

DRAFT STORAGE FACILITY PERMIT

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

In compliance with North Dakota Century Code (NDCC) Chapter 38-22 (Carbon Dioxide Underground Storage) and North Dakota Administrative Code (NDAC) Chapter 43-05-01 (Geologic Storage of Carbon Dioxide), Summit Carbon Storage #3, LLC 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 Section 43-05-01-07.2 indicating the Commission's tentative decision to issue a storage facility permit. Before preparing the draft permit, the Commission through the Department of Mineral Resources Oil and Gas Division, consulted with the Department of Environmental Quality, and has determined the storage facility permit application to be complete. The draft permit contains permit conditions required under NDAC Sections 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 April 15, 2024, and shall remain in effect until a storage facility permit is granted under NDAC Section 43-05-01-05, unless amended or terminated by the Department of Mineral Resources Oil and Gas Division (Commission).

Tamara Madche, Geologist
Department of Mineral Resources
Oil and Gas Division
Date: April 15, 2024

I. APPLICANT

Summit Carbon Storage #3, LLC
2321 North Loop Drive, Suite #221
Ames, IA 50010

II. PERMIT CONDITIONS (NDAC Section 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 section 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 Section 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 KJ Hintz (File No. 40127 – NENE 17-142N-86W) and KJ Hintz 2 (File No. 40128 – NENE 17-142N-86W) injectors and the Slash Lazy H 5 (File No. 38701 – LOT 1 6-142N-86W) monitor well.
2. NDAC Section 43-05-01-11, subsection 14 and NDAC Section 43-05-01-11.4, subsection 1, subdivision c; 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 KJ Hintz 1, KJ Hintz 2 and Slash Lazy H 5 wells. The operator shall run logs with the same capabilities for the KJ Hintz 1 and KJ Hintz 2 wells on a 5 year schedule, unless analysis of corrosion coupons or subsequent logging necessitates a more frequent schedule.
3. NDAC Section 43-05-01-11.4, subsection 1, subdivision d and NDAC Section 43-05-01-13, subsection 2; The storage operator shall notify the Commission within 24 hours of any release of carbon dioxide from the storage facility, flow lines, or of carbon dioxide detected above the upper confining zone. Where the Commission or the storage operator obtains evidence that the injected carbon dioxide stream and associated pressure front may endanger an underground source of drinking water, the storage operator shall cease injection immediately, implement the emergency and remedial plan approved by the Commission, and take all steps reasonably necessary to identify and characterize any release.
4. NDAC 43-05-01-11.1 subsections 3 and 5 and NDAC 43-05-01-11.4, subsection 1, subdivision e; External mechanical integrity shall be continuously monitored with the proposed fiber optic lines for the KJ Hintz 1, KJ Hintz 2 and Slash Lazy H 5 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 (Soil Gas 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 wells and casing annulus for the monitor well. The packer must be set within 100' of the upper most perforation and in the 25CR-80 casing for the KJ Hintz 1 and KJ Hintz 2 injectors and 13CR-80 casing for the Slash Lazy H 5 monitor should tubing and packer be installed. Dependent on evaluation, the operator shall run the same test on a 5 year schedule for the KJ Hintz 1, KJ Hintz 2 and Slash Lazy H 5 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 of any 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 Summit Carbon Storage #3, LLC, Summit Carbon Storage #1, LLC, Summit Carbon Storage #2, LLC and SCS Carbon Transport LLC operations. 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 300 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

Summit Carbon Storage #3, LLC (SCS #3) is a wholly owned subsidiary of SCS Permanent Carbon Storage LLC (SCS PCS) which is a wholly owned subsidiary of Summit Carbon Solutions, LLC (SCS). SCS, under the wholly owned subsidiary SCS Carbon Transport LLC, intends to construct, own, and operate a carbon dioxide transmission pipeline, the Midwest Carbon Express (MCE) pipeline. The MCE pipeline will receive carbon dioxide from over 30 anthropogenic sources, including biofuels from ethanol facilities and other industries across the Midwest, including Iowa, Minnesota, Nebraska, South Dakota, and North Dakota. The MCE pipeline will be capable of transporting up to 18 million metric tons per year, to North Dakota to be stored in three storage facilities located in Mercer, Morton, and Oliver Counties, near the city of Beulah, North Dakota, owned by SCS #3, Summit Carbon Storage #1, LLC (SCS #1) and Summit Carbon Storage #2, LLC (SCS #2). SCS #1 and SCS #2 are wholly owned subsidiaries of SCS PCS. All three storage facilities are intended to operate in tandem with each other.

2. Quantity and Quality of Carbon Dioxide Stream

The storage facility was modeled to receive a maximum of 129.7 million metric tons over a 20-year injection period, equating to approximately 6.49 million metric tons annually. The combined maximum modeled storage volume across all three storage facilities is 352 million metric tons over 20 years.

The commingled carbon dioxide stream being transported by the MCE pipeline at the time of this application is anticipated to average at least 98.25% carbon dioxide, <1.44% nitrogen, with trace quantities of oxygen, water, hydrocarbons, hydrogen sulfide, sulfur, and glycol, equaling less than 0.31% combined.

The MCE pipeline and storage facility have been conservatively designed to accommodate a carbon dioxide stream that is 95% carbon dioxide, 2% oxygen, and 3% nitrogen. SCS #3 is proposing that the carbon dioxide stream must be between 95% and 99.9% carbon dioxide to be accepted into the MCE pipeline to allow flexibility to receive carbon dioxide from a variety of industrial sources.

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

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

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 300 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:

April 15, 2024 to 5:00 P.M. CDT June 10, 2024

The address where comments will be received:

Oil and Gas Division, 1016 East Calgary Avenue, Bismarck, North Dakota 58503-5512
or slforsberg@nd.gov

Date, time, and location of the storage facility permit hearing:

June 11-12, 2024 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: Sara Forsberg – slforsberg@nd.gov – 701-328-8020

February 6, 2024

Tammy Madche
North Dakota Department of Mineral Resources
1000 East Calgary Avenue
Bismarck, ND 58502

RE: SUMMIT CARBON STORAGE #3, LLC SFP AND CLASS VI APPLICATION

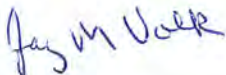
Dear Mrs. Madche,

Summit Carbon Storage #3, LLC (SCS3) respectfully submits for the review and consideration of the Department of Mineral Resources – Oil & Gas Division, one application for carbon dioxide storage facility permits for the injection site called the KJ Hintz; which is located in Oliver County, North Dakota. This application was prepared pursuant to and in accordance with Chapter 38-22 of the North Dakota Century Code and Chapter 43-05-01 of the North Dakota Administrative Code.

The storage facility permit application, associated simulation data and the Permit Application Certification – Broom Creek, has been sent electronically.

Please contact me with any questions.

Sincerely,



Jay M. Volk, PhD
Sequestrations – Director of Health, Safety & Environmental

Enclosure

Cc: Lawrence Bender, lbender@fredlaw.com (w/o enclosure)

Permit Application Certification
-Broom Creek-

BEFORE ME, the undersigned authority, personally appeared Wade Boeshans, Executive Vice President of Summit Carbon Solutions, LLC the ultimate parent company of the wholly owned subsidiary, **Summit Carbon Storage #3, LLC**, a Delaware Limited Liability Company whose office is located at 2321 North Loop Drive, Suite #221, Ames, IA, 50010 who being duly sworn, upon oath stated and certified that:

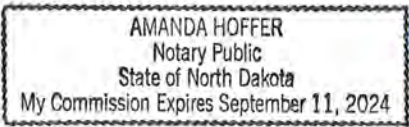
1. I, Wade Boeshans, am over eighteen years of age. I have personal knowledge of the information and facts stated by me in the Certification and that they are true and correct. I have never been convicted of any felony or of any crime involving moral turpitude and am fully competent to make these representations.
2. I hold the position of Executive Vice President for Summit Carbon Solutions, LLC. As required in accordance with North Dakota Administrative Code § 43-05-01-07.1 and by virtue of my position with Summit Carbon Solutions, LLC, I am authorized to make these representations on behalf of **Summit Carbon Storage #3, LLC**.
3. Attached hereto is 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, Mercer and Morton County’s, North Dakota. Further, enclosed is the accompanying Class VI drilling permit information for two (2) carbon dioxide injection wells and one (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 representation contained in the 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 **Summit Carbon Storage #3, LLC**.

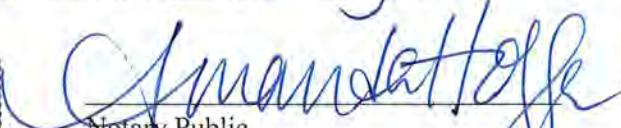
Executed this 6 day of February, 2024


Wade Boeshans

STATE OF NORTH DAKOTA)
) SS
COUNTY OF BURLEIGH)

Subscribed and sworn to before me this 6 day of February, 2024

(SEAL) 


Notary Public

SUMMIT CARBON STORAGE #3, LLC – CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT

North Dakota CO₂ Storage Facility Permit Application

Prepared for:

Richard Suggs
Tammy Madche

Department of Mineral Resources
Oil and Gas Division
600 East Boulevard Avenue
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Prepared by:

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February 2024

TABLE OF CONTENTS

LIST OF ACRONYMS v

PROJECT SUMMARY PS-1

1.0 PORE SPACE ACCESS 1-1

2.0 GEOLOGIC EXHIBITS 2-1

 2.1 Overview of Project Area Geology 2-1

 2.2 Data and Information Sources 2-4

 2.2.1 Existing Data 2-4

 2.2.2 Site-Specific Data 2-6

 2.3 Storage Reservoir..... 2-16

 2.3.1 Mineralogy of the Injection Zone 2-26

 2.3.2 Mechanism of Geologic Confinement..... 2-31

 2.3.3 Geochemical Information of the Injection Zone 2-31

 2.4 Confining Zones 2-31

 2.4.1 Upper Confining Zone 2-32

 2.4.2 Additional Overlying Confining Zones 2-39

 2.4.3 Lower Confining Zone 2-42

 2.4.4 Geomechanical Information of Confining Zone..... 2-48

 2.5 Faults, Fractures, and Seismic Activity 2-63

 2.5.1 Stanton Fault 2-63

 2.5.2 Interpreted Basement Faults 2-63

 2.5.3 Mohr–Coulomb Critical Stress Analysis of Faults 2-66

 2.5.4 Seismic Activity 2-68

 2.6 Potential Mineral Zones 2-71

 2.7 References..... 2-78

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF
CO₂ INJECTION..... 3-1

 3.1 Introduction..... 3-1

 3.2 Overview of Simulation Activities 3-1

 3.2.1 Modeling of the Injection Zone and Overlying and Underlying Seals..... 3-1

 3.2.2 Structural Framework Construction 3-1

 3.2.3 Data Analysis and Property Distribution..... 3-2

 3.3 Numerical Simulation of CO₂ Injection 3-5

 3.3.1 Simulation Model Development..... 3-5

 3.3.2 Sensitivity Analysis 3-16

 3.4 Simulation Results 3-16

 3.4.1 Maximum Injection Pressure and Rates 3-28

 3.4.2 Stabilized Plume and Storage Facility Area 3-29

 3.5 Delineation of the Area of Review 3-30

Continued . . .

TABLE OF CONTENTS (continued)

3.5.1	EPA Methods 1 and 2: AOR Delineation for Class VI Wells.....	3-30
3.5.2	Risk-Based AOR Delineation.....	3-32
3.5.3	Critical Threshold Pressure Increase Estimation.....	3-34
3.5.4	Risk-Based AOR Calculations	3-35
3.5.5	Risk-Based AOR Results.....	3-39
3.6	References.....	3-44
4.0	AREA OF REVIEW	4-1
4.1	Area of Review Delineation	4-1
4.2	Corrective Action Evaluation	4-6
4.3	Reevaluation of AOR and Corrective Action Plan.....	4-11
4.4	Protection of USDWs	4-11
4.4.1	Introduction of USDW Protection.....	4-11
4.4.2	Geology of USDW Formations	4-12
4.4.3	Hydrology of USDW Formations.....	4-15
4.4.4	Protection for USDWs.....	4-18
4.5	References.....	4-20
5.0	TESTING AND MONITORING PLAN	5-1
5.1	CO ₂ Stream Analysis	5-9
5.1.1	CO ₂ Stream Analysis QASP.....	5-10
5.2	Surface Facilities Leak Detection Plan.....	5-10
5.2.1	Data Sharing and Custody Transfer.....	5-13
5.2.2	Surface Facility Leak Detection Plan QASP.....	5-13
5.3	CO ₂ Flowline Corrosion Prevention and Detection Plan	5-14
5.3.1	Corrosion Prevention.....	5-14
5.3.2	Corrosion Detection.....	5-15
5.4	Wellbore Mechanical Integrity Testing.....	5-16
5.4.1	Wellbore Mechanical Integrity Testing QASP.....	5-17
5.5	Baseline Wellbore Logging and Testing Plan	5-18
5.5.1	Baseline Wellbore Logging and Testing Plan QASP.....	5-21
5.6	Wellbore Corrosion Prevention and Detection Plan.....	5-21
5.6.1	Downhole Corrosion Prevention	5-21
5.6.2	Downhole Corrosion Detection	5-22
5.7	Environmental Monitoring Plan	5-22
5.7.1	Soil Gas Monitoring	5-22
5.7.2	Groundwater Monitoring.....	5-26
5.7.3	Deep Subsurface Monitoring.....	5-28
5.8	Reporting Requirements.....	5-33
5.8.1	Surface Facilities Leak Detection Reporting	5-33
5.9	Adaptive Management Approach.....	5-33
5.10	References.....	5-34

Continued . . .

TABLE OF CONTENTS (continued)

6.0	POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN	6-1
6.1	Predicted Postinjection Subsurface Conditions	6-4
6.1.1	Pre- and Postinjection Pressure Differential.....	6-4
6.1.2	Predicted Extent of CO ₂ Plume	6-6
6.2	Postinjection Testing and Monitoring Plan	6-7
6.2.1	Mechanical Integrity Testing and Corrosion Detection.....	6-7
6.2.2	Soil Gas and Groundwater Monitoring.....	6-7
6.2.3	Deep Subsurface Monitoring	6-8
6.3	Postinjection Site Care Plan.....	6-9
6.3.1	Schedule for Submitting Postinjection Monitoring Results	6-9
6.4	Facility Closure Plan.....	6-9
6.4.1	Submission of Facility Closure Report, Survey, and Deed	6-10
7.0	EMERGENCY AND REMEDIAL RESPONSE PLAN	7-1
7.1	Background.....	7-1
7.2	Local Resources and Infrastructure	7-4
7.3	Identification of Potential Emergency Events	7-4
7.3.1	Definition of an Emergency Event	7-4
7.3.2	Potential Project Emergency Events and Their Detection.....	7-10
7.4	Emergency Response Actions	7-10
7.4.1	General Emergency Response Actions.....	7-10
7.4.2	Incident-Specific Response Actions	7-15
7.5	Response Personnel/Equipment and Training	7-17
7.5.1	Response Personnel and Equipment.....	7-17
7.5.2	Staff Training and Exercise Procedures	7-18
7.5.3	Emergency Response Procedures	7-18
7.5.4	Qualified Individual.....	7-19
7.5.5	Local Response Team.....	7-19
7.5.6	Company Support Team	7-19
7.5.7	Preplanning Emergency Response Activities with Public Safety Answering Point, Fire, Police, and Other Public Officials.....	7-21
7.5.8	Required Controller Actions.....	7-21
7.6	Emergency Communications Plan.....	7-21
7.7	ERRP Review and Updates	7-24
8.0	WORKER SAFETY PLAN	8-1
9.0	WELL CASING AND CEMENTING PROGRAM.....	9-1
9.1	KJ Hintz 1: Proposed Injection Well Casing and Cementing Programs	9-1
9.2	KJ Hintz 2: Proposed Injection Well Casing and Cementing Programs	9-6
9.3	Slash Lazy H 5: As-Constructed CO ₂ Monitoring Well Casing and Cementing Programs	9-11

Continued . . .

TABLE OF CONTENTS (continued)

10.0	PLUGGING PLAN	10-1
10.1	KJ Hintz 1: Proposed Injection Well P&A Program	10-1
10.2	KJ Hintz 2: Proposed Injection Well P&A Program	10-8
10.3	Slash Lazy H 5: Proposed Reservoir-Monitoring Well P&A Program.....	10-15
11.0	INJECTION WELL AND STORAGE OPERATIONS	11-1
11.1	KJ Hintz 1: Proposed Completion Procedure to Conduct Injection Operations.....	11-2
11.2	KJ Hintz 2: Proposed Completion Procedure to Conduct Injection Operations.....	11-10
11.3	Slash Lazy H 5: Proposed Completion Procedure for Monitoring Well Operations.....	11-18
12.0	FINANCIAL ASSURANCE DEMONSTRATION PLAN.....	12-1
12.1	Facility Information.....	12-2
12.2	Approach to Financial Responsibility Cost Estimates.....	12-2
12.2.1	Corrective Action.....	12-2
12.2.2	Plugging of Injection Wells.....	12-3
12.2.3	Implementation of the PISC Plan and Facility Closure Activities	12-3
12.2.4	Implementation of Emergency and Remedial Response Actions.....	12-6
12.3	Financial Instruments.....	12-11
12.4	References.....	12-12
	WELL AND WELL FORMATION FLUID SAMPLING LAB ANALYSIS	Appendix A
	FRESHWATER WELL FLUID SAMPLING ANALYSIS.....	Appendix B
	GEOCHEMICAL INTERACTIONS	Appendix C
	MONITORING EQUIPMENT SPECIFICATION INFORMATION	Appendix D
	STORAGE FACILITY PERMIT REGULATORY COMPLIANCE TABLE	Appendix E

LIST OF ACRONYMS

1D MEM	1D mechanical earth model
AI	acoustic impedance
amsl	above mean sea level
AOR	area of review
API	American Petroleum Institute
ASLMA	Analytical Solution for Leakage in Multilayered Aquifers
AZMI	above-zone monitoring interval
bbl	oilfield barrel
BHP	bottomhole pressure
BOP	blowout preventer
BPV	backpressure valve
BTC	buttress
CA	contact angle
CaCO ₃	calcium carbonate
CCS	carbon capture and storage
CFR	Code of Federal Regulations
CI	carbon intensity
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
CRA	corrosion-resistant alloy
CRC	Company Response Crew
CST	Company Support Team
DMR-O&G	Department of Mineral Resources, Oil and Gas Division
DOC	dissolved organic carbon
DST	drill stem test
DTC	dipole sonic compressional slowness values (delta-T compressional)
DTS	dipole shear sonic slowness, distributed temperature sensing
DWR	Department of Water Resources
E	dynamic Young's moduli
EC	electrical conductivity
EDS	energy-dispersive spectrometry
EERC	Energy & Environmental Research Center
EMS	emergency management service
EPA	U.S. Environmental Protection Agency
ER	electrical resistance

Continued . . .

LIST OF ACRONYMS (continued)

ERRP	emergency remedial response plan
FA	friction angle
FADP	financial assurance demonstration plan
FANG	friction angle
FEL	from the east line
FNL	from the north line
FSP	fault slip potential
GHG	greenhouse gas
GL	ground level
GR	gamma ray
H ₂ S	hydrogen sulfide
HazMat	hazardous materials
HAZWOPER	hazardous waste operations and emergency response
HCON	hydraulic conductivity
HSE	health, safety, and environmental
HSGR	standard (total) gamma ray
IAM-CS	integrated assessment model for carbon storage
IC	Incident Commander
ICS	Incident Command System
IFT	interfacial tension
JFE BEAR	gastight premium connection
K	permeability
K _{int}	intrinsic permeability
KINT	permeability
LCFS	low-carbon fuel standard
LD	lay down
LDS	leak detection system
LEPC	Local Emergency Planning Committee
LRT	Local Response Team
LTC	long-thread and coupled
MASP	maximum anticipated surface pressure
MCE	Midwest Carbon Express
mD	millidarcy
MD	measured depth
MDT	modular dynamics testing
MI	mechanical integrity
MICP	mercury injection capillary pressure
MIRU	move in and rig up
MIT	mechanical integrity test
MLVs	main line valves
MMI	modified Mercalli intensity

Continued . . .

LIST OF ACRONYMS (continued)

MMt	million metric tons
MMtpa	million metric tons per annum
MMscf	million standard cubic ft
MVTL	Minnesota Valley Testing Laboratories
NAD	North American Datum
ND	nipple down
N.D.A.C.	North Dakota Administrative Code
N.D.C.C.	North Dakota Century Code
NDIC	North Dakota Industrial Commission
NEUT	neutron porosity
NFPA	National Fire Protection Association
NU	nipple up
O ₂	oxygen
OSHA	Occupational Safety and Health Administration
P&A	plugged and abandoned
PBTD	plug back total depth
Pce	Capillary entry pressure
PCOR	Plains CO ₂ Reduction Partnership [Partnership]
Phi	porosity
PHIE	effective porosity
PHIT	total porosity
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIG	pipeline inspection gauge
PISC	postinjection site care
PLT	production logging tool
PNL	pulsed-neutron log
POOH	pull out of hole
PPE	personal protective equipment
ppg	pounds per gallon
PSAP	public safety answering point
psig	pounds per square inch
P/T	pressure/temperature
PU	pick up
PV	pore volume
PVC	pore volume compressibility
QASP	quality assurance and surveillance plan
QI	qualified individual
Qtr	quarter
RCBL	radial cement bond log

Continued . . .

LIST OF ACRONYMS (continued)

RD	rig down
RDMO	rig down and move out
RHOB	bulk density
RIH	run in hole
RNG	range
RQI	reservoir quality index
RU	Rig up
SCADA	supervisory control and data acquisition
scf	standard cubic ft
SCS	Summit Carbon Solutions, LLC
SCS1	Summit Carbon Storage #1, LLC
SCS2	Summit Carbon Storage #2, LLC
SCS3	Summit Carbon Storage #3, LLC
SCS PCS	SCS Permanent Carbon Storage LLC
SEM	scanning electron microscopy
SFA	storage facility area
SFP	storage facility permit
Shmin	minimum horizontal stress
SHmax	maximum horizontal stress
SLRA	screening-level risk assessment
SP	spontaneous potential
SRT	step rate test
SS	specific storage
SSTVD	subsea true vertical depth
STC	short-thread and coupled
sx	sacks
TA	temporarily abandoned
TATD	temporarily abandoned, drilled to total depth
TBD	to be determined
TD	total depth
TDS	total dissolved solids
TIH	trip in hole
To	tensile strength
TOC	top of cement, total organic carbon
TOOH	trip out of hole
TWP	township
TVD	true vertical depth
UC	Unified Command
UCS	Unconfined compressive strength
UIC	underground injection control
USDW(s)	underground source of drinking water
USGS	U.S. Geological Survey

Continued . . .

LIST OF ACRONYMS (continued)

USIT	ultrasonic imaging tool
VAM TOP	gastight premium connection
VBA	Visual Basic for Applications
VDL	variable-density log
WHP	wellhead pressure
WHT	wellhead temperature
WO	workover
WSP	Worker Safety Plan
XRD	x-ray diffraction
XRF	x-ray fluorescence

**SUMMIT CARBON STORAGE #3, LLC
CARBON DIOXIDE GEOLOGIC STORAGE FACILITY PERMIT APPLICATION**

PROJECT SUMMARY

General Applicant and Project Information. Summit Carbon Storage #3, LLC (SCS3) is a wholly owned subsidiary of SCS Permanent Carbon Storage LLC (SCS PCS), which is a wholly owned subsidiary of Summit Carbon Solutions, LLC (SCS), as shown in Figure PS-1. SCS3 is requesting consideration of this storage facility permit (SFP) application for the geologic storage of anthropogenic carbon dioxide (CO₂) within Oliver County, North Dakota.

The current mailing address for SCS3, as the storage facility operator of KJ Hintz, is as follows:

Summit Carbon Storage #3, LLC
c/o Summit Carbon Solutions, LLC
Attn: Wade Boeshans
2321 North Loop Drive, Suite 221
Ames, IA 50010-8218

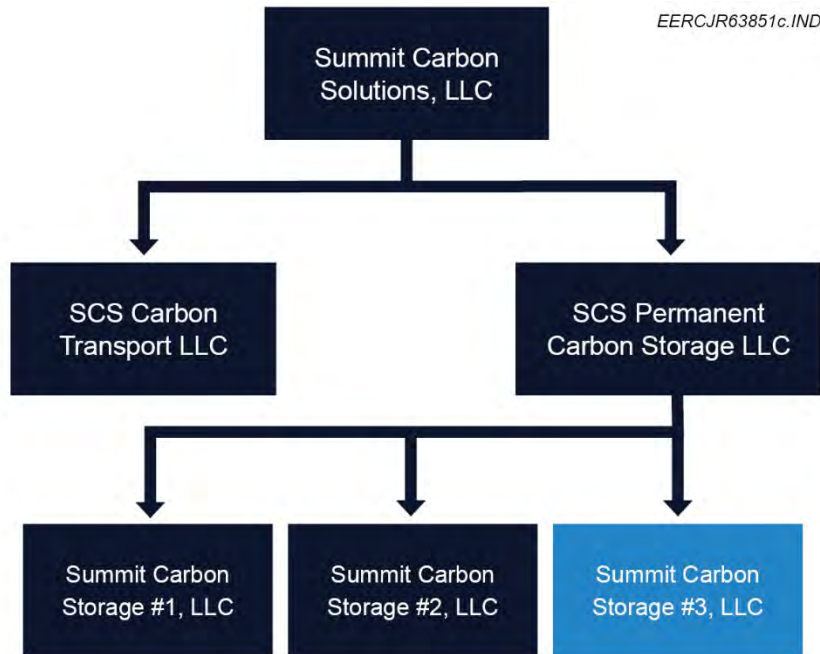


Figure PS-1. SCS3 business structure.

SCS proposes to construct, own, and operate the Midwest Carbon Express (MCE) Project (Figure PS-2), which will capture or receive CO₂ from over 30 anthropogenic sources (biofuel and

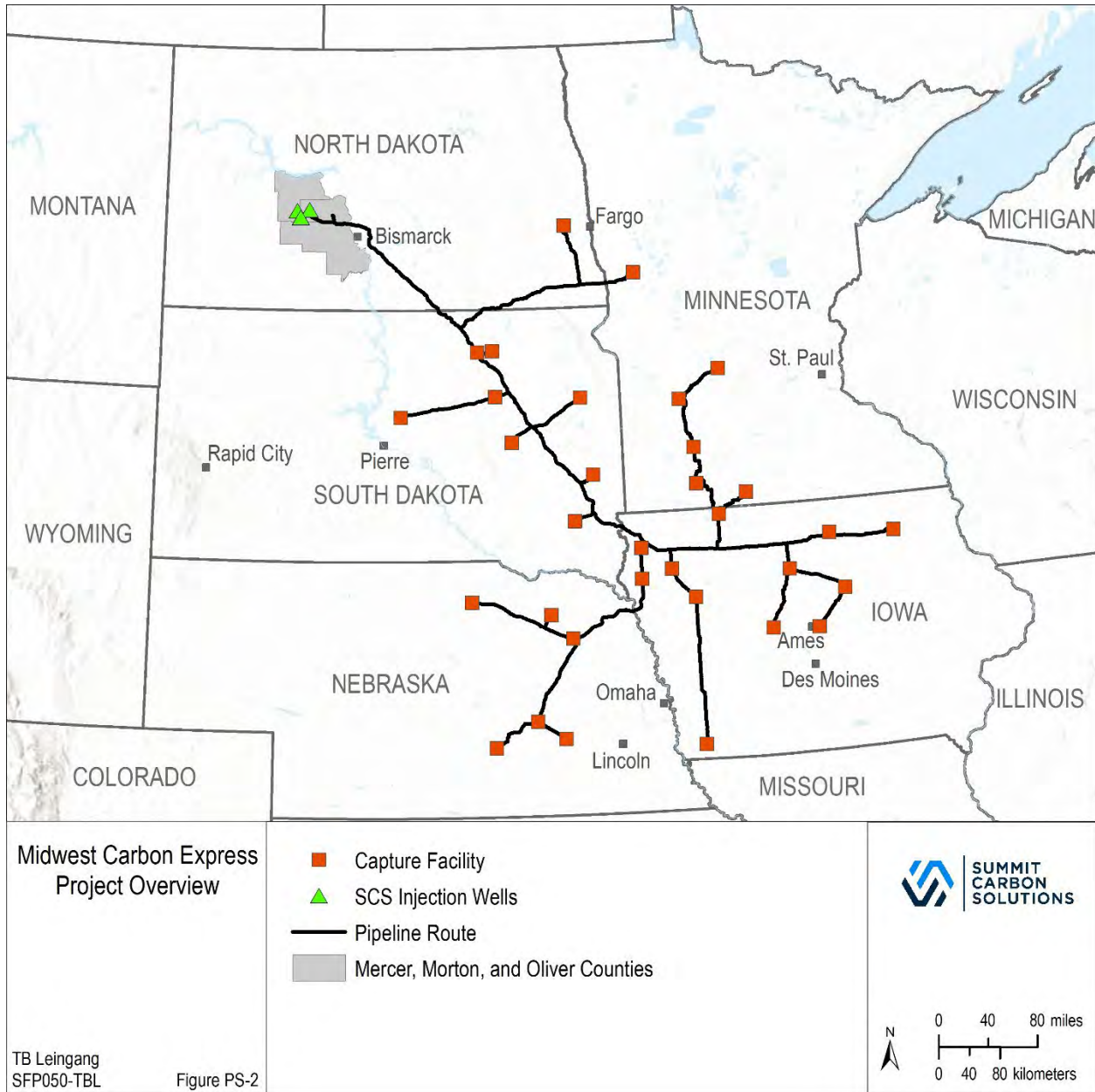


Figure PS-2. MCE Project overview map.

other industrial facilities) across the Midwest and transport the CO₂ via pipeline to North Dakota to be permanently stored within deep underground formations. The commingled stream composition in the MCE pipeline from all sources is anticipated to average $\geq 98.25\%$ CO₂, with less than 1.75% trace quantities of other constituents (Table PS-1). The MCE Project is conservatively designed with a 95% CO₂, 2% O₂, and 3% N₂ specification; therefore, SCS3 is requesting a commercial permit for the operation of the storage facility for injection of a CO₂ stream that will range from 95% CO₂ to $\leq 99.9\%$ CO₂. This commercial permit will provide flexibility to receive CO₂ from a variety of industrial sources.

Table PS-1. Anticipated Average CO₂ Stream Composition

Chemical Content	System Specification
Carbon Dioxide, CO ₂	≥98.25%
Inert, N ₂	≤1.44%
Oxygen, O ₂	≤0.31%
Water, H ₂ O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H ₂ S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition.

The MCE Project will generate approximately 11,400 construction and 1100 operational jobs across the project. The MCE Project contributes to the North Dakota economy by employing workers, paying salaries and benefits, purchasing goods and services from local businesses, contributing to other household consumption, and paying taxes. Capital expenditures in North Dakota from SCS and its contractors during the construction phase will support 1934 annual jobs on average consisting of direct, indirect, and through induced contributions. Likewise, during operations, SCS will support 150 jobs in North Dakota through direct, indirect, and induced contributions. (Ernst and Young, LLP, 2022)

The MCE Project aims to reduce the carbon intensity (CI) of biofuels produced from ethanol facilities and work toward achieving climate goals while creating jobs and other economic benefits across the project. The MCE Project is being designed to transport up to 18 million metric tonnes per annum (MMtpa) of CO₂ via a 2000-mile greenfield pipeline system (permitted through relevant state regulatory agencies and associated processes) to North Dakota for permanent storage approximately 1 mile underground in secure geologic formations across three CO₂ storage facilities owned and operated by Summit Carbon Storage #1, LLC (SCS1); Summit Carbon Storage #2, LLC (SCS2); and SCS3. Within this application, SCS3 was modeled at 129.7 million metric tonnes (MMt) over 20 years while all three storage facilities were modeled over 352 MMt (124.4 TB Leingang + 98.3 BK Fischer + 129.7 KJ Hintz). The KJ Hintz 1 and KJ Hintz 2 were modeled at 3.29 and 3.20 MMtpa, respectively. The captured CO₂ will be injected into the Broom Creek Formation, a sandstone reservoir and saline aquifer underlying the project area (Figure PS-3) and surrounding region. SCS3’s proposed CO₂ storage facility location in North Dakota provides not only favorable and plentiful geologic storage capacity supportive of the MCE Project but also CO₂ storage critical to both the agriculture and energy industries in North Dakota and surrounding regions.

By efficiently utilizing North Dakota’s vast pore-space resource, estimated at approximately 250 billion metric tons of potential (U.S. Department of Energy, 2015), SCS seeks to lower greenhouse gas (GHG) emissions by storing up to 18 MMtpa of CO₂ through the MCE Project across three CO₂ storage facilities owned and operated by SCS1, SCS2, and SCS3, equivalent to removing the annual CO₂ emissions from approximately 3.9 million vehicles. This initiative directly supports U.S. and international climate change policies, goals, and efforts. When placed into service, the MCE Project will provide the largest and single most meaningful technology-

based reduction of carbon emissions in the world. To date, more than 30 ethanol plants across the MCE Project's footprint have entered long-term CO₂ offtake agreements with SCS, opening new economic opportunities to sell their products in markets that pay more for lower-carbon fuels. This improved market accessibility ensures Midwestern ethanol plants' environmental and economic sustainability by significantly reducing their CO₂ emissions footprint and lowering the CI of ethanol-based fuels. Specifically, by participating in the MCE Project and reducing the CI of their product, ethanol producers can compete in low-carbon fuel standard (LCFS) markets for an increased margin. If ethanol facilities are unable to reduce their CI, their access to the LCFS markets will decline, thus limiting their ability to compete in these markets and risking the jobs and communities they help sustain.

The importance of CO₂ pipelines for the ethanol industry and the agriculture industry that relies on them, as well as other anthropogenic industrial CO₂ sources, is further supported by the fact that other proposed carbon capture, pipeline transportation, and geologic storage projects in the Midwest have entered similar agreements with other ethanol plants. The primary challenge for Midwestern ethanol plants and other industrial sources of CO₂ is the lack of suitable and economic geologic formations for storage in proximity to their sites, as well as other economic and practicable solutions for use of the CO₂. The MCE Project offers a solution for this proximity challenge and a service for biofuel and industrial facilities across the Midwest by connecting these facilities via a greenfield pipeline system directly to the project area (Figure PS-2) located within North Dakota.

The project area (Figure PS-3) will consist of three separate CO₂ SFP locations: KJ Hintz, TB Leingang, and BK Fischer (Figure PS-3). Each SFP location will be owned and operated by individual operators: SCS3, SCS1, and SCS2, respectively. Each proposed SFP's surface use area covers approximately 30,000 acres and will include up to two Broom Creek Formation injection wells, a dedicated Broom Creek Formation stratigraphic and reservoir monitoring well, and a dedicated monitoring well(s) for the lowest underground source of drinking water (USDW). Each site will also have associated surface facility infrastructure that will accept CO₂ transported via a CO₂ flowline. SCS3 will own and operate the CO₂ flowline (NDL-326) beginning at the terminus point located in Oliver County (Figure PS-3) of the MCE (North Dakota Public Service Commission Case No. PU 22-391; NDM-106) and consists of approximately 4.8 miles of 16-inch flowline delivering CO₂ downstream to the KJ Hintz 1 and 2 injection wells, located in Oliver County. Operating agreements between SCS1, SCS2, SCS3, SCS PCS, and Summit Carbon Transport LLC will include, but are not limited to, defining financial responsibilities, measurement and custody transfers, data access and data sharing, and general operations including leak detection and reporting, emergency response, monitoring, and maintenance of the NDL-326 as Summit Carbon Transport LLC will be operating the MCE line and respective SCS1, SCS2, and SCS3 flowlines as one system. Likewise, operating agreements will include, but are not limited to, allowing the sharing of geologic models, monitoring equipment and associated data, as well as operational data, leak detection and monitoring, and emergency response actions.

The underlying target storage reservoir for this application, the Broom Creek Formation, and more specifically its CO₂ storage potential, has been the subject of numerous studies conducted by

KJ HINTZ/SLASH LAZY H 5

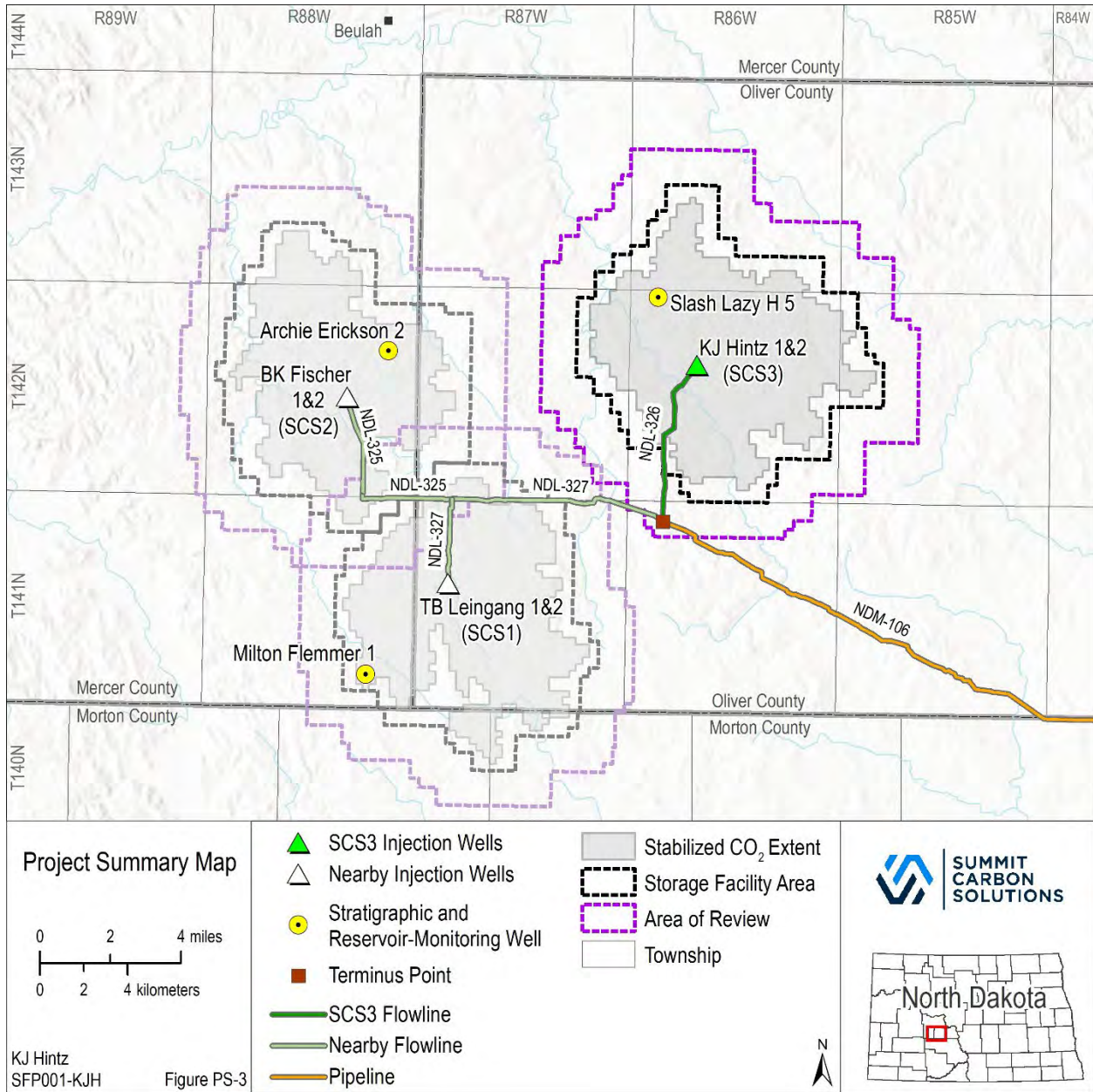


Figure PS-3. Project summary map.

the North Dakota Geological Survey, the U.S. Geological Survey (USGS), and the Energy & Environmental Research Center (EERC). The Broom Creek Formation is an ideal storage candidate because of its superior reservoir quality, depth, impermeable upper and lower confining zones, and expansive areal extent. The suitability of these formations has been further verified by the extensive data sets collected by SCS to illustrate the long-term, safe storage of CO₂ within the proposed project area (Figure PS-3).

SCS collected data and completed a detailed characterization of the injection and confining zones to ensure that the injected CO₂ will remain permanently stored in the subsurface. Data

acquisition began by first obtaining seismic consent from >95% of landowners via surface access agreements, allowing SCS to collect seismic data. Seismic data collection commenced in October 2021 and spanned approximately six townships over 200 square miles. Thereafter, three stratigraphic wells were drilled and completed; drilling operations started in January 2022 and ended in May 2022. The Milton Flemmer 1 [North Dakota Industrial Commission (NDIC) File No. 38594, American Petroleum Institute (API) No. 33-057-00041, Mercer County] well was drilled, cored, and logged into the Deadwood Formation at approximately 12,000 ft, while Archie Erickson 2 (NDIC File No. 38622, API No. 33-057-00042, Mercer County) and Slash Lazy H 5 (NDIC File No. 38701, API No. 33-065-00021, Oliver County) were both drilled, cored, and logged through the Broom Creek Formation, at approximately 6400 and 6100 ft, respectively.

In the following SFP application, SCS3 presents a detailed evaluation of site geology and characterizations that provide the data required to conduct an in-depth evaluation of the proposed SFP. Thus confirming the proposed SCS3 storage facility is suitable to receive and permanently store CO₂. This SFP application has been presented in conjunction with two other SFP applications within the project area (Figure PS-3): TB Leingang (SCS1) and BK Fischer (SCS3).

References

Ernst and Young, LLP, 2022, Economic contributions of Summit Carbon Solutions: Final report prepared for Summit Carbon Solutions, April 2022, 60 p.

U.S. Department of Energy National Energy Technology Laboratory, 2015, Carbon storage atlas, 114 p., 5th ed.: www.netl.doe.gov/sites/default/files/2018-10/ATLAS-V-2015.pdf (accessed 2023).

SECTION 1.0

PORE SPACE ACCESS

1.0 PORE SPACE ACCESS

North Dakota law explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [N.D.C.C.] § 47-31-03). Prior to issuance of the storage facility permit (SFP), North Dakota law mandates the storage operator obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir for geologic storage of CO₂ (N.D.C.C. § 38-22-08[5]). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are, or will be, equitably compensated (N.D.C.C §§ 38-22-08[4], [14]). North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (N.D.C.C. § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential aboveground activities is not included in pore space amalgamation.

Summit Carbon Storage #3, LLC (SCS3) has identified the owners (surface and mineral) (N.D.C.C. §§ 38-22-06[3], [4]; North Dakota Administrative Code [N.D.A.C.] § 43-05-01-08[1]). No mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles of its outside boundary. SCS3 will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO₂ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (N.D.C.C. §§ 38-22-06[3], [4]; N.D.A.C. §§ 43-05-01-08[1], [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 (N.D.C.C. § 47-31-03). The review of pertinent county recorder records identified no severance of pore space from the surface estate or leasing of pore space to a third party prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record.

The map in Figure 1-1 shows the extent of the pore space that will be occupied by CO₂ at the cessation of injection (20 years) and over the life of the project (the stabilized CO₂ extent) as well as the storage facility area boundary and 0.5 miles outside of the storage facility area boundary (the hearing notification area).

KJ HINTZ/SLASH LAZY H 5

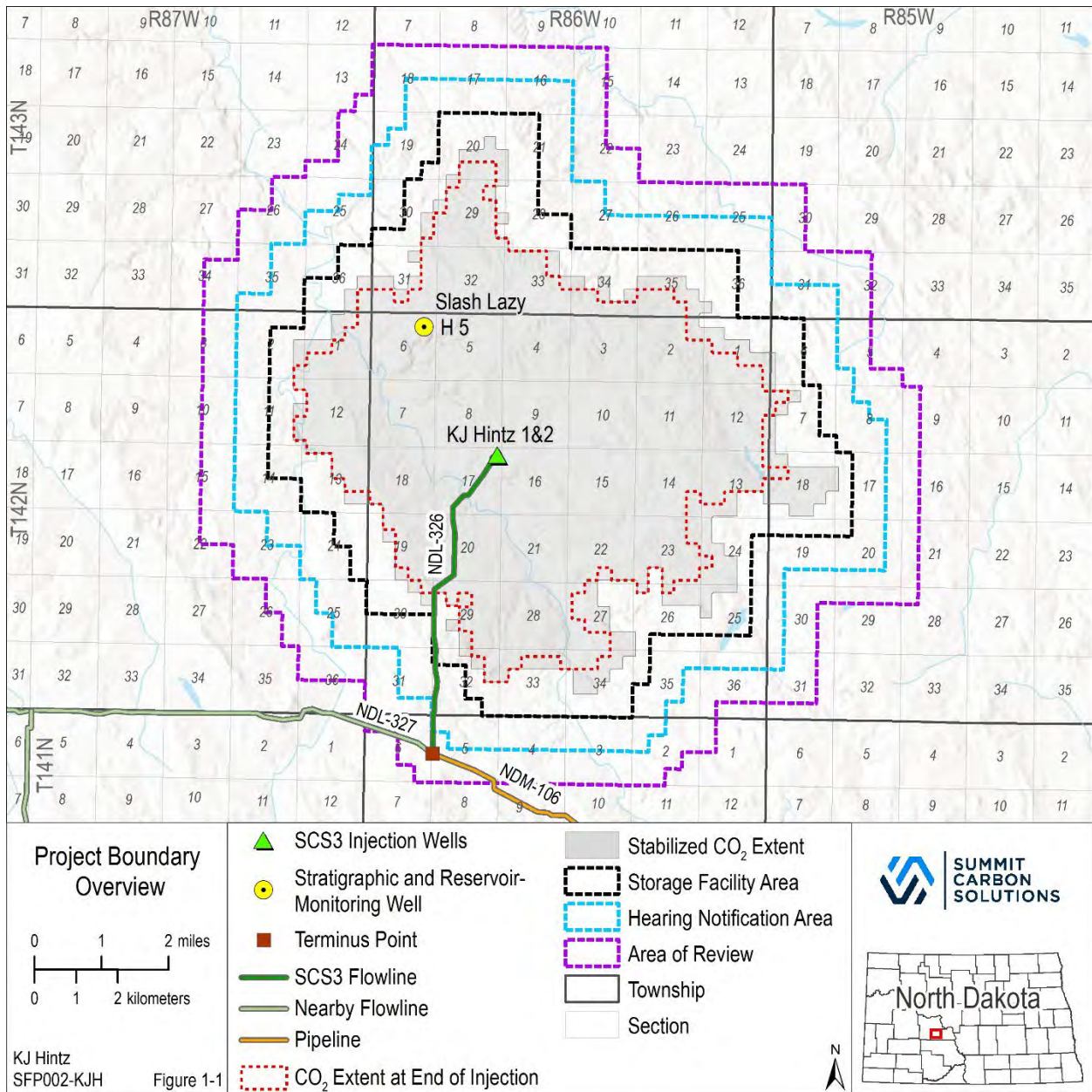


Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20 years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted.

April 8, 2024

HAND DELIVERED

Mr. Mark Bohrer
Assistant Director
North Dakota Industrial Commission
Oil and Gas Division
1016 East Calgary Avenue
Bismarck, North Dakota 58503



**RE: IN THE MATTER OF A HEARING
CALLED ON A MOTION OF THE
COMMISSION TO CONSIDER THE
APPLICATIONS OF SUMMIT CARBON
STORAGE #1, LLC, SUMMIT CARBON
STORAGE #2, LLC AND SUMMIT
CARBON STORAGE #3, LLC FOR THE
GEOLOGIC STORAGE OF CARBON
DIOXIDE IN THE BROOM CREEK
FORMATION**

Dear Mr. Bohrer:

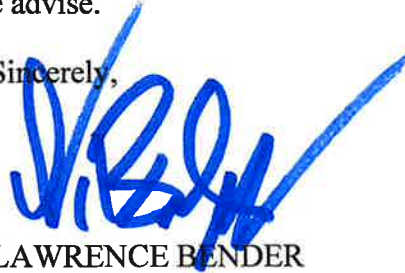
Enclosed herewith for filing in the above-captioned matters, please find copies of the following storage agreements:

1. STORAGE AGREEMENT, SCS #1 BROOM CREEK – SECURE GEOLOGIC STORAGE, MERCER, MORTON, & OLIVER COUNTIES, NORTH DAKOTA;
2. STORAGE AGREEMENT, SCS #2 BROOM CREEK – SECURE GEOLOGIC STORAGE, MERCER & OLIVER COUNTIES, NORTH DAKOTA; and
3. STORAGE AGREEMENT, SCS #3 BROOM CREEK – SECURE GEOLOGIC STORAGE, OLIVER COUNTY, NORTH DAKOTA.

Mr. Mark Bohrer
April 8, 2024
Page 2

Should you have any questions, please advise.

Sincerely,

A handwritten signature in blue ink, appearing to read 'L. Bender', with a long, sweeping flourish extending to the right.

LAWRENCE BENDER

LB/tjg
Enclosures
#82133072v1

cc: Mr. Wade Boeshans *via e-mail* (w/enc.)

**STORAGE AGREEMENT
SCS #3 BROOM CREEK – SECURE GEOLOGIC STORAGE
OLIVER COUNTY, NORTH DAKOTA**

**STORAGE AGREEMENT
SCS #3 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 (NDIC) acting by and through the Department of Mineral Resources.

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 31,238.68 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/Spearfish (Upper Confining Zone), Broom Creek (Injection Zone), and Amsden (Lower Confining Zone) Formation(s) and which are defined as identified by the well logging suite performed at one stratigraphic well, the Slash Lazy H 5 well (NDIC File No. 38701) located in Lot 1, Section 6, Township 142 North, Range 86 West, Oliver County, North Dakota. The Storage Reservoir is defined as the stratigraphic interval from below the top of the Opeche/Spearfish Formation found at a depth of 5,587 feet below the Kelly Bushing, to above the base of the Amsden Formation, found at a depth of 6,421 feet below the Kelly Bushing, as identified by the Array Induction Gamma log run in the Milton Flemmer 1 well (NDIC File No. 38594) located in the NW¼ of the NE¼, Section 35, Township 141 North, Range 88 West, Mercer County, North Dakota. The logging suite included triple combo (Gamma Ray [GR], density, porosity, and resistivity), caliper, spectral GR, combinable magnetic resonance (CMR), dipole sonic including four-arm caliper and inclinometer, and an image log. Further, the acquired logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data obtained from three 3D seismic surveys and one 5-mile long 2D seismic-line covering an area totaling 208 miles in and around the Slash Lazy H 5 stratigraphic well. Formation top depths were picked from the top of the Pierre Formation to the top of the Amsden Formation. The average depth of the top of the Opeche/Spearfish Formation (Upper Confining Zone) across the storage facility area is 5,336 feet total vertical depth (TVD). The

average depth of the base of the Amsden Formation (Lower Confining Zone) across the storage facility area is 6,033 feet TVD. The average thickness of the Storage Reservoir across the storage facility area is 698 feet.

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.”

1.19 **Transfer Storage Facility** has the meaning given such term in Section 3.7 of this Agreement.

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 SCS #3 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 SCS #3 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 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 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 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 (a “Transfer Storage Facility”), *provided that*, the Pore Space ownership between the Storage Facility and Transfer Storage Facility is common.

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 Transfer Storage Facility, *provided that*, the Pore Space ownership between the Storage Facility and Transfer Storage Facility is common.

3.9 **Royalty Payments Upon Transfer.** The transfer or receipt of Storage Substances to or from a Transfer Storage Facility in accordance with Section 3.7 and Section 3.8 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.

3.10 **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.

3.11 **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.** Summit Carbon Storage #3, 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. Subject to Section 3.9, 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.

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

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

Dated: _____, 20__

STORAGE OPERATOR

Summit Carbon Storage #3, LLC

By: _____

[Name]

Its: [Title]

#81618965v1

EXHIBIT A

Tract Map

Attached to and made part of the Storage Agreement
SCS #3 Broom Creek – Secure Geological Storage
Oliver County, North Dakota

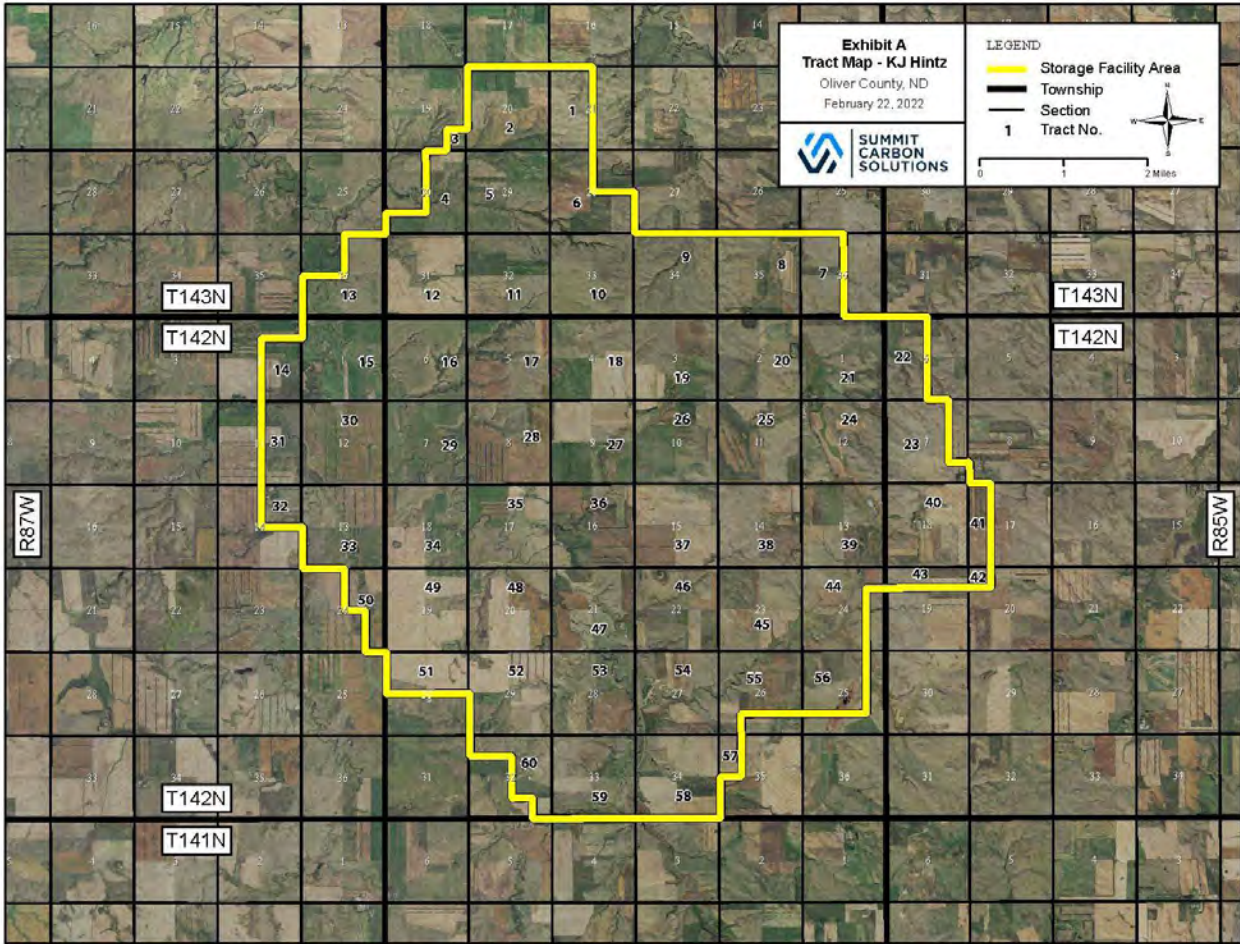


EXHIBIT B

Tract Summary

Attached to and made part of the Storage Agreement
SCS #3 Broom Creek – Secure Geological Storage
Oliver County, North Dakota

<u>Tract No.</u>	<u>Land Description</u>	<u>Total Acres</u>	<u>Owner</u>	<u>Acres Owned</u>	<u>Tract Participation</u>	<u>Storage Facility Participation</u>
1	Section 21-143N-86W	320	Burton Baier & LaRita Baier, aka LaRita R. Baier, as Joint Tenants, Life Estate	320.0000	100.00000000%	1.02437107%
			Joel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
2	Section 20-143N-86W	640	Burton Baier & LaRita Baier, aka LaRita R. Baier, as Joint Tenants, Life Estate	120.0000	18.75000000%	0.38413915%
			Joel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Chad Oberlander	320.0000	50.00000000%	1.02437107%
			Wade L. Unterseher	160.0000	25.00000000%	0.51218553%
			Lindsey J. Robertson & Tammi M. Robertson	40.0000	6.25000000%	0.12804638%
			Wade L. Unterseher, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
3	Section 19-143N-86W	40	Jolaine M. Bornemann, a widow, Life Estate	40.0000	100.00000000%	0.12804638%
			Shawn Allen Bornemann, Remainderman	0.0000	0.00000000%	0.00000000%
4	Section 30-143N-86W	396.38	Wade L. Unterseher & Dorinda L. Unterseher, husband & wife, as Joint Tenants	396.3800	100.00000000%	1.26887564%

5	Section 29-143N-86W	640	Wade L. Unterseher & Dorinda L. Unterseher, husband & wife, as Joint Tenants	320.0000	50.00000000%	1.02437107%
			Joel Baier	160.0000	25.00000000%	0.51218553%
			Burton Baier & LaRita Baier, aka LaRita R. Baier, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Joel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
6	Section 28-143N-86W	480	Burton Baier & LaRita Baier, aka LaRita R. Baier, as Joint Tenants, Life Estate	200.0000	41.66666667%	0.64023192%
			Joel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel Baier, Remainderman	0.0000	0.00000000%	0.00000000%
			Chad Oberlander	240.0000	50.00000000%	0.76827830%
			James E. Goetz & Sharon M. Goetz, husband & wife, as Joint Tenants	40.0000	8.33333333%	0.12804638%
7	Section 36-143N-86W	320	Haley Bohmbach, fka Haley Bargmann	80.0000	25.00000000%	0.25609277%
			Robert Bargmann and Pamela Bargmann, as Joint Tenants, Life Estate	80.0000	25.00000000%	0.25609277%
			Haley Bohmbach, Remainderman	0.0000	0.00000000%	0.00000000%

			Free Karges & Endine Karges, as Joint Tenants	160.0000	50.00000000%	0.51218553%
8	Section 35-143N-86W	640	Sandy Bargmann	320.0000	50.00000000%	1.02437107%
			Carolyn Oster, aka Carolyn L. Oster, Life Estate	320.0000	50.00000000%	1.02437107%
			Lyn Kull, Remainderman	0.0000	0.00000000%	0.00000000%
			Todd Oster, Remainderman	0.0000	0.00000000%	0.00000000%
			Audra Oster, Remainderman	0.0000	0.00000000%	0.00000000%
9	Section 34-143N-86W	640	Carolyn Oster, aka Carolyn L. Oster, Life Estate	640.0000	100.00000000%	2.04874214%
			Lyn Kull, Remainderman	0.0000	0.00000000%	0.00000000%
			Todd Oster, Remainderman	0.0000	0.00000000%	0.00000000%
			Audra Oster, Remainderman	0.0000	0.00000000%	0.00000000%
10	Section 33-143N-86W	640	James E. Goetz & Sharon M. Goetz, husband & wife, as Joint Tenants	640.0000	100.00000000%	2.04874214%
11	Section 32-143N-86W	640	Rachel Baier	320.0000	50.00000000%	1.02437107%
			Wade L. Unterseher & Dorinda L. Unterseher, husband & wife, as Joint Tenants	80.0000	12.50000000%	0.25609277%
			Charmayne Liebelt	80.0000	12.50000000%	0.25609277%
			Clarence Foss, Jr.	160.0000	25.00000000%	0.51218553%
12	Section 31-143N-86W	626.59	Dean D. Unterseher	614.8900	98.13275028%	1.96836102%
			Brandon Unterseher	11.7000	1.86724972%	0.03745357%
13	Section 36-143N-87W	480	Dean D. Unterseher	160.0000	33.33333333%	0.51218553%

			Andrea Joy Blohm	160.0000	33.33333333%	0.51218553%
			State of North Dakota	160.0000	33.33333333%	0.51218553%
14	Section 02-142N-87W	240	Andrea Joy Blohm	80.0000	33.33333333%	0.25609277%
			David Degenstein & Vicki Degenstein, husband & wife, as Joint Tenants	160.0000	66.66666667%	0.51218553%
15	Section 01-142N-87W	640.5	Andrea Joy Blohm	640.5000	100.00000000%	2.05034272%
16	Section 06-142N-86W	628.47	Ross Glass & Sheri Glass, husband & wife, as Joint Tenants	628.4700	100.00000000%	2.01183277%
17	Section 05-142N-86W	639.9	Robert C. Folk & Penelope C. Folk, as Joint Tenants	159.6800	24.95389905%	0.51116116%
			Steven R. Hintz & Stacy Hintz, husband & wife, as Joint Tenants	53.406667	8.34609574%	0.17096326%
			Kevin K. Hintz & Traci Hintz, husband & wife, as Joint Tenants	53.406667	8.34609574%	0.17096326%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Kelly G. Hintz Living Trust dated May 5, 2022 and any amendments thereto	53.406667	8.34609574%	0.17096326%
			Ronald Kessler & Carol Kessler, husband & wife, as Joint Tenants	160.0000	25.00390686%	0.51218553%
			Theresa Christenson	160.0000	25.00390686%	0.51218553%

18	Section 04-142N-86W	637.32	Charles E. Wittenberg, aka Charles Wittenberg & Shiela M. Wittenberg, aka Shiela Wittenberg, husband & wife, as Joint Tenants, Life Estate	318.2900	49.94194439%	1.01889709%
			Dawn D. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
			Jacob H. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
			Steven R. Hintz & Stacy Hintz, husband & wife, as Joint Tenants	53.0100	8.31764263%	0.16969347%
			Kevin K. Hintz & Traci Hintz, husband & wife, as Joint Tenants	53.0100	8.31764263%	0.16969347%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Kelly G. Hintz Living Trust dated May 5, 2022 and any amendments thereto	53.0100	8.31764263%	0.16969347%
			Karen K. Erwin, fka Karen K. Bozenski and Gregory J. Erwin, wife & husband, Life Estate	160.0000	25.10512772%	0.51218553%
			Kristy L. Bozenski, Remainderman	0.0000	0.00000000%	0.00000000%
19	Section 03-142N-86W	635.92	Carolyn Oster, aka Carolyn L. Oster, Life Estate	158.0000	24.84589257%	0.50578321%
			Lyn Kull, Remainderman	0.0000	0.00000000%	0.00000000%

			Todd Oster, Remainderman	0.0000	0.00000000%	0.00000000%
			Audra Oster, Remainderman	0.0000	0.00000000%	0.00000000%
			Charles E. Wittenberg, aka Charles Wittenberg & Shiela M. Wittenberg, aka Shiela Wittenberg, husband & wife, as Joint Tenants, Life Estate	317.9200	49.99370990%	1.01771266%
			Dawn D. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
			Jacob H. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
			Rebecca D. Orgaard & Todd M. Orgaard	160.0000	25.16039753%	0.51218553%
			Marc J. Jensen & Marilyn D. Jensen, husband & wife, as Joint Tenants, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
20	Section 02-142N-86W	636.78	Rebecca D. Orgaard & Todd M. Orgaard	478.5300	75.14840290%	1.53185090%
			Marc J. Jensen & Marilyn D. Jensen, husband & wife, as Joint Tenants, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
			Carolyn Oster, aka Carolyn L. Oster, Life Estate	158.2500	24.85159710%	0.50658350%
			Lyn Kull, Remainderman	0.0000	0.00000000%	0.00000000%

			Todd Oster, Remainderman	0.0000	0.00000000%	0.00000000%
			Audra Oster, Remainderman	0.0000	0.00000000%	0.00000000%
21	Section 01-142N-86W	638.64	Lonnie Henke, Trustee of the Joyce Henke Farm Irrevocable Trust U/A dated 04/19/2018	478.6400	74.94676187%	1.53220303%
			Lonnie Henke	160.0000	25.05323813%	0.51218553%
			Joyce Henke, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
22	Section 06-142N-85W	315.16	Robert Bargmann & Pamela Bargmann, husband & wife, as Joint Tenants, Life Estate	117.2800	37.21284427%	0.37543200%
			Cody Bargmann, Remainderman	0.0000	0.00000000%	0.00000000%
			Delbert Bargmann, aka Delbert H. Bargmann & Audrey Bargmann, aka Audrey I. Bargmann as Joint Tenants, Life Estate	157.8800	50.09518974%	0.50539908%
			Troy Bargmann, Remainderman	0.0000	0.00000000%	0.00000000%
			Justin Bargmann, Remainderman	0.0000	0.00000000%	0.00000000%
			Briana Scheid, Remainderman	0.0000	0.00000000%	0.00000000%
			Cody Bargmann	40.0000	12.69196599%	0.12804638%

23	Section 07-142N-85W	515.28	Blaine Douglas Wilkins & Mikell Roeshell Wilkins, as Joint Tenants	505.2800	98.05930756%	1.61748192%
			Blake L. Wilkins & Patricia A. Wilkins, husband & wife, as Joint Tenants	10.0000	1.94069244%	0.03201160%
24	Section 12-142N-86W	640	Lonnie Henke	578.2000	90.34375000%	1.85091047%
			Robert Kuch	7.8000	1.21875000%	0.02496904%
			Joelene J. Opp or Larry Opp, as Joint Tenants	54.0000	8.43750000%	0.17286262%
25	Section 11-142N-86W	640	Rebecca D. Orgaard & Todd M. Orgaard	600.0000	93.75000000%	1.92069575%
			Marc J. Jensen & Marilyn D. Jensen, husband & wife, as Joint Tenants, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
			Marc J. Jensen & Marilyn D. Jensen, husband & wife, as Joint Tenants, Life Estate	40.0000	6.25000000%	0.12804638%
			Rebecca D. Orgaard & Todd M. Orgaard, as Joint Tenants	0.0000	0.00000000%	0.00000000%
26	Section 10-142N-86W	640	Casey Allen Blohm and Stacy M. Karabensh, Joint Tenants	160.0000	25.00000000%	0.51218553%
			Karen K. Erwin, fka Karen K. Bozenski and Gregory J. Erwin, wife & husband, Life Estate	160.0000	25.00000000%	0.51218553%

			Kristy L. Bozenski, Remainderman	0.0000	0.00000000%	0.00000000%
			Steven R. Hintz & Stacy Hintz, husband & wife, as Joint Tenants	53.3333	8.33333333%	0.17072851%
			Kevin K. Hintz & Traci Hintz, husband & wife, as Joint Tenants	53.3333	8.33333333%	0.17072851%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Kelly G. Hintz Living Trust dated May 5, 2022 and any amendments thereto	53.3333	8.33333333%	0.17072851%
			Charles E. Wittenberg, aka Charles Wittenberg & Shiela M. Wittenberg, aka Shiela Wittenberg, husband & wife, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Dawn D. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
			Jacob H. Wittenberg, Remainderman	0.0000	0.00000000%	0.00000000%
27	Section 09-142N-86W	640	Kenneth E. Hintz & Joyce R. Hintz, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Ginger M. Flemmer, Remainderman	0.0000	0.00000000%	0.00000000%
			Danielle R. Werth, Remainderman	0.0000	0.00000000%	0.00000000%

			Duane D. Kessler & Marilyn A. Kessler, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Warren Kessler, Remainderman	0.0000	0.00000000%	0.00000000%
			Steven R. Hintz & Stacy Hintz, husband & wife, as Joint Tenants	106.0000	16.56250000%	0.33932292%
			Kevin K. Hintz & Traci Hintz, husband & wife, as Joint Tenants	106.0000	16.56250000%	0.33932292%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Kelly G. Hintz Living Trust dated May 5, 2022 and any amendments thereto	106.0000	16.56250000%	0.33932292%
			Cemetery	2.0000	0.31250000%	0.00640232%
28	Section 08-142N-86W	640	Duane D. Kessler & Marilyn A. Kessler, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Kerry Hinsz, Remainderman	0.0000	0.00000000%	0.00000000%
			Donna Soland, Life Estate	160.0000	25.00000000%	0.51218553%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			Jesse Roth	160.0000	25.00000000%	0.51218553%
			Duane D. Kessler & Marilyn A. Kessler, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Warren Kessler, Remainderman	0.0000	0.00000000%	0.00000000%

29	Section 07-142N-86W	629.44	Ross Glass & Sheri Glass, husband & wife, as Joint Tenants	429.4400	68.22572445%	1.37470597%
			Donna Soland, Life Estate	160.0000	25.41942044%	0.51218553%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			Rod W. Allsworth & Luann M Allsworth, husband & wife, as Joint Tenants	40.0000	6.35485511%	0.12804638%
30	Section 12-142N-87W	640	Dennison G. Davis & Brenda K. Davis, husband & wife, as Joint Tenants	317.5000	49.60937500%	1.01636817%
			Mark S. Singer	320.0000	50.00000000%	1.02437107%
			St. John's Evangelical Lutheran Church and Cemetery Committee of Rhein	2.5000	0.39062500%	0.00800290%
31	Section 11-142N-87W	320	Scott Allen Miller & Robyn Marie Miller, husband & wife	320.0000	100.00000000%	1.02437107%
32	Section 14-142N-87W	160	Scott Allen Miller & Robyn Marie Miller, husband & wife	160.0000	100.00000000%	0.51218553%
33	Section 13-142N-87W	640	Mark S. Singer	320.0000	50.00000000%	1.02437107%
			Shirley Riedemann, Life Estate	320.0000	50.00000000%	1.02437107%
			Kyle K. Riedemann, Remainderman	0.0000	0.00000000%	0.00000000%

34	Section 18-142N-86W	632.16	Byron J. Faut & LaVerne J. Faut, as Trustees of the Faut Family Revocable Living Trust	475.6800	75.24677297%	1.52272759%
			Sandra Riedemann	156.4800	24.75322703%	0.50091745%
35	Section 17-142N-86W	640	Kenneth E. Hintz & Joyce R. Hintz, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Ginger M. Flemmer, Remainderman	0.0000	0.00000000%	0.00000000%
			Danielle R. Werth, Remainderman	0.0000	0.00000000%	0.00000000%
			Steven R. Hintz & Stacy Hintz, husband & wife, as Joint Tenants	106.6667	16.66666667%	0.34145702%
			Kevin K. Hintz & Traci Hintz, husband & wife, as Joint Tenants	106.6667	16.66666667%	0.34145702%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Kelly G. Hintz Living Trust dated May 5, 2022 and any amendments thereto	106.6667	16.66666667%	0.34145702%
			Hintz Buffalo Ranch, LLP	160.0000	25.00000000%	0.51218553%
36	Section 16-142N-86W	640	Byron J. Faut & LaVerne J. Faut, as Trustees of the Faut Family Revocable Living Trust	320.0000	50.00000000%	1.02437107%
			Donna Soland, Life Estate	160.0000	25.00000000%	0.51218553%

			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			Joseph Jochim	20.0000	3.12500000%	0.06402319%
			Hintz Buffalo Ranch, LLP	140.0000	21.87500000%	0.44816234%
37	Section 15-142N-86W	640	Byron J. Faut & LaVerne J. Faut, as Trustees of the Faut Family Revocable Living Trust	320.0000	50.00000000%	1.02437107%
			Timothy Faut & Sheila Faut, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Joan M. Bickel	80.0000	12.50000000%	0.25609277%
			John W. Bickel	80.0000	12.50000000%	0.25609277%
38	Section 14-142N-86W	640	Casey A. Blohm	73.7500	11.52343750%	0.23608552%
			Lonnie Henke	205.9500	32.17968750%	0.65927882%
			Tim Doll & Dianne Doll, as Joint Tenants	320.0000	50.00000000%	1.02437107%
			Mike Huber	40.3000	6.29687500%	0.12900673%
39	Section 13-142N-86W	640	Lonnie Henke	319.0000	49.84375000%	1.02116991%
			Roughrider Electric Cooperative, Inc.	1.0000	0.15625000%	0.00320116%
			Mark Albers & Laurie Albers, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Jeffrey Goetz	160.0000	25.00000000%	0.51218553%
40	Section 18-142N-85W	634.36	Blaine Wilkens & Mikell R. Wilkens	472.8600	74.54126994%	1.51370032%
			Kelly Hintz & Judith M. Hintz	160.0000	25.22227127%	0.51218553%
			Kelly Hintz, Co-Trustee of the Hintz Irrevocable Children's Trust, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%

			Pamela Hintz, Co-Trustee of the Hintz Irrevocable Children's Trust, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
			Carla Hintz, Co-Trustee of the Hintz Irrevocable Children's Trust, Contract for Deed Seller	0.0000	0.00000000%	0.00000000%
			Montana-Dakota Utilities Co.	1.5000	0.23645879%	0.00480174%
41	Section 17-142N-85W	160	Raymond W. Hintz, aka Raymond Hintz & Carol Hintz, aka Carol Jenness Hintz, husband & wife, as Joint Tenants	80.0000	50.00000000%	0.25609277%
			Diane E. Wilkens	80.0000	50.00000000%	0.25609277%
			Wesley J. Wilkens & Lori Wilkens, aka Lory Wilkens, husband & wife, as Joint Tenants, Contract for Deed Sellers	0.0000	0.00000000%	0.00000000%
42	Section 20-142N-85W	40	Travis T. Wilkens & Marcia Wilkens, as Joint Tenants	40.0000	100.00000000%	0.12804638%
			Wesley J. Wilkens & Lori Wilkens, aka Lory Wilkens, husband & wife, as Joint Tenants	0.0000	0.00000000%	0.00000000%
43	Section 19-142N-85W	158.58	Blaine Wilkens & Mikell R. Wilkens	80.0000	50.44772355%	0.25609277%

			Kelly Hintz, aka Kelly A. Hintz & Judith M. Hintz, husband & wife, as Joint Tenants	78.5800	49.55227645%	0.25154712%
44	Section 24-142N-86W	520	Michael J. Fedorchak & Julie Fedorchak, fka Julie Liffriq, husband & wife, as Joint Tenants	400.1600	76.95384615%	1.28097602%
			Carissa Severance	39.8400	7.66153846%	0.12753420%
			Leona Doll, aka Leona C. Doll, Life Estate	80.0000	15.38461538%	0.25609277%
			Robert Doll, aka Robert C. Doll, Remainderman	0.0000	0.00000000%	0.00000000%
			Aaron Huck, Remainderman	0.0000	0.00000000%	0.00000000%
45	Section 23-142N-86W	640	Michael Huber & Laura Huber, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Timothy Faut & Sheila Faut, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Dwight K. Huber & Sheila Huber, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Michael J. Fedorchak & Julie Fedorchak, fka Julie Liffriq, husband & wife, as Joint Tenants	160.0000	25.00000000%	0.51218553%

46	Section 22-142N-86W	640	Duane M. Goetz, aka Duane Goetz & Claudia A. Goetz, aka Claudia Goetz, husband & wife, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Darrell O. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Ronald D. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Gerald E. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Lloyd A. Huber & Heidi Huber, husband & wife, as Joint Tenants	320.0000	50.00000000%	1.02437107%
			JoAnn Becker, Life Estate	160.0000	25.00000000%	0.51218553%
			Todd L. Becker, Remainderman	0.0000	0.00000000%	0.00000000%
			Brad T. Becker, Remainderman	0.0000	0.00000000%	0.00000000%
47	Section 21-142N-86W	640	Jeffrey Goetz	320.0000	50.00000000%	1.02437107%
			Austin Hintz	320.0000	50.00000000%	1.02437107%
48	Section 20-142N-86W	640	Steve Hintz & Stacy Hintz, as Joint Tenants	160.0000	25.00000000%	0.51218553%
			Donna Soland, Life Estate	400.0000	62.50000000%	1.28046384%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			Kelly G. Hintz and Ruby J. Hintz, Trustees of the Ruby J. Hintz Living Trust dated May 5, 2022 and any amendments thereto	80.0000	12.50000000%	0.25609277%

49	Section 19-142N-86W	634.72	Donna Soland, Life Estate	474.7200	74.79203428%	1.51965448%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			LaVern Brunmeier, Life Estate	160.0000	25.20796572%	0.51218553%
			Debra Lindquist, Remainderman	0.0000	0.00000000%	0.00000000%
			Maurein Schroeder, Remainderman	0.0000	0.00000000%	0.00000000%
			Pamela Collar, Remainderman	0.0000	0.00000000%	0.00000000%
			Peggy Lewis, fka Peggy Slawson, Remainderman	0.0000	0.00000000%	0.00000000%
50	Section 24-142N-87W	240	Kimberly M. Montoya & Javier Montoya, Trustees, or their successors in trust, under the Kimberly M. Montoya Living Trust, dated November 27, 2018, and any amendments thereto	80.0000	33.33333333%	0.25609277%
			Marvin Fiest & Karen Fiest, husband & wife, as Joint Tenants, Life Estate	80.0000	33.33333333%	0.25609277%
			Amber Myhre, Remainderman	0.0000	0.00000000%	0.00000000%
			Nicole Johnson, Remainderman	0.0000	0.00000000%	0.00000000%
			Kristen Fiest, Remainderman	0.0000	0.00000000%	0.00000000%
			LaVern Brunmeier, Life Estate	80.0000	33.33333333%	0.25609277%

			Debra Lindquist, Remainderman	0.0000	0.00000000%	0.00000000%
			Maurein Schroeder, Remainderman	0.0000	0.00000000%	0.00000000%
			Pamela Collar, Remainderman	0.0000	0.00000000%	0.00000000%
			Peggy Lewis, fka Peggy Slawson, Remainderman	0.0000	0.00000000%	0.00000000%
51	Section 30-142N-86W	318.48	LaVern Brunmeier, Life Estate	158.4800	49.76136649%	0.50731977%
			Debra Lindquist, Remainderman	0.0000	0.00000000%	0.00000000%
			Maurein Schroeder, Remainderman	0.0000	0.00000000%	0.00000000%
			Pamela Collar, Remainderman	0.0000	0.00000000%	0.00000000%
			Peggy Lewis, fka Peggy Slawson, Remainderman	0.0000	0.00000000%	0.00000000%
			Donna Soland, Life Estate	160.0000	50.23863351%	0.51218553%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
52	Section 29-142N-86W	640	Ron Kessler & Carol Kessler, husband & wife, as Joint Tenants	320.0000	50.00000000%	1.02437107%
			Donna Soland, Life Estate	160.0000	25.00000000%	0.51218553%
			Jamie L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%
			Dean Unterseher	160.0000	25.00000000%	0.51218553%
53	Section 28-142N-86W	640	Jeffrey Goetz	320.0000	50.00000000%	1.02437107%
			Lloyd A. Huber	160.0000	25.00000000%	0.51218553%
			Donna Soland, Life Estate	160.0000	25.00000000%	0.51218553%
			Darin L. Soland, Remainderman	0.0000	0.00000000%	0.00000000%

54	Section 27-142N-86W	640	Dwight K. Huber & Sheila Huber, husband & wife, as Joint Tenants	636.0000	99.37500000%	2.03593750%
			Justin D. Huber & Crystal L. Huber	4.0000	0.62500000%	0.01280464%
55	Section 26-142N-86W	520	Duane M. Goetz, aka Duane Goetz & Claudia A. Goetz, aka Claudia Goetz, husband & wife, as Joint Tenants, Life Estate	280.0000	53.84615385%	0.89632468%
			Darrell O. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Ronald D. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Gerald E. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Dwight K. Huber & Sheila Huber, husband & wife, as Joint Tenants	240.0000	46.15384615%	0.76827830%
56	Section 25-142N-86W	360	Michael J. Fedorchak & Julie Fedorchak, fka Julie Liffbrig, husband & wife, as Joint Tenants	80.0000	22.22222222%	0.25609277%
			Duane M. Goetz, aka Duane Goetz & Claudia A. Goetz, aka Claudia Goetz, husband & wife, as Joint Tenants, Life Estate	240.0000	66.66666667%	0.76827830%
			Darrell O. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%

			Ronald D. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Gerald E. Goetz, Remainderman	0.0000	0.00000000%	0.00000000%
			Leona Doll, aka Leona C. Doll, Life Estate	40.0000	11.11111111%	0.12804638%
			Robert Doll, aka Robert C. Doll, Remainderman	0.0000	0.00000000%	0.00000000%
			Aaron Huck, Remainderman	0.0000	0.00000000%	0.00000000%
57	Section 35-142N-86W	80	Joan M. Bickel	40.0000	50.00000000%	0.12804638%
			John W. Bickel	40.0000	50.00000000%	0.12804638%
58	Section 34-142N-86W	640	Joan M. Bickel	40.0000	6.25000000%	0.12804638%
			John W. Bickel	40.0000	6.25000000%	0.12804638%
			Albers Farms, LLP, a North Dakota Limited Liability Partnership	240.0000	37.50000000%	0.76827830%
			William F. Breimeier & Norma J. Breimeier, husband & wife, as Joint Tenants, Life Estate	140.0000	21.87500000%	0.44816234%
			Sandra L. Wolf, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel M. Breimeier, Remainderman	0.0000	0.00000000%	0.00000000%
			Ruth Mae Yoder	20.0000	3.12500000%	0.06402319%
			Bruce Huber & Diane Huber, as Joint Tenants	160.0000	25.00000000%	0.51218553%
59	Section 33-142N-86W	640	Dwight Huber & Sheila Huber, husband & wife, as Joint Tenants	320.0000	50.00000000%	1.02437107%
			Craig Albers	160.0000	25.00000000%	0.51218553%

			William F. Breimeier & Norma J. Breimeier, husband & wife, as Joint Tenants, Life Estate	160.0000	25.00000000%	0.51218553%
			Sandra L. Wolf, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel M. Breimeier, Remainderman	0.0000	0.00000000%	0.00000000%
60	Section 32-142N-86W	360	Lynn Hammer	200.0000	55.55555556%	0.64023192%
			Bryan T. Reinhardt and Tammy J. Reinhardt, husband & wife, as Joint Tenants	120.0000	33.33333333%	0.38413915%
			William F. Breimeier & Norma J. Breimeier, husband & wife, as Joint Tenants, Life Estate	40.0000	11.11111111%	0.12804638%
			Sandra L. Wolf, Remainderman	0.0000	0.00000000%	0.00000000%
			Rachel M. Breimeier, Remainderman	0.0000	0.00000000%	0.00000000%
	Total Acres:	31,238.68		31,238.68	Total Participation:	100.00000000%

EXHIBIT C

Tract Participation Factors

Attached to and made part of the Storage Agreement
SCS #3 Broom Creek – Secure Geological Storage
Oliver County, North Dakota

Tract No.	Land Description	Acres	Tract Participation Factor
1	Section 21-143N-86W	320	1.02437107%
2	Section 20-143N-86W	640	2.04874214%
3	Section 19-143N-86W	40	0.12804638%
4	Section 30-143N-86W	396.38	1.26887564%
5	Section 29-143N-86W	640	2.04874214%
6	Section 28-143N-86W	480	1.53655660%
7	Section 36-143N-86W	320	1.02437107%
8	Section 35-143N-86W	640	2.04874214%
9	Section 34-143N-86W	640	2.04874214%
10	Section 33-143N-86W	640	2.04874214%
11	Section 32-143N-86W	640	2.04874214%
12	Section 31-143N-86W	626.59	2.00581459%
13	Section 36-143N-87W	480	1.53655660%
14	Section 02-142N-87W	240	0.76827830%
15	Section 01-142N-87W	640.5	2.05034272%
16	Section 06-142N-86W	628.47	2.01183277%
17	Section 05-142N-86W	639.9	2.04842202%
18	Section 04-142N-86W	637.32	2.04016303%
19	Section 03-142N-86W	635.92	2.03568141%
20	Section 02-142N-86W	636.78	2.03843440%
21	Section 01-142N-86W	638.64	2.04438856%
22	Section 06-142N-85W	315.16	1.00887746%
23	Section 07-142N-85W	515.28	1.64949351%
24	Section 12-142N-86W	640	2.04874214%
25	Section 11-142N-86W	640	2.04874214%
26	Section 10-142N-86W	640	2.04874214%
27	Section 09-142N-86W	640	2.04874214%
28	Section 08-142N-86W	640	2.04874214%
29	Section 07-142N-86W	629.44	2.01493789%
30	Section 12-142N-87W	640	2.04874214%
31	Section 11-142N-87W	320	1.02437107%
32	Section 14-142N-87W	160	0.51218553%
33	Section 13-142N-87W	640	2.04874214%
34	Section 18-142N-86W	632.16	2.02364505%
35	Section 17-142N-86W	640	2.04874214%

36	Section 16-142N-86W	640	2.04874214%
37	Section 15-142N-86W	640	2.04874214%
38	Section 14-142N-86W	640	2.04874214%
39	Section 13-142N-86W	640	2.04874214%
40	Section 18-142N-85W	634.36	2.03068760%
41	Section 17-142N-85W	160	0.51218553%
42	Section 20-142N-85W	40	0.12804638%
43	Section 19-142N-85W	158.58	0.50763989%
44	Section 24-142N-86W	520	1.66460299%
45	Section 23-142N-86W	640	2.04874214%
46	Section 22-142N-86W	640	2.04874214%
47	Section 21-142N-86W	640	2.04874214%
48	Section 20-142N-86W	640	2.04874214%
49	Section 18-142N-86W	634.72	2.03184001%
50	Section 24-142N-87W	240	0.76827830%
51	Section 30-142N-86W	318.48	1.01950531%
52	Section 29-142N-86W	640	2.04874214%
53	Section 28-142N-86W	640	2.04874214%
54	Section 27-142N-86W	640	2.04874214%
55	Section 26-142N-86W	520	1.66460299%
56	Section 25-142N-86W	360	1.15241745%
57	Section 35-142N-86W	80	0.25609277%
58	Section 34-142N-86W	640	2.04874214%
59	Section 33-142N-86W	640	2.04874214%
60	Section 32-142N-86W	360	1.15241745%
Total:		31,238.68	100.00000000%

EXHIBIT D

Form of Pore Space Lease

Attached to and made part of the Storage Agreement
SCS #3 Broom Creek – Secure Geological Storage
Oliver County, North Dakota

PORE SPACE LEASE

THIS PORE SPACE LEASE (this “Lease”) is made effective as of the Effective Date (as defined below) by and between _____, whose address is _____, (whether one or more, “Lessor”), and Summit Carbon Storage #3, LLC, a Delaware limited liability company, whose address is 2321 N. Loop Dr., Ames, IA 50010 (whether one or more, “Lessee”). Lessor and Lessee may be individually referred to herein as a “Party” and collectively as the “Parties”.

