon | Mudstone | 4529 | 146 | 3279 Piper (Kline Member) | Carbonate | 4675 | 109 | 3425	**Table 2-5**. Description of Fluid Sample Test and Corresponding Total Dissolved Solids (TDS) Value for J-LOC 1 (p. 2-11) **Figure 2-37.** Change in fluid pH vs. time. Red line shows pH for the center of C1, 0.5 meters above the Opeche/Spearfish Formation cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. pH for C2 does not begin to change until after Year 24. (p. 2-55) **Figure 2-38**. Dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1 at 0.5 meters above the cap rock base. Solid lines show results for C2, 1.5 meters above the cap rock base. (p. 2-56) **Figure 2-39**. Weight percentage (wt.%) of potentially reactive minerals present in the Opeche/Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2(gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt.% associated with dissolution. (p. 2-57)

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				2.4.3 Lower Confining Zones (p. 2-60) The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, sandstone, and anhydrite. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, with relatively high GR character that can be correlated across the DCC West SGS area (Figure 2-10). The Amsden Formation is 5210 ft below land surface and 259 ft thick at the J-LOC 1 well site (Table 2-12, Figures 2-44 and 2-45). The contact between the overlying Broom Creek and Amsden Formations is evident on wireline logs as there is a lithological change from the porous sandstones of the Broom Creek Formation to the dolostone and anhydrite beds of the Amsden Formation. This lithologic change is recognized in the core from the J-LOC 1 well. The lithology of the cored section of the Amsden Formation from the J-LOC 1 well is dolostone and anhydrite, with laminated, fine-grained sandstone. ***2.4.3.1 Mineralogy*** (p. 2-65) The well logs and thin-section analyses show that the Amsden Formation comprises dolostone, sandstone, and anhydrite. The dolostone is expressed by very fine- to fine-grained dolomite (35%), with the presence of quartz of variable size and shape, feldspar, clay, anhydrite, and iron oxides. Quartz overgrowth and the absence of intercrystalline porosity were observed in thin sections (Figure 2-46). The existing porosity (secondary porosity) is mainly due to the dissolution of feldspar and quartz and averages 5%. Anhydrite is present as beds that separate the dolomite intervals and cement and mineral components. It comprises anhydrite minerals with minor inclusions of iron oxides. The porosity is almost null. The sandy dolomite mainly comprises dolomite and grains of quartz. Minor iron oxides and feldspar are present, with rare occurrence of anhydrite observed. The grains of quartz are almost always separated by dolomite cement. The porosity is mainly due to the dissolution of feldspar and quartz and averages 5%. The shaly sandstone comprises quartz, clay, and dolomite. A minor presence of feldspar, anhydrite, and iron oxides exists. The grains of quartz and anhydrite are frequently separated by clay cement. The porosity is very low, averaging 7%, and is mainly due to the dissolution of feldspar and quartz. XRD was performed, and the results confirm the observations made during core description, thin-section description, and well log analysis. XRF data show the Amsden Formation has the same major chemical constituents as the Opeche/Spearfish Formation (Table 2-18). However, the interval at the contact with the Broom Creek Formation is underlain by anhydrite. As the formation gets deeper, the chemistry changes to a more carbonate-rich siltstone, as shown by the higher percentages of SiO_2, CaO, and MgO.	**Figure 2-40.** Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Minerals precipitated in C2 are too small to be seen in the figure. (p. 2-58). **Figure 2-41.** Change in percent porosity of the Opeche/Spearfish cap rock. Red line shows porosity change calculated for C1 at 0.5 meters above the cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals and negative change is due to mineral precipitation. (p. 2-59) **Table 2-17.** Description of Zones of Confinement above the Immediate Upper Confining Zone, Opeche-Picard Interval (data based on the J-LOC 1 well) (p. 2-60) **Figure 2-42.** Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval

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					represents the primary and secondary confining zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-61) **Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-62) **Figure 2-44.** Structure map of the Amsden Formation across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.project area in feet below mean sea level. (p. 2-63) **Figure 2-45.** Isopach map of the Amsden Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-64) **Figure 2-46**. Plane-polarized light thin-section image from the J-

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
					LOC 1 well, Amsden Formation. This image shows the dolomite–quartz-rich nature of this interval of the Amsden Formation. The example shows dolomite, corroded quartz grains, and iron oxides. Porosity (blue) is due to dissolution. (p. 2-65) **Table 2-18.** XRF Data for the Amsden Formation from the J-LOC 1 Well. (p. 2-66) **Table 2-19**. Mineral Composition of the Amsden Formation Derived from XRD Analysis of J-LOC 1 Core Samples at a Depth of 5211 ft and 5218 MD (p. 2-67) **Figure 2-47**. Change in fluid pH for C1–C22 in the Amsden Formation underlying confining layer. (p. 2-68) **Figure 2-48**. CO_2 concentration (molality) in the Amsden Formation underlying confining layer for C1–C22. (p. 2-69) **Figure 2-49**. Dissolution and precipitation of minerals in the Amsden underlying confining layer. Dashed lines show results for C1, 0 to 1 meter below the Amsden Formation top. Solid lines show results for C2, 1 to 2 meters below the Amsden Formation top. Dotted lines show the results for C22, 21 to 22 meters below the Amsden

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
					Formation top. C22 shows minimal dissolution and precipitation which is associated with the initial model equilibration as CO2 doesn't penetrate this cell by the end of 45 years simulation. (p. 2-70) **Figure 2-50**. Weight percent of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt.% associated with dissolution. (p. 2-71) **Figure 2-51.** Weight percentage (wt.%) of initial (blue) and precipitated (orange) minerals in the C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in the C1 and C2 after 20 years of injection and 25 years of postinjection. Hematite precipitation in C1 and C2 is too small to be seen in the figure. (p.2-72) **Figure 2-52**. Change in percent porosity in the Amsden Formation underlying confining layer red line shows porosity change for C1, 0 to 1 meter below the Amsden Formation top. Yellow line shows C2, 1

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>to 2 meters below the Amsden Formation top. Green line shows C3, 2 to 3 meters below the Amsden Formation top. Long-term change in porosity is minimal and stabilized. Positive change in porosity is related to dissolution of minerals, and negative change is due to mineral precipitation. (p. 2-73)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)</td><td>NDAC § 43-05-01-05(1)(b)
(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond</td><td>d. A description of the storage reservoir's mechanisms of geologic confinement characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir, including:
Rock properties
Regional pressure gradients
Adsorption processes</td><td>2.2.2.3 Formation Temperature and Pressure (p. 2-8)
Temperature data recorded from logging the J-LOC 1 wellbore were used to derive a temperature gradient for the proposed injection site (Table 2-2). In combination with depth, the temperature gradient was used to distribute a temperature property throughout the simulation model of the DCC West SGS area. The temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for the geochemical modeling.

Formation pressure testing at the J-LOC 1 well was performed with the Schlumberger MDT (modular formation dynamics testing) tool. The MDT is a wireline-conveyed tool assembly incorporated with a dual-packer module to isolate intervals, a large-diameter probe for formation pressure and temperature measurements, a pump-out module to pump unwanted mud filtrate, a flow control module, and sample chambers for formation fluid collection. The MDT tool formation pressure measurements from the Broom Creek Formation are included in Table 2-3. The calculated pressure gradients were used to model formation pressure profiles for use in the numerical simulations of CO_2 injection.

Table 2-2. Description of J-LOC 1 Temperature Measurements and Calculated Temperature Gradients
<table>
<tr><th>Formation</th><th>Test Depth, ft</th><th>Temperature, °F</th></tr>
<tr><td>Broom Creek</td><td>4920.0</td><td>136.26</td></tr>
<tr><td>Broom Creek</td><td>5045.1</td><td>136.60</td></tr>
<tr><td>Broom Creek</td><td>5129.1</td><td>137.26</td></tr>
<tr><td>Mean Broom Creek Temp., °F</td><td colspan="2">136.71</td></tr>
<tr><td>Broom Creek Temperature Gradient, °F/ft</td><td colspan="2">0.02*</td></tr>
</table>
* The temperature gradient is an average of the MDT tool-measured temperatures minus the average annual surface temperature of 40°F, divided by the associated test depth.
** Measured depth.

Table 2-3. Description of J-LOC 1 Formation Pressure Measurements and Calculated Pressure Gradients
<table>
<tr><th>Formation</th><th>Test Depth, ft</th><th>Formation Pressure, psi</th></tr>
<tr><td>Broom Creek</td><td>4920.0</td><td>2415.86</td></tr>
<tr><td>Broom Creek</td><td>5045.1</td><td>2471.43</td></tr>
<tr><td>Broom Creek</td><td>5129.1</td><td>2509.60</td></tr>
<tr><td>Mean Broom Creek Pressure, psi</td><td colspan="2">2465.63</td></tr>
<tr><td>Broom Creek Pressure Gradient, psi/ft</td><td colspan="2">0.49*</td></tr>
</table></td><td>Table 2-2. Description of J-LOC 1 Temperature Measurements and Calculated Temperature Gradients (p. 2-9)

Table 2-3. Description of J-LOC 1 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-9)</td></tr>
</table>

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td>the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:</td><td></td><td>
* The pressure gradient is an average of the MDT tool-measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.
** Measured depth.

2.3.3 Mechanism of Geologic Confinement (p. 2-27)
For the DCC West SGS project, the initial mechanism for geologic confinement of CO_2 injected into the Broom Creek Formation will be the cap rock (Opeche–Picard interval), which will contain the initially buoyant CO_2 under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO_2 will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO_2 into the native formation brine), which confines the CO_2 within the proposed storage reservoir. After the injected CO_2 becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period of time (>100 years), mineralization of the injected CO_2 will ensure long-term, permanent geologic confinement. Injected CO_2 is not expected to adsorb to any of the mineral constituents of the target formation and, therefore, is not considered to be a viable trapping mechanism in this project. However, adsorption of CO_2 is a trapping mechanism notable in the storage of CO_2 in deep unminable coal seams.

2.4.4.2 Fracture Analysis Core Description (p. 2-74)
Fractures within the Opeche/Spearfish Formation are primarily resistive and mixed. They are commonly filled with anhydrite. However, some conductive fractures are highlighted. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to, in rare cases, centimeter-scale.

In the Amsden Formation, resistive fractures are common and are coincident with the horizontal compaction features (stylolite) observed. Calcite is the dominant mineral found to fill observable fractures. Very few-to-no connected fractures were observed in the Amsden Formation core interval from the J-LOC 1 well.

Table 2-22 (p. 2-92). Elastic Properties Obtained Through Experimentation for the Opeche/Spearfish Formation: E = Young’s Modulus, n = Poisson’s Ratio, K = Bulk Modulus, G = Shear Modulus, P = Uniaxial Strain Modulus
<table>
<tr><th colspan="8">Elastic Properties Measured at Different Confining Pressures</th></tr>
<tr><th>Event</th><th>Conf., MPa</th><th>Diff., MPa</th><th>E, GPa</th><th>n</th><th>K, GPa</th><th>G, GPa</th><th>P, GPa</th></tr>
<tr><td>1</td><td>10.2</td><td>10.0</td><td>55.14</td><td>0.140</td><td>25.51</td><td>24.19</td><td>57.76</td></tr>
<tr><td>2</td><td>20.3</td><td>20.2</td><td>58.07</td><td>0.150</td><td>27.65</td><td>25.25</td><td>61.32</td></tr>
<tr><td>3</td><td>30.2</td><td>30.1</td><td>60.84</td><td>0.161</td><td>29.93</td><td>26.20</td><td>64.86</td></tr>
<tr><td>4</td><td>40.3</td><td>40.0</td><td>60.94</td><td>0.195</td><td>33.35</td><td>25.49</td><td>67.34</td></tr>
</table>
</td><td></td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(g)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(g) Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir;</td><td>e. Identification of all characteristics controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir, including:
Structural spill points
Stratigraphic discontinuities</td><td>
2.2.2.6 Seismic Survey (p. 2-11)
Approximately 45 miles of 2D seismic data were licensed and reprocessed for characterization of subsurface structure within the DCC West SGS area (Figure 2-7). The seismic data allowed for the visualization of deep geologic formations. The 2D data were tied to nearby 3D seismic surveys to the east. Together, the 2D and 3D seismic data and J-LOC 1 well logs were used to interpret surfaces for the formations of interest within the project area. The surfaces were converted to depth using the time-to-depth relationship derived from the J-LOC 1 sonic log. These surfaces captured detail about structure and varying thicknesses of the formations away from well control. Interpretation of the seismic data suggests no major stratigraphic pinch-outs or structural features with associated spill points are located within the DCC West SGS area. No structural features, faults, or discontinuities were observed in the seismic data that cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation.

Additionally, 3D seismic data from the Beulah 3D seismic (a 200-mi2 survey to the west of the site) was interpreted to evaluate the subsurface (Figure 2-7). Data products generated from the interpretation and inversion of the seismic data from the three 3D seismic surveys were used as inputs into the geologic model (Figure 2-7). Acoustic impedance (AI) volumes were created using the 3D seismic and petrophysical data (e.g., dipole sonic and density logs) from the J-LOC 1, Liberty 1, Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 wells. The AI volumes were used to classify facies of the Broom Creek Formation and distribute facies through the geologic model, as well as inform petrophysical property distribution in the geologic model. Additionally, the geologic model that was informed by the seismic data was used to simulate migration of the CO_2 plume. These simulated CO_2 plumes were used to inform the testing and monitoring plan (Section 5).

2.3.3 Mechanism of Geologic Confinement (p. 2-27)
</td><td>Figure 2-10. Well log display of the interpreted lithologies of the Opeche–Picard interval and Broom Creek and Amsden Formations in J-LOC 1 well. Well logs displayed in tracks from left to right are 2) GR (green) and caliper (red), 3) delta time (light blue), 4) neutron porosity (blue) and density (red), 5) resistivity deep (black) and resistivity shallow (light blue), and 6) facies (lithology). (p. 2-15)

Figure 2-11a. Regional well log stratigraphic</td></tr>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				See discussion above under 2.3.3 Mechanism of Geologic Confinement	cross sections of the Opeche–Picard interval and the Broom Creek Formation flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Cross-sections scaled in SSTVD (SubSea True Vertical Depth). (p. 2-16) **Figure 2-11b.** Regional well log structural cross sections of the Opeche–Picard interval and the Broom Creek and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is. Cross-sections scaled in SSTVD. (p. 2-17) **Figure 2-12.** Structure map of the Broom Creek Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-18) **Figure 2-13**. Cross section from A-A' of the DCC West SGS area

<table>
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(Page Number)</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>from the geologic model showing facies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. Geologic model extent is displayed by dark blue box in the upper-left corner. (p.2-19)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(c)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(c) Any regional or local faulting;</td><td>f. Any regional or local faulting;</td><td>2.5 Faults, Fractures, and Seismic Activity (First two paragraphs on p. 2-94)
In the DCC West SGS area, no known or suspected regional faults or fractures with sufficient permeability and vertical extent to allow fluid movement between formations have been identified through site-specific characterization activities, previous studies, or oil and gas exploration activities. A suspected Precambrian basement fault was interpreted in the 3D seismic data set evaluated as part of site characterization (North Dakota Industrial Commission, 2021). This feature is confined to the Precambrian basement which is approximately 4000 feet below the Broom Creek Formation. This suspected fault does not have sufficient vertical extent to allow fluid movement between formations and does not pose a risk for potential induced seismicity.</td><td>Figure 2-69. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations labeled in Table 2-23.
(p. 2-96)</td></tr>
<tr><td></td><td>NDAC § 43-05-01-05(1)(b)(2)(j)</td><td>NDAC § 43-05-01-05(1)(b)(2)
(j) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone in the area of review, and a determination that they would not interfere with containment;</td><td>g. Properties of known or suspected faults and fractures that may transect the confining zone in the area of review:
Location
Orientation
Determination of the probability that they would interfere with containment</td><td>See discussion above under 2.5 Faults, Fractures, and Seismic Activity (p. 2-93)</td><td>Figure 2-69. Location of major faults, tectonic boundaries, and seismic events in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations labeled in Table 2-22.
(p. 2-95)</td></tr>
<tr><td></td><td>NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m)</td><td>NDAC § 43-05-01-05(1)(b)
(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity</td><td>h. Information on any regional tectonic activity, and the seismic history, including:
The presence and depth of seismic sources;
Determination of the probability that seismicity would interfere with containment;</td><td>2.5.2 Seismic Activity (p. 2-94)
The Williston Basin is a tectonically stable region of the North American Craton. Zhou and others (2008) summarize that “the Williston Basin as a whole is in an overburden compressive stress regime,” which could be attributed to the general stability of the North American Craton. Interpreted structural features associated with tectonic activity in the Williston Basin in North Dakota include anticlinal and synclinal structures in the western half of the state, lineaments associated with Precambrian basement block boundaries, and faults (North Dakota Industrial Commission, 2019).
Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Table 2-23) (Anderson, 2016). Of these 13 seismic events, only three have occurred along one of the eight interpreted Precambrian basement faults in the North Dakota portion of the Williston Basin (Figure 2-69). The seismic event recorded closest to the DCC West SGS area occurred near Hebron, North Dakota, 35.82 miles from the planned injection wells (Table 2-23). The magnitude of this seismic event is estimated to have been 0.2.

Table 2-23. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)
<table>
<tr><th>Date</th><th>Magnitude</th><th>Depth, mi</th><th>Longitude</th><th>Latitude</th><th>City or Vicinity of Seismic Event</th><th>Map Label</th><th>Distance to the Injection Wells, mi</th></tr>
<tr><td>Sept. 28, 2012</td><td>3.3</td><td>0.4*</td><td>−103.48</td><td>48.01</td><td>Southeast of Williston</td><td>A</td><td>118.89</td></tr>
<tr><td>June 14, 2010</td><td>1.4</td><td>3.1</td><td>−103.96</td><td>46.03</td><td>Boxelder Creek</td><td>B</td><td>142.10</td></tr>
<tr><td>March 21, 2010</td><td>2.5</td><td>3.1</td><td>−103.98</td><td>47.98</td><td>Buford</td><td>C</td><td>138.32</td></tr>
</table>
</td><td>Table 2-23. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016)
(p. 2-95)

Figure 2-69. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate seismic event locations labeled in Table 2-22.
(p. 2-96)</td></tr>
</table>

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td></td><td></td><td>and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:

NDAC § 43-05-01-05(1)(b)(2)
(m) Information on the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment;</td><td></td><td><table>
<tr><td>Aug. 30, 2009</td><td>1.9</td><td>3.1</td><td>−102.38</td><td>47.63</td><td>Ft. Berthold southwest</td><td>D</td><td>62.40</td></tr>
<tr><td>Jan. 3, 2009</td><td>1.5</td><td>8.3</td><td>−103.95</td><td>48.36</td><td>Grenora</td><td>E</td><td>150.41</td></tr>
<tr><td>Nov. 15, 2008</td><td>2.6</td><td>11.2</td><td>−100.04</td><td>47.46</td><td>Goodrich</td><td>F</td><td>68.64</td></tr>
<tr><td>Nov. 11, 1998</td><td>3.5</td><td>3.1</td><td>−104.03</td><td>48.55</td><td>Grenora</td><td>G</td><td>161.97</td></tr>
<tr><td>March 9, 1982</td><td>3.3</td><td>11.2</td><td>−104.03</td><td>48.51</td><td>Grenora</td><td>H</td><td>159.96</td></tr>
<tr><td>July 8, 1968</td><td>4.4</td><td>20.5</td><td>−100.74</td><td>46.59</td><td>Huff</td><td>I</td><td>44.03</td></tr>
<tr><td>May 13, 1947</td><td>3.7**</td><td>U***</td><td>−100.90</td><td>46.00</td><td>Selfridge</td><td>J</td><td>75.99</td></tr>
<tr><td>Oct. 26, 1946</td><td>3.7**</td><td>U***</td><td>−103.70</td><td>48.20</td><td>Williston</td><td>K</td><td>135.05</td></tr>
<tr><td>April 29, 1927</td><td>0.2**</td><td>U***</td><td>−102.10</td><td>46.90</td><td>Hebron</td><td>L</td><td>35.82</td></tr>
<tr><td>Aug. 8, 1915</td><td>3.7**</td><td>U***</td><td>−103.60</td><td>48.20</td><td>Williston</td><td>M</td><td>131.19</td></tr>
</table>
* Estimated depth.
** Magnitude estimated from reported modified Mercalli intensity (MMI) value.
*** Unknown depth.</td><td>Figure 2-70. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2022). The map shows there is a low probability of damaging seismic events occurring in North Dakota. (p. 2-97)</td></tr>
<tr><td></td><td>NDAC §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)</td><td>NDAC § 43-05-01-05(1)(b)
(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage</td><td>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:
Geologic maps
Topographic maps
Cross sections</td><td>2.1 Overview of Project Area Geology (p. 2-1)
See discussion above under 2.1 Overview of Project Area Geology

4.4.3 Hydrology of USDW Formations (p. 4-30)
The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, which isolates it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AOR is to the east</td><td>Figure 2-1. Topographic map of DCC West SGS showing well locations and MRYS in relation to the city of Center. (p. 2-2)</td></tr>
</table>

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		reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following: **NDAC § 43-05-01-05(1)(b)(2)** (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the		(Figure 4-16). Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a TDS (total dissolved solids) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride, more than 5 mg/L (Trapp and Croft, 1975). As such, the Fox Hills–Hell Creek system is typically not used as a primary source of drinking water. However, it is occasionally produced for irrigation and/or livestock watering. (p. 4-33) Multiple other freshwater-bearing units, primarily of Tertiary age, overlie the Fox Hills–Hell Creek aquifer system in the AOR. A cross section of these formations is presented in Figure 4-17. The upper formations are generally used for domestic and agricultural purposes. The Cannonball and Tongue River Formations comprise the major aquifer units of the Fort Union Group, which overlies the Hell Creek Formation. The Cannonball Formation consists of interbedded sandstone, siltstone, claystone, and thin lignite beds of marine origin. The Tongue River Formation is predominantly sandstone interbedded with siltstone, claystone, lignite, and occasional carbonaceous shales. The basal sandstone member of the Tongue River is persistent and a reliable source of groundwater in the region. The thickness of this basal sand ranges from approximately 200 to 500 ft and directly underlies surficial glacial deposits in the AOR. Tongue River groundwaters are generally a sodium bicarbonate type with a TDS of approximately 1000 ppm (Croft, 1973). In the far western portion of the AOR, the Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation ranges from approximately 400–1000 ppm (Croft, 1973).	**Figure 2-8.** Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green line has been modified based on new well control. (p. 2-13) **Figure 2-11a.** Regional well log stratigraphic cross sections of the Opeche–Picard interval and the Broom Creek Formation flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Cross-sections scaled in SSTVD (SubSea True Vertical Depth). (p. 2-16) **Figure 2-11b.** Regional well log structural cross sections of the Opeche–Picard interval and the Broom Creek and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is. Cross-sections scaled in SSTVD (p. 2-17)