1. Leased Premises. Lessor, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, does hereby grant, demise, lease and let unto Lessee for Lessee’s geologic storage operations and other purposes set forth herein, the lands described and incorporated herein by reference in Exhibit A attached (the “Leased Premises”).

2. Term.

(a) Initial and Primary Term. This Lease shall commence on the date Lessee executes this Lease (“Effective Date”) and continue for an initial term of twenty (20) years (“Initial Term”) unless sooner terminated in accordance with the terms of this Lease. As consideration for the Initial Term, Lessee shall pay to Lessor TWENTY-FIVE and NO/100 DOLLARS (\$25.00) per acre as a single one-time bonus payment, and an annual rental of Four and No/100 Dollars (\$4.00) per acre on or before January 1 of each year of the Initial Term. The annual rental shall increase by TWO percent (2.0%) commencing on January 1, 2026 and on January 1 each year thereafter. The first year’s rental has been paid in full, the receipt and sufficiency of which is hereby acknowledged by Lessor. Lessee may, at any time prior to the expiration of the Initial Term, elect to extend the Initial Term for up to an additional twenty (20) years by providing written notice to Lessor and payment of One Hundred and No/100 Dollars (\$100.00) per acre (the Initial Term, together with all extensions shall be referred to herein as the “Primary Term”). For the avoidance of doubt, Lessor’s consent to any such extension will not be required provided that the foregoing payment is tendered to Lessor prior to the expiration of the Initial Term. Lessee shall pay to Lessor the annual rentals when due throughout the Primary Term; *provided, however*, Lessee shall not be liable to Lessor for annual rentals with respect to any portion of the Leased Premises which are or become subject to Permit as set forth in Section 2(b), below.

(b) Operational Term. This Lease shall continue beyond the Primary Term for so long as any portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises (including without limitation, any Reservoirs) are subject to a permit issued by the North Dakota Industrial Commission (the "Commission") (a "Permit") or under the ownership or control of the State of North Dakota; *provided, however*, that all of Lessee's obligations under this Lease shall

terminate upon issuance of a certificate of project completion pursuant to Chapter 38-22 of the North Dakota Century Code (the "Operational Term"). If the Primary Term expires and no portion of the Leased Premises or Lessee's storage facilities located in, on or under the Leased Premises is subject to a Permit, 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. As consideration for the Operational Term, Lessee shall pay to Lessor the royalty set forth in Section 3, below.

3. Royalty. Lessee shall pay to Lessor its proportionate share of FIFTY cents (\$0.50) per metric ton of carbon dioxide (CO₂) injected into the reservoirs and subsurface pore spaces (as used herein, such terms shall have the meanings set forth in Chapter 38-22 and Chapter 47-31 of the North Dakota Century Code), stratum or strata underlying the Leased Premises (collectively, "Reservoirs"), or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith. The royalty shall increase TEN percent (10.0%) on January 1, 2026 and an additional TEN percent (10.0%) every five years thereafter, as outlined on attached Exhibit B. The quantity of CO₂ so injected shall be measured by meters installed by Lessee. Lessor's "proportionate share" shall be determined on a net acre basis and the Parties hereby stipulate that the acreage set forth in Section 1 shall be used to calculate Lessor's proportionate share. The quantity of carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith shall be determined through the use of metering equipment installed and operated by Lessee at the injection site. All royalties due hereunder for carbon dioxide injected into the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith during any calendar month shall be paid to Lessor annually on or before March 31st for the prior year's injection volumes. Lessor and Lessee agree that this Lease shall continue as specified herein even in the absence of injection operations and the payment of royalties.

4. Right to Pore Space/Storage of Carbon Dioxide. Lessor grants to Lessee the exclusive right to inject and store carbon dioxide (CO₂) and other incidental gaseous substances into the Reservoirs, together with the right to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances. Lessor shall not grant any other person the right to inject or store CO₂ or any other incidental substances.

5. Facility Right of Ways/Compensation. Lessor grants Lessee the right of reasonable use of the surface of the Leased Premises, including without limitation, the rights of ingress and egress over the Leased Premises together with the right of way over, under and across the Leased Premises and the right from time to time to construct, replace, inspect, repair, monitor, maintain, relocate, change the size of such surface or subsurface facilities on the Leased Premises that Lessee determines necessary or desirable for Lessee's storage operations, including, but not limited to fences, pipelines, tanks, reservoirs, electric and communication lines, roadways, underground facilities and equipment, surface facilities and equipment, buildings, structures and other such facilities and appurtenances, (each a "Facility" and collectively the "Facilities"); *provided, however,* that (i) Lessee shall provide Lessor with notice of operations and an offer of damage, disruption and loss of production payments, as each may be applicable, prior to the installation of any such Facilities on the Leased Premises, and (ii) the agreed up terms, including the amount of damage payments to be paid to Lessor, shall be memorialized in an agreement separate from this Lease, such agreement to be consistent with the grant contained herein. Lessee shall be entitled to proceed with the installation of the Facilities while the separate agreement and amount of damage, disruption or loss is being agreed or determined. Lessee shall have the further right to fence the perimeter of any Facility on the Leased Premises and sufficiently illuminate the site for the safety and security of operations.

6. Amalgamation. Lessee, in its sole discretion, shall have the right and power, at any time and from time to time during the term of this Lease to pool, unitize, or amalgamate any reservoirs or subsurface pore spaces, stratum or strata underlying the Leased Premises with any other lands or interests into which such reservoirs or subsurface pore spaces extend and document such unit in accordance with applicable law or agency order. Amalgamated units shall be of such shape and dimensions as Lessee may elect and as are approved by the Commission. Amalgamated areas may include, but are not required to include, land upon which injection or extraction wells have been completed or upon which the injection and/or withdrawal of carbon dioxide and/or related gaseous substances 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 is located. Amalgamating in one or more instances shall, if approved by the Commission, not exhaust the rights of Lessee to amalgamate Reservoirs or portions of Reservoirs into other amalgamation areas, and Lessee shall have the recurring right to revise any amalgamated area formed under this Lease by expansion or contraction or both. Lessee may dissolve any amalgamated area at any time and document such dissolution by recording an instrument in accordance with applicable law or agency order. Lessee shall have the right to negotiate, on behalf of and as agent for Lessor, any unit, amalgamation, storage or operating agreements with respect to amalgamation of reservoir or pore space interests underlying the Leased Premises or the operation of any amalgamated areas formed under such agreements. To the extent any of the terms of such agreements conflict with the terms of this Lease, the terms of such agreements shall control, and the provisions of this Lease shall be deemed modified to conform to the terms, conditions, and provisions of any such agreements which are approved by the Commission.

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

8. Ownership. Lessee shall at all times be the owner of (i) the carbon dioxide and other gaseous substances stored in the Reservoirs or any reservoirs or subsurface pore spaces, stratum or strata unitized or amalgamated therewith, and (ii) all equipment, buildings, structures, facilities and other property constructed or installed by Lessee on the Leased Premises. Lessee shall have the right, but not the obligation, at any time during this Lease to remove all or any portion of the property or fixtures placed by Lessee on the Lease Premises. Notwithstanding the foregoing, title to the storage facility and to the stored carbon dioxide or other gaseous substances shall be transferred to the State of North Dakota upon issuance of a certificate of project completion by the Commission in accordance with Chapter 38-22 of the North Dakota Century Code.

9. 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 oil and gas, that may exist on or under the Leased Premises.

10. Surrender of Leased Premises. Lessee shall have the right, but not the obligation, at any time from time to time to execute and deliver to Lessor a surrender and/or release covering all or any part of the Leased Premises for which the Reservoirs are 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. Lessee shall be able to surrender the any and or all of the Leased Premises if not utilizing the Reservoirs located thereunder.

11. Hold Harmless and Indemnification. The Lessee agrees to defend, indemnify, and hold harmless Lessor from any claims by any person that are a direct result of the Lessee's use of the Leased Premises or Reservoirs. Notwithstanding the foregoing, such indemnity/hold harmless obligation excludes (i) any claim or cause of action, or alleged or threatened claim or cause of action, damage, judgment, interest, penalty or other loss arising or resulting from the negligence or intentional acts of Lessor or Lessor's agents, invitees, or licensees; or third parties, and (ii) any claim for exemplary, punitive, special or consequential damages claimed by Lessor. Lessee further accepts liability and indemnifies Lessor for reasonable costs, expenses and attorneys' fees incurred in establishing and litigating the indemnification coverage provided above. The legal defense provided by Lessee to the Lessor under this paragraph must be free of any conflicts of interest even if this requires Lessee to retain separate legal counsel for Lessor.

12. 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 about the Leased Premises by Lessor or any third-party 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. As used herein, “hazardous substances” shall have the meaning set forth in the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and any amendments thereto, or any other local, state or federal statutes.

13. Termination. A material violation or default of any terms of this Lease by Lessee shall be grounds for termination of the Lease. Lessor shall give Lessee written notice of violation or default and Lessee shall have sixty (60) days after receipt of said notice to substantially cure such violations or defaults. If Lessee fails to substantially cure such violations or defaults within the 60-day cure period, Lessor may terminate the Lease; provided that if it is not possible to cure such violations or defaults within the 60-day cure period, Lessee shall have a reasonable longer period of time to cure such violations or defaults provided it commences cure within the initial 60-day cure period and thereafter diligently pursues such cure. Lessee may terminate the lease with thirty (30) days written notice to Lessor. Upon termination of this Lease, Lessee shall have one hundred eighty (180) days to remove all facilities and property of Lessee located on the Leased Premises. For the avoidance of doubt, Lessee shall not be required to remove any CO₂ or other incidental gaseous substances injected into the Reservoirs.

14. Taxes. Lessee shall pay all taxes, if any, levied against its personal property or on its improvements to the Leased Premises. Lessor shall pay for all real estate taxes and other assessments levied upon the Leased Premises. Lessee shall have the right to pay all taxes, assessments and other fees on behalf of Lessor and to deduct the amount so paid from other payments due to Lessor hereunder.

15. Conduct of Operations. In conducting its operations hereunder, Lessee shall use its best efforts to comply with all applicable laws, rules and regulations and ordinances pertaining thereto. Lessee reserves and shall have the right to challenge and/or appeal any law, ruling, regulation, order or other determination and to carry on its operations in accordance with Lessee’s interpretation of the same, pending final determination.

16. Force Majeure. Should Lessee be prevented from complying with any express or implied covenant of this Lease or from utilizing the Lease Premises for underground storage purposes by reason of scarcity of or an inability to obtain or to use equipment or material or failure or breakdown of equipment, or by operation of force majeure, any federal or state law or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and the primary term of 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.

17. Surface Damage Compensation. The bonus and royalty amounts contemplated and paid to Lessor hereunder is compensation for, among other things, damages sustained by Lessor for lost land value, lost use of and access to Lessor's land and lost value of improvements, if any and to the extent applicable. Subject to Lessee's obligation to compensate Lessor for the installation of any Facilities on the Leased Premises pursuant to Section 5 of this Agreement, Lessor agrees that such compensation is just and adequate for any and all such damages and all other damages which Lessor may sustain as a result of Lessee's use of the property for its storage operations.

18. Warranty of Title and Quiet Enjoyment. Lessor represents and warrants to Lessee that Lessor is the owner of the surface of the Leased Premises and the pore space located thereunder. Lessor hereby warrants and agrees to defend title to the Leased Premises and the pore space located thereunder 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 royalty payments or any other payments due to Lessor toward satisfying the same.

Lessor warrants that, except as disclosed to Lessee in writing, there are no liens, encumbrances, leases, mortgages, deeds of trust, options, or other exceptions to Lessor's fee title ownership of the Leased Premises (collectively, "Liens") which are not recorded in the public records of the County in which the Leased Premises is located. Lienholders (including tenants), whether or not their Liens are recorded, shall be Lessor's responsibility, and Lessor shall cooperate with Lessee to obtain a non-disturbance agreement from each party that holds a Lien (recorded or unrecorded) that might interfere with Lessee's rights under this Lease. A non-disturbance agreement is an agreement between Lessee and a lienholder which provides that the lienholder shall not disturb Lessee's possession or rights under the Lease or terminate this Lease so long as Lessor is not entitled to terminate this Lease under the provisions hereof.

Lessor shall have the quiet use and enjoyment of the Leased Premises in accordance with the terms of this Lease. Lessor's activities and any grant of rights Lessor makes to any person or entity, whether located on the Leased Premises or elsewhere, shall not, currently or prospectively, materially interfere with activities permitted hereunder. If Lessor has any right to select, determine, prohibit or control the location of sites for drilling, exploitation, production and/or exploration of minerals, hydrocarbons, water, gravel, or any other similar resource in, to or under the Lease Premises, then Lessor shall exercise such right so as to minimize interference with any of the foregoing.

19. Environmental Incentives and Tax Credits. Lessee shall be the owner of (i) any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to Lessee's geologic storage operations, including any avoided emissions and the reporting rights related to these avoided emissions, such as 26 U.S.C. §45Q Tax Credits, and any other attributes of Lessee's ownership of the Facilities and Lessee's geologic storage operations ("Environmental Attributes"), and (ii) any and all credits, rebates, subsidies, payments or other incentives that relate to the use of technology incorporated into Lessee's geologic storage operations, environmental benefits of such operations, or other similar programs available from any regulated entity or any governmental authority ("Environmental Incentives"). Lessee is further entitled to the benefit of 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 Lessee's geologic storage operations ("Tax Credits"). Lessor shall (i) cooperate with Lessee in obtaining, securing and transferring all Environmental Attributes and Environmental Incentives and the benefit of all Tax Credits, and (ii) shall allow Lessee to take any actions necessary to install additional equipment on the Facilities to comply with all monitoring and reporting obligations, and allow Lessee's personnel to enter the premises and collect any data Lessee requires to satisfy its obligations required in connection with obtaining Tax Credits and Environmental Attributes. 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.

20. Assignment. The rights of either Party hereto may be assigned in whole or part. The assigning party shall provide written notice of any assignment within sixty (60) days after such assignment has become effective; *provided, however*, that an assigning party's failure to deliver written notice of assignment within such 60-day period shall not be deemed a breach of this Lease unless such failure is willful and intentional. The Lessor's consent shall not be required for an assignment by the Lessee of this Lease, whether by way of a collateral assignment to its financiers or otherwise.

21. Change of Ownership. No change of ownership in the Leased Premises shall be binding on the Lessee for purpose of making payments to Lessor hereunder until the date Lessor, or Lessor's successors or assigns, furnishes Lessee the recorded original or a certified copy of the instrument evidencing the change in ownership. The Lessor's consent shall not be required for a change in the direct or indirect control of the Lessee.

22. Notices. All notices required to be given under this Lease shall be in writing and addressed to the respective Party at the addresses set forth at the beginning of this Lease unless otherwise directed by either Party.

23. 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.

24. Notice of Lease. This Lease shall not be recorded in the real property records. Lessee shall cause a memorandum of this Lease to be recorded in the real property records of the county in which the Leased Premises are situated.

25. Confidentiality. Lessor shall 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 or operations on the Leased Premises or on any other lands, the capacity and suitability of any Reservoir or reservoirs and subsurface pore spaces, stratum or strata unitized or amalgamated therewith, 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.

26. 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.

27. Severability. If any provision of this Lease is found to be invalid, illegal or unenforceable in any respect, such provision shall be deemed to be severed from this Agreement, and the validity, legality and enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

28. Governing Law. This Lease shall be governed by, construed and enforced in accordance with the laws of the State of North Dakota and the Parties hereby submit to the jurisdiction of the state or federal courts located in the State of North Dakota.

29. Further Assurances. 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 this Lease and all documents required to obtain any necessary government approvals.

30. Entire Agreement. This Lease constitutes the entire agreement between the Parties and supersedes all prior negotiations, undertakings, notices, memoranda and agreement between the Parties, whether oral or written, with respect to the subject matter hereof. This Lease may only be amended or modified by a written agreement duly executed by Lessor and Lessee.

31. Cooperation with Financiers. The Lessor hereby acknowledges and consents that Lessee may grant a collateral assignment or leasehold mortgage of Lessee's rights under this Lease to Lessee's debt financiers, it being understood that such collateral assignment or leasehold mortgage would only encumber the leasehold interest created hereunder.

32. Favored Nations. If, at any time within the twelve (12) month period following the Effective Date, Lessee enters into a pore space lease agreement with a third party landowner covering any part of Lessee's storage facility ("Third-Party Lease"), and if any of the payments specified in the Third-Party Lease would have been more favorable to Lessor had Lessor executed a lease agreement similar to the Third-Party Lease, then Lessor and Lessee will amend this Lease so that it reflects compensation terms similar to the Third-Party Lease, and Lessee will pay to Lessor the additional compensation, if any, that Lessor would have been paid had Lessor signed a lease agreement similar to the Third-Party Lease. For the purposes of this Section 32, "Lessee's storage facility" shall mean any storage facility (as such term is defined in ch. 38-22 of the North Dakota Century Code) operated by Lessee within a ten (10) mile radius of the Leased Premises which is subject to a permit is issued by the Commission pursuant to ch. 38-22 of the North Dakota Century Code.

33. Electronic Signatures. This Lease, and any amendments hereto, to the extent signed and delivered by means of electronic transmission in portable document format (pdf) or by DocuSign or similar electronic signature process, shall be treated in all manner and respects as an original contract and shall be considered to have the same binding legal effect as if it were the original signed version thereof delivered in person.

34. Insurance. Lessee shall obtain and maintain in force commercial general liability insurance covering the Facilities and Lessee's activities on the Leased Premises at all times during the term of this Lease, with a minimum occurrence and aggregate limit of one million dollars (\$1,000,000). Such insurance coverage for the Facilities and Leased Premises may be provided as part of a blanket policy that covers other Facilities or properties as well. Any such policies shall include Lessor as an additional insured. Lessee, or its insurer, shall provide thirty (30) days prior written notice (except ten (10) days for nonpayment of premium) to Lessor of any cancellation. Lessee shall provide Lessor with copies of certificates of insurance evidencing this coverage upon request by Lessor.

IN WITNESS WHEREOF, the Parties have executed this Lease effective for all purposes as of the Effective Date.

LESSOR:

By: _____

Print: _____

By: _____

Print: _____

LESSEE:

SUMMIT CARBON STORAGE #3, LLC

By: _____

Print: _____

Its: _____

EXHIBIT A

Leased Premises

EXHIBIT B

Royalty Escalation Provision

This Lease is subject to a Royalty Escalation. The royalty shall increase TEN percent (10.0%) on January 1, 2026, and an additional TEN percent (10.0%) every five years thereafter. For the avoidance of doubt, the royalty to be paid is calculated below:

<u>Date:</u>	<u>Royalty Rate:</u>
Beginning January 1, 2026	\$0.550
Beginning January 1, 2031	\$0.605
Beginning January 1, 2036	\$0.666
Beginning January 1, 2041	\$0.733
Beginning January 1, 2046	\$0.806
Beginning January 1, 2051	\$0.887
Beginning January 1, 2056	\$0.976
Beginning January 1, 2061	\$1.074
Beginning January 1, 2066	\$1.181
Beginning January 1, 2071	\$1.299
Beginning January 1, 2076	\$1.429

SUMMIT CARBON STORAGE #3, LLC

Dated: _____

By: _____

Print: _____

Its: _____

KJ HINTZ

UNIT LEGAL DESCRIPTION

OLIVER COUNTY

Township 143 North, Range 86 West

Section 19: SESE

Section 20: All

Section 21: W2

Section 28: NW, S2

Section 29: All

Section 30: Lot 4 (36.38), SESW (a/k/a S2SW), E2

Section 31: Lots 1 (36.43), 2 (36.57), 3 (36.74), 4 (36.85), E2W2, E2 (a/k/a All)

Section 32: All

Section 33: All

Section 34: All

Section 35: All

Section 36: W2

[Containing 6,022.97 acres]

Township 143 North, Range 87 West

Section 36: E2, SW

[Containing 480.00 acres]

Township 142 North, Range 85 West

Section 06: Lots 3 (39.61), 4 (38.76), 5 (38.91), 6 (38.93), 7 (38.95), SENW, E2SW (a/k/a W2)

Section 07: Lots 1 (38.93), 2 (38.86), 3 (38.78), 4 (38.71), E2W2, W2NE, NWSE, S2SE (a/k/a All)

Section 17: W2W2

Section 18: Lots 1 (38.66), 2 (38.61), 3 (38.57), 4 (38.52), E2W2, E2 (a/k/a All)

Section 19: Lot 1 (38.58), N2NE, NENW (a/k/a N2N2)

Section 20: NWNW

[Containing 1823.38]

Township 142 North, Range 86 West

Section 01: Lots 1 (39.92), 2 (39.75), 3 (39.57), 4 (39.40), S2N2, S2 (a/k/a All)

Section 02: Lots 1 (39.30), 2 (39.23), 3 (39.16), 4 (39.09), S2N2, S2 (a/k/a All)

Section 03: Lots 1 (39.01), 2 (38.99), 3 (38.97), 4 (38.95), S2N2, S2 (a/k/a All)

Section 04: Lots 1 (39.05), 2 (39.24), 3 (39.42), 4 (39.61), S2N2, S2 (a/k/a All)

Section 05: Lots 1 (39.77), 2 (39.91), 3 (40.04), 4 (40.18), S2N2, S2 (a/k/a All)

Section 06: Lots 1 (40.21), 2 (40.15), 3 (40.09), 4 (36.96), 5 (36.98), 6 (37.02), 7 (37.06) S2NE, SENW, E2SW, SE (a/k/a All)

Section 07: Lots 1 (37.15), 2 (37.29), 3 (37.43), 4 (37.57), E2W2, E2 (a/k/a All)

Section 08: All

Section 09: All

Section 10: All

Section 11: All

Section 12: All

Section 13: All

Section 14: All

Section 15: All

Section 16: All

Section 17: All

Section 18: Lots 1 (37.74), 2 (37.94), 3 (38.14), 4 (38.34), E2W2, E2 (a/k/a All)

Section 19: Lots 1 (38.50), 2 (38.62), 3 (38.74), 4 (38.86), E2W2, E2 (a/k/a All)

Section 20: All

Section 21: All

Section 22: All

Section 23: All

Section 24: NENE, W2E2, W2

Section 25: E2NE, NW, N2SW, NWSE

Section 26: N2, NESW, W2SW, N2SE

Section 27: All

Section 28: All

Section 29: All

Section 30: Lots 1 (39.08), 2 (39.40) E2NW, NE (a/k/a N2)

Section 32: NE, N2NW, N2SE, SESE

Section 33: All

Section 34: All

Section 35: W2NW

[Containing 20,031.83]

Township 142 North, Range 87 West

Section 01: Lots 1 (40.02), 2 (40.09), 3 (40.16), 4 (40.23), S2N2, S2 (a/k/a All)

Section 02: S2NE, SE

Section 11: E2

Section 12: All

Section 13: All

Section 14: NE

Section 24: NE, E2SE

[Containing 2,880.50]

UNIT LEGAL DESCRIPTION BY TRACT NUMBER

Tract 1 – Oliver County

Township 143 North, Range 86 West
Section 21: W2 containing 320 acres

Tract 2 – Oliver County

Township 143 North, Range 86 West
Section 20: All containing 640 acres

Tract 3 – Oliver County

Township 143 North, Range 86 West
Section 19: SESE containing 40 acres

Tract 4 – Oliver County

Township 143 North, Range 86 West
Section 30: Lot 4 (36.38), SESW, E2 containing 396.38 acres

Tract 5 – Oliver County

Township 143 North, Range 86 West
Section 29: All containing 640 acres

Tract 6 – Oliver County

Township 143 North, Range 86 West
Section 28: NW, S2 containing 480 acres

Tract 7 – Oliver County

Township 143 North, Range 86 West
Section 36: W2 containing 320 acres

Tract 8 – Oliver County

Township 143 North, Range 86 West
Section 35: All containing 640 acres

Tract 9 – Oliver County

Township 143 North, Range 86 West
Section 34: All containing 640 acres

Tract 10 – Oliver County

Township 143 North, Range 86 West
Section 33: All containing 640 acres

Tract 11 – Oliver County

Township 143 North, Range 86 West
Section 32: All containing 640 acres

Tract 12 – Oliver County

Township 143 North, Range 86 West
Section 31: Lots 1 (36.43), 2 (36.57), 3 (36.74), 4 (36.85), E2W2, E2 [aka All]
containing 626.59 acres

Tract 13 – Oliver County

Township 143 North, Range 87 West
Section 36: E2, SW containing 480 acres

Tract 14 – Oliver County

Township 142 North, Range 87 West
Section 02: S2NE, SE containing 240 acres

Tract 15 – Oliver County

Township 142 North, Range 87 West
Section 01: Lots 1 (40.02), 2 (40.09), 3 (40.16), 4 (40.23), S2N2, S2 [aka All] containing 640.5 acres

Tract 16 – Oliver County

Township 142 North, Range 86 West
Section 06: Lots 1 (40.21), 2 (40.15), 3 (40.09), 4 (36.96), 5 (36.98), 6 (37.02), 7 (37.06) S2NE, SENW, E2SW, SE [aka All] containing 628.47 acres

Tract 17 – Oliver County

Township 142 North, Range 86 West
Section 05: Lots 1 (39.77), 2 (39.91), 3 (40.04), 4 (40.18), S2N2, S2 [aka All] containing 639.90 acres

Tract 18 – Oliver County

Township 142 North, Range 86 West
Section 04: Lots 1 (39.05), 2 (39.24), 3 (39.42), 4 (39.61), S2N2, S2 [aka All] containing 637.32 acres

Tract 19 – Oliver County

Township 142 North, Range 86 West
Section 03: Lots 1 (39.01), 2 (38.99), 3 (38.97), 4 (38.95), S2N2, S2 [aka All] containing 635.92 acres

Tract 20 – Oliver County

Township 142 North, Range 86 West
Section 02: Lots 1 (39.30), 2 (39.23), 3 (39.16), 4 (39.09), S2N2, S2 [aka All] containing 636.78

Tract 21 – Oliver County

Township 142 North, Range 86 West
Section 01: Lots 1 (39.92), 2 (39.75), 3 (39.57), 4 (39.40), S2N2, S2 [aka All] containing 638.64 acres

Tract 22 – Oliver County

Township 142 North, Range 85 West
Section 06: Lots 3 (39.61), 4 (38.76), 5 (38.91), 6 (38.93), 7 (38.95), SENW, E2SW containing 315.16 acres

Tract 23 – Oliver County

Township 142 North, Range 85 West
Section 07: Lots 1 (38.93), 2 (38.86), 3 (38.78), 4 (38.71), W2NE, E2W2, NWSE, S2SE containing 515.28 acres

Tract 24 – Oliver County

Township 142 North, Range 86 West
Section 12: All containing 640 acres

Tract 25 – Oliver County

Township 142 North, Range 86 West

Section 11: All containing 640 acres

Tract 26 – Oliver County

Township 142 North, Range 86 West

Section 10: All containing 640 acres

Tract 27 – Oliver County

Township 142 North, Range 86 West

Section 09: All containing 640 acres

Tract 28 – Oliver County

Township 142 North, Range 86 West

Section 08: All containing 640 acres

Tract 29 – Oliver County

Township 142 North, Range 86 West

Section 07: Lots 1 (37.15), 2 (37.29), 3 (37.43), 4 (37.57), E2W2, E2 [aka All]
containing 629.44 acres

Tract 30 – Oliver County

Township 142 North, Range 87 West

Section 12: All containing 640 acres

Tract 31 – Oliver County

Township 142 North, Range 87 West

Section 11: E2 containing 320 acres

Tract 32 – Oliver County

Township 142 North, Range 87 West

Section 14: NE containing 160 acres

Tract 33 – Oliver County

Township 142 North, Range 87 West

Section 13: All containing 640 acres

Tract 34 – Oliver County

Township 142 North, Range 86 West

Section 18: Lots 1 (37.74), 2 (37.94), 3 (38.14), 4 (38.34), E2W2, E2 [aka All]
containing 632.16 acres

Tract 35 – Oliver County

Township 142 North, Range 86 West

Section 17: All containing 640 acres

Tract 36 – Oliver County

Township 142 North, Range 86 West

Section 16: All containing 640 acres

Tract 37 – Oliver County

Township 142 North, Range 86 West

Section 15: All containing 640 acres

Tract 38 – Oliver County

Township 142 North, Range 86 West

Section 14: All containing 640 acres

Tract 39 – Oliver County

Township 142 North, Range 86 West

Section 13: All containing 640 acres

Tract 40 – Oliver County

Township 142 North, Range 85 West

Section 18: Lots 1 (38.66), 2 (38.61), 3 (38.57), 4 (38.52), E2W2, E2 [aka All]
containing 634.36 acres

Tract 41 – Oliver County

Township 142 North, Range 85 West

Section 17: W2W2 containing 160 acres

Tract 42 – Oliver County

Township 142 North, Range 85 West

Section 20: NWNW containing 40.00 acres

Tract 43 – Oliver County

Township 142 North, Range 85 West

Section 19: Lot 1 (38.58), N2NE, NENW containing 158.58 acres

Tract 44 – Oliver County

Township 142 North, Range 86 West

Section 24: NENE, W2E2, W2 containing 520 acres

Tract 45 – Oliver County

Township 142 North, Range 86 West

Section 23: All containing 640 acres

Tract 46 – Oliver County

Township 142 North, Range 86 West

Section 22: All containing 640 acres

Tract 47 – Oliver County

Township 142 North, Range 86 West

Section 21: All containing 640 acres

Tract 48 – Oliver County

Township 142 North, Range 86 West

Section 20: All containing 640 acres

Tract 49 – Oliver County

Township 142 North, Range 86 West

Section 19: Lots 1 (38.50), 2 (38.62), 3 (38.74), 4 (38.86), E2W2, E2 [aka All]
containing 634.72

Tract 50 – Oliver County

Township 142 North, Range 87 West

Section 24: NE, E2SE containing 240 acres

Tract 51 – Oliver County

Township 142 North, Range 86 West

Section 30: Lots 1 (39.08), 2 (39.40) E2NW, NE containing 318.48 acres

Tract 52 – Oliver County

Township 142 North, Range 86 West
Section 29: All containing 640 acres

Tract 53 – Oliver County

Township 142 North, Range 86 West
Section 28: All containing 640 acres

Tract 54 – Oliver County

Township 142 North, Range 86 West
Section 27: All containing 640 acres

Tract 55 – Oliver County

Township 142 North, Range 86 West
Section 26: N2, NESW, W2SW, N2SE containing 520 acres

Tract 56 – Oliver County

Township 142 North, Range 86 West
Section 25: E2NE, NW, N2SW, NWSE containing 360 acres

Tract 57 – Oliver County

Township 142 North, Range 86 West
Section 35: W2NW containing 80 acres

Tract 58 – Oliver County

Township 142 North, Range 86 West
Section 34: All containing 640 acres

Tract 59 – Oliver County

Township 142 North, Range 86 West
Section 33: All containing 640 acres

Tract 60 – Oliver County

Township 142 North, Range 86 West
Section 32: NE, N2NW, N2SE, SESE containing 360 acres



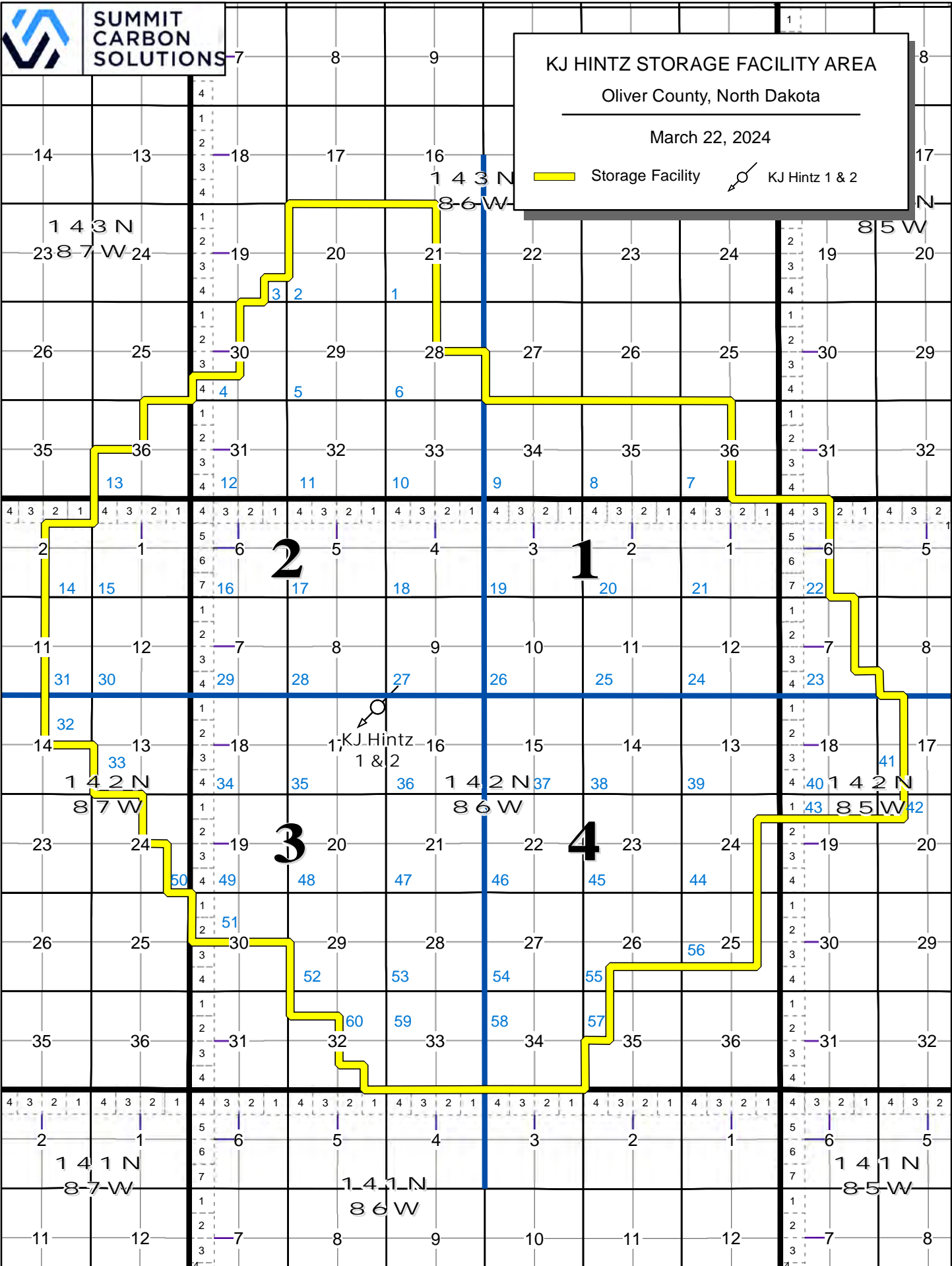
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CARBON
SOLUTIONS

KJ HINTZ STORAGE FACILITY AREA

Oliver County, North Dakota

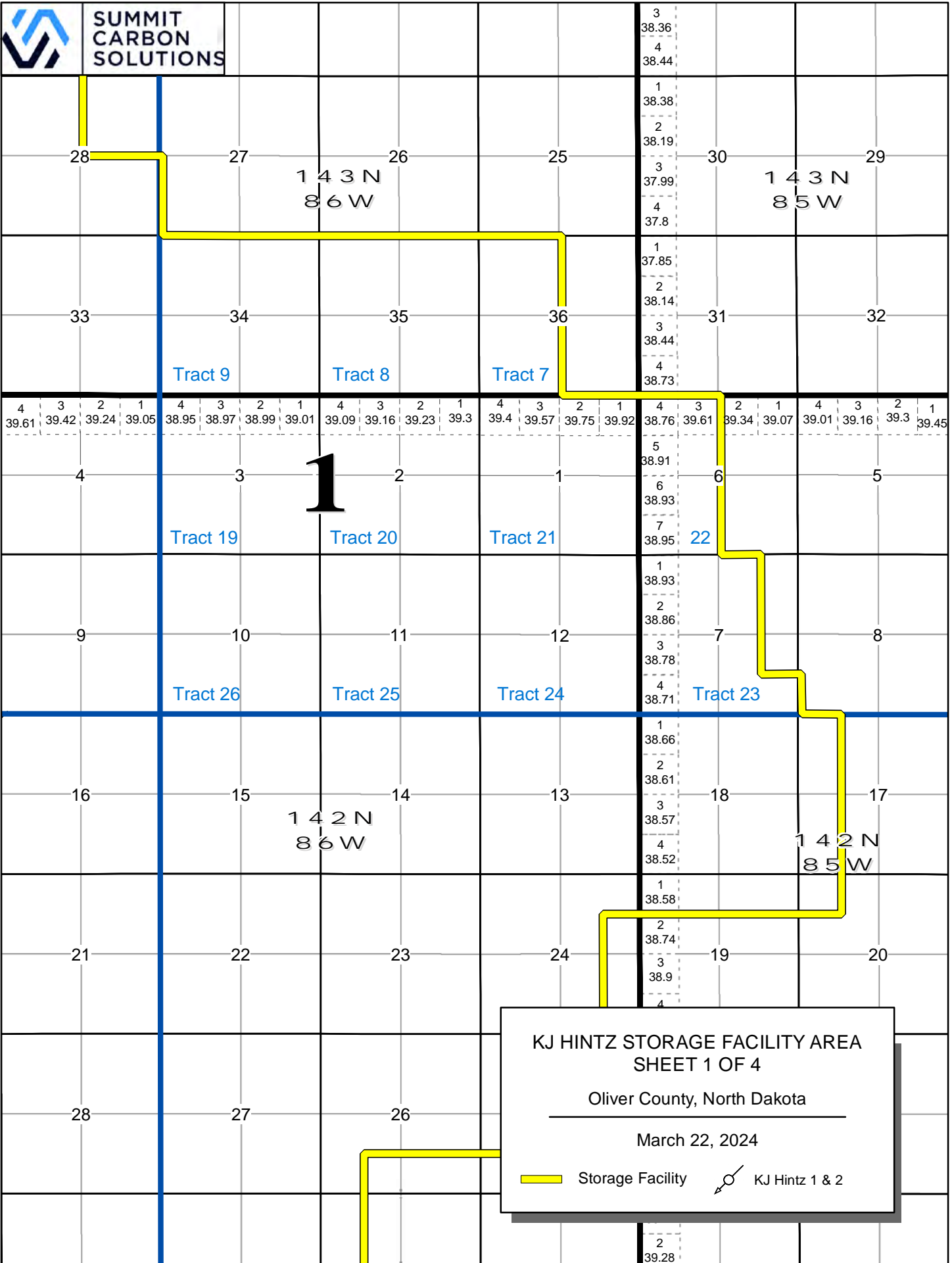
March 22, 2024

Storage Facility KJ Hintz 1 & 2







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KJ HINTZ STORAGE FACILITY AREA
SHEET 1 OF 4

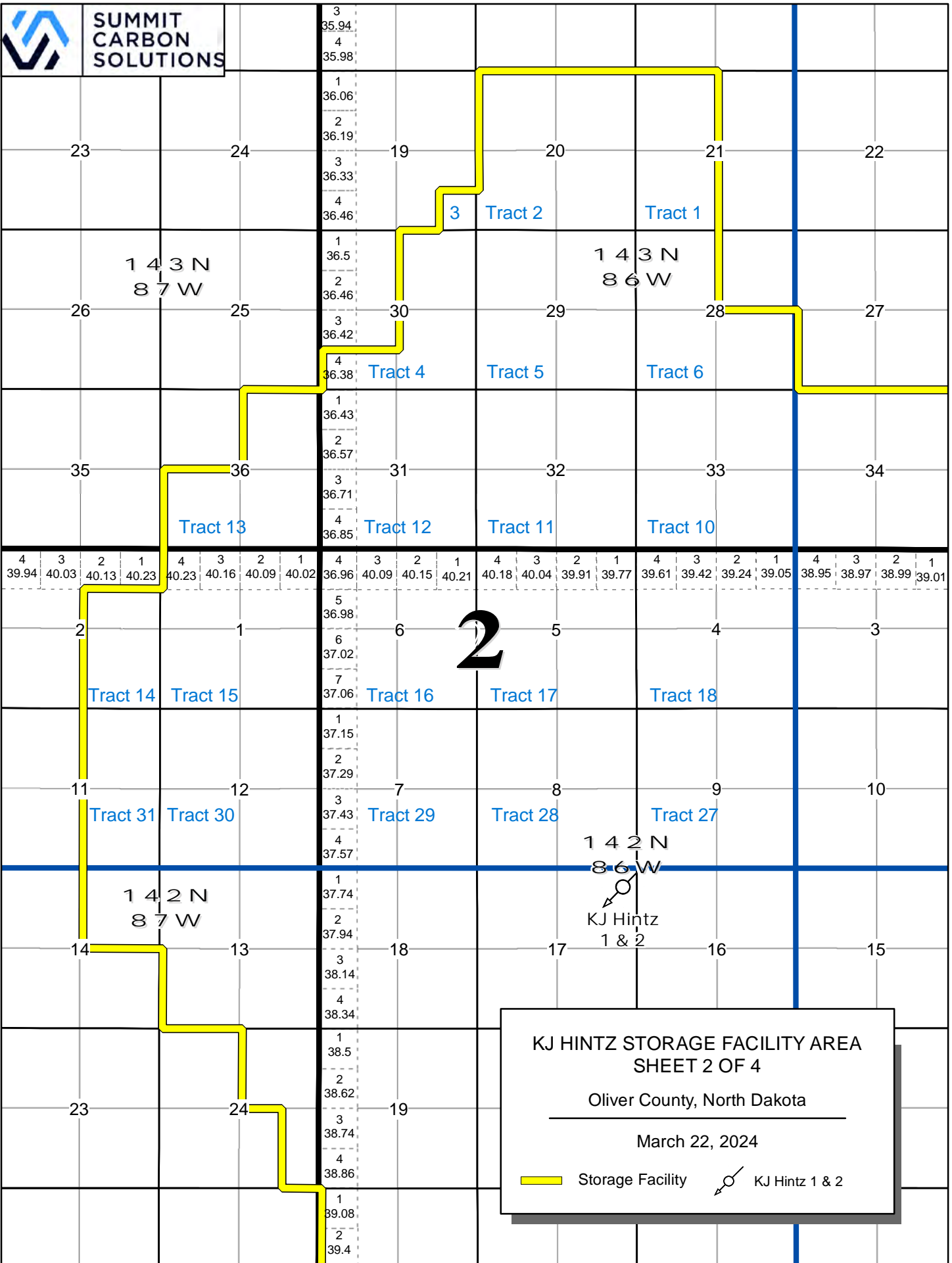
Oliver County, North Dakota

March 22, 2024



 Storage Facility  KJ Hintz 1 & 2



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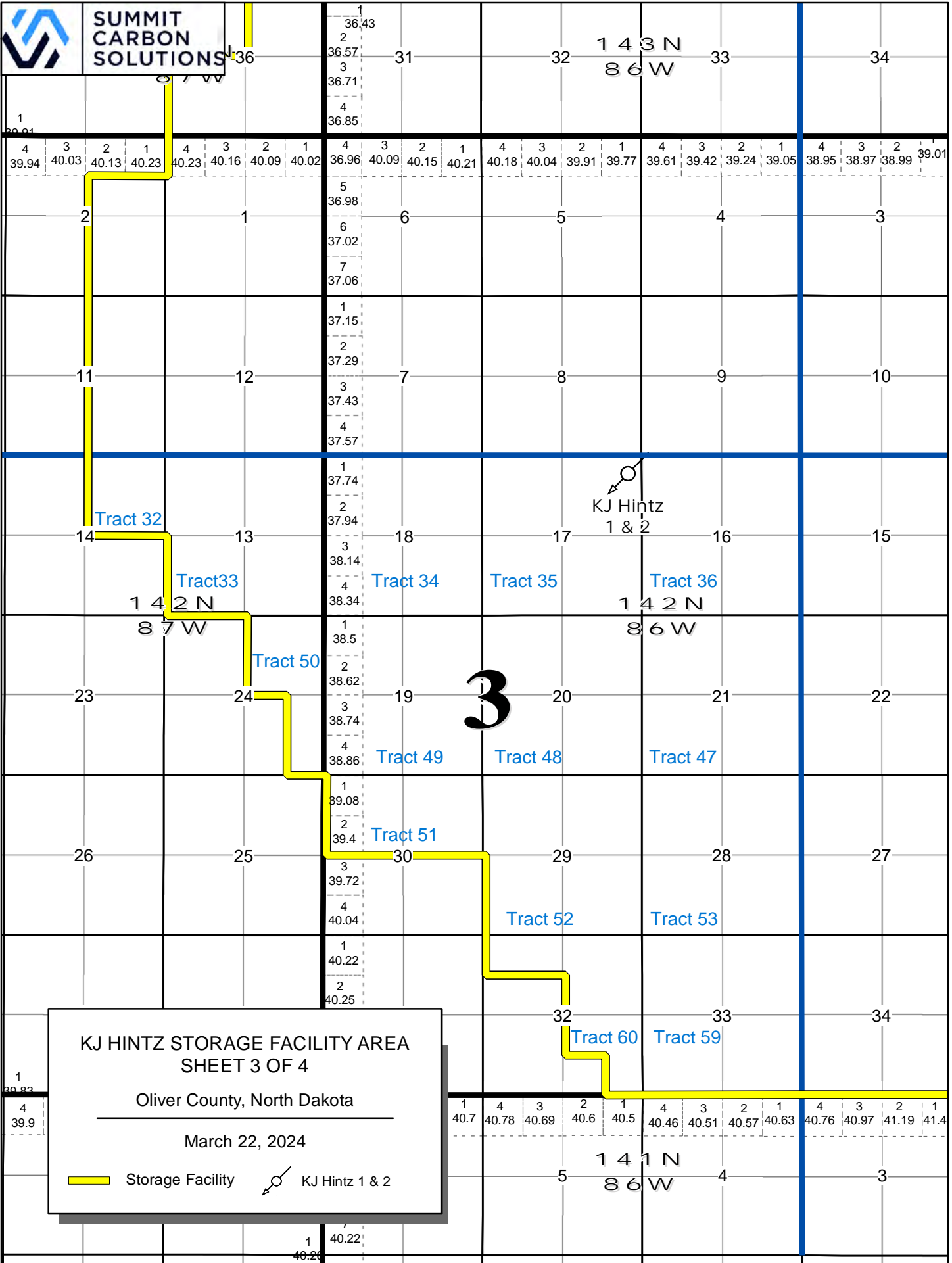


KJ HINTZ STORAGE FACILITY AREA
 SHEET 2 OF 4
 Oliver County, North Dakota
 March 22, 2024

 Storage Facility
  KJ Hintz 1 & 2



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**KJ HINTZ STORAGE FACILITY AREA
SHEET 3 OF 4**

Oliver County, North Dakota

March 22, 2024

Storage Facility



KJ Hintz 1 & 2



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34 1 4 3 N
8 6 W

35

36

37

35 2

38.14

3

38.44

4

38.73

31 1 4 3 N
8 5 W

32

2

39.77

1

4

3

2

1

4

3

2

1

4

3

2

1

4

3

2

1

4

3

2

1

4

3

2

1

4

3

39.3

39.77

39.61

39.42

39.24

39.05

38.95

38.97

38.99

39.01

39.09

39.16

39.23

39.3

39.4

39.57

39.75

39.92

38.76

39.61

39.34

39.07

39.01

39.16

5

38.91

6

38.93

7

38.95

1

38.93

2

38.86

3

38.78

4

38.71

1

38.66

2

38.61

3

38.57

4

38.52

1

38.58

2

38.74

3

38.9

4

39.06

1

39.19

2

39.3

3

39.4

4

39.51

1

39.47

2

39.28

3

39.35

4

39.64



KJ Hintz
1 & 2

16

Tract 37

1 4 2 N
8 6 W

4

Tract 45

Tract 39

Tract 40

1 4 2 N
8 5 W

Tract 43

21

Tract 46

Tract 45

Tract 44

28

Tract 54

Tract 55

Tract 56

33

Tract 58

57

40.5

40.46

40.51

40.57

40.63

40.76

40.97

41.19

41.4

41.47

41.42

41.37

1 4 1 N
8 6 W

KJ HINTZ STORAGE FACILITY AREA
SHEET 4 OF 4

Oliver County, North Dakota

March 22, 2024

Storage Facility KJ Hintz 1 & 2

39.82

9.76

5

39.35

1

39.64

5

SECTION 2.0
GEOLOGIC EXHIBITS

2.0 GEOLOGIC EXHIBITS

2.1 Overview of Project Area Geology

The KJ Hintz is situated approximately 13 miles southeast of Beulah, 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 by the Energy & Environmental Research Center (EERC) via the Plains CO₂ Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO₂ storage due, in part, to the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015).

The CO₂ storage reservoir for this project is the Broom Creek Formation, a predominantly sandstone formation 5568 ft below kelly bushing (KB) elevation at the stratigraphic and reservoir-monitoring well (Slash Lazy H 5: NDIC File No. 38701) (Figure 2-2). Unconformably overlying the Broom Creek Formation is 179 ft of predominantly siltstone with interbedded dolostone and anhydrite of the undifferentiated Opeche and Spearfish Formations, hereafter referred to as the Opeche/Spearfish Formation. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish Formation (above) and Opeche Formation (below); since the Minnekahta Formation is absent at the Slash Lazy H 5 location, and due to the similarity in lithology between the two formations, the Opeche and Spearfish are undifferentiated. The Opeche/Spearfish Formation serves as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, anhydrite, sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche/Spearfish, Broom Creek, and Amsden Formations comprise the CO₂ storage complex for KJ Hintz (Table 2-1).

Including the Opeche/Spearfish Formation, there are 1116 ft (thickness in Slash Lazy H 5) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2571 ft (thickness at the Slash Lazy H 5) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).

KJ HINTZ/SLASH LAZY H 5

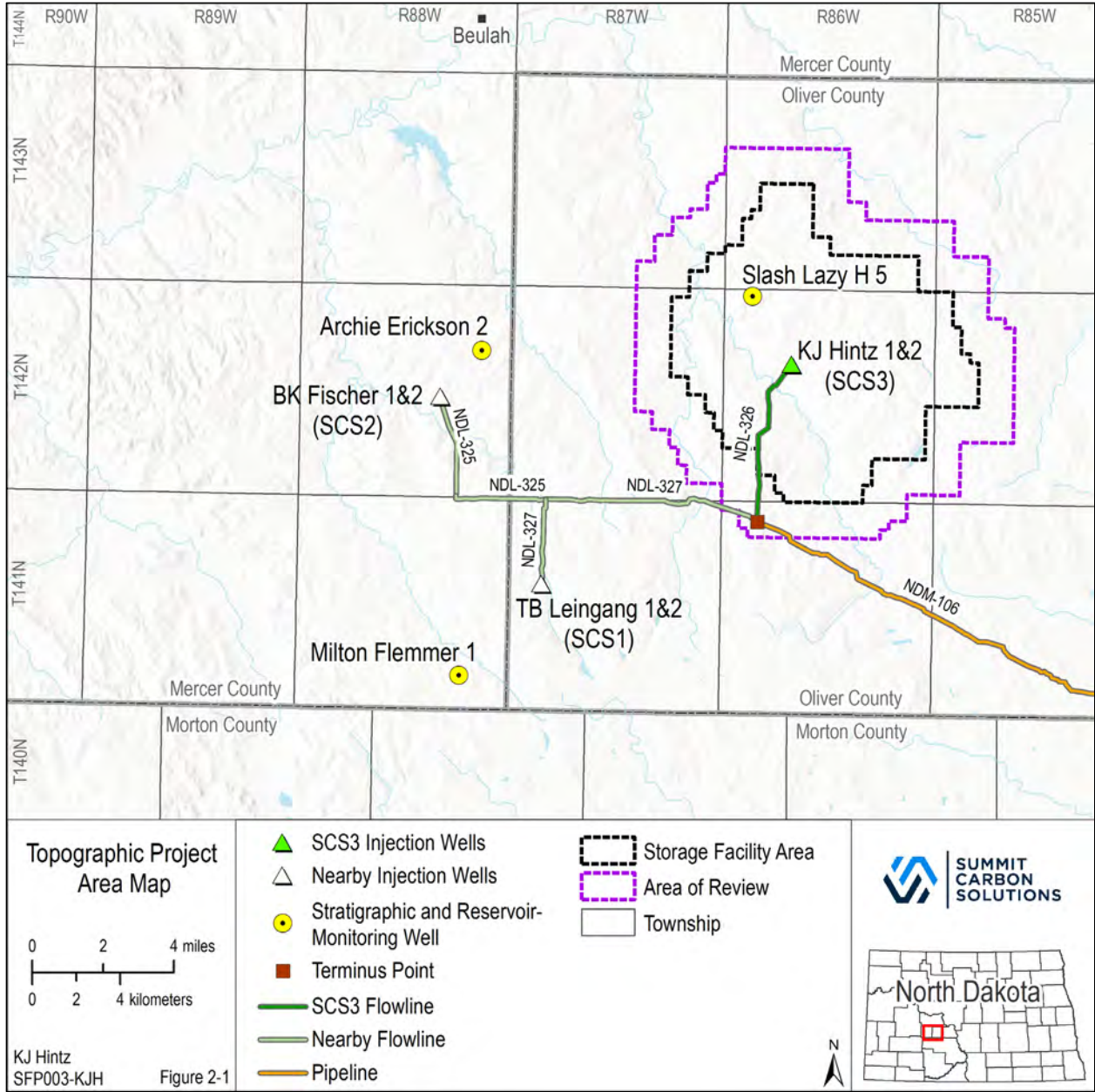


Figure 2-1. Topographic map showing well locations and KJ Hintz in relation to the city of Beulah, North Dakota.

KJ HINTZ/SLASH LAZY H 5

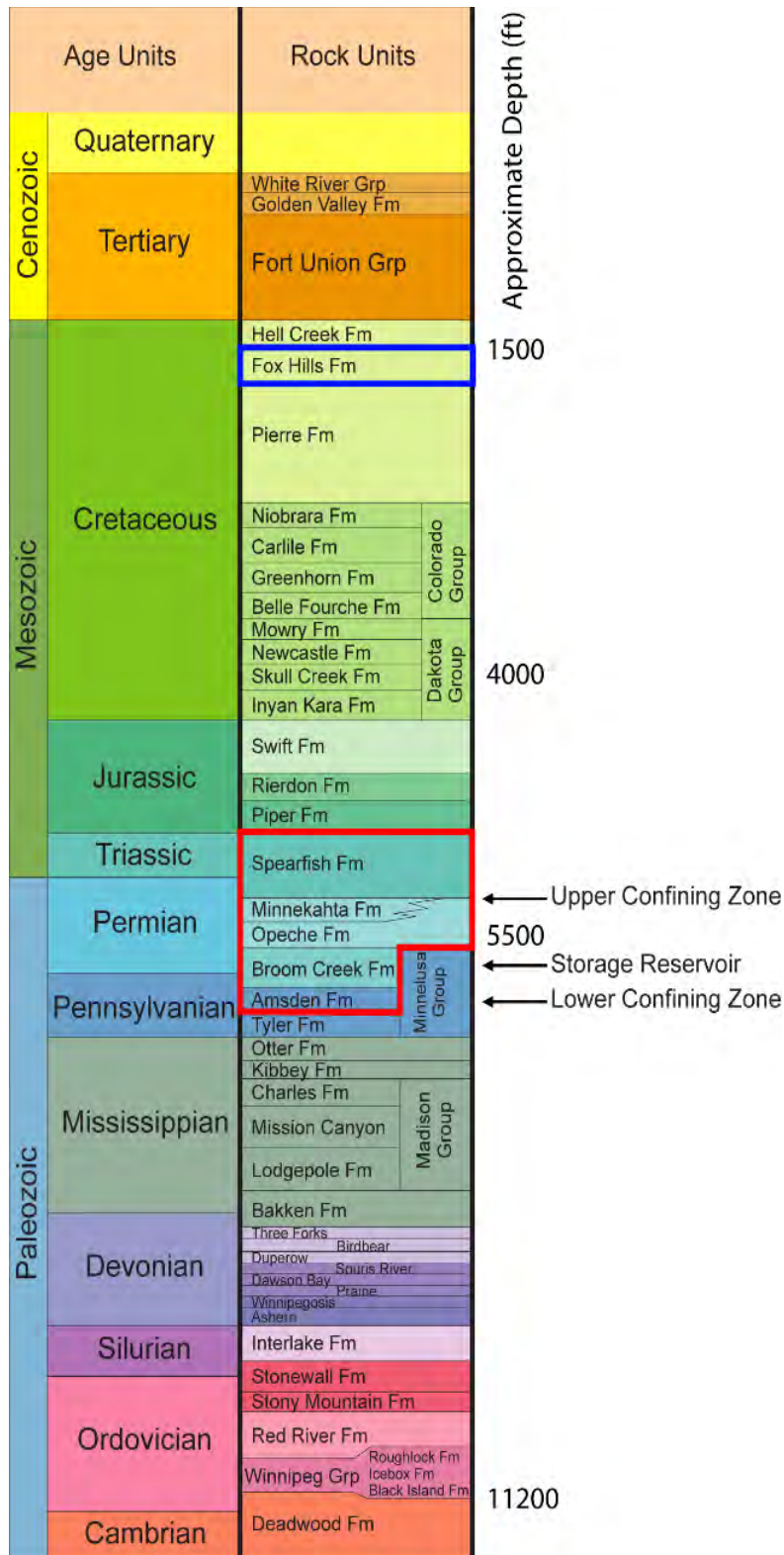


Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation is not present at Slash Lazy H 5.

**Table 2-1. Formations Comprising the KJ Hintz Storage Complex
(simulation model values calculated from model extent shown in Figure 2-3)**

Formation	Purpose	Thickness at Slash Lazy H 5, ft	Depth at Slash Lazy H 5, MD* ft	Average Simulation Model Thickness, ft	Average Simulation Model Depth, (TVD),** ft	Lithology
Opeche/ Spearfish	Upper confining zone	179	5389	138	5106	Siltstone, dolostone, anhydrite
Broom Creek	Storage reservoir (i.e., injection zone)	272	5568	280	5244	Sandstone, dolostone, anhydrite, siltstone
Amsden	Lower confining zone	242***	5840	257	5524	Dolostone, sandstone anhydrite

* Measured depth (MD).

** True vertical depth.

*** Thickness estimated based on offset well information.

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 CO₂. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, purchased/leased digital well logs, existing 3D and 2D seismic) and site-specific data acquired specifically to characterize the storage complex.

2.2.1 Existing Data

Well log data and interpreted formation top depths from 115 wellbores within the 4070-mi² (74-mi × 55-mi) area covered by the geologic model were used to characterize the depth, thickness, and extent of the subsurface geologic formations (Figure 2-3). Seismic interpretation products (seismic horizons and acoustic impedance volumes) from legacy 3D seismic data and 2D seismic data shown in Figure 2-3 were used to support generation of the 3D geologic model.

In addition to data from the Slash Lazy H 5, existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from nine additional wells: ANG 1 (ND-UIC-101), Flemmer 1 (NDIC File No. 34243), BNI 1 (NDIC File No. 34244), J-LOC 1 (NDIC File No. 37380), 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), and Archie Erickson 2 (NDIC File No. 38622) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.

KJ HINTZ/SLASH LAZY H 5

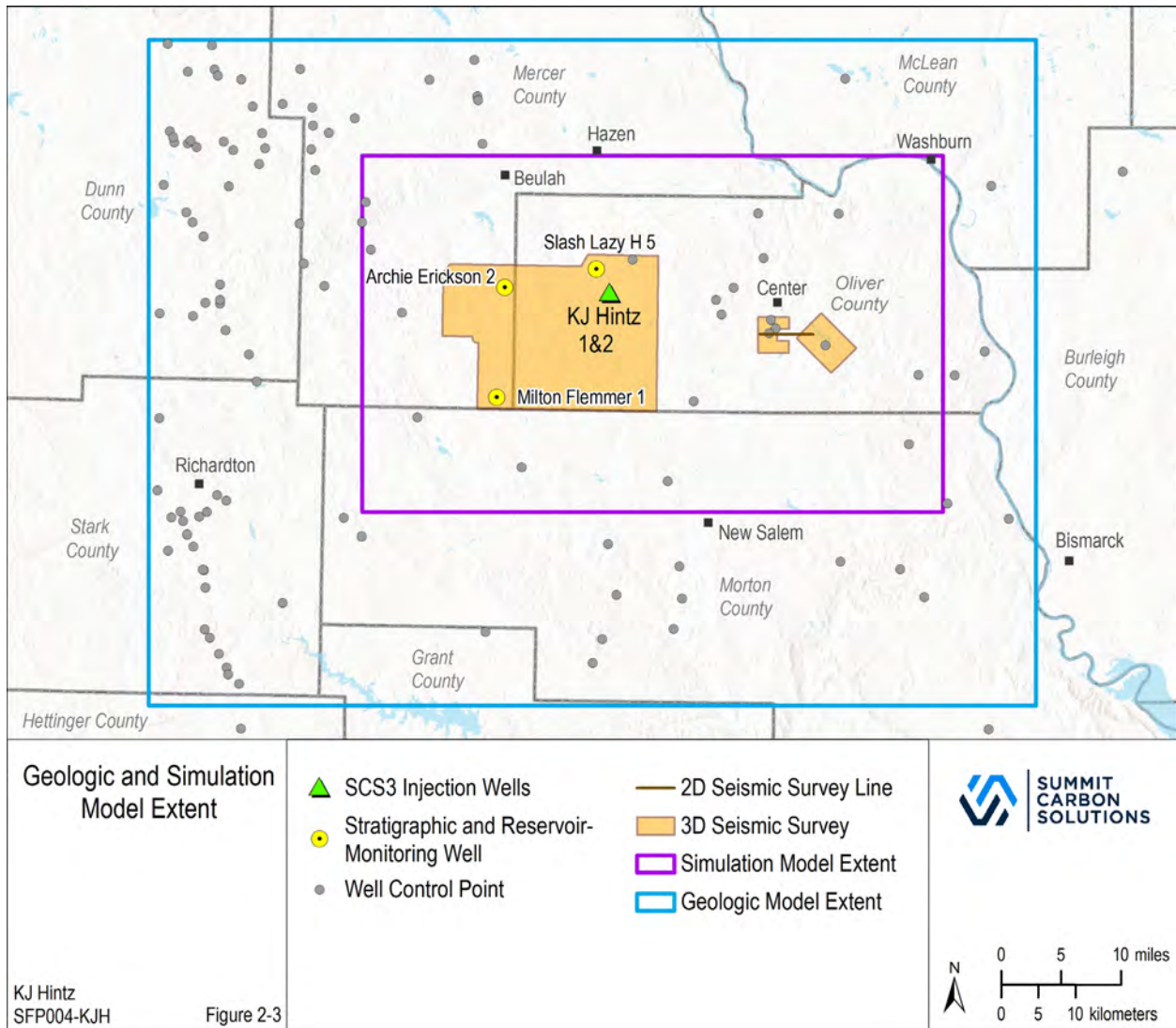


Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, 2D and 3D seismic, and extent of the simulation model. The wells shown penetrate the storage reservoir and the upper and lower confining zones.

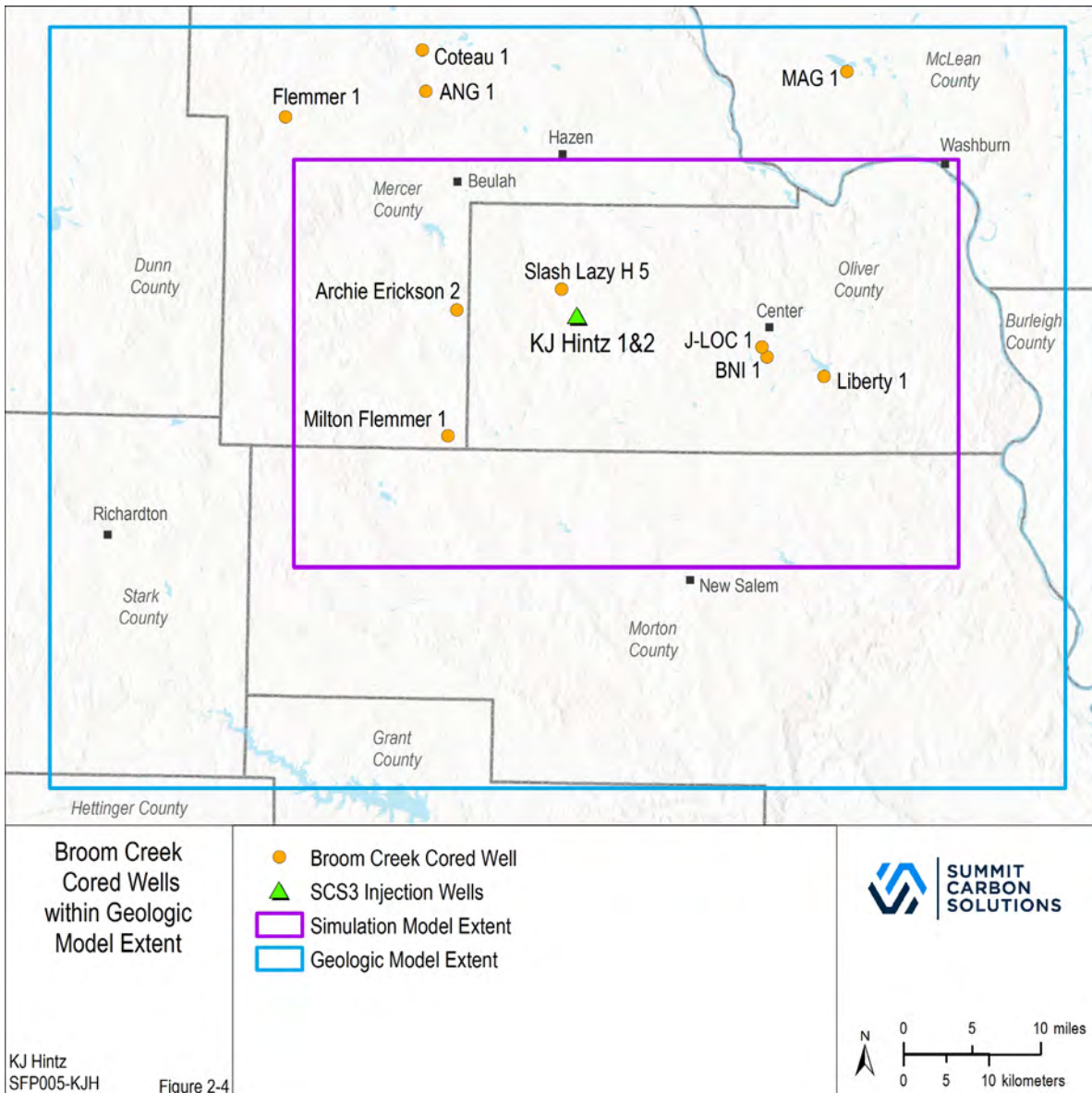


Figure 2-4. Map showing the spatial relationship between the KJ Hintz and ten wells where core samples were collected from the formations comprising the storage complex.

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 3D seismic data. Slash Lazy H 5 was drilled to a depth of 6110 ft MD in 2022, specifically to gather subsurface geologic data to support the development of this CO₂ storage facility permit (SFP) application and serve as a future CO₂ reservoir-monitoring well. Downhole logs were acquired, and cores were collected from the associated storage complex (Opeche/Spearfish, Broom Creek, and Amsden Formations). Broom Creek Formation stress tests, a fluid sample, and temperature and pressure measurements were collected in the Slash Lazy H 5 (Figure 2-5).

KJ HINTZ/SLASH LAZY H 5

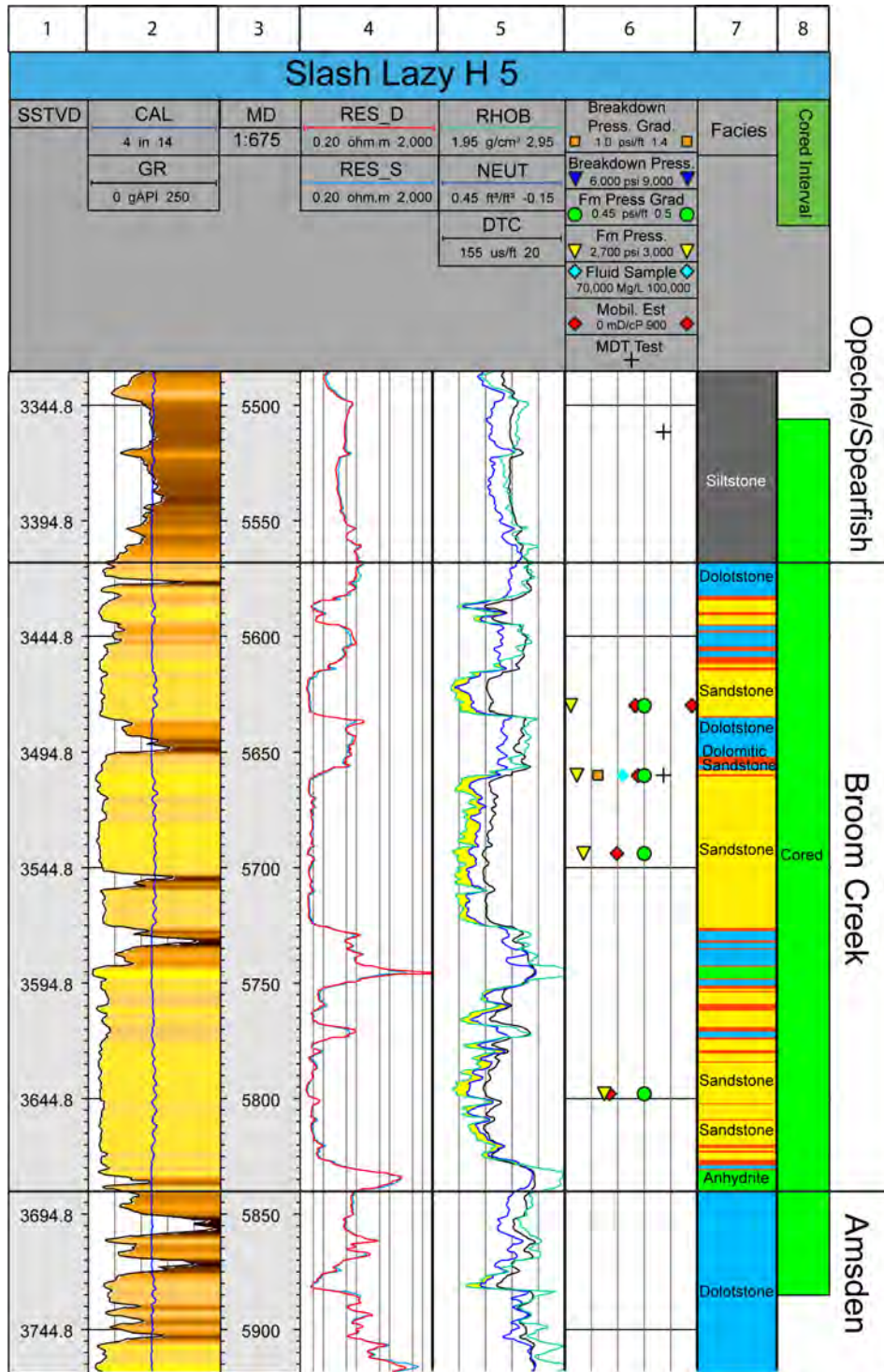


Figure 2-5. Schematic showing vertical relationship of coring and testing intervals in the Opeche/Spearfish Formation, the Broom Creek Formation, and the Amsden Formation in Slash Lazy H 5. Tracks from left to right are 1) subsea true vertical depth (SSTVD); 2) gamma ray (GR or HSGR) (black) and caliper (dark blue); 3) MD; 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), neutron porosity (NEUT) (blue), and density (green); 6) testing intervals; 7) facies, and 8) cored interval.

Site-specific and existing data were used to assess the suitability of the storage complex for safe and permanent storage of CO₂. Site-specific data were also used as inputs for geologic model construction (Section 3.0), numerical simulations of CO₂ injection (Section 3.0), geochemical simulation (Appendix C), and geomechanical information (Section 2.4). The site-specific data improved the understanding of the subsurface and directly informed the selection of monitoring technologies, development of the timing and frequency for monitoring data collection, 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 Slash Lazy H 5. The logging suite included triple combo (GR, density, porosity, and resistivity), caliper, spectral GR, combinable magnetic resonance (CMR), dipole sonic including four-arm caliper and inclinometer, and an image log.

The acquired well logs were used to pick formation top depths and interpret lithology, petrophysical properties, and time-to-depth shifting of seismic data. Formation top depths were picked from the Pierre Formation to the base of the Amsden Formation (Figure 2-2). The site-specific formation top depths were added to the existing data of the 115 wellbores within the 4070-mi² area covered by KJ Hintz to understand the geologic extent, depth, and thickness of the subsurface geologic strata. Formation top depths of the Opeche/Spearfish, Broom Creek, and Amsden Formations were interpolated to create structural surfaces which served as inputs for the 3D geologic model construction.

2.2.2.2 Core Sample Analyses

Three hundred seventy-nine (379) ft of 4-in whole core was recovered from the storage complex in the Slash Lazy H 5: 61 ft core from the Opeche/Spearfish Formation, 272 ft core from the Broom Creek Formation, and 46 ft core from the Amsden Formation. Core was analyzed to characterize the lithologies of the Opeche/Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. A core gamma ray log was acquired and matched to wireline gamma ray-to-depth correct core depth measurements (Table 2-2a). Core analyses included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, scanning electron microscopy (SEM), interfacial tension (IFT) and contact angle (CA), geomechanics and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.

Table 2-2a. Core Depth Shift

Core No.	Start Bit Depth, ft	End Bit Depth, ft	Depth Shift, ft
Core 6	5506	5626	0.50
Core 7	5626	5719	1.00
Core 8	5719	5839	1.00
Core 9	5839	5890	0.50

Core depth + depth shift = log depth.

2.2.2.3 Formation Temperature and Pressure

Temperature measurements from Slash Lazy H 5 were used to derive a temperature gradient for the proposed injection site (Table 2-2b). In combination with depth, the temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for geochemical modeling.

Formation pressure testing at Slash Lazy H 5 was performed with the SLB (formerly Schlumberger) MDT (modular formation dynamics tester) tool. The MDT tool’s 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 CO₂ injection.

Table 2-2b. Description of Slash Lazy H 5 Temperature Measurements and Calculated Temperature Gradients

Formation	Sensor Depth MD, ft	Sensor Depth TVD, ft	Temperature, °F
Opeche/Spearfish	5514.45	5514.29	_*
Broom Creek	5630.00	5629.84	115.43
	5630.00	5629.84	116.39
	5630.00	5629.84	119.07
	5660.12	5659.97	120.36
	5693.88	5693.72	121.96
	5797.93	5797.77	123.72
Mean Broom Creek Temperature, °F			119.49
Broom Creek Temperature Gradient, °F/ft			0.014**

* Dry test. Temperature measurement is unreliable because it was impacted by tool temperature rather than fluid.

** The temperature gradient is an average of the measured temperature minus the average annual surface temperature (40°F), divided by the associated test TVD depth.

Table 2-3. Description of Slash Lazy H 5 Formation Pressure Measurements and Calculated Pressure Gradients

Formation	Sensor Depth	Sensor Depth	Sensor Formation Pressure, psia
	MD, ft	TVD, ft	
Opeche/Spearfish	5514.45	5514.29	—*
Broom Creek	5630.00	5629.84	2713.37
	5630.00	5629.84	2713.36
	5630.00	5629.84	2713.29
	5660.12	5659.97	2727.20
	5693.88	5693.72	2742.29
	5797.93	5797.77	2789.43
Mean Broom Creek Pressure, psi			2733.16
Broom Creek Pressure Gradient, psi/ft			0.48**

* Dry test. No fluid was withdrawn because of low permeability.

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

2.2.2.4 *Microfracture In Situ Stress Tests*

Using the SLB MDT tool, microfracture in situ stress tests were performed in the Slash Lazy H 5 wellbore. As shown in Figures 2-6 and 2-7, in situ reservoir stress-testing measurements provided real-time formation breakdown, instantaneous shut-in, propagation, and closure pressures.

KJ HINTZ/SLASH LAZY H 5

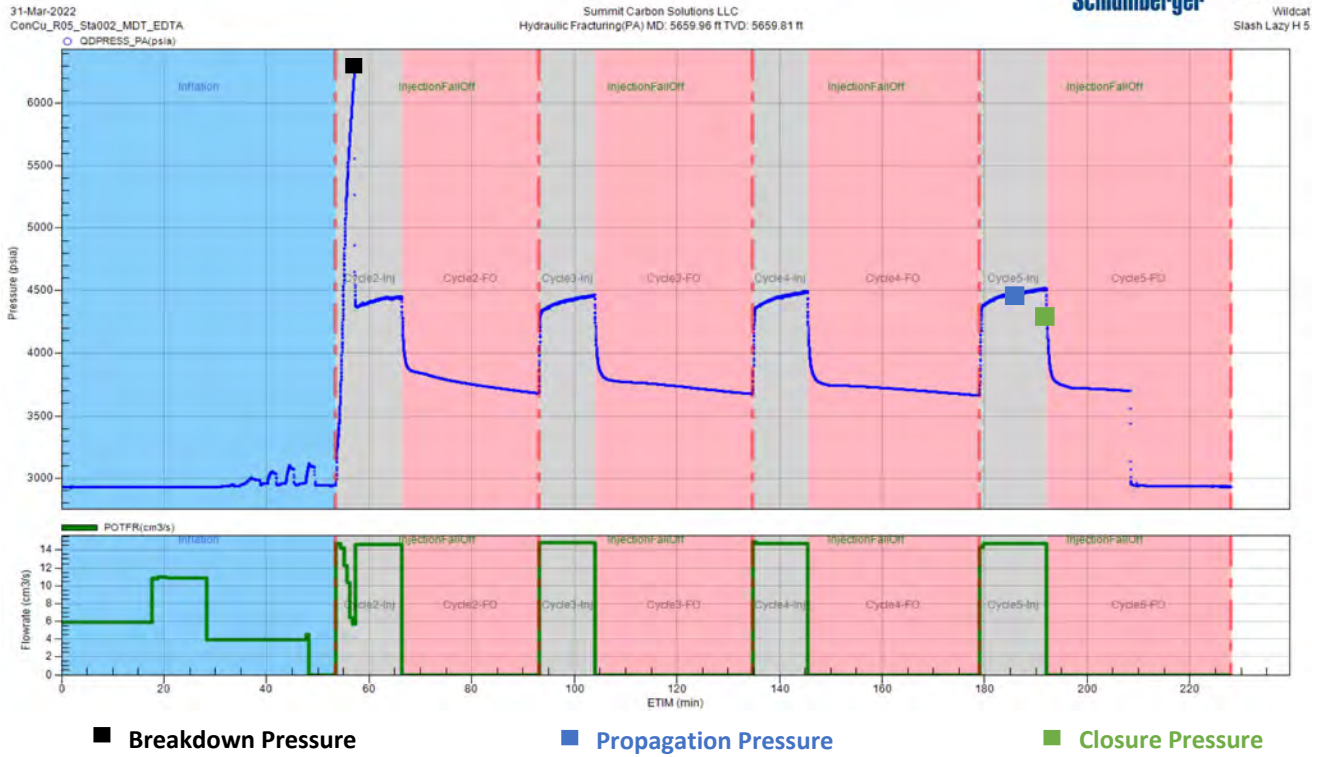


Figure 2-6. Slash Lazy H 5, Broom Creek Formation MDT microfracture in situ stress pump cycle graph at 5659.96 ft MD.

KJ HINTZ/SLASH LAZY H 5

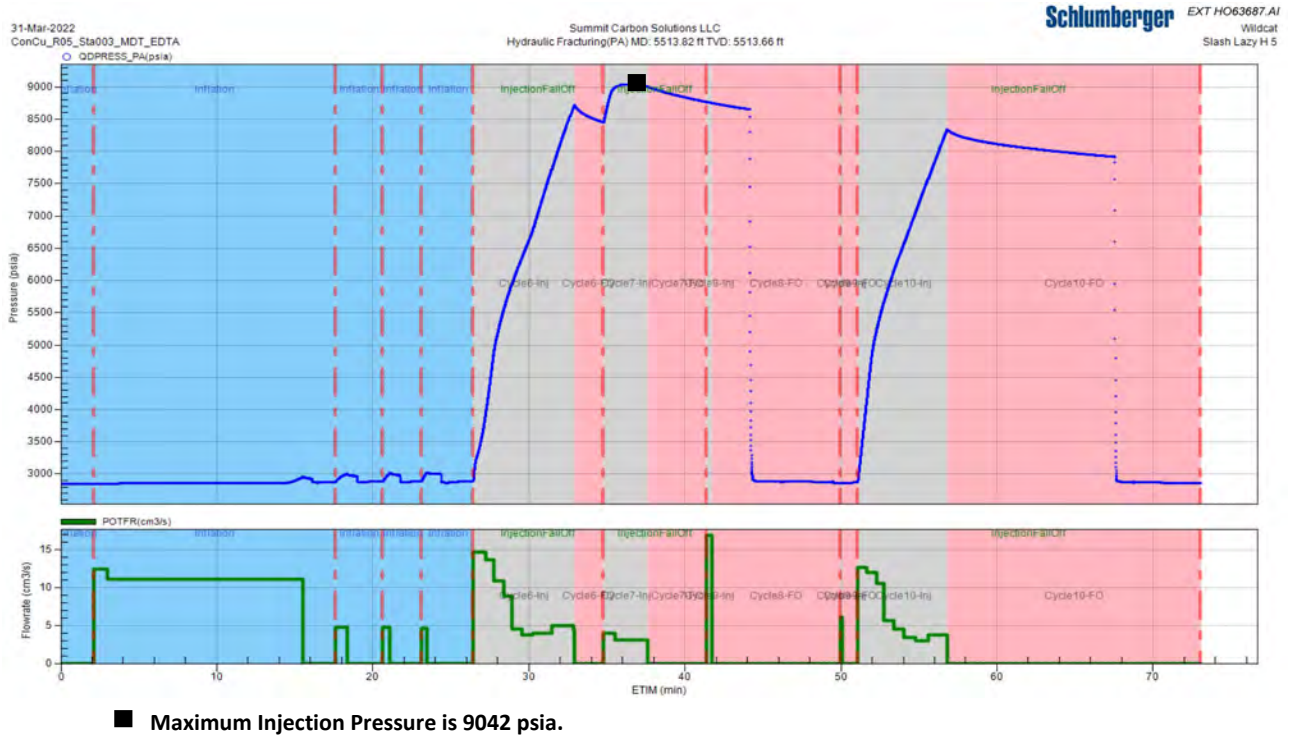


Figure 2-7. Slash Lazy H 5, Opeche/Spearfish Formation MDT microfracture in situ stress pump cycle graph at 5513.82 ft MD. No clear breakdown was observed.

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) and a 1D mechanical earth model (1D MEM) that was generated using well log data from the Slash Lazy H 5. Discussion of the 1D MEM can be found in Section 2.4.

Table 2-4. Description of Slash Lazy H 5 Microfracture In Situ Stress Tests

Formation	Test Depth		Breakdown Pressure		Propagation Pressure		Closure Pressure (G-func)	
	MD, ft	TVD, ft	psia	Gradient, psi/ft*	Avg., psia	Gradient, psi/ft*	Avg., psia	Gradient, psi/ft*
Opeche/Spearfish	5513.82	5513.67	No observed formation breakdown.					
Broom Creek	5659.96	5659.81	6268.52	1.10	4450	0.784	4345.57	0.765

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

No breakdown pressure was observed for Slash Lazy H 5 in the Opeche/Spearfish Formation, at 5513.82 ft MD with applied maximum injection pressure of 9042 psi (Figure 2-7). One predominant reason included limitations with the dual-packer mechanical specifications, the maximum injection pressures were limited by the maximum differential pressure rating for the MDT tool. The inability to break down the Opeche/Spearfish Formation at the depth indicates that the formation is tight competent rock and exhibits sufficient geologic integrity to contain the injected CO₂.

2.2.2.5 Fluid Sample Testing

Fluid samples from the Inyan Kara and the Broom Creek Formations were collected from the Slash Lazy H 5 wellbore via an MDT tool (“SLB Saturn 3D Radial Probe”). Results were analyzed by Minnesota Valley Testing Laboratories (MVTL), a state-certified lab. The salinity values from the Slash Lazy H 5 wellbore samples are shown in Table 2-5. A more detailed fluid sample analysis report can be found in Appendix A. Fluid sample analysis results were used as inputs for geochemical modeling and dynamic reservoir simulations.

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

Formation	Well	Test Depth/Interval, ft, MD	MVTL TDS, mg/L
Inyan Kara	Slash Lazy H 5	4275	12,800
Broom Creek	Slash Lazy H 5	5660	83,100

In situ fluid pressure testing was performed in the Opeche/Spearfish and Broom Creek Formations with the MDT tool. This test utilized the tool’s extra-large-diameter probe to test both the mobility and reservoir pressure. The MDT probe was unable to draw down reservoir fluid from the Opeche/Spearfish Formation 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 CO₂ stream.

2.2.2.6 *Seismic Survey*

A 208-square-mile 3D seismic survey was conducted from November 2021 to February 2022 south of Beulah, North Dakota (Figure 2-8). The Beulah 3D seismic data provided visualization of deep geologic formations at lateral-spatial intervals as short as 82.5 ft. Additionally, seismic data from nearby 3D surveys to the east, namely, the Center 3D and Minnkota 3D, and a connecting 2D line were used to interpret and evaluate the subsurface (Figure 2-8). The seismic data were used for assessment of the geologic structure and reservoir properties.

Data products generated from the interpretation of the Beulah 3D were used as inputs for the geologic model that was used to simulate migration of the CO₂ plume. The Beulah 3D seismic data and the Slash Lazy H 5 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from Archie Erickson 2, Milton Flemmer 1, and Slash Lazy H 5 dipole sonic logs. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. Detailed information about the structure and varying thickness of the formations away from well control was derived from these surfaces. A prestack seismic inversion was generated from the 3D seismic data and well logs from the Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 stratigraphic test wells. Depth-converted surfaces and poststack seismic inversion results from the Center 3D and Minnkota 3D were also used as inputs for the geologic model.

Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points (e.g., folds, domes, or fault traps) in KJ Hintz. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 3D seismic data in KJ Hintz.

KJ HINTZ/SLASH LAZY H 5

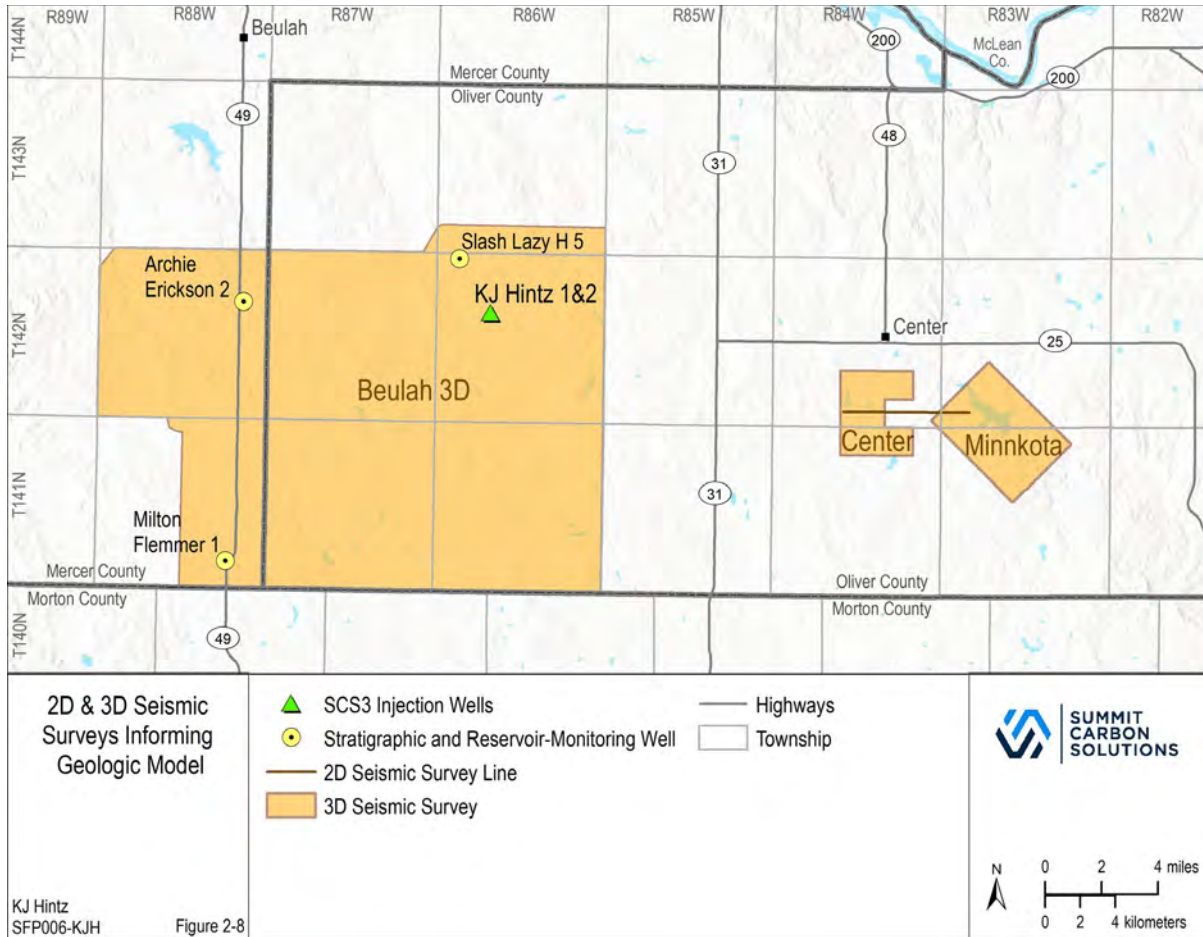


Figure 2-8. Map showing the 2D and 3D seismic surveys used to characterize KJ Hintz and inform the construction of the geologic model. The 3D seismic surveys from west to east are the Beulah 3D, Center 3D, and Minnkota 3D.

2.3 Storage Reservoir (injection zone)

The Broom Creek Formation is laterally extensive across the simulation model area and surrounding region (Figure 2-9). The Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with minor amounts of siltstone and 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).

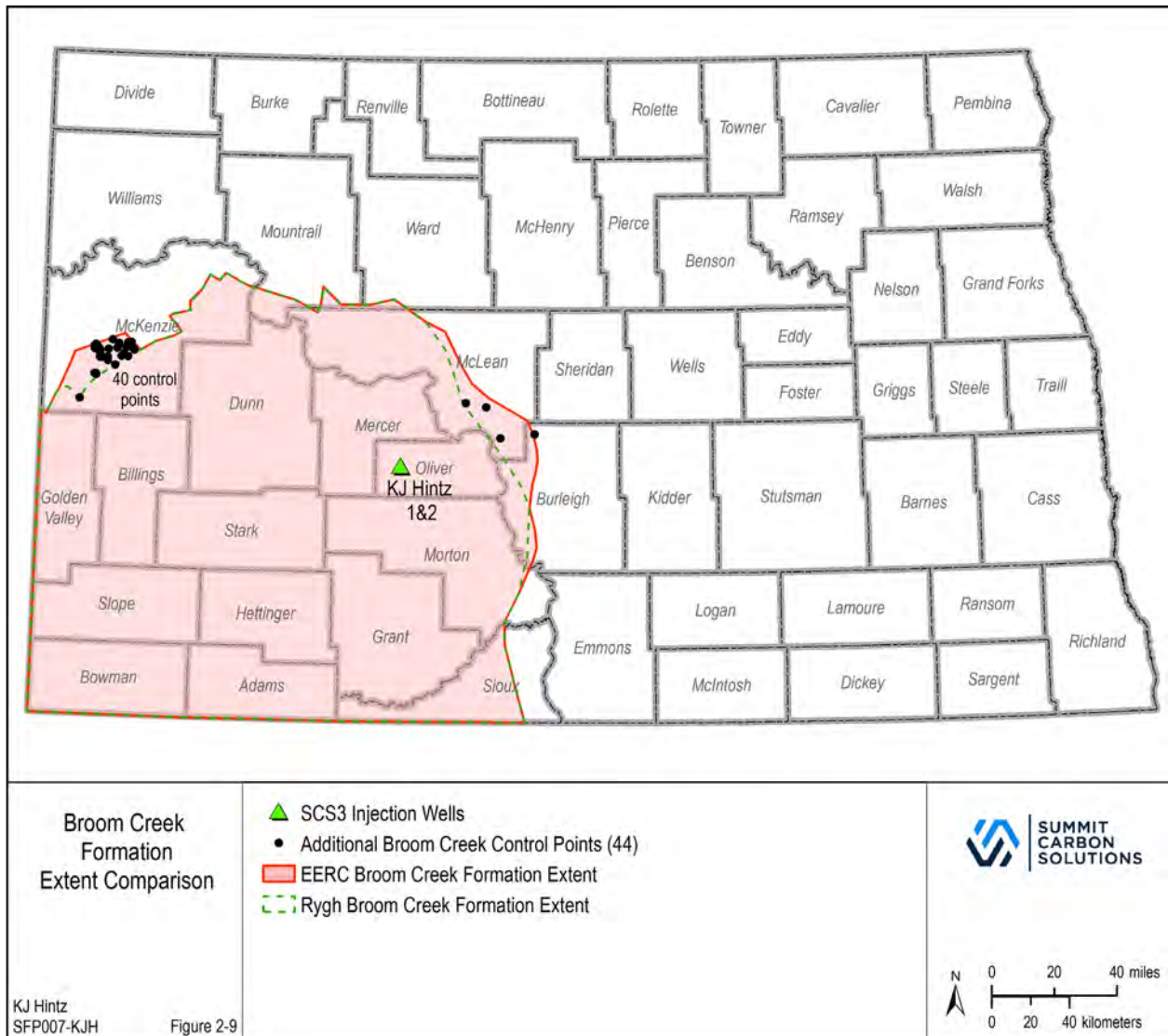


Figure 2-9. Broom Creek Formation in North Dakota. The area within the green dashed line shows the extent originally proposed by Rygh (1990), and the area outside of the green dashed line has been modified based on new well control.

KJ HINTZ/SLASH LAZY H 5

The top of the Broom Creek Formation is located at a depth of 5568 ft below KB elevation at Slash Lazy H 5 and the cored interval is made up of 186 ft of sandstone, 71 ft of dolostone, and 15 ft of anhydrite. The thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft. Cored wells within the extent of the simulation model show minor anhydrite and siltstone intervals are also present in the Broom Creek Formation. Across the simulation model area, the Broom Creek Formation ranges in thickness from 139 to 492 ft (Figures 2-10a and 2-10b), with an average thickness of 280 ft based on offset-well data and geologic model characteristics. The net sandstone thickness within the simulation model area ranges from 6 to 397 ft, with an average thickness of 140 ft.

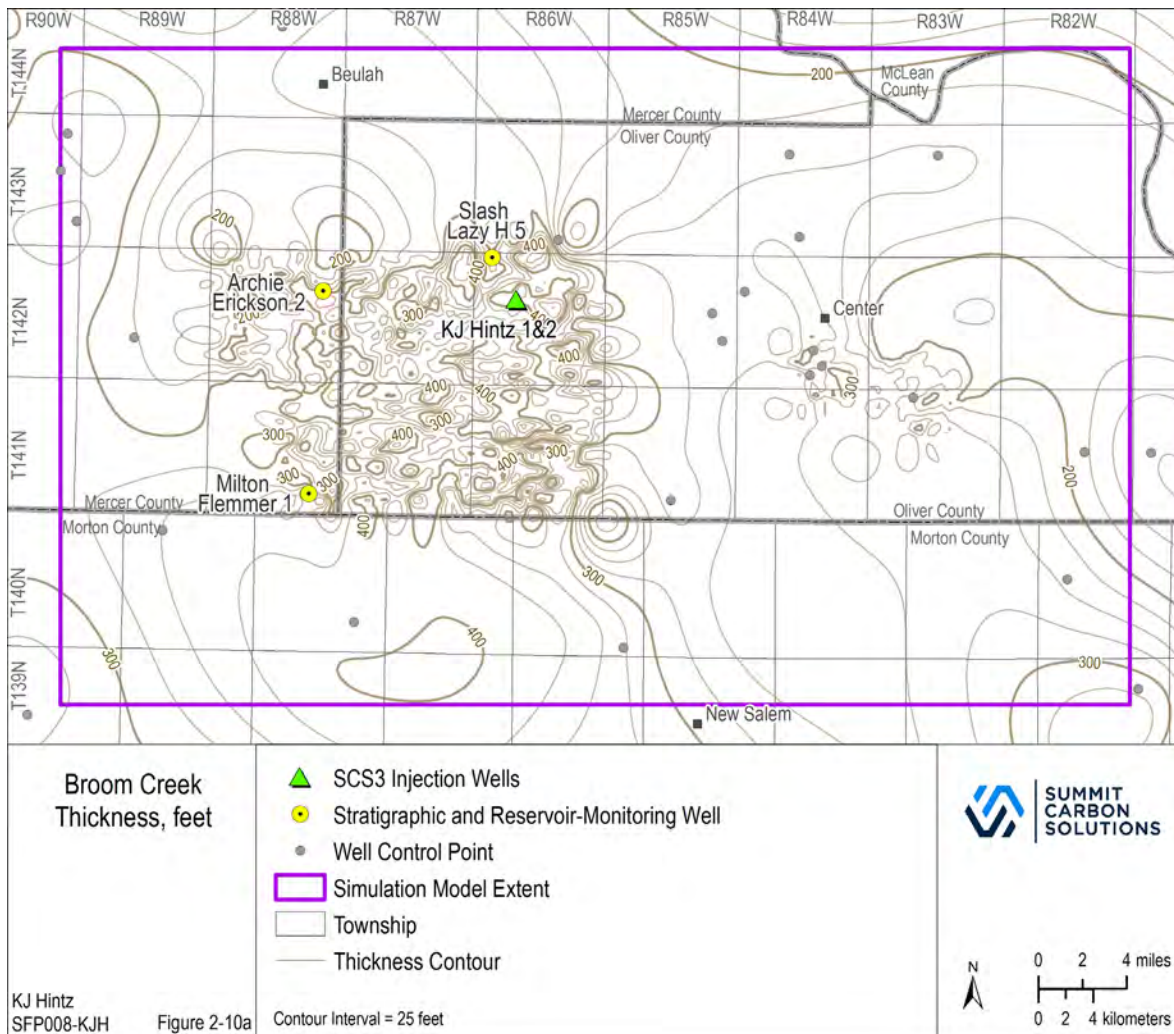


Figure 2-10a. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6).

KJ HINTZ/SLASH LAZY H 5

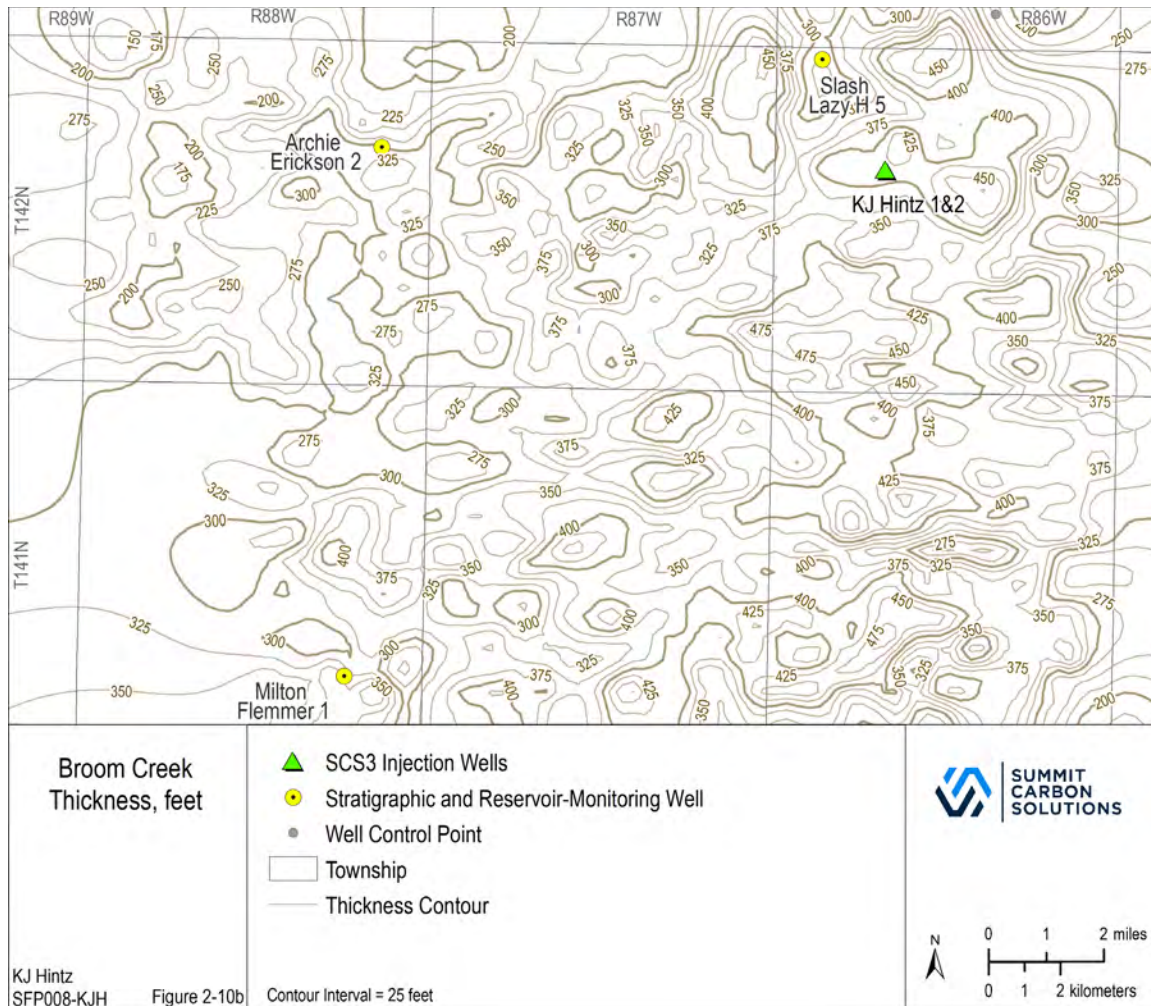


Figure 2-10b. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6).

The top of the Broom Creek Formation was picked based on the stratigraphic transition from a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation to a relatively high GR signature representing the siltstones of the Opeche/Spearfish Formation (Figure 2-11). This transition is also noted with a drop in bulk density (RHOB) and dipole sonic compressional slowness values (DTC) and an increase in neutron porosity (NEUT) and resistivity (RES_D, RES_S). The bottom of the Broom Creek Formation was placed at the base of a relatively low GR package representing a 10-ft package of anhydrite that can be correlated across much of the study area. This rock package divides the clean sandstones and dolostone lithologies of the Broom Creek Formation from the dolostone and anhydrite of the Amsden Formation. Seismic data collected as part of site characterization efforts (Figure 2-8) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and seismic interpretation indicate that the formation is continuous across the area near Slash Lazy H 5 (Figures 2-12 and 2-13). A structure map of the Broom Creek Formation shows no detectable features with associated spill points in the simulation model area (Figures 2-14 and 2-15).

KJ HINTZ/SLASH LAZY H 5

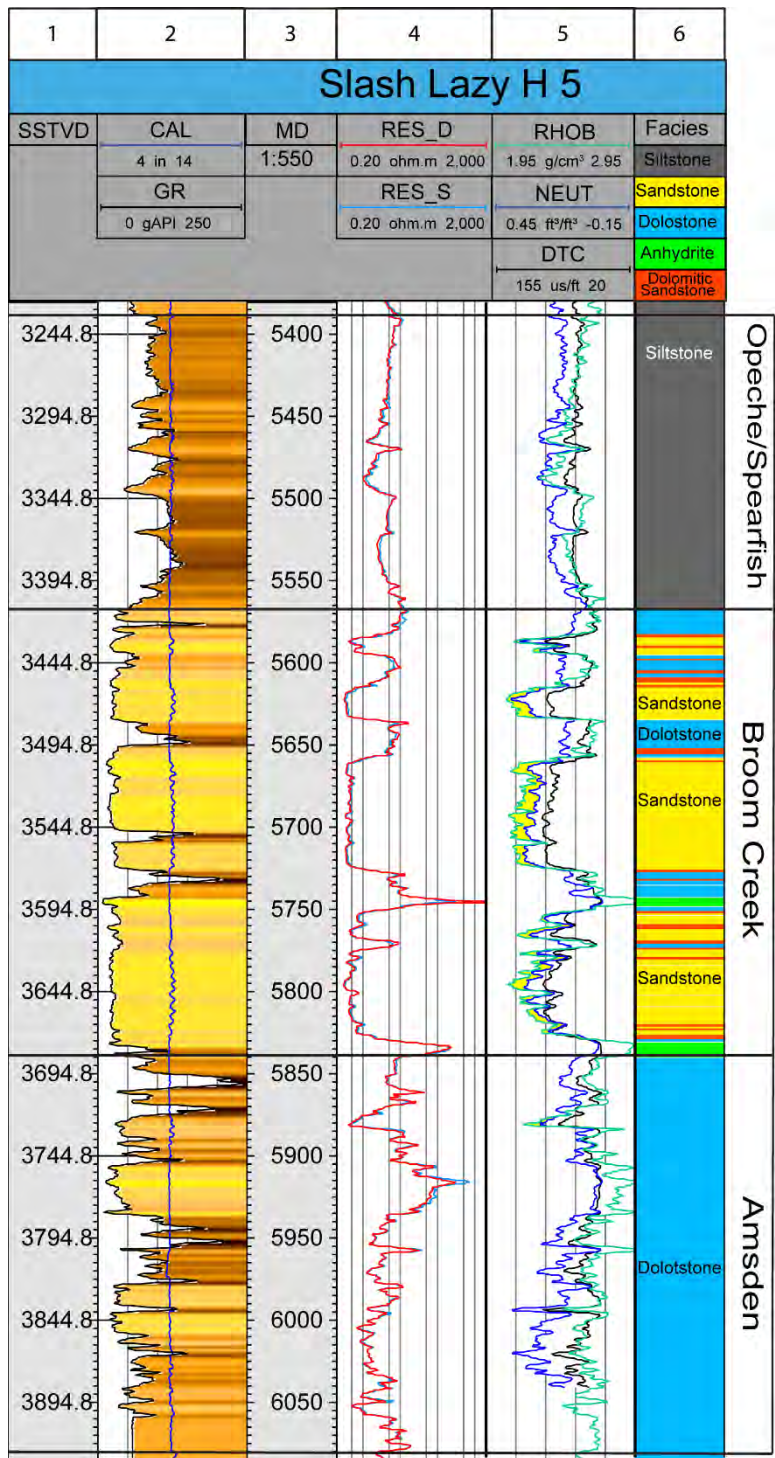


Figure 2-11. Well log display of the interpreted facies of the Opeche/Spearfish, Broom Creek, and Amsden Formations in Slash Lazy H 5. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), NEUT (blue), and density (green); and 6) facies.

KJ HINTZ/SLASH LAZY H 5

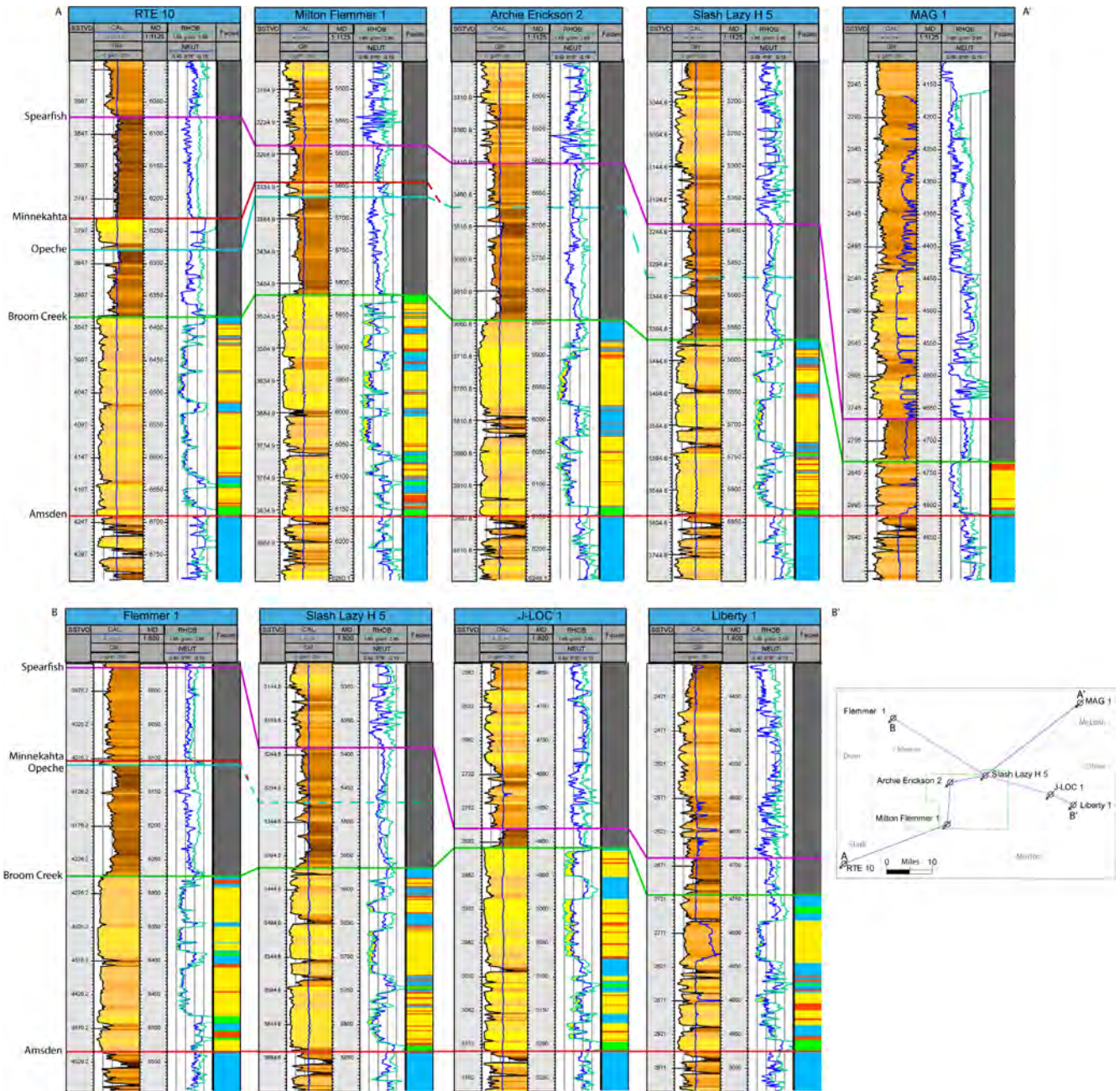


Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD.

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.

KJ HINTZ/SLASH LAZY H 5

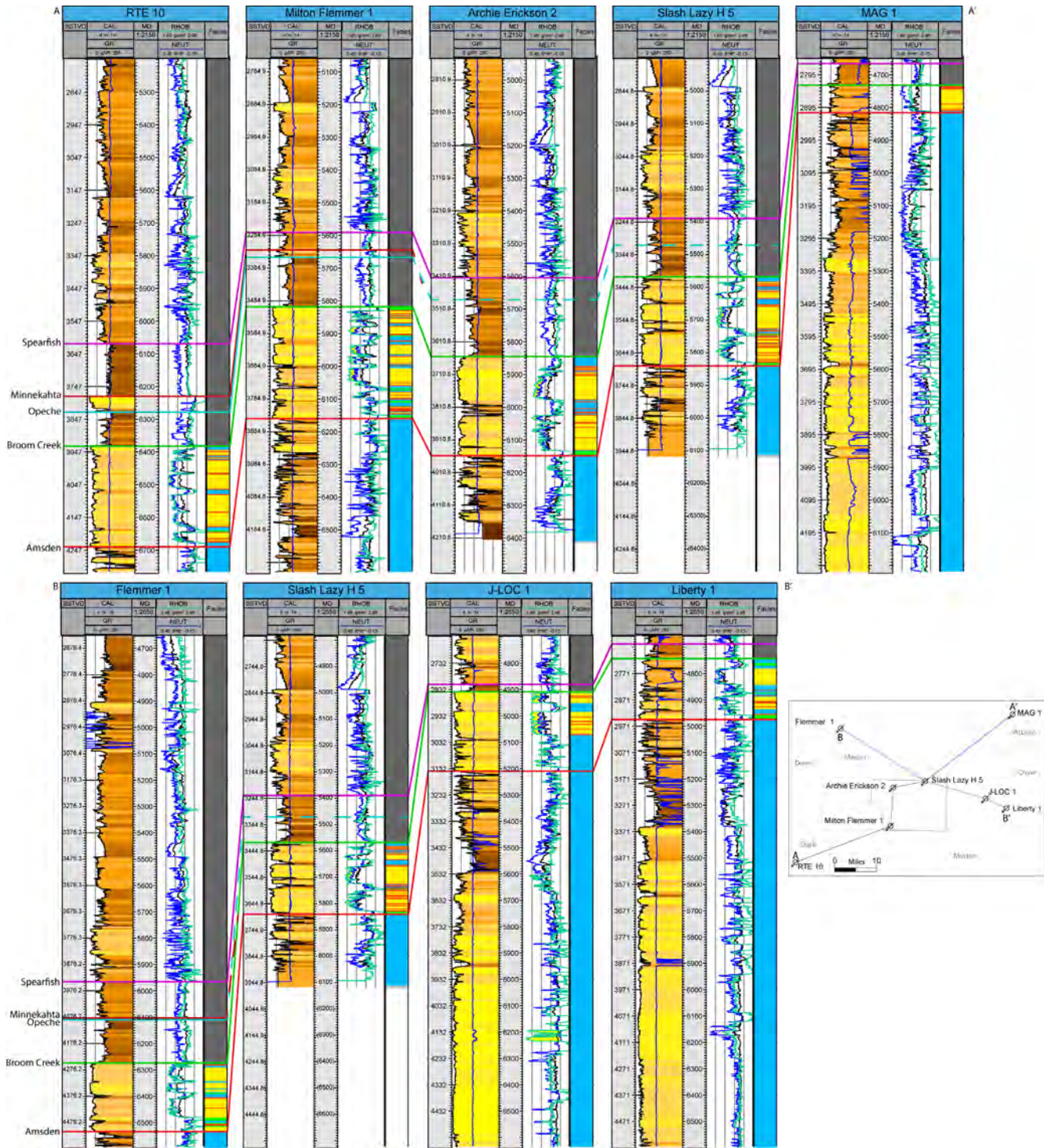


Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD.

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.

KJ HINTZ/SLASH LAZY H 5

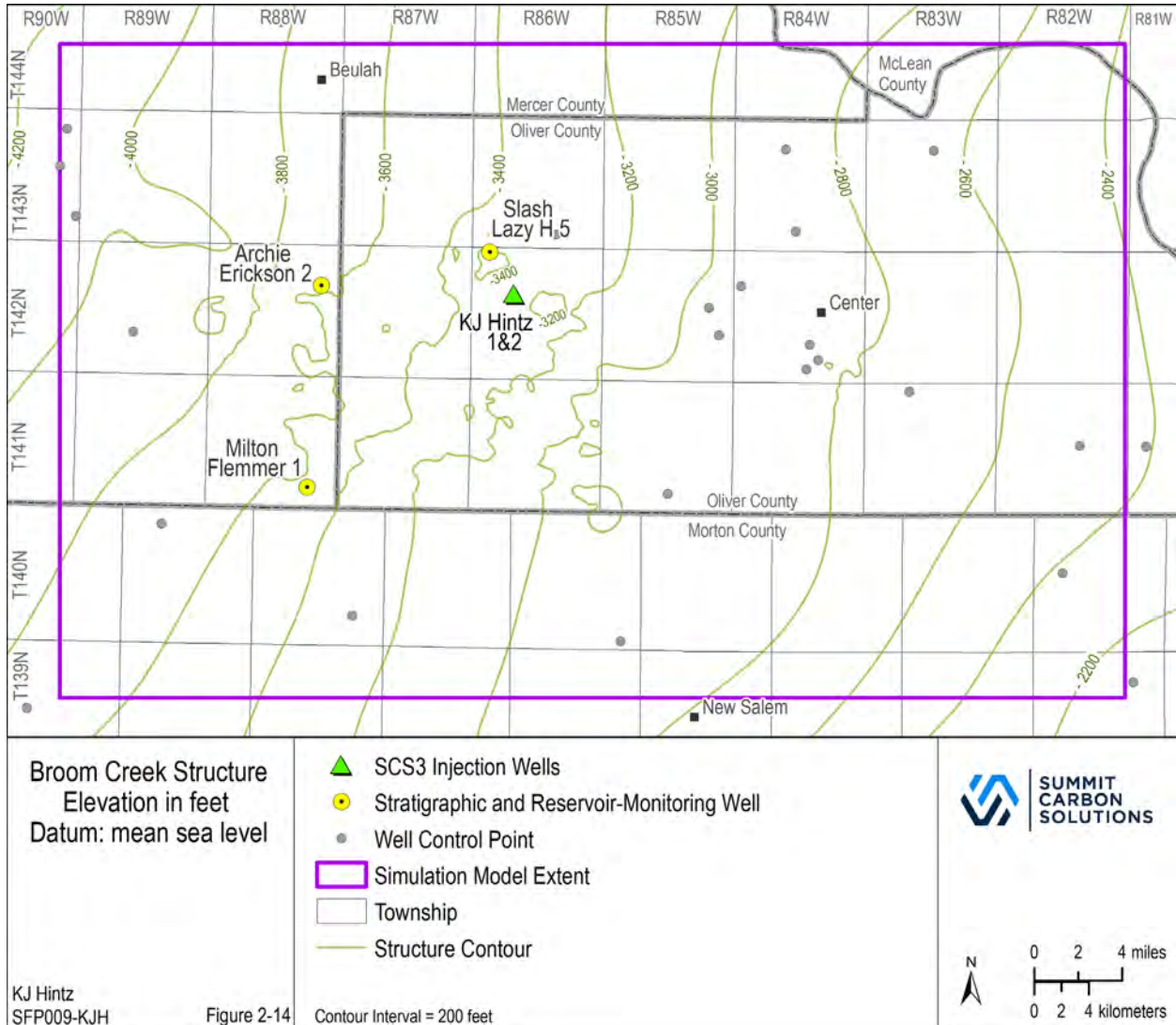


Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map.

Twenty-eight (28) 1-in.-diameter core plugs collected from the Broom Creek Formation were sampled and used to determine the distribution of porosity and permeability values throughout the formation (Table 2-6, Figure 2-16). All but four samples were successfully tested in the lab. Some of the samples tested were fractured or chipped which could have resulted in optimistic porosity and/or permeability measurements. The range in porosity and permeability predominantly captured the sandstone variability as this rock type was prominent in the sampling program over the dolostone.

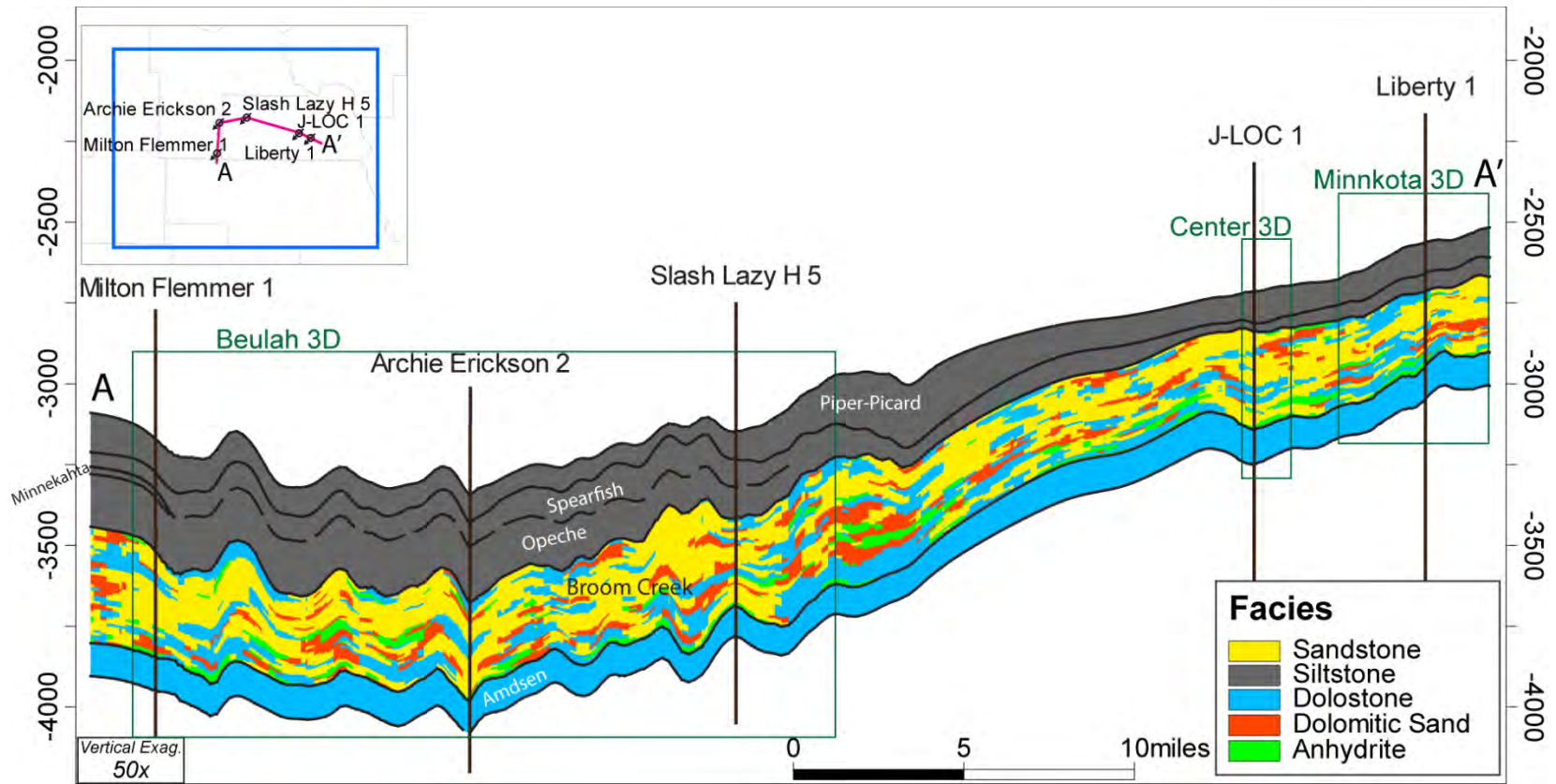


Figure 2-15. Cross section of the KJ Hintz storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner.

Table 2-6. Description of CO₂ Storage Reservoir (injection zone) at the Slash Lazy H 5 Injection Zone Core Derived Properties

Property	Description		
Formation Name	Broom Creek		
Lithology	Sandstone, dolostone, anhydrite		
Formation Top Depth, (MD), ft	5568		
Thickness, ft	272 (sandstone 186, dolostone 71, anhydrite 15)		
Capillary Entry Pressure (brine/CO ₂), psi	1.12		
Geologic Properties			
Formation	Property	Laboratory Analysis	Simulation Model Property Distribution
Broom Creek (sandstone)	Porosity, %*	17.1 (6.6–27.2)	22.0 (0.0–35.3)
	Permeability, mD**	409.1194, 18.5984 (0.0599–2410)	458.79, 136.96 (0.0–3401.2)
Broom Creek (dolostone)	Porosity, %*	7.9 (4.6–10.6)	4.4 (0.0–34.9)
	Permeability, mD**	0.6995, 0.0328 (0.0013–6.51)	2.07, 0.0221 (0.0–919.6)

* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses. Values are measured at 2400 psi.

** Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation. Values are measured at 2400 psi.

Core-derived measurements from Slash Lazy H 5 were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The 1-in.-diameter core plug sample measurements showed good agreement with the geologic model property distribution at the location of Slash Lazy H 5. This agreement gave confidence to the geologic model, which is a spatially and computationally larger data set created with the extrapolation of porosity and permeability from offset well logs. The geologic model property distribution statistics shown in Table 2-6 are derived from a combination of the core plug analysis and the larger data set derived from offset well logs.

Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity because of brine salinity, and high sonic slowness measurements (Figure 2-11). 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 slowness measurements. The dolomitic sandstone intervals in the formation are the transitions between sandstone and dolostone, where the porosity begins to decrease, and density begins to increase in a transition from predominantly sandstone to dolostone (Figure 2-16).

KJ HINTZ/SLASH LAZY H 5

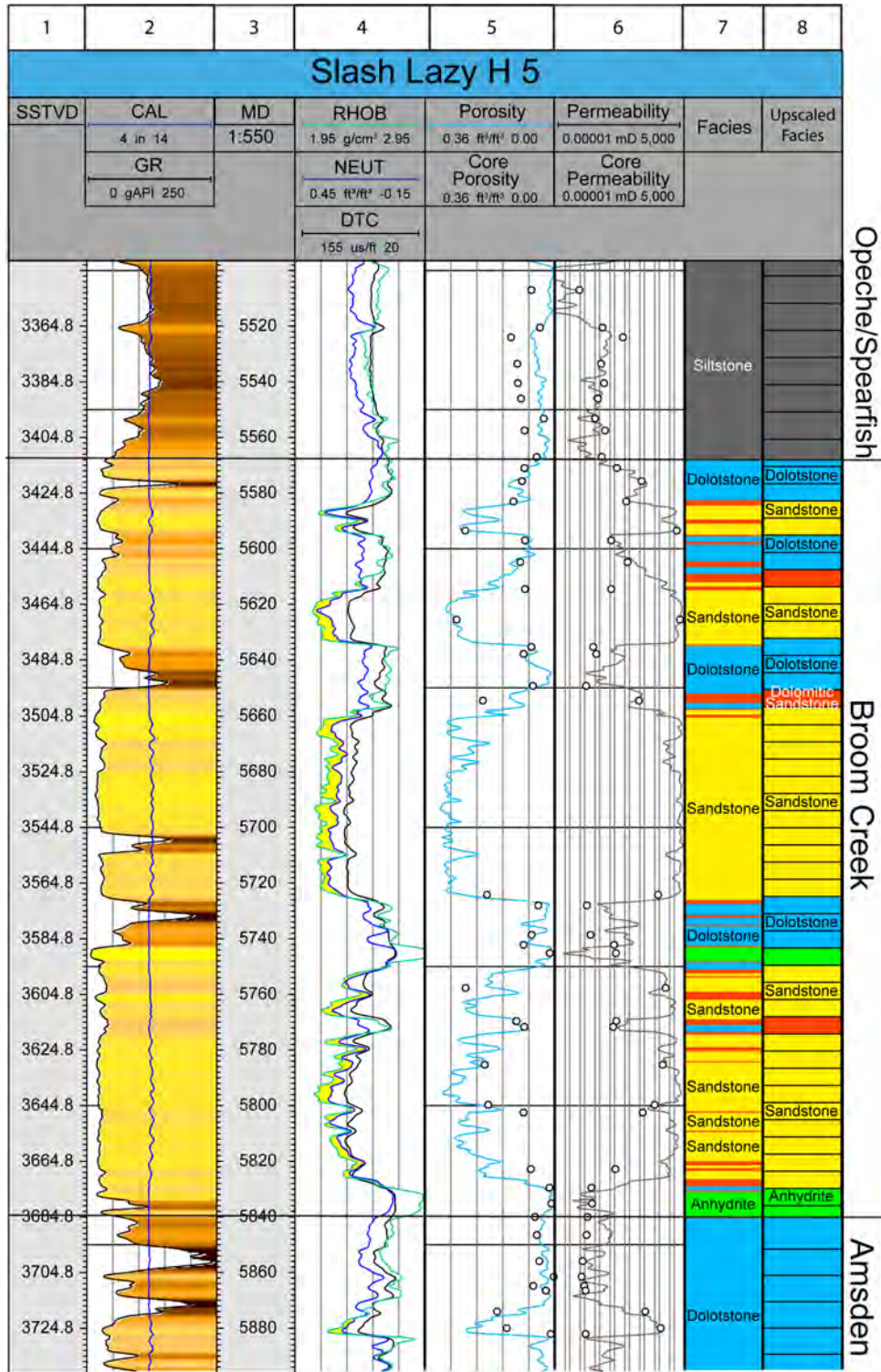


Figure 2-16. Vertical distribution of core-derived porosity and permeability values in the KJ Hintz storage complex from Slash Lazy H 5. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) delta time (black), NEUT (blue), and bulk density (green); 5) core porosity (2400 psi) and log porosity (light blue); 6) core permeability (2400 psi) and log permeability (black); 7) facies; and 8) upscaled facies.

2.3.1 Mineralogy of the Injection Zone

Powder XRD for average bulk composition analysis of 32 finely ground, homogenized samples from the Broom Creek Formation shows quartz as the most common mineral (~44%) followed by carbonates (~34%, mostly dolomite with a minor contribution from ankerite), sulfates (~9%, mostly anhydrite with minor contributions from gypsum and barite), feldspar (~6%, mostly K-feldspar), and clay minerals (~5%, primarily illite) (Figure 2-17a). Minor amounts of halide (~0.2%) make up the rest of the mineralogy. The major constituents of the Broom Creek Formation obtained by XRD are also shown in Table 2-7a. These results align with the average elemental composition obtained by XRF which shows silica (Si) as the dominant element followed by calcium (Ca), magnesium (Mg), sulfur (S), aluminum (Al), potassium (K), and other trace elements (Figure 2-17a).

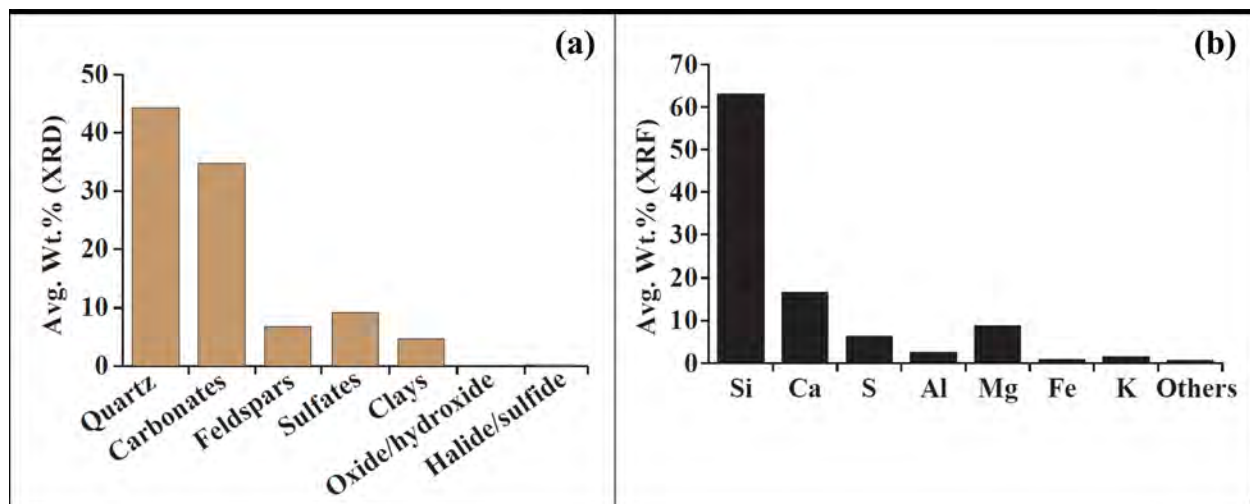


Figure 2-17a. Bar charts showing a) average mineralogy (wt%), and b) average elemental composition (wt%) of the Broom Creek Formation at Slash Lazy H 5 (note: elemental data by XRF were determined as oxides of the respective elements).

XRF analysis of the Broom Creek Formation (Figure 2-17b) shows a high percentage of SiO_2 (1.5%–93.8%), CaO (0.8%–40%), and MgO (0.2%–23%) that confirms the dominance of sandstone and dolomite intervals in the Broom Creek Formation. A high percentage of CaO (~32%) and MgO (~20%) at the top of the formation indicates the presence of dolomite layer that isolates the Broom Creek Formation from the Opeche/Spearfish Formation. As the formation gets deeper, the mineralogy changes to anhydrite-rich as indicated by a higher percentage of CaO (~39%) and SO_3 (~49%) that separates the Broom Creek Formation from the bottom Amsden Formation. The Broom Creek Formation consists of a clay content ranging from 0.1% to 26%, with an average of ~5%, with illite being the dominant clay type.

KJ HINTZ/SLASH LAZY H 5

Table 2-7a. XRD Analysis of the Opeche/Spearfish Formation at Slash Lazy H 5. Only major constituents are shown.

Formation	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others, wt%	Illite/Total Clay,* %
Broom Creek	5570.5	5571.0	4.00	1.90	9.20	83.70	0.50	0.70	100.00
Broom Creek	5575.2	5575.7	0.00	0.80	11.00	84.80	1.30	2.10	NA**
Broom Creek	5582.5	5583.0	14.50	51.70	0.00	26.40	6.10	1.30	100.00
Broom Creek	5593.0	5593.5	5.10	87.00	0.00	3.20	1.50	3.20	100.00
Broom Creek	5596.5	5597.0	11.50	32.70	0.00	42.20	11.60	2.00	100.00
Broom Creek	5604.3	5604.8	0.00	0.70	0.00	99.20	0.10	0.00	100.00
Broom Creek	5614.0	5614.5	9.40	53.60	0.00	36.20	0.50	0.30	100.00
Broom Creek	5625.0	5625.5	11.90	83.30	0.00	2.20	2.10	0.50	100.00
Broom Creek	5634.3	5635.3	5.60	4.30	0.00	84.30	2.30	3.50	100.00
Broom Creek	5636.8	5637.8	6.90	11.20	0.00	79.80	0.70	1.40	100.00
Broom Creek	5648.3	5649.3	21.60	29.00	0.00	26.80	18.60	4.00	97.31
Broom Creek	5653.6	5654.6	1.90	68.80	2.60	21.90	2.20	2.60	100.00
Broom Creek	5663.0	5664.0	6.90	75.40	0.00	1.20	9.90	6.60	100.00
Broom Creek	5677.7	5678.7	11.80	78.00	5.20	0.50	4.10	0.40	100.00
Broom Creek	5691.0	5692.0	6.40	89.50	0.00	2.60	1.20	0.30	100.00
Broom Creek	5704.3	5705.3	4.60	84.50	0.00	6.30	3.90	0.70	100.00
Broom Creek	5710.2	5711.2	5.20	85.70	2.70	3.90	2.20	0.30	100.00
Broom Creek	5723.2	5724.2	4.20	72.30	0.00	21.40	1.70	0.40	100.00
Broom Creek	5727.0	5728.0	5.00	14.40	0.00	65.60	13.40	1.60	100.00
Broom Creek	5731.5	5732.5	23.10	41.50	0.00	8.10	26.50	0.80	100.00
Broom Creek	5737.6	5738.6	2.90	4.60	0.00	84.80	7.40	0.30	100.00
Broom Creek	5741.2	5742.2	7.00	18.10	2.40	70.00	2.30	0.20	100.00
Broom Creek	5744.2	5745.2	0.00	1.00	96.40	1.30	0.90	0.40	NA
Broom Creek	5756.7	5757.7	4.00	71.00	0.00	18.30	5.00	1.70	100.00
Broom Creek	5768.6	5769.6	14.70	16.20	0.90	63.70	3.80	0.70	100.00
Broom Creek	5770.7	5771.7	5.10	0.80	1.90	89.70	1.80	0.70	100.00
Broom Creek	5784.3	5785.3	3.70	78.50	0.00	14.50	1.50	1.80	100.00
Broom Creek	5798.7	5799.7	4.90	74.90	0.00	18.20	1.50	0.50	100.00
Broom Creek	5801.5	5802.5	4.20	12.60	3.90	68.70	5.60	5.00	100.00
Broom Creek	5821.8	5822.8	2.50	70.50	21.10	2.00	1.90	2.00	100.00
Broom Creek	5828.5	5829.5	2.70	58.00	35.50	1.00	1.30	1.50	100.00
Broom Creek	5834.2	5835.2	1.40	2.10	88.40	5.00	3.00	0.10	100.00

* Illite component of clays.

** NA; no illite component was detected by XRD.

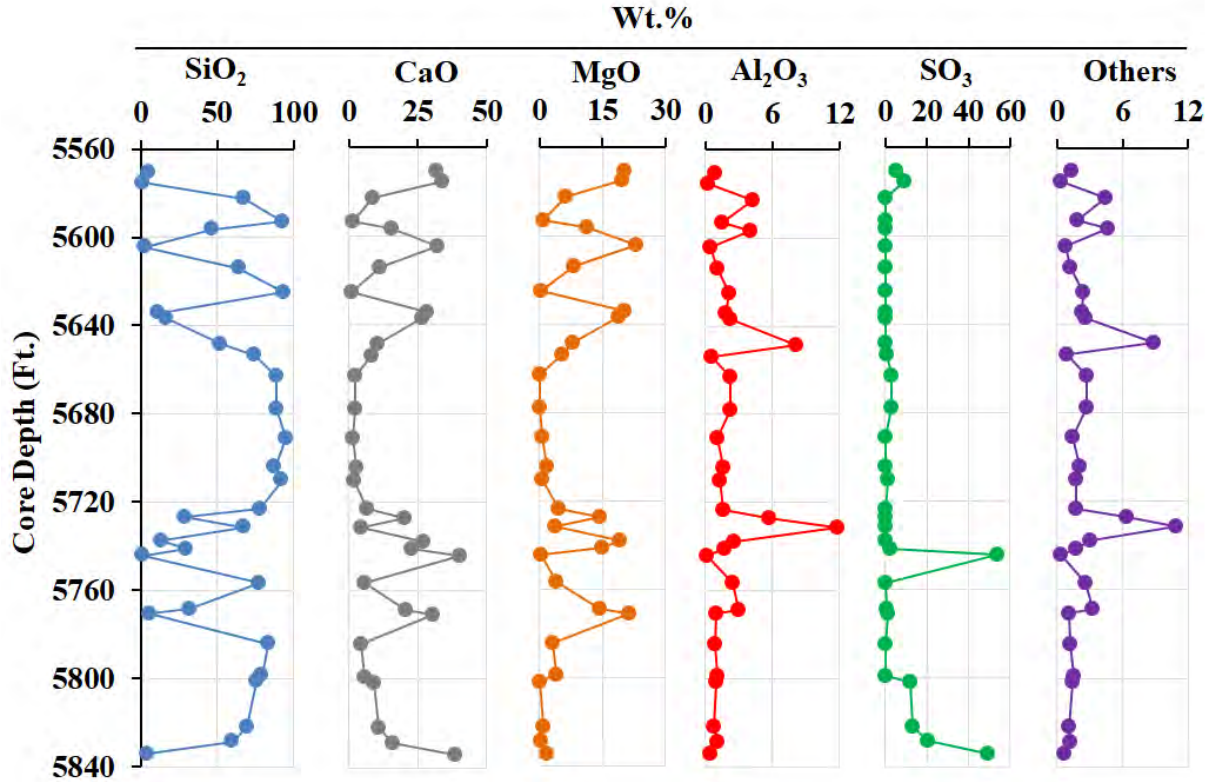


Figure 2-17b. Elemental composition by XRF as a function of depth in the Broom Creek Formation at Slash Lazy H 5.

Thin-section and SEM-EDS (energy-dispersive spectroscopy) micrographs of the most porous sample located at the Broom Creek Formation midsection at the core depth of 5691 ft – KB elevation of 5692 ft show moderately sorted subangular to subrounded quartz and feldspar grains, with quartz constituting about 89% of the composition (Figures 2-18a and c). Contact between the grains is mostly tangential with intergranular spaces occasionally occupied by dolomite and halite (Figure 2-18c). In contrast, the least porous sample located at the Broom Creek–Amsden boundary at 5834.2 ft – KB elevation of 5835.2 ft primarily consists of anhydrite (~88%) with feldspar and quartz clasts making this layer an ultralow permeable layer (Figures 2-18b and d). Figure 2-19 shows changes in the mineralogy at Slash Lazy H 5 as a function of depth next to the core sample porosity and permeability data. The Broom Creek Formation is highlighted in gray.

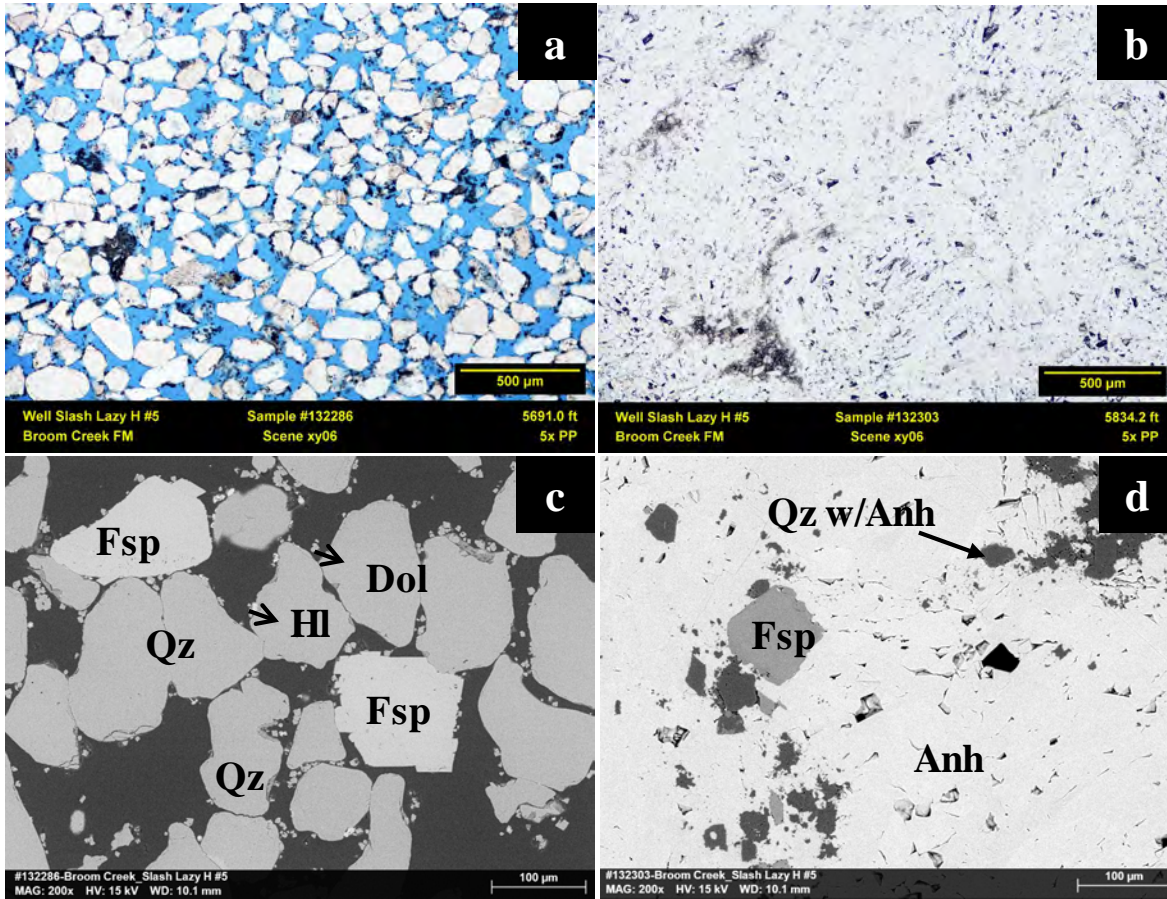


Figure 2-18. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Broom Creek Formation at Slash Lazy H 5. The most porous sample has a total porosity and permeability of 32% and >2000 mD, respectively, which notably reduced to 1.3% and 0.0265 mD in the least porous sample. The blue color in the thin sections a and b represents porosity.

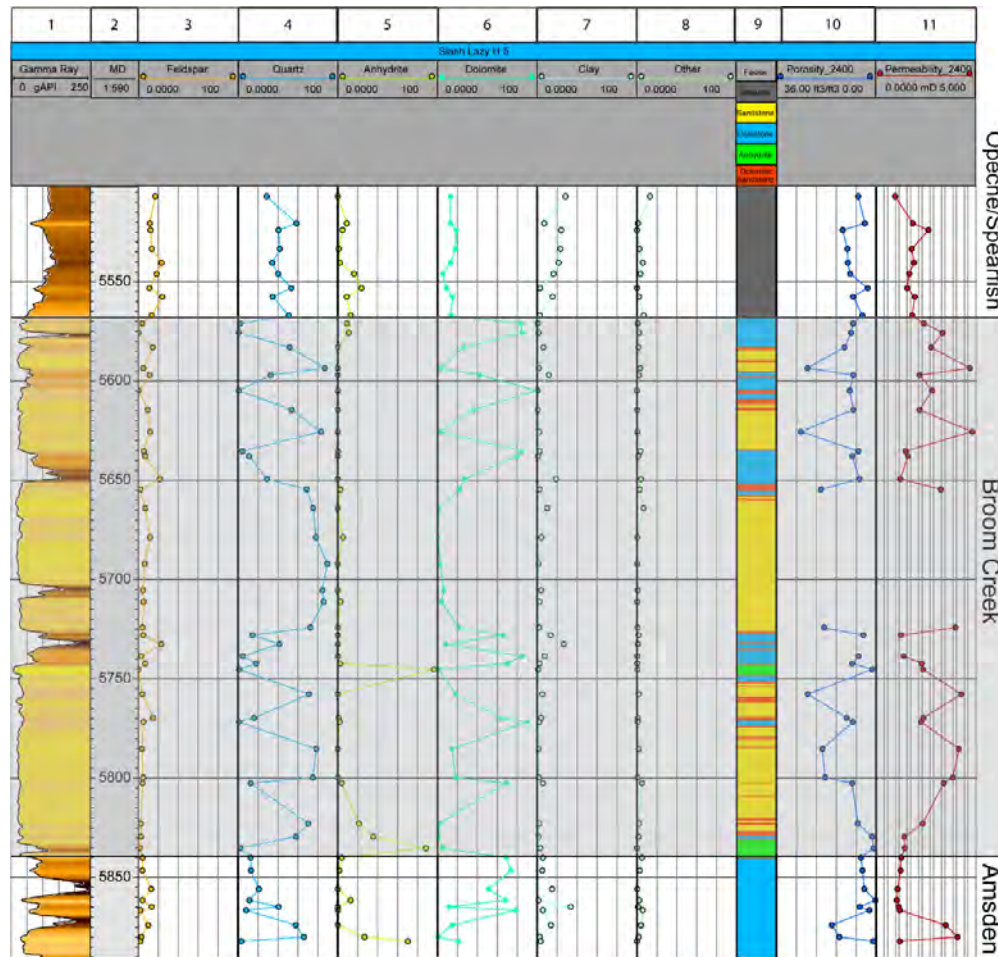


Figure 2-19. Change in the mineralogy of the target reservoir Broom Creek Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.3.2 Mechanism of Geologic Confinement

For the KJ Hintz, the initial mechanism for geologic confinement of CO₂ injected into the Broom Creek Formation will be the upper confining formation (Opeche/Spearfish Formation), which will contain the initially buoyant CO₂ in the reservoir under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO₂ will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO₂ into the native formation brine), confining the CO₂ within the proposed storage reservoir. After injected CO₂ becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period (>100 years), mineralization of the injected CO₂ will ensure long-term, permanent geologic confinement. Injected CO₂ is not expected to adsorb to any of the mineral constituents of the target formation; therefore, this process is not considered to be a viable trapping mechanism in this project.

2.3.3 Geochemical Information of the Injection Zone

Geochemical simulation was performed to calculate the effects of introducing the CO₂ stream to the injection zone. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum BHP and maximum wellhead pressure (WHP) constraints of 3663 and 2100 psi, respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO₂ injection is stopped.

A geochemical simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared. The results do not show an evident difference in the CO₂ gas molality fraction between the two cases for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection rate have no observable difference between the geochemical and nongeochemical cases. Additionally, the simulation results showed no significant precipitation caused by the presence of O₂ that would affect the CO₂ injection volume, as demonstrated by the comparison in injection rates between the case with and without geochemical modeling. Simulation results show that during CO₂ injection, the supercritical CO₂ (free CO₂ gas) remains dominant. CO₂ dissolution in the formation water and residual trapping of CO₂ slowly increased over time, while CO₂ mineralization is negligible. The result is a small change in simulated porosity, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years of postinjection. A full description of the geochemical results for the injection zone can be found in Appendix C.

2.4 Confining Zones

The confining zones for the Broom Creek Formation are the overlying Opeche/Spearfish Formation and the underlying Amsden Formation (Figure 2-2, Table 2-7b). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.

Table 2-7b. Properties of Upper and Lower Confining Zones at the Slash Lazy H 5

Confining Zone Properties	Upper Confining Zone	Lower Confining Zone
Stratigraphic Unit	Opeche/Spearfish	Amsden
Lithology	Siltstone/anhydrite/ dolostone	Dolostone/ anhydrite/sandstone
Formation Top Depth (MD), ft	5389	5840
Thickness, ft	179	242
Capillary Entry Pressure (brine/CO ₂), psi	61.04	307.61
Depth below Lowest Identified USDW, ft	3702	4153

Formation	Property	Simulation Model	
		Laboratory Analysis	Property Distribution
Opeche/Spearfish	Porosity, % *	7.7 (3.1–12.1)	2.1 (0.0–14.6)
	Permeability, mD **	0.0512, 0.0126 (0.0004–0.3620)	0.1088, 0.0021 (0.00–6.37)
Amsden	Porosity, % *	4.7 (0.3–13.3)	2.9 (0.0–35.1)
	Permeability, mD **	15.6259, 0.0045 (0.0006– 125.0000)	0.7056, 0.0070 (0.00–156.05)

* Porosity values recorded at 2400-psi confining pressure. Porosity values from the model are reported as the arithmetic mean followed by the range of values in parentheses.

** Permeability values recorded at 2400-psi confining pressure. Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation.

2.4.1 Upper Confining Zone

In KJ Hintz, the upper confining zone, the Opeche/Spearfish Formation, consists of predominantly siltstone with interbedded dolostone and anhydrite (Table 2-7b). The upper confining zone is laterally extensive across the simulation model area (Figure 2-20) and is 5389 ft below KB elevation and 179 ft thick as observed in Slash Lazy H 5 (Figures 2-20 and 2-21). The contact between the underlying Broom Creek Formation and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Opeche/Spearfish Formation (Figure 2-11).

KJ HINTZ/SLASH LAZY H 5

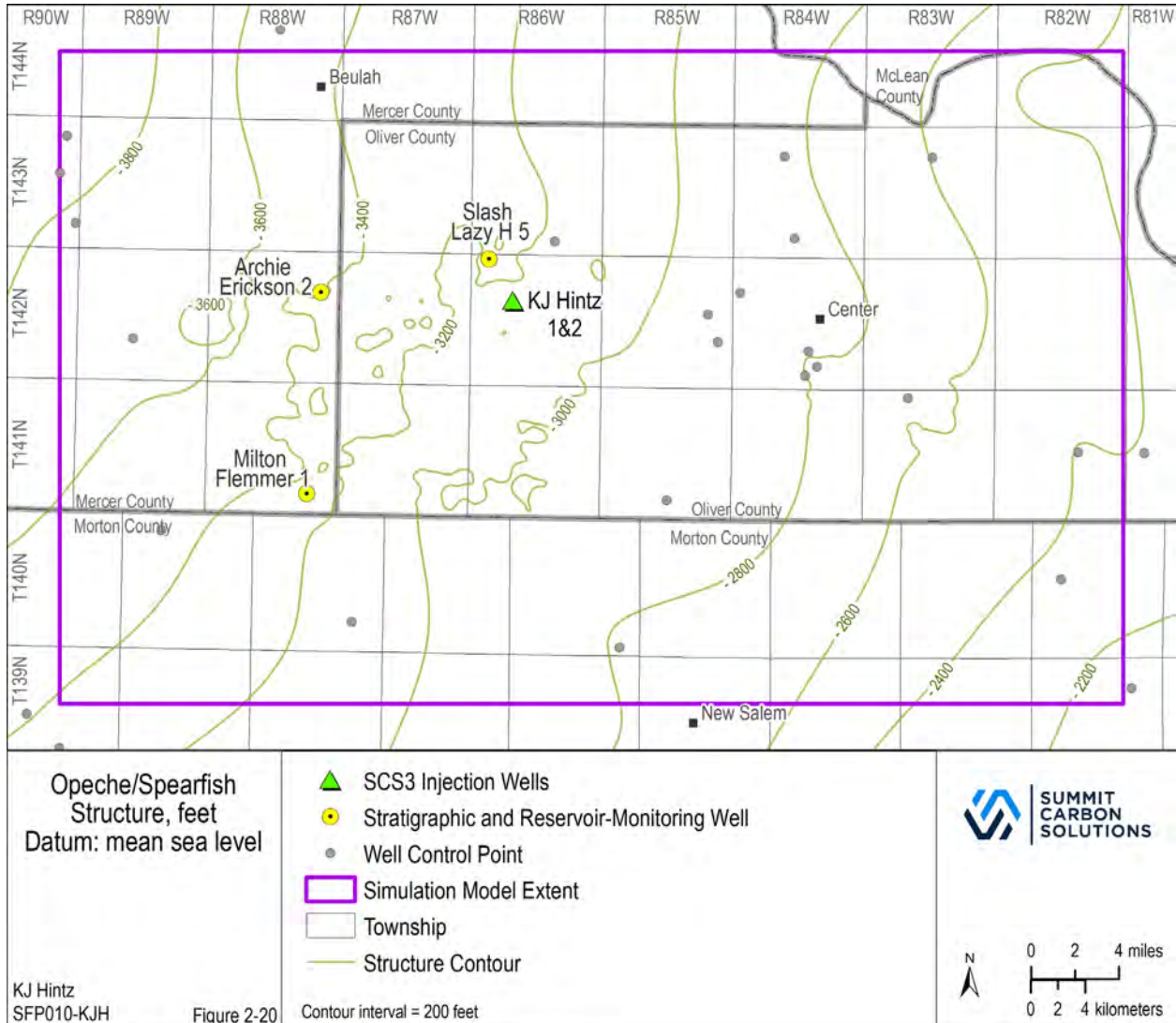


Figure 2-20. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

KJ HINTZ/SLASH LAZY H 5

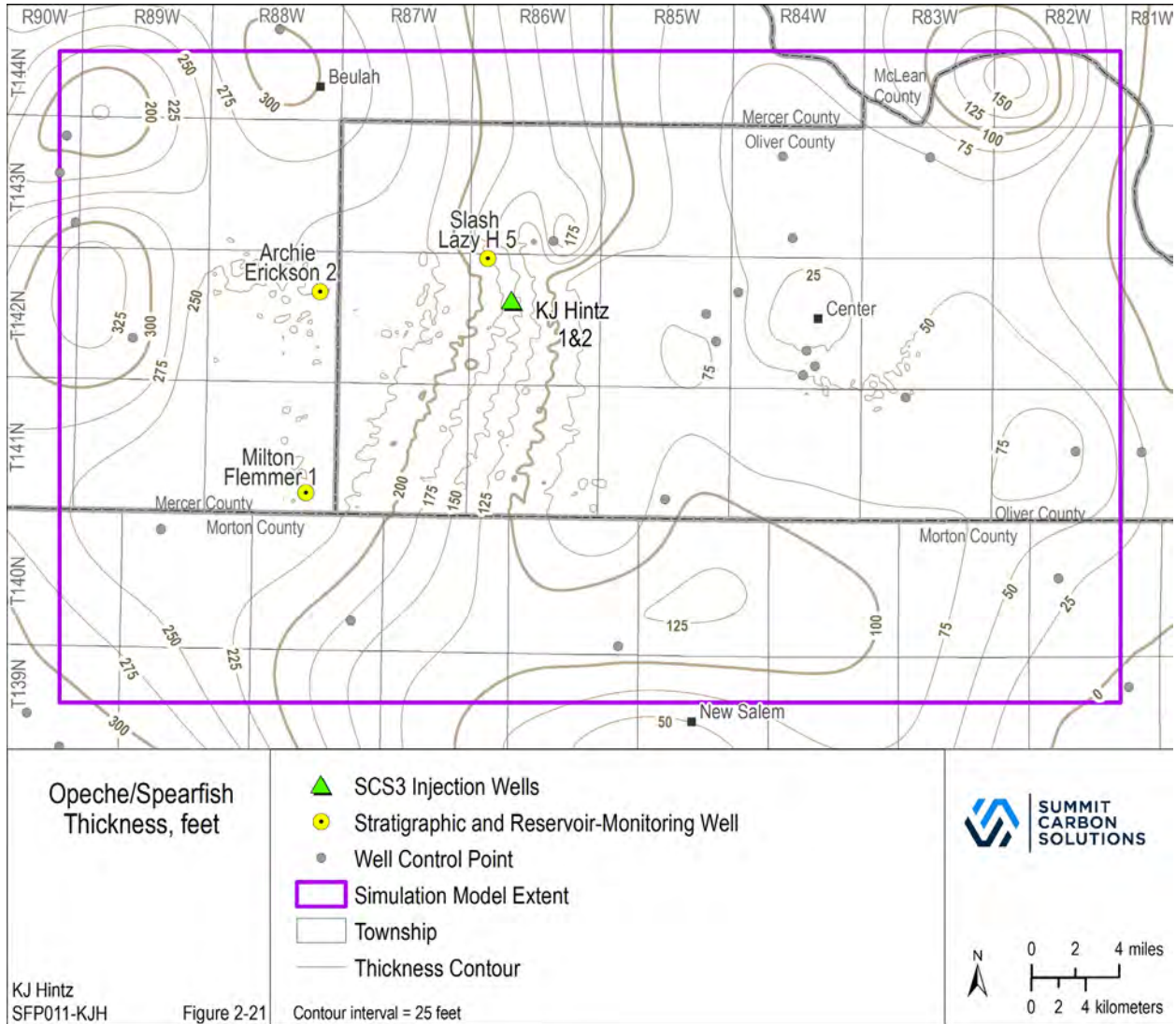


Figure 2-21. Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

2.4.1.1 Mineralogy of the Upper Confining Zone

Powder XRD for average bulk composition analysis of nine finely ground, homogenized samples from the Opeche/Spearfish Formation shows quartz as the most common mineral (~38%) followed by carbonates (~23%, mostly dolomite with minor contributions from ankerite and calcite), feldspar (~15%, mostly K-feldspar), clay minerals (~14%, mostly illite with minor contributions from chlorite and kaolinite), and sulfates (~9%, mostly anhydrite) (Figure 2-22a). Minor amounts of oxide/hydroxide (~0.5%) and sulfide (~0.1%) minerals make up the rest of the mineralogy. The major constituents of the Opeche/Spearfish Formation obtained by XRD are also shown in Table 2-7c. XRD data align with the average elemental composition obtained by XRF, which shows silica (Si) as the dominant element followed by calcium (Ca), aluminum (Al), magnesium (Mg), sulfur (S), potassium (K), iron (Fe), and other trace elements (Figure 2-22b).

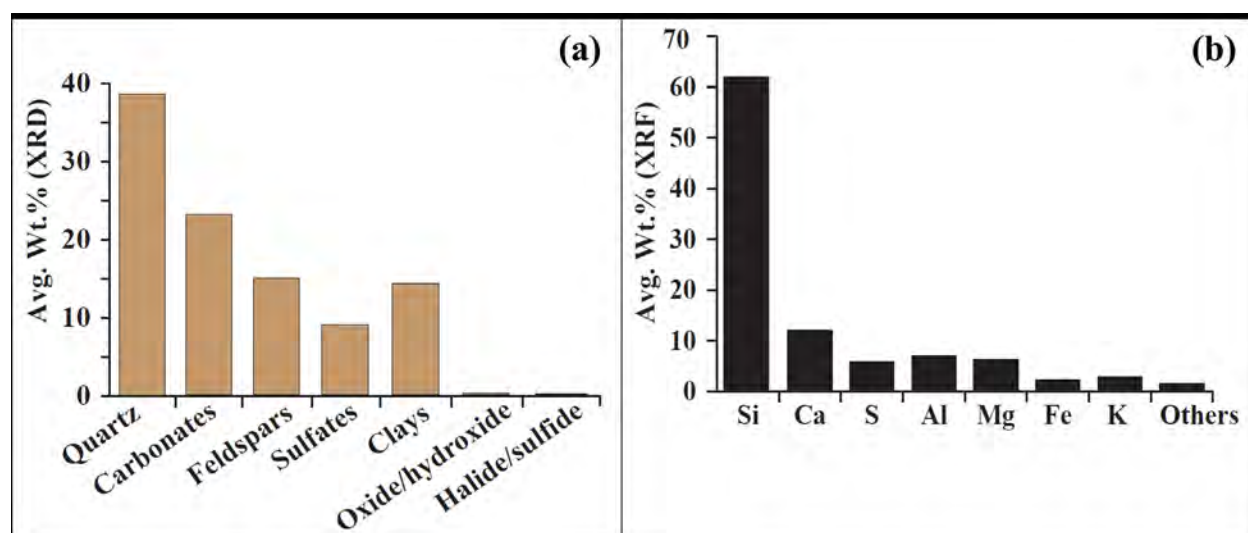


Figure 2-22a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Opeche/Spearfish Formation at the Slash Lazy H 5 (note: elemental data by XRF were determined as oxides of the respective elements).

XRF analysis of the Opeche/Spearfish Formation (Figure 2-22b) identifies SiO_2 (55%–72%), CaO (6%–13%), Al_2O_3 (2%–11%), and MgO (2%–9%), correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. A high percentage of CaO (~32%) and MgO (~20%) with SO_3 (5%) at the base of the Opeche/Spearfish Formation indicates the presence of a dolomite and anhydrite interval separating the Opeche/Spearfish Formation from the Broom Creek Formation. The Opeche/Spearfish Formation consists of clay content ranging from 0.5% to 28%, with an average of ~14%, with illite being the most dominant clay type.