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		geologic structure of the facility area; and			**Figure 2-13.** Cross section from A-A' of the DCC West SGS area from the geologic model showing facies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. Geologic model extent is displayed by dark blue box in the upper-left corner. (p. 2-19) **Figure 2-32**. Structure map of the lower Piper of the upper confining zone across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-47) **Figure 4-16.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the AOR in central Oliver County (modified from Fischer, 2013). (p. 4-31) **Figure 4-17.** West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section. (p. 4-32)
	NDAC § 43-05-01-05(1)(b)(2)(d)	**NDAC § 43-05-01-05(1)(b)(2)**	j. An isopach map of the storage reservoir(s);	See Figure 2-9 on p. 2-14	**Figure 2-9**. Isopach map of the Broom Creek Formation in the DCC

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		(d) An isopach map of the storage reservoirs;			West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-14)
	NDAC § 43-05-01-05(1)(b)(2)(e)	**NDAC § 43-05-01-05(1)(b)(2)** (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;	k. An isopach map of the primary containment barrier for the storage reservoir;	See Figure 2-33 on p. 2-48	**Figure 2-33.** Isopach map of the Opeche/Spearfish Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-48)
			l. An isopach map of the secondary containment barrier for the storage reservoir;	See Figure 2-34 on p. 2-49 and Figure 2-43 on p. 2-62	**Figure 2-34.** Isopach map of the lower Piper Formation of the upper confining zone in the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-49) **Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-62)
	NDAC § 43-05-01-05(1)(b)(2)(f)	**NDAC § 43-05-01-05(1)(b)(2)** (f) A structure map of the top and base of the storage reservoirs;	m. A structure map of the top of the storage formation;	See Figure 2-12 on p. 2-18	**Figure 2-12.** Structure map of the Broom Creek Formation across the DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D

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					seismic in the creation of this map. (p. 2-18)
			n. A structure map of the base of the storage formation;	See Figure 2-44 on p. 2-63	**Figure 2-44.** Structure map of the Amsden Formation across the greater DCC West SGS area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-63)
	NDAC § 43-05-01-05(1)(b)(2)(i)	**NDAC § 43-05-01-05(1)(b)(2)** (i) Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	o. Structural cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11b on p. 2-17 and Figure 2-13 on p. 2-19	**Figure 2-11b**. Regional well log structural cross sections of the Opeche–Picard interval and the Broom Creek and Amsden Formations. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Note: Wells in these cross sections are spaced evenly. These figures do not portray the relative distance between wells. Because of the spacing, structure may appear more drastic than it actually is. Cross-sections scaled in SSTVD. (p. 2-17) **Figure 2-13.** Cross section from A-A' of the DCC West SGS area from the geologic model showing facies distribution in the Broom Creek Formation. Elevations are referenced to mean sea level. Geologic model extent is displayed by dark blue box in the upper-left corner. (p. 2-19)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-11a on p. 2-16	**Figure 2-11a.** Regional well log stratigraphic cross sections of the Opeche–Picard interval

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					and the Broom Creek Formation flattened on the top of the Amsden Formation. The logs displayed in tracks from left to right are 1) GR (green) and caliper (orange), 2) delta time (blue), and 3) facies (lithology). Cross-sections scaled in SSTVD (SubSea True Vertical Depth). (p. 2-16)
	NDAC § 43-05-01-05(1)(b)(2)(h)	**NDAC § 43-05-01-05(1)(b)(2)** (h) Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	q. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any;	**3.4 Simulation Results** (p. 3-14) Numerical simulations of CO_2 injection for DCC West SGS were assumed to be operating at the same time as the DCC East SGS Project, with the given well and group constraints listed in Table 3-4. This section discusses the injection constraints for IIW-S and IIW-N and the resulting simulation results. The predicted injection WHP of both wells, IIW-S and IIW-N, in DCC West SGS would not exceed 2100 psi during injection. The BHPs are reaching the maximum values of 3233 and 3242 psi for IIW-N and IIW-S wells, respectively (Figure 3-9). An average injection rate of 6.11 MMt/yr, with 1.768 MMt/yr for well IIW-N, and 4.342 MMt/yr for well IIW-S, was achievable over the 20 years of injection. A total of 122.9 MMt of CO_2 was injected into the Broom Creek Formation with the two wells at the end of 20 years of simulated injection (Figure 3-10). The injected volume was 35.7 MMt and 87.2 MMt for the IIW-N and IIW- S wells, respectively. (p. 3-16) During and after injection, supercritical CO_2 (free-phase CO_2) accounts for the majority of the CO_2 observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO_2 is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO_2 saturation and inability to flow under the effects of relative permeability. CO_2 also dissolves into the formation brine throughout injection operations (and continues afterward), although the rate of dissolution slows over time. The free-phase CO2 transitions to either residually trapped or dissolved CO_2 during the postinjection period, resulting in a decline in the mass of free-phase CO_2. The relative portions of supercritical, trapped, and dissolved CO_2 can be tracked throughout the duration of the simulation (Figure 3-11). The pressure front (Figure 3-12) shows the distribution of pressure increase throughout the Broom Creek Formation at 1, 10, and 20 years of injection and 10 years postinjection. A maximum increase of 677 psi is estimated in the near wellbore area after the 20 year injection period. (p. 3-17) Long-term CO_2 migration potential was also investigated through the numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO_2 injected into the formation rises to the cap rock or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO_2 at the center which gradually spreads out toward the model edges where the CO_2 saturation is lower. Trapped CO_2 saturations, employed in the model to represent fractions of CO_2 trapped in small pores as immobile, tiny bubbles, ultimately immobilize the CO_2 plume and limit the plume's lateral migration and spreading. Figures 3-13 and 3-14 show the gas saturation at the end of injection in north-to-south and east-to-west cross-sectional views, respectively. ***6.1.1 Pre- and Postinjection Pressure Differential*** (p. 6-1) Model simulations were performed to estimate the change in pressure in the Broom Creek Formation during and after the cessation of CO_2 injection. The simulations were conducted for 20 years of CO_2 injection in the Broom Creek Formation at an average rate of 6.11 million metric tons per year, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the conclusion of CO_2 injection. At the time that CO_2 injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 677 psi at the location of the CO_2 injection well pad. There is insufficient pressure increase caused by CO_2 injection to move more than 1 cubic meter of formation fluids from the storage reservoir to the lowest USDW. The details of the pressure evaluation are provided as part of the AOR delineation of this permit application (see Section 3.5). Figure 6-2 illustrates the predicted gradual pressure decrease in the storage reservoir, over a 10-year period following the cessation of CO_2 injection. The pressure at the CO_2 injection well pad at the end of the 10-year period is anticipated to decrease 300–350 psi as compared to the pressure in the storage reservoir at the time CO_2 injection ends. This trend of decreasing pressure is anticipated to continue over time until the pressure of the storage reservoir approaches the original reservoir pressure conditions.	**Figure 3-12.** Average pressure increase within the Broom Creek Formation after 1, 10, and 20 years of injection, and 10 years of postinjection. Simulated injection at both DCC East SGS and DCC West SGS begin at the same time. (p. 3-17) **Figure 6-1.** Predicted pressure increase in storage reservoir following 20 years of injection of an average 6.11 million metric tons per year of CO_2. (p. 6-2) **Figure 6-2.** Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO_2 injection. (p. 6-3)

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	NDAC § 43-05-01-05(1)(b)(2)(l)	**NDAC § 43-05-01-05(1)(b)(2)** (l) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream;	r. Geomechanical information on the confining zone. The confining zone must be free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide: Fractures Stress Ductility Rock strength In situ fluid pressure	*2.4.4.3 Borehole Image Fracture Analysis* (p. 2-76) Borehole image logs were used to evaluate fractures within the upper and lower confining zones. The natural fractures and in situ stress directions were assessed through the interpretation of the image log acquired from the J-LOC 1 well. The image log provides a 360-degree image of the formation of interest and can be oriented to provide an understanding of the general direction of features observed. Figure 2-53 shows the interpreted borehole imagery and primary features observed in the lower Piper Formation and demonstrates that the tool provides information on surface boundaries and bedding features. The far-right track on Figure 2-53 notes the presence and dip orientation of tectonic and sedimentary features, which fall into several categories. The lowest features are dominantly stylolites and anhydrite layers. Several electrically resistive features are present and these are interpreted as a minor anhydrite-filled fracture. Some isolated conductive fractures were identified by the BHI data, and these are likely clay-filled because of their electrically conductive signal. The rose diagrams shown in Figures 2-54 through 2-56 provide the orientation of the conductive, resistive, and mixed fractures in the lower Piper Formation. *2.4.4.4 Stress* (p. 2-91) J-LOC 1 openhole logging data were used to construct a 1D mechanical earth model (1D MEM) to evaluate geomechanical properties of the Opeche/Spearfish Formation. The data available were loaded and quality-checked using Techlog software, where the overburden stress and pore pressure were estimated and calibrated with available MDT data. The elastic properties, such as Young's modulus, Poisson's ratio, shear modulus, and bulk modulus, were calculated based on the available well logs. The formation strength properties, like uniaxial compressive strength (UCS), tensile strength, friction angle, and cohesion, were also estimated from the available data (Figure 2-67). Table 2-20 provides the summary of stresses in the Opeche/Spearfish Formation generated using 1D MEM. *2.4.4.5 Ductility and Rock Strength* (p. 2-92) Ductility and rock strength have been determined through laboratory testing of rock samples acquired from the Opeche/Spearfish Formation core in the J-LOC 1 well. To determine these parameters, a multistage triaxial test was performed at confining pressures exceeding 40 MPa (5800 psi). This commonly used test provides information regarding the elastic parameters and peak strength of a material. Because of the low porosity and anhydrite mineralogy, the sample was not saturated for testing. Table 2-21 shows the parameters of the sample tested, and Table 2-22 shows the elastic parameters obtained. Rock strength was determined at the final stage of confinement and axial loading. As shown in Figure 2-68, the sample failed at a maximum stress of 113.8 MPa (16,5053 psi). The final stage (Radial Stage 4) of testing, as shown in yellow (Figure 2-68), has significant residual strength postfailure, indicating a high degree of ductility.	**Figure 2-53.** Sedimentary and tectonic features in the lower Formation observed on the borehole image log. The figure shows; Track1: Gamma-ray (HSGR), Caliper (HCal); Track2: Borehole dynamic image log; Track3: Borehole static image log. Track4: Tectonic and sedimentary tadpoles' orientation in the interval between 4,805and 4,882.5 ft. (p. 2-76) **Figure 2-54.** Strike orientation of conductive fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-77) **Figure 2-55.** Strike orientation of resistive fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-78) **Figure 2-56.** Strike orientation of Mixed fractures that characterize the lower Piper Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-79) **Figure 2-57.** Sedimentary and tectonic features in Piper Picard,

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					Opeche/Spearfish, and Broom Creek Formations observed on the borehole image log. The figure shows; Track1: Gamma-ray (HSGR), Caliper (HCal); Track2: Borehole dynamic image log; Track3: Borehole static image log. Track4: Tectonic and sedimentary tadpoles' orientation. in the interval between 4,874 and 4,912 ft (p. 2-80) **Figure 2-60.** Strike orientation of conductive fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-83) **Figure 2-61**. Strike orientation of resistive fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-84) **Figure 2-62a.** Strike orientation of mixed fractures that characterize the Opeche/Spearfish Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-85) **Figure 2-62b.** Strike orientation of microfaults that characterize the Opeche/Spearfish