KJ HINTZ/SLASH LAZY H 5

Table 2-7c. XRD Analysis of the Opeche/Spearfish Formation at Slash Lazy H 5. Only major constituents are shown.

Formation	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others wt%	Illite/Total Clay,* wt%
Opeche/Spearfish	5506.5	5507.0	17.00	28.70	0.00	13.00	28.30	13.00	41.70
Opeche/Spearfish	5520.0	5520.5	11.60	58.50	9.00	13.00	7.00	0.90	67.14
Opeche/Spearfish	5523.5	5524.0	12.20	40.60	4.70	18.60	23.90	0.00	94.98
Opeche/Spearfish	5533.0	5533.5	13.50	41.90	1.00	17.90	23.30	2.40	82.40
Opeche/Spearfish	5540.0	5540.5	23.40	34.30	2.00	13.10	21.40	5.80	90.65
Opeche/Spearfish	5545.5	5546.0	18.40	40.20	16.30	5.40	16.30	3.40	93.87
Opeche/Spearfish	5552.7	5553.2	11.10	53.40	23.80	8.80	2.90	0.00	100.00
Opeche/Spearfish	5557.0	5557.5	24.00	34.70	8.90	15.00	15.40	2.00	100.00
Opeche/Spearfish	5566.5	5567.0	13.40	50.90	12.80	13.60	2.50	6.80	100.00

*Illite component of clay.

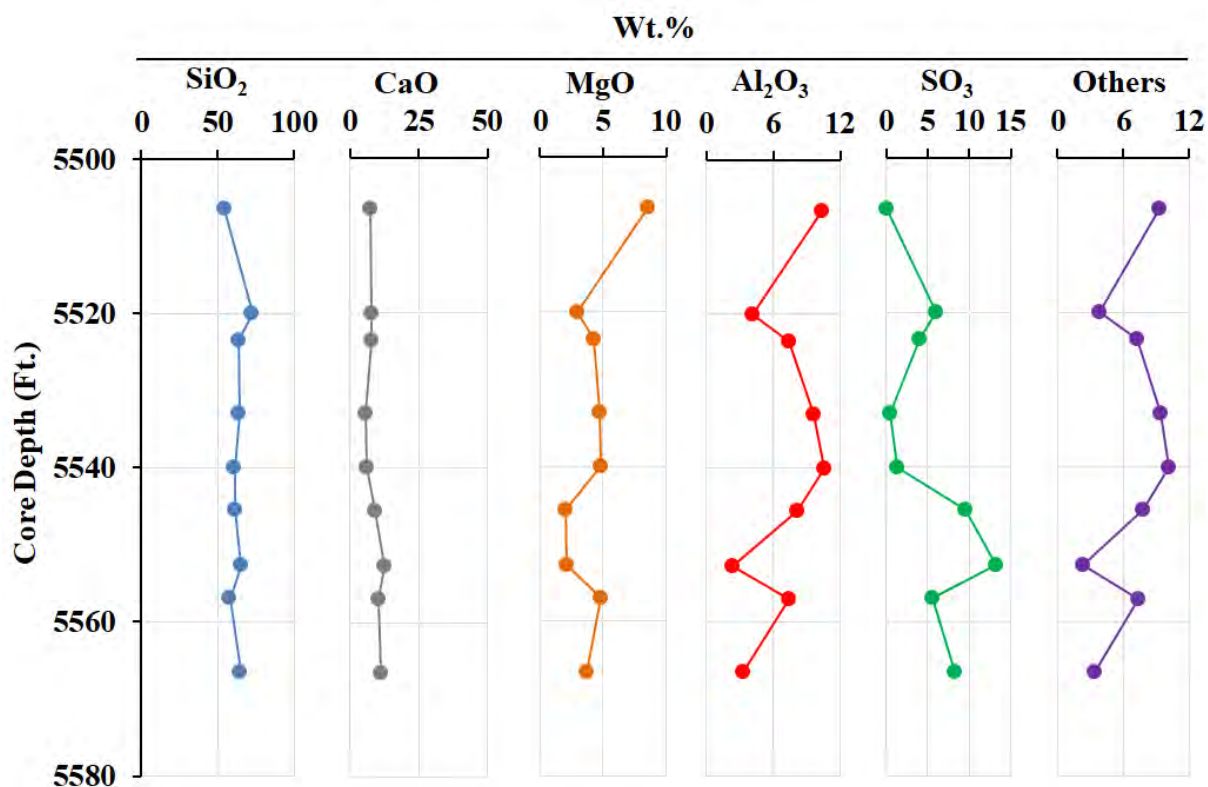


Figure 2-22b. Elemental composition by XRF as a function of depth in the Opeche/Spearfish Formation at Slash Lazy H 5.

Thin-section and SEM-EDS micrographs of the most porous sample at the core depth of 5523.5 ft – KB elevation of 5524 ft show tightly associated, moderately sorted fine-grained subrounded to subangular quartz and feldspar grains. Contacts between the grains are mostly long, sutured, and concavo-convex grain creating isolated and discontinuous pore spaces (Figures 2-23a and 2-23c). The least porous sample at the core depth of 5552.7 ft – KB elevation of 5553.2 ft is mainly composed of highly cemented, poorly sorted quartz and feldspar grains (Figures 2-23b and 2-23d) creating an ultralow permeable layer. Figure 2-24 shows changes in the mineralogy at the Slash Lazy H 5 well as a function of depth next to the core sample porosity and permeability data. The Opeche/Spearfish Formation is highlighted in gray.

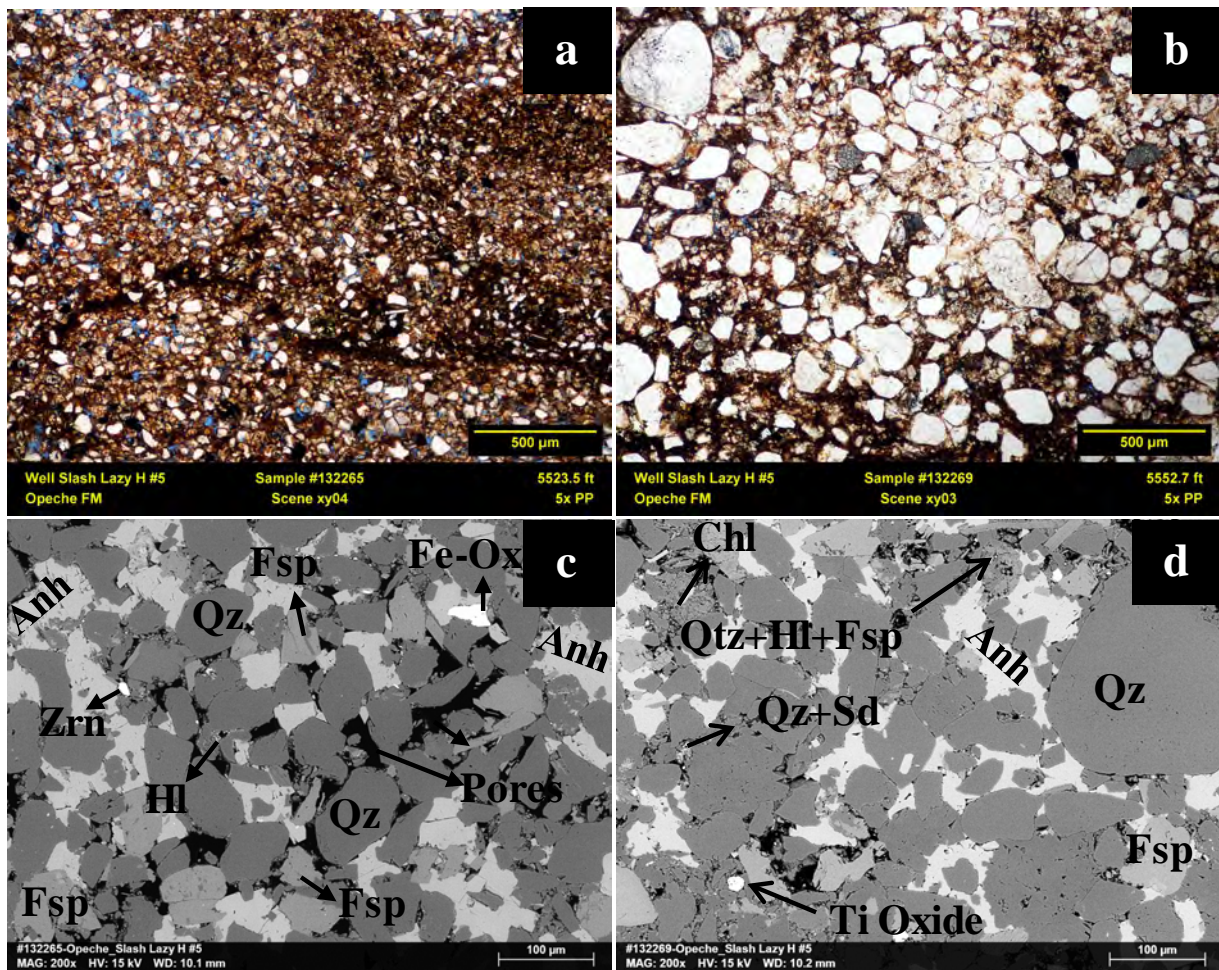


Figure 2-23. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Opeche/Spearfish Formation at the Slash Lazy H 5 well. The most porous sample has a total porosity and permeability of 12.42% and 0.46 mD, respectively, which is notably reduced to 4.31% and 0.0367 mD in the least porous sample. The blue color in thin sections a and b represents porosity.

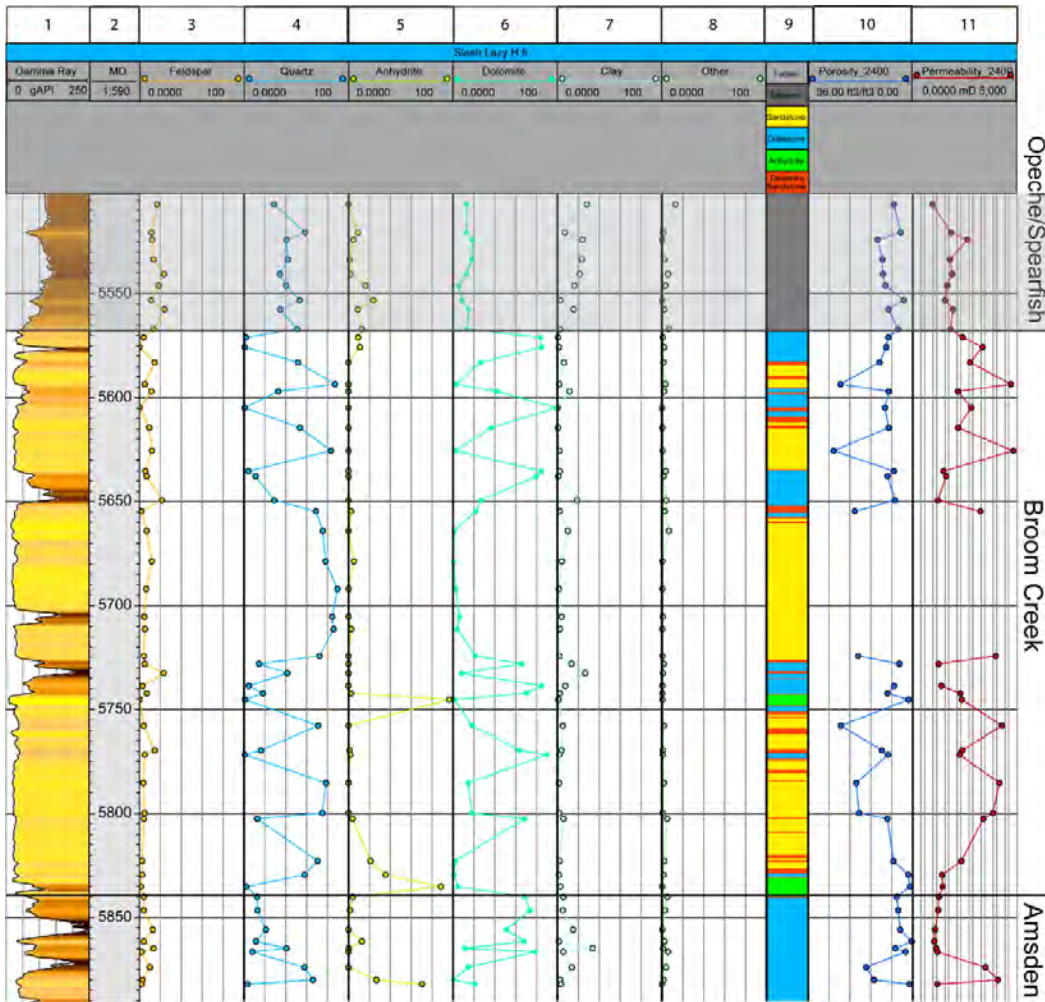


Figure 2-24. Change in the mineralogy of the upper-confining Opeche/Spearfish Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Very low total porosity and permeability with a high clay content make the Opeche/Spearfish Formation an ultralow permeable formation. Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.4.1.2 Geochemical Interaction

Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO₂ stream on the Opeche/Spearfish Formation. This geochemical simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Results showed geochemical processes at work. The pH at the interface between the injection zone and upper confining zone has the greatest change in value, declining from its initial value of 6.47 to a level of 5.05 after 10 years of injection and stabilizing at 5.03 by the end of 25 years of postinjection. K-feldspar starts to dissolve from the beginning of the simulation period, while illite and quartz start to precipitate at the same time. The net change due to precipitation or dissolution at a 1–2-meter interval above the injection zone is less than 5 kg per cubic meter, with little dissolution or precipitation taking place during the later years of simulation. The overall net porosity changes from dissolution and precipitation are minimal, less than 0.1% change during the life of the simulation. These results suggest that geochemical change from exposure to CO₂ is minor; therefore, the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes. A full description of the geochemical results for the upper confining zone can be found in Appendix C.

2.4.2 Additional Overlying Confining Zones

Several other formations provide additional confinement above the Opeche/Spearfish Formation. Impermeable rocks above the primary seal include the Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-8a). At the Slash Lazy H 5, together with the Opeche/Spearfish Formation, these intervals are 1116 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-25). Above the Inyan Kara Formation, 2571 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and the lowermost USDW, the Fox Hills Formation (Figure 2-26). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-8a).

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

Table 2-8a. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the Slash Lazy H 5)

Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft
Pierre	Mudstone	1687	1429	0
Niobrara	Mudstone	3116	389	1429
Carlile	Mudstone	3505	49	1818
Greenhorn	Mudstone	3554	105	1867
Belle Fourche	Mudstone	3659	287	1972
Mowry	Mudstone	3946	82	2259
Skull Creek	Mudstone	4033	225	2346
Swift	Mudstone	4452	535	2765
Rierdon	Mudstone	4987	208	3300
Piper (Kline Member)	Carbonate	5195	108	3508
Piper (Picard Member)	Mudstone	5303	86	3616

KJ HINTZ/SLASH LAZY H 5

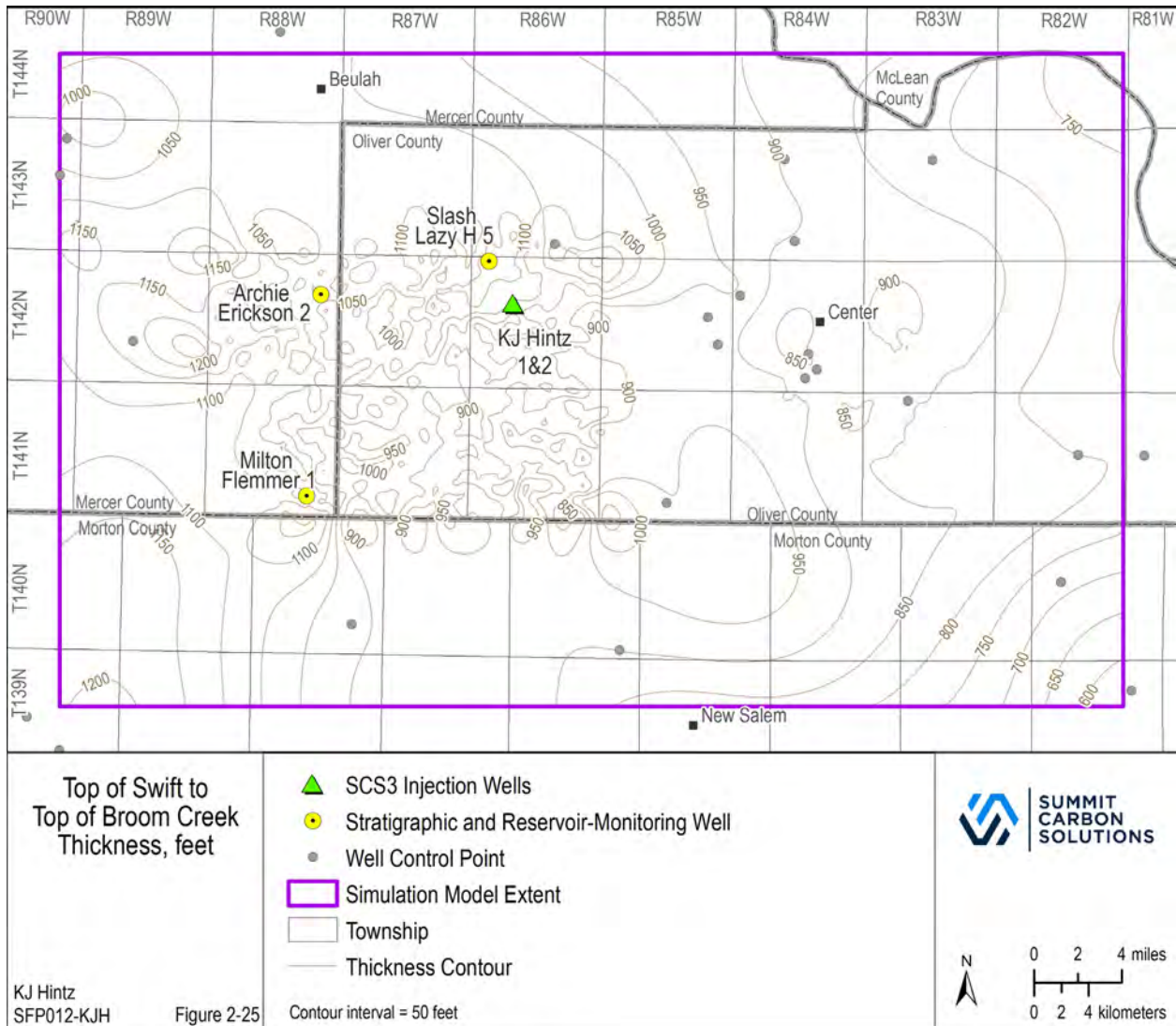


Figure 2-25. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability stratigraphically above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensor data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5.0). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO₂ would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Slash Lazy H 5 location is 4258 ft below KB elevation, and the interval itself is 194 ft thick.

KJ HINTZ/SLASH LAZY H 5

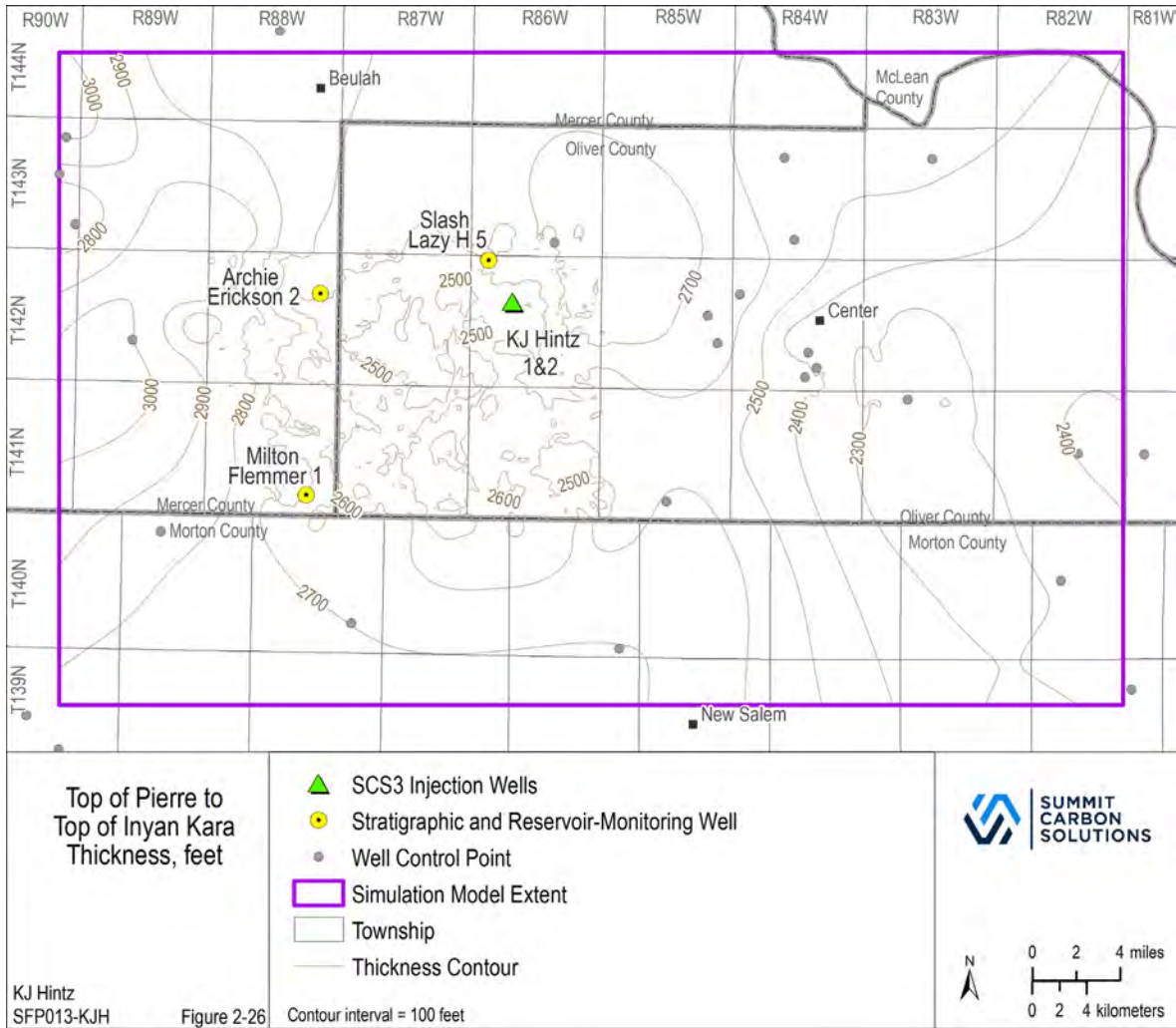


Figure 2-26. Isopach map of the interval between the top of the Inyan Kara Formation and the top of the Pierre Formation. This interval represents the tertiary confinement zone. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

2.4.3 Lower Confining Zone

The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, and anhydrite. The Amsden Formation does include some thin sandstone intervals on the order of 1 to 8 in. thick. The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone and anhydrite intervals. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the simulation model area (Figure 2-11). The Amsden Formation is 5840 ft below KB elevation and 242 ft thick at the KJ Hintz as determined at the Slash Lazy H 5 (Figures 2-27 and 2-28).

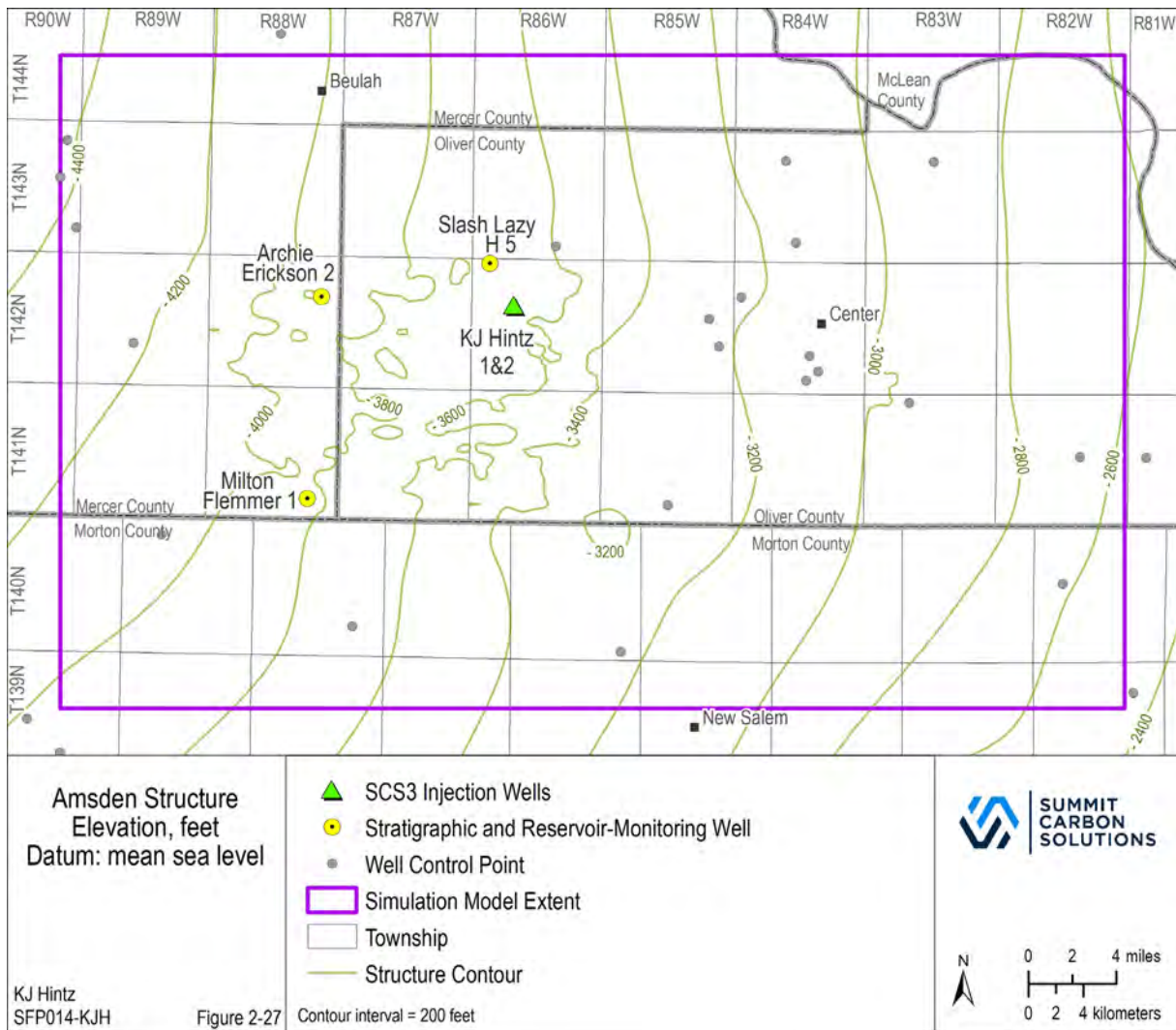


Figure 2-27. Structure map of the Amsden Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

KJ HINTZ/SLASH LAZY H 5



Figure 2-28. Isopach map of the Amsden Formation across the simulation model area. The convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map.

The contact between the underlying Amsden Formation and the overlying Broom Creek Formation is evident on wireline logs as there is a lithological change from the dolostone and anhydrite beds of the Amsden Formation to the porous sandstones of the Broom Creek Formation (Figure 2-11). The top of the Amsden in Slash Lazy H 5 is picked at the base of a 10-ft anhydrite bed in the Broom Creek Formation, which can be correlated across much of the study area. This lithologic change is also recognized in the core from Slash Lazy H 5. The lithology of the cored section of the Amsden Formation from Slash Lazy H 5 is predominantly dolostone and anhydrite with lesser predominant lithologies of sandstone.

2.4.3.1 Mineralogy of the Lower Confining Zone

Powder XRD for average bulk composition analysis of nine finely ground, homogenized samples from the Amsden Formation shows carbonates as the most common minerals (~45%, mostly dolomite with a minor contribution from ankerite) followed by quartz (~25%), sulfates (~13%, mostly anhydrite with a minor amount of gypsum), clay (~10%, mostly illite), and feldspar (~6%, mostly K-feldspar) (Figure 2-29a[a]). Minor amounts of halide (~0.2%), oxide (~0.1%), and sulfide (~0.03%) make up the rest of the mineralogy. The major constituents of the Amsden Formation obtained by XRD are also shown in Table 2-8b. These data align with the average elemental composition obtained by XRF, which shows silica (Si) as the dominant element followed by calcium (Ca), magnesium (Mg), sulfur (S), aluminum (Al), potassium (K), iron (Fe), and other trace elements (Figure 2-29a[b]).

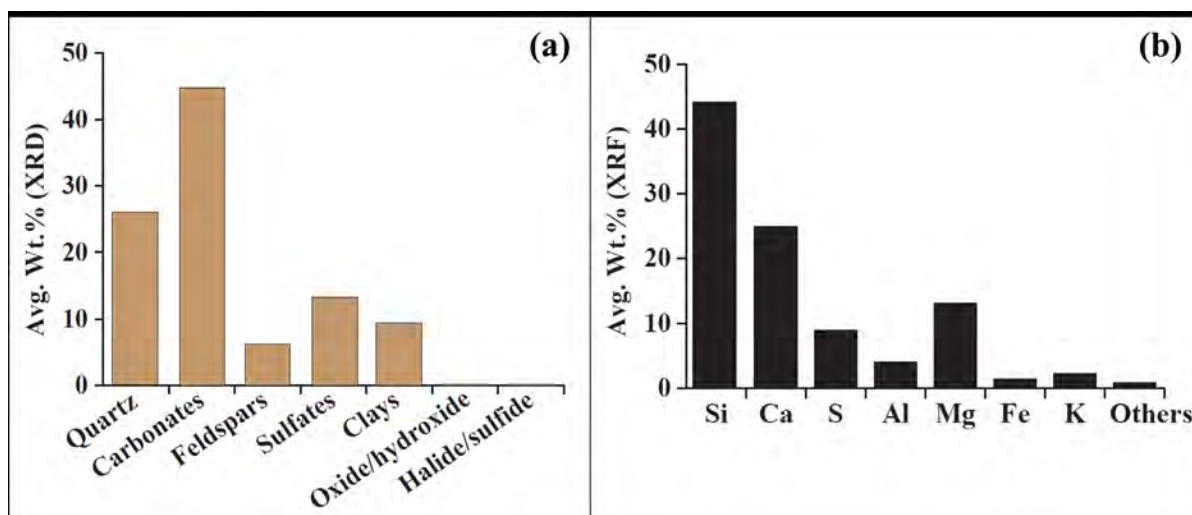


Figure 2-29a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Amsden Formation at the Slash Lazy H 5 well. Elemental data by XRF were determined as oxides of the respective elements.

XRF analysis of the Amsden Formation (Figure 2-29b) shows that the contact between the Amsden and Broom Creek Formations is dominated by SiO_2 , CaO , and MgO , indicating the presence of sandstone and dolomite. As the formation gets deeper, the chemistry changes to more anhydrite-rich, as shown by the high percentage of CaO (~37%) and SO_3 (~40%). The Amsden Formation contains clay as high as 34%, with an average of ~10%, with illite being the dominant clay type.

Similar to the Opeche/Spearfish Formation, the higher content of anhydrite (up to 70% with an average of ~13%) and clay minerals (up to 34% with an average of ~10%) makes the Amsden Formation less porous and more impermeable compared to the target Broom Creek Formation. The thin-section and SEM-EDS micrographs of the most porous sample at the core depth of 5873.5 ft – KB elevation of 5874 ft show moderately sorted, fine-grained subangular quartz and very fine-grained feldspar grains with some anhydrite (Figures 2-30a and c). Iron oxide is also present frequently as a filling material (Figure 2-30c). Contacts between the grains are mostly tangential, long, and sutured as well as concavo-convex creating isolated and discontinuous pore spaces (Figure 2-30c).

Table 2-8b. XRD Analysis of the Amsden Formation at Slash Lazy H 5. Only major constituents are shown.

Formation	Core Depth, ft, MD	Log Depth, ft, MD	Feldspar, wt%	Quartz, wt%	Anhydrite, wt%	Dolomite, wt%	Clay, wt%	Others, wt%	Illite/Total Clay,* wt%
Amsden	5839.5	5840.0	4.20	12.60	3.90	68.70	5.60	5.00	100.00
Amsden	5846.0	5846.5	4.10	12.90	1.50	73.70	5.00	2.80	100.00
Amsden	5855.4	5855.9	12.80	20.90	0.00	51.10	14.90	0.30	100.00
Amsden	5861.0	5861.5	4.10	11.40	12.80	68.10	1.30	2.30	100.00
Amsden	5864.3	5864.8	13.40	40.70	0.00	11.30	33.60	1.00	100.00
Amsden	5866.0	5866.5	2.10	8.00	0.00	78.70	5.50	5.70	100.00
Amsden	5873.5	5874.0	9.90	57.90	0.00	14.60	13.70	3.90	100.00
Amsden	5879.5	5880.0	2.90	66.00	26.70	0.40	2.50	1.50	100.00
Amsden	5881.6	5882.1	2.00	3.30	70.30	21.10	3.30	0.00	100.00

* Illite component of clay.

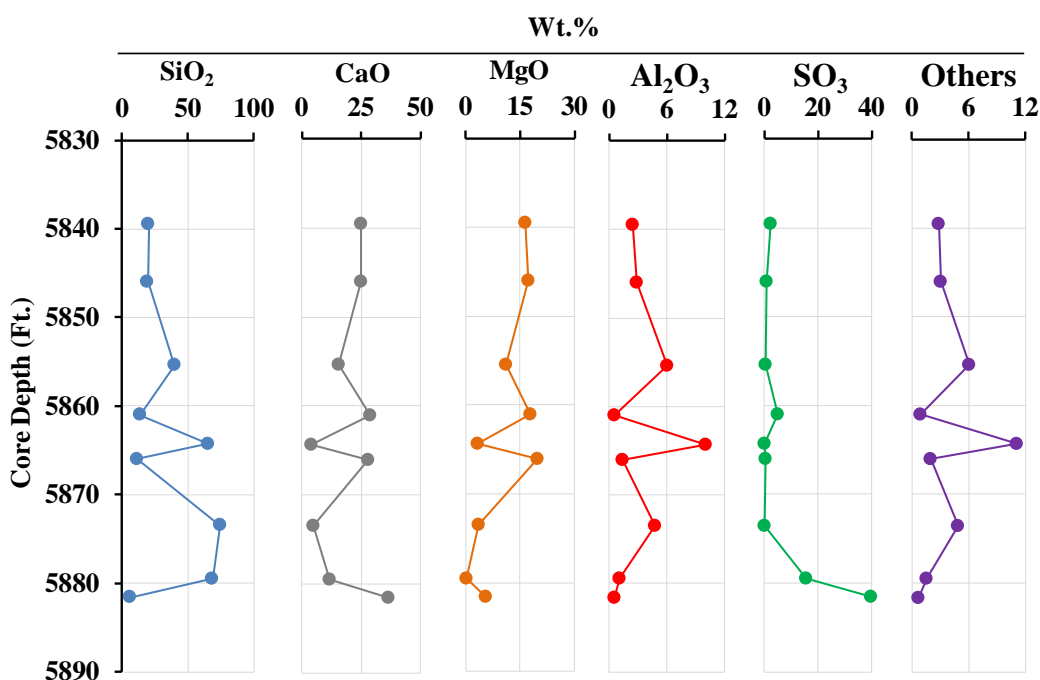


Figure 2-29b. Elemental composition by XRF as a function of depth in the Amsden Formation at Slash Lazy H 5.

The least porous sample located at the bottom of the section at the core depth of 5881.6 ft – KB elevation of 5882.1 ft, predominantly consists of anhydrite with dolomite clasts (Figures 2-30b and d) constituting ~70% and ~21% of the mineralogy, respectively. Figure 2-31 shows changes in the mineralogy at the Slash Lazy H 5 well as a function of depth next to the core sample porosity and permeability data. Although core sample porosity and permeability show a porous and permeable interval between the core depth of 5873.5 (KB elevation of 5874 ft) and 5879.5 ft (KB elevation of 5880 ft) in the Amsden Formation, it must be noted that this layer is isolated and confined between an ultralow permeable dolomite-rich clay layer above and an anhydrite-rich quartz layer below.

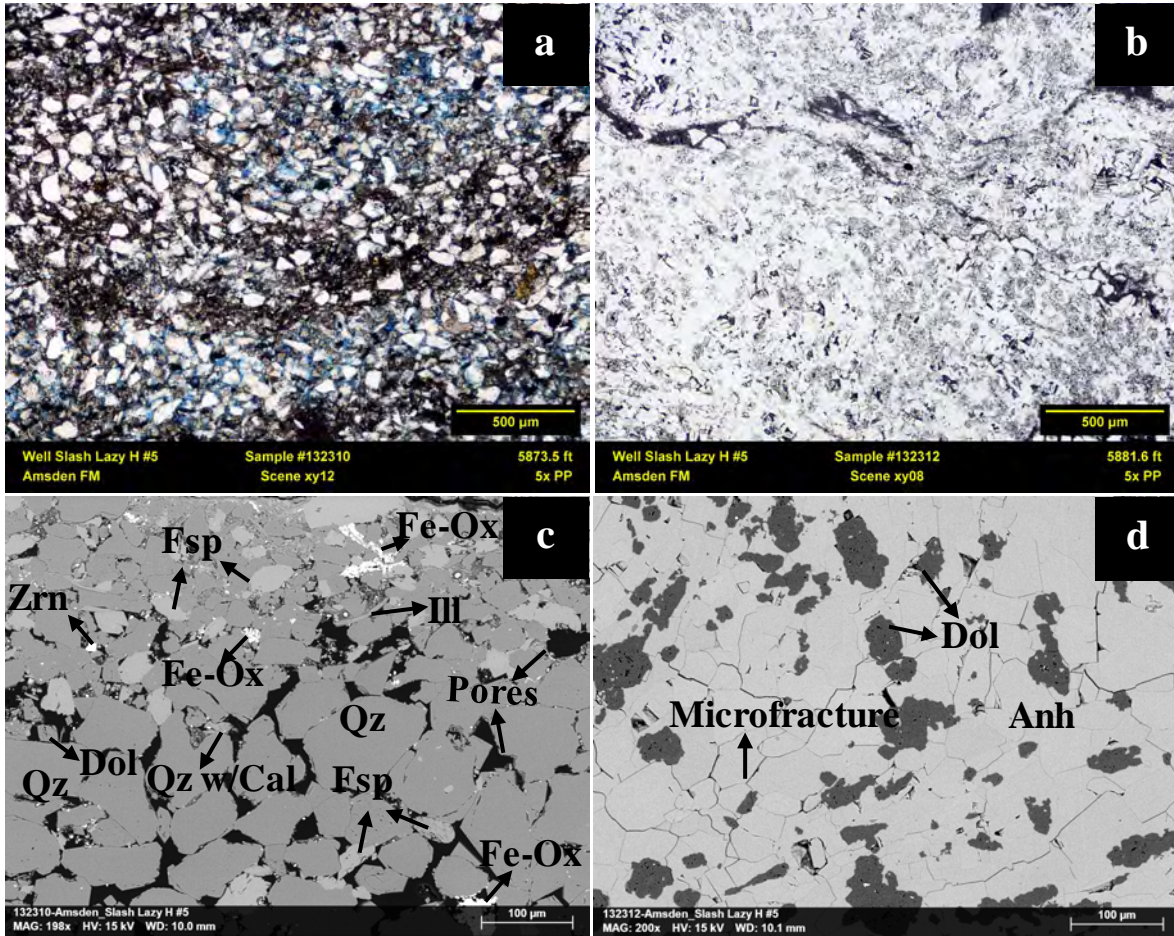


Figure 2-30. Thin-section (a, b) and SEM (c, d) micrographs of the most porous samples (a, c) and the least porous samples (b, d) of the Amsden Formation at Slash Lazy H 5. The most porous sample has a total porosity and permeability of 13.93% and 129 mD, respectively, which notably reduced to 1.58% and 0.00786 mD in the least porous sample. The blue color in thin section a represents porosity.

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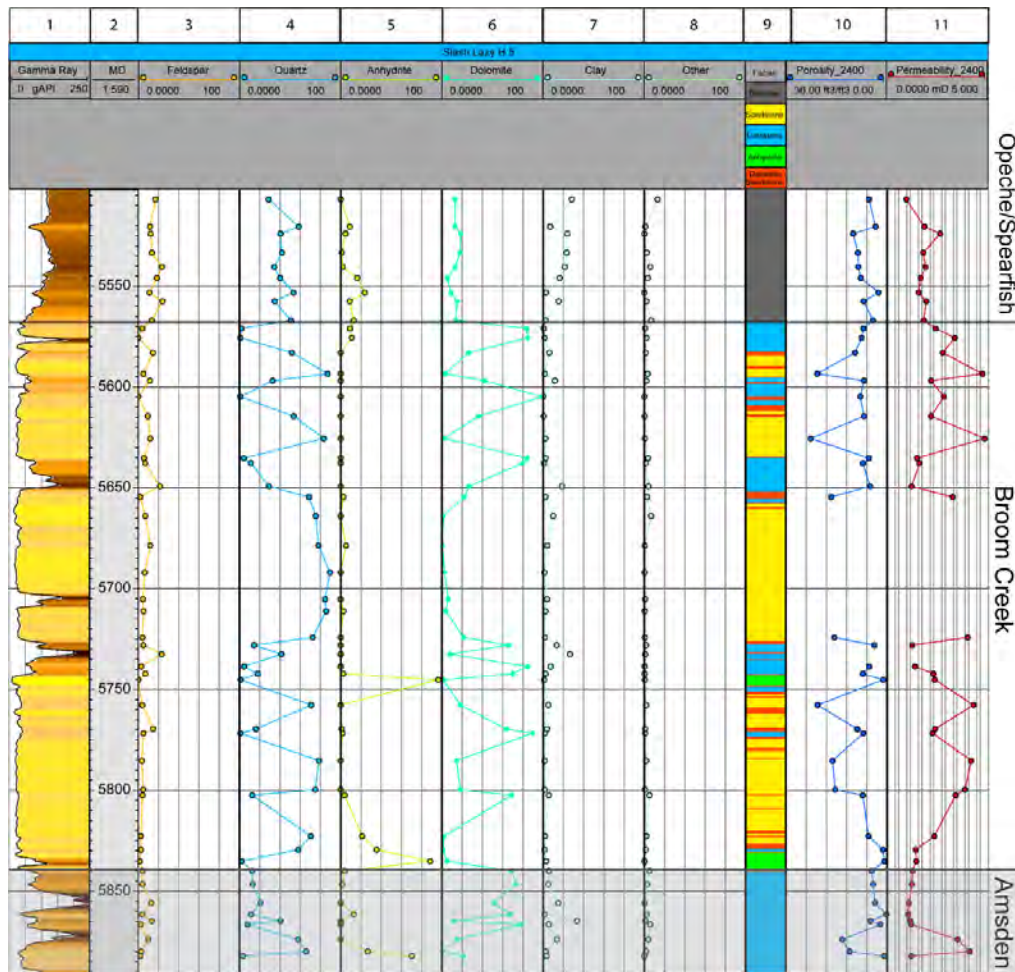


Figure 2-31. Change in the mineralogy of the lower confining Amsden Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red).

2.4.3.2 Geochemical Interaction

Geochemical simulation using PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO₂ stream on the Amsden Formation. This simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Modeling results show geochemical processes at work. The pH at the interface between the injection zone and lower confining zone has the greatest change in value, declining to a level of 5.7 after 7 years of injection, further declining to 4.8 by the end of the modeled injection period, and hitting 4.5 by the end of simulation period. Progressively lower or slower pH changes occur

for each cell that is more distant from the CO₂ interface. Albite and K-feldspar start to dissolve from the beginning of the simulation period, while quartz and illite start to precipitate. Albite and K-feldspar are the primary minerals that dissolve, and their initial fractions have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals. The overall net porosity changes from dissolution and precipitation are minimal, less than 2% change during the life of the simulation. These results suggest that geochemical change from exposure to CO₂ is minor; therefore, the ability of the Amsden Formation to maintain its sealing integrity will not be compromised by geochemical processes. A full description of the geochemical results for the upper confining zone can be found in Appendix C.

2.4.4 Geomechanical Information of Confining Zone

2.4.4.1 Fracture Analysis

Fractures within the overlying confining zone (the Opeche/Spearfish Formation) and the underlying confining zone (Amsden Formation) were assessed during the description of the Slash Lazy H 5 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 Slash Lazy H 5.

2.4.4.2 Core-Fracture Analysis

The fractures observed in the Opeche/Spearfish Formation were tectonic, vertical to subvertical, closed, and cemented with anhydrite. The Amsden Formation was determined to be a nonfractured interval. A few discontinuous closed fractures were noted. The presence of stylolites was also noted in the dolomitic intervals of the Amsden Formation.

2.4.4.3 Borehole Image- Fracture Analysis

Natural fractures and in-situ stresses were assessed through the interpretation of borehole image log, dipole shear sonic slowness (DTS), and DTC (compressional) logs acquired during the drilling of the Slash Lazy H 5 well. A borehole image log provides a 360-degree image of the formation of interest and is oriented to provide an understanding of the general orientation of the observed features.

Fractures within Opeche/Spearfish Formation are primarily resistive continuous fractures, anastomosed without preferential orientation. They are commonly filled with anhydrite (Figure 2-32). No microfaults were found in the Opeche/Spearfish interval. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to millimeter-scale (Figure 2-33a and Figure 2-33b).

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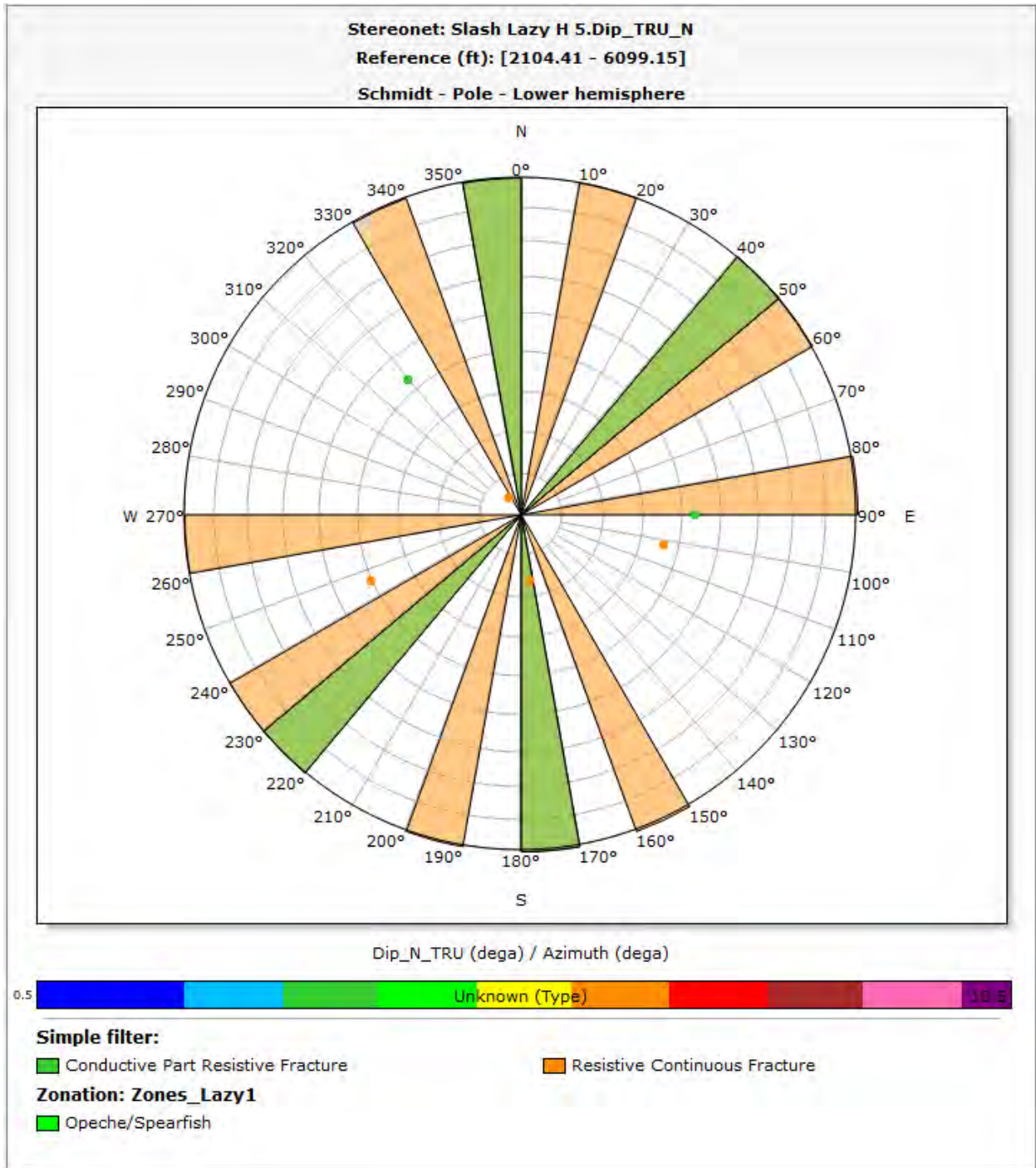


Figure 2-32. Strike orientation per type of fracture that characterizes the Opeche/Spearfish Formation: resistive continuous fractures (orange) and conductive partially resistive fractures (green). Colored dots represent the dip value for corresponding type of fracture and the dip azimuth of the fracture.

KJ HINTZ/SLASH LAZY H 5

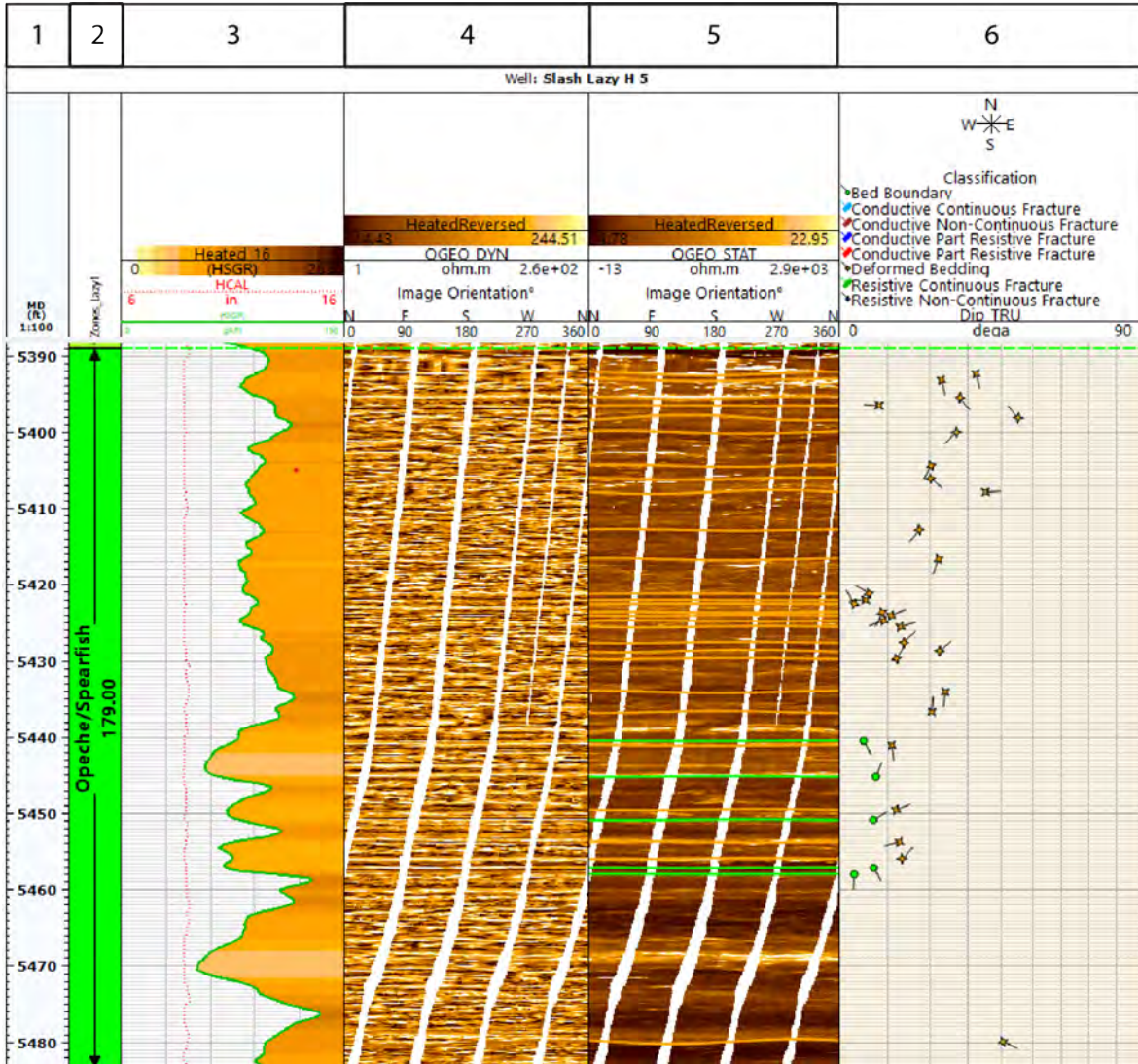


Figure 2-33a. Sedimentary and tectonic features in the Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5389 and 5483 ft MD.

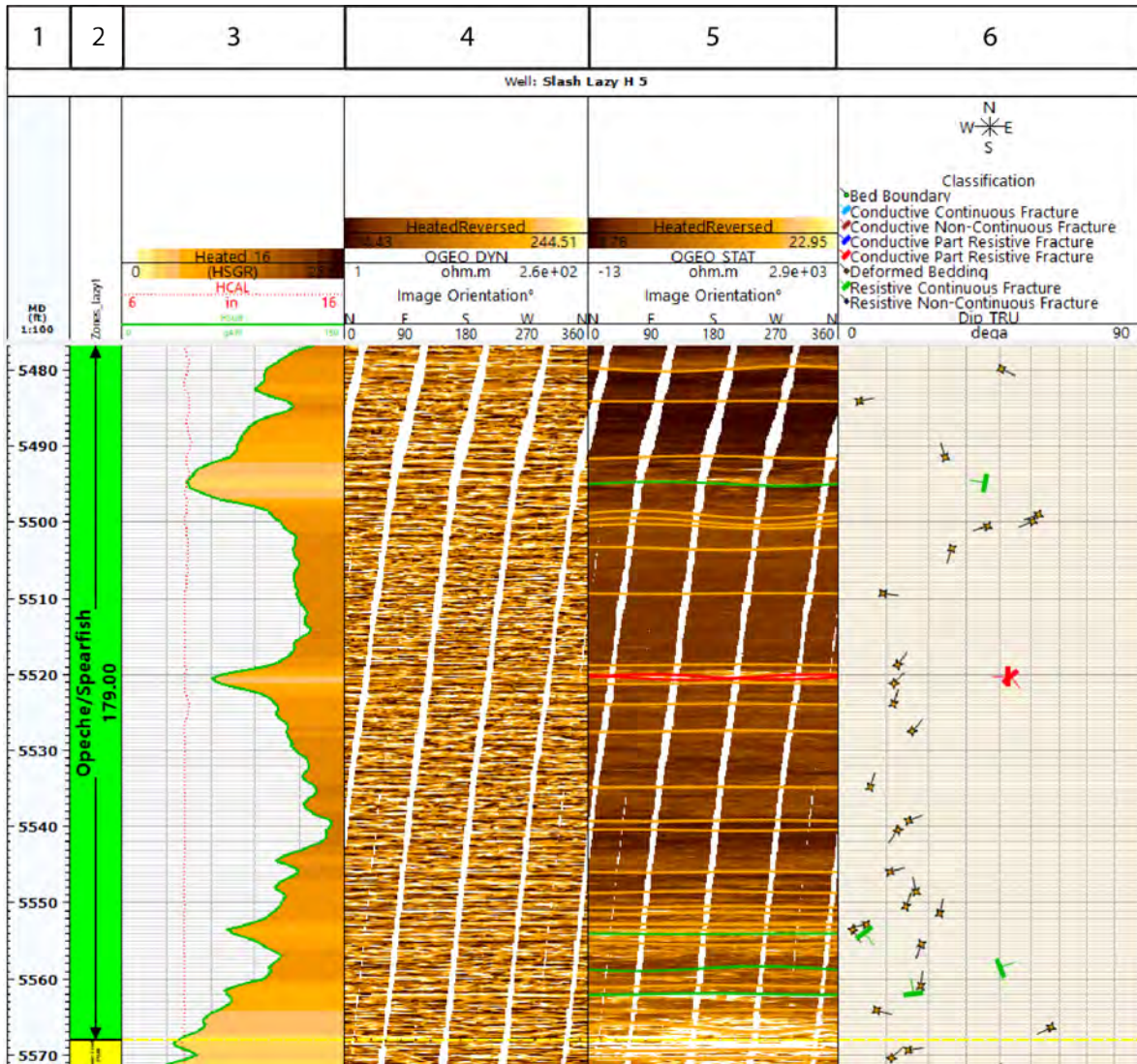


Figure 2-33b. Sedimentary and tectonic features in the Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5477 and 5571 ft MD.

The Amsden Formation is considered a nonfractured interval; however, eleven (11) discontinuous resistive fractures are highlighted with the presence of horizontal compaction features (stylolites). These fractures are filled with quartz and considered closed. The fractures are oriented mainly to N-S, with the presence of NE-SW and NW-SE fracture sets (Figure 2-34) and filled with quartz. The fractures vary in orientation and exhibit oblique and vertical trends. The aperture varies from closed to millimeter-scale (Figure 2-35, and Figure 2-36a and Figure 2-36b).

One conductive partially resistive fracture is highlighted oriented E-W and filled with quartz and clay. Also, five (05) conductive noncontinuous fractures were underlined, oriented N-S, NW-SE, and E-W, and are filled with clay. These fractures are closed and do not constitute any risk for fluid leakage. In addition, one minor fault was present in the Amsden interval at a depth of 6024 ft MD and is located around 190 feet below the bottom of the Broom Creek Formation. Oriented NNE-SSW and dipping to the west with a dip angle equal to 50 degrees, this minor fault shows normal faulting, with an offset of 0.05 ft (Figure 2-36c). The analysis of the different attributes such as the fault's depth, length, strike, dip, offset, and aperture demonstrates that the minor fault appears isolated and does not interact with any fracture network and will not act as a conduit for fluid migration.

KJ HINTZ/SLASH LAZY H 5

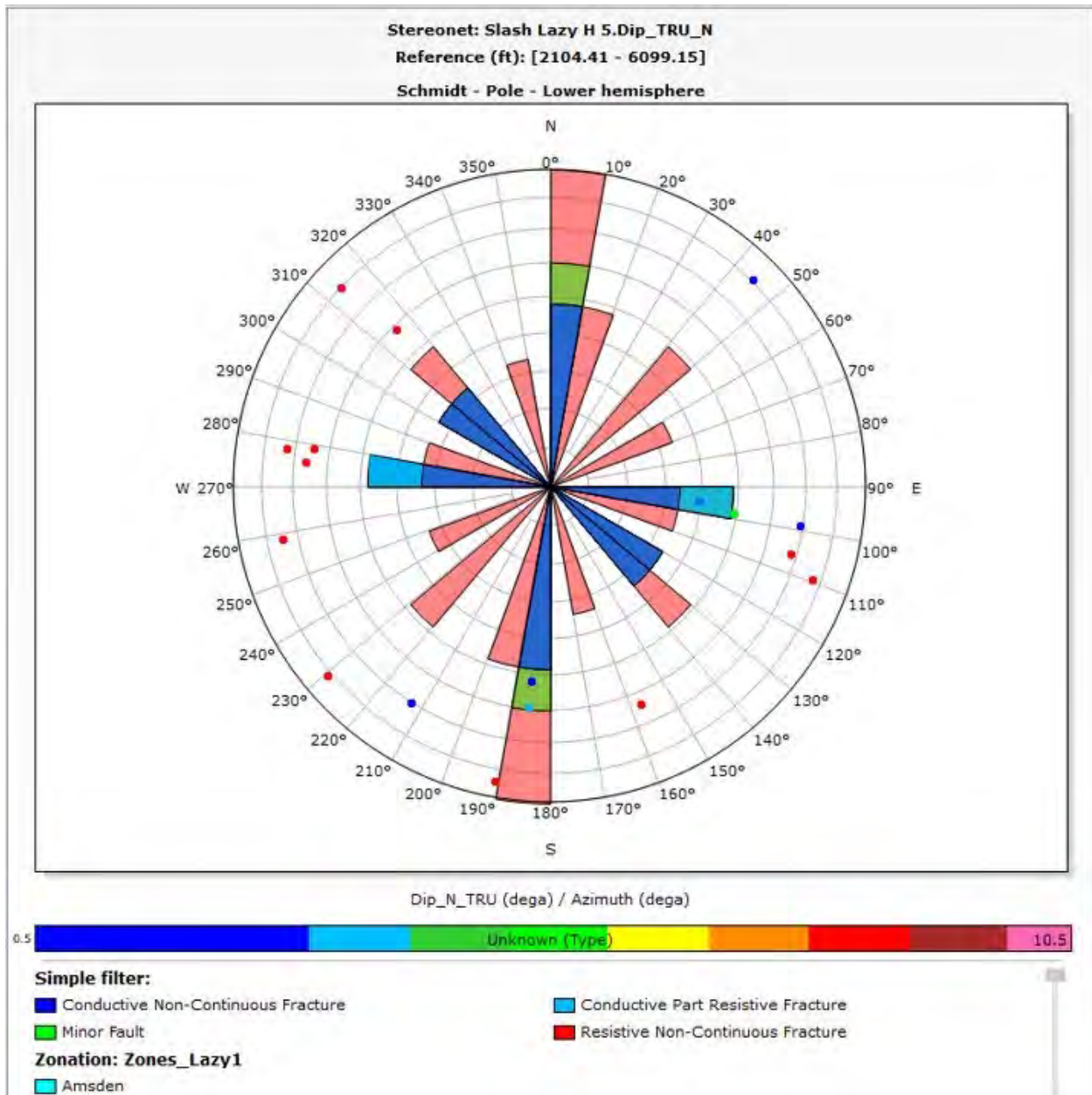


Figure 2-34. Strike orientation per type of fracture that characterizes the Amsden Formation: resistive noncontinuous fractures (red), conductive partially resistive fractures (teal), conductive noncontinuous fractures (blue), and minor fault (green). Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture.

KJ HINTZ/SLASH LAZY H 5

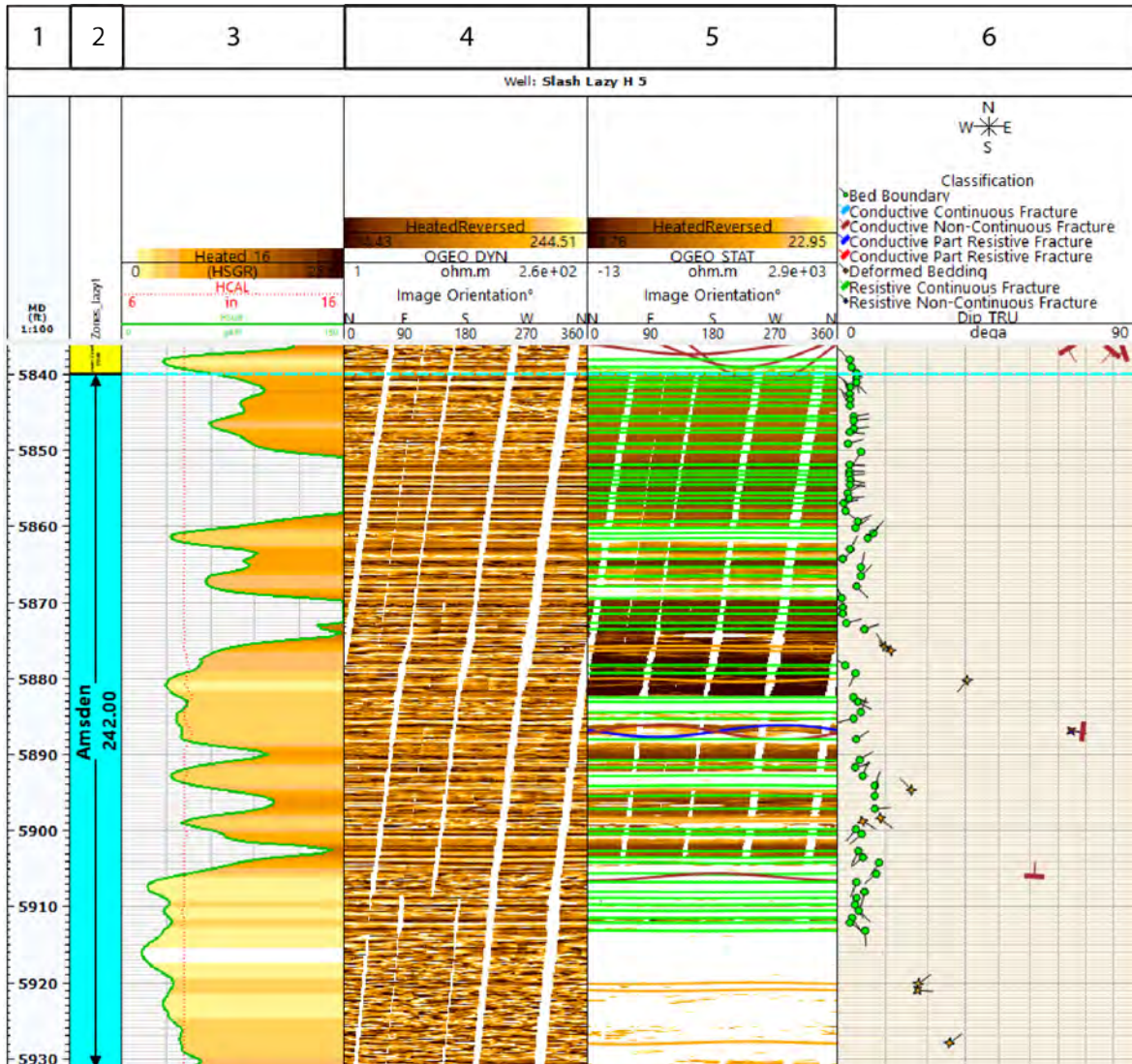


Figure 2-35. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5836 and 5930 ft MD.

KJ HINTZ/SLASH LAZY H 5

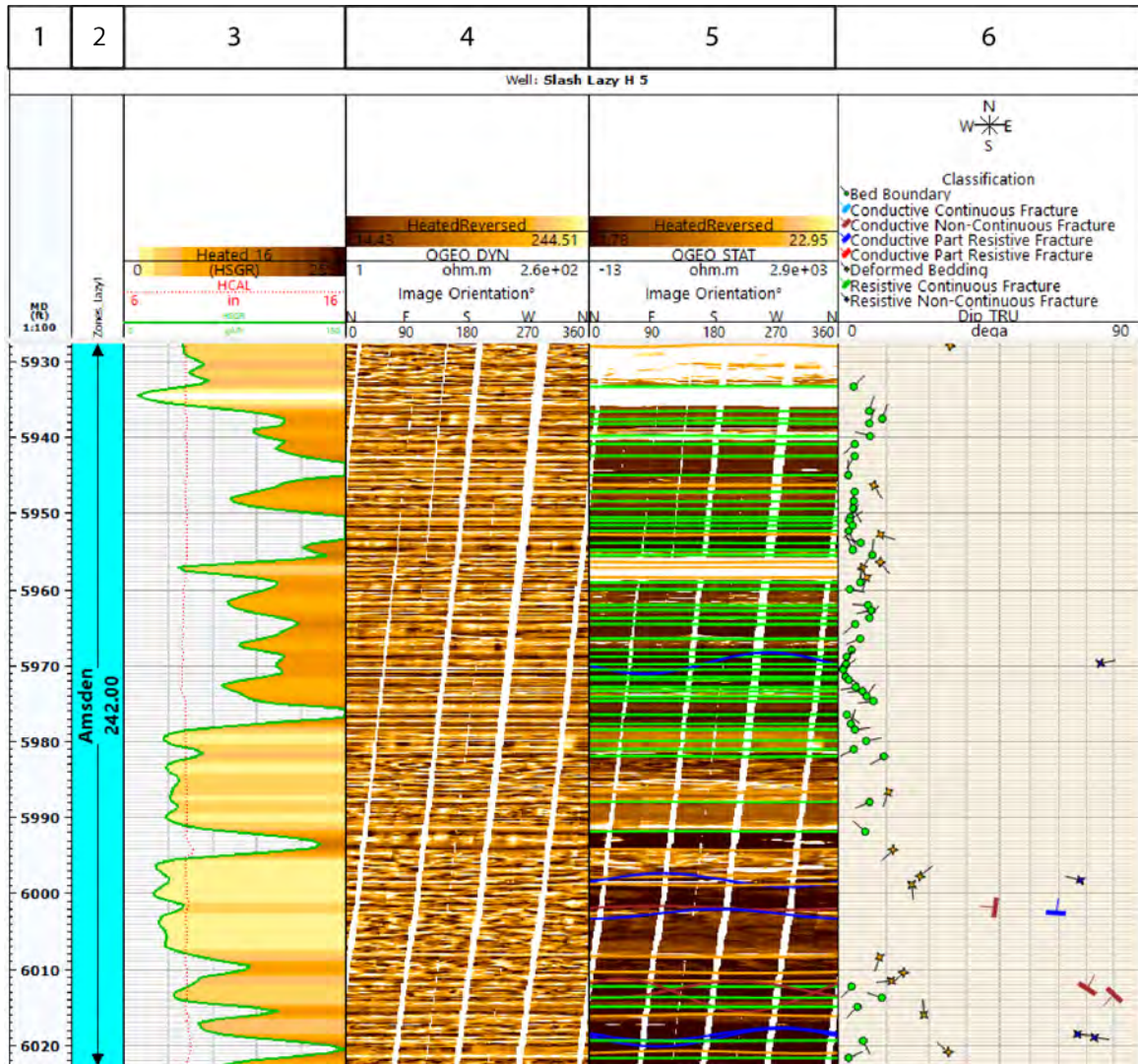


Figure 2-36a. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; 6) tectonic and sedimentary tadpole orientation in the interval between 5928 and 6023 ft MD.

KJ HINTZ/SLASH LAZY H 5

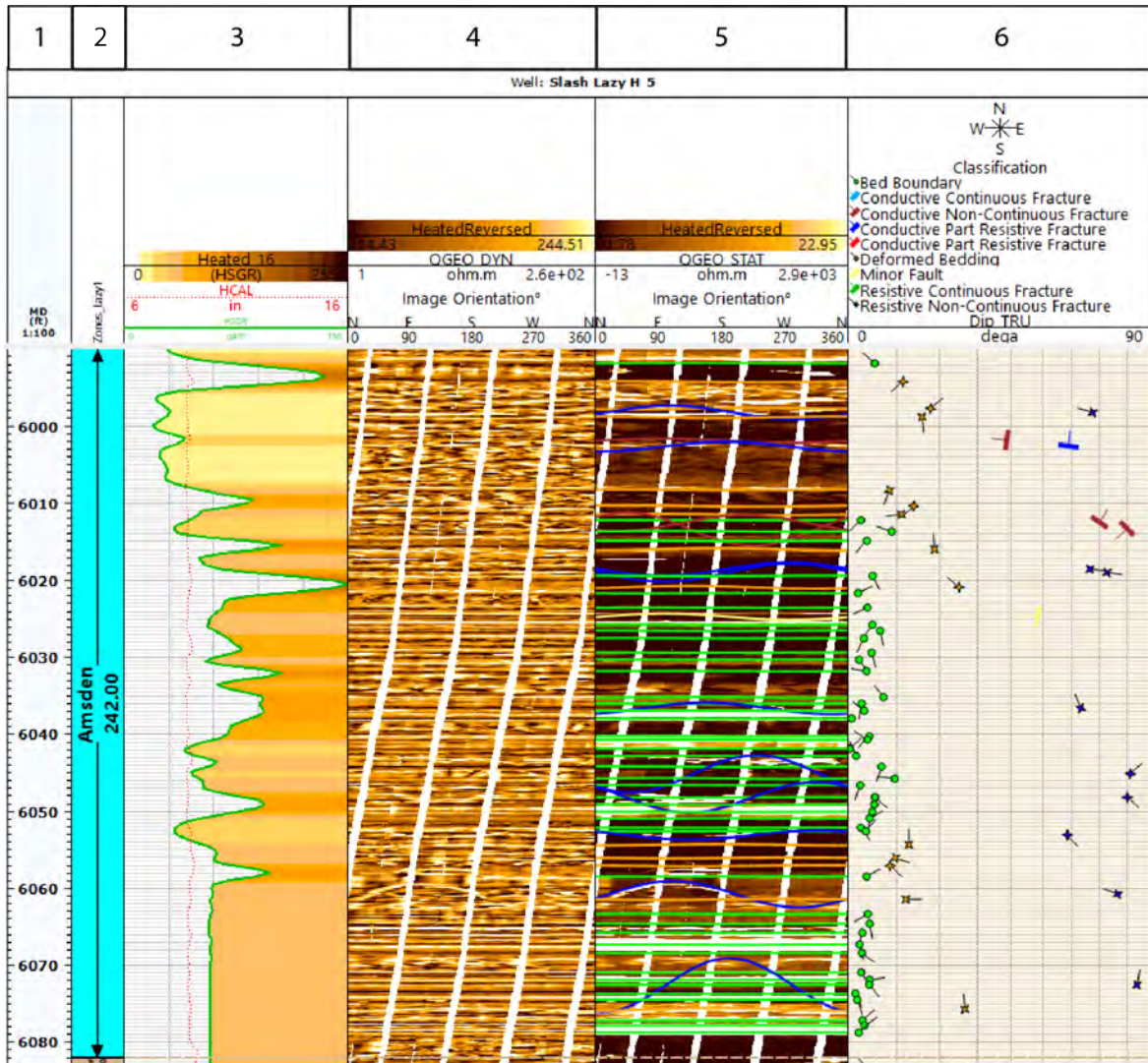


Figure 2-36b. Sedimentary and tectonic features in the Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5990 and 6083 ft MD.

KJ HINTZ/SLASH LAZY H 5

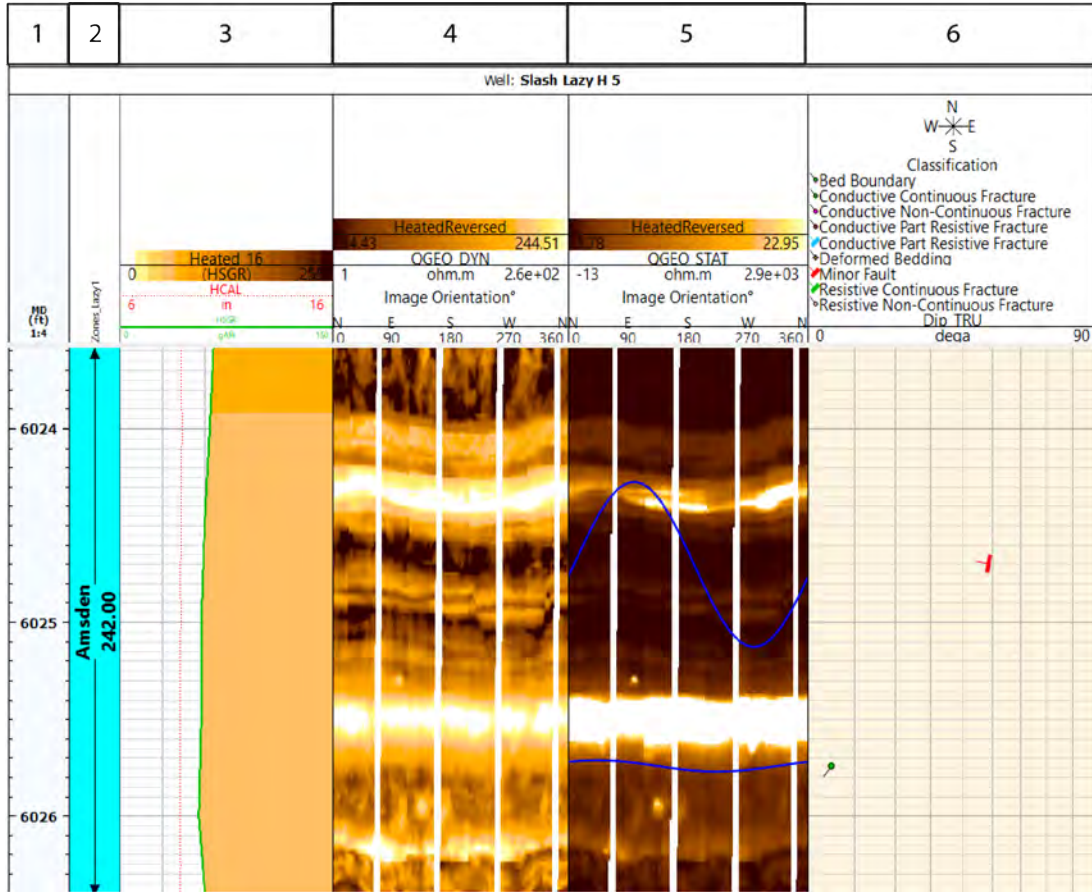


Figure 2-36c. Minor fault and its attribute in the Amsden Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) minor fault and bed boundary tadpole orientation in the interval between 6 023.6 and 6026.4 ft MD.

Drilling-induced fractures (DIF) were identified in the Swift and Piper Kline Formations and oriented NNE-SSW (Figure 2-37). Because the wellbore is vertical, mainly tensile fractures were observed. The tensile fractures might indicate that the maximum horizontal stress (SHmax) has an orientation of N025°.

KJ HINTZ/SLASH LAZY H 5

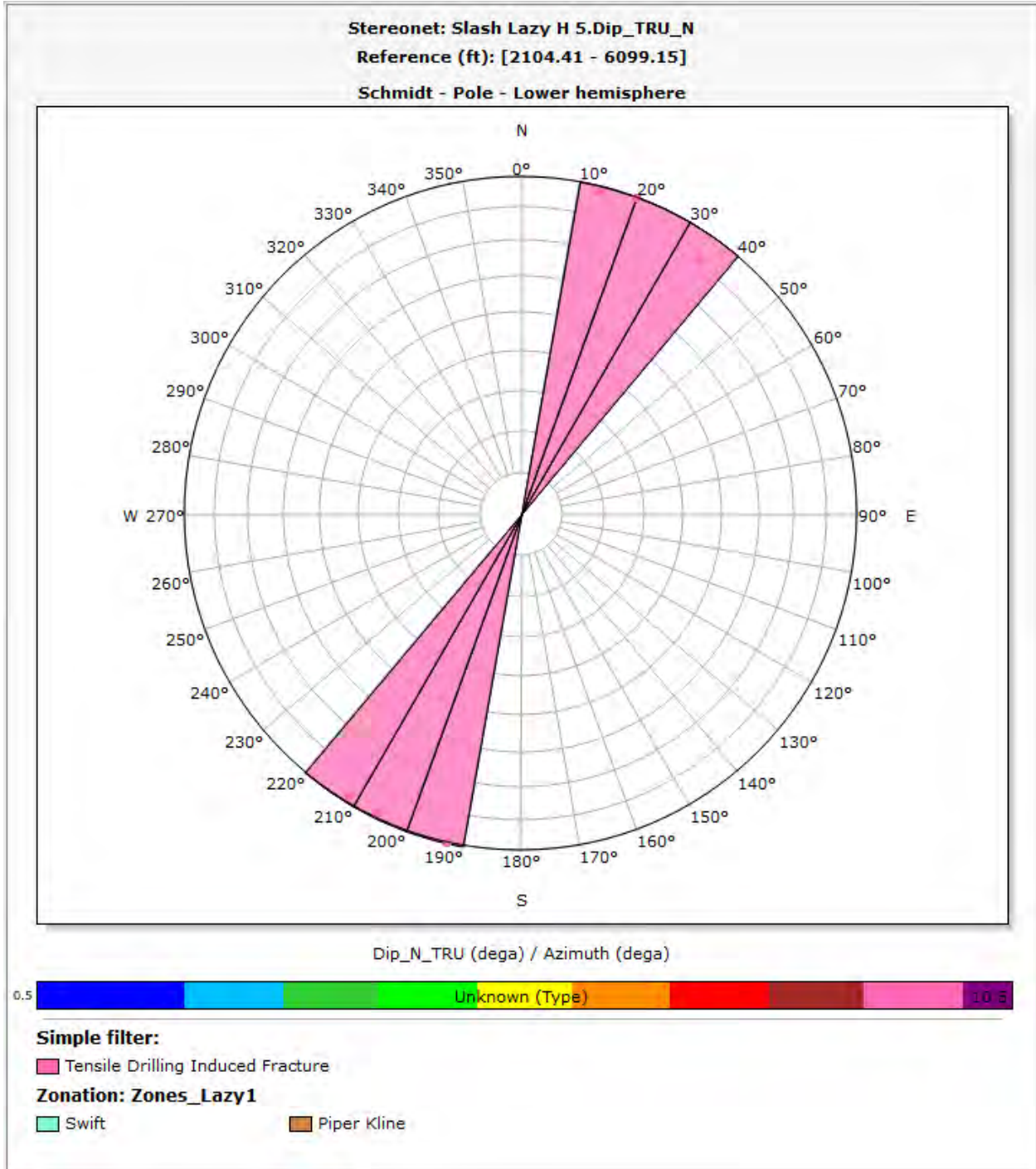


Figure 2-37. Orientation of the tensile drilling-induced fractures in the Slash Lazy H 5 well observed in Swift and Piper Kline Formations showing maximum horizontal stress (SHmax) direction about N025°.

2.4.4.4 Stress, Ductility and Rock Strength

The dynamic elastic properties (dynamic Young’s modulus and Poisson’s ratio) for Opeche/Spearfish, Broom Creek, and Amsden Formations were calculated by using DTC, DTS, and density log collected from Slash Lazy H 5. These dynamic elastic properties were converted to static elastic properties with calibrations of geomechanical laboratory core measurements.

A 1D MEM in the Broom Creek section was built for Slash Lazy H 5 using the available wireline data such as GR logs, caliper logs, density logs (RHOB), dipole sonic logs (DTC, DTS), and image logs. The 1D MEM consists of pore pressure, the vertical in situ stress (Sv, overburden), minimum and maximum horizontal in situ stresses (Shmin, SHmax), static and dynamic Young’s moduli (E), static and dynamic Poisson’s ratio (v), bulk modulus (K), shear modulus (G), unconfined compressive strength (UCS), tensile strength (To), and friction angle (FA or FANG) (Tables 2-9 and 2-10).

Table 2-9. Ranges and Averages of the Elastic Properties Estimated from 1D MEM in Opeche/Spearfish, Broom Creek, and Amsden Formations: Static Young’s Modulus (E_Stat), Static Poisson’s Ratio (v_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Unconfined Compressive Strength (UCS), Dynamic Young’s Modulus (E_Dyn), and Dynamic Poisson’s ratio (v_Dyn)

Formation	Stats	E_Stat, Mpsi	v_Stat, unitless	K, Mpsi	G, Mpsi	UCS, psi	E_Dyn, Mpsi	v_Dyn, unitless
Opeche/Spearfish	Min.	2.53	0.23	0.88	0.45	6930.74	4.38	0.23
	Max.	7.22	0.31	2.68	1.45	21311.92	8.74	0.31
	Average	3.61	0.28	1.31	0.69	8987.37	5.48	0.28
Broom Creek	Min.	0.47	0.17	0.27	0.10	4086.65	1.72	0.17
	Max.	10.58	0.36	4.78	2.29	31185.75	11.82	0.36
	Average	2.67	0.30	1.14	0.59	11334.95	4.55	0.30
Amsden	Min.	0.67	0.20	0.35	0.13	5304.22	1.93	0.20
	Max.	10.01	0.39	4.64	2.23	36137.62	11.47	0.39
	Average	5.17	0.30	2.17	1.07	23700.20	7.22	0.30

Table 2-10. Ranges and Averages of the Sv, Pore Pressure, Shmin, and FA Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations

Formation	Stats	Sv, Vertical Stress, psi	Pore Pressure, psi	Shmin, psi	Fang, FA, degrees
Opeche/Spearfish	Min.	5378.32	2476.87	3281.50	36.54
	Max.	5461.56	2550.16	3832.70	47.52
	Average	5419.78	2493.90	3598.67	38.55
Broom Creek	Min.	5461.56	2550.16	3164.75	19.07
	Max.	5740.17	2811.30	4367.51	57.80
	Average	5600.96	2742.18	3952.94	37.92
Amsden	Min.	5740.17	2631.00	3386.75	30.21
	Max.	5956.78	2714.92	4630.34	57.80
	Average	5848.71	2672.96	4046.00	53.81

S_v is one of the three principal stresses that act upon a rock. It is defined as the stress applied by the overlaying lithostatic column, at the depth (z), and is estimated using the Plumb and others (1991) equation. S_v is calculated using the RHOB log as an input. For the pore pressure, porosity proxy logging data based on a normal compaction trendline concept were used (for hydraulic static pressure, $1.03 \text{ g/cm}^3 = 0.44675 \text{ psi/ft} = 8.6 \text{ ppg}$). For the Broom Creek Formation, the MDT data taken in sand bodies show pore pressure equivalent to 9.2 ppg equivalent to 0.48 psi/ft, which is slightly overpressured. The pore pressure estimation honored the MDT measurement. Dynamic to static Young's modulus function used a linear conversion where a dynamic Young's modulus log was calculated from the available sonic (DTC, DTS) and density log. For Poisson's ratio, dynamic and static parameters were assumed to be equal. The Biot factor was estimated using the formula Biot's factor $= 1 - (K_0/K_{\text{mineral}})$; where K_0 is the bulk modulus of the porous medium and K_{mineral} is the bulk modulus of solid parts of the porous medium. It is a function of mineral volumes and minerals' bulk modulus. For rock properties, Young's modulus, and Poisson's ratio, were estimated from well logs and were calibrated with the triaxial core laboratory measurements (Figure 2-38).

Unconfined compressive strength (UCS) was calculated using empirical correlations between UCS and DTC for shale, sandstone, and dolostone: the Chang (2006) method was used for shale formation, the McNally (1987) method was used for sandstone formation, and Golubev and Rabinovich (1976) was used for dolostone formation. The tensile strength was assumed to be 10% of the calculated UCS. The friction angle (FA or FANG) was estimated using an empirical correlation between the internal angle of friction and DTC: Lal's approach (1999) was used to calculate the friction angle in the Opeche/Spearfish and Amsden Formations, and Weingarten and Perkins (1995) in the Broom Creek Formation. Horizontal stresses (S_{hmin} and S_{Hmax}) were estimated using the poroelastic equations (Plumb et al, 2000). The orientations of S_{hmin} and S_{Hmax} were estimated with the help of a borehole image log (Figure 2-37). The magnitude of S_{hmin} was calibrated by the closure pressures which were measured with a mini-frac stress test. In addition, the 1D MEM shows that the stress regime observed in the Opeche/Spearfish, Broom Creek, and Amsden Formations is normal ($S_v > S_{\text{Hmax}} > S_{\text{hmin}}$). The analysis of the pore pressure measured in the Broom Creek Formation attests that it could be considered an overpressured reservoir, with a gradient of 0.48 psi/ft.

Triaxial test (static elastic properties), ultrasonic velocity (dynamic elastic properties), destructive test (compressive strength) at reservoir conditions, and pore volume compressibility (PVC) for reservoir samples were conducted on nine core samples acquired from the Opeche/Spearfish, Broom Creek, and Amsden Formations in Slash Lazy H 5 well. These values were used to calibrate the static and dynamic Young's modulus and Poisson's ratio generated from well logs (Table 2-11).

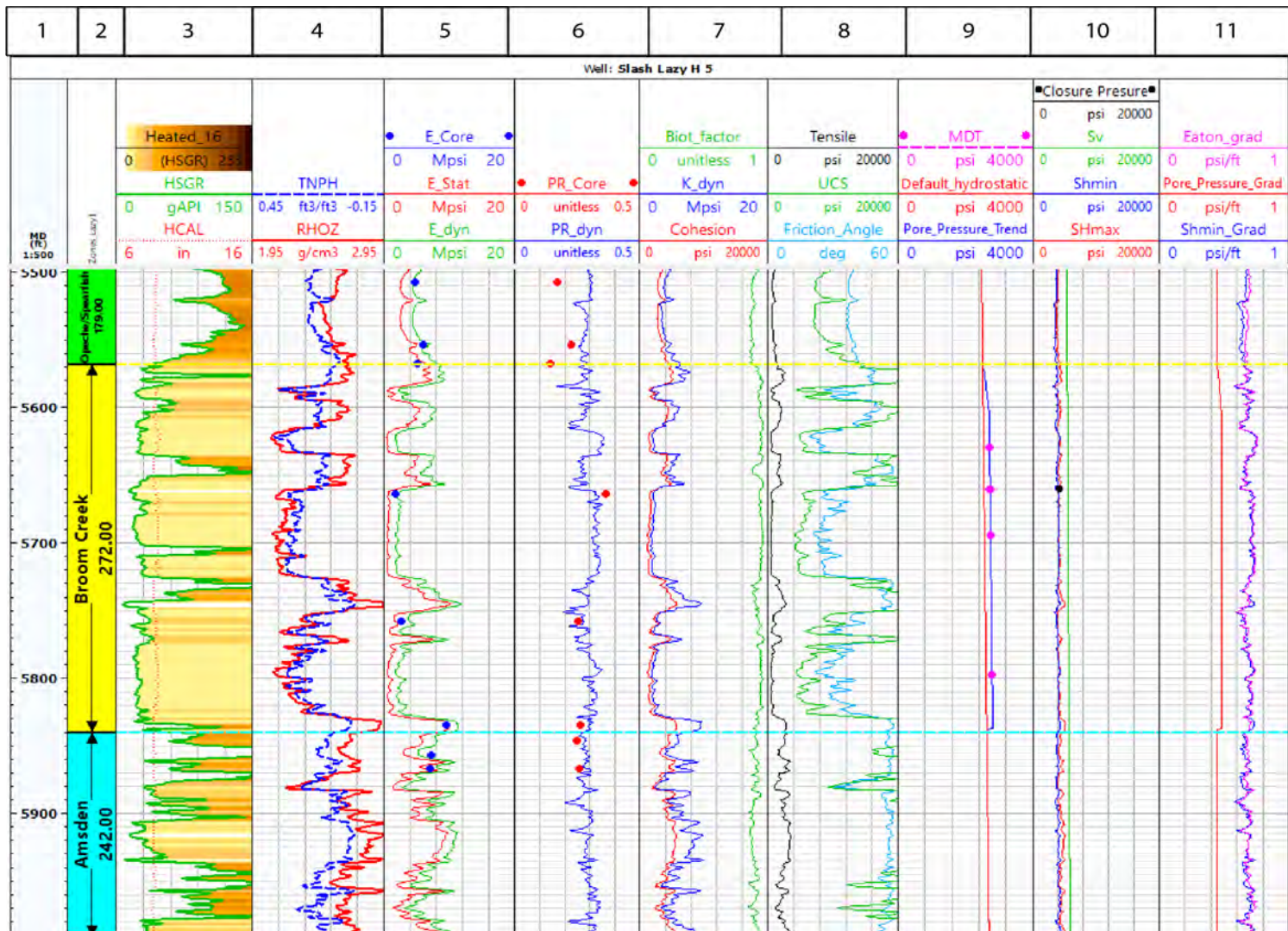


Figure 2-38. Geomechanical parameters in the Opeche/Spearfish, Broom Creek, and Amsden Formations. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, (HCal); 4) TNPH (neutron porosity), RHOZ (bulk density); 5) dynamic Young's modulus (E_dyn), static Young's modulus (E_Stat)_calibrated with core measurements (E_Core); 6) dynamic Poisson's ratio (PR_dyn) calibrated with core measurements (PR_Core); 7) cohesion, bulk modulus (K_dyn), and Biot's factor; 8) UCS, tensile strength, FA; 9) pore pressure, hydropressure calibrated with MDT pressure data; 10) Sv, SHmax, Shmin calibrated with the MDT stress test; and 11) pore pressure, Shmin, and Eaton fracture gradients.

Table 2-11. Formation, Lithology, Sample Depth (MD), Vertical Stress, Pore Pressure, Effective Vertical Stress, Horizontal Stress, Static Young's Modulus, Poisson's ratio, and Compressive Strength in Opeche/Spearfish, Broom Creek, and Amsden Formations

Sample Information				Reservoir Conditions			Elastic Properties		
Formation	Lithology/ Rock Type	Depth, ft*	Vertical Stress, psi	Pore Pressure, psi	Effective Stress, psi	Horizontal Stress, psi	Static Young's Modulus, Mpsi	Static Poisson's Ratio, unitless	Compressive Strength,**** psi
Opeche/ Spearfish	Silty shale	5506.5	5286.2	2488.9	2797.3	1118.9	4.81	0.168	13,377
Opeche/ Spearfish	Anhydritic sandstone	5552.7	5330.6	2509.8	2820.8	1128.3	6.1	0.227	22,549
Opeche/ Spearfish	Anhydritic sandstone	5566.5	5343.8	2516.1	2827.8	1131.1	5.13	0.143	21,644**
Broom Creek	Sandstone	5625	5400	2542.5	2857.5	1143	NA***	NA	NA
Broom Creek	Sandstone	5663	5436.5	2559.7	2876.8	1150.7	1.89	0.366	6835
Broom Creek	Sandstone	5756.7	5526.4	2602.0	2924.4	1169.8	2.75	0.253	5926
Broom Creek	Anhydrite	5834.2	5600.8	2637.1	2963.8	1185.5	9.5	0.261	14,751
Amsden	Dolostone	5846	5612.2	2642.4	2969.8	1187.9	7.36	0.248	30,529
Amsden	Dolostone	5866	5631.4	2651.4	2979.9	1192.0	7.04	0.26	32,082

* Sample depth corresponds to cored depth. A depth shift must be applied to align the values with log depth (see Table 2-2a).

** Sample is at the boundary between Broom Creek and Opeche/Spearfish.

*** Because of the unconsolidated nature of the Broom Creek sandstone and anhydritic sandstone samples, velocity and triaxial test data could not be collected.

**** Compressive strength is equivalent to the peak failure pressure of the sample.

2.5 Faults, Fractures, and Seismic Activity

This section discusses local and regional faults including a regional structural feature, the Stanton Fault and interpreted basement faults. In the area of review (AOR), none of these known or suspected faults or fractures has sufficient permeability and vertical extent to allow fluid movement out of the storage reservoir. The absence of transmissive faults is supported by fluid sample analysis results from Slash Lazy H 5 that suggest the injection interval, the Broom Creek Formation (83,100 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (12,800 mg/L) (Appendix A).

This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.

2.5.1 Stanton Fault

The Stanton Fault is a suspected Precambrian basement fault interpreted by Sims and others (1991) using available borehole data and regional gravity and magnetic data as a northeast-southwest trending feature. The Stanton Fault as interpreted by Sims and others (1991) is ~7.9 mi from the Slash Lazy H 5 stratigraphic and reservoir-monitoring well (Figure 2-39). Given the resolution of the regional gravity and magnetic data and limited amount of borehole data used to interpret this suspected fault, there is a lot of uncertainty in the lateral extent and the location of the feature. No studies describing the possible vertical extent of this feature or impact on overlying sedimentary layers have been published. The Beulah 3D survey was used to characterize the subsurface, with a primary objective of identifying structures. No basement faults were identified with the orientation of the mapped Stanton fault, which is mapped just north of the survey extent. No indication of the Stanton fault was interpreted within the Beulah 3D survey.

2.5.2 Interpreted Basement Faults

Basement-rooted faults with offset apparent in the overlying rock formations were interpreted from the 3D seismic data (Figures 2-39 and 2-40). Displacement along the interpreted basement faults diminishes below or within the Interlake Formation, the top of which is located over 3000 feet below the base of the Broom Creek Formation. These faults do not extend into the Broom Creek formation, or into any associated Broom Creek confining intervals.

Figure 2-40 shows a map and cross-sectional view of the discontinuities that are interpreted as faults and fractures. The linear trends visible in Figure 2-40 are interpreted as basement rooted faults. The bottom of Figure 2-40 shows Section A-A' from the Beulah 3D survey where offset is visible along basement-rooted faults in the Deadwood Formation. These faults extend through the Deadwood Formation into the overlying confining interval, the Winnipeg group. Some of the interpreted faults extend into the Red River Formation with offset ultimately diminishing by the Interlake Formation.

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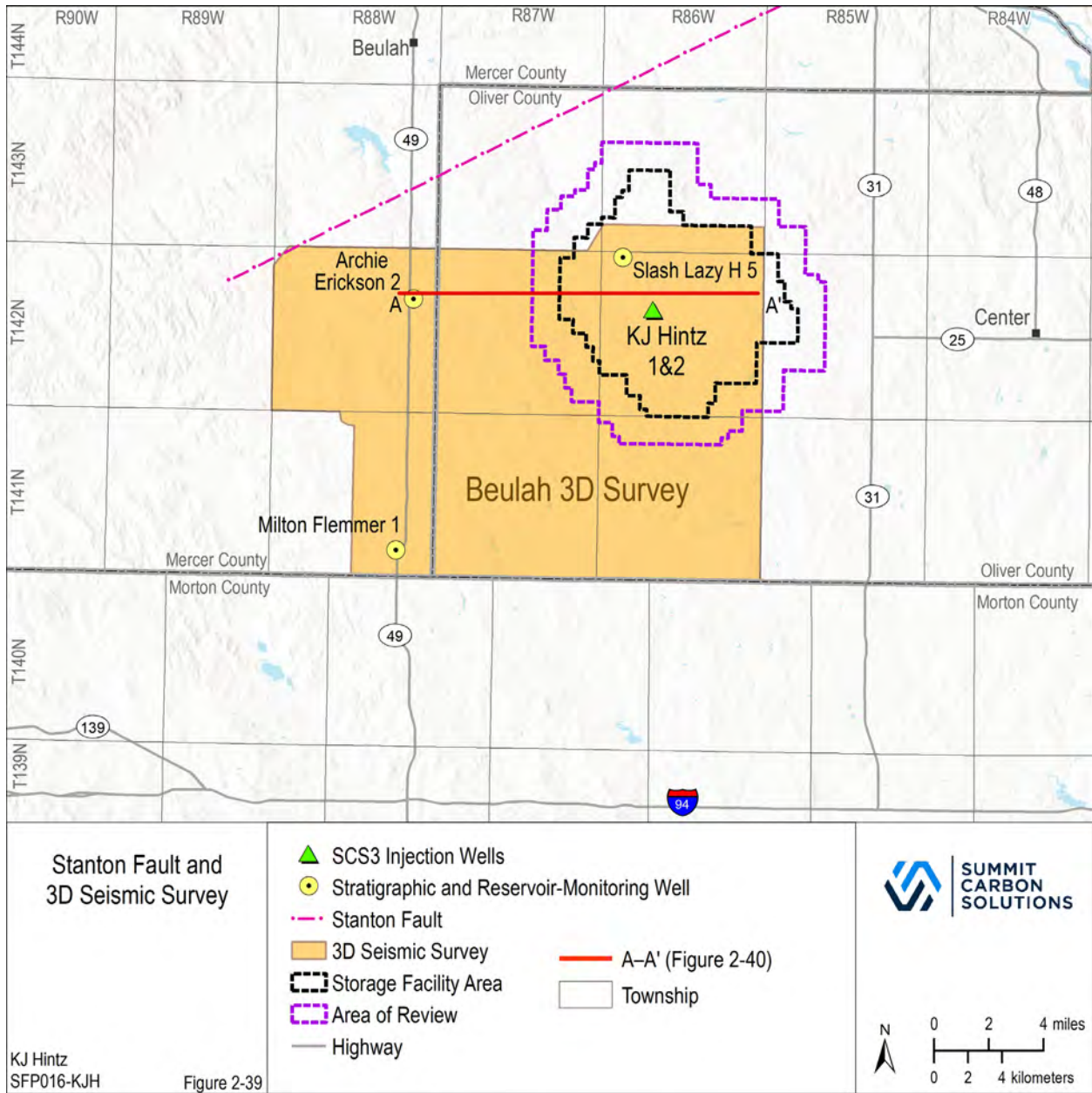


Figure 2-39. Suspected location of the Stanton Fault as interpreted by Sims and others (1991) and Anderson (2016) in relation to the Beulah 3D seismic survey extent. The red line on the map shows the location of the seismic section A-A' shown in Figure 2-40.

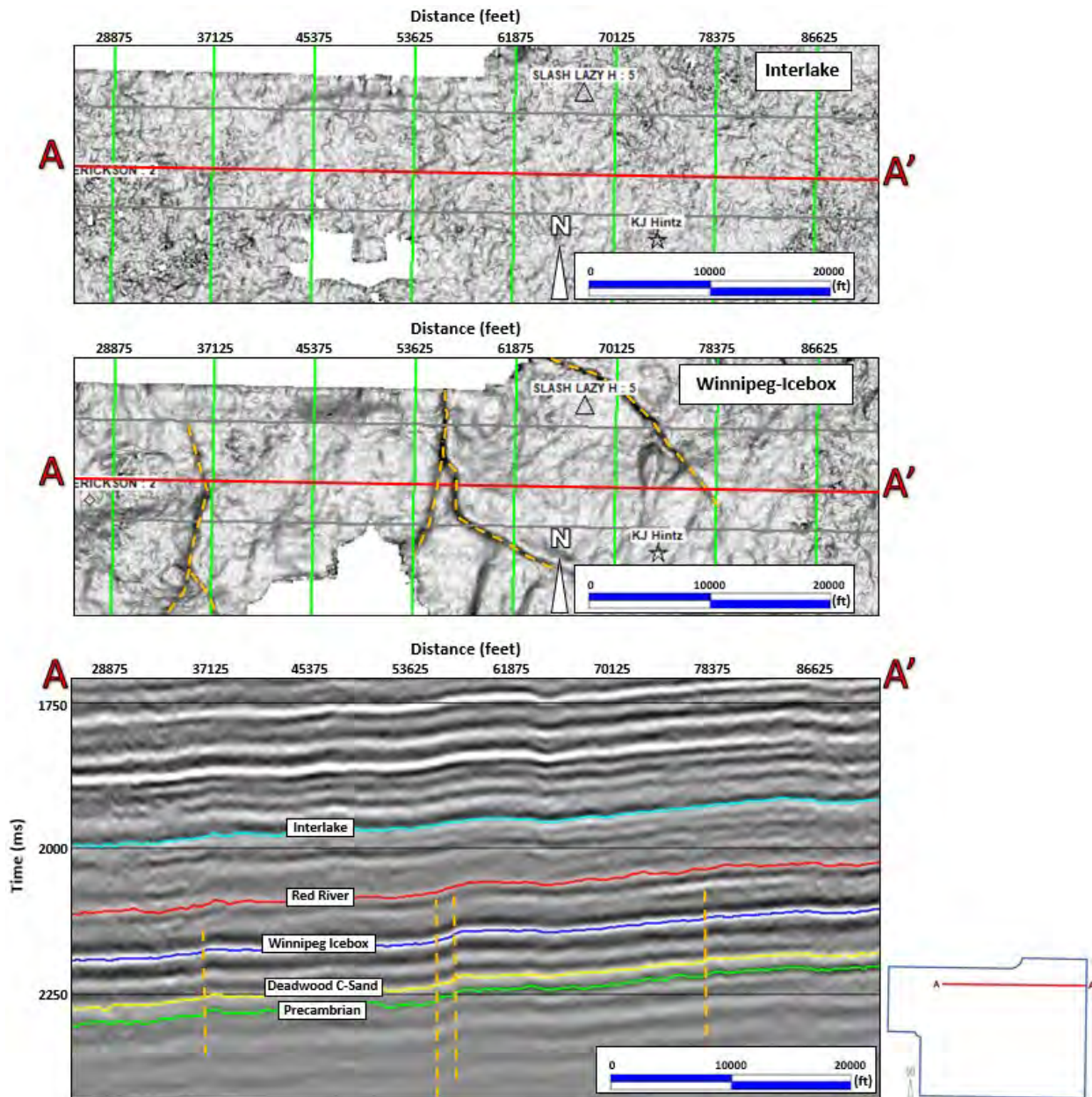


Figure 2-40. Top: similarity attribute map taken from the Beulah 3D survey of the Interlake Formation (aqua horizon) and the Winnipeg–Icebox Formation (blue horizon). Time is displayed on the y-axis in milliseconds; distance is shown on x-axis in feet. Bottom: cross-section A-A' (location within the Beulah 3D extent shown in the inset) showing seismic amplitude data, interpreted horizons, and interpreted faults. Similarity attributes highlight discontinuities shown as black linear trends marked with dashed yellow lines in the top figure. These linear trends are interpreted as faults and fractures rooted within the Precambrian basement (green horizon). Displacement along these faults diminishes below the Interlake Formation (aqua horizon).

2.5.3 *Mohr–Coulomb Critical Stress Analysis of Faults*

An integrated Mohr–Coulomb deterministic and probabilistic critical stress analysis study was carried out across the Beulah 3D seismic survey area. Results of the study allowed for evaluation of the risk and range of uncertainty for potential fault slippage in response to CO₂ injection. The analysis used the fault segments interpreted from the 3D seismic data which exhibit a range of strikes and dips. Four injection locations were selected for this evaluation, with the objective of testing a full range of fault slip stability scenarios. Three of these locations are planned SCS injection wells, Wells 1, 2, and 4 in Figure 2-41, with Well 3 being a potential location that was ultimately not selected for further development.

The Milton Flemmer 1 1D MEM was used as a basis for the boundary conditions for the Mohr-Coulomb critical stress analysis across the Beulah 3D seismic study area. SLB Techlog, Ikon RokDoc and Stanford University Fault Slip Potential (FSP) software tools were used to carry out the integrated study.

The main conclusion of this evaluation is the interpreted fault segments have a low probability of slippage in response to pore pressure increases in response to CO₂ injection, so long as the maximum differential pressure increase at the fault is below ~3000 psi (Figures 2-41 and 2-42). The pore pressure necessary to initiate slip on the interpreted fault segments is dominantly controlled by the geomechanical factors: fault strike, SHmax azimuth and pore pressure gradient. Additionally, the fault segments have a very low probability of slippage in response to pore pressure increases from injection in the Broom Creek Formation because of the large vertical distance between the reservoir and the interpreted fault (>3000 ft).

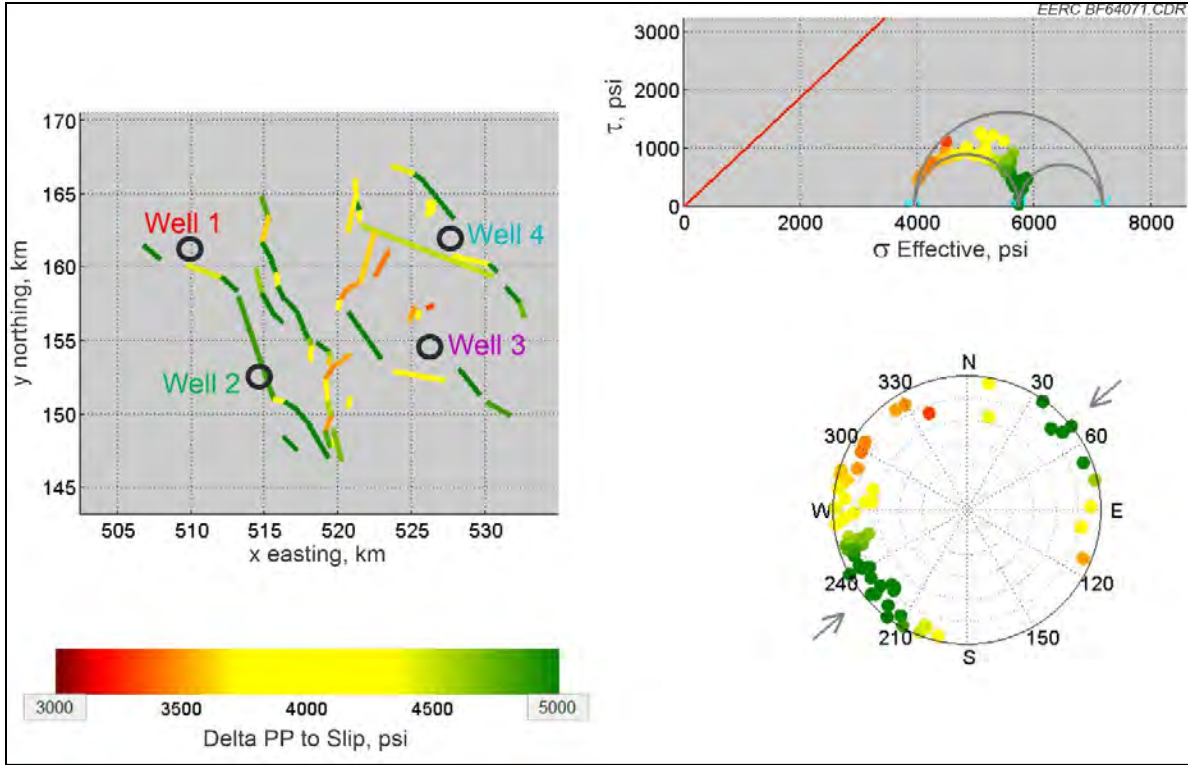


Figure 2-41. Results of the deterministic FSP analysis of the interpreted fault segments in response to pore pressure increase associated with injection at four well locations. Dominant SHmax azimuth is North 50 degrees East, indicated by the arrows in the polar plot of fault strikes and dips in the lower right of the figure.

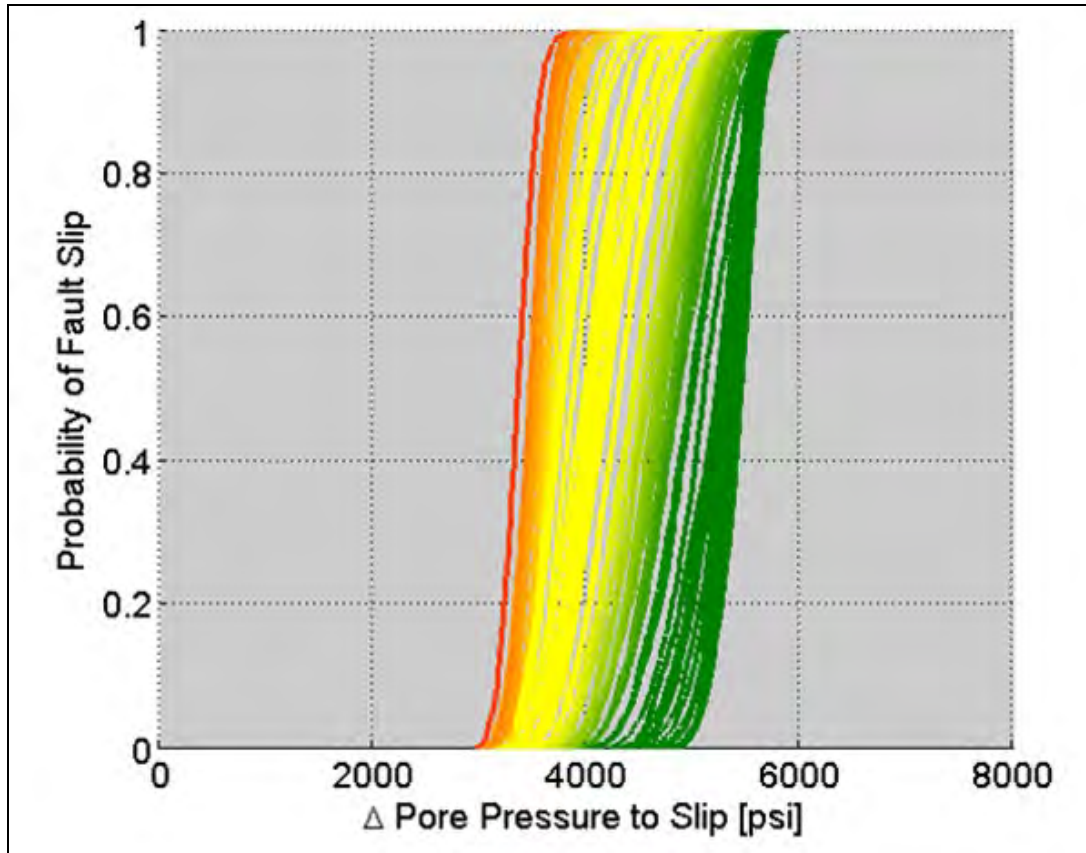


Figure 2-42. Probabilistic FSP analysis of the interpreted fault segments in response to pore pressure and four injection-well locations showing a minimum of ~3000 psi pressure increase is needed to initiate slip on the most unstable interpreted faults in red vs. the more stable faults in green, where a minimum of ~5000 psi is required to initiate slip.

2.5.4 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, 2022).

Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-12) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight Precambrian basement faults interpreted by Anderson (2016) in the North Dakota portion of the Williston Basin (Figure 2-43). The earthquake recorded closest to the project area occurred in 1927, located 28.37 miles southwest of the KJ Hintz 2 injection well, near Hebron, North Dakota (Table 2-12). The magnitude of this earthquake is estimated to have been 3.2.

Table 2-12. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016)

Map Label	Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Distance to KJ Hintz 2 injection well, miles
A	Sept. 28, 2012	3.3	0.4*	-103.48	48.01	Southeast of Williston	107.22
B	June 14, 2010	1.4	3.1	-103.96	46.03	Boxelder Creek	135.57
C	March 21, 2010	2.5	3.1	-103.98	47.98	Buford	126.16
D	Aug. 30, 2009	1.9	3.1	-102.38	47.63	Ft. Berthold southwest	50.71
E	Jan. 3, 2009	1.5	8.3	-103.95	48.36	Grenora	138.97
F	Nov. 15, 2008	2.6	11.2	-100.04	47.46	Goodrich	78.10
G	Nov. 11, 1998	3.5	3.1	-104.03	48.55	Grenora	150.03
H	March 9, 1982	3.3	11.2	-104.03	48.51	Grenora	148.27
I	July 8, 1968	4.4	20.5	-100.74	46.59	Huff	54.86
J	May 13, 1947	3.7**	U***	-100.90	46.00	Selfridge	84.45
K	Oct. 26, 1946	3.7**	U	-103.70	48.20	Williston	123.11
L	April 29, 1927	3.2**	U	-102.10	46.90	Hebron	28.37
M	Aug. 8, 1915	3.7**	U	-103.60	48.20	Williston	119.43

* Estimated depth.

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

*** Unknown.

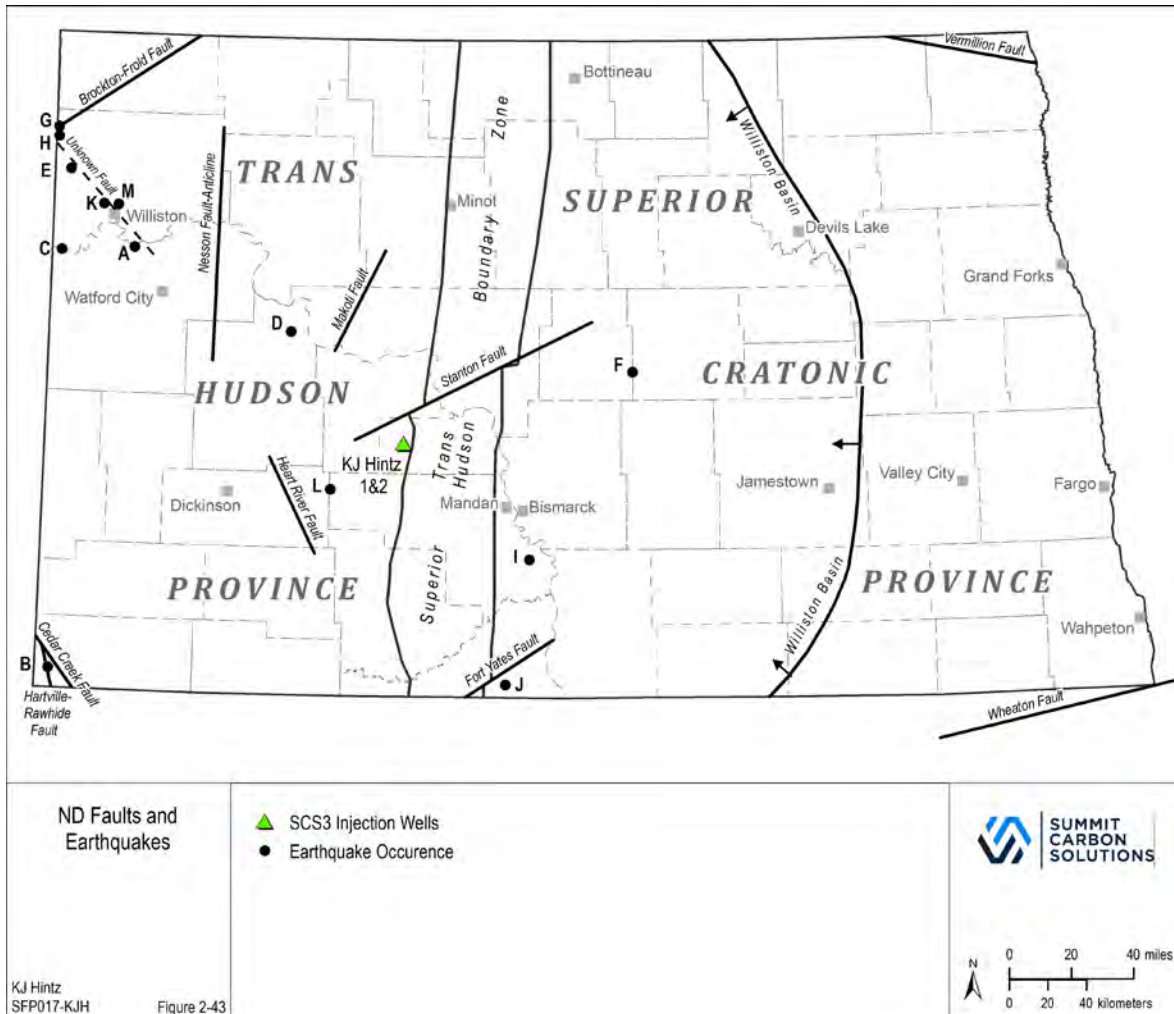


Figure 2-43. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12.

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in North Dakota that would cause damage to infrastructure, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-44) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) states there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. Additionally, no earthquakes occurring along the Stanton Fault have been reported. This indicates stable geologic conditions in the region

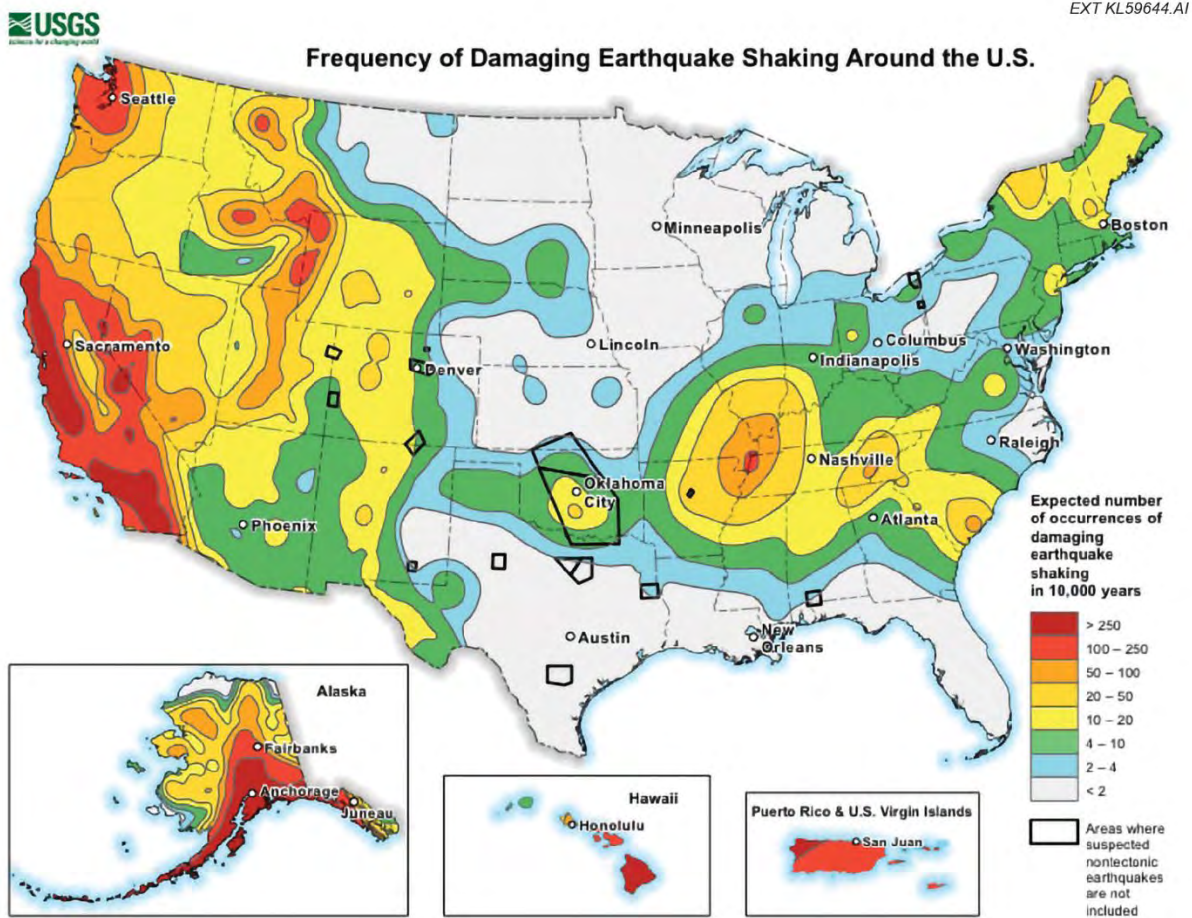


Figure 2-44. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake events occurring in North Dakota.

surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the depth of the target reservoir in proximity to the basement and vertical extents of the interpreted faults suggest the probability that seismicity interfering with CO₂ containment is low.

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 2-45). There has been no exploration for, nor development of, a hydrocarbon resource from the Spearfish Formation in the storage facility area. There has been no historic hydrocarbon exploration in, or production from, formations below the Broom Creek Formation in the storage facility area. Well

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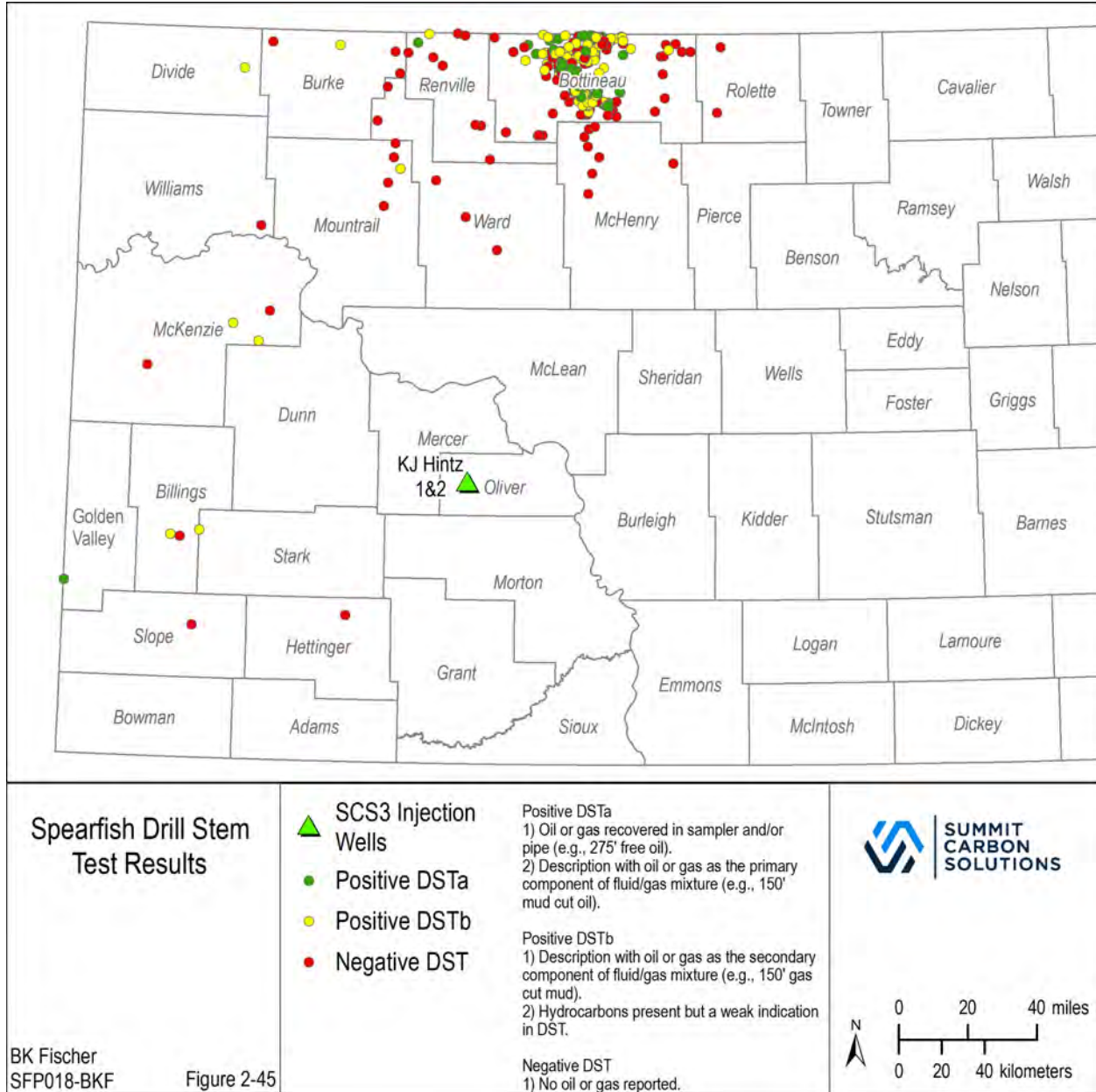


Figure 2-45. Drillstem test results indicating the presence of oil in the Spearfish Formation (modified from Stollendorf, 2020).

NDIC File No. 4942, located within the storage facility area, drilled to the Kibby Lime Formation, was a dry well and did not suggest the presence of hydrocarbons. The next two wells closest to the storage facility area, NDIC File Nos. 3277 and 5145, drilled to the Duperow Formation and the Mowry Formation, respectively, were also dry and did not suggest the presence of hydrocarbons. Published studies suggest no economical deposits of hydrocarbons in the Bakken Formation in the storage facility area (Bergin, 2012; Theloy, 2016). The nearest hydrocarbon production well is Entze 29 1 (NDIC File No. 7616), located ~21 mi northwest (Figure 2-46a). Entze 29 1 was drilled in June 1980 and produced from the Red River Formation a cumulative total of 7799 bbl until June 1982. The well is now plugged and abandoned (P&A).

Shallow gas resources can be found in many areas of North Dakota. N.D.C.C. § 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 five thousand feet (1524 meters) below the surface, or located more than five thousand feet (1524 meters) below the surface but above the top of the Rierdon Formation (Jurassic), from which gas may be produced” (N.D.C.C. §§ 57-51-01[10]-[11]).

In the event that hydrocarbons are discovered in commercial quantities below the Broom Creek Formation, a horizontal well could be used to produce hydrocarbons while avoiding drilling through the CO₂ plume, or a vertical well could be drilled using proper controls. Aside from meeting regulatory and jurisdictional requirements, should an operator decide to drill wells for hydrocarbon exploration or production, real-time Broom Creek Formation BHP data will be available while the KJ Hintz 1 and KJ Hintz 2 wells are in operation, which will allow prospective operators to design an appropriate well control strategy via increased drilling mud weight. Pressure increase in the Broom Creek caused by injection of CO₂ will relax postinjection as the area returns to its preinjection pressure profile. Any future wells drilled for hydrocarbon exploration or production that may encounter the CO₂ should be designed to include an intermediate casing string placed across the storage reservoir, with CO₂-resistant cement used to anchor the casing in place.

Active and reclaimed coal mines are near the storage facility area. Coal is mined from the Sentinel Butte Formation of the Fort Union Group of Paleocene age (the Beulah of the Beulah–Zap interval and Twin Butte coal beds) (Figure 2-46b). The thickness of the Beulah–Zap interval averages between 18 and 22 ft (Figure 2-47). Above the Beulah horizon are several thin beds of lignite. In ascending order, these are the Schoolhouse and Twin Butte beds. Overburden on top of the Beulah horizon ranges from 95 to 145 ft (Figure 2-48). The Twin Butte has an average thickness of about 6 ft, under 25–30 ft of overburden, where it is actively mined (Zygarlicke and others, 2019). The Beulah, Twin Butte, and other coal seams thicken and deepen to the west. The Beulah–Zap and Twin Butte seams pinch out to the east. The underlying Hagel coal seam is mined farther to the east by BNI Coal at its Center Mine and the Falkirk Mine near Falkirk, North Dakota. Currently, no existing mine has plans to mine coal in the storage facility area during the project’s operational period. The Coyote Creek Mine is the closest mine to the storage facility area. Figure 2-49 depicts the future mining area for the Coyote Creek Mine through 2040. The Beulah Mine is a mine near the storage facility area that no longer has active coal removal and is undergoing final reclamation. Figure 2-49 depicts areas that have been mined out at both the Coyote Creek Mine and the Beulah Mine.

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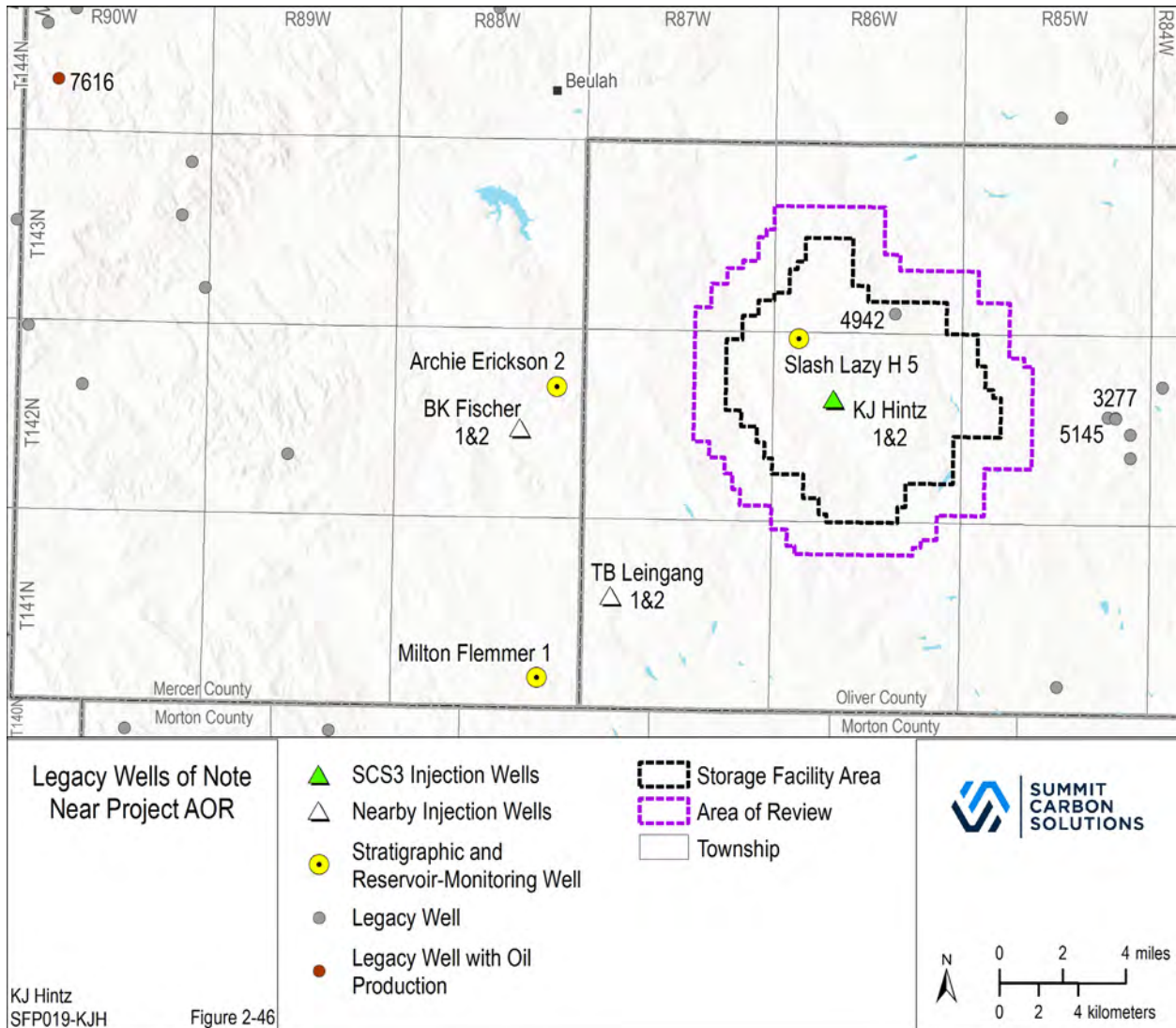


Figure 2-46a. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616).

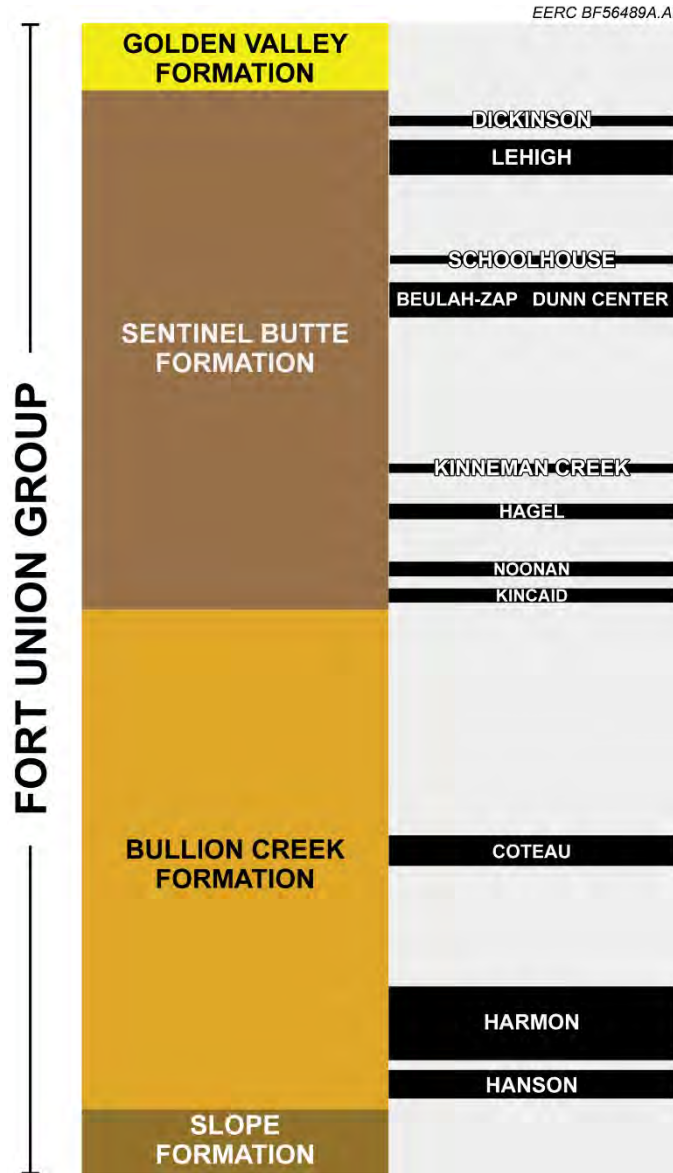


Figure 2-46b. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019).

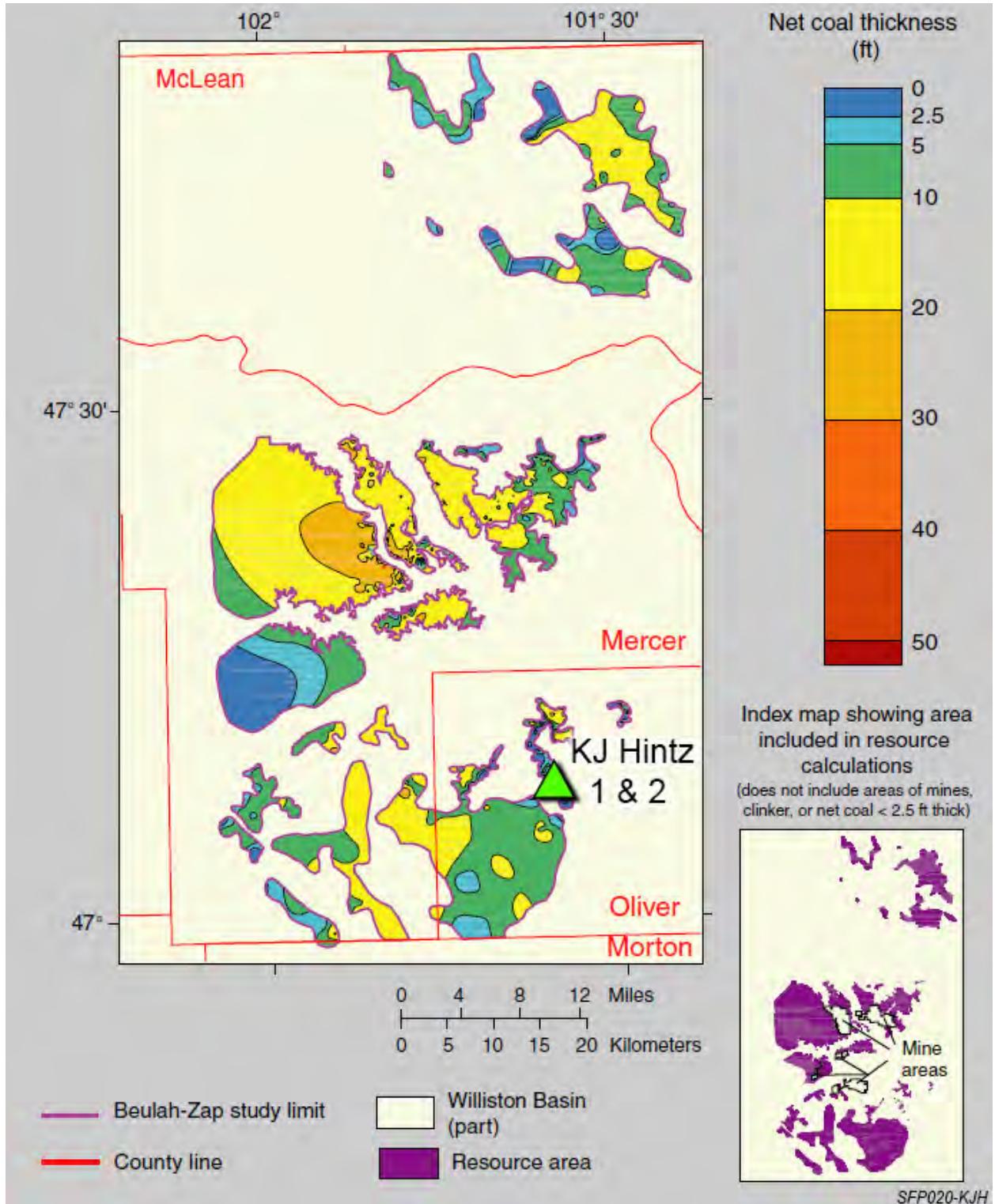


Figure 2-47. Beulah net coal isopach map and resource area (modified from Ellis and others, 1999).

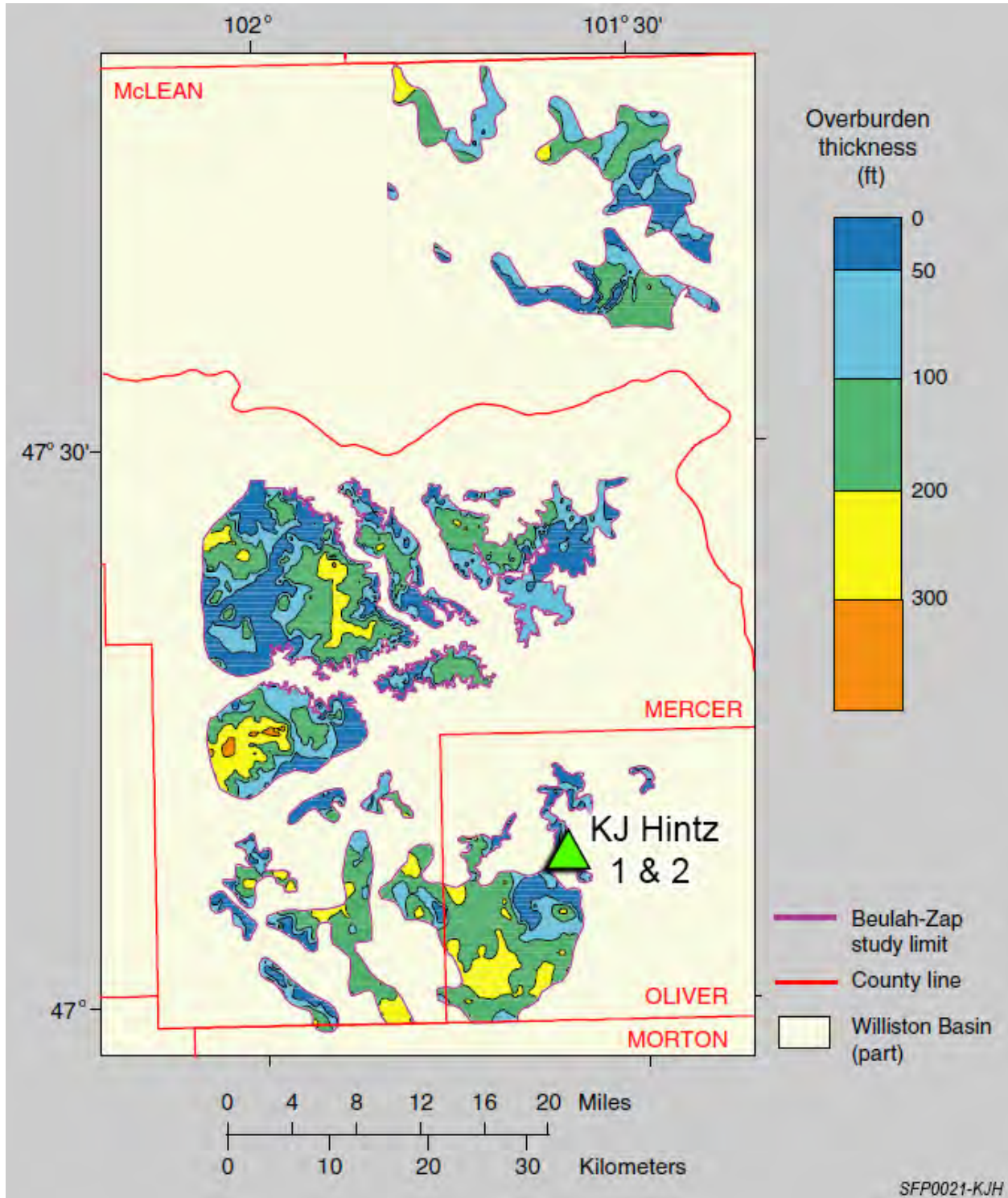


Figure 2-48. Beulah overburden isopach map (modified from Ellis and others, 1999).

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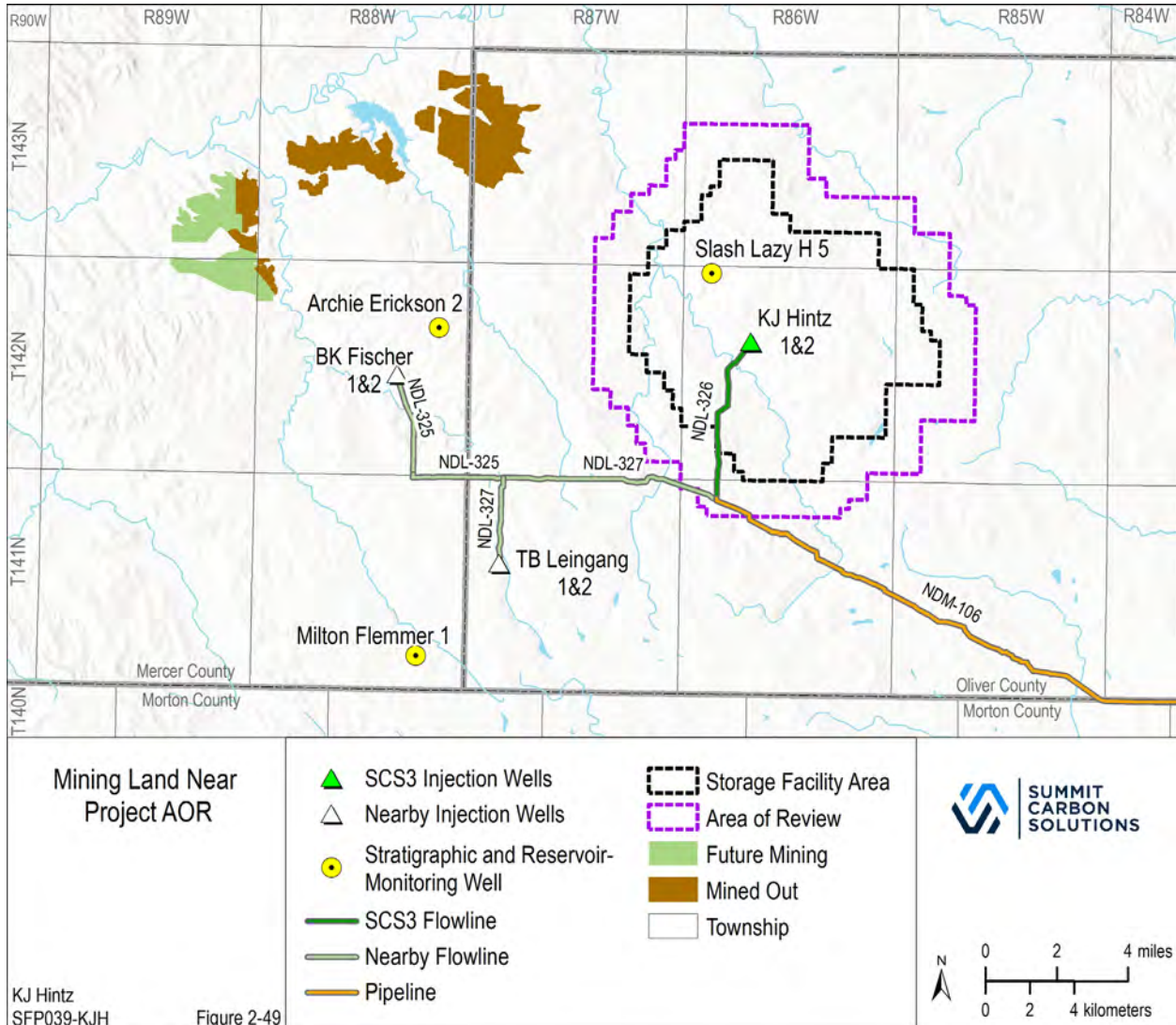


Figure 2-49. Map showing the past and future mining area for the Coyote Creek Mine and Beulah Mine through 2040.

2.7 References

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SECTION 3.0

GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO₂ INJECTION

3.0 GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO₂ 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 SLB's Petrel software (Schlumberger, 2020) to construct a geologic model of the injection zone (Broom Creek Formation), the upper confining zone (Opeche/Spearfish Formation), and the lower confining zone (Amsden Formation). The geologic model encompasses a 4070-mi² (74-mi × 55-mi) area around the KJ Hintz site 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 CO₂ injection using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd., 2021). Numerical simulations of CO₂ injection were conducted to assess potential CO₂ injection rate, disposition of injected CO₂, 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 CO₂ 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 all existing wells that penetrate both the storage reservoir and associated upper and lower confining zones within the geologic model area. Major inputs for the geologic model also included seismic survey data and core sample measurements. The core sample measurement acted as control points during the distribution of the geologic properties throughout the modeled area. The geologic properties distributed throughout the model include acoustic impedance (AI), total porosity, effective porosity, permeability, and facies.

Three 3D seismic AI volumes (Figure 2-8) were upscaled and integrated into the geologic model grid using a volume-weighted method. (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*

SLB's Petrel software was used to interpolate structural surfaces for the undifferentiated Opeche/Spearfish (i.e., Spearfish, Minnekahta, Opeche), Broom Creek, and Amsden Formations. Input data included formation top depths from the online North Dakota Industrial Commission (NDIC) Department of Mineral Resources, Oil and Gas Division (DMR-O&G) database; data

collected from ten cored wells: ANG 1, Flemmer 1, BNI 1, J-LOC 1, Liberty 1, MAG 1, Coteau 1, Milton Flemmer 1, Archie Erickson 2 , and Slash Lazy H 5 (Figure 2-4); three 3D seismic surveys (Figure 2-8); and one 5-mi-long 2D seismic line (Figure 2-8). 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 (Opeche/Spearfish and Amsden Formations)

The upper confining zone (Opeche/Spearfish Formation) and the lower confining zone (Amsden Formation) were each assigned a single facies. Based on their primary lithology determined by well log analysis, the upper confining zone is assigned siltstone, and the lower confining zone is assigned dolostone. The lower Piper Formation was included in the geologic model in addition to the Opeche/Spearfish Formations because the Opeche/Spearfish Formation pinches out within the geologic model, approximately 29 miles east of the Slash Lazy H 5 well. The lower Piper is assigned as siltstone. 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 (Figure 2-16). 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 variogram 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 and bulk density well logs in the geologic model 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 identification of a trend between the AI data and well logs, 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 2-11). 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. Upscaled mineral fraction logs were also used to generate a facies trend model, which were 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 2-15).

Prior to distributing the porosity and permeability properties, total porosity (PHIT), effective porosity (PHIE; total porosity less occupied or isolated pore space), and intrinsic permeability (KINT) well logs were calculated 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. The Gaussian random-function simulation algorithm was used to distribute the PHIE property using calculated PHIE well logs. The PHIE well logs were upscaled to the resolution of the 3D model and were used as control points and as the variogram structures described previously. The PHIE was cokriged with the AI seismic volumes and conditioned to the distributed facies (Figure 3-1). A KINT property was distributed using the same variogram structures and Gaussian random-function algorithm but was paired with PHIE volume cokriging (Figure 3-2).

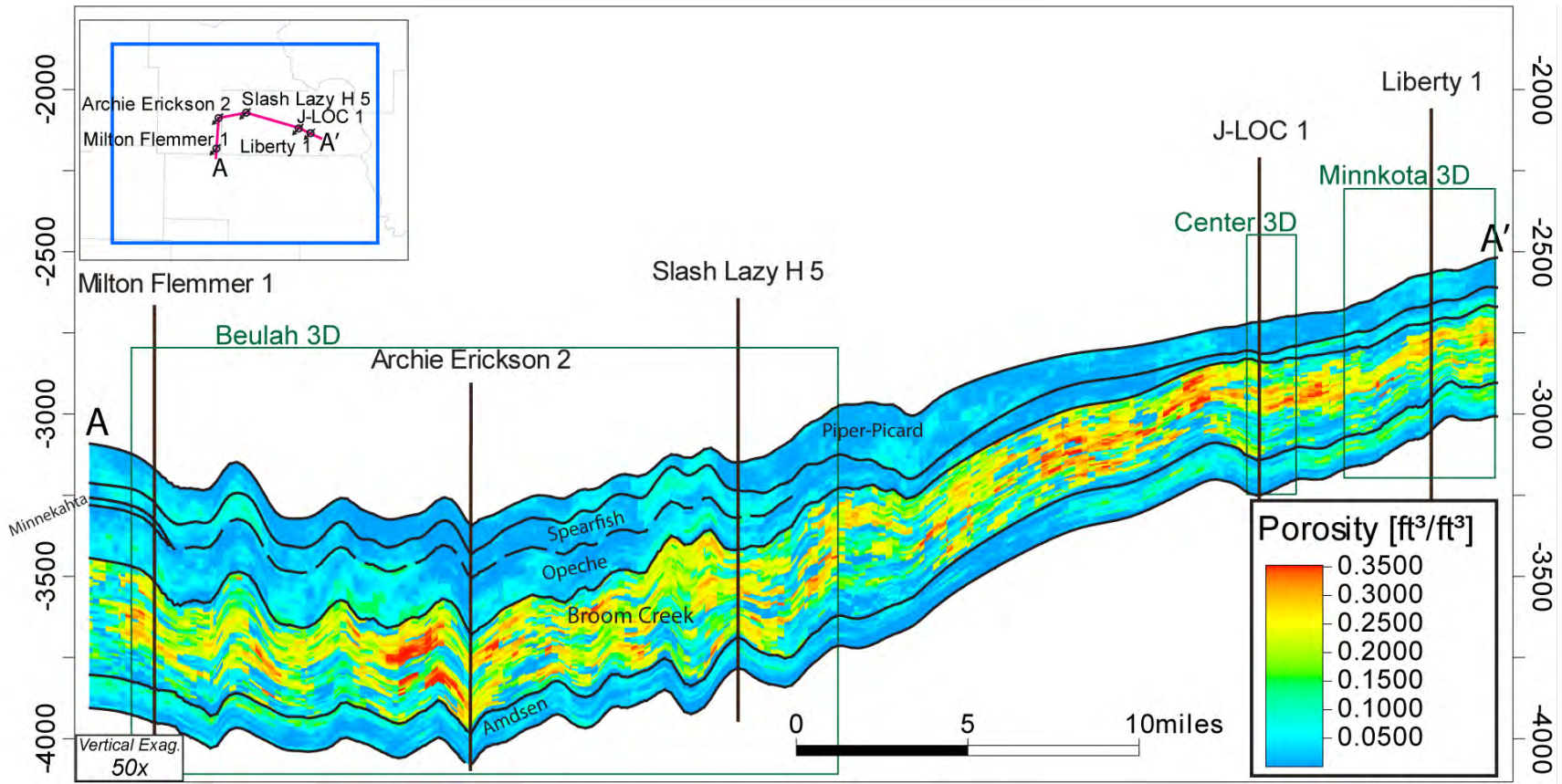


Figure 3-1. Distributed PHIE property along a roughly W-E cross section. The distributed PHIE property was used to distribute permeability throughout the model. Units on the y-axis represent feet below mean sea level (50× vertical exaggeration shown).

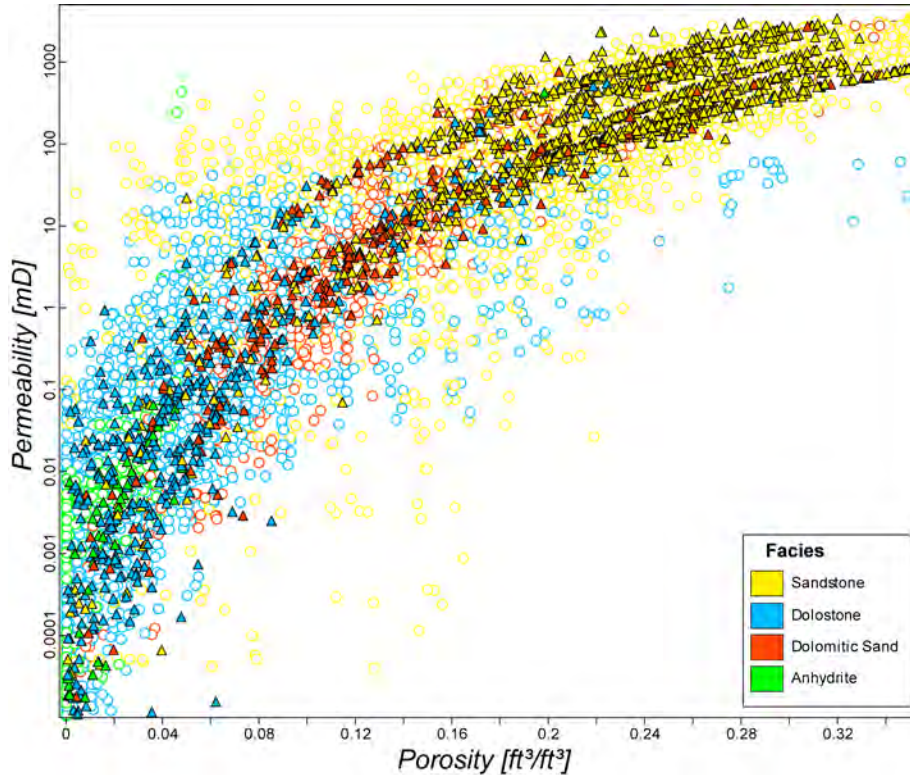


Figure 3-2. Illustration of the relationship between the modeled porosity and permeability of the Broom Creek Formation facies. Upscaled well log values are represented by triangles, while circles represent distributed values. Values are colored according to facies classification.

3.3 Numerical Simulation of CO₂ Injection

3.3.1 Simulation Model Development

Numerical simulations of CO₂ 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. Calculated values based on measured temperature and pressure data, along with the reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation. Figures 3-3 and 3-4 display a 3D and aerial view, respectively, of the simulation model with the permeability property and injection wells (KJ Hintz 1 and 2) for KJ Hintz. BK Fischer 1 and 2 and TB Leingang 1 and 2 were also included to represent adjacent injection sites.

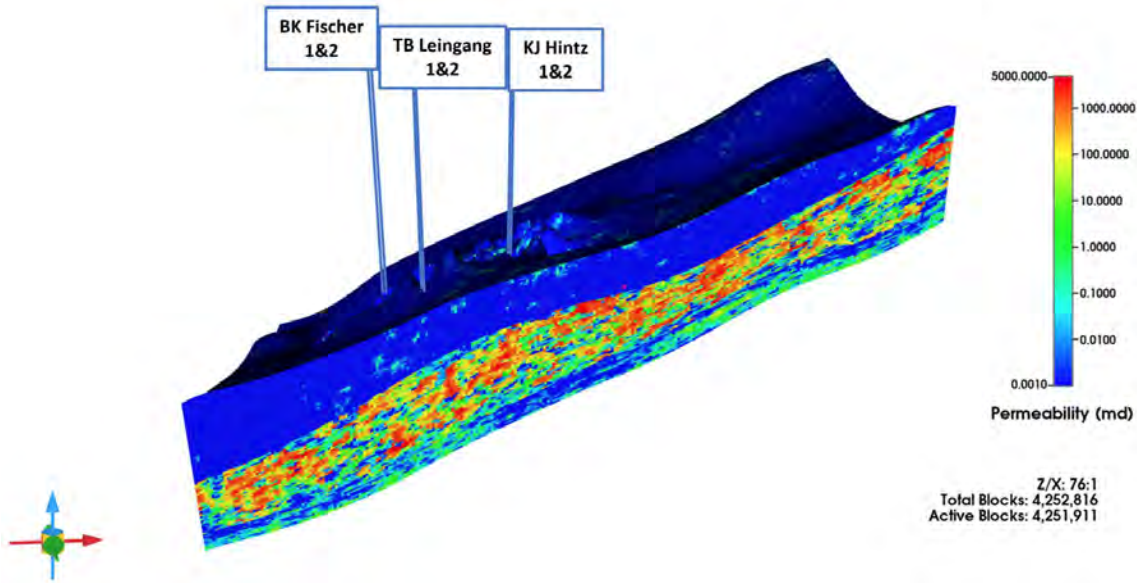


Figure 3-3. 3D view of the simulation model with the permeability property and injection wells displayed. The low-permeability layers (light blue and green) at the top and bottom of the figure should be noted. These layers represent the Opeche/Spearfish Formation (upper confining zone) and the Amsden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

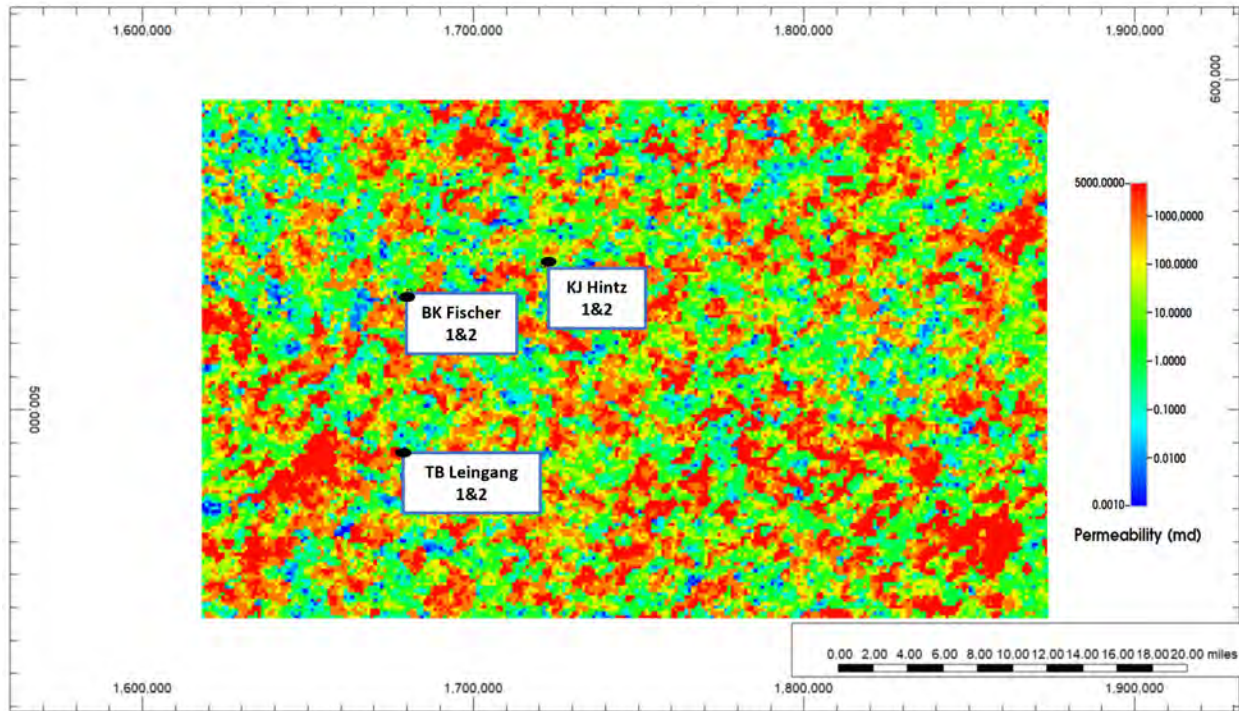


Figure 3-4. Aerial view of the simulation model with the permeability property of Broom Creek Formation (Layer 26, 5426 ft TVD at KJ Hintz 1 top perforation, estimated prior to wellsite selection) and the injection wellsites displayed.

The simulation model encompasses an area of 48.5 mi by 29.7 mi. KJ Hintz is located approximately 12 mi from the north edge of the model and approximately 23 mi 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. 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 west. Therefore, the volume modifiers are 28.25, 283, 10, 185, and 286 for east, north, northeast, west, and south, respectively. These modifiers are multipliers to a block's bulk volume when rock and pore volume are considered. A fluid sample from the Broom Creek Formation collected from Milton Flemmer 1 was analyzed by Minnesota Valley Testing Laboratories, and the measured total dissolved solids (TDS) of 105,000 mg/L was used as input for the numerical simulation. The reservoir was assumed to be 100% brine-saturated with the initial TDS as indicated from Milton Flemmer 1 TDS analysis. Table 3-2 shows the general reservoir properties extracted from the model and used for numerical simulation analysis.

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

Formation	Pore Volume (PV) Weighted Average Permeability, mD	Average Porosity, %*	Initial Pressure, P_i, psi	Salinity, mg/L	Boundary Condition
Opeche/Spearfish	0.019	3.8	2741 (at 5882 ft, TVD**)	105,000	Partially closed
Broom Creek	1105.5	21.3			
Amsden	6.67	6.7			

* Porosity and permeability values are reported as PV weighted mean. Permeability averages were calculated after a 2.5 multiplier was applied.

** True vertical depth.

Numerical simulations of CO₂ injection performed allowed CO₂ 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 through 3-9). Samples tested within the Opeche/Spearfish, Broom Creek, and Amsden Formations included all five 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 facies and used in the numerical simulations. These modified capillary pressure curves are also shown in Figures 3-5 through 3-9. The capillary entry pressure values applied in the model were determined by deriving a ratio between the reservoir quality index of core samples of the modeled region 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 domain. This resulted in two different ratios, derived first from MICP data (same MICP sample for both facies) and second from the porosity and permeability properties for each of these facies in the model. These results demonstrated that there are two different capillary pressure curves for siltstone and anhydrite facies, Figures 3-6 and 3-9. It is worth noting that the relative permeability and capillary data selection are based on a broader data selection from the modeled region. All site-specific data in the modeled region, collected from Milton Flemmer 1, Archie Erickson 2, Slash Lazy H 5, and J-LOC 1, are screened, and the data from the most representative samples that are close to the reservoir properties are selected in dynamic flow simulations.

The calculated temperature and pressure based on reported temperature and pressure gradients derived from data recorded in the Milton Flemmer 1 wellbore were used to initialize the numerical simulation model for the proposed injection site. In combination with depth, a temperature gradient of 0.017°F/ft was used to calculate subsurface temperatures throughout the simulation model area. A pressure reading recorded from the Broom Creek Formation was used to derive a pore pressure gradient of 0.466 psi/ft.