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					Formation. Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-86) **Figure 2-67.** J-LOC 1, 1D MEM (Piper Picard, Opeche/Spearfish, Broom Creek, and Amsden Formations). Track1: Gamma-ray (HSGR), caliper (HCal); Track 2: Shear Sonic (DTSH), Compressional Sonic (DTCO); Track 3: Uniaxial Confining Stress (UCS), Tensile Strength (TSTR), Friction angle (FANG); Track 4: Static Young's modulus (YME_Sta) and Dynamic Young's modulus (YME_Dyn); Track 5: Static Poisson's ratio (PR_Sta) and Dynamic Poisson's ratio (PR_Dyn); Track 6: Dynamic Shear Modulus (SMG_Dyn), Dynamic Bulk Modulus (BMK_Dyn), Cohesion.; Track 7: Pore pressure (Hydropressure), MDT, Vertical stress (Svertical); Track 8: Maximum horizontal stress (SHmax_PHS), Minimum horizontal stress (Shmin_PHS), and closure pressure. (p. 2-91) **Table 2-20.** Summary of Stresses Generated Using 1D MEM in Opeche/Spearfish Formation (p. 2-92) **Table 2-21.** Multistage Triaxial Test Sample Parameters for the

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					Opeche/Spearfish Formation (p. 2-91) **Table 2-22.** Elastic Properties Obtained Through Experimentation for the Opeche/Spearfish Formation (p. 2-92)
	NDAC § 43-05-01-05(1)(b)(2)(o)	**NDAC § 43-05-01-05(1)(b)(2)** (o) Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are free of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement: Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation.	***2.4.2 Additional Overlying Confining Zones (p.2-59)*** Several other formations provide additional confinement above the Opeche–Picard interval. Impermeable rocks above the primary seal include the Piper (Kline Member), Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-17). Together with the Opeche–Picard interval, these formations are 851 ft thick (thickness at the J-LOC 1 well) and will impede Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-42, Broom Creek to Swift). Above the Inyan Kara Formation, 2638 ft (thickness at the J-LOC 1 well) of impermeable rocks acts as an additional seal between the Inyan Kara Formation and lowermost USDW, the Fox Hills Formation (Figure 2-43, Inyan Kara to Pierre). Confining layers above the Inyan Kara Formation include the Skull Creek, Mowry, Greenhorn, and Pierre Formations (Table 2-17). These formations, between the Broom Creek Formation and Inyan Kara Formation and between the Inyan Kara Formation and the lowest USDW, have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988). Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability above the injection zone and primary sealing interval. The Inyan Kara Formation represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensing (DTS) data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5). In the unlikely event of out-of-zone migration through the primary and secondary confining zones, CO_2 would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation in the DCC West SGS area is 3888 ft, and the formation itself is 169 ft thick measured at the J LOC 1 well.	**Table 2-17** Description of Zones of Confinement above the Immediate Upper Confining Zone, Opeche–Picard Interval (data based on the J-LOC 1 well) (p. 2-60) **Figure 2-42**. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confining zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.. (p. 2-61) **Figure 2-43.** Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-62)
Area of Review Delineation	NDAC §§ 43-05-01-05(1)(j) and (1)(b)(3)	**NDAC § 43-05-01-05(1)** j. An area of review and corrective action plan that meets the requirements pursuant to section 43-05-01-05.1;	The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities.	***4.1.1 Written Description*** (p. 4-1) North Dakota regulations for geologic storage of carbon dioxide (CO_2) require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure	**Figure 4-3**. AOR map in relation to nearby legacy wells (wells that penetrate the Broom Creek as gray circles and wells that do not penetrate the Broom

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		NDAC § 43-05-01-05(1)(b) (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following:	The area of review delineation must include the following:	increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the J-LOC 1 well shows that the storage reservoir in the project area is overpressured with respect to the deepest USDW (i.e., the allowable increase in pressure is less than zero). The storage reservoir is calculated to be overpressured, with a value of −241 psi calculated using data from the J-LOC 1 well. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 677 psi in the raster cell intersected by the injection well, which corresponds to less than 0.033 m3 of flow over 20 years (Section 3.5 Delineation of the Area of Review). NDAC § 43-05-01-05(1)(b)(3) requires "a review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-4, Table 4-1) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action was required and included a review of all available well records (Table 4-2). The evaluation determined that all abandoned wells within the AOR have sufficient isolation to prevent formation fluids or injected CO2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-3 through 4-12 and Figures 4-5 through 4-11). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (1)(b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1. See Figure 4-3 on p. 4-4	Creek as white circles) and groundwater wells. Shown are the storage facility area (dashed purple boundary) and 1-mi AOR boundary (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. One spring is present in the AOR. (p. 4-4)
	NDAC §§ 43-05-01-05(1)(b)(3) and (1)(a)	**NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC § 43-05-01-05(1)** a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed	a. A map showing the following within the carbon dioxide reservoir area: i. Boundaries of the storage reservoir ii. Location of all proposed wells iii. Location of proposed cathodic protection boreholes iv. Any existing or proposed aboveground facilities;	**2.3 Storage Reservoir (injection zone)** (p. 2-13) See Figure 2-8 on page 2-13. ***5.7.1 Near-Surface Monitoring*** (p. 5-16) See Figure 5-6 on page 5-17. *3.5.2.2 Incremental Leakage Maps and AOR Delineation* (p. 3-25) See Figure 3-19 on page 3-29. **5.2 Surface Facilities Leak Detection Plan** (p. 5-3) See Figure 5-1 on page 5-5.	**Figure 2-8.** Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green line has been modified based on new well control. (p. 2-13) **Figure 5-6.** DCC West's planned baseline and operational near-surface sampling locations. (p. 5-17) **Figure 3-19.** Land use in and around the AOR of the DCC West storage facility. (p. 3-29)

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		cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;			**Figure 5-1.** Site map detailing the surface facilities layout. Inset map illustrates a generalized injection wellsite layout with monitoring equipment identified. (p. 5-5)
	NDAC § 43-05-01-05(1)(b)(2)(a)	**NDAC § 43-05-01-05(1)(b)(2)** (a) All wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the facility area and within one mile [1.61 kilometers] of its outside boundary;	b. A map showing the following within the storage reservoir area and within one mile outside of its boundary: i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines;	***4.1.2 Supporting Maps*** (p. 4-2) See Figure 4-3 on page 4-4. *3.5.2.2 Incremental Leakage Maps and AOR Delineation* (p. 3-25) See Figure 3-19 on page 3-29.	**Figure 4-3.** AOR map in relation to nearby legacy wells (wells that penetrate the Broom Creek as gray circles and wells that do not penetrate the Broom Creek as white circles) and groundwater wells. Shown are the storage facility area (dashed purple boundary) and 1-mi AOR boundary (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. One spring is present in the AOR. (p. 4-4) **Figure 3-19.** Land use in and around the AOR of the DCC West storage facility. (p. 3-29)
	NDAC § 43-05-01-05(1)(c) and NDAC § 43-05-01-05.1(1)(a)	**NDAC § 43-05-01-05(1)** c. The extent of the pore space that will be occupied by carbon dioxide as determined by utilizing all appropriate geologic and reservoir engineering information and reservoir analysis, which must include various computational models for reservoir characterization, and the projected response of the carbon dioxide plume	c. A description of the method used for delineating the area of review, including: i. The computational model to be used ii. The assumptions that will be made iii. The site characterization data on which the model will be based;	***3.5.2 Risk-Based AOR* (p. 3-23)** The risk-based method uses ASLMA to derive a relationship between storage unit pressure buildup and potential incremental formation fluid migration into overlying aquifers. Incremental fluid migration is flow that is attributable to storage unit pressure increase and ignores flow that would occur along leakage pathways that existed before injection began A macro-enabled Microsoft Excel file was used to define the inputs, including aquifer characteristics to represent the storage unit, storage USDW, and intermediate aquifers, as well as calculations that were employed in the method. For example, the initial reference case total heads for the storage reservoir (Aquifer 1), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-6 and illustrate the state of overpressure in the storage complex, as Aquifer 1 has a greater initial hydraulic head than Aquifers 2 and 3. Intermediate aquifers between the storage unit and the lowest USDW may act as thief zones where present and divert upward fluid flow away from the USDW. ASLMA allows for the use of multiple layers to act as aquifers or potential thief zones (e.g., Aquifer 1, Aquifer 2). Pressure buildup estimates derived from numerical simulations of CO_2 injection were used with ASLMA to generate potential incremental leakage maps within the areal extent of the simulation model. These potential leakage maps indicate the areas hypothetical leakage is more likely to occur and were used to inform the AOR delineation.	**Table 3-6.** Simplified Stratigraphy and Average Properties Used to Represent the Storage Complex (p. 3-24)

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		and storage capacity of the storage reservoir. The computational model must be based on detailed geologic data collected to characterize the injection zones, confining zones, and any additional zones; **NDAC § 43-05-01-05.1(1)** a. The method for delineating the area of review, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;			
	NDAC § 43-05-01-05.1(1)(b)(1-4)	**NDAC § 43-05-01-05.1(1)** b. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and (4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if	d. A description of: (1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review; (2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date; (3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; (4) How corrective action will be conducted if necessary, including: a. What corrective action will be performed prior to injection b. How corrective action will be adjusted if there are changes in the area of review;	**4.3 Reevaluation of AOR and Corrective Action Plan** (p. 4-25) The AOR and corrective action plan will periodically be reevaluated in accordance with NDAC § 43-05-01-05.1, with the first reevaluation taking place not later than the fifth anniversary of NDIC's issuance of a permit to operate under NDAC § 43-05-01-10 and every fifth anniversary thereafter (each referred to as a Reevaluation Date). The AOR reevaluations will address the following: • Any changes to the monitoring and operational data prior to the scheduled Reevaluation Date. • Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and computational simulations. These updates will then be used to inform a reevaluation of the AOR and corrective action plan, including the computational model that was used to determine the AOR, and operational data to be utilized as the basis for that update will be identified. • The protocol to conduct corrective action, if necessary, will be determined, including 1) what corrective action will be performed and 2) how corrective action will be adjusted if there are changes in the AOR.	N/A

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.			
	NDAC § 43-05-01-05(1)(b)(2)(b)	**NDAC § 43-05-01-05(1)(b)(2)** (b) All manmade surface structures that are intended for temporary or permanent human occupancy within the facility area and within one mile [1.61 kilometers] of its outside boundary;	e. A map showing the areal extent of all manmade surface structures that are intended for temporary or permanent human occupancy within the storage reservoir area, and within one mile outside of its boundary;	***3.5.2.2 Incremental Leakage Maps and AOR Delineation (p. 3-25)*** *See Figure 3-19 on page 3-29.*	**Figure 3-19.** Land use in and around the AOR of the DCC West storage facility. (p. 3-29)
	NDAC § 43-05-01-05(1)(b)(2)	**NDAC § 43-05-01-05(1)(b)** (2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties,	f. A map and cross section identifying any productive existing or potential mineral zones occurring within the storage reservoir area and within one mile outside of its boundary;	**2.6 Potential Mineral Zones** (p. 2-97) See Figure 2-71, Figure 2-73 and Figure 2-74.	**Figure 2-71.** Drillstem test results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020). (p. 2-98) **Figure 2-73.** Hagel net coal isopach map (modified from Ellis and others, 1999). (p. 2-100) **Figure 2-74.** Hagel overburden isopach map (modified from Ellis and others, 1999). (p. 2-101)

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		regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation must also identify any productive existing or potential mineral zones occurring within the facility area and any underground sources of drinking water in the facility area and within one mile [1.61 kilometers] of its outside boundary. The evaluation must include exhibits and plan view maps showing the following:			
	NDAC § 43-05-01-05(1)(b)(3) and NDAC § 43-05-01-05.1(2)(b)	**NDAC § 43-05-01-05(1)(b)** (3) A review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary. The review must include the following: **NDAC § 43-05-01-05.1(2)** b. Using methods approved by the commission, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining	g. A map identifying all wells within the area of review, which penetrate the storage formation or primary or secondary seals overlying the storage formation.	*3.5.2.2 Incremental Leakage Maps and AOR Delineation (p. 3-25)* See Figure 3-18 on p. 3-28 for nearby legacy wells.	**Figure 3-18**. Final AOR estimations of DCC West SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), AOR (gray boundary and shaded area), and city of Center. Gray and white circles represent nearby legacy wells in or near the storage facility area. (p. 3-28)

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;			
	NDAC § 43-05-01-05(1)(b)(3)(a) NDAC § 43-05-01-05(1)(b)(3)(b) NDAC § 43-05-01-05(1)(b)(3)(c) NDAC §§ 43-05-01-05(1)(b)(3)(d) and (e)	**NDAC § 43-05-01-05(1)(b)(3)** (a) A determination that all abandoned wells have been plugged and all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping from the storage reservoir; **NDAC § 43-05-01-05(1)(b)(3)** (b) A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion; **NDAC § 43-05-01-05(1)(b)(3)** (c) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all underground sources of drinking water, water wells, and springs within the area of review; their positions relative to the injection zone; and the direction of water movement, where known; **NDAC § 43-05-01-05(1)(b)(3)** (d) Maps and cross sections of the area of review;	h. A review of these wells must include the following: (1) A determination that all abandoned wells have been plugged in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (2) A determination that all operating wells have been constructed in a manner that prevents the carbon dioxide or associated fluids from escaping the storage formation; (3) A description of each well: a. Type b. Construction c. Date drilled d. Location e. Depth f. Record of plugging g. Record of completion (4) Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating the following: a. Their positions relative to the injection zone b. The direction of water movement, where known c. General vertical and lateral limits d. Water wells e. Springs	*4.1.1 **Written*** Description (p. 4-1) North Dakota regulations for geologic storage of carbon dioxide (CO_2) require that each storage facility permit (SFP) delineate an AOR, which is defined as "the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO_2 plume and the region overlying the extent of formation fluid pressure increase sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present. The minimum fluid pressure increase in the reservoir that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Calculation of the allowable increase in pressure using site-specific data from the J-LOC 1 well shows that the storage reservoir in the project area is overpressured with respect to the deepest USDW (i.e., the allowable increase in pressure is less than zero). The storage reservoir is calculated to be overpressured, with a value of −241 psi calculated using data from the J-LOC 1 well. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 677 psi in the raster cell intersected by the injection well, which corresponds to less than 0.033 m3 of flow over 20 years (Section 3.5 Delineation of the Area of Review). NDAC § 43-05-01-05(1)(b)(3) requires "a review of the data of public record, conducted by a geologist or engineer, for all wells within the facility area, which penetrate the storage reservoir or primary or secondary seals overlying the reservoir, and all wells within the facility area and within one mile [1.61 kilometers], or any other distance as deemed necessary by the commission, of the facility area boundary." Based on the computational methods used to simulate CO_2 injection activities and associated pressure front (Figure 4-1), the resulting AOR for the geologic storage project is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations. All wells located in the AOR that penetrate the storage reservoir and its primary overlying seal were evaluated (Figures 4-2 through 4-4, Table 4-1) by a professional engineer pursuant to NDAC § 43-05-01-05(1)(b)(3). The evaluation was performed to determine if corrective action was required and included a review of all available well records (Table 4-2). The evaluation determined that all abandoned wells within the AOR have sufficient isolation to prevent formation fluids or injected CO_2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary (Tables 4-3 through 4-12 and Figures 4-5 through 4-11). An extensive geologic and hydrogeologic characterization performed by a team of geologists from the Energy & Environmental Research Center (EERC) resulted in no evidence of transmissive faults or fractures in the upper confining zone within the AOR and revealed that the upper confining zone has sufficient geologic integrity to prevent vertical fluid movement. All geologic data and investigations indicate the storage reservoir within the AOR has sufficient containment and geologic integrity, including geologic confinement above and below the injection zone, to prevent vertical fluid movement. Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation, pursuant to NDAC § 43-05-01-05(1)(a) and (1)(b)(3) and § 43-05-01-05.1(2). Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1. ***4.1.2 Supporting Maps*** (p. 4-2) See Figure 4-3 on page 4-4. **4.2 Corrective Action Evaluation (p. 4-7)** See Table 4-2 on p. 4-7, Table 4-3 on p. 4-8, Table 4-4 on p. 4-9, Table 4-5 on p. 4-10, Table 4-6 on p. 4-11, Table 4-7 on p. 4-12, Table 4-8 on p. 4-13, and Table 4-9 on p. 14.	**Figure 4-3.** AOR map in relation to nearby legacy wells (wells that penetrate the Broom Creek as gray circles and wells that do not penetrate the Broom Creek as white circles) and groundwater wells. Shown are the storage facility area (dashed purple boundary) and 1-mi AOR boundary (dashed black boundary). All groundwater wells in the AOR are identified above. All observation/monitoring wells shown are shallow groundwater wells associated with the mine activities. One spring is present in the AOR. (p. 4-4) **Figure 3-18.** Final AOR estimations of DCC West SGS storage facility area in relation to nearby legacy wells. Shown is the storage facility area (purple boundary and shaded area), AOR (gray boundary and shaded area), and city of Center. Gray and white circles represent nearby legacy wells in or near the storage facility area. (p. 3-28) **Table 4-2.** Wells in AOR Evaluated for Corrective Action (p. 4-7)

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	NDAC § 43-05-01-05(1)(b)(3)(f)	**NDAC § 43-05-01-05(1)(b)(3)** (e) A map of the area of review showing the number or name and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state-approved or United States environmental protection agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features, including structures intended for human occupancy, state, county, or Indian country boundary lines, and roads; **NDAC § 43-05-01-05(1)(b)(3)** (f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;	(5) Map and cross sections of the area of review; (6) A map of the area of review showing the following: a. Number or name and location of all injection wells b. Number or name and location of all producing wells c. Number or name and location of all abandoned wells d. Number of name and location of all plugged wells or dry holes e. Number or name and location of all deep stratigraphic boreholes f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites g. Name and location of all surface bodies of water h. Name and location of all springs i. Name and location of all mines (surface and subsurface) j. Name and location of all quarries k. Name and location of all water wells l. Name and location of all other pertinent surface features m. Name and location of all structures intended for human occupancy n. Name and location of all state, county, or Indian country boundary lines o. Name and location of all roads	See Figure 4-5 on p. 4-18, Figure 4-6 on p. 4-19, Figure 4-7 on p. 4-20, Figure 4-8 on p. 4-21, Figure 4-9 on p. 4-22, Figure 4-10 on p. 4-23 and Figure 4-11 on p. 4-24. **4.4 Protection of USDWs** (p. 4-25) Figure 4-15 on page 4-30 and Figure 4-16 on page 4-31	**Table 4-3**. Paul Bueligen 1 (NDIC File No. 2183) Well Evaluation (p. 4-8) **Figure 4-5.** Paul Bueligen 1 (NDIC File No. 2183) well schematic showing the location and thickness of cement plugs. (p. 4-18) **Table 4-4.** Raymond Henke 1-24 (NDIC File No. 4940) Well Evaluation (p. 4-9) **Figure 4-6.** Raymond Henke 1-24 (NDIC File No. 4940) well schematic showing the location and thickness of cement plugs. (p. 4-19) **Table 4-5.** Ervin V. Henke 1 (NDIC File No. 3277) Well Evaluation (p. 4-10) **Figure 4-7**. Ervin V. Henke 1 (NDIC File No. 3277) well schematic showing the location and thickness of cement plugs. (p. 4-20) **Table 4-6.** Herbert Dresser 1-34 (NDIC File No. 4937) Well Evaluation (p. 4-11) **Figure 4-8**. Herbert Dresser 1-34 (NDIC File No. 4937) well schematic showing the location and thickness of cement plugs. (p. 4-21) **Table 4-7.** BNI 1 (NDIC File No. 34244) Well Evaluation (p. 4-12) **Figure 4-9**. BNI 1 (NDIC File No. 34244) well

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			(7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.		schematic showing the location and thickness of cement plugs. (p. 4-22) **Table 4-8.** J-LOC 1 (NDIC File No. 37380) Well Evaluation (p. 4-13) **Figure 4-10.** J-LOC 1 (NDIC File No. 37380) well schematic showing the location and thickness of cement plugs and cement retainers. (p. 4-23) **Table 4-9.** Kenneth Henke 1-7 (NDIC File No. 4941) Well Evaluation (p. 4-14) **Figure 4-11**. Kenneth Henke 1-7 (NDIC File No. 4941) well schematic showing the location and thickness of cement plugs. (p. 4-24) **Figure 4-16.** Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the northeast through the AOR in central Oliver County (modified from Fischer, 2013). (p. 4-31) **Figure 4-17.** West–east cross section of the major regional aquifer layers in Mercer and Oliver Counties and their associated geologic relationships (modified from Croft, 1973). The black dots on the inset map represent the locations of the water wells illustrated on the cross section. (p. 4-32)

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	NDAC § 43-05-01-05(1)(b)(3)(g)	**NDAC § 43-05-01-05(1)(b)(3)** (g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and	i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.	See Appendices A (Well and Well Formation Fluid-Sampling Laboratory Analysis) and B (Freshwater Well Fluid Sampling)	N/A
Required Plans	NDAC § 43-05-01-05(1)(k)	**NDAC § 43-05-01-05(1)** k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;	a. Financial Assurance Demonstration	**12.3 Financial Instruments (p.12-1)** DCC West is providing financial responsibility pursuant to NDAC § 43-05-01-09.1 using the following financial instruments: Based on review and consideration of the available financial instruments contained in NDAC § 43-05-01-09.1, applicant proposes to use a combination of commercial insurance and combination of additional funds to pour over into a separate account under the established standby trust approved by the DCC West SGS Project to fulfill the FADP requirements of the project Class VI permit. The details contained in this FADP along with supporting documentation establish the approach the applicant proposes to use to meet the financial responsibility requirements and that each of these instruments sufficiently addresses the activities and costs associated with the corrective action plan, injection well-plugging program, PISC and facility closure, emergency and remedial response plan (ERRP), and endangerment of USDWs.	**Table 12-1.** Cost Estimate for PISC Activities, Assuming a 10-year PISC Period. (p. 12-4) **Table 12-2.** Monitoring and AOR Reevaluation (part of the PISC) (p. 12-4) **Table 12-3.** Plugging CO2 Injection Wells and CO2 Flowline (p. 12-5). **Table 12-4.** Cost Estimate for Facility Closure Activities (p. 12-5).
	NDAC § 43-05-01-05(1)(d)	**NDAC § 43-05-01-05(1)(d)** d. An emergency and remedial response plan pursuant to section 43-05-01-13;	b. An emergency and remedial response plan;	**7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN** (p. 7-1) DCC West, operator of the West Site storage facility, will enter into an agreement whereby DCC West employees, contractors, and agents are required to follow the DCC West facility emergency action plans, including, but not limited to, the DCC West facility response plan. This emergency and remedial response plan (ERRP) for the geologic storage project 1) describes the local resources and infrastructure in proximity to the project site; 2) identifies events that have the potential to endanger underground sources of drinking water (USDWs) during the construction, operation, and postinjection site care periods of the geologic storage project, building upon the screening-level risk assessment (SLRA); and 3) describes the response actions that are necessary to manage these risks. In addition, the integration of the ERRP with the existing DCC West facility response plan and risk management plan (and incorporated into the DCC West integrated contingency plan [ICP]) is described, emphasizing the facility response team and command structure, facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for regularly conducting an evaluation of the adequacy of the ERRP and updating it, if warranted, over the lifetime of the geologic storage project. Copies of this ERRP are available at the geologic storage facility and the DCC West facility and can be made available upon request. Note: Refer to the following key tables: Table 7-3 on p. 7-6 and Table 7-4 on p. 7-8 through 7-10.	**Table 7-3.** Risk Category Matrix (p. 7-6) **Table 7-4.** Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (p. 7-8 through 7-10)
	NDAC § 43-05-01-05(1)(e)	**NDAC § 43-05-01-05(1)** e. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility pursuant to section 43-05-01-13;	c. A detailed worker safety plan that addresses the following: i. Carbon dioxide safety training ii. Safe working procedures at the storage facility;	**8.0 WORKER SAFETY PLAN** (p. 8-1)	N/A