A fracture gradient of 0.784 psi/ft was calculated from a microfracture in situ stress test using a SLB MDT (modular dynamics testing) tool (Figure 2-6, Table 2-4). The calculated maximum BHP constraints of 3828 and 3808 psi for KJ Hintz 1 and KJ Hintz 2, respectively, were derived by multiplying the fracture gradient by the depth of the top perforation in the injection zone

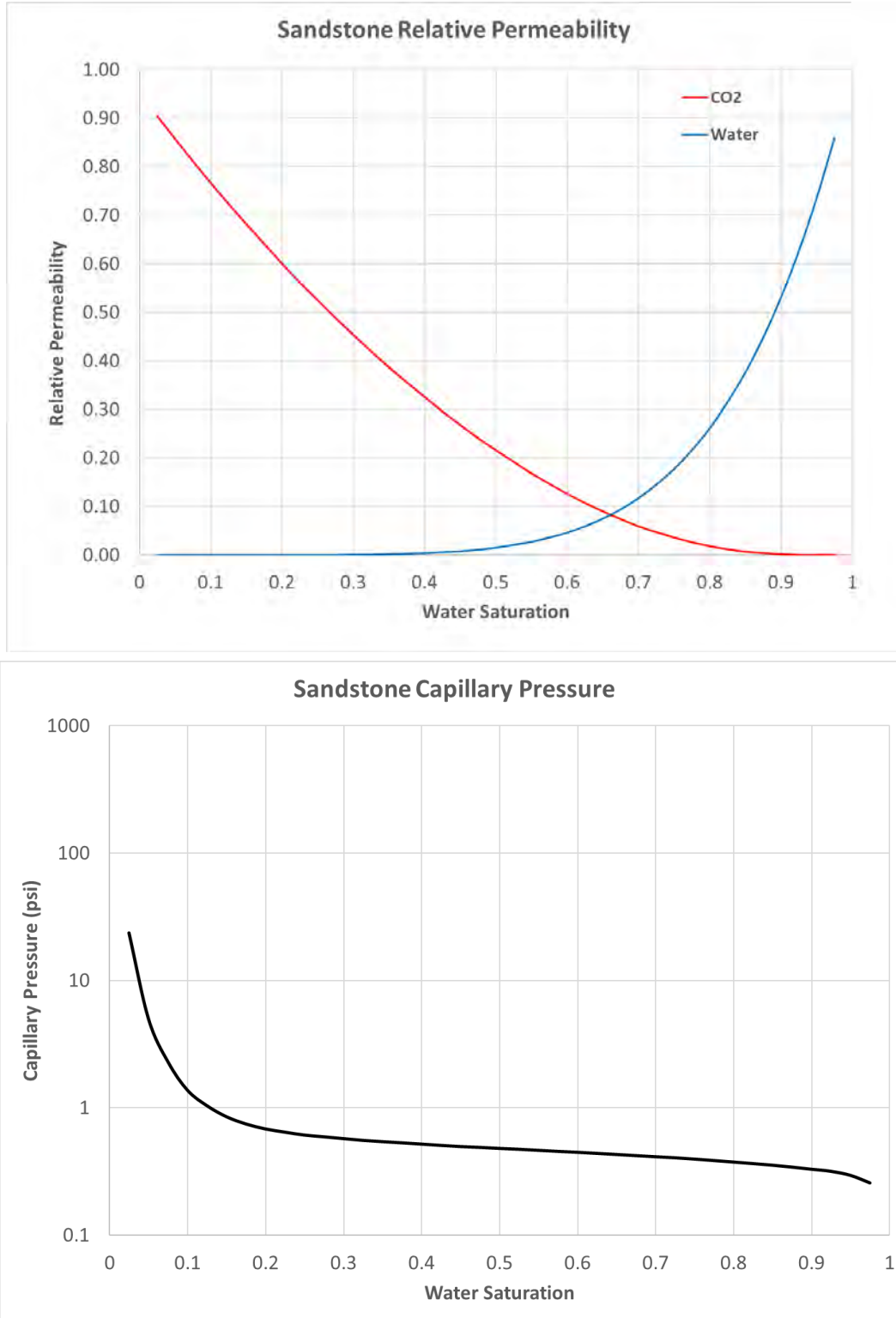


Figure 3-5. Relative permeability (top) and capillary pressure curves (bottom) for the sandstone facies the Broom Creek Formation.

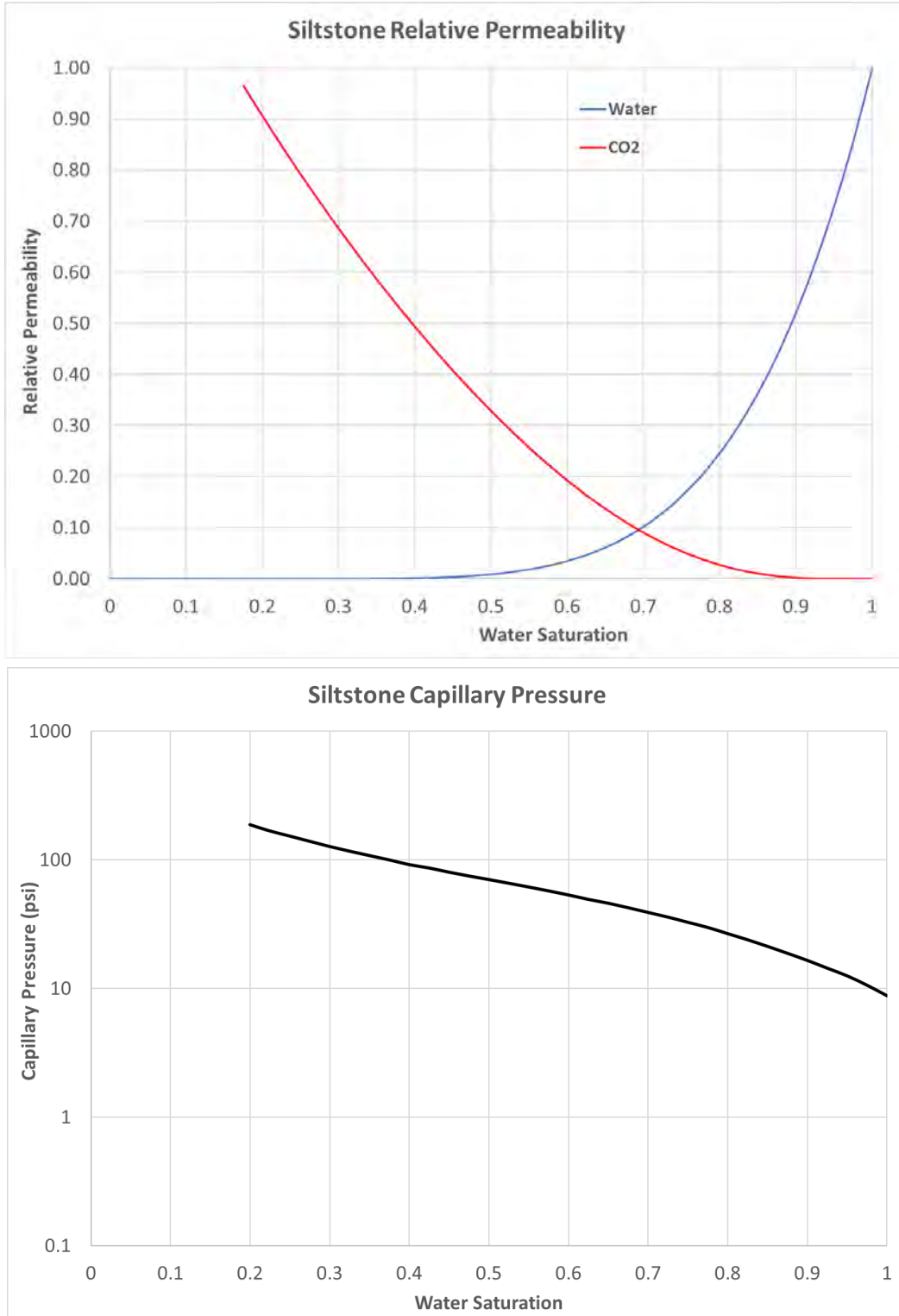


Figure 3-6. Relative permeability (top) and capillary pressure curves (bottom) for the siltstone facies of the Opeche/Spearfish Formation.

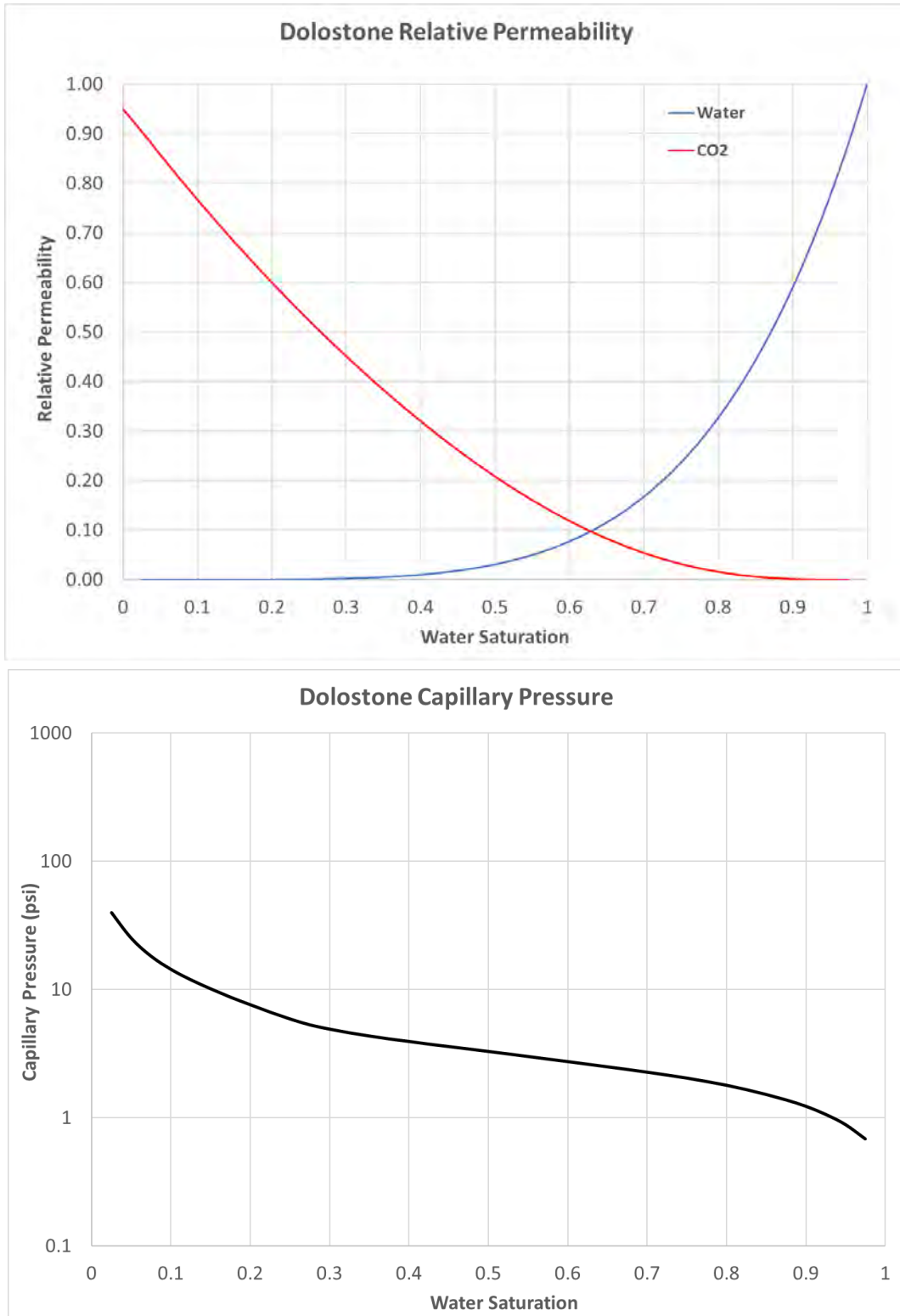


Figure 3-7. Relative permeability (top) and capillary pressure curves (bottom) for the dolostone facies of the Broom Creek and Amsden Formations.

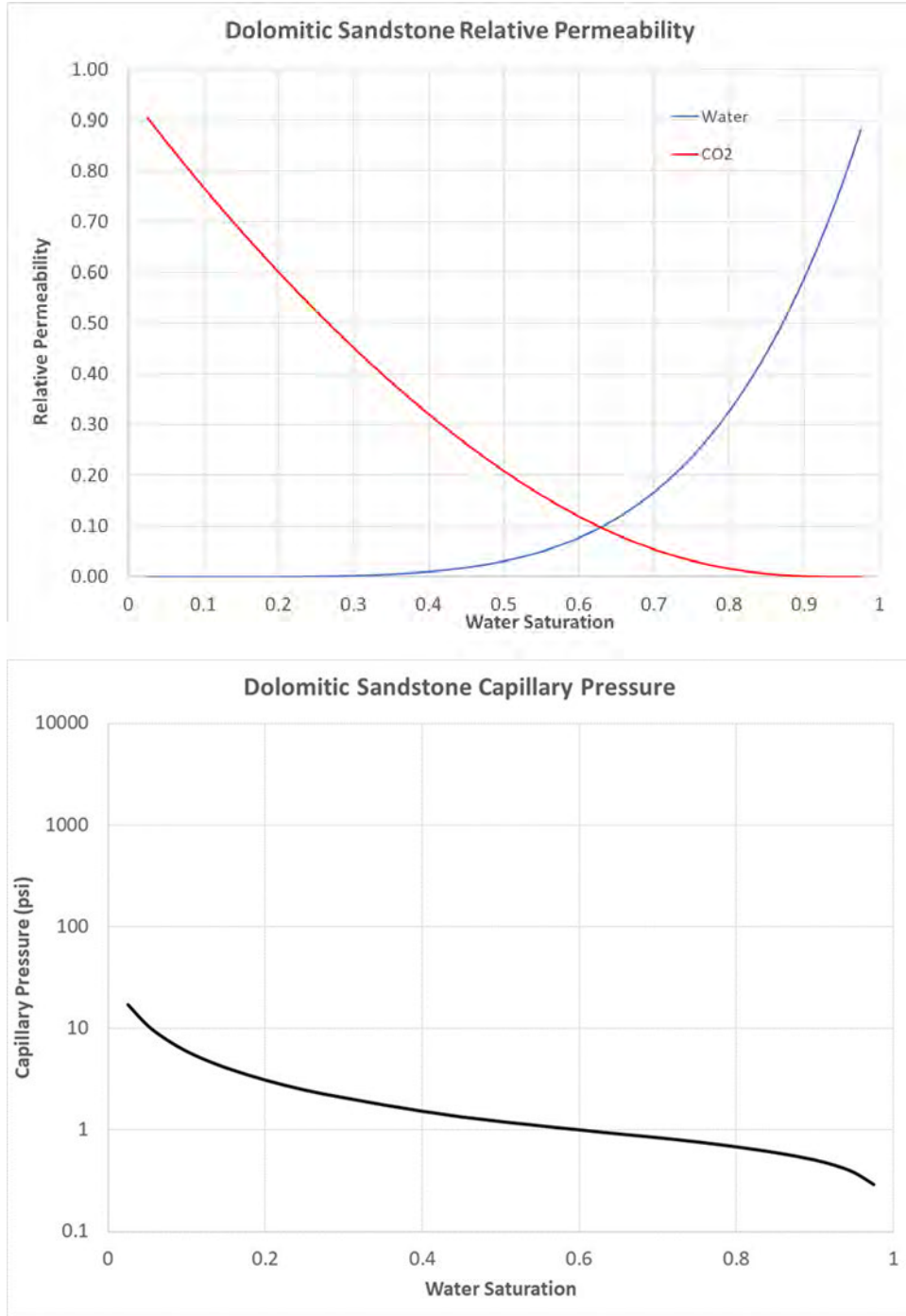


Figure 3-8. Relative permeability (top) and capillary pressure curves (bottom) for the dolomitic sandstone facies of the Broom Creek and Amsden Formations.

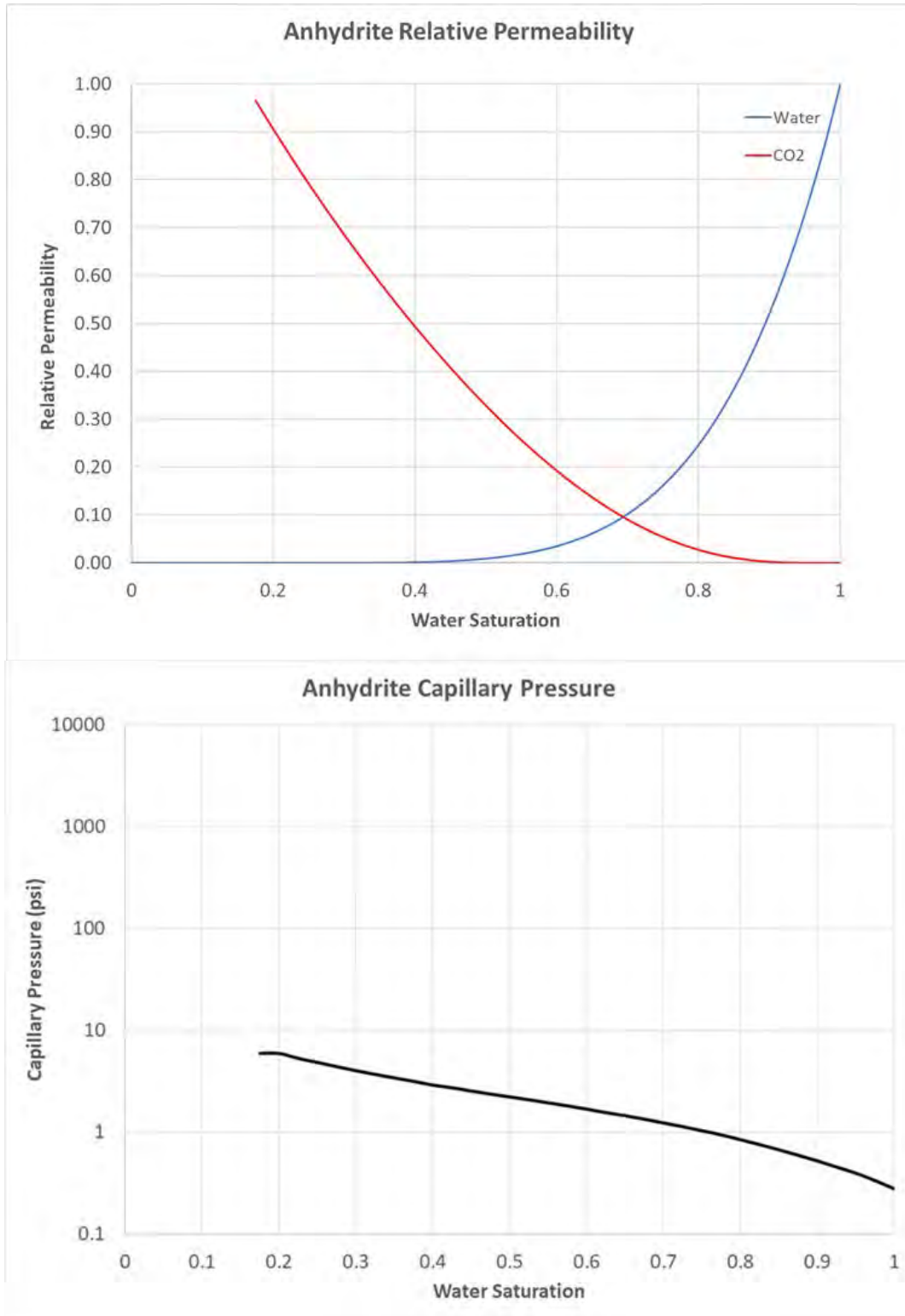


Figure 3-9. Relative permeability (top) and capillary pressure curves (bottom) for the anhydrite facies of the Broom Creek and Amsden Formations.

Table 3-3. Core and Model Properties (Porosity [Phi], Permeability [K], and Reservoir Quality Index [RQI] Showing the Multiplication Factor Used to Calculate Capillary Entry Pressure (Pce) Used in the Simulation Model

	Core					Model				Multiplication Factor
	Phi (fraction)	K, mD	Pce A/Hg, psi	Pce B/CO ₂ , psi	RQI	Phi (fraction)	K, mD	Pce B/CO ₂ , psi	RQI	
Sandstone Sample	0.267	1147	3.04	0.2006	2.058	0.238	1379.000	0.173	2.393	0.860
Siltstone Sample	0.017	0.00002	2630	168.1	0.001	0.048	0.016	9.987	0.018	0.059
Dolostone Sample	0.048	0.00478	274	18.08	0.010	0.086	13.430	0.458	0.391	0.025
Dolomitic Sands Sample	0.087	0.00683	400	25.6	0.009	0.155	272.100	0.171	1.315	0.007
Anhydrite Sample	0.017	0.00002	2630	168.1	0.001	0.028	9.842	0.308	0.589	0.002

of the model (5426 ft TVD for KJ Hintz 1 and 5397 ft TVD for KJ Hintz 2), and then multiplying this product by 90% as a safety factor. These values were used as the injection constraint in the numerical simulation of the expected injection scenario. The top perforations were placed within the uppermost sandstone of the Broom Creek just below the capping anhydrite, which will act as a barrier to CO₂ flow because of the anhydrite's low porosity and permeability. Perforation depths for the KJ Hintz 1 and KJ Hintz 2 were calculated prior to final injection site selection and were based on expected ground-level elevation.

The simulation model permeability was tuned globally by applying a permeability multiplier to match reservoir properties estimated from the well-testing data in the Broom Creek Formation near the Milton Flemmer 1 well. The permeability multiplier was calculated based on the area of study during the injectivity test, the radius of investigation, and the permeability thickness (transmissibility) values from the pressure transient analysis. Ultimately, a global multiplier of 2.5 was applied before numerical simulations to provide a more conservative input for simulation.

The CO₂ stream used to conduct numerical simulations of CO₂ injection was composed of 98.25% (by volume) CO₂ and 1.75% trace quantities of other constituents, including 1.44% nitrogen (N₂), 0.31% oxygen (O₂), and 0.001% hydrogen sulfide (H₂S). This is the anticipated average CO₂ injection stream based on compositional studies of CO₂ from potential sources. Other constituents such as sulfur, hydrocarbons, glycol, amine, aldehydes, NO_x, and NH₃ may also be present but in a negligible amount that would impact neither fluid flow dynamics nor geochemical reactions in the storage formation and were not included.

Approximately 9.4 mi southwest from KJ Hintz is the injection site identified for TB Leingang and approximately 10 mi west is BK Fischer, as shown in Figures 2-1 and 3-4. KJ Hintz is included in the numerical model and simulated injecting simultaneously with BK Fischer and TB Leingang. KJ Hintz consists of two Broom Creek injection wells (KJ Hintz 1 and KJ Hintz 2), which are proposed to inject at the maximum allowable BHP (90% of the product when multiplying the fracture gradient by top perforation depth) with a secondary maximum allowable WHP constraint of 2100 psi for a total 20-year CO₂ injection period. The well constraints and wellbore model inputs for the simulation model are shown in Table 3-4. The wells (BK Fischer 1 and 2 and TB Leingang 1 and 2) at nearby sites are also operated under the same conditions with their corresponding maximum BHPs and WHP (2100 psi).

Results using the 7-in. 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.

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 made to the wellbore model parameters suggested, at the given injection volume rates and BHP conditions, 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. For evaluating the expected injection design, a wellhead temperature value of 60°F was chosen to most closely represent the expected operational temperature.

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

Well Constraint, maximum BHP	Secondary Well Constraint, WHP	Tubing Size	Wellhead Temp.	Downhole Temperature**
3663 psi (TB Leingang 1)	2100 psi (TB Leingang 1 and 2)			136.4°F at 5668 ft TVD (TB Leingang 1)
3669 psi (TB Leingang 2)				136.5°F at 5678 ft TVD (TB Leingang 2)
3633psi (BK Fischer 1)	2100 psi (BK Fischer 1 and 2)	7 in.	60°F	127.6°F at 5841 ft TVD (BK Fischer 1)
3624 psi (BK Fischer 2)				127.4°F at 5828 ft TVD (BK Fischer 2)
3828 psi (KJ Hintz 1)	2100 psi (KJ Hintz 1 and 2)			116°F at 5426 ft TVD (KJ Hintz 1)
3808 psi (KJ Hintz 2)				115.5°F at 5397 ft TVD (KJ Hintz 2)

* A WHT temperature of 60°F was used for wellbore modeling, and an average ambient surface temperature of 40°F was used for reservoir modeling.

** The formula used to calculate downhole/reservoir temperature in both wellbore and reservoir modeling is $\text{Depth} \times \text{Reservoir Temperature Gradient} + 40^\circ\text{F} = \text{Downhole/Reservoir Temperature}$.

3.4 Simulation Results

The maximum WHP constraint of 2100 psi was one of the constraints on the injection wells for the entire 20 years of simulated injection. The maximum BHP constraint of 3828 psi for KJ Hintz 1 and 3808 psi for KJ Hintz 2 (equal to 90% of the product when multiplying the fracture gradient by top perforation depth) was approached near year 20 of injection but was never reached (Figure 3-10), translating to a cumulative combined 129.7 MMt of CO₂ injected into the Broom Creek Formation by KJ Hintz 1 and 2 (Figure 3-11). Simulations of CO₂ injection with the given well constraints, listed in Table 3-4, predicted the injection rate would decline from a maximum initial injection rate of approximately 3.7 MMt/yr per well to a final rate of approximately 3.2 MMt/yr per well (with a 20-year combined average of approximately 3.24 MMt/yr per injection well) (Figure 3-12).

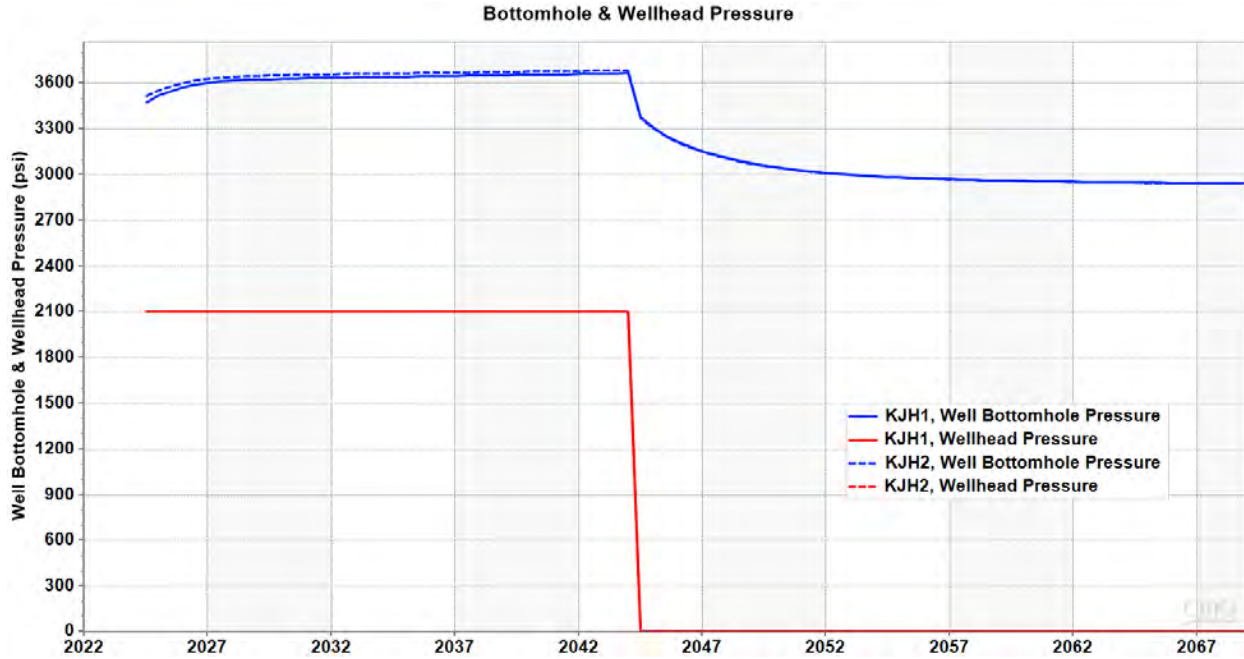


Figure 3-10. Predicted WHP and BHP responses.

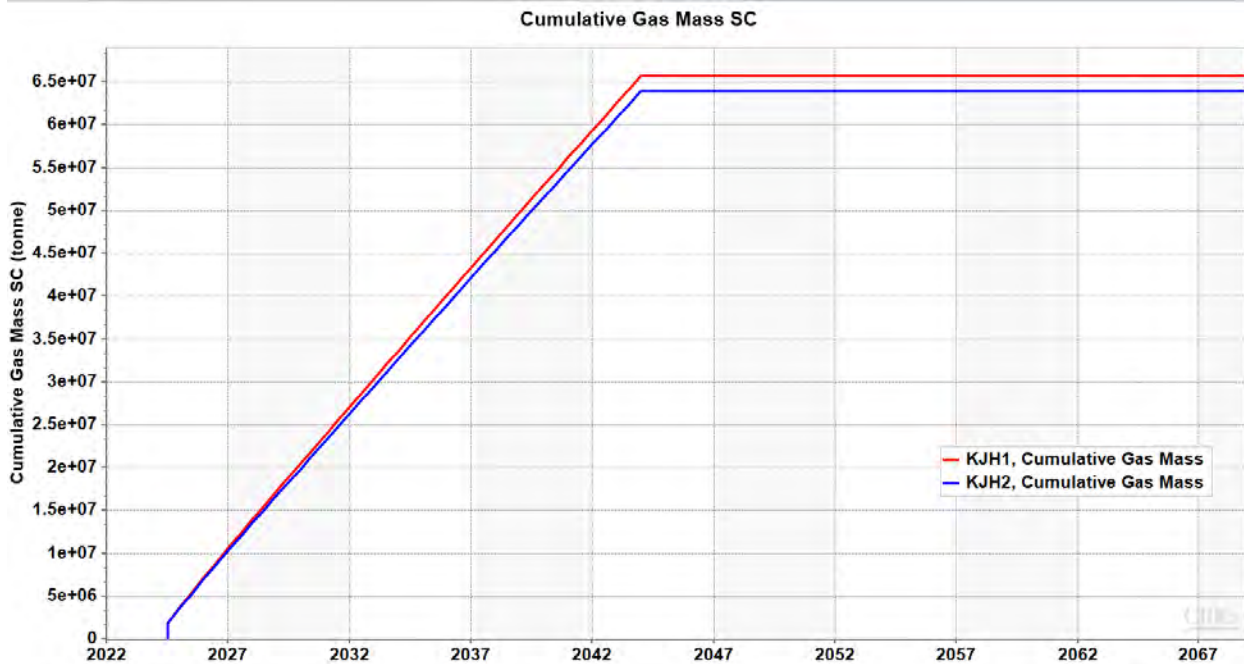


Figure 3-11. Cumulative injected gas mass over 20 years of injection with well pressure constraints.

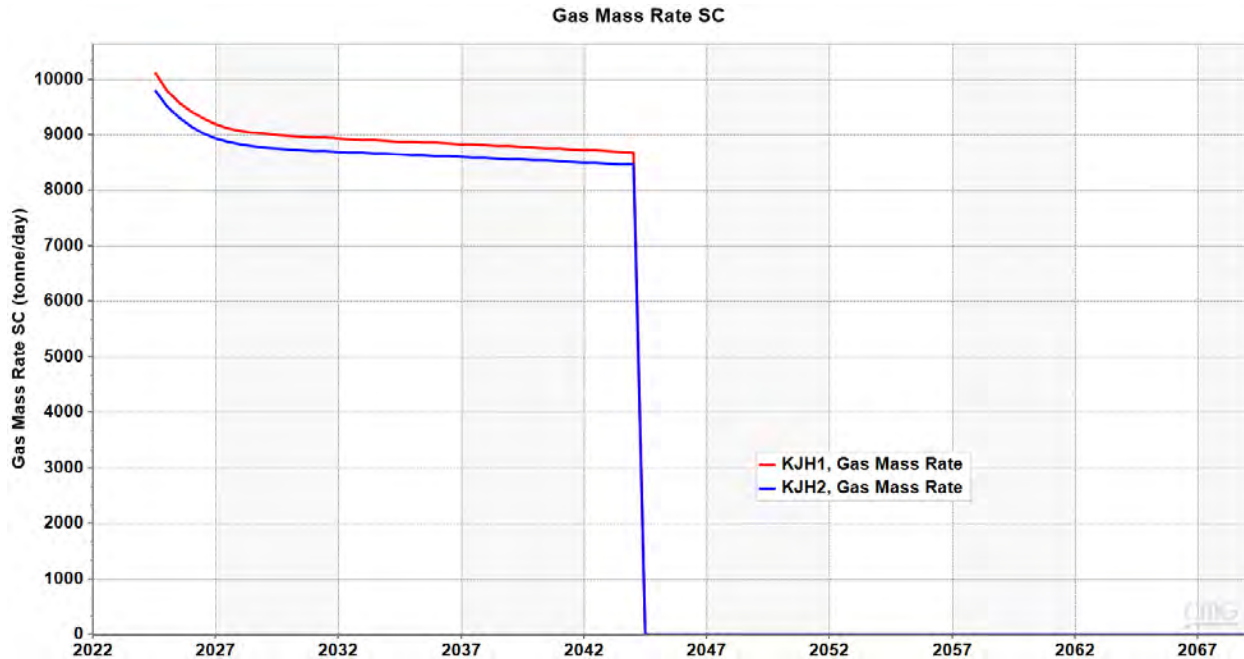


Figure 3-12. Predicted mass injection rate over 20 years of injection with well pressure constraints.

WHP and BHP responses depend on several factors, including predicted injection rate, injection tubing parameters (tubing internal radius and relative roughness), and surface injection temperature. For the designed tubing size of 7 in., the wells are operated at the maximum WHP of 2100 psi during the 20-year injection period (Figure 3-10).

During and after injection, supercritical CO₂ (free-phase CO₂) accounts for the majority of CO₂ observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO₂ is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO₂ saturation and inability to flow under the effects of relative permeability. CO₂ 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 CO₂ during the postinjection period, resulting in a decline in the mass of free-phase CO₂. The relative portions of supercritical, trapped, and dissolved CO₂ can be tracked throughout the duration of the simulation (Figure 3-13).

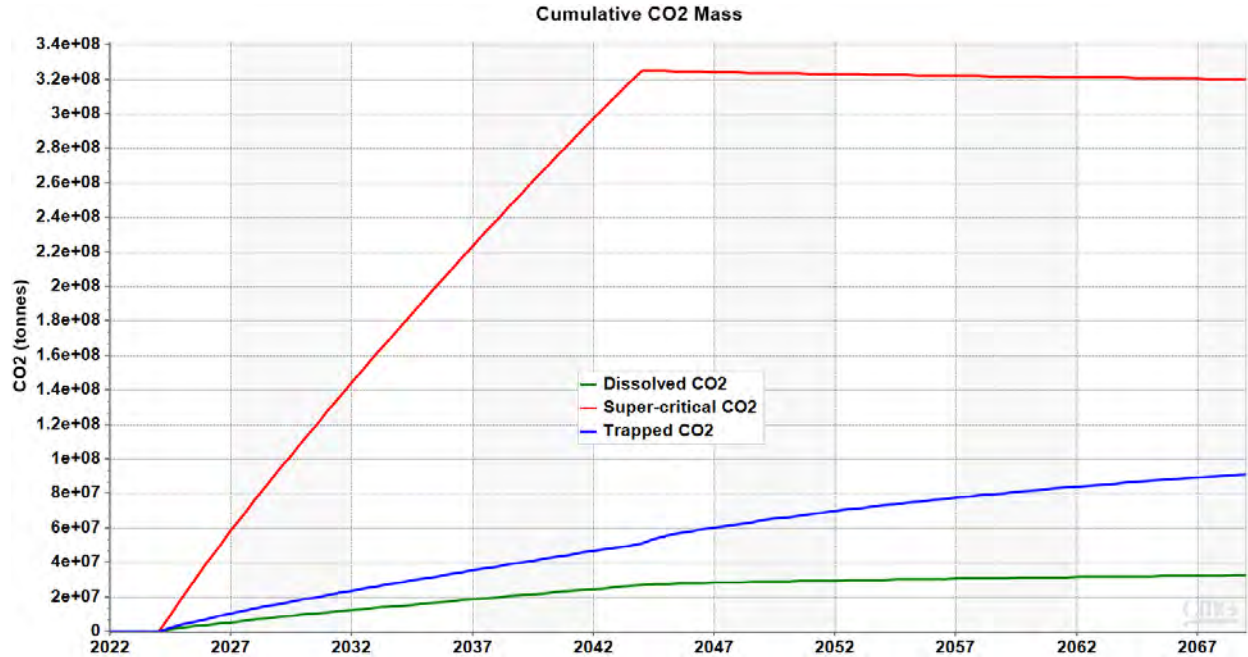


Figure 3-13. Simulated total supercritical free-phase CO₂, trapped CO₂, and dissolved CO₂ in brine, for the three adjacent project sites (comprising six injection wells, namely TB Leingang 1 and 2, BK Fischer 1 and 2, and KJ Hintz 1 and 2).

The pressure fronts (Figures 3-14a–d) show the distribution of average pressure increase throughout the Broom Creek Formation after 5, 10, and 20 years of injection as well as 10 years postinjection. A maximum increase of approximately 1024 psi was estimated in the near-wellbore area at the end of the 20-year injection period (Figure 3-14c).

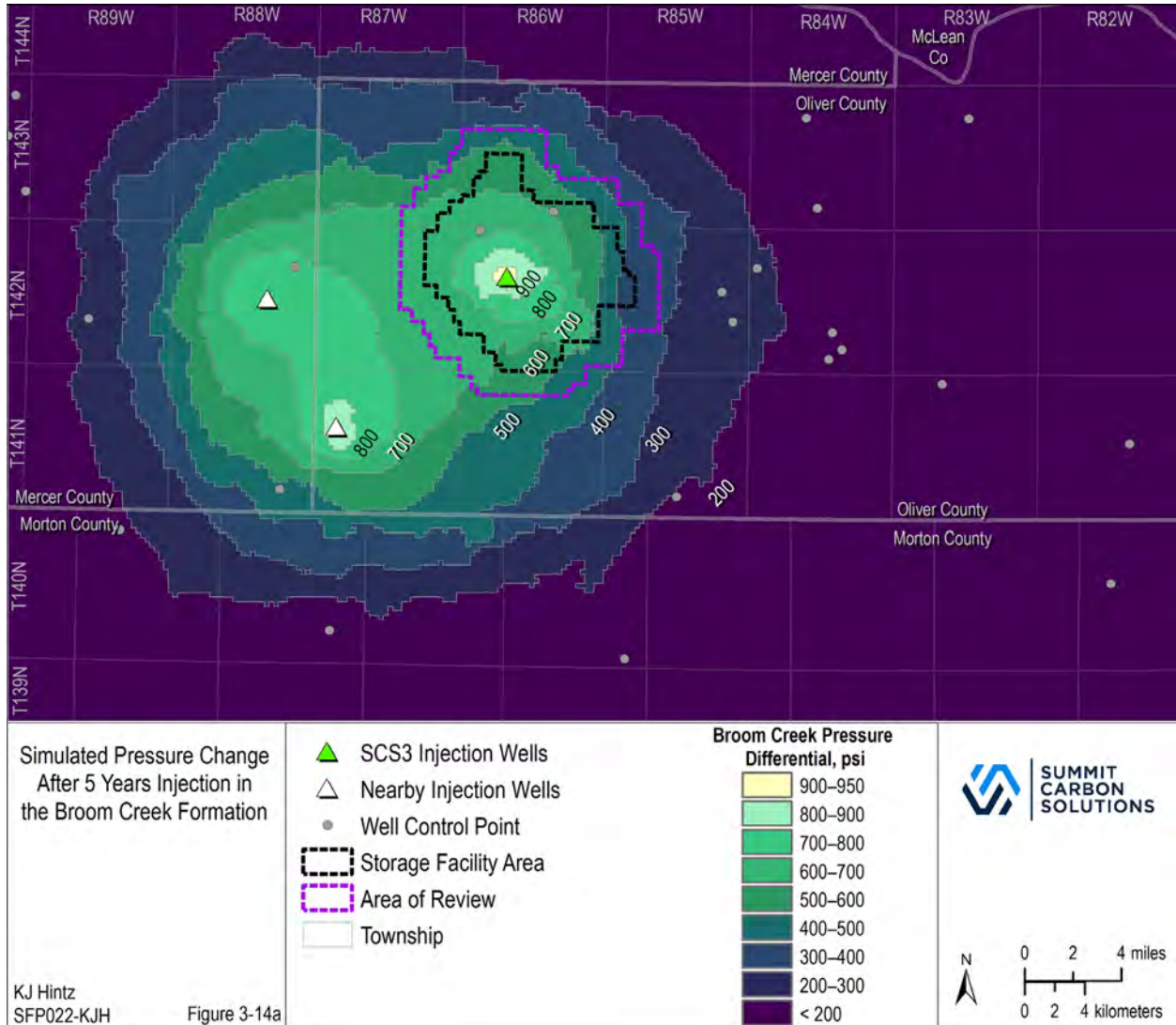


Figure 3-14a. Average pressure increase within the Broom Creek Formation after 5 years of simulated CO₂ injection operation.

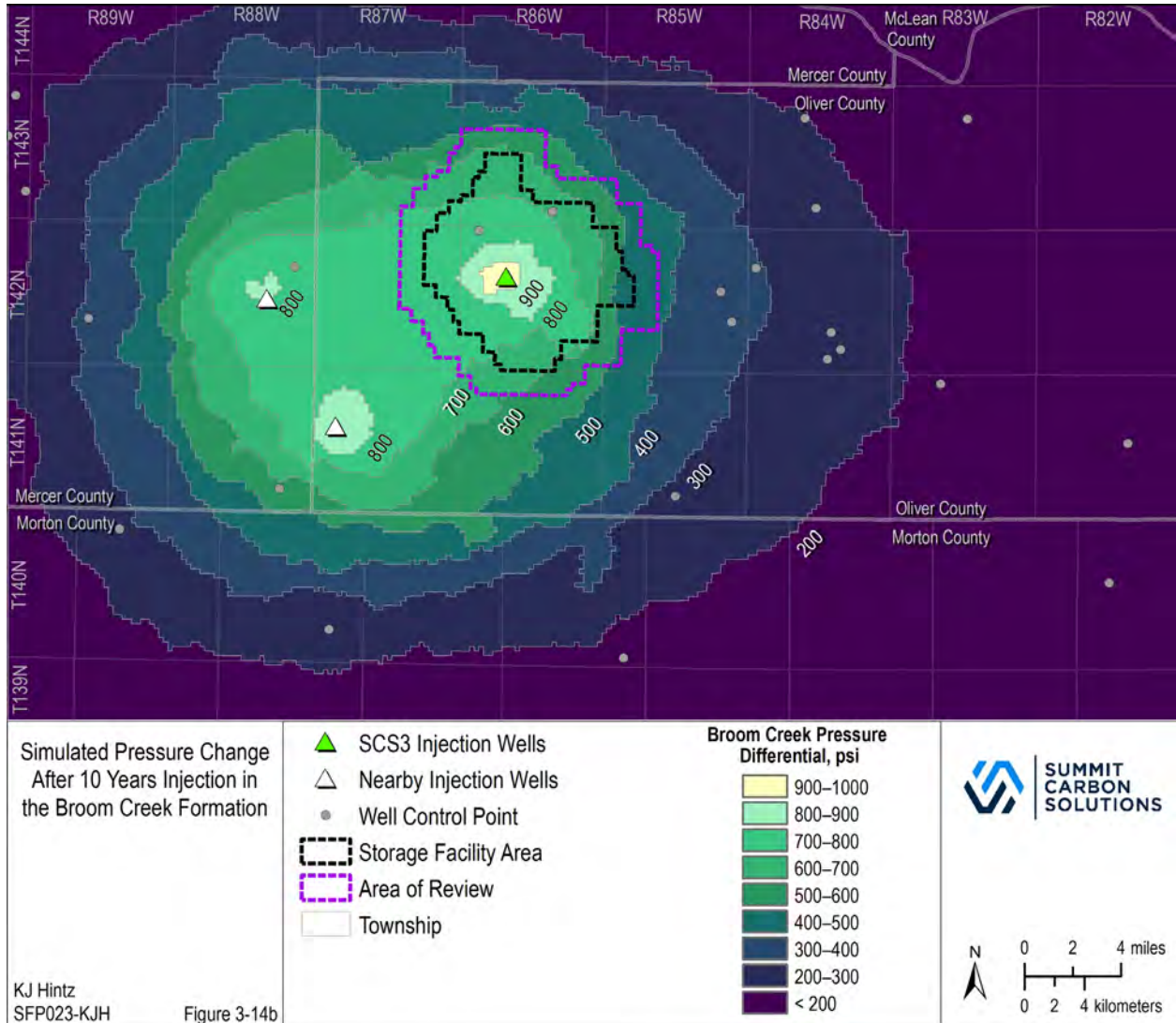


Figure 3-14b. Average pressure increase within the Broom Creek Formation after 10 years of simulated CO₂ injection operation.

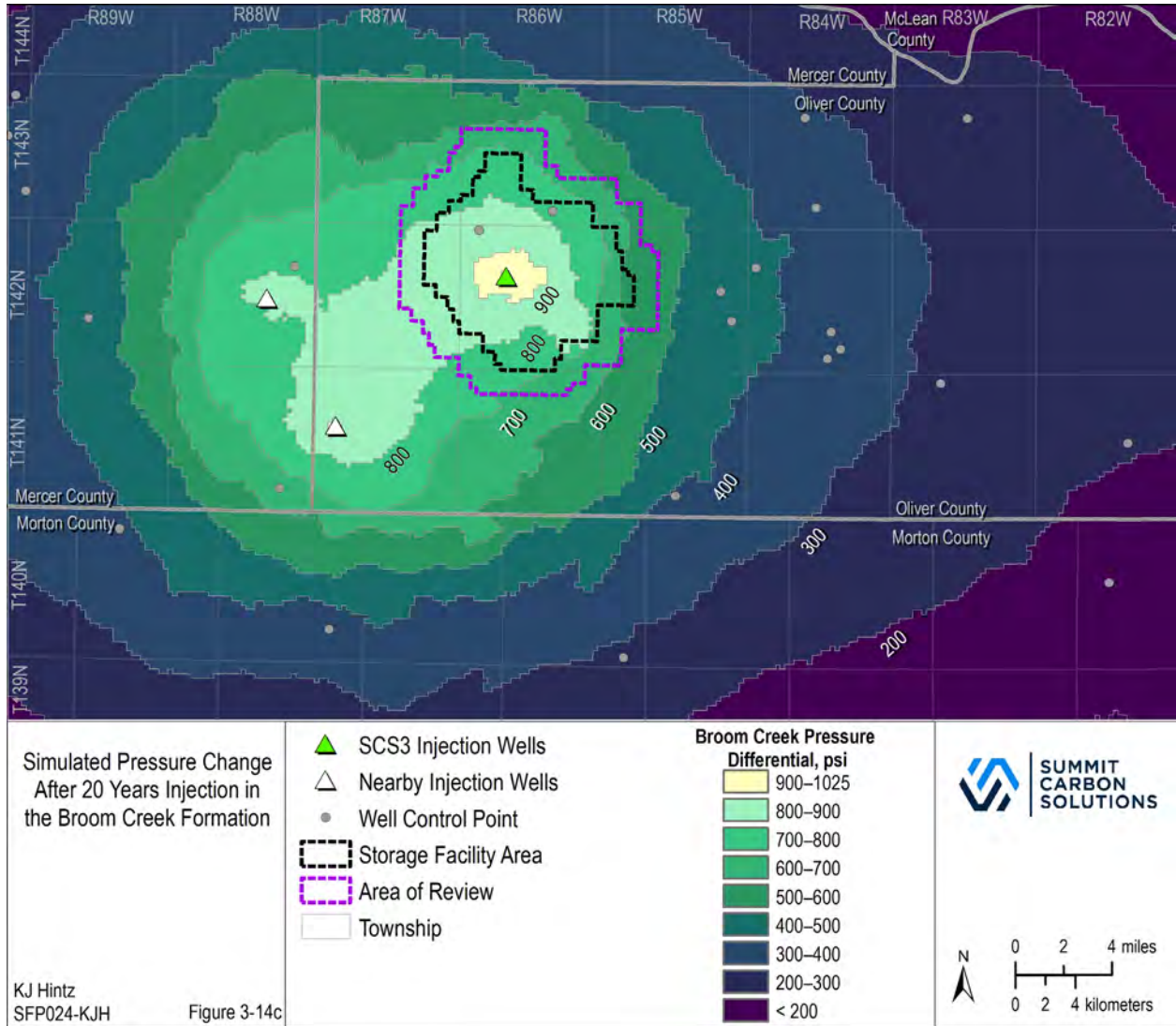


Figure 3-14c. Average pressure increase within the Broom Creek Formation after 20 years of simulated CO₂ injection operation (end of injection operation).

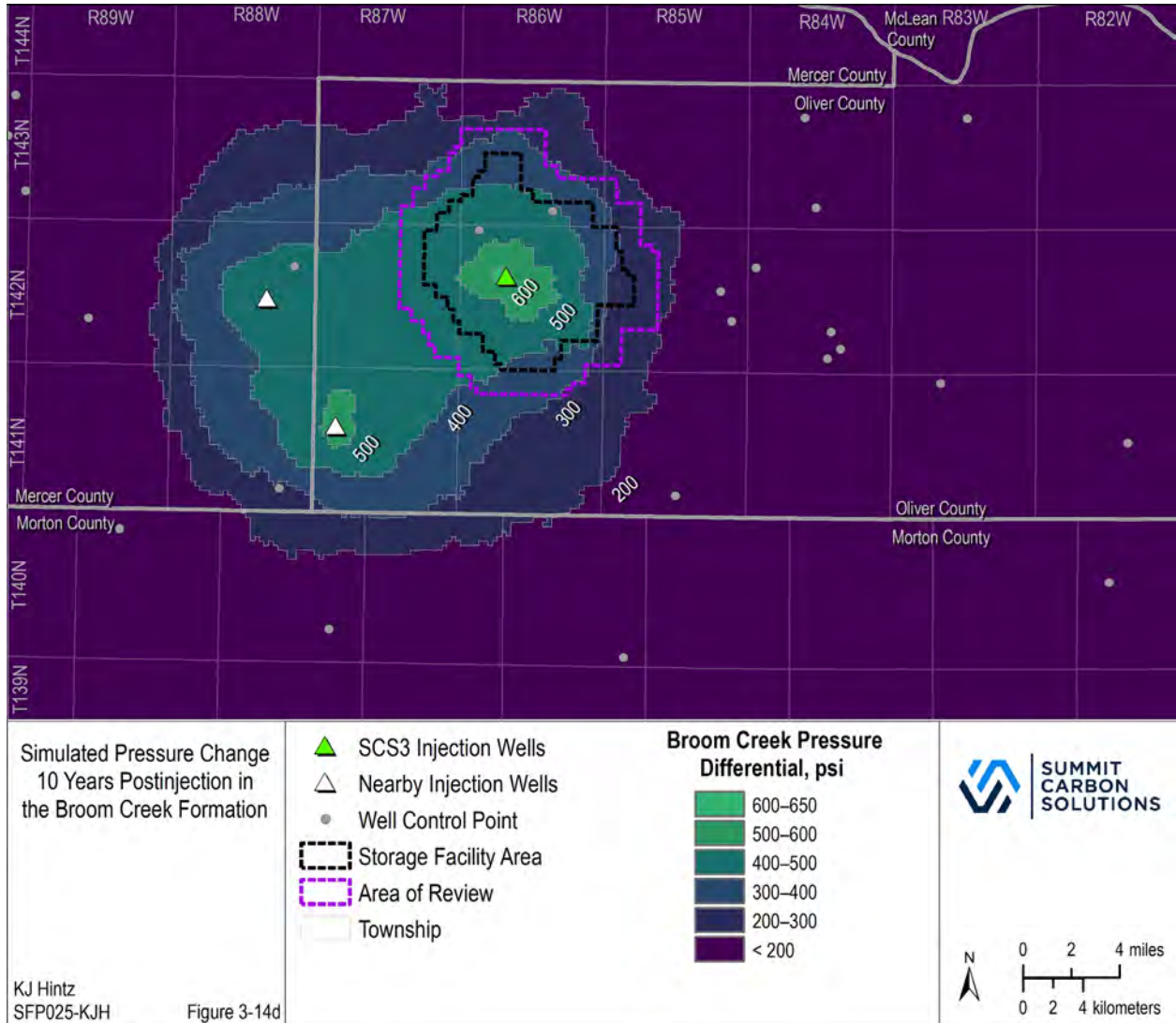


Figure 3-14d. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO₂ injection.

Long-term CO₂ migration potential was also investigated through numerical simulation efforts. The slow lateral migration of the plume is caused by the effects of buoyancy where the free-phase CO₂ injected into the formation rises to the bottom of the upper confining zone or lower-permeability layers present in the Broom Creek Formation and then outward. This process results in a higher concentration of CO₂ at the center which gradually spreads out toward the model edges where the CO₂ saturation is lower. Trapped CO₂ saturations, employed in the model to represent fractions of CO₂ trapped in small pores as immobile supercritical fluids, ultimately immobilize the CO₂ plume and limit the plume's lateral migration and spreading. Figures 3-15a-c show the CO₂ saturation at the end of injection in west-to-east and north-to-south cross-sectional views.

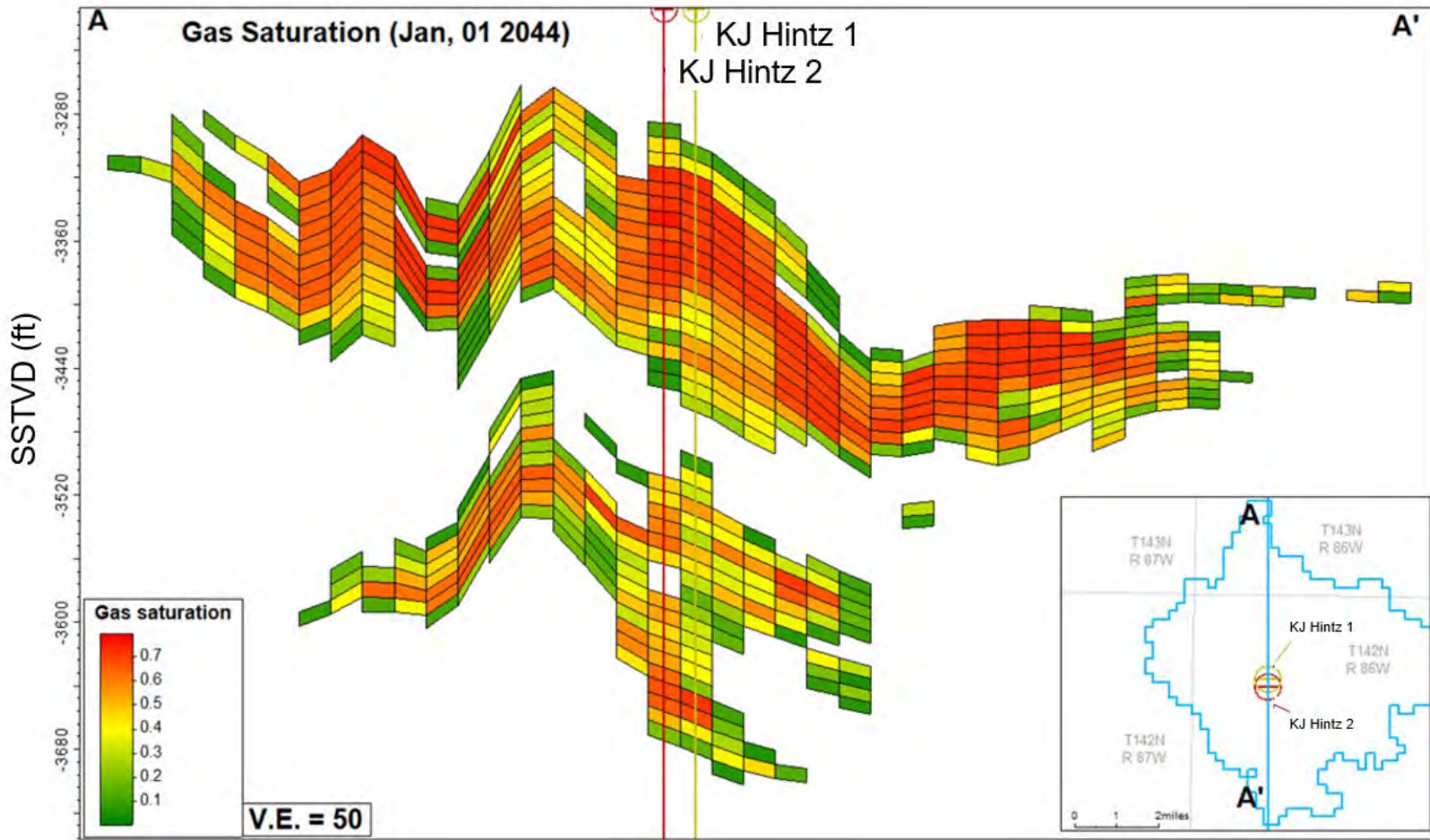


Figure 3-15a. North-to-south (I-Layer 109) cross section showing the CO₂ plume at the end of injection. White cells or “empty” intervals contain CO₂ saturation that is less than 5%. 50× vertical exaggeration is shown.

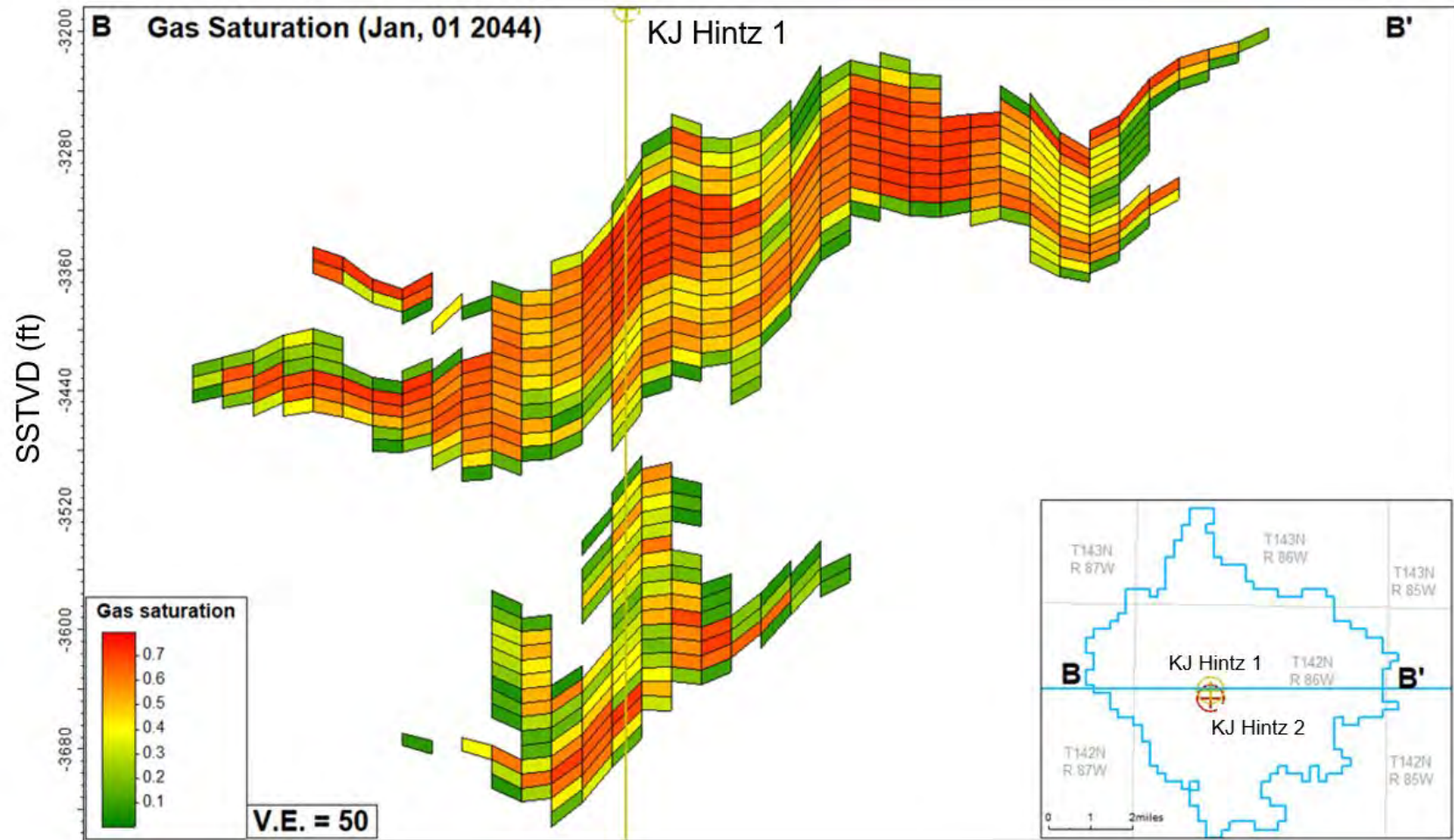


Figure 3-15b. West-to-east (J-Layer 98) cross section showing the CO₂ plume at the end of injection. White cells or “empty” intervals contain CO₂ saturation that is less than 5%. 50× vertical exaggeration is shown.

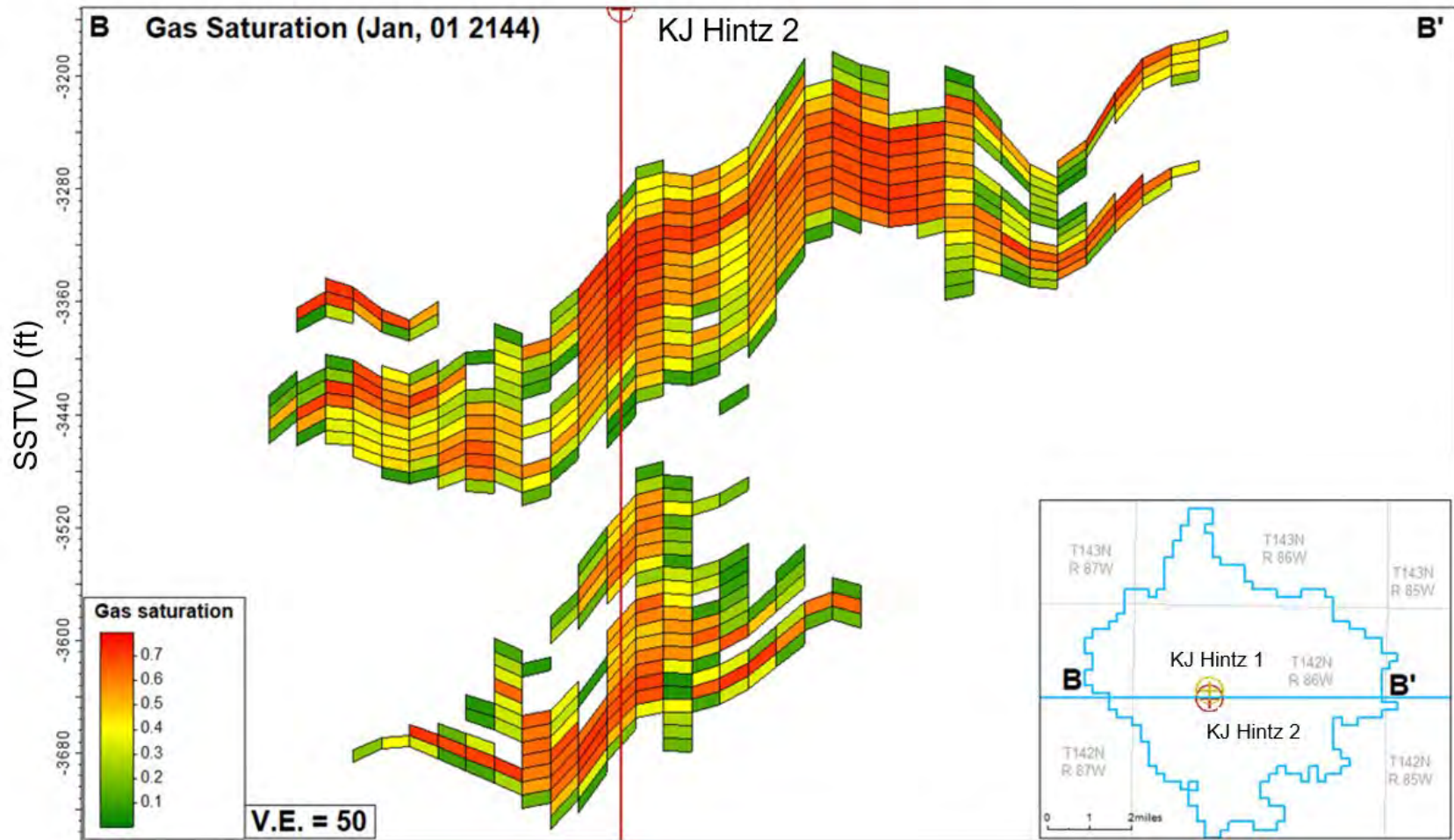


Figure 3-15c. West-to-east (J-Layer 97) cross section showing the CO₂ plume at the end of injection. White cells or “empty” intervals contain CO₂ saturation that is less than 5%. 50× vertical exaggeration is shown.

3.4.1 Maximum Injection Pressure and Rates

An additional case was run to determine if a well would ultimately be limited by the maximum WHP of 2100 psi or maximum calculated downhole pressure of 90% of the fracture propagation pressure at the perforated depth (3828 psi [KJ Hintz 1]) and (3808 psi [KJ Hintz 2]). The estimated fracture propagation pressure gradient of 0.784 psi/ft was used for the calculated maximum BHP as the only well constraint to evaluate maximum storage potential for each injection well.

When a single injection well reaches the maximum BHP condition of 3828 or 3808 psi in the simulation, the corresponding predicted average WHPs are reaching approximately 6500 and 5800 psi, respectively, for KJ Hintz 1 and KJ Hintz 2 (Figure 3-16). The predicted maximum daily injection rate could reach approximately 30,000 and 27,563 tonnes/day, respectively, for KJ Hintz 1 and KJ Hintz 2.

A total volume of 215.7 and 197.3 MMt of gas was injected over 20 years, respectively, resulting in the calculated daily averaged maximum gas injection rate of 29,548 and 27,027 tonnes/day (the total volume divided by 20 years \times 365 days) respectively, for KJ Hintz 1 and KJ Hintz 2 (see Table 11-1).

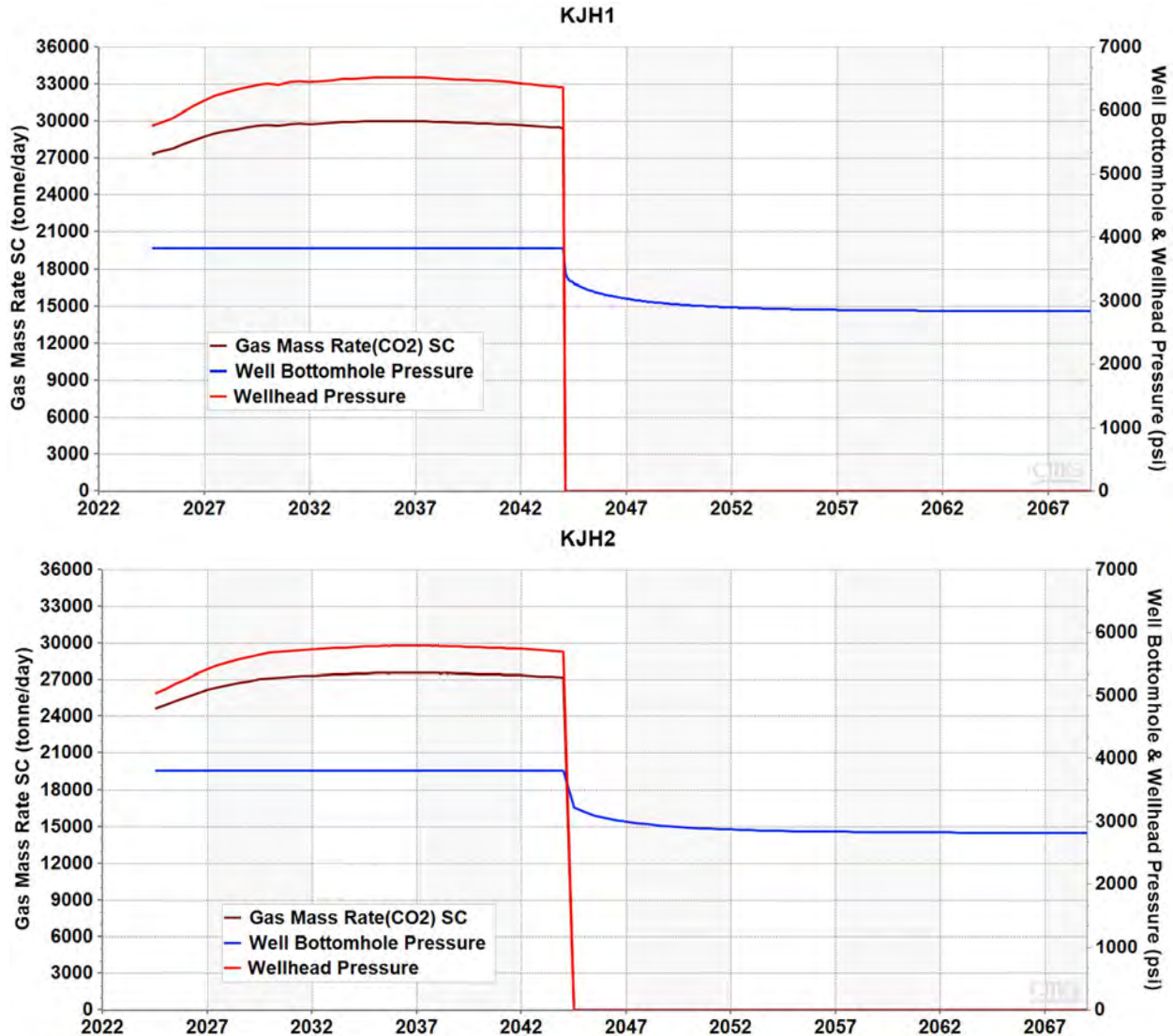


Figure 3-16. Maximum pressure and gas rate response when the well was operated at max BHP only (without any WHP limits) for KJ Hintz 1 (top) and KJ Hintz 2 (bottom).

3.4.2 *Stabilized Plume and Storage Facility Area*

Movement of the injected CO₂ plume is driven by the potential energy found in the buoyant force of the injected CO₂. As the plume spreads out within the reservoir and CO₂ is trapped residually through the effects of relative permeability and dissolution, the potential energy of the buoyant CO₂ is gradually lost. Eventually, the buoyant force of the CO₂ is no longer able to overcome the capillary entry pressure of the surrounding reservoir rock. At this point, the CO₂ plume ceases to move within the subsurface and becomes stabilized. The extent of the stabilized plume is important for determining the project’s AOR and the corresponding scale and scope of the project’s monitoring plans.

Plume stabilization can be visualized at the microscale as CO₂ 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 CO₂ plume's extent.

For this permit, the CO₂ plume was assessed in 1-year time steps until the rate of total areal extent change slowed to less than 0.2 square mi per 1-year time step to define the stabilized plume extent boundary and the associated buffers and boundaries. This estimate is anticipated to be regularly updated during the CO₂ storage operation as data collected from the site are used to update predictions made about the behavior of the injected CO₂.

3.5 Delineation of the Area of Review

The North Dakota Administrative Code (N.D.A.C.) defines an AOR as the region surrounding the geologic sequestration project [storage project] where underground sources of drinking water [USDWs] may be endangered by the [CO₂] injection activity (N.D.A.C. § 43-05-01-01[4]). The primary endangerment risk is the potential for vertical migration of CO₂ and/or formation fluids from the storage reservoir into a USDW. At a minimum, the AOR includes the areal extent of the CO₂ plume within the storage reservoir.

However, the CO₂ plume has an associated pressure front where CO₂ injection increases the formation pressure above initial (preinjection) conditions. Generally, the pressure front is larger in areal extent than the CO₂ plume. Therefore, the AOR encompasses both the areal extent of the CO₂ plume within the storage reservoir and the extent of the reservoir fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways for this migration (e.g., legacy oil and gas wells or fractures) are present. Because the pressure front is larger in areal extent than the CO₂ plume, AOR delineation focuses on the pressure front.

The minimum pressure increase in the reservoir that results in a sustained flow of brine upward from the storage reservoir into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase" and resultant pressure as the "critical threshold pressure." Therefore, the AOR is the areal extent of the storage reservoir that exceeds the critical pressure threshold. U.S. Environmental Protection Agency (EPA) guidance for AOR delineation under the underground injection control (UIC) program for Class VI wells provides several methods for estimating the critical threshold pressure increase and resulting critical threshold pressure.

In this document, "storage reservoir" refers to the Broom Creek Formation (the injection zone), "potential thief zone" refers to the Inyan Kara Formation, and "lowest USDW" refers to the Fox Hills Formation).

3.5.1 EPA Methods 1 and 2: AOR Delineation for Class VI Wells

EPA guidance for AOR evaluation includes several computational methods for estimating the pressure buildup in the storage reservoir in response to CO₂ injection and the resultant areal extent of pressure buildup above a "critical threshold pressure" that could potentially drive higher-salinity formation fluids from the storage reservoir up an open conduit to the lowest USDW (U.S. Environmental Protection Agency, 2013). The following equations and analytical approach define the EPA methods used to delineate AOR. Each method can be applied both at a single location

(e.g., the KJ Hintz 1 simulation well) using site-specific data or for each vertical stack of grid cells in a geocellular model, considering the varying stratigraphic thickness between storage reservoir and lowest USDW.

EPA 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:

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

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).
- (* amsl = above mean sea level)

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 underpressured relative to the USDW; and if $\Delta P_{i,f} < 0$, then the reservoir is overpressured 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):

$$\Delta P_c = \frac{1}{2} g \xi (z_u - z_i)^2 \quad [\text{Eq. 2}]$$

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \quad [\text{Eq. 3}]$$

Where:

- ΔP_c is the critical threshold pressure increase (Pa).
- g is the acceleration of gravity (m/s^2).

z_u is the elevation of the base of the lowermost USDW (m amsl).

z_i is the elevation of the top of the injections zone (m amsl).

ρ_i is the fluid density in the injection zone (kg/m^3).

ρ_u is the fluid density in the USDW (kg/m^3).

3.5.2 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 overpressured 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 overpressured 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").

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 overpressured 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 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 CO₂ plume domain can be reasonably described by a single-phase flow calculation by representing CO₂ 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 CO₂ 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 3-17).

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.

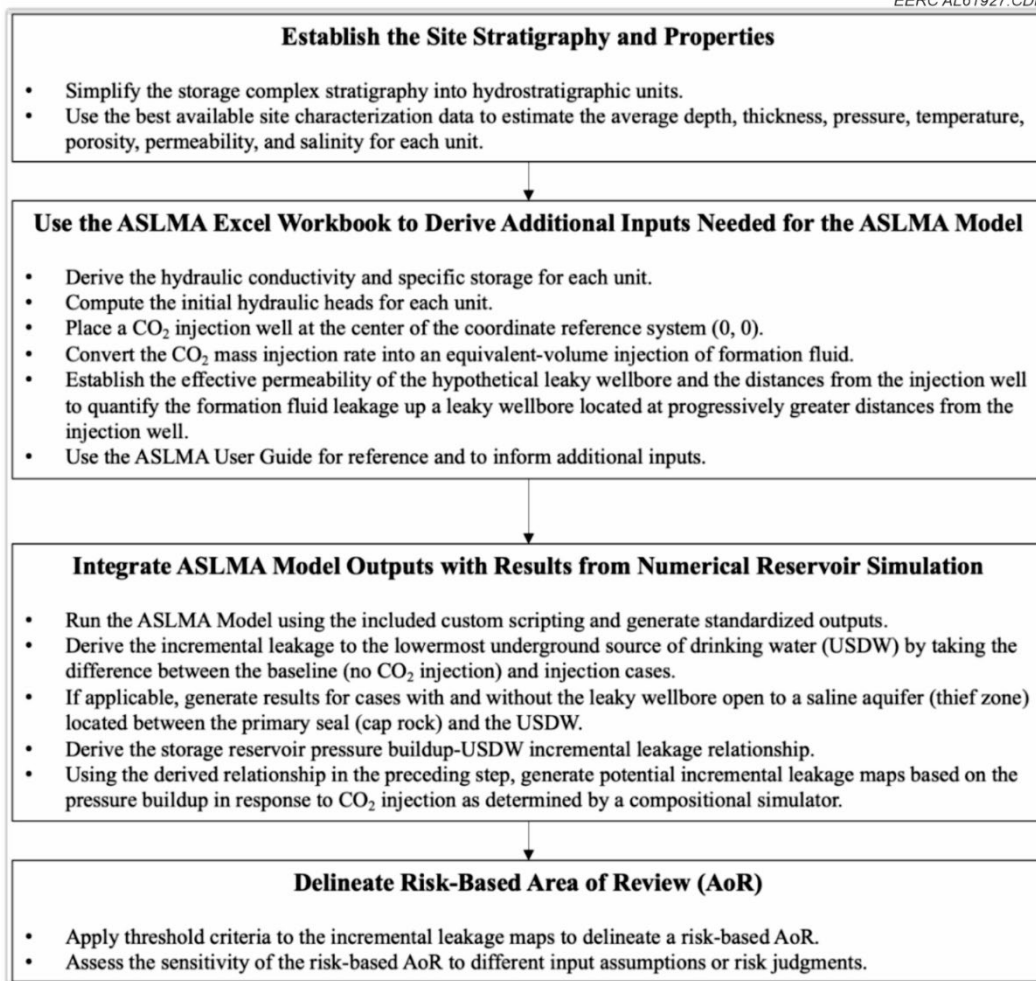


Figure 3-17. Workflow for delineating a risk-based AOR for an SFP (modified from Burton-Kelly and others, 2021).

3.5.3 Critical Threshold Pressure Increase Estimation

For the purposes of delineating AOR for this permit, 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 Slash Lazy H 5 stratigraphic test well.

Application of EPA Method 1 (Eq. 1) using model data from the KJ Hintz 1 simulation well shows that the injection zone is overpressured 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 KJ Hintz 1 Simulation Well

Depth,*		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 psi	
5627.2 ft	1715 m	18.7	4.07	1052	159	-1092	-1.73	-251

* Ground surface elevation is 624 m, amsl. Depth provided is the midpoint of the Broom Creek Formation in feet below ground surface.

In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value 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.

3.5.4 Risk-Based AOR Calculations

Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter “ASLMA Workbook”).

3.5.4.1 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 CO₂ 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 3-6. They illustrate the state of overpressure in the storage complex, because Aquifer 1 has a greater initial hydraulic head than Aquifer 2 and Aquifer 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).

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		HCON,** m/d	Specific Storage, m ⁻¹	Total Head, m
Overlying Units to Ground Surface (not directly modeled)	0	335										
Aquifer 3 (USDW, Fox Hills Fm)	335	130	3.4	16	1563	1001	37.5	280.0	2.76E-13	2.12E-01	5.68E-06	574
Aquitard 2 (Pierre Fm–Inyan Kara Fm)	465	777	8.4	29	1780	1000	4.39	0.025	2.47E-17	2.58E-05	8.98E-06	624
Aquifer 2 (potential thief zone – Inyan Kara Fm)	1241	58	11.7	46	3340	996	13.4	7.2	7.13E-15	1.02E-02	4.90E-06	547
Aquitard 1 (primary upper seal – Swift Fm–Broom Creek Fm)	1299	355	14.5	48	52,500	1030	2.14	0.0021	2.07E-18	2.86E-06	9.17E-06	582
Aquifer 1 (storage reservoir – Broom Creek Fm)	1654	122	18.7	48	83,100	1052	14.1	7.5	7.40E-15	9.90E-03	5.17E-06	721

* Ground surface elevation 624 m amsl.

** Hydraulic conductivity.

3.5.4.2 CO₂ Injection Parameters

The ASLMA Model for the project used a Broom Creek CO₂ 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 CO₂ 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 CO₂ density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-7. The CO₂ mass injection rate and CO₂ density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-7.

Table 3-7. CO₂ Density and Injection Parameters Used for the ASLMA Model

CO₂ Density, Reservoir Conditions, kg/m³	Average CO₂ Injection Rate, tonnes per day	Average Equivalent Water Injection Rate, m³ per day	Injection Period, years
770	17,767	23,079	20

3.5.4.3 Hypothetical Leaky Wellbore

In the simulation model 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 CO₂ injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 20-year injection period, provides the data set needed to derive the risk-based AOR.

Published ranges for the effective permeability of a leaky wellbore (Figure 3-18) have included an “open wellbore” with an effective permeability as high as 10⁻⁵ m² (10¹⁰ mD) to values more representative of leakage through a wellbore annulus of 10⁻¹² to 10⁻¹⁰ m² (10³ to 10⁵ mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO₂ storage sites and estimated a wide range from 10⁻²⁰ to 10⁻¹⁰ m² (10⁻⁵ to 10⁵ 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 CO₂ storage sites (Figure 3-18).

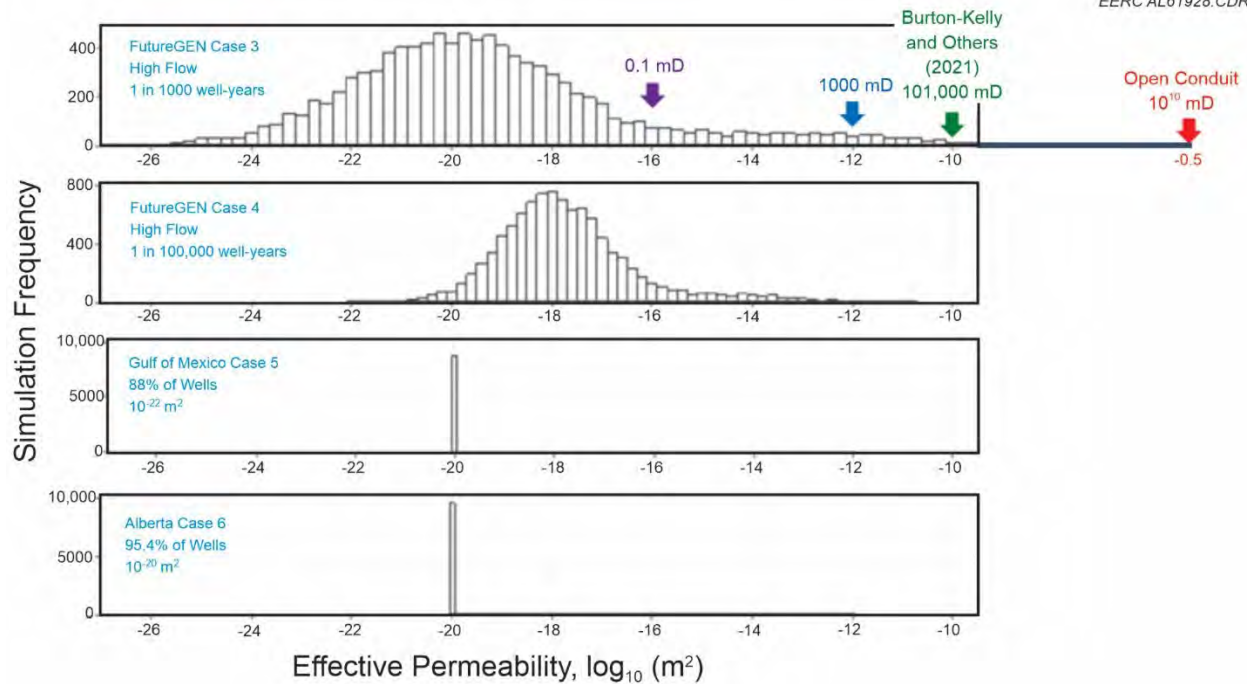


Figure 3-18. Histograms describing the expected frequency of leaky wellbore effective permeabilities under different scenarios. The ASLMA Model used for AOR delineation used a value of approximately 0.1 mD (constructed from data presented by Carey [2017]).