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
	NDAC § 43-05-01-05(1)(f)	**NDAC § 43-05-01-05(1)** f. A corrosion monitoring and prevention plan for all wells and surface facilities pursuant to section 43-05-01-15;	d. A corrosion monitoring and prevention plan for all wells and surface facilities;	**5.3 CO_2 Flowline Corrosion Prevention and Detection Plan (p. 5-6)** The purpose of this corrosion prevention and detection plan is to monitor the flowline and well materials during the operational phase of the project to ensure that all materials meet the minimum standards for material strength and performance. 5.3.1 Corrosion Prevention The CO2 stream concentration is highly pure (at least 96% by volume; Table 5-2). The high-purity CO2 stream helps to prevent corrosion of the surface facilities. In addition, the flowline construction materials will be in accordance with American Petroleum Institute (API) 5L X-65 PSL 2 (2018) requirements, which includes applying external coatings to the pipe (e.g., fusion-bonded epoxy) and any borings or crossings (e.g., abrasive-resistant overcoats) to prevent corrosion. The flowline will also use a cathodic protection system in accordance with 49 Code of Federal Regulations (CFR) Part 195. DCC West will supply the NDIC with a map of cathodic protection borehole locations to meet NDAC § 43-05-01-05(1)(a) prior to injection. 5.3.2 Corrosion Detection Pursuant to NDAC § 43-05-01-11.4(1)(c)(3), DCC West will use the corrosion coupon method to monitor for corrosion in the CO2 flowline throughout the operational phase of the project, focusing on the loss of mass, thickness, cracking, and pitting as well as other visual signs of corrosion of the materials of interest. Coupon sample ports will be located near the point of transfer and near each injection wellhead (Figure 5-2), and sampling will occur quarterly. At the request of the NDIC, DCC West may also utilize a coupon sample port for conducting longer-term coupon testing (e.g., annually). The process that will be used to conduct each coupon test is described in Appendix D under Section 1.3.2. **5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-15)** The purpose of this corrosion prevention and detection plan is to monitor the well materials to ensure they meet the minimum standards for material strength and performance, pursuant to NDAC § 43-05-01-11.4(1)(c). 5.6.1 Downhole Corrosion Prevention To prevent corrosion of the well materials from CO2 exposure, the following preemptive measures will be implemented in the IIW-N and IIW-S wellbores: 1) cement in the injection well opposite the injection interval and extending approximately 1850 feet uphole and above the top of the Mowry Formation (upper confining zone above the Inyan Kara Formation) will be CO2-resistant; 2) the well casing will also be CO2-resistant from the bottomhole to a depth just above the Mowry Formation; 3) the well tubing will be CO2-resistant from the injection interval to surface; 4) the packer will be CO2-resistant; and 5) the packer fluid will be an industry standard corrosion inhibitor. Figures 5-3 and 5-4 summarize the downhole corrosion prevention measures in each of the injection wellbores, and Figure 5-5 illustrates the corrosion prevention measures for the reservoir-monitoring wellbore, even though the reservoir-monitoring wellbore (J-LOC 1) is not anticipated to come into contact with the CO2 plume. 5.6.2 Downhole Corrosion Detection PNLs will be acquired in the IIW-N, IIW-S, and J-LOC 1 wellbores prior to injection. Repeat ultrasonic logs in the CO2 injection wells may be run during well workovers in cases where the well tubing must be pulled. Repeat PNLs acquired in Year 1 of injection, Year 3, and at least once every three years thereafter in the IIW-N and IIW-S wellbores may also be useful for detecting signs of corrosion.	**Figure 5-1.** Site map detailing the surface facilities layout. Inset map illustrates a generalized injection wellsite layout with monitoring equipment identified. (p. 5-5) **Figure 5-2.** Generalized flow diagram from the capture facility outlet to the IIW-N injection well illustrating key surface connections and monitoring equipment. This flow diagram is identical for the IIW-S injection well (not shown). (p. 5-6) **Table 5-2.** Calculated MRYS CO2 Stream Specifications (p. 5-2)
	NDAC § 43-05-01-05(1)(g)	**NDAC § 43-05-01-05(1)** g. A leak detection and monitoring plan for all wells and surface facilities pursuant to section 43-05-01-14. The plan must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on	e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to NDAC § 43-05-01-14;	***5.2 Surface Facilities Leak Detection Plan (p. 5-3)*** The purpose of this leak detection plan is to specify the monitoring strategies DCC West will use to quantify any losses of CO2 during operations from the surface facilities. Surface facilities include the CO2 injection wellheads (IIW-N and IIW-S), the reservoir-monitoring wellhead (J-LOC 1), and the CO2 flowline from the point of transfer to the injection wellheads. Figure 5-1 is a site map showing the locations of the surface facilities and a generalized injection wellsite layout. Figure 5-2 is a generalized flow diagram from the point of transfer to the injection wellheads, illustrating key surface connections and monitoring equipment. The CO2 flowline will be monitored with a P/T gauge and flowmeter located downstream of the point of transfer and near each of the injection wellheads for performing mass balance calculations. The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Acoustic detectors, further described in Attachment A-1 of Appendix D, will be installed at strategic locations along the flowline path to help detect any auditory anomalies. Gas detection stations will also be placed at the injection wellheads and key wellsite locations (e.g., flowline risers and inside enclosures). The gas detection stations, further described in Attachment A-2 in Appendix D, will have an integrated alarm system to monitor for multiple gases, including but not limited to CO2 and H2S. The leak detection equipment will be spliced to a SCADA system for continuous, real-time monitoring and integrated with automated warning systems to notify the operations center, giving DCC West the ability to remotely close the valves in the event of an emergency. The SCADA system is briefly described in Attachment A-3 of Appendix D.	N/A

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.		Each of the injection and reservoir-monitoring wellheads will be equipped with a gas detection station. Gas detection stations will also be placed inside the wellhead enclosures. The stations will be integrated with the SCADA system for continuous, real-time monitoring. Field personnel will have multigas detectors with them for all visits to the wellsite or during flowline inspections. The multigas detectors, which will primarily monitor CO_2 levels in workspace atmospheres, are described in Attachment A-4 in Appendix D. The multigas detectors will be inspected prior to every field visit and be maintained according to the manufacturer's recommendations. In addition, CO_2 detection safety lights (part of the integrated alarm system) will be placed outside of all enclosures to warn field personnel of potential indoor air quality threats. Pursuant to NDAC § 43-05-01-14, leak detection equipment will be inspected and tested on at least a semiannual basis. Any defective equipment will be repaired or replaced and retested. A record of each inspection result will be kept by the site operator, maintained for at least 10 years, and made available to the NDIC upon request. Any detected leaks at the surface facilities shall be promptly reported to NDIC. 5.2.1 Data Sharing The CO_2 flowline from the capture facility (MRYS) to injection wellsites associated with DCC East's permitted geologic CO_2 storage project and DCC West (this application) will be operated as one integrated SCADA system with data flowing to a single operations center, which will allow DCC East and West to share operational data and controls in real-time and ensure operational parameters (e.g., flowline pressures) are safely maintained between the two sites at all times.	
	NDAC § 43-05-01-05(1)(h)	**NDAC § 43-05-01-05(1)** h. A leak detection and monitoring plan to monitor any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile [1.61 kilometers] of the facility area's outside boundary. Provisions in the plan will be dictated by the site characteristics as documented by materials submitted in support of the permit application but must: (1) Identify the potential for release to the atmosphere; (2) Identify potential degradation of ground water resources with particular emphasis on	f. A subsurface leak detection and monitoring plan to monitor for any movement of the carbon dioxide outside of the storage reservoir. This may include the collection of baseline information of carbon dioxide background concentrations in ground water, surface soils, and chemical composition of in situ waters within the facility area and the storage reservoir and within one mile of the facility area's outside boundary;	***5.7 Environmental Monitoring Plan (p. 5-15, paragraphs 1, 3, and 4)*** To verify the injected CO_2 is contained in the storage reservoir and to protect all USDWs, multiple environments will be monitored. As required by NDAC § 43-05-01-11.4(1)(d and h), the near-surface environment, defined as the region from the surface down to the lowest USDW (Fox Hills Aquifer), will be monitored by sampling three new vadose zone soil gas profile stations, two new dedicated Fox Hills Formation monitoring wells, and up to five existing groundwater wells. The deep subsurface environment, defined as the region from below the lowest USDW to the base of the storage reservoir, will be monitored with multiple methods, starting with the above-zone monitoring interval (AZMI) or the geologic interval from the confining zone above the storage reservoir to the confining zone above the next permeable zone above the storage reservoir (i.e., Opeche–Picard Formations to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the IIW-N and IIW-S wellbores as well as periodic PNLs. Wellbore data collected from the reservoir-monitoring well (J-LOC 1) have been integrated with the geologic model to inform the reservoir simulations used to characterize the initial state of the storage reservoir prior to injection operations (Section 3.0). The simulated CO_2 plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan. Pursuant to NDAC § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optic (DTS- and distributed acoustic sensing [DAS]-capable) and downhole P/T measurements. In addition, falloff tests and PNLs will be performed in the IIW-N and IIW-S wellbores. The DAS is further described in Attachment A-9 of Appendix D. Indirect methods include time-lapse VSPs and seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO_2 is safely and permanently contained in the storage reservoir. In addition, DCC West will install seismometer stations for passively detecting and locating seismic events. **5.7.1 Near-Surface Monitoring** Figure 5-6 describes the near-surface baseline and operational monitoring plan, which includes sampling from three vadose zone soil gas profile stations, two new dedicated Fox Hills Formation monitoring wells, and up to five existing groundwater wells. DCC West plans to initiate soil gas sampling to establish baseline conditions at the project site. Soil gas will be sampled at three permanent soil gas profile stations installed on or adjacent to the CO_2 injection well pad, the J-LOC 1 well, and NDIC File No. 4937. Samples will be collected from each station roughly quarterly, or 3–4 times prior to injection, to establish baseline conditions and any seasonal fluctuations. Once injection begins, the sampling frequency will remain the same during the operational phase of the project.	

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
		underground sources of drinking water; and (3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.		Soil gas analytes will include concentrations of CO2, O2, and N2 (further described in Section 1.7.1 of Appendix D), and the results of the baseline soil gas sampling program will be provided to NDIC prior to injection. NDIC File No. 4937 was plugged and abandoned with three cement plugs placed between the Broom Creek Formation and the Fox Hills Formation (Figure 4-8). The surface location of NDIC File No. 4937 is just inside the stabilized CO2 plume boundary by approximately 160 feet, but there is not anticipated to be sufficient pressure increase in the storage reservoir from CO2 injection to move more than 0.011 m3 of fluid into the lowest USDW at NDIC File No. 4937 (discussed in Section 3.5.1). A soil gas profile station (i.e., SGPS03) for sampling soil gas throughout the operational phase of the project is proposed at NDIC File No. 4937 as an assurance-monitoring technique, as shown in Figure 5-7. DCC West plans to acquire baseline samples in up to five existing groundwater wells within the AOR boundary, collecting 3–4 samples from each well prior to injection. Once injection begins, the groundwater sampling program will shift to a new dedicated Fox Hills monitoring well (FH01) placed near the CO2 injection well pad that will collect samples 3–4 times in Years 1–4 and reduce sampling frequency to annually thereafter. Additional sampling of wells in the AOR may be phased in for sampling as the CO2 plume expands and migrates in the storage reservoir. NDIC File Nos. 2183 and 4940 were plugged and abandoned with two cement plugs placed between the Broom Creek Formation and the Fox Hills Formation (Figures 4-5 and 4-6, respectively). In addition, NDIC File Nos. 2183 and 4940 are outside the stabilized CO2 plume boundary; therefore, neither wellbore is anticipated to come into contact with CO2. DCC West plans to monitor both of these legacy wellbores to provide additional assurance of nonendangerment to USDWs near these legacy wells. Once the CO2 plume comes within 1 mile of NDIC File No. 4940 (projected to occur in Year 9), DCC West plans to drill a second dedicated Fox Hills monitoring well (FH02) near the legacy well. FH02 will be sampled 3–4 times in the first year after drilling, with the sampling frequency decreasing to annually thereafter. The existing Fox Hills well, W295, will also be sampled at least annually once the CO2 plume comes within 1 mile of NDIC File No. 2183 (projected to occur in Year 17). Figure 5-7 shows the locations of the Fox Hills monitoring wells near each legacy well. DCC West will employ a proactive monitoring approach to track the CO2 plume extent and associated pressure front near NDIC File Nos. 2183, 4937, and 4940 (Section 5.7.2) to ensure nonendangerment to the near-surface environment. Water analytes for all groundwater well locations will include pH, conductivity, total dissolved solids, and alkalinity as well as major cations/anions and trace metals (further described in Section 1.7.2 of Appendix D). Table 5-6 includes baseline groundwater monitoring results for two of the existing groundwater wells located on the eastern edge of the AOR boundary. State-certified laboratory reports for the baseline data provided in Table 5-6 are available in Appendix B. A state-certified laboratory analysis will be provided to NDIC prior to injection for all baseline groundwater testing. DCC West will evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO2 plume extent in the subsurface. Table 5-7 summarizes the near-surface baseline (preinjection) and operational monitoring plans for the geologic CO2 storage project. 5.7.2 Deep Subsurface Monitoring DCC West will implement direct and indirect methods to monitor the location, thickness, and distribution of the free-phase CO2 plume and associated pressure relative to the permitted storage reservoir. The direct and indirect storage reservoir monitoring methods described in Table 5-8 and throughout this section of the permit application will be used to characterize the CO2 plume's saturation and pressure within the AOR for the baseline and operational phases of the project. 5.7.2.1 AZMI Monitoring Prior to injection, DCC West will acquire PNL data in the IIW-N and IIW-S wellbores from the storage reservoir (Broom Creek Formation) up through the Opeche–Picard Formations (upper confining zone) and Skull Creek Formation (upper confining zone above the Inyan Kara Formation or dissipation interval). Baseline PNLs will be run in the IIW-N, IIW-S, and J-LOC 1 wellbores. Repeat PNLs will be run in the IIW-N and IIW-S wellbores in Year 1 of injection, Year 3, and at least every 3 years thereafter (Years 6, 9, 12, and so on) until the end of injection. These time-lapse data from the PNLs will be used to ensure CO2 is not detected in the AZMI as an additional assurance-monitoring technique for evaluating the performance of the storage reservoir complex and protecting USDWs. Repeat PNLs for the J-LOC 1 are not planned because the well is not anticipated to come into contact with the CO2 plume during the operational phase of the project.	

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				DTS fiber optics installed in the IIW-N and IIW-S wellbores will monitor the temperature profile along the AZMI continuously. 5.7.2.2 Direct Reservoir Monitoring DTS fiber optics installed in the IIW-N and IIW-S wellbores will directly monitor the temperature in the storage reservoir continuously. P/T readings from a tubing-conveyed bottomhole pressure gauge in each of the CO2 injection wells and reservoir-monitoring well will also be continuously recorded. Baseline PNLs will be run in the IIW-N, IIW-S, and J-LOC 1 wellbores. Repeat PNLs will be collected over the Broom Creek Formation in the IIW-N and IIW-S wellbores preinjection and in Year 1, Year 3, and at least every 3 years thereafter until the end of CO2 injection. Falloff testing will be performed prior to injection and once every five years in each of the CO2 injection wells. The temperature and saturation profiles collected over the storage reservoir will provide information about the uniformity of CO2 injectivity within the injection interval. The falloff testing data will confirm projections of the storage capacity and injectivity of the storage reservoir. The pressure data will be used primarily to track the pressure front and ensure the pressure differential in the Broom Creek Formation conforms to numerical simulations. 5.7.2.3 Indirect Reservoir Monitoring Indirect monitoring will include time-lapse VSPs and 2D seismic surveys. Prior to injection, DCC West plans to acquire a VSP at the CO2 injection wellsite using the DAS-capable fiber optics installed in each of the CO2 injection wells. DCC West will also acquire a 2D fence design seismic survey, which is illustrated in Figure 5-8. A repeat VSP survey will be acquired in Year 1 of injection operations to confirm the CO2 plume is migrating in the subsurface as expected. The VSP will be sourced along the 2D lines shown in Figure 5-8. In Years 2 and 4 of injection operations, repeat 2D seismic surveys will be acquired. DCC West will reevaluate the design and frequency of the repeat 2D seismic surveys but anticipates that repeat seismic surveys will be acquired on at least a 5-year frequency thereafter (e.g., Years 9, 14, and 19). If necessary, the time-lapse VSP and seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO2 plume, including extending the 2D lines to capture additional data as the CO2 plume expands. These time-lapse monitoring efforts will help demonstrate conformance between the reservoir model simulation and site performance and monitor the evolution of the CO2 plume. DCC West will install seismometer stations prior to injection. The seismometer stations, combined with the DAS-enabled fiber optics in the CO2 injection wells, will continuously monitor for and passively detect and locate seismicity events near injection operations. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented in Section 1.7.3.3 of Appendix D. 5.7.3 Adaptive Management Approach DCC West will monitor the geologic CO2 storage project with an adaptive management approach (Ayash and others, 2017). Monitoring data gathered from the testing and monitoring plan will be reported to the NDIC as required under NDAC § 43-05-01-18, which will provide the basis for justifying any updates to an approved testing and monitoring plan, including the 5-year reevaluation of the testing and monitoring plan. During each 5-year review, monitoring and operational data will be analyzed, and the AOR will be reevaluated. Based on this reevaluation, it will either be demonstrated that 1) no amendment to the testing and monitoring program is needed, or 2) modifications are necessary to ensure proper monitoring of storage performance is achieved moving forward. This determination will be submitted to NDIC for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by NDIC. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed. Monitoring and operational data will be used to evaluate conformance between observations and history-matched simulation of the CO2 plume and pressure distribution relative to the permitted geologic storage facility. If significant variance is observed, the monitoring and operational data will be used to calibrate the geologic model and associated simulations. The monitoring plan will be adapted to provide suitable characterization and calibration data as necessary to achieve such conformance. Subsequently, history-matched predictive simulation and model interpretations will, in turn, be used to inform adaptations to the monitoring program to demonstrate lateral and vertical containment of the injected CO2 within the permitted geologic storage facility.	
	NDAC § 43-05-01-05(1)(l)	**NDAC § 43-05-01-05(1)** l. A testing and monitoring plan pursuant to section 43-05-01-11.4;	g. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4;	See Section **5.0 TESTING AND MONITORING PLAN** and **APPENDIX D: QUALITY ASSURANCE SURVEILLANCE PLAN** Note: See Table 5-1 on p. 5-1; Table 5-3 on p. 5-9; Table 5-4 on p. 5-13; and Table 5-7 on p. 5-19, for detailed summaries of the testing and monitoring plan.	**Table 5-1.** Overview of the Testing and Monitoring Plan (p. 5-1)

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
					Table 5-3. Overview of the Mechanical Integrity Testing Plan (p. 5-9) **Table 5-4.** Completed Logging and Testing for the Reservoir-Monitoring Well (p. 5-13) **Table 5-5.** Proposed Logging and Testing Plan for the CO2 Injection Wellbores (p. 5-14) **Table 5-7.** Summary of Near-Surface Baseline and Operational Monitoring Plan(p. 5-19)
	NDAC § 43-05-01-05(1)(i)	**NDAC § 43-05-01-05 (1)** i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;	h. The proposed well casing and cementing program;	**9.0 WELL CASING AND CEMENTING PROGRAM** (p. 9-1)	**Figure 9-2**. IIW-N proposed injection wellbore schematic. (p. 9-3) **Figure 9-4.** IIW-S proposed injection wellbore schematic. (p. 9-7) **Figure 9-6.** Proposed design of the J-LOC1 CO2-monitoring wellbore schematic. (p. 9-11)
	NDAC § 43-05-01-05(1)(m)	**NDAC § 43-05-01-05(1)** m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	***Refer to Section 10.1 IIW-N: Proposed Injection Well P&A Program (p. 10-1)*** ***Refer to Section 10.2 IIW-S: Proposed Injection Well P&A Program (p. 10-7)*** ***Refer to Section 10.3 J-LOC 1: Proposed Monitoring Well P&A Program (p. 10-12)***	**Figure 10-1**. Proposed CO2 injection well schematic for IIW-N. (p. 10-2) **Figure 10-2.** Schematic of proposed P&A plan for IIW-N. (p. 10-6) **Figure 10-3**. Proposed CO2 injection well schematic for IIW-S. (p. 10-7) **Figure 10-4.** Schematic of proposed P&A plan for IIW-S. (p. 10-11)

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th>Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td rowspan="2"></td><td></td><td></td><td></td><td></td><td>Figure 10-5. As-built wellbore schematic for J-LOC 1. (p. 10-12)

Figure 10-6. Schematic of proposed abandonment plan for monitoring well J-LOC 1. (p. 10-16)</td></tr>
<tr><td>NDAC § 43-05-01-05(1)(n)</td><td>NDAC § 43-05-01-05(1)
n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and</td><td>j. A post-injection site care and facility closure plan.</td><td>6.0 POSTINJECTION SITE AND FACILITY CLOSURE PLAN (p. 6-1)

Note: Refer to Table 6-1 on p. 6-4, Table 6-2 on p. 6-5, and Table 6-3 on p. 6-6 for a summary of the postinjection site care monitoring plan.</td><td>Table 6-1. Mechanical Integrity Testing Plan for the J-LOC 1 Wellbore During the PISC Period (p. 6-4)

Table 6-2. Soil Gas and Groundwater Monitoring Plan During the PISC Period (p. 6-5)

Table 6-3. Deep Subsurface Monitoring Plan During the PISC Period (p. 6-6)</td></tr>
<tr><td rowspan="3">Storage Facility Operations</td><td>NDAC § 43-05-01-05(1)(b)(4)</td><td>NDAC § 43-05-01-05(1)(b)
(4) The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide stream using a method acceptable to and filed with the commission;</td><td>The following items are required as part of the storage facility permit application:

a. The proposed average and maximum daily injection rates;</td><td rowspan="3">11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)
This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDW). The information that is presented in Table 11-1 meets the permit requirements for injection well and storage operations as documented in North Dakota Administrative Code (NDAC) § 43-05-01-05.1(b)(4) & (5) and § 43-05-01-11.3.