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.

3.5.4.4 Saline Aquifer Potential Thief Zone

As shown in Table 3-6, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the storage reservoir primary seal and the 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, 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 to 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 high-permeability zone encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 were run and the results evaluated to quantify the effect of a thief zone on the risk-based AOR.

3.5.4.5 *Aquifer- and Aquitard-Derived Properties*

The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-6). For each unit shown in Table 3-6, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: HCON and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; 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), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-6. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).

3.5.5 *Risk-Based AOR Results*

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

Figure 3-19 shows the relationship between the maximum pressure buildup in the storage reservoir and incremental leakage to Aquifer 3 (USDW) for scenarios with and without the leaky wellbore open to Aquifer 2 (thief zone). 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 3-19) is used to predict incremental leakage using a linear interpolation between the points making up the curve. The estimated cumulative leakage potential from Aquifer 1 to Aquifer 3 along a hypothetical leaky wellbore without injection occurring (i.e., leakage due to natural overpressure) and no thief zone is shown in Table 3-8.

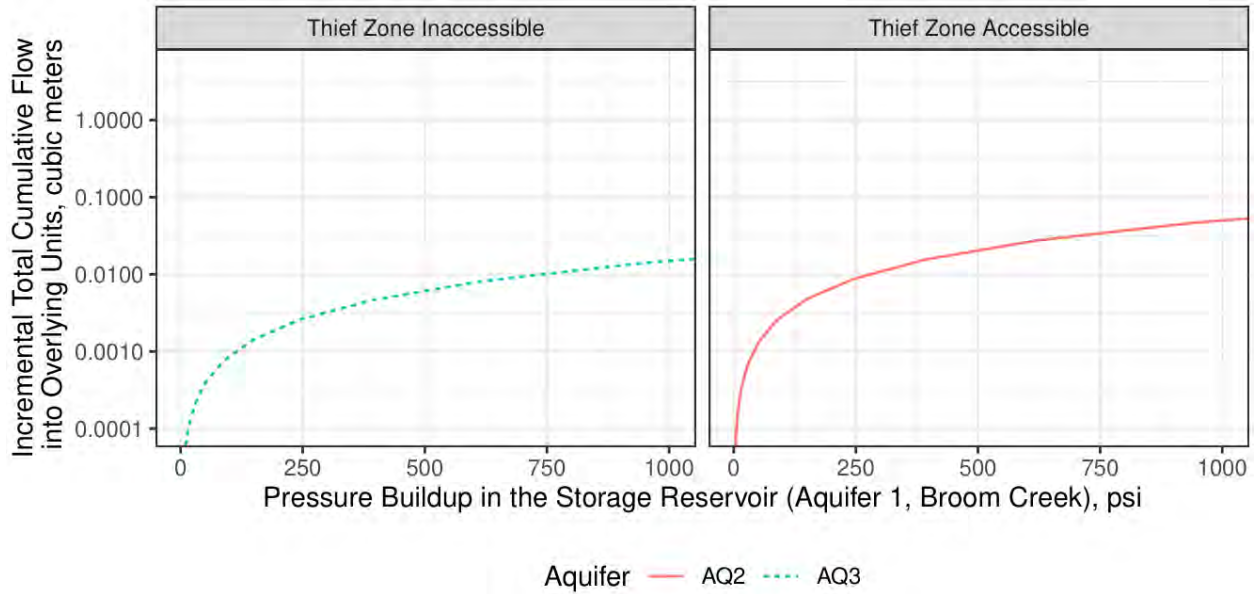


Figure 3-19. Relationship between pressure buildup (x-axis, psi) in the storage reservoir (Aquifer 1, Broom Creek) and incremental total cumulative leakage (y-axis, m³) into Aquifer 2 (thief zone, Inyan Kara, red solid line) and Aquifer 3 (USDW, Fox Hills, dashed blue line). In the left-hand scenario, the leaky wellbore is closed to Aquifer 2, so all flow is from the storage reservoir to the USDW. In the right-hand scenario, the leaky wellbore is open to Aquifer 2, so the vast majority of flow is from the storage reservoir to the Aquifer 2 thief zone, and the curve showing flow into the Aquifer 3 USDW is not visible on this plot.

3.5.5.2 Incremental Flow Maps and AOR Delineation

The pressure buildup–incremental flow relationship, shown in Figure 3-19, results in the incremental flow map, shown in Figure 3-20, which show the estimated total cumulative incremental flow potential from a hypothetical leaky well into Aquifer 3 (USDW) over the entire injection period if the modeled leaky wellbore is not open to the thief zone.

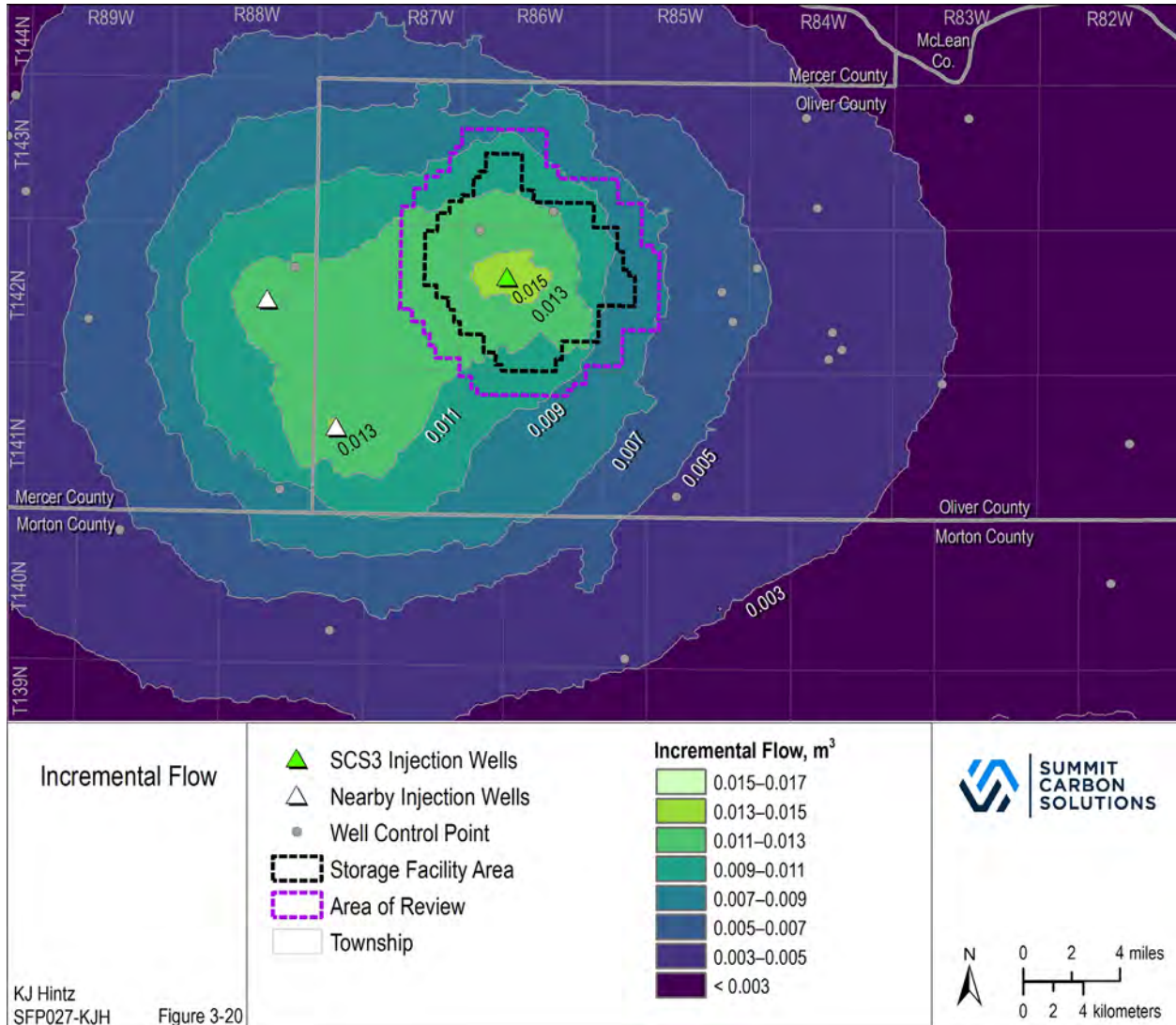


Figure 3-20. Map of potential incremental flow into the USDW at the end of 20 years of CO₂ injection for the scenario where the modeled leaky wellbore is closed to Aquifer 2 (thief zone).

The final step of the risk-based AOR workflow is to apply a threshold criterion to the incremental flow maps to delineate a risk-based AOR. For the Broom Creek Formation injection at the project site, a threshold of 1 m³ of potential incremental flow into the Fox Hills Formation USDW along a hypothetical leaky wellbore over the injection period is established. A value of 1 m³ is the lowest meaningful value that can be produced by the ASLMA Model; although the model can return smaller values, they likely represent statistical noise. This potential incremental flow threshold is greater than all calculated potential incremental flow values described by the curve in Figure 3-19. The maximum vertically averaged change in pressure in the storage reservoir at the end of the simulated injection period and the corresponding flow over the injection period are shown in Table 3-8. This pressure is below the potential incremental flow threshold of 1 m³.

Table 3-8. Summary Results from the Risk-Based AOR Method of Estimated Potential Cumulative Leakage after 20 years of Injection and No Thief Zone

Maximum Vertically Averaged Change in Reservoir Pressure, psi	1004
Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore <i>Without</i> Injection, m ³	0.009
Maximum Estimated Cumulative Leakage (reservoir to USDW) along Leaky Wellbore <i>Attributable to</i> Injection, m ³	0.015

Therefore, the storage reservoir pressure buildup is not a deciding factor in determining the AOR extent.

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

- The statistical overestimation of hypothetical leaky wellbore permeability compared to known and estimated values in the literature—a more statistically likely hypothetical leaky wellbore permeability would be lower and allow less flow into the USDW.
- The lack of communication between the hypothetical leaky wellbore and Inyan Kara Formation, which would act as a thief zone—a real leaky wellbore would likely communicate with the Inyan Kara Formation, which would receive much, if not all, of the brine leaked from the storage reservoir.
- The low density of known legacy wellbores in the KJ Hintz area—CO₂ 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., 1 year) timescales, overpressured aquifers with leakage pathways would demonstrate a change in upward flow rate and corresponding pressure (Oldenburg and others, 2016).

The risk-based method detailed above shows that storage reservoir pressure buildup is not necessary for determining AOR because the potential incremental flow into the USDW is below the identified threshold of 1 m³. Therefore, the AOR is delineated as the storage facility area plus a 1-mi buffer (Figure 3-21).

KJ HINTZ/SLASH LAZY H 5

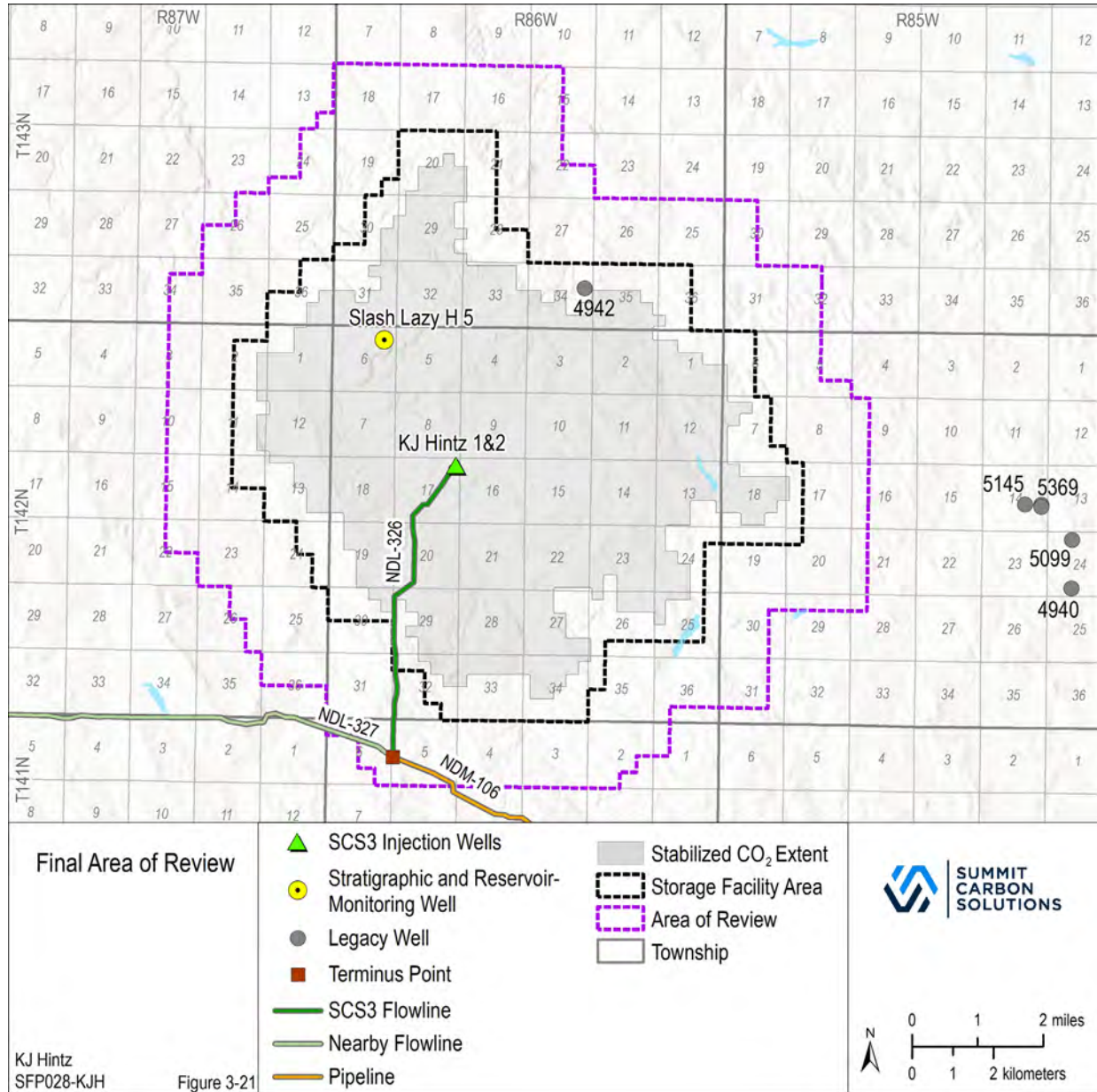


Figure 3-21. Final AOR estimations and stabilized CO₂ extent of the project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (black dashed line) and AOR (purple dashed line). The gray circles represent legacy oil and gas wells near the storage facility area.

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

North Dakota regulations for geologic storage of CO₂ 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)¹ may be endangered by the injection activity” (North Dakota Administrative Code [N.D.A.C.] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO₂ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO₂ plume and the region overlying the extent of formation fluid pressure increase that is 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 Slash Lazy H 5 (NDIC File No. 38701) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero. The storage reservoir is calculated to be overpressured, with a value of -251 psi calculated using data from the Slash Lazy H 5 well at the KJ Hintz simulation well location. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 1004 psi in the raster cell intersected by the injection well, which corresponds to less than 0.015 m³ of flow over 20 years (Section 3.5). Based on the computational methods used to simulate CO₂ injection activities and associated pressure front (Figure 4-1), the resulting AOR for KJ Hintz is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.

In accordance with N.D.A.C. § 43-05-01-05(1)(b)(3), a geologist or engineer reviewed the data of public record for all wells within the storage facility area, including those which penetrate the storage reservoir or primary or secondary seals overlying the reservoir and all wells within 1 mi of the storage facility area boundary (Table 4-1).

¹ The Fox Hills Aquifer underlying western North Dakota, including KJ Hintz, is a confined aquifer system that does not receive measurable flow from overlying aquifers or the underlying Pierre Shale. The overlying confining layer in the Hell Creek Formation comprises impermeable clays, and the underlying Pierre Shale serves as the lower confining layer (Trapp and Croft, 1975). Recharge occurs hundreds of miles to the southwest in the Black Hills of South Dakota, where the corresponding geologic layers are exposed at the surface. Flow within the aquifer is to the east with a rate on the order of single feet per year. Groundwater in the Fox Hills Aquifer at KJ Hintz is geochemically stable, as it is isolated from its source of recharge and does not receive other sources of recharge (Fischer, 2013). The aquifer itself is a quartz-rich sand and is not known to contain reactive mineralogy. Minimal geochemical variation can be expected to occur across the site, attributable to minor variations in the geologic composition of the aquifer sediments.

KJ HINTZ/SLASH LAZY H 5

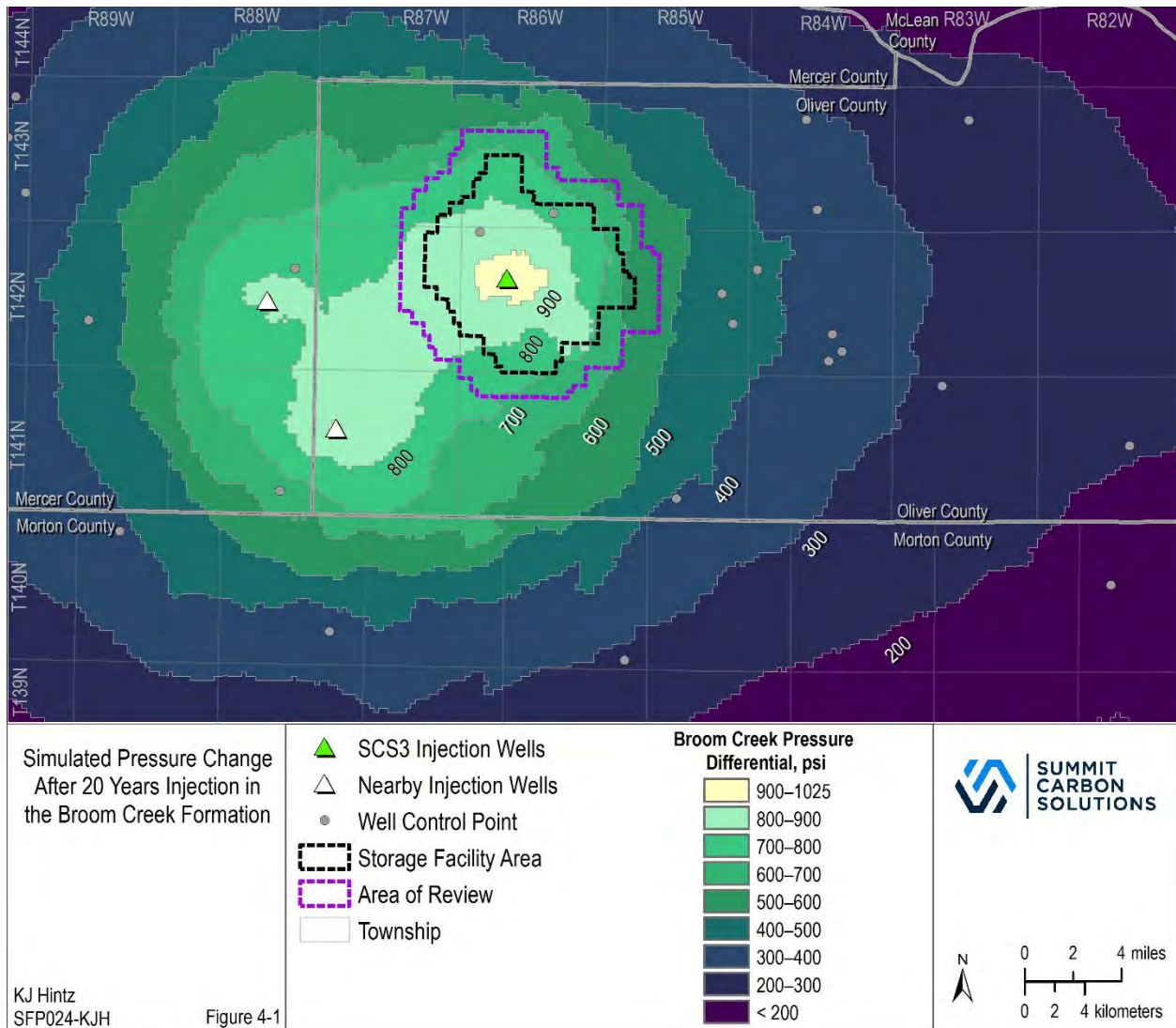


Figure 4-1. Pressure map showing the maximum subsurface pressure influence associated with CO₂ injection in the Broom Creek Formation for KJ Hintz. Shown are the storage facility area and AOR boundary in relation to the predicated maximum subsurface pressure influence. Subsurface pressure subsides at the cessation of injection.

This section of the SFP application is accompanied by maps and tables that include information required and in accordance with N.D.A.C. § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area; location of any proposed injection wells, presence of occupied structures or gravel pits (Figure 4-2); and location of water wells and any other wells within the AOR (Figure 4-3). Table 4-1 lists all the surface and subsurface features that were investigated as part of the AOR evaluation. Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.

Table 4-1. Investigated and Identified Surface and Subsurface Features in the AOR (Figures 2-49, 4-2, and 4-3)

Surface and Subsurface Features	Investigated and Identified (Figures 4-2 and 4-3)	Investigated But Not Found in AOR
Producing (active) Wells		X
Abandoned Wells		X
Plugged Wells or Dry Holes	X	
Deep Stratigraphic Boreholes	X	
Subsurface Cleanup Sites		X
Surface Bodies of Water	X	
Springs		X
Water Wells	X	
Mines (surface and subsurface) (Figure 2-49)		X
Quarries/Gravel Pits	X	
Man-Made Subsurface Structures and Activities	X	
Location of Proposed Wells	X	
Location of Proposed Cathodic Protection Boreholes*		X
Surface Facilities	X	
Roads	X	
State Boundary Lines		X
County Boundary Lines	X	
Indian Country Boundary Lines		X

* No cathodic protection boreholes are currently included in the site design, and none were identified within the AOR.

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 (Section 2.5) 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.

KJ HINTZ/SLASH LAZY H 5

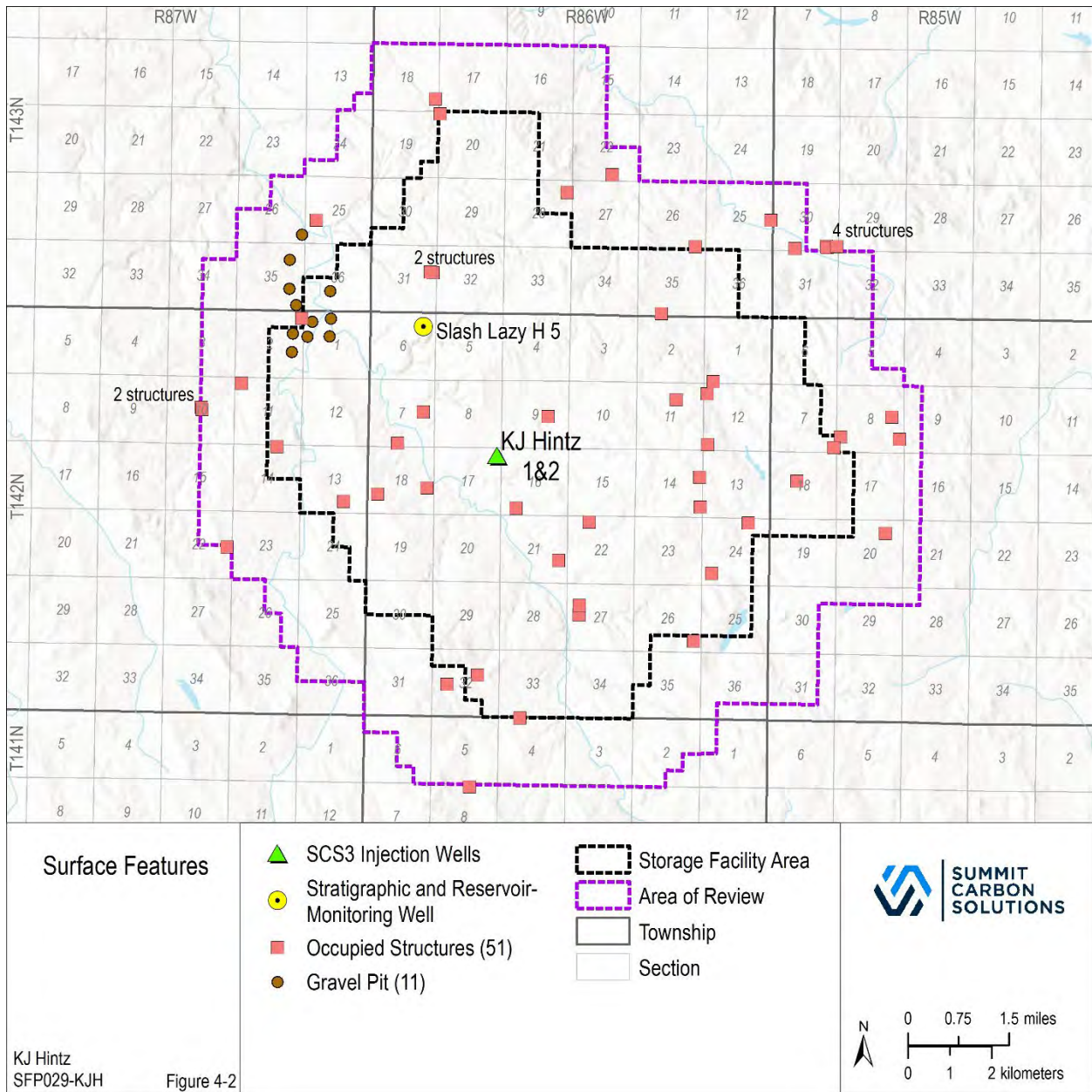


Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]).

KJ HINTZ/SLASH LAZY H 5

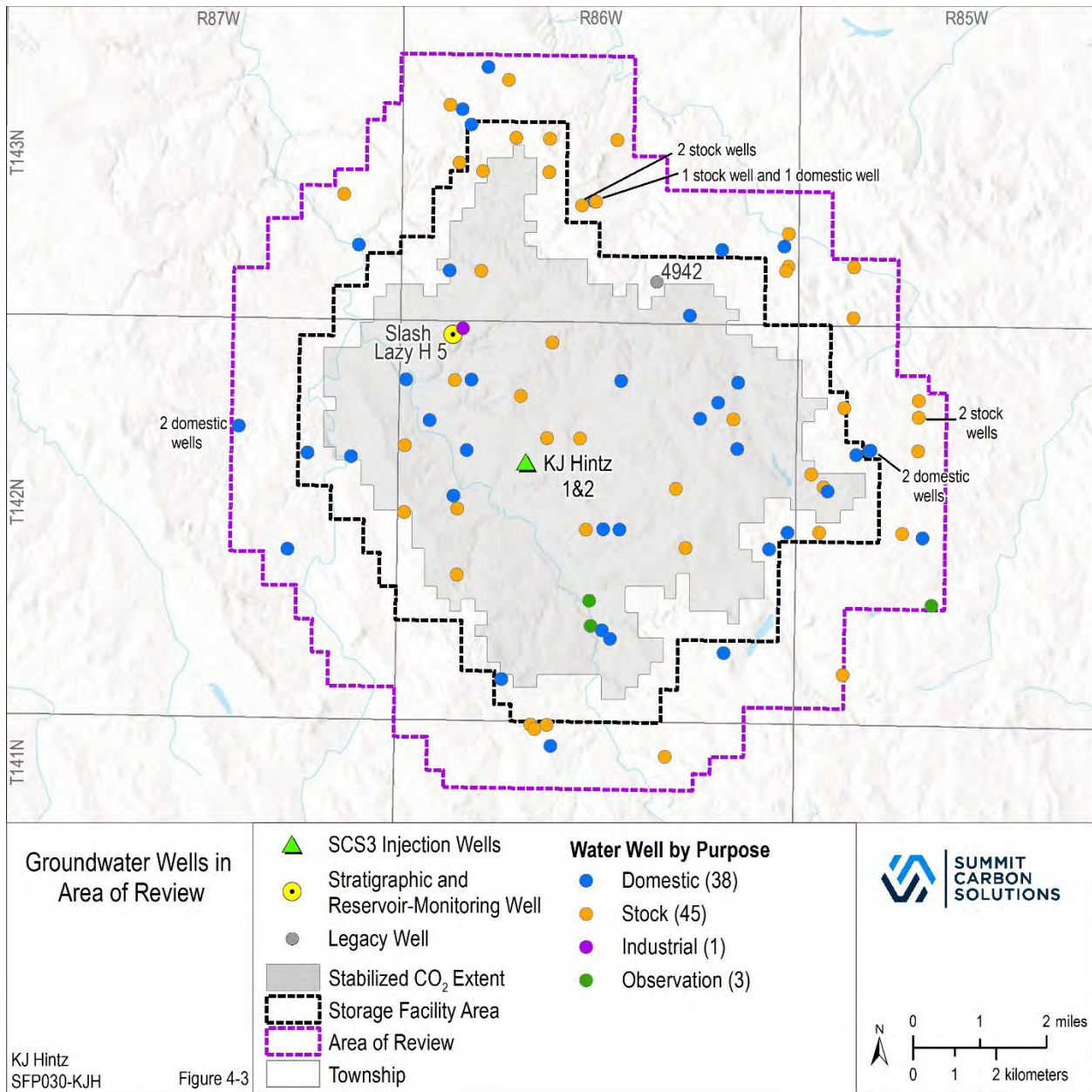


Figure 4-3. Map showing all wells located in the AOR. Shown are the stabilized CO₂ plume extent postinjection (gray-shaded area), storage facility area (dashed black boundary), and AOR (dashed purple boundary). All groundwater wells in the AOR are identified based on data available from the Department of Water Resources (DWR). There are two existing Broom Creek Formation penetrations within the AOR, namely, the Slash Lazy H 5 well and Raymond Jensen 1-34 (NDIC File No. 4942). No other legacy oil and gas wells are present in the AOR (see Figure 2-46a for any nearby legacy wells outside of the AOR). No springs are present in the AOR (note: springs were evaluated using the National Map hosted by the U.S. Geological Survey [2023]).

4.2 Corrective Action Evaluation

As identified in Table 4-1, any active and abandoned wells and underground mines in the AOR that may penetrate the confining zone were evaluated pursuant to N.D.A.C. § 43-05-01-05.1(2). Tables 4-2 through 4-4 and Figures 4-4 and 4-5 provide a description of each identified well, including well type, construction, date drilled, location, depth, record of plugging and completion, and any additional pertinent information. The evaluation determined that all 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.

KJ HINTZ/SLASH LAZY H 5

Table 4-2. Well(s) in AOR Evaluated for Corrective Action*

NDIC Well File No.	Operator	Well Name	Well Type	Spud Date	Surface Casing OD, in.	Surface Casing Depth, ft MD	Long-String Casing OD, in.	Long-String Casing Depth, ft MD	Hole Direction	TD, ft MD	TVD, ft	Status	Plug Date	TWN	RNG	SEC	Qtr/Qtr	County	Area	Corrective Action Needed
38701	Summit Carbon Storage #3, LLC	Slash Lazy H 5	Stratigraphic Test	2/1/2022	10.750	2071	7	6078	Vertical	6110	6110	TATD	NA	142 N	86 W	6	Lot 1	Oliver	SFA	No
4942	General American Oil Company of Texas	Raymond Jensen 1-34	Oil and Gas	8/14/1970	8.625	330	Open-hole		Vertical	6461	6461	Dry	8/26/1970	143 N	86 W	34	SE/NE	Oliver	SFA	No

* Abbreviations used in table: outside diameter; total depth; true vertical depth; township; range, quarter; temporarily abandoned, drilled to total depth; and storage facility area.

Table 4-3. Slash Lazy H 5 (NDIC File No. 38701) Well Evaluation

Well Name: Slash Lazy H 5 (NDIC File No. 38701)																																				
No cement plugs in wellbore; procedure as approved by DMR-O&G.																																				
Section	Type	Lead/Tail/Single	Interval, ft MD	Volume, sacks																																
Surface	VariCem GS1	Single	0-2071	775																																
Long String	EconoCem	Lead	0-3527	265																																
Long String	CorrosaCem	Tail		555																																
Long String	CorrosaCem	Single	3527-6078	770																																
All depths are MD based off KB elevation.																																				
Spud Date: 2/1/2022																																				
Total Depth: 6110' (Amsden Formation)																																				
Surface Casing: 10¾" from 0' to 2071'																																				
Cased Hole 7" to 6078'																																				
<table border="1" style="width: 100%;"> <thead> <tr> <th colspan="2">Formation</th> <th rowspan="2">Estimated Top, ft MD</th> <th rowspan="2"></th> </tr> <tr> <th>Name</th> <th>Estimated Top, ft MD</th> </tr> </thead> <tbody> <tr> <td>Pierre</td> <td>1687</td> <td>10¾" casing</td> <td rowspan="2">Class G cement</td> </tr> <tr> <td>10¾" Casing Shoe</td> <td>2071</td> <td></td> </tr> <tr> <td>Greenhorn</td> <td>3554</td> <td rowspan="10">7" casing cemented by CO₂-resistant cement from 418' to 6110' MD and Class G from 0' to 418' MD</td> </tr> <tr> <td>Mowry</td> <td>3946</td> </tr> <tr> <td>Newcastle</td> <td>4028</td> </tr> <tr> <td>Skull Creek</td> <td>4033</td> </tr> <tr> <td>Inyan Kara</td> <td>4258</td> </tr> <tr> <td>Swift</td> <td>4452</td> </tr> <tr> <td>Opeche/Spearfish</td> <td>5389</td> </tr> <tr> <td>Broom Creek</td> <td>5568</td> </tr> <tr> <td>Amsden</td> <td>5840</td> </tr> </tbody> </table>					Formation		Estimated Top, ft MD		Name	Estimated Top, ft MD	Pierre	1687	10¾" casing	Class G cement	10¾" Casing Shoe	2071		Greenhorn	3554	7" casing cemented by CO ₂ -resistant cement from 418' to 6110' MD and Class G from 0' to 418' MD	Mowry	3946	Newcastle	4028	Skull Creek	4033	Inyan Kara	4258	Swift	4452	Opeche/Spearfish	5389	Broom Creek	5568	Amsden	5840
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Inyan Kara	4258																																			
Swift	4452																																			
Opeche/Spearfish	5389																																			
Broom Creek	5568																																			
Amsden	5840																																			
<p>Corrective Action: No corrective action is necessary. The well is set up as a reservoir-monitoring well within the SFA. It has no perforations and has corrosion-resistant alloy (CRA) material and CO₂-resistant cement placed across the Broom Creek Formation. See Figure 4-4 for depths. The well will be completed as shown in Section 11.</p>																																				

Table 4-4. Raymond Jensen 1-34 (NDIC File No. 4942) Well Evaluation

Well Name: Raymond Jensen 1-34 (NDIC File No. 4942)							
Cement Plugs				Formation		Cement Plug Class G*	
Number	Interval, Ft MD		Thickness, ft	Volume, sacks	Name		Estimated Top, ft MD
1	4353	4438	85	25	8 ⁵ / ₈ " Casing Shoe	330	Plug 3 isolates the bottom of the surface casing.
2	4183	4268	85	25	Pierre	1575	
3	291	368	77	25	Greenhorn	3578	
4	0	16	16	5	Mowry	3940	
					Newcastle	4012	Plugs 1 and 2 are both in the Inyan Kara but provide no isolation from other formations.
					Inyan Kara	4178	
					Swift	4453	
					Spearfish/Opeche	5388	
					Broom Creek	5530	
					Amsden	5797	
					Kibbey Lime	6310	

*Cement type is assumed to be Class G (no cement type was on file.)

All depths are based off of MD.

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

Spud Date: 8/14/1970
 Total Depth: 6461' MD (Charles Formation)
 Surface Casing: 8⁵/₈"

Corrective Action: No corrective action is necessary. Cement Plug 1 is near the base of the Inyan Kara Formation. The cement provides an initial barrier between the Broom Creek Formation and the USDW. Cement Plug 2 prevents additional movement of fluids to the Fox Hills Formation. A mud-laden fluid with a density of 10 pounds/gallon was pumped between all cement plugs. See Figure 4-5.

4-8

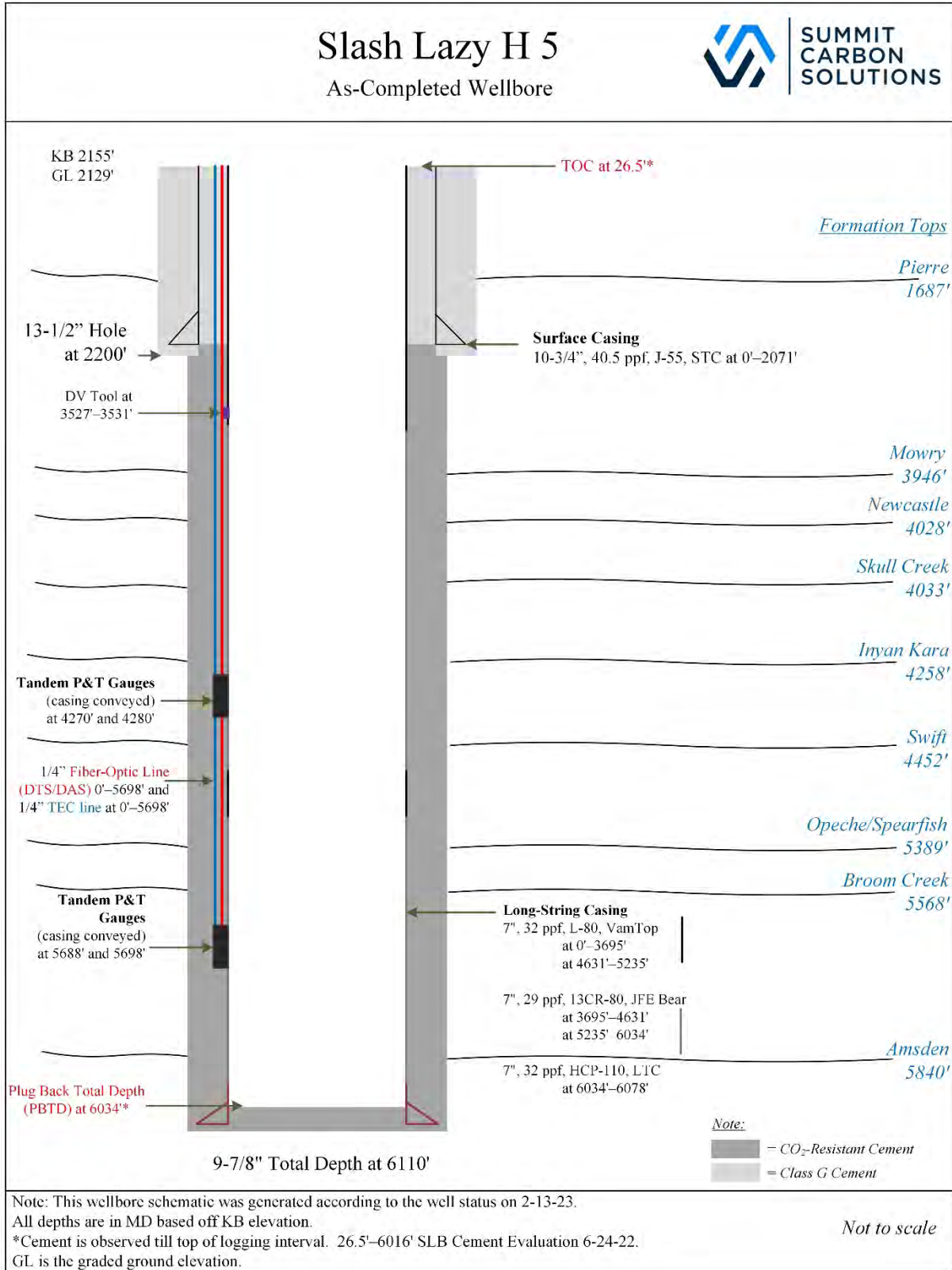


Figure 4-4. Slash Lazy H 5 (NDIC File No. 38701) well schematic.

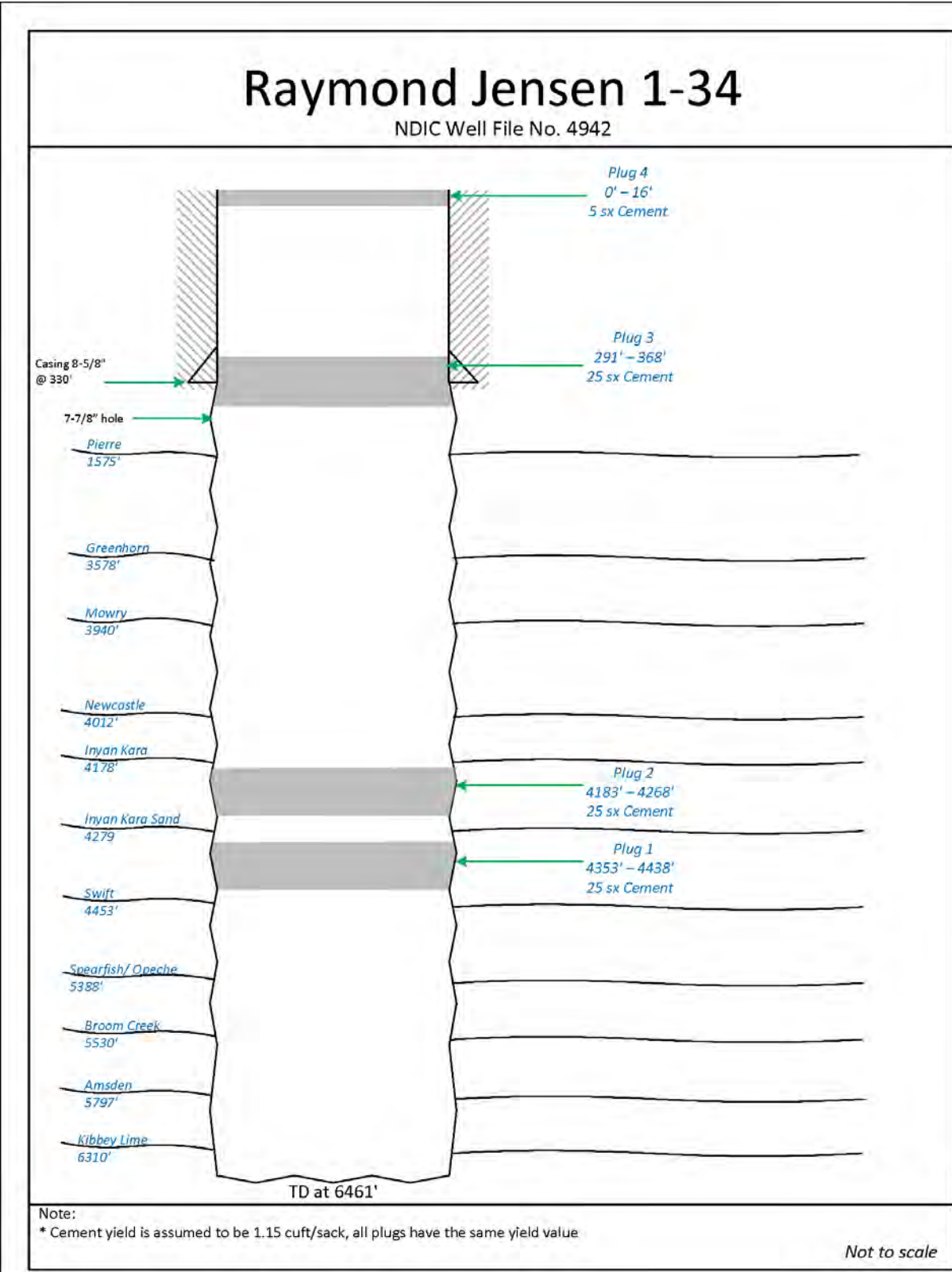


Figure 4-5. Raymond Jensen 1-34 (NDIC File No. 4942) well schematic showing the location of cement plugs.

4.3 Reevaluation of AOR and Corrective Action Plan

The AOR and corrective action plan will be reevaluated in accordance with N.D.A.C. § 43-05-01-05.1, with the first reevaluation taking place at a period not to exceed 5 years from the date the permit for CO₂ injection is issued (N.D.A.C. § 43-05-01-10) or when monitoring and operational conditions warrant a reevaluation. Each successive reevaluation shall take place at a period not to exceed 5 years from the date of the previous reevaluation (each referred to as a “Reevaluation Date”). The AOR reevaluations will address the following:

- Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the 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 the 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 delineation.

As part of the reevaluation, Summit Carbon Storage #3, LLC (SCS3) will either a) demonstrate to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G) using monitoring data and modeling results that no plan amendment is necessary or b) submit an amended AOR and corrective action plan for DMR-O&G approval. Plan amendments must be incorporated into the permit and are subject to permit modification requirements.

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 and Hell Creek Formations, the lowest USDWs in the AOR, from the underlying injection zone. The Opeche/Spearfish Formation is the primary confining zone for the injection 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 more than 1000 ft thick, providing an additional seal for all USDWs in the region (Table 4-5).

Table 4-5. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche/Spearfish Formation) (data based on Slash-Lazy H 5)

Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft MD
Pierre	Mudstone	1687	1429	0
Niobrara	Mudstone	3116	389	1429
Carlile	Mudstone	3505	49	1818
Greenhorn	Mudstone	3554	105	1867
Belle Fourche	Mudstone	3659	287	1972
Mowry	Mudstone	3946	82	2259
Skull Creek	Mudstone	4033	225	2346
Swift	Mudstone	4452	535	2765
Rierdon	Mudstone	4987	208	3300
Piper (Kline Member)	Carbonate	5195	108	3508
Piper (Picard Member)	Mudstone	5303	86	3616
Opeche/Spearfish	Mudstone	5389	179	3702

4.4.2 Geology of USDW Formations

The hydrogeology of western North Dakota is composed of several shallow freshwater-bearing formations of the Quaternary, Tertiary, and upper Cretaceous-aged sediments underlain by multiple saline aquifer systems of the Williston Basin (Figure 4-6). These saline and freshwater systems are separated by the Cretaceous Pierre Shale of the Williston Basin, a regionally extensive shale between 1000 ft and 1500 ft thick (Thamke and others, 2014).

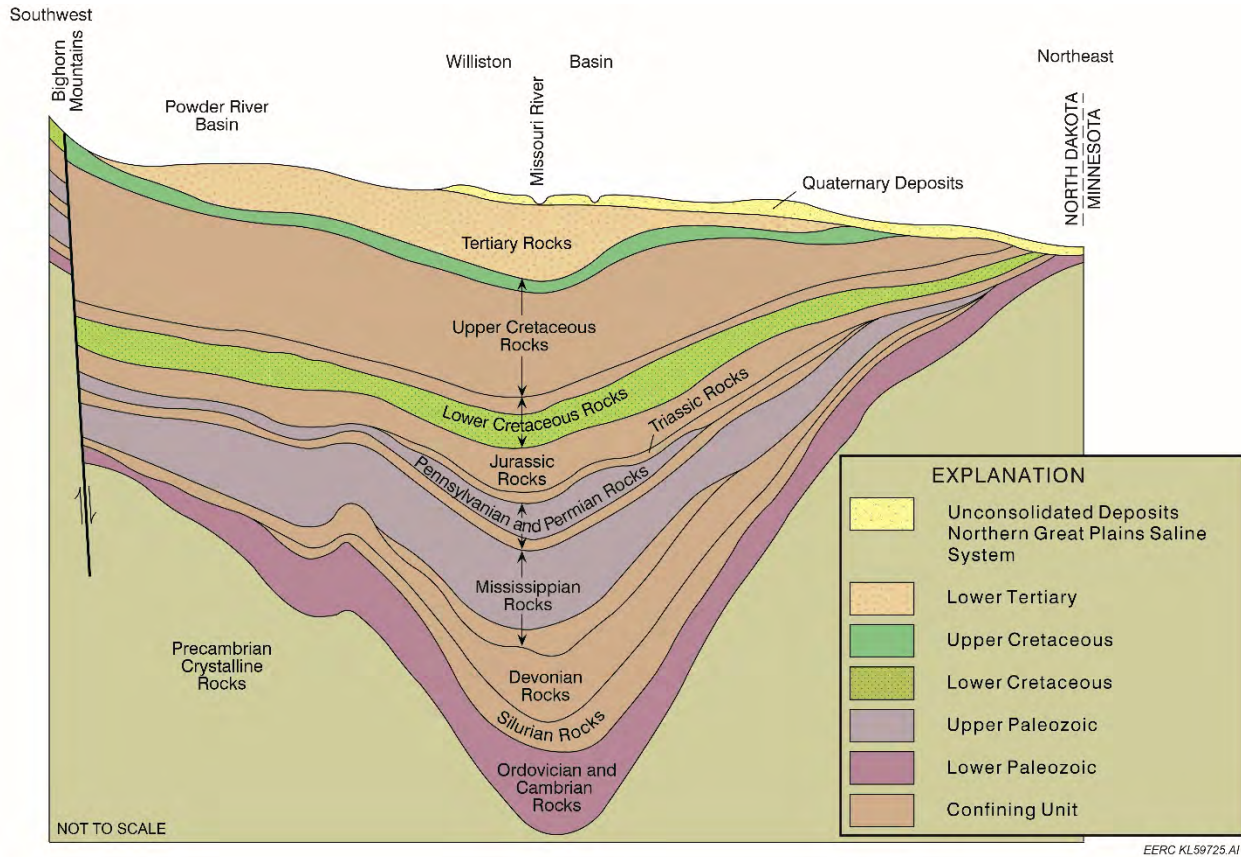


Figure 4-6. Major aquifer systems of the Williston Basin (modified from Downey and Dinwiddie, 1988).

The freshwater aquifers comprise the Cretaceous Fox Hills and Hell Creek Formations; the overlying Cannonball, Tongue River, and Sentinel Butte Formation of the Tertiary Fort Union Group; and the Tertiary Golden Valley Formation (Figure 4-7). Above these formations are undifferentiated alluvial and glacial drift Quaternary aquifer layers which are not necessarily present in all parts of the AOR (Croft, 1973).

Era	Period	Group	Formation	Freshwater Aquifer(s) Present
Cenozoic	Quaternary		Glacial Drift	Yes
			Golden Valley	Yes
	Tertiary	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 4-7. Upper stratigraphy of Mercer, Oliver, and Morton Counties showing the stratigraphic relationship of Quaternary, Cretaceous, and Tertiary groundwater-bearing formations (modified from Croft, 1973).

The lowest USDW in the AOR is the Fox Hills Formation, which together with the overlying Hell Creek Formation, is a confined aquifer system. The Hell Creek Formation is a poorly consolidated unit composed of interbedded sandstone, siltstone, and claystones with occasional carbonaceous beds, all of fluvial origin. The underlying Fox Hills Formation is interpreted as interbedded nearshore marine deposits of sand, silt, and shale deposited as part of the final Western Interior Seaway retreat (Fischer, 2013). The Fox Hills Formation in the AOR is approximately 1500 ft deep and 250–300 ft thick (Information reported from stratigraphic well installation). The structure of the Fox Hills and Hell Creek Formations follows that of the Williston Basin, dipping gently toward the center of the basin to the northwest of the AOR (Figure 4-8).

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

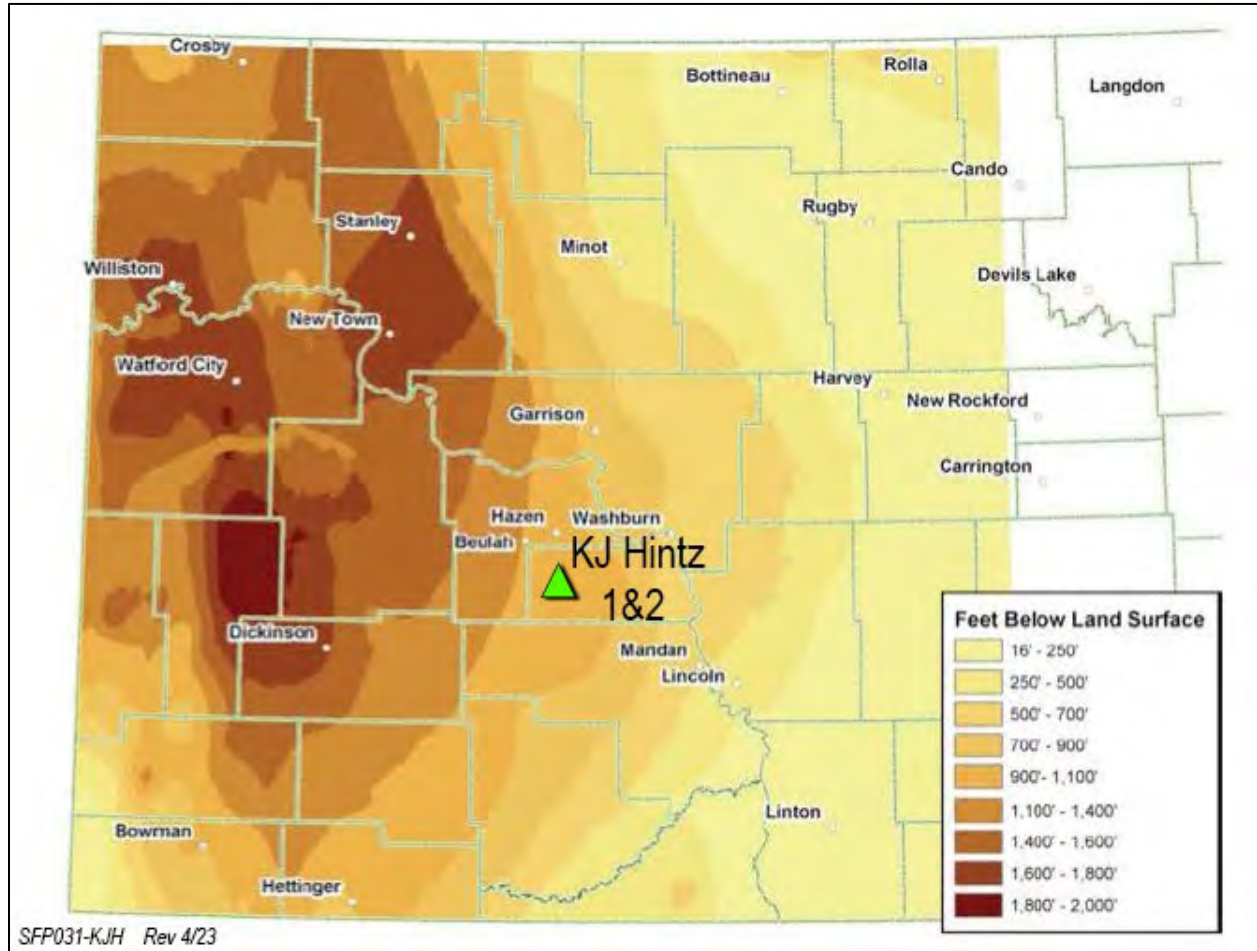


Figure 4-8. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013).

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, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AOR is to the east (Figure 4-9).

Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride in excess of 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.

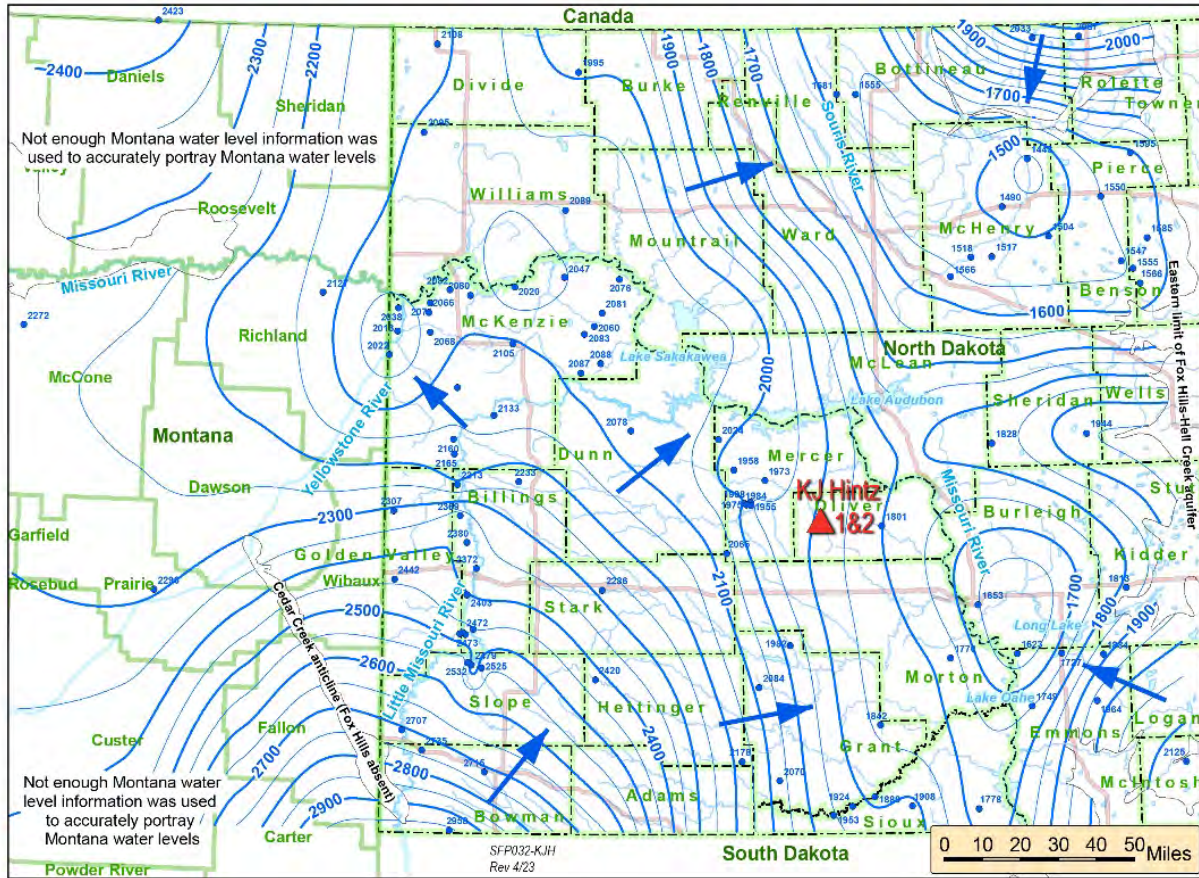


Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013).

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 4-10. 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 it 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).

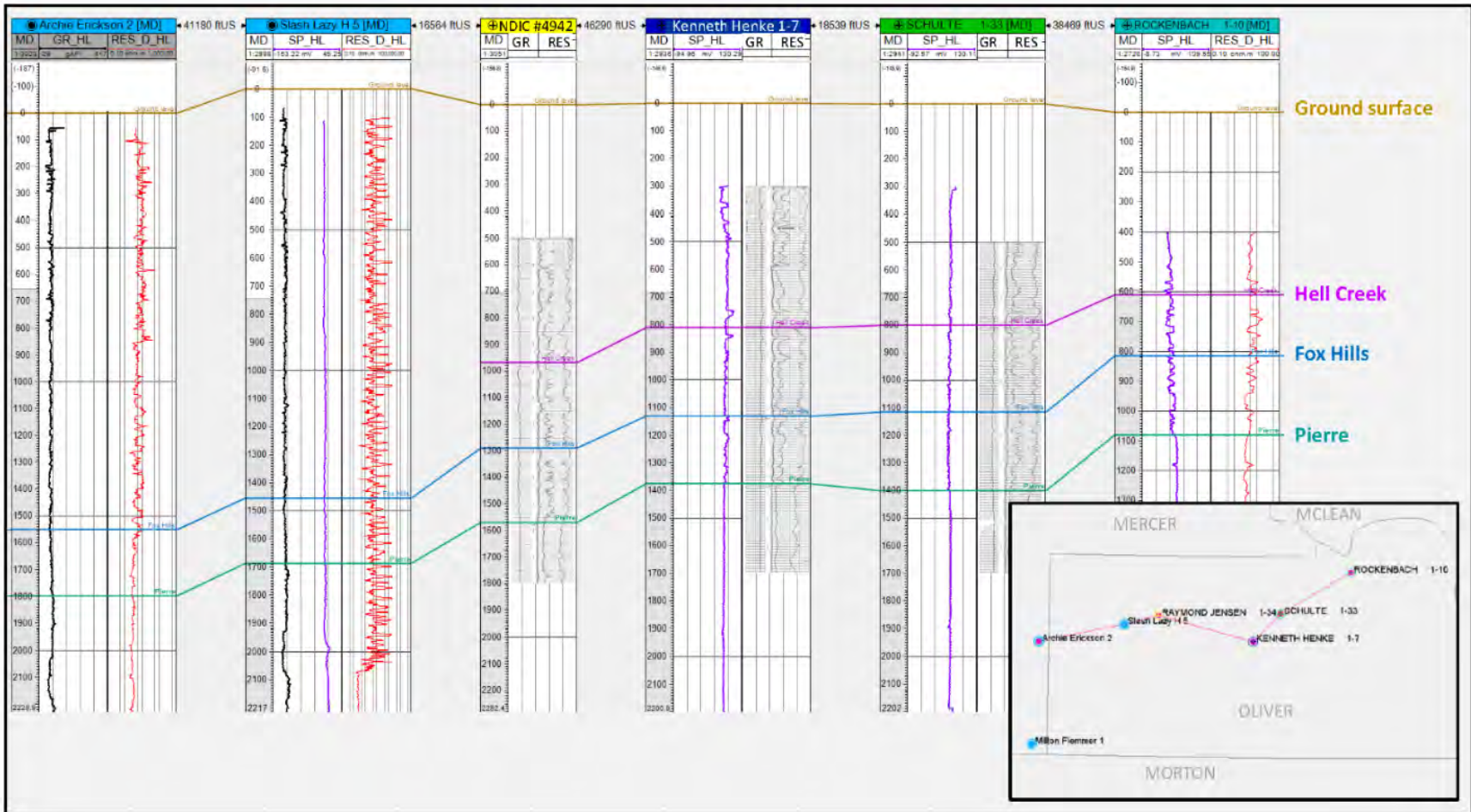


Figure 4-10. West-east cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown in the inset map and labeled with corresponding well names (NDIC File No. 4942 is Raymond Jensen 1-34.)

The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in western portions of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte Formation is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400 to 1000 ppm (Croft, 1973). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.

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 the lowest USDW (Fox Hills–Hell Creek aquifer system) are isolated geologically and hydrologically by multiple impermeable rock layers consisting of shale and siltstone formations (Figure 4-6).

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 Formation is the confined saltwater aquifer system of the Inyan Kara Formation that extends across much of the Williston Basin. Above the Inyan Kara Formation are Cretaceous-aged shale formations, namely the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlisle, 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 CO₂ injection activities in the AOR.

Figure 4-11 shows the location of groundwater wells selected to be included in the near-surface baseline and operational monitoring plan, which includes two new Fox Hills monitoring wells, and up to two existing groundwater wells. The two existing wells (two in the Tongue River) were chosen based on depth (>300 ft), location within the AOR, and accessibility. SCS3 screened all wells within the AOR to determine suitability for inclusion into the testing and monitoring program. Wells were screened based on land use permissions, site accessibility, and access to historical well data such as drilling, logging, and stratigraphic information. Table 4-6 correlates DWR well numbers with the well numbers used by SCS3 throughout this permit application.

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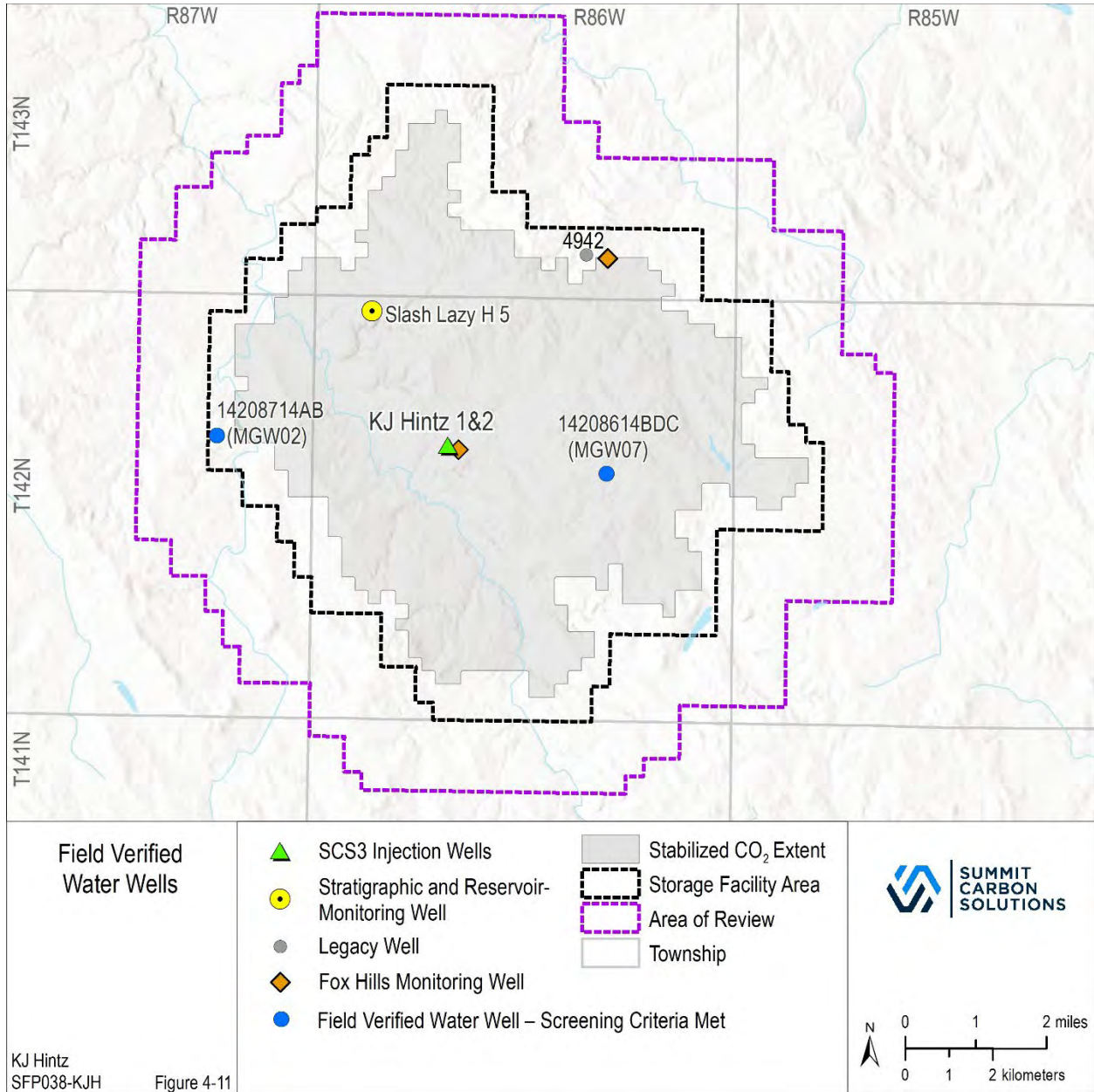


Figure 4-11. Field verified water wells located within the AOR.

Table 4-6. DWR and SCS3 Well No. Correlation

DWR Well No.	SCS3 Field Verified Location*	SCS3 Well No.	Formation
14208714AB	142-087-14ABA	MGW02	Tongue River
14208614BDC	142-086-14BDC	MGW07	Tongue River

* SCS3 Field Verified Location follows an alpha numeric system indicating the township - range - section and quarter-quarter-quarter. This is a similar system used by the DWR but adds the precise quarter-quarter-quarter location from field verification.

SCS3 will work with landowners of the two existing groundwater wells to collect three to four samples from each well to establish baseline conditions prior to CO₂ injection and periodically thereafter during subsequent phases of the project as outlined in Section 5.0. The actual number of wells and samples collected from each existing groundwater well location may vary because some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months).

SCS3 will install one Fox Hills monitoring well adjacent to the CO₂ injection well pad prior to injection and one Fox Hills monitoring well adjacent to Raymond Jensen 1-34 (NDIC File No. 4942) by Year 19 of injection. The Fox Hills monitoring wells will be sampled to establish a seasonal baseline and periodically thereafter during subsequent phases of the project as outlined in Section 5.0.

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.
- Downey, J.S., and Dinwiddie, G.A., 1988, The regional aquifer system underlying the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming—summary: U.S. Geological Survey Professional Paper 1402-A.
- 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.
- North Dakota Department of Transportation, 2002, ND GIS Hub landmarks data layer, February 11: <https://gishubdata-ndgov.hub.arcgis.com/datasets/NDGOV::ndgishub-landmarks-nddot/explore> (accessed May 2023).
- 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.
- U.S. Geological Survey, 2023, <https://apps.nationalmap.gov/downloader/> (accessed May 2023).

SECTION 5.0

TESTING AND MONITORING PLAN

5.0 TESTING AND MONITORING PLAN

Pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-11.4(1)(k), this testing and monitoring plan includes 1) a plan for analyzing the captured CO₂ stream, 2) leak detection and corrosion-monitoring plans for surface facilities and all wells associated with the geologic CO₂ storage project, 3) a well-logging and -testing plan, 4) an environmental monitoring plan to verify the injected CO₂ is contained in the storage reservoir, and 5) a quality assurance and surveillance plan (QASP).

This site-specific testing and monitoring plan was informed by the injection scenario (as described in the Project Summary), site characterization activities (Section 2.0), geologic modeling and simulations (Section 3.0), area of review delineation and corrective action evaluation (Section 4.0), and well design (Section 9.0). Activities described in Table 5-1 will be used to establish preinjection (baseline) conditions at the storage site. Pursuant to N.D.A.C. § 43-05-01-11.4, the set of activities described in Table 5-2 will be used to verify that KJ Hintz is operating as permitted and is not endangering underground sources of drinking water (USDW). Summit Carbon Storage #3, LLC (SCS3) will also specify data-quality measures through the QASP.

SCS3 will review this testing and monitoring plan at a minimum of every 5 years from the start of injection, as required by N.D.A.C. § 43-05-01-11.4(j), to ensure the technologies and strategies deployed remain appropriate for demonstrating containment of CO₂ in the storage reservoir and conformance with predictive modeling and simulations.

A detailed testing and monitoring plan for the baseline and operational phases is provided in the remainder of this section. Section 6.0 describes the testing and monitoring activities associated with the postinjection phase.

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

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Preinjection/Baseline Sampling Frequency
CO₂ Stream Analysis	Injection composition	CO ₂ stream sampling	CO ₂ accounting and ensures stream compatibility with project materials in contact with CO ₂	Gas chromatograph and CO ₂ stream compositional commercial laboratory results	Downstream of pipeline inspection gauge (PIG) receiver	At least once
Wellbore Mechanical Integrity (external)	Casing wall thickness	Ultrasonic logging or other equivalent casing inspection log [CIL] and sonic array logging (inclusive of casing collar locator [CCL], variable density log [VDL] and radial cement bond log [RCBL]), and gamma ray (GR)	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO ₂ injection and reservoir-monitoring wells	Once per well
	Radial cement bond					
	Saturation profile (behind casing)	Pulsed-neutron logging (PNL)		PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	
	Temperature profile	Temperature logging		Temperature log	CO ₂ injection and reservoir-monitoring wells	
Real-time, continuous data recording via supervisory control and data acquisition (SCADA) system		Distributed temperature sensing (DTS) casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO ₂ injection and reservoir-monitoring wells	Install at casing deployment		
Wellbore Mechanical Integrity (internal)	Pressure/temperature (P/T)	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO ₂ injection and reservoir-monitoring wells	Install at well completion
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure testing truck with pressure chart	CO ₂ injection and reservoir-monitoring wells	Once per well
	P/T	Real-time, continuous data recording via SCADA system		Digital surface P/T gauge	Between tubing and long-string casing annulus of CO ₂ injection and reservoir-monitoring wells	Install at well completion
	Annular fluid level	Real-time, continuous data recording via SCADA system	Prevention of microannulus and monitoring annular fluid volume	Nitrogen (N ₂) cushion on tubing-casing annulus with seal pot system	On well pad for each CO ₂ injection well	Add initial volumes to KJ Hintz 1 and 2
	P/T	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO ₂ injection and reservoir-monitoring wells	Install at well completion
	Saturation profile (tubing-casing annulus)	PNL		PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Once per well
Downhole Corrosion Detection	Saturation profile (behind casing)	PNL	Corrosion detection of project materials in contact with CO ₂ and operational safety assurance	PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Once per well
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO ₂ injection and reservoir-monitoring wells	

Continued ...

Table 5-1. Overview of Major Components of the Testing and Monitoring Plan – Preinjection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Preinjection/Baseline Sampling Frequency		
Near Surface	Soil gas composition	Soil gas sampling (See Figure 5-4)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG03 & MSG06	One station per CO ₂ injection and reservoir-monitoring well pad	3–4 seasonal samples per station (with isotopes)		
	Soil gas isotopes		Source attribution					
	Water composition	Groundwater well sampling (See Figure 5-4)	Assurance that USDWs are protected	Up to two existing groundwater wells from the Tongue River Aquifer (e.g., MGW02 and MGW07)	Within area of review (AOR)	3–4 seasonal samples per well (water quality with isotopes)		
	Water isotopes		Source attribution					
	Water composition		Assurance that lowest USDW is protected	Two Fox Hills monitoring wells			MGW12 adjacent to CO ₂ injection well pad and MGW14 ⁷ adjacent to North Dakota Industrial Commission (NDIC) File No. 4942	3–4 seasonal samples (water quality with isotopes)
	Water isotopes		Source attribution					
Above-Zone Monitoring Interval (Opeche/Spearfish to Skull Creek)	Saturation profile	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL Tool	CO ₂ injection and reservoir-monitoring wells	Once per well		
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment		
		Temperature logging		Temperature log		Once per well		
Storage Reservoir (direct)	P/T	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed downhole P/T gauge	CO ₂ injection and reservoir-monitoring wells	Install at casing deployment		
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Install at casing deployment		
		Temperature logging		Temperature log		Once per well		
	Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff test	CO ₂ injection wells	Once per injection well		
Storage Reservoir (indirect)	CO ₂ saturation	3D time-lapse seismic surveys	Site characterization and CO ₂ plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and distributed acoustic sensing (DAS) fiber-optic cable (receivers)	Within AOR	Collect 3D baseline survey		
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Install stations		

¹ In addition to the reports, submittals, notifications, and other information described in Table 5-1 and N.D.A.C. § 43-05-01-18, Reporting Requirements, the Director may require other additional information to be reported not outlined in Table 5-1.

² SCS3 will notify the Director as soon as possible of any planned changes which may result in noncompliance with permit requirements.

³ Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements shall be submitted no later than 30 days following each scheduled reporting date. SCS3 shall file with the Director an annual report that summarizes the quarterly reports.

⁴ The storage operator shall file with the Director quarterly, or more frequently, if the Director requires. The quarterly report shall also contain events that trigger a shutoff device and any monitoring results.

⁵ SCS3 shall file with the Director an annual report that summarizes the quarterly reports and include projections of the response and storage capacity of the storage reservoir including anomalies and assumptions. All anomalies in predicted behavior as indicated in permit conditions or in the assumptions upon which the permit was issued must be explained and, if necessary, the permit conditions amended in accordance with N.D.A.C. § 43-05-01-12. The annual report is due 45 days after the end of the year.

⁶ SCS3 shall verbally report noncompliance or malfunction within 24 hours from the time SCS3 became aware of the circumstances. A written submission shall also be provided within 5 days of the time SCS3 became aware and include a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

⁷ Monitoring well MGW14 is scheduled to be drilled by Year 19 of injection; should MGW14 be drilled prior to start of injection, MGW14 will be included in the preinjection sampling program.

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18) ¹	Reporting Method	DMR-O&G Reporting Schedule ^{2,3}
CO ₂ Stream Analysis Section 5.1	Injection volume/mass	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO ₂ accounting, leak detection, and operational safety assurance	Multiple Coriolis mass flowmeters	One flowmeter per injection wellhead placed on flowline after flowline splits on injection pad	Continuous	Monthly average volume (metric tons/MCF) and mass of CO ₂ stream injected over reporting period and cumulative volume injected to date	Form 26 - Carbon Dioxide Storage Report - SFN 18667; NorthSTAR Sundry (e.g., underground injection control [UIC] supplemental information – date of first injection)	Any evidence of injected CO ₂ or associated pressure front that may cause an endangerment to USDW or any noncompliance which may endanger health and safety of persons or cause pollution of the environment ⁶ must be reported with 24 hours. File quarterly ⁴ Annual report ⁵
	Injection flow rate						Monthly average maximum and minimum injection flow rate		
	Injection P/T			Multiple P/T gauges	Along NDL-326 flowline; downstream or upstream of flowmeters; and upstream of injection wellheads		Monthly average pressure (psi) and monthly average temperature (Fahrenheit)		
	Injection composition (See Table 5-3, Stream System Specification)	CO ₂ stream sampling	CO ₂ accounting and ensures stream compatibility with project materials in contact with CO ₂	Gas chromatograph	Downstream of the PIG receiver	Quarterly with option to reduce sampling frequency with approval from DMR O&G	Average CO ₂ stream composition; any changes to its physical, chemical, and/or relevant characteristics from proposed operating data	Form 26A – Carbon Dioxide Storage Source Report – SFN 18668	File quarterly ⁴ Annual report ⁵
			Verify accuracy of field measurements	CO ₂ stream sampling with sample port	Upstream of the gas chromatograph		CO ₂ stream compositional commercial laboratory results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File quarterly ⁴ if analysis is performed during quarter. Annual report ⁵
		Isotopes	Source attribution				Within first year of injection and within one year of adding new CO ₂ source(s) (other than ethanol)		
Surface Facilities Leak Detection Plan Section 5.2	Mass balance	Real-time, continuous data recording with automated triggers and alarms via SCADA system	CO ₂ accounting, leak detection, and operational safety assurance	Leak detection system (LDS) software, multiple P/T gauges, and Coriolis mass flowmeters	Flowmeter and P/T gauge near each injection wellhead in pump/metering building and flowmeter and P/T gauge at point of transfer	Continuous	Any release of CO ₂ into the atmosphere or triggering of a surface facilities shutoff device	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Atmospheric releases or triggering of a shutoff device to be reported within 24 hours ³ after event is confirmed by operator. File quarterly ⁴ Annual report ⁵
	Gas concentrations (e.g., CO ₂ , CH ₄ , and H ₂ S)			Gas detection stations and safety lights	Stations on each injection and reservoir-monitoring wellhead; station inside pump/metering building and safety light mounted on building exterior; multigas detectors worn by field personnel				

Continued . . .

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18) ¹	Reporting Method	DMR-O&G Reporting Schedule ^{2,3}
CO ₂ Flowline Corrosion Prevention and Detection Plan Section 5.3	Loss of mass	Real-time, continuous data recording with automated triggers and alarms via SCADA system	Corrosion detection of project materials in contact with CO ₂ and operational safety assurance	Electrical resistance (ER) probe	Flowline NDL-326 begins at the point of transfer and ends at the inlet valve upstream of the emergency shut off valve at each injection wellhead	Continuous	Summary of ER probe monitoring results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File quarterly ⁴ Annual report ⁵
		Pipeline Inspection		PIG	PIG receiver upstream of the gas chromatograph on NDL-326 flowline	Once every 5 years	Summary of PIG monitoring results		
	Flow conditions (e.g., saturation point of water)	Real-time, continuous data recording with automated triggers and alarms via SCADA system	Real-time model with LDS software and multiple P/T gauges and Coriolis mass flowmeters	Flowmeter and P/T gauge near each injection wellhead and at point of transfer	Continuous	Operator statement about flowline operation conditions			
	Cathodic protection	Continuous data recording	Corrosion prevention of project materials	Impressed current cathodic protection (ICCP) system			Anodes buried along the length of NDL-326 flowline		
Wellbore Mechanical Integrity (external) Section 5.4	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, RCBL), and GR	Mechanical integrity demonstration and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL) and GR	CO ₂ injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers	Mechanical integrity test (MIT), injection well test, well workover, and logging results and interpretations	NorthSTAR Sundry (e.g., casing/cement supplemental information; logs and testing – notification of work performed, supplemental information, etc.)	Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. File quarterly ⁴ if analysis is performed or log is acquired during quarter. Annual report ⁵
	Radial cement bond			PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)			
	Saturation profile (behind casing)	PNL		Temperature log	CO ₂ injection and reservoir-monitoring wells	Annually only if DTS fails	MIT (i.e., annual external mechanical integrity demonstration test results) injection well test, well workover, and logging results and interpretations		
	Temperature profile	Temperature logging		DTS casing-conveyed fiber-optic cable	Along the outside of the long-string casing of the CO ₂ injection and reservoir-monitoring wells	Continuous			

Continued...

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18) ¹	Reporting Method	DMR-O&G Reporting Schedule ^{2,3}
Wellbore Mechanical Integrity (internal) Section 5.4	P/T	Real-time, continuous data recording via SCADA system	Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Between surface and long-string casing annulus on CO ₂ injection and reservoir-monitoring wells	Continuous	Wellhead temperatures and pressures (surface casing)	Form 26 - Carbon Dioxide Storage Report - SFN 18667; NorthSTAR Sundry (e.g., casing/cement supplemental information; logs and testing – notification of work performed, supplemental information, etc.)	Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. Form 26 – Monthly File quarterly ⁴ Annual report ⁵
	Annulus pressure	Tubing-casing annulus pressure testing		Pressure testing truck with pressure chart	CO ₂ injection and reservoir-monitoring wells	Repeat during workover operations in cases where the tubing must be pulled and no less than once every 5 years.			Monthly average maximum and minimum annular pressure; MIT or well workover results and interpretations; description of event that exceeds operating procedures
	P/T	Real-time, continuous data recording via SCADA system	Prevention of microannulus and monitoring annular fluid volume	Digital surface P/T gauge	Between tubing and long-string casing annulus of CO ₂ injection and reservoir-monitoring wells	Continuous	Wellhead temperatures and pressures (annulus)		Mechanical integrity failures to be reported within 24 hours after event is confirmed by operator. Form 26 – Monthly File quarterly ⁴ Annual report ⁵
	Annular fluid level			Nitrogen (N ₂) cushion on tubing-casing annulus with seal pot system	On well pad for each CO ₂ injection well		Monthly annulus fluid volumes added		
	P/T		Mechanical integrity demonstration and operational safety assurance	Digital surface P/T gauge	Tubing of CO ₂ injection and reservoir-monitoring wells		Wellhead temperatures and pressures (tubing) and monthly average, maximum, and minimum injection pressure		
	Saturation profile (tubing-casing annulus)	PNL	Mechanical integrity demonstration and operational safety assurance	PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	MIT, injection well test, well workover, and logging results and interpretation		File report by quarter ⁴ in which the log is acquired. Annual report ⁵

Continued...