Table 11-1. DCC West SGS Proposed Injection Well Operating Parameters
<table>
<tr><th>Item</th><th>Values</th><th colspan="2">Description/Comments</th></tr>
<tr><th colspan="4">Injected Volume</th></tr>
<tr><td>Total Injected Volume</td><td>122.9 MMt
2,363,160.5 MMCF</td><td colspan="2">Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint</td></tr>
<tr><th>Injection Rates</th><th>IIW-N</th><th>IIW-S</th><th>Description/Comments</th></tr>
<tr><td>Average Injection Rate</td><td>4844 tonnes/day
(94 MMscf/day)
1.768 MMt/yr
686,353.6 MMCF
35.686 MMt</td><td>11,897 tonnes/day
(230 MMscf/day)
4.342 MMt/yr
1,676,806.8 MMCF
87.183 MMt</td><td>Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint</td></tr>
<tr><td>Average Maximum Daily Injection Rate</td><td>10,834 tonnes/day
(208.3 Mscf/day)
3.954 MMt/yr</td><td>19,503 tonnes/day
(374.7 Mscf/day)
7.118 MM tonnes/year</td><td>Based on maximum BHP with only one well injecting at a time:
IIW-N: 3233 psi and</td></tr>
</table></td><td>Table 11.1. DCC West SGS Proposed Injection Well Operating Parameters
(p. 11-1)</td></tr>
<tr><td rowspan="2"></td><td rowspan="2"></td><td>b. The proposed average and maximum daily injection volume;</td><td rowspan="2"></td></tr>
<tr><td>c. The proposed total anticipated volume of the carbon dioxide to be stored;</td></tr>
</table>

<table>
<tr><th>Subject</th><th>NDCC / NDAC Reference</th><th>Requirement</th><th colspan="2">Regulatory Summary</th><th>Storage Facility Permit Application
(Section and Page Number; see main body for reference cited)</th><th>Figure/Table Number and Description
(Page Number)</th></tr>
<tr><td rowspan="4"></td><td rowspan="2">NDAC § 43-05-01-05(1)(b)(5)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)
(5) The proposed average and maximum bottom hole injection pressure to be utilized at the reservoir. The maximum allowed injection pressure, measured in pounds per square inch gauge, shall be approved by the commission and specified in the permit. In approving a maximum injection pressure limit, the commission shall consider the results of well tests and other studies that assess the risks of tensile failure and shear failure. The commission shall approve limits that, with a reasonable degree of certainty, will avoid initiating a new fracture or propagating an existing fracture in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water;</td><td>d.</td><td>The proposed average and maximum bottom hole injection pressure to be utilized;</td><td rowspan="2"><table>
<tr><td></td><td>1,484,680.4 MMCF
77.193 MMt</td><td>2,622,375.5 MMCF
136.346 MMt</td><td>IIW-S: 3242 psi</td></tr>
<tr><th>Pressures</th><th>IIW-N</th><th>IIW-S</th><th>Description/Comments</th></tr>
<tr><td>Formation Fracture Pressure at Top Perforation</td><td>3592 psi</td><td>3602 psi</td><td>Based on geomechanical analysis of formation fracture gradient as 0.712 psi/ft</td></tr>
<tr><td>Average Surface Injection Pressure</td><td>1633 psi</td><td>2085 psi</td><td>Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint</td></tr>
<tr><td>Surface Maximum Injection Pressure</td><td>1997 psi</td><td>2459psi</td><td>Based on maximum BHP with only one well injecting at a time:
IIW-N: 3233 psi and
IIW-S: 3242 psi (using the designed 7-inch tubing)</td></tr>
<tr><td>Average BHP</td><td>3233 psi</td><td>3216 psi</td><td>Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint</td></tr>
<tr><td>Calculated Maximum BHP</td><td>3233 psi</td><td>3242 psi</td><td>Based on 90% of the formation fracture pressure of 3592.4 psi for IIW-N and 3602.1 psi for IIW-S</td></tr>
</table></td><td rowspan="2"></td></tr>
<tr><td>e.</td><td>The proposed average and maximum surface injection pressures to be utilized;</td></tr>
<tr><td rowspan="2">NDAC § 43-05-01-05(1)(b)(6)</td><td rowspan="2">NDAC § 43-05-01-05(1)(b)
(6) The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone pursuant to section 43-05-01-11.2;</td><td>f.</td><td>The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;</td><td rowspan="2">5.5 Baseline Wellbore Logging and Testing Plan (p. 5-13)
Pursuant to NDAC § 43-05-01-11.2, DCC West will collect baseline logging and testing measurements from subsurface geologic formations in the CO_2 injection wellbores to: 1) verify the depth, thickness, porosity, permeability, lithology, and salinity of the storage reservoir complex; 2) ensure conformance with the injection well construction requirements; and 3) establish accurate baseline data for making future time-lapse measurements.

Table 5-4 specifies baseline logging and testing activities completed in the reservoir-monitoring well (J-LOC 1). Table 5-5 identifies the planned logging and testing activities for the CO_2 injection wells (coring activities are separately addressed in Section 2.2.2). The logging and testing plan for the IIW-S wellbore will be the same as what is presented for the IIW-N but may exclude dipole sonic logging (assuming dipole sonic logging is successful in the IIW-N). Table 5-3 (see Section 5.4) and Table 5-6 (see Section 5.7) specify the logging activities and operational frequencies for demonstrating mechanical integrity and gathering monitoring data, respectively, from project wellbores.

DCC West will provide NDIC with an opportunity to witness all logging and testing carried out under this section and inform NDIC of logging and testing activities as required. Log and well test files will be submitted to NDIC as required.

See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LABORATORY ANALYSIS

2.0 GEOLOGIC EXHIBITS
Refer to 2.2 Data and Information Services (p. 2-1)
Refer to 2.2.2 Site-Specific Data (p. 2-4)

2.2.2.2 Core Sample Analyses (p. 2-8)</td><td rowspan="2">Table 5-5. Proposed Logging and Testing Plan for the CO_2 Injection Wellbores (p. 5-14)</td></tr>
<tr><td>g.</td><td>The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</td></tr>
</table>

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
				From the Broom Creek Formation storage reservoir in the J-LOC 1 well, 302 ft of core was collected. This core was analyzed to characterize the lithologies of the Broom Creek, Opeche/Spearfish, and Amsden Formations and correlated to the well log data. Core analysis also included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), relative permeability testing, thin-section analysis, capillary entry pressure measurements, and triaxial geomechanics testing. The results were used to inform geologic modeling, predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.	

Table 5-5. Proposed Logging and Testing Plan for the CO_2 Injection Wellbores

	Logging/Testing	Justification	NDAC § 43-05-01-11.2
Surface Section	Openhole Logs: Resistivity, SP, Caliper, and Temperature	Quantify variability in reservoir properties, such as resistivity and lithology, and measure hole conditions.	(1)(b)(1)
Surface Section	Cased-Hole Logs: Ultrasonic Logging Tool, CBL, VDL, GR, and Temperature	Identify cement bond quality radially, evaluate the cement top and zonal isolation, and establish external mechanical integrity. Establish baseline temperature profile for temperature-to-DTS calibration.	(1)(b)(2) and (1)(d)
Long-String Section	Openhole Logs: Quad Combo (triple combo plus dipole sonic), SP, GR, and Caliper	Quantify variability in reservoir properties, including resistivity, porosity, and lithology and measure hole conditions. Provide input for enhanced geomodeling and predictive simulation of CO_2 injection into the interest zones to improve interpretations. Identify mechanical properties, including stress anisotropy. Provide compression and shear waves for seismic tie-in and quantitative analysis of the seismic data.	(1)(c)(1)
Long-String Section	Openhole Log: Fracture Finder Log	Quantify fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO_2.	(1)(c)(1)
Long-String Section	Openhole Log: Magnetic Resonance Log	Aid in interpreting reservoir permeability and determined the best location for modular dynamics testing (MDT) fluid-sampling depths, packer-setting depths, and stress-testing depths.	(1)(c)(1)
Long-String Section	Fluid Sampling and Testing	Collect fluid sample from the Broom Creek Formation for analysis.	(2) and (3)
Long-String Section	Openhole Log: Spectral GR	Identify clays and lithology that could affect injectivity. Also used for core to log depth correlation.	(4)(b)
Long-String Section	Injectivity Test	Perform to define the fracture gradient and maximum allowable injection pressure of the storage reservoir.	(4)
Long-String Section	Pressure Falloff Test	Perform to verify hydrogeologic characteristics of the Broom Creek Formation.	(5)
Long-String Section	Cased-Hole Log: Pulsed-Neutron Log	Confirm mechanical integrity and establish baseline saturation profile from the Broom Creek to the Skull Creek Formations.	11.4(g)(1)
Long-String Section	Cased-Hole Logs: CCL, Ultrasonic Logging Tool, VDL, and Temperature	Confirm mechanical integrity and establish baseline temperature profile for temperature-to-DTS calibration.	(1)(c)(2) and (d)

Subject	NDCC / NDAC Reference	Requirement	Regulatory Summary	Storage Facility Permit Application (Section and Page Number; see main body for reference cited)	Figure/Table Number and Description (Page Number)
	NDAC § 43-05-01-05(1)(b)(7)	**NDAC § 43-05-01-05(1)(b)** (7) The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment; and	h. The proposed stimulation program: 1. A description of the stimulation fluids to be used 2. A determination of the probability that stimulation will interfere with containment	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDW). The information that is presented in Table 11-1 meets the permit requirements for injection well and storage operations as documented in North Dakota Administrative Code (NDAC) § 43-05-01-05.1(b)(4) & (5) and § 43-05-01-11.3.	N/A
	NDAC § 43-05-01-05(1)(b)(8)	**NDAC § 43-05-01-05(1)(b)** (8) The proposed procedure to outline steps necessary to conduct injection operations.	i. Steps to begin injection operations	**11.0 INJECTION WELL AND STORAGE OPERATIONS (p. 11-1)** This section of the storage facility permit (SFP) application presents the engineering criteria for completing and operating the injection wells in a manner that protects underground sources of drinking water (USDW). The information that is presented in Table 11-1 meets the permit requirements for injection well and storage operations as documented in North Dakota Administrative Code (NDAC) § 43-05-01-05.1(b)(4) & (5) and § 43-05-01-11.3. **Refer to 11.1 IIW-N Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)** **Refer to 11.2 IIW-S Well – Proposed Completion Procedure to Conduct Injection Operations (p. 11-6)**	N/A