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18) ¹	Reporting Method	DMR-O&G Reporting Schedule ^{2,3}
Downhole Corrosion Detection Section 5.6.2	Saturation profile (behind casing)	PNL	Corrosion detection of project materials in contact with CO ₂ and operational safety assurance	PNL tool	CO ₂ injection and reservoir-monitoring wells (run log from Opeche/Spearfish Formation to surface)	Year 1, Year 3, and at least once every 3 years thereafter	Logging results and interpretations	NorthSTAR Sundry (e.g., casing/cement supplemental information)	File quarterly ⁴ in which the log is acquired. Annual report ⁵
	Casing wall thickness	Ultrasonic logging or other equivalent CIL and sonic array logging (inclusive of CCL, VDL, and RCBL), and GR		Ultrasonic or other equivalent CIL and sonic array tools (inclusive of CCL, VDL, and RCBL), and GR	CO ₂ injection and reservoir-monitoring wells	Repeat when required and when tubing is pulled during workovers			
Near Surface Sections 5.7.1 and 5.7.2	Soil gas composition (See Table 5-7)	Soil gas sampling (See Figure 5-4)	Assurance near-surface environment is protected	Two soil gas profile stations: MSG03 and MSG06	One station per CO ₂ injection and reservoir-monitoring well pad	Collect 3–4 seasonal samples annually per station (no isotopes; perform concentration analysis)	Summary of lab results	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Any CO ₂ release of CO ₂ to the atmosphere or biosphere requires 24-hour notification. File quarterly ⁴ Annual report ⁵
	Water composition (See Table 5-9)	Groundwater well sampling (See Figure 5-4)	Assurance that USDWs are protected	Up to two existing groundwater wells from the Tongue River Aquifer (e.g., MGW02 and MGW07)	AOR	At the start of injection, shift sampling program to the Fox Hills monitoring well near the CO ₂ injection well pad (MGW12). Additional wells may be phased in over time as the CO ₂ plume migrates.			
	Water composition		Assurance that lowest USDW is protected	Fox Hills monitoring well	MGW12 adjacent to CO ₂ injection well pad; additional wells may be phased in over time as the CO ₂ plume migrates.	3–4 seasonal samples in Years 1–4 and reduce to annually thereafter. (water quality only; no isotopic testing)			
					MGW14 adjacent to NDIC File No. 4942; MGW14 to be installed by Year 19 of injection.	3–4 seasonal samples after the first year the well is drilled			
Above-Zone Monitoring Interval Opeche/Spearfish to Skull Creek Section 5.7.3.1	Saturation profile	PNL	Assurance of containment in the storage reservoir and protection of USDWs	PNL tool	CO ₂ injection and reservoir-monitoring wells	Year 1, Year 3, and at least every 3 years thereafter	Logging results and interpretations	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File by quarter ⁴ in which the log is acquired. Annual report ⁵
	Temperature profile	Real-time, continuous data recording via SCADA system		DTS casing-conveyed fiber-optic cable		Continuous			
		Temperature logging		Temperature log		Annually only if DTS fails			

Continued . . .

Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency	Injection Reporting (20 years)		
							Report Content (N.D.A.C. § 43-05-01-18) ¹	Reporting Method	DMR-O&G Reporting Schedule ^{2,3}
Storage Reservoir (direct) Sections 5.7 and 5.7.3.2	P/T	Real-time, continuous data recording via SCADA system	Storage reservoir monitoring and conformance with model and simulation projections	Casing-conveyed downhole P/T gauge	CO ₂ injection and reservoir-monitoring wells	Continuous	Downhole temperatures and pressures	Form 26 - Carbon Dioxide Storage Report - SFN 18667; NorthSTAR Sundry (e.g., logs and testing – supplemental information)	Form 26 - monthly
	Temperature profile			DTS casing-conveyed fiber-optic cable	CO ₂ injection and reservoir-monitoring wells				Annually only if DTS fails
		Temperature logging		Temperature log		Annual report ⁵			
Storage reservoir performance	Injectivity testing	Demonstration of storage reservoir performance	Pressure falloff tests	CO ₂ injection wells	Once every 5 years per well after the start of injection	Injection well test results	Annual report ⁵		
Storage Reservoir, (indirect) Section 5.7.3.3	CO ₂ saturation	3D time-lapse seismic surveys (See Figure 5-6)	Site characterization and CO ₂ plume tracking to ensure conformance with model and simulation projections	Vibroseis trucks (source) and geophones and DAS fiber-optic cable (receivers)	Within AOR	Repeat 3D seismic survey by the end of Year 2 and in Years 4 and 9 and at least once every 5 years thereafter.	Summary of seismic results and interpretations	NorthSTAR Sundry (e.g., logs and testing – supplemental information)	File by quarter ⁴ in which the analysis is performed.
	Seismicity	Continuous data recording	Seismic event detection and source attribution and operational safety assurance	Seismometer stations and DAS fiber optics	Area around injection wells (within 1 mile)	Continuous			Report on seismic events detected within 24 hours.
									File quarterly ⁴
									Annual report ⁵

¹ In addition to the reports, submittals, notifications, and other information described in Table 5-1 and N.D.A.C. § 43-05-01-18, Reporting Requirements, the Director may require other additional information to be reported not outlined in Table 5-1.

² SCS3 will notify the Director as soon as possible of any planned changes which may result in noncompliance with permit requirements.

³ Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements shall be submitted no later than 30 days following each scheduled reporting date. SCS3 shall file with the Director an annual report that summarizes the quarterly reports.

⁴ The storage operator shall file with the Director quarterly, or more frequently, if the Director requires. The quarterly report shall also contain events that trigger a shutoff device and any monitoring results.

⁵ SCS3 shall file with the Director an annual report that summarizes the quarterly reports and include projections of the response and storage capacity of the storage reservoir including anomalies and assumptions. All anomalies in predicted behavior as indicated in permit conditions or in the assumptions upon which the permit was issued must be explained and, if necessary, the permit conditions amended in accordance with N.D.A.C. § 43-05-01-12. The annual report is due 45 days after the end of the year.

⁶ SCS3 shall verbally report noncompliance or malfunction within 24 hours from the time SCS3 became aware of the circumstances. A written submission shall also be provided within 5 days of the time SCS3 became aware and include a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times; and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

5.1 CO₂ Stream Analysis

The CO₂ stream will be monitored during injection operations to accurately measure CO₂ volumes transported from the CO₂ flowline to the CO₂ injection wellheads (KJ Hintz 1 and 2). A pressure/temperature (P/T) gauge and Coriolis mass flowmeter installed near each of the CO₂ injection wellheads will provide continuous, real-time measurements of the injection volume, flow rate, pressure, and temperature of the CO₂ stream during operations. The equipment will be spliced to a supervisory control and data acquisition (SCADA) system and have automated triggers and alarms for notifying the operations center in the event of any anomalous readings.

Another goal of monitoring the CO₂ stream is to ensure materials and equipment in contact with the stream are protected. Prior to injection, SCS3 determined the composition of each individual CO₂ source and the resultant CO₂ stream to establish a system specification, as shown in Table 5-3. Selected flowline and well materials are designed to meet or exceed the system specification. Any new CO₂ streams from third-party entities not accounted for at the time of permitting must also meet or exceed the system specification once commingled with the existing CO₂ stream as described in Table 5-3.

Table 5-3. CO₂ Stream System Specification

Chemical Content	System Specification
Carbon Dioxide, CO ₂	≥98.25%
Inert, N ₂	≤1.44%
Oxygen, O ₂	≤0.31%
Water, H ₂ O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H ₂ S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition

N.D.A.C. § 43-05-01-11.4(1)(a) requires “[a]nalysis of the CO₂ 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.” Key chemical and physical characteristics of interest include composition, corrosiveness, temperature, and density (N.D.A.C. § 43-05-01-11[9][b]). SCS3 plans to sample the CO₂ stream continuously with a gas chromatograph installed on the injection well pad. The gas chromatograph will be spliced to the SCADA system to collect real-time data. Tables 5-1 and 5-2 specify the CO₂ stream sampling strategy.

For isotopic analysis of the CO₂ stream, a sample port will be placed upstream of the gas chromatograph to collect samples. Figure 5-1 illustrates the anticipated ranges for stable carbon isotopes from various CO₂ source signals. At the time of permitting, the CO₂ stream is expected to be sourced by ethanol (biofuel) facilities. Therefore, the corresponding stable carbon isotope signature of the CO₂ stream is anticipated to be approximately -10 ‰ to -20 ‰, as shown in

Figure 5-1. If sources of CO₂ other than ethanol are added that were not originally accounted for at the time of permitting, SCS3 will repeat sampling of the CO₂ stream within a year of adding the new CO₂ source(s) to redetermine its isotopic signature.

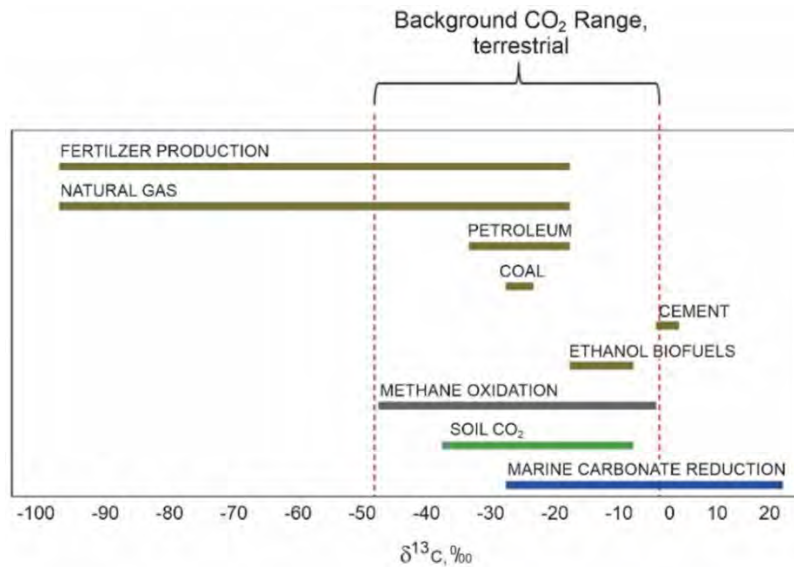


Figure 5-1. Stable carbon isotope signatures of various CO₂ source signals (from Dixon and Romanak, 2015).

5.1.1 CO₂ Stream Analysis QASP

SCS3 will follow manufacturer guidelines to regularly calibrate and maintain the gas chromatograph (specification sheet provided in Appendix D, Attachment D-1). The gas chromatograph will measure the CO₂ stream's individual chemical components for concentration analysis using a thermal conductivity detector. The onboard electronics and software will calculate the concentrations of each individual chemical component and output the results in a tabulated format, similar to what is shown in Table 5-3. CO₂ stream analysis with the gas chromatograph will be performed at regularly scheduled intervals determined by SCS3 that meets N.D.A.C. § 43-05-01-11.4(1)(a). Isotopic analyses of the CO₂ stream will be outsourced to commercial laboratories that will employ standard analytical quality assurance/quality control (QA/QC) protocols used by the industry. CO₂ stream sampling will be performed at regularly scheduled intervals determined by SCS3 that meets N.D.A.C. § 43-05-01-11.4(1)(a) and analyzed by a third-party commercial laboratory.

5.2 Surface Facilities Leak Detection Plan

The purpose of this leak detection plan is to specify the monitoring strategies SCS3 will use to quantify any losses of CO₂ from surface facilities during operations. Surface facilities include the CO₂ injection wellheads (KJ Hintz 1 and 2), the reservoir-monitoring wellhead (Slash Lazy H 5), and the NDL-326 CO₂ flowline, which begins at the first weld seam at the NDL-326/NDL-327 connection (i.e., point of transfer) and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO₂ injection wellhead. Figure 5-2 illustrates the CO₂ flowline path to CO₂ injection wellsite, and Figure 5-3 is a generalized flow diagram from the point of transfer to the CO₂ injection wellheads, illustrating key surface facilities' connections and monitoring equipment.

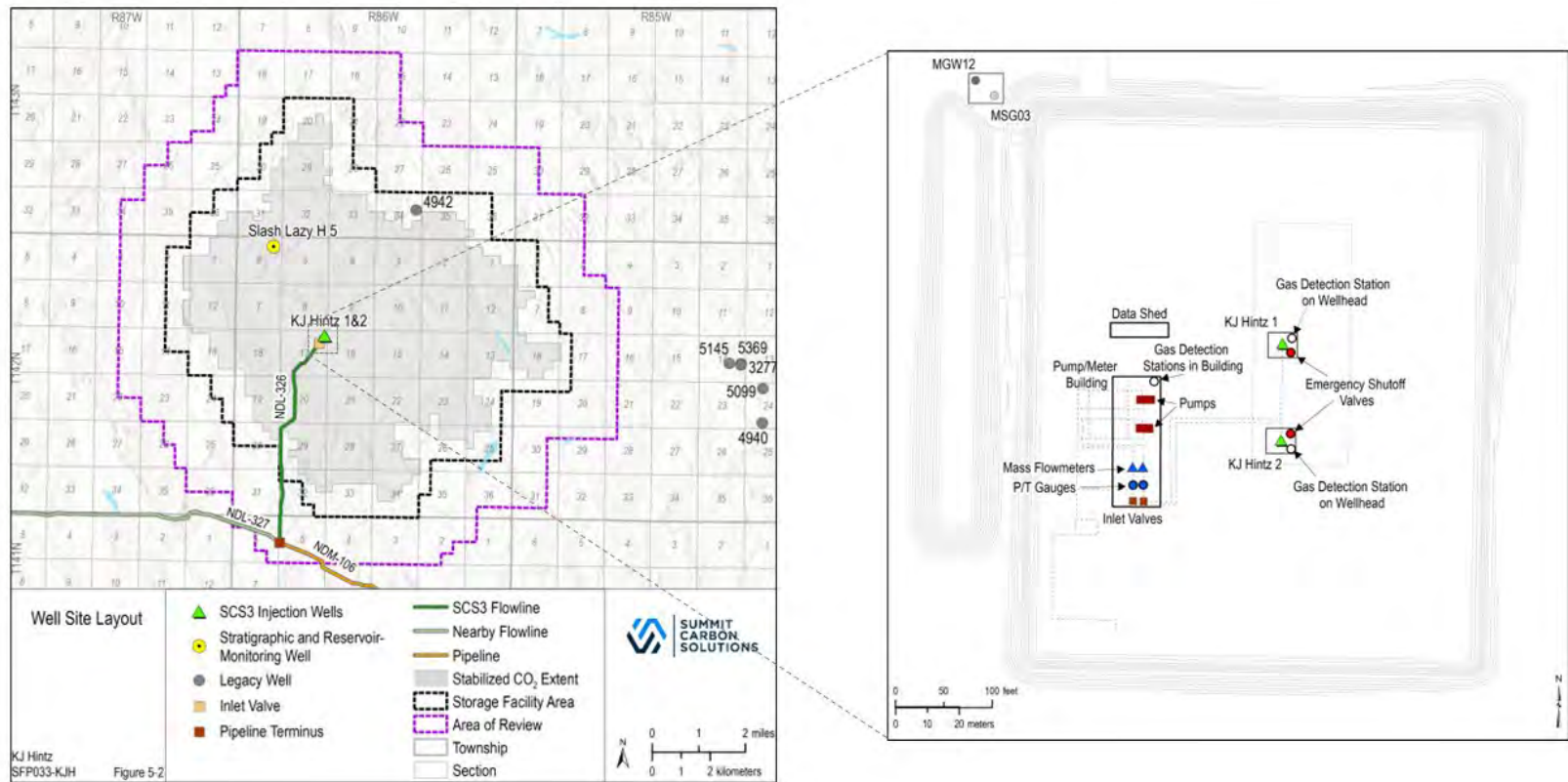


Figure 5-2. Map detailing CO₂ flowline path to CO₂ injection wellsite (left) and layout of surface facilities at the wellsite (right), illustrating key surface facilities leak detection and monitoring equipment. Soil gas profile station, MSG03, and groundwater well, MGW12, off-pad monitoring locations are also shown.

Generalized Flow Diagram KJ Hintz 1

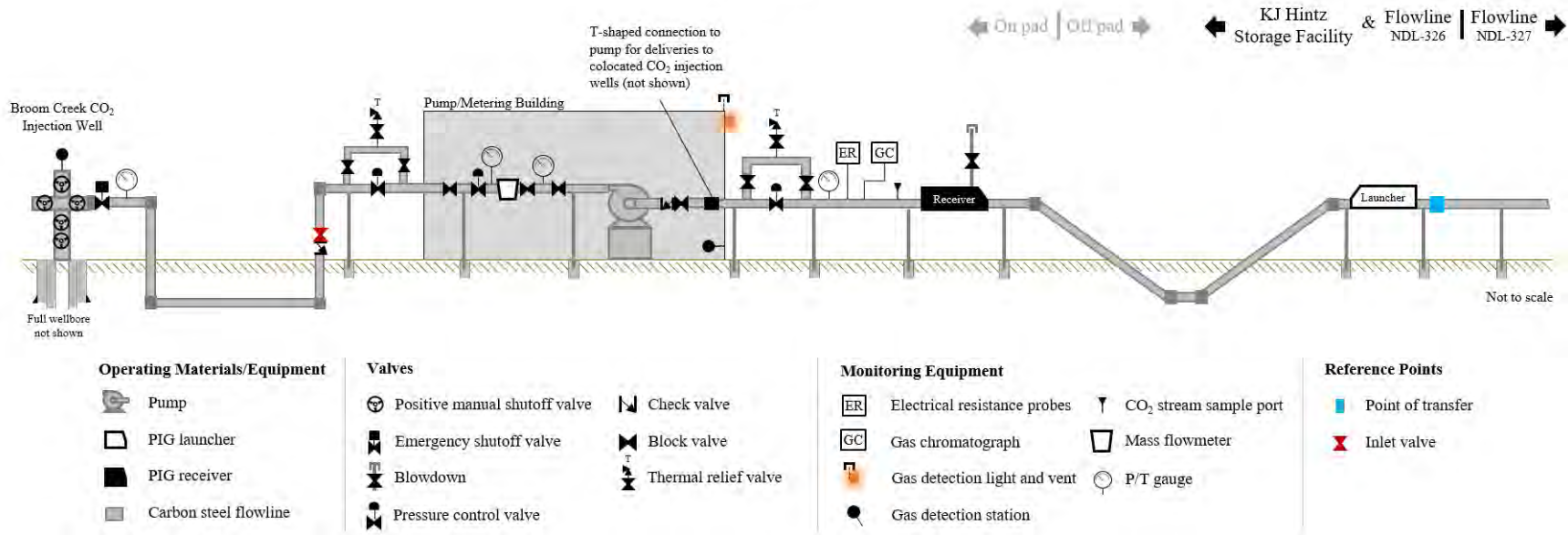


Figure 5-3. Generalized flow diagram from the point of transfer to the KJ Hintz 1 CO₂ injection well, illustrating key surface facilities' connections and monitoring equipment. The flow diagram is identical for the KJ Hintz 2 CO₂ injection well (not shown).

As illustrated in Figure 5-3, leak detection equipment includes 1) P/T gauges along the flowline, 2) a Coriolis mass flowmeter placed near each of the injection wellheads, and 3) gas detection stations placed on the CO₂ injection wellheads pursuant to N.D.A.C. § 43-05-01-14(1) and inside the pump/metering building. The gas detection stations, which will detect gases such as CO₂, methane (CH₄), and hydrogen sulfide (H₂S), will have automated triggers and alarms to alert SCS3 of any anomalous readings. The SCADA system, which will continuously collect data streams from the leak detection equipment in real time, will also monitor for leaks with leak detection software.

Field personnel from SCS3 will have multigas detectors with them for visiting wellsites or conducting flowline inspections. In addition, gas detection safety lights (part of the integrated alarm system) will be placed outside of the pump/metering building to warn field personnel of potential indoor air quality threats.

5.2.1 Data Sharing and Custody Transfer

The entire CO₂ flowline (NDL-326), which begins at the point of transfer and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO₂ injection wellhead (Figure 5-3), will be owned by SCS3 and operated by SCS Carbon Transport, LLC. NDL-326 consists of 4.82 miles of 16-inch flowline in Oliver County.

NDL-327 and NDL-326 to the CO₂ injection wellsite will be operated as one integrated SCADA system with data flowing to a single operations center. Summit Carbon Storage #1, LLC (SCS1); Summit Carbon Storage #2 LLC (SCS2); SCS3; SCS Permanent Carbon Storage LLC; and SCS Carbon Transport LLC will share operational data and controls in real time and ensure operational parameters (e.g., flowline pressures) are safely maintained between all injection sites at all times. Data shared will include, but are not limited to, defining the financial and operational responsibilities, mass balance and custody transfers, data access and data sharing, and general operations including leak detection and reporting, emergency response, monitoring, and maintenance of NDL-326 and respective wellsites.

Custody transfer of the CO₂ will occur using flowmeters placed at each individual CO₂ capture facility prior to entering NDM-106 operated by SCS Carbon Transport LLC. Once the transported CO₂ stream reaches the NDM-106 pipeline terminus, the CO₂ will be metered with a Coriolis mass flowmeter to transfer custody from SCS Carbon Transport LLC to SCS1 at the start of the NDL-327 flowline (Figure PS-3). At the point of transfer, the CO₂ stream will not be metered to transfer custody to SCS3. Instead, Coriolis mass flowmeters dedicated to each CO₂ injection well (BK Fischer 1 and 2) will be used to meter the injected CO₂ stream per well, while the metering equipment associated with SCS1, SCS2 and SCS3 that is operated by SCS Carbon Transport LLC will be used together to monitor the entire flowline system and perform mass balance calculations, including the section of NDL-326 flowline from the point of transfer to the mass flowmeters at the KJ Hintz injection wellsite (Figure 5-3).

5.2.2 Surface Facility Leak Detection Plan QASP

Pursuant to N.D.A.C. § 43-05-01-14(1), the leak detection equipment will be inspected and tested on a semiannual basis. If equipment is defective, SCS3 will repair or replace the equipment within 10 days or, acting with good cause, SCS3 will propose an alternate timeline for approval by the

DMR-O&G. Each repaired or replaced detector will be retested, if required. The gas detection stations are described in Appendix D, Attachment D-2. The SCADA system and leak detection software are described in further detail in Appendix D, Attachment D-3, and the personnel multigas detectors are described in Appendix D, Attachment D-4. SCS3 will install leak detection equipment according to the manufacturer’s recommendations.

The flowline will be regularly inspected for any visual or auditory signs of equipment failure. Any release of CO₂ to the atmosphere or near-surface environments from the surface facilities will be reported to DMR-O&G within 24 hours pursuant to N.D.A.C. § 43-05-01-18(9)(e).

5.2.2.1 NDL-326 Flowline Design

The NDL-326 flowline will be manufactured with a high-frequency electrical resistance weld or double submerged arc weld process. Based upon volume requirements and pressure service, the 16-inch NDL-326 flowline design is summarized in Table 5-4.

Table 5-4. NDL-326 Flowline Design Specification¹

Parameter	Design Specification
Maximum Operating Pressure	2183 psig
Maximum Discharge Pressure ²	2160 psig
Typical Operating Pressure	1250–2150 psig
Design Temperature (above-grade piping)	–50–120°F
Design Temperature (below-grade piping)	23–120°F
Anticipated CO ₂ Stream Temperature Range	30–115°F
Maximum Design Flow Rate	314.5 million scf per day ³

¹Abbreviation used in table: pounds per square inch gauge; standard cubic foot

²At pump stations or individual capture facilities.

³Approximately equivalent to 6 million tonnes of CO₂ annually.

The NDL-326 flowline and associated structures will be designed, constructed, inspected, tested, and operated in accordance with industry standards. The flowline will be constructed of high-strength carbon steel pipe, exceeding the American Petroleum Institute (API) 5L (2018) pipe specification. API 5L is the industry standard specification for seamless and welded steel line pipes used in pipeline transportation systems, including the energy industry. These regulations and industry standards specify pipeline and associated facilities materials and qualification and other controls to mitigate the risk of an incident while providing protection for the public and environment.

5.3 CO₂ Flowline Corrosion Prevention and Detection Plan

The purpose of this plan is to prevent and detect any signs of corrosion in the flowline.

5.3.1 Corrosion Prevention

To protect against corrosion, an external fusion-bonded epoxy coating will be applied to the NDL-326 flowline. Flowline installed by trenchless methods, such as road crossings, will also have an abrasion-resistant overcoat installed as a secondary coating, over the fusion-bonded epoxy, prior to installation.

SCS3 will install an impressed current cathodic protection (ICCP) system along the buried flowline to mitigate the threat of external soil corrosion on the line. The ICCP system, which will be continuously monitored, involves the installation of deep anode beds along the flowline that are connected to external power through a rectifier. The power provides the current needed to drive an electrochemical reaction whereby the anodes corrode instead of the flowline. Except for a rectifier, junction box, and small diameter vent pipe posted above the anode beds, the ICCP system will be buried.

Because the CO₂ stream will contain only trace amounts of water (Table 5-3), SCS3 will operate the surface facilities above the saturation point of water to prevent corrosive conditions from forming.

5.3.1.1 Corrosion Prevention QASP

The flowline construction materials will be in accordance with API 5L (2018) X-70 PSL 2 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's ICCP system will be in accordance with Title 49 of the Code of Federal Regulations (CFR), Part 195 and will be pressure-tested prior to CO₂ injection operations. SCS3 will supply DMR-O&G with a map of cathodic protection borehole locations to meet N.D.A.C. § 43-05-01-05(1)(a) prior to injection.

5.3.2 Corrosion Detection

Real-time, continuous monitoring of the CO₂ flowline with P/T gauges and Coriolis mass flowmeter measurements from the pump/metering building to the point of transfer combined with continuous analysis of the CO₂ stream with the gas chromatograph will provide strong evidence that noncorrosive conditions are maintained in the flowline during injection operations. The equipment will be spliced to the SCADA system and have automated triggers and alarms for alerting SCS3 of any anomalous readings.

The flowline segment from point of transfer to the pipeline inspection gauge (PIG) receiver (shown on Figure 5-3) will allow the passage of internal inspection devices (commonly referred to as "smart PIGs"), which are designed to detect certain internal and external anomalies in the line, such as loss of mass/wall thickness, dents, pitting, cracking, and scratches. The launchers and receiver facilities are designed to launch and receive these internal inspection devices along with other types of PIGs (e.g., maintenance pigs). The launchers and receivers will be located at standalone sites in Oliver County. The frequency for running PIGs in the flowline during operations is described in Table 5-2.

In addition to the activities described above, SCS3 will install at least one electrical resistance (ER) probe along the CO₂ flowline upstream of the gas chromatograph to continuously monitor for loss of mass throughout the operational phase. The ER probe will be spliced to the SCADA system for real-time monitoring and will be removable for visual inspection and replacement, if required. The SCADA system will have automated triggers and alarms for alerting SCS3 of any anomalous readings.

5.3.2.1 *Corrosion Detection QASP*

SCS3 will utilize PIG equipment that has been maintained and calibrated according to the manufacturer's recommendations and 40 CFR Part 195 rules and regulations. The ER probe will be exposed to the CO₂ stream and spliced to the SCADA system for continuously measuring losses of mass to calculate a real-time corrosion rate. The ER measurements are mathematically translated into terms of changes in mass and the results are plotted over time. Changes in the regression of the data trend correspond to changes in the corrosion rate. Changes in mass of the exposed probe material can be attributable to changes in the length or cross-sectional area of the probe material, which may include pitting. The ER probe will be spliced to the SCADA system and programmed with triggers and alarms for alerting the operations center of anomalous ER measurements. Specification sheets for the ER probe and data transmitter are provided in Appendix D, Attachments D-5 and D-6, respectively.

SCS3 will investigate anomalies in flowline operating parameters to ensure noncorrosive conditions are maintained during injection operations, including pulling the ER probe for inspection and replacement, as required by DMR-O&G.

5.4 Wellbore Mechanical Integrity Testing

Pursuant to N.D.A.C. § 43-05-01-11.1, SCS3 will conduct mechanical integrity testing of the CO₂ injection and reservoir-monitoring wellbores to ensure there is no significant leak in the casing, tubing, or packer and that there is no significant fluid movement into an USDW adjacent to the wellbore. Below is a summary of the methods that SCS3 will use to verify mechanical integrity. Tables 5-1 and 5-2 specify the sampling frequency for the set of activities described in this section.

External mechanical integrity in the CO₂ injection wells and reservoir-monitoring well will be demonstrated with the following:

- 1) Ultrasonic or other equivalent casing inspection log (CIL) and sonic array logging tools [inclusive of variable density log (VDL), casing collar locator (CCL), and radial cement bond log (RCBL)].
- 2) Pulsed-neutron logging (PNL) to examine the saturation profile behind casing from the Opeche/Spearfish Formation to surface. If repeat PNLs detect evidence of unexpected vertical migration of CO₂, then SCS3 will notify and work with DMR-O&G to identify and take appropriate action, such as pulling tubing and running an ultrasonic or other equivalent CIL tool for attributing the source of the suspected out-of-zone migration.
- 3) Distributed temperature sensing (DTS) fiber-optic cable installed outside of the long-string casing will continuously monitor the temperature profile of each wellbore from the storage reservoir to surface. A baseline temperature log will be acquired in case the DTS fiber-optic cable fails and temperature logging is required in the future pursuant to N.D.A.C. § 43-02-05-07(3)(b).

Internal mechanical integrity in the CO₂ injection wells and reservoir-monitoring well will be demonstrated with the following:

- 1) The surface and long-string casing annulus will be continuously monitored with a digital surface P/T gauge.
- 2) Tubing-casing annulus pressure testing.
- 3) The tubing-casing annulus pressure will be continuously monitored with a digital surface P/T gauge on each wellhead.
- 4) A seal pot system with a nitrogen (N₂) cushion will be used to continuously monitor and maintain the packer fluid pressure in the tubing-casing annular space at the surface below 300 psi. The N₂ cushion accommodates for packer fluid level/volume changes due to temperature fluctuations to ensure that the tubing-casing annular space is kept full.
- 5) The tubing conditions will be continuously monitored with a digital surface P/T gauge on each wellhead.
- 6) PNL to examine the saturation profile in the tubing-casing annulus from the Opeche/Spearfish Formation to surface. If repeat PNLs detect evidence of unexpected vertical migration of CO₂, then SCS3 will notify and work with DMR-O&G to identify and take appropriate action, such as performing a tubing-casing annulus pressure test or pulling tubing and performing a casing pressure test or running an ultrasonic or other equivalent CIL tool for attributing the source of the suspected out-of-zone migration.

All digital P/T gauges mentioned in the plan will be spliced to the SCADA system for real-time monitoring. Wellbore schematics illustrating the monitoring equipment for the CO₂ injection wells and reservoir-monitoring well are shown in Figures 11-2, 11-4, and 11-5, respectively, in Section 11.0.

5.4.1 Wellbore Mechanical Integrity Testing QASP

Specification sheets for the ultrasonic, array sonic, and PNL tools are provided in Appendix D, Attachments D-7, D-8, and D-9, respectively, and specification sheets for the DTS fiber-optic cable and interrogator are provided in Appendix D, Attachments D-10 and D-11, respectively.

An example procedure for conducting an annulus pressure test prior to CO₂ injection is provided in Appendix D, Attachment D-12. A diagram of the seal pot system design is provided in Appendix D, Attachment D-13.

Digital surface P/T gauges will be maintained and calibrated according to the manufacturer's recommendations; copies of calibration certificate will be submitted. Pursuant to N.D.A.C. § 43-05-01-14(1), the leak detection equipment (i.e., P/T gauges on wellheads and seal pot system) will be inspected and tested on a semiannual basis. If equipment is defective, SCS3 will repair or replace the equipment within 10 days or, acting with good cause, SCS3 will propose an alternate timeline for approval by DMR-O&G. Each repaired or replaced detector will be retested, if required.

For all well-logging activities, SCS3 will ensure that third-party contractors follow industry standard or better QA/QC protocols. SCS3 will also ensure reports of logging activities are prepared by a qualified geologist or engineer.

SCS3 will contract a third-party entity to conduct a feasibility study to quantify the CO₂ detection capabilities using the proposed PNL method based on the design of the CO₂ injection and reservoir-monitoring wellbores. Results of the feasibility study will be submitted to DMR-O&G prior to injection.

5.5 Baseline Wellbore Logging and Testing Plan (Site Characterization)

Pursuant to N.D.A.C. § 43-05-01-11.2, SCS3 will collect baseline well-logging and -testing measurements from subsurface geologic formations in the CO₂ injection wellbores to 1) verify the depth, thickness, porosity, permeability, lithology, and salinity of the storage complex; 2) ensure conformance with the injection well construction requirements; and 3) establish accurate baseline data for making future time-lapse measurements. Baseline well-logging and -testing measurements will also be collected from the reservoir-monitoring well.

Table 5-5 specifies baseline well-logging and -testing activities completed in the reservoir-monitoring well (Slash Lazy H 5), and Table 5-6 identifies the well-logging and -testing plan for the KJ Hintz 1. The plan for the KJ Hintz 2 wellbore will be the same as what is presented for the KJ Hintz 1 but may exclude dipole sonic logging (assuming dipole sonic logging is successful in the KJ Hintz 1).

Tables 5-1 and 5-2 specify well-logging and -testing activities associated with establishing mechanical integrity and monitoring the deep subsurface, including the storage complex. Coring activities are described separately in the Section 9.0 as-drilled wellbore diagrams for KJ Hintz 1 and 2 and in the text in Section 2.0 for Slash Lazy H 5.

SCS3 will provide DMR-O&G with an opportunity to witness all well-logging and -testing activities as required under N.D.A.C. § 43-05-01-11.2(6).

Table 5-5. Completed Logging and Testing Activities for Slash Lazy H 5

	Logging/Testing	Justification
Surface Section	Open-hole logs: triple combo (resistivity and neutron and density porosity), dipole sonic, spontaneous potential (SP), 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 and array sonic tools (inclusive of CCL, VDL, and RCBL), 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	Open-hole 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.
	Open-hole log: dipole sonic	Identified mechanical properties, including stress anisotropy.
	Open-hole log: fracture finder log	Quantified fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO ₂ .
	Open-hole log: combinable magnetic resonance (CMR)	Interpreted reservoir properties (e.g., porosity and permeability) and determined the best location for pressure test depths, formation fluid sampling depths, and stress testing depths.
	Open-hole log: fluid sampling (modular formation dynamics tester)	Collected fluid samples from the Inyan Kara and Broom Creek Formation for analysis. Collected in situ microfracture stress tests in the Broom Creek and Opeche/Spearfish Formation for formation breakdown pressure, fracture propagation pressure, and fracture closure pressure.
	Cased-hole logs: ultrasonic and array sonic tools (inclusive of CCL, VDL, RCBL), GR, and temperature	Identified cement bond quality radially, evaluated the cement top and zonal isolation, confirmed mechanical integrity, and established baseline temperature profile.

Table 5-6. Logging and Testing Plan for the KJ Hintz 1 and KJ Hintz 2 Wellbores

	Logging/Testing	Justification	N.D.A.C. § 43-05-01-11.2
Surface Section	Open-hole logs: triple combo, 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 tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), 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	Open-hole 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)
	Open-hole 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)
	Open-hole log: magnetic resonance log	Aid in interpreting reservoir permeability and determining the best location for modular formation dynamics testing (MDT) fluid-sampling depths, packer-setting depths, and stress-testing depths.	(1)(c)(1)
	Open-hole log: MDT fluid sampling and testing	Collect fluid sample from the Broom Creek Formation for analysis. Conduct in situ microfracture stress test in the Broom Creek in one injection well for formation breakdown pressure.	(1), (2), and (3)
	Open-hole 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: PNL	Confirm mechanical integrity from Opeche/Spearfish Formation to surface.	11.4(g)(1)
	Cased-hole logs: ultrasonic tool or other CIL and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature	Confirm cement bond quality radially, evaluate cement top and zonal isolation and demonstrate mechanical integrity. Establish baseline for casing inspection logging and temperature profile for temperature-to-DTS calibration.	(1)(c)(2) and (d)

* Dipole sonic logging may be excluded in KJ Hintz 2 assuming that the dipole sonic log is successful in KJ Hintz 1.

** A sundry will be submitted requesting a waiver of the SP log and that an alternative method providing equivalent data will be utilized instead upon the DMR-O&G's approval pursuant to N.D.A.C. § 43-05-01-11.2 (e).

Wellbore data collected from the reservoir-monitoring well (Slash Lazy H 5) have been integrated with the geologic model to inform the reservoir simulations that are used to characterize the initial state of the reservoir before injection operations (Section 3.0). The simulated CO₂ plume extents informed the timing and frequency of the application of the direct and indirect monitoring methods of the testing and monitoring plan.

5.5.1 Baseline Wellbore Logging and Testing Plan (Site Characterization) QASP

For all planned well-logging and -testing activities, SCS3 will ensure that third-party contractors follow industry standard or better QA/QC protocols for acquiring and processing the data and that reports of activities are prepared by a qualified geologist or engineer.

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 N.D.A.C. § 43-05-01-11.4(1)(c).

5.6.1 Downhole Corrosion Prevention

To prevent corrosion of the well materials in the KJ Hintz 1 and 2 wellbores, the following preemptive measures will be implemented: 1) cement opposite of the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation will be CO₂-resistant; 2) the well casing will also be CO₂-resistant from the bottomhole to just above the Opeche/Spearfish Formation and from below the top of the Swift Formation to just below the top of the Skull Creek 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. The tubing-casing annulus will be filled with the packer fluid system that is planned to be a brine-based fluid treated with antimicrobial biocide, corrosion inhibitor, and oxygen scavenger to minimize potential corrosive effects of soluble oxygen.

To prevent corrosion of the well materials in the Slash Lazy H 5 wellbore, the following preemptive measures are implemented: 1) cement opposite the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation is CO₂-resistant; 2) the well casing is CO₂-resistant from 194 feet below the top of the Amsden Formation to 154 feet above the top of the Opeche/Spearfish Formation and from 179 feet below the top of the Swift Formation to 250 feet above the top of the Mowry Formation; and 3) the long-string casing is filled with an industry standard corrosion inhibitor.

Figures 11-2, 11-4, and 11-5 in Section 11.0 illustrate the downhole corrosion prevention measures in each of the wellbores.

5.6.1.1 Downhole Corrosion Prevention QASP

Specification sheets for the antimicrobial biocide, corrosion inhibitor, and oxygen scavenger treatment are provided in Appendix D, Attachments D-14, D-15, and D-16, respectively.

SCS3 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 meet the standards selected and presented in Sections 9.0, 10.0, and 11.0 of this permit application.

5.6.2 Downhole Corrosion Detection

PNLs will be run in the KJ Hintz 1 and 2 and Slash Lazy H 5 wellbores to detect saturations of CO₂. Further investigative methods of inspecting for corrosion in the wellbore could include ultrasonic logging or other equivalent CIL when required. Tables 5-1 and 5-2 specify the sampling frequency for acquiring data related to this downhole corrosion detection plan.

5.6.2.1 Downhole Corrosion Detection QASP

If the PNLs detect possible signs of out-of-zone vertical migration, SCS3 will work with DMR-O&G to take appropriate action, such as running an ultrasonic tool or other equivalent CIL to confirm downhole conditions in the wellbore. For any logging activities related to corrosion detection, SCS3 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

5.7 Environmental Monitoring Plan

To verify the injected CO₂ is contained in the storage reservoir, protect all USDW, and demonstrate hydrogeologic properties of the storage reservoir, multiple environments will be monitored.

As required by N.D.A.C. § 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 and analyzing vadose-zone soil gas at two soil gas profile stations, two new Fox Hills monitoring wells, and up to two 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/Spearfish Formation to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the KJ Hintz 1 and 2 wellbores as well as PNLs.

Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optics (DTS) and downhole P/T measurements in the KJ Hintz 1 and 2 and Slash Lazy H 5 wells, and falloff tests and PNLs in the KJ Hintz 1 and 2 wellbores. Falloff testing analysis will provide reservoir pressure data and the completion condition including transmissibility, skin factor, and well flowing and static pressure data for technical adequacy to demonstrate no migration from the reservoir. Indirect methods include time-lapse seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO₂ is safely and permanently contained in the storage reservoir. In addition, SCS3 will install multiple seismometer stations for passively detecting and locating seismic events.

5.7.1 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. Two permanent soil gas profile stations installed adjacent to both the CO₂ injection and Slash Lazy H 5 well pads will be sampled, as shown in Figure 5-4. Figure 5-5 is a typical wellbore schematic of a soil gas profile station.

KJ HINTZ/SLASH LAZY H 5

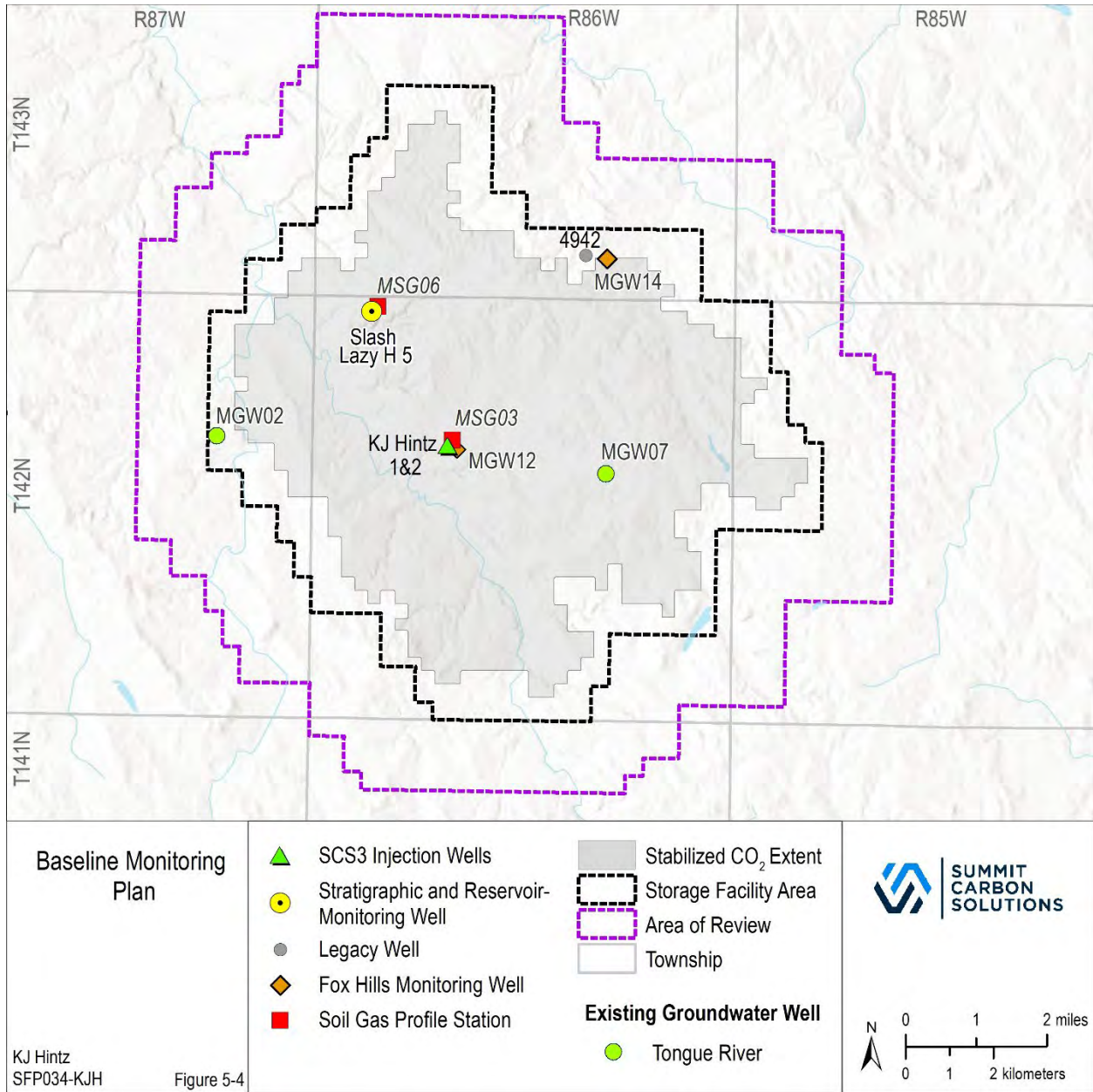


Figure 5-4. SCS3 baseline and operational near-surface sampling locations.

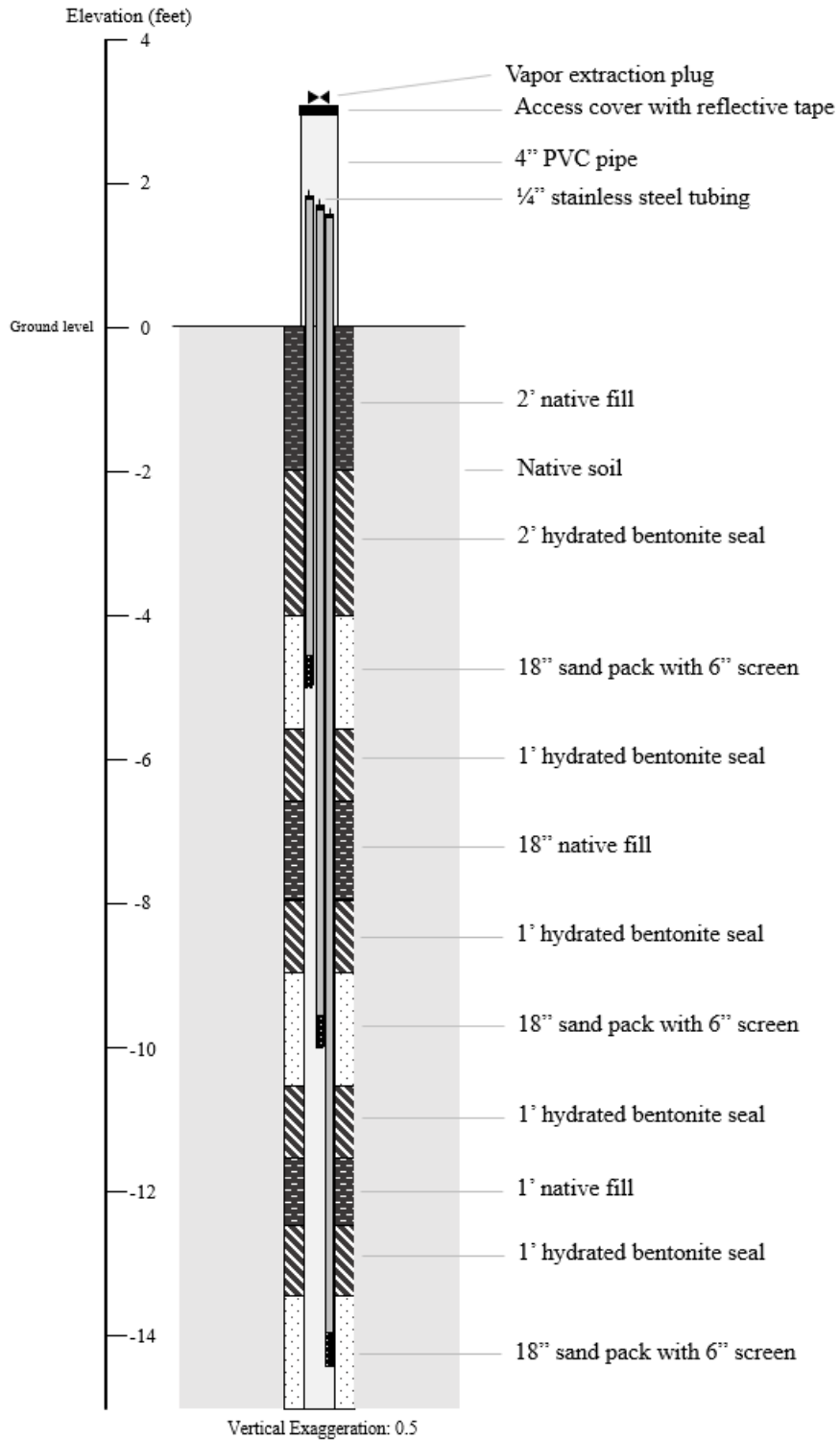


Figure 5-5. A typical wellbore schematic of a soil gas profile station.

The sampling frequency for soil gas is summarized in Tables 5-1 and 5-2. During injection, SCS3 may install additional replacement or alternative soil gas sampling sites based on monitoring data results. SCS3 will notify DMR-O&G if either replacement or alternative soil gas sampling sites are added pursuant to N.D.A.C. § 43-05-01-18(2). The results of the baseline soil gas sampling program will be provided to DMR-O&G prior to injection.

5.7.1.1 Soil Gas Monitoring QASP

Tables 5-7 and 5-8 indicate a minimum set of analytes that will be included for the soil gas analysis.

Table 5-7. Soil Gas Compositional Analysis–Primary Components

Analyte	Units
N ₂	Volume %
O ₂	Volume %
CO ₂	Volume %
Ar	Volume %
CH ₄	Volume %

Table 5-8. Stable and Radiocarbon Isotope Soil Gas Measurements

Isotope	Units
δ ¹³ C of CO ₂ and CH ₄	‰ (per mil)
δ ¹⁴ C of CO ₂ and CH ₄	‰ (per mil)
δD of CH ₄	‰ (per mil)

At minimum, SCS3 will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below. Figure 5-5 is a typical wellbore schematic of a soil gas profile station.

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 CO₂, total volatile organic compounds (VOCs), and O₂ using a handheld multigas meter. The handheld meter will be calibrated daily during sampling 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 analysis.

Soil Gas Sampling QA/QC Procedures

SCS3 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.

5.7.2 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. Figure 5-4 identifies the sampling locations associated with the near-surface baseline and operational monitoring plan, which includes two new Fox Hills monitoring wells and up to two existing groundwater wells.

SCS3 will work with landowners of the two existing groundwater wells (MGW02 and MGW07) to attempt to collect samples as specified in Tables 5-1 and 5-2. The number of samples collected from each existing groundwater well may vary by location, since some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months). If SCS3 is unable to access the wells because of operational status or access concerns, the reason why the sample is unable to be collected will be documented. An attempt was made to identify alternative wells that operate year-round with reduced access concerns but produced no results.

SCS3 will install one Fox Hills monitoring well (MGW12) adjacent to the injection well pad (as shown in Figure 5-4). The Fox Hills monitoring well will be sampled according to the sampling frequency specified in Tables 5-1 and 5-2.

NDIC File No. 4942 was plugged and abandoned with two cement plugs placed between the Broom Creek and Fox Hills Formations. In addition, NDIC File No. 4942 is outside the stabilized CO₂ plume boundary; therefore, the wellbore is not anticipated to come into contact with CO₂. SCS3 plans to monitor this legacy wellbore with a new Fox Hills monitoring well installed by SCS3 to provide additional assurance of nonendangerment to the lowest USDW. The Fox Hills monitoring well (MGW14) will be installed by Year 19 of injection. Seismic data acquisitions (described later in the Indirect Reservoir Monitoring section of the application) prior to Year 19 of injection will help track the migration of the CO₂ plume and may help determine timing of installation of MGW14. After the well is installed, SCS3 will sample wells according to the sampling frequency described in Tables 5-1 and 5-2.

SCS3 reserves the right to evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO₂ plume extent in the subsurface. SCS3 will notify DMR-O&G if alternative or new water wells are added to the sampling program pursuant to N.D.A.C. § 43-05-01-18(2).

Appendix B includes a supplemental baseline dataset of historic geochemistry results for two shallow groundwater wells within the area of review (AOR) boundary. The data were obtained from the Department of Water Resources (DWR). These shallow groundwater wells (DWR 9450 and 18181) were excluded from the baseline and operational monitoring plan primarily because they did not meet the depth criterion used to select wells for inclusion in the testing and monitoring plan.

5.7.2.1 Groundwater Monitoring QASP

State-certified commercial laboratories will be identified by SCS3 to analyze the water samples for the analytes described in Tables 5-9 and 5-10.

Table 5-9. General Analytes for Groundwater Samples

Analyte	Cation (total and dissolved)	Anion (total)
pH	Aluminum	Bromide
Conductivity	Antimony	Chloride
Alkalinity	Arsenic	Fluoride
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 5-10. Stable and Radiocarbon Isotope Measurements in Groundwater

Isotope	Units
δD H ₂ O	‰ (per mil)
$\delta^{18}O$ H ₂ O	‰ (per mil)
$\delta^{13}C$ Dissolved Inorganic Carbon (DIC)	‰ (per mil)
3H H ₂ O	‰ (per mil)
$\delta^{14}C$ DIC	‰ (per mil)

SCS3 will select third-party service providers to collect groundwater samples and ensure that standard industry QA/QC procedures are followed. At minimum, SCS3 will ensure that third-party service providers apply a standard procedure for sampling the wells, such as the one provided below.

Example Groundwater Well Sampling Procedure

Groundwater samples will be collected by a third party from the dedicated Fox Hills monitoring well as well as other shallower groundwater wells, specified by SCS3 and with landowner approval, using a submersible pump. The standard procedure for sampling the wells is provided below:

1. Purge the well, removing a minimum of three casing volumes.
2. Wait for field measurements to stabilize and collect the sample.
 - a. Record the location of the sample point.
 - b. Collect field readings: temperature, conductivity, and pH.
Fill appropriate sample containers for analysis with minimum headspace and refrigeration/cooling (chill each sample to $\leq 6^{\circ}\text{C}$) to reduce microbial activity.
3. Collect a duplicate sample from about 1 in every 10 samples for QA/QC purposes.

Groundwater Sampling QA/QC Procedures

SCS3 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.

5.7.3 Deep Subsurface Monitoring

Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), SCS3 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 this subsection 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.

5.7.3.1 Above-Zone Monitoring Interval

Monitoring of the AZMI during injection operations includes monitoring of the temperature and saturation profiles from the Opeche/Spearfish Formation through the Skull Creek Formation. Temperature in the AZMI will be continuously monitored via DTS fiber-optic cable installed in the KJ Hintz 1 and 2 and Slash Lazy H 5 wellbores. The plan for acquiring saturation data from PNLs is described in Tables 5-1 and 5-2.

5.7.3.2 *Above-Zone Monitoring Interval QASP*

SCS3 will ensure that all continuous monitoring devices (e.g., fiber optics) are inspected and maintained in accordance with the manufacturer's recommendations. For any logging activities, SCS3 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

Time-lapse data from the PNLs will be used to ensure CO₂ is not detected in the AZMI as an assurance-monitoring technique for evaluating the performance of the storage complex and protecting USDWs.

5.7.3.3 *Direct Reservoir Monitoring*

DTS fiber optics installed in the KJ Hintz 1 and 2 and Slash Lazy H 5 wellbores will directly monitor the temperature of the storage reservoir. P/T readings from the casing-conveyed gauges in the CO₂ injection wells will also monitor conditions in the storage reservoir. To track the pressure front from CO₂ injection in the storage reservoir, pressure will be measured continuously from the casing-conveyed P/T gauge installed in the Slash Lazy H 5 well. To track the CO₂ plume in the storage reservoir, the DTS fiber-optic cable and temperature measurements from the casing-conveyed P/T gauge installed in the Slash Lazy H 5 well will be used to estimate the timing of arrival of the CO₂ plume at the reservoir-monitoring well. The pressure and temperature data will be used to ensure the monitoring data from the Broom Creek Formation (from Amsden through Opeche/Spearfish Formation) is conforming to the geologic model and numerical simulations. Pressure falloff tests will also be performed in the CO₂ injection to demonstrate the performance of the storage reservoir.

5.7.3.4 *Direct Reservoir Monitoring QASP*

SCS3 will ensure that all continuous monitoring devices (e.g., fiber-optics and casing-conveyed P/T gauges) are inspected and maintained in accordance with the manufacturer's recommendations. Casing-conveyed P/T gauges will be calibrated within one year of initial installation; copies of calibration certificate will be submitted. Example specification sheets for the casing-conveyed P/T gauges in the CO₂ injection wells and reservoir-monitoring well are provided in Appendix D, Attachment D-17. For any logging activities, SCS3 will ensure that third-party contractors follow industry standard or better QA/QC protocols and that reports of logging activities are prepared by a qualified geologist or engineer.

5.7.3.5 *Indirect Reservoir Monitoring*

SCS3 will acquire 3D time-lapse seismic surveys to track the extent of the CO₂ plume within the storage reservoir. The 200-mi² 3D Beulah seismic survey referenced in Section 2.0 will serve as the baseline survey. To demonstrate conformance between the reservoir model simulation and site performance, a localized 3D seismic survey will be collected to monitor the extent of the CO₂ plume, as shown in Figure 5-6 and detailed in Table 5-2.

SCS3 will reevaluate the testing and monitoring plan, inclusive of the design and frequency of the repeat 3D seismic surveys, at least once every 5 years as required. If necessary, the time-lapse seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO₂ plume, including expanding the 3D survey area to capture additional data as the CO₂ plume expands in the storage reservoir.

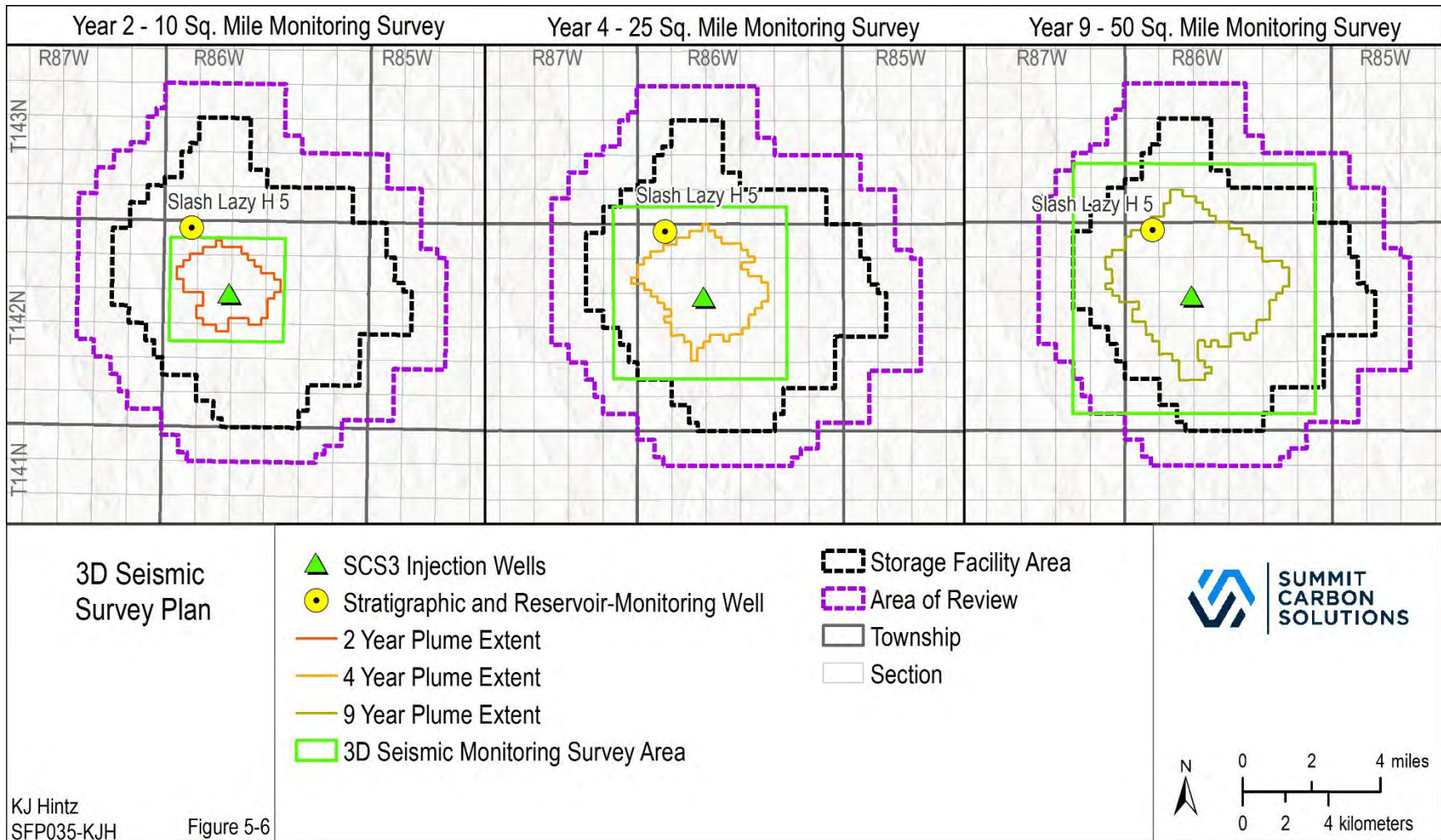


Figure 5-6. Simulated extent of the CO₂ plume at the end of Years 2, 4, and 9. The green boxes show the planned 3D seismic monitoring survey extents.

SCS3 plans to install multiple seismometer stations to continuously monitor for seismic events with a magnitude of >1.5 within the AOR boundary during injection. The 3D seismic survey data (e.g., velocity modeling) collected within the AOR boundary will provide supporting evidence for confidently locating seismic events. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented with the Indirect Reservoir Monitoring QASP section of this application.

5.7.3.5.1 Indirect Reservoir Monitoring QASP

The geophysical monitoring that is planned for the project includes 3D time-lapse seismic surveys. Time-lapse seismic surveys provide a measurement of the change in acoustic properties of the storage formation as injected CO₂ 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.

For seismic survey acquisitions, SCS3 will follow the required permitting process pursuant to N.D.C.C. § 38-08.1-04 and N.D.A.C. § 43-02-12-04. Seismic acquisition and processing are performed by highly specialized companies and crews that provide the equipment, procedures, and QA/QC protocols based on the technology selected for acquisition and parameters for processing the data. SCS3 will work with third-party contractors to select the appropriate equipment, procedures, QA/QC protocols, acquisition and processing parameters, and seismic interpreters for all repeat surveys.

5.7.3.5.2 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. While few seismic events have been recorded in the region, SCS3 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.

5.7.3.5.3 Seismicity Monitoring QASP

SCS3 will work with third-party contractors and landowners to ensure proper design and installation of the passive seismicity monitoring array. The design and installation of the seismometer station array is performed by specialized contractors including the following activities:

- Project management support to design seismometer array, model network performance, coordinate permitting and equipment installation, testing and maintenance, and ensuring optimum execution of project.
- Field operation to deploy surface seismic station instrumentation, power and communication systems, data quality, and commissioning.

- Data acquisition, system configuration, and processing setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst review and alert notifications for events at or above predetermined magnitude thresholds over the seismic area.

SCS3 will follow a traffic light system if a seismic event is recorded by either the local or public national array during injection operations.

Traffic Light System

If an event is recorded by either the local private array or the public national array to have occurred within 3 miles of an injection well, SCS3 will implement its Emergency Remedial and Response Plan (Section 7.0) subject to detected earthquake magnitude limits defined below:

- For an event >2.7 located within three miles of injection, SCS3 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 an event >4.0 located within 3 miles of injection, SCS3 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 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 will 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 an event >4.5 located within 3 miles of injection, the operator will stop injection. The operator will inform the regulator of seismic activity and inform them that operations have stopped pending 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 will 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.

5.8 Reporting Requirements

SCS3 shall retain the following records for a period of at least 10 years from the date of sample, measurement, or report:

- All data collected for the application of the storage facility permit, injection well permit, and operation of injection well permit.
- Data on the nature and composition of all injected fluids collected pursuant to N.D.A.C. § 43-05-01-11.4(1).
- All records from the closure period, including well plugging reports, postinjection site care data, and the final assessment.
- Upon project completion, SCS3 shall deliver any required records described in N.D.A.C. § 43-05-01-18(11).

SCS3 shall retain the following records for a period of at least 10 years from the date of sample, measurement, or report (N.D.A.C. § 43-05-01-18[12]):

- Monitoring data collected pursuant to N.D.A.C. § 43-05-01-11.4(b-i).
- Calibration and maintenance records.
- All original strip chart records for continuous monitoring instrumentation.
- Copies of all reports required by the storage facility permit.

5.8.1 Surface Facilities Leak Detection Reporting

Leak detection equipment at the wellhead of KJ Hintz 1, KJ Hintz 2, and Slash Lazy H 5 will be inspected and tested on a semiannual basis. If detection equipment is found to be defective, it will be repaired or replaced within 10 days of operator being aware of failure. An extension of time to repair or replacement of a leak detector may be granted by DMR-O&G upon SCS3 showing good cause. Semiannual inspection records will be maintained by SCS3 for at least 10 years and will be made available to DMR-O&G upon request pursuant to N.D.A.C. § 43-05-01-14(1).

5.9 Adaptive Management Approach

SCS3 will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each 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 DMR-O&G for approval. Should amendments to the testing

and monitoring plan be necessary, they will be incorporated into the permit following approval by DMR-O&G. 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.

5.10 References

- American Petroleum Institute, 2018, Line pipe: API Specification 5L, Forty-Sixth Ed., April 2018, Errata 1, May 2018, 210 p.
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- Dixon, T., and Romanak, K.D., 2015, Improving monitoring protocols for CO₂ geological storage with technical advances in CO₂ attribution monitoring: *International Journal of Greenhouse Gas Control*, v. 41, p. 29–40, doi: 10.1016/j.ijggc.2015.05.029.
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SECTION 6.0

**POSTINJECTION SITE CARE AND FACILITY
CLOSURE PLAN**

6.0 POSTINJECTION SITE CARE AND FACILITY CLOSURE PLAN

This postinjection site care (PISC) and facility closure plan describes the activities that Summit Carbon Storage #3, LLC (SCS3) will perform following the cessation of CO₂ injection to achieve final closure and issuance of a certificate of project completion. An overview of postinjection testing and monitoring activities is provided in Table 6-1. The postinjection testing and monitoring data will provide evidence that the injected CO₂ plume is stable (i.e., CO₂ migration will be unlikely to cross the storage facility area [SFA] boundary).

Pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-19(1)(d), SCS3 proposes to submit the PISC monitoring results annually to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G).

Table 6-1. Overview of Postinjection Testing and Monitoring Activities¹

Monitoring Type/SFP Reference	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency (10 years minimum)
Wellbore Mechanical Integrity (external) Section 6.2.1	Material wall thickness	Ultrasonic or other equivalent casing inspection log (CIL) and sonic array logging	Mechanical integrity confirmation and operational safety assurance	Ultrasonic or other equivalent CIL and sonic array tools	Slash Lazy H 5	Repeat when required and when tubing is pulled during workovers.
	Radial cement bond					
	Temperature profile	Continuous data recording		Distributed temperature sensing (DTS) fiber		Continuous
		Temperature logging		Temperature log		Annually only if DTS fiber fails
Saturation profile	Pulsed-neutron log (PNL)	PNL tool	Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.			
Wellbore Mechanical Integrity (internal) Section 6.2.1	Pressure/temperature (P/T)	Continuous data recording via supervisory control and data acquisition (SCADA) system	Mechanical integrity confirmation and operational safety assurance	Digital surface P/T gauge on the casing annulus (between surface and long-string sections)	Slash Lazy H 5	Continuous
		Tubing-casing annulus pressure testing		Pressure testing truck with pressure chart		Repeat during workover operations in cases where the tubing must be pulled and no less than every 5 years.
		Continuous data recording via SCADA system		Digital surface P/T gauge on tubing-casing annulus		Continuous
		Continuous data recording via SCADA system		Digital surface P/T gauge on tubing		Continuous
	Saturation profile	PNL		PNL tool		Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
Downhole Corrosion Detection Section 6.2.1	Saturation profile	PNL	Corrosion detection of project materials in contact with CO ₂	PNL tool	Slash Lazy H 5	Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
	Material wall thickness	Ultrasonic or other equivalent CIL		Ultrasonic or other approved CIL tools		Repeat when required and when tubing is pulled during workovers. ²

¹ Pursuant to N.D.A.C. § 43-05-01-19(1)(d), SCS3 proposes to submit monitoring results annually. The annual report is due 45 days after the end of the year.

² If PNL indicates out-of-zone migration, the operator will work with DMR-O&G to take appropriate action.

Continued...

Table 6-1. Overview of Postinjection Testing and Monitoring Activities (continued)

Monitoring Type	Parameter	Activity Description	Primary Purpose(s) of Activity	Equipment/Test	Location	Sampling Frequency (10 years minimum)
Near Surface Section 6.2.2	Soil gas composition (see Table 5-6)	Soil gas sampling (see Figure 6-3)	Protection of near-surface environment	Field meter and sample bags	MSG03 and MSG06	Collect 3–4 seasonal samples at each station (MSG03 and MSG06) in Year 1 and Year 3 of postinjection and every 3 years thereafter (e.g., Years 6 and 9).
	Water composition (see Table 5-9)	Groundwater sampling (see Figure 6-3)	Protection of underground sources of drinking water (USDW)	Field meter and sample containers	MGW07	Collect 3–4 seasonal samples in Year 1 and Year 3 of postinjection and at least once every 3 years thereafter until facility closure (anticipated in Year 10 of postinjection).
					MGW02	Collect 3–4 seasonal samples in Year 4 of postinjection and prior to facility closure (anticipated in Year 10 of postinjection).
					MGW12 and MGW14	Collect samples annually until facility closure (anticipated in Year 10 of postinjection).
Above-Zone Monitoring Interval Section 6.2.3	Temperature profile	Continuous data recording via SCADA system	Assurance of containment in storage reservoir	DTS casing-conveyed fiber-optic cable	Slash Lazy H 5	Continuous
		Temperature logging		Temperature log		Annually only if DTS fiber fails
	Saturation profile	PNL		PNL tool		Repeat PNL in Year 4 and Year 9 of postinjection. Run log from Opeche/Spearfish Formation to surface.
Storage Reservoir (direct) Section 6.2.3	P/T	Continuous data recording via SCADA system	Pressure front tracking	Casing-conveyed P/T gauge	Slash Lazy H 5	Continuous
	Temperature profile	Continuous data recording via SCADA system	CO ₂ plume tracking	DTS casing-conveyed fiber-optic cable		Continuous
Storage Reservoir (indirect) Section 6.2.3	CO ₂ saturation	Time-lapse seismic monitoring	CO ₂ plume tracking	Time-lapse seismic surveys with source and receivers	Within area of review (AOR) boundary (CO ₂ plume extents)	Actual design to be determined based on reevaluations of the testing and monitoring plan (Section 5.0) and migration of the CO ₂ plume over time. Multiple repeat time-lapse seismic surveys will be collected during postinjection, with the first survey occurring by Year 4 of postinjection.

¹ Pursuant to N.D.A.C. § 43-05-01-19(1)(d), SCS3 proposes to submit monitoring results annually. The annual report is due 45 days after the end of the year.

² If PNL indicates out-of-zone migration, the operator will work with DMR-O&G to take appropriate action.

Based on the current simulations of CO₂ plume movement following the cessation of CO₂ injection, it is projected that the CO₂ plume will stabilize within the storage facility area (SFA) boundary (Section 3.0), confirming nonendangerment of USDW within the AOR. Based on these projections, a minimum 10-year postinjection monitoring period is planned to confirm CO₂ plume extent and postinjection stabilization pursuant to North Dakota Century Code (N.D.C.C.) § 38-22-17. Monitoring will be extended beyond 10 years if it is determined that additional data are required to demonstrate a stable CO₂ plume and nonendangerment of USDW. The nature and duration of that extension will be determined based on an update of this plan and DMR-O&G approval.

In addition to the foregoing postinjection monitoring program, the CO₂ injection wells will be plugged as described in the plugging plan (Section 10.0). All surface equipment not associated with long-term monitoring will be removed, and all surface land associated with the project will be reclaimed 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 DMR-O&G as part of a facility closure report. After application by the storage operator, NDIC shall consider issuing a certificate of project completion after notice and hearing pursuant to N.D.C.C. § 38-22-17.

6.1 Predicted Postinjection Subsurface Conditions

6.1.1 Pre- and Postinjection Pressure Differential

Model simulations were performed to predict the change in pressure in the Broom Creek Formation during and after the cessation of CO₂ injection. The simulations were conducted for 20 years of CO₂ injection in the Broom Creek Formation at an average total rate of 6.49 MMt/yr, followed by a postinjection period of 10 years.

Figure 6-1 illustrates the predicted pressure differential at the cessation of CO₂ injection. At the time that CO₂ injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 1023 psi at the KJ Hintz CO₂ injection well pad. There is insufficient pressure increase caused by CO₂ injection to move more than 1 m³ 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 discussion within Section 3.0 of this application.

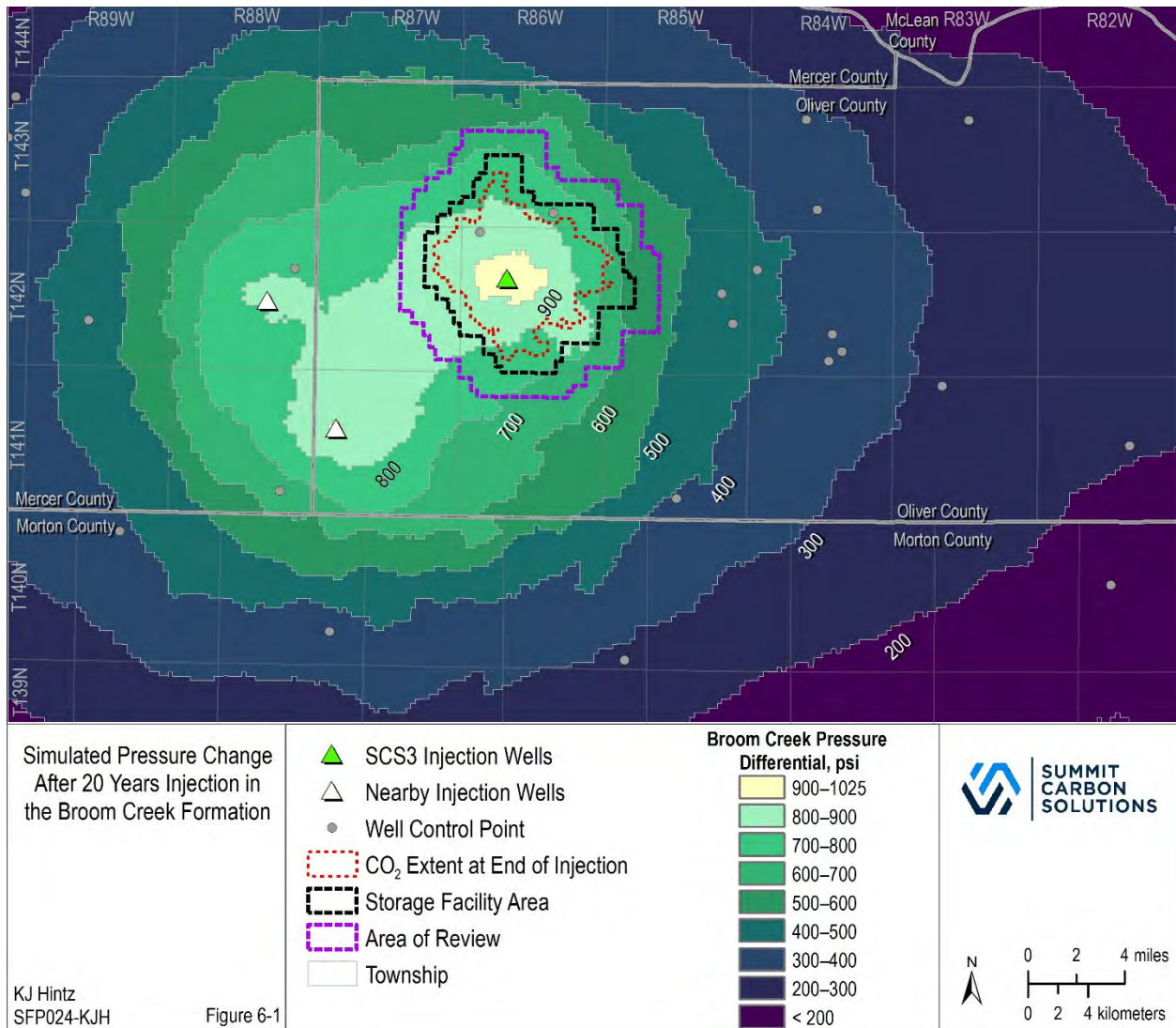


Figure 6-1. Predicted pressure increase in the storage reservoir following 20 years of injection of an average 6.49 MMt/yr of CO₂.

Figure 6-2 illustrates the predicted gradual pressure decrease in the storage reservoir, over a 10-year period following the cessation of CO₂ injection. The pressure at the KJ Hintz CO₂ injection well pad at the end of the 10-year period is anticipated to decrease 600–650 psi as compared to the pressure in the storage reservoir at the time CO₂ 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.

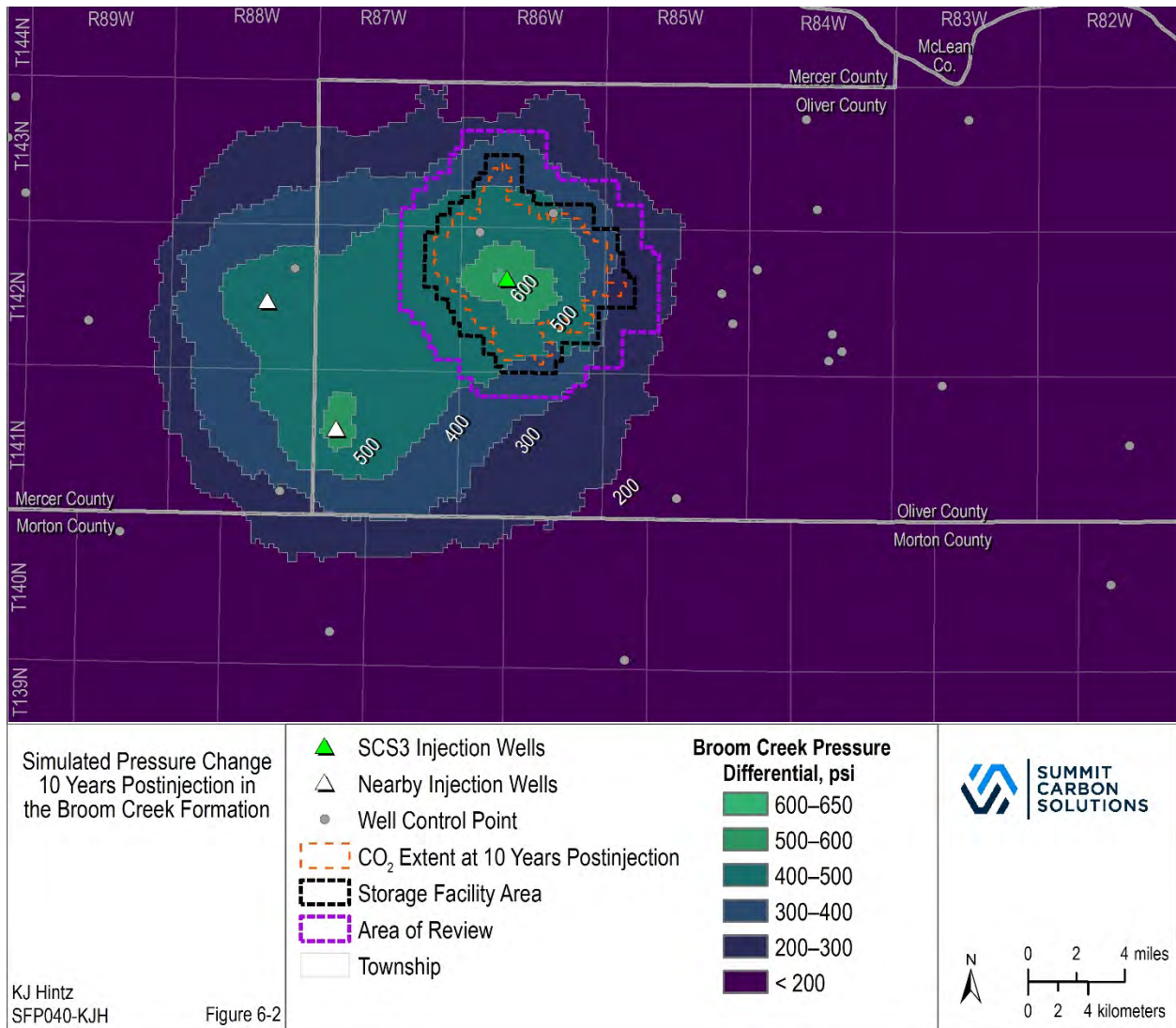


Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO₂ injection.

6.1.2 Predicted Extent of CO₂ Plume

Figure 6-2 illustrates the extent of the CO₂ plume following the planned 10-year PISC period, which is based on numerical simulation predictions. The results of these simulations predict that the CO₂ plume extent will expand to an area of approximately 33 mi² by the end of the 10-year PISC period.

If SCS3 demonstrates at the end of the 10-year PISC period that the CO₂ plume at the site is unlikely to extend beyond the SFA boundary, then the CO₂ plume will meet the definition of stabilization as presented in N.D.C.C. § 38-22-17(5)(d) as part of qualifying the storage site for receipt of a certificate of project completion.

6.2 Postinjection Testing and Monitoring Plan

This postinjection testing and monitoring plan assumes that the CO₂ injection wells will be plugged at cessation of injection. Planned postinjection monitoring activities include 1) a mechanical integrity testing and corrosion detection plan for the reservoir-monitoring well (Slash Lazy H 5) and 2) an environmental monitoring plan for the near surface and deep subsurface for evidence that the injected CO₂ plume is essentially stationary within the storage reservoir and USDWs are nonendangered.

6.2.1 Mechanical Integrity Testing and Corrosion Detection

The postinjection mechanical integrity testing and corrosion detection plan for the Slash Lazy H 5 is provided in Table 6-1. The supervisory control and acquisition (SCADA) system will be used to collect real-time and continuous measurements from the surface and downhole gauges in the Slash Lazy H 5.

SCS3 will follow the Wellbore Mechanical Integrity Testing Quality Assurance and Surveillance Plan (QASP) and Downhole Corrosion Detection QASP described within Section 5.0 of this application for the set of mechanical integrity and corrosion detection postinjection monitoring activities presented in Table 6-1.

6.2.2 Soil Gas and Groundwater Monitoring

Figure 6-3 identifies the locations of the soil gas profile stations and groundwater wells that are included in this monitoring effort. The two stations (MSG03 and MSG06), the two Fox Hills monitoring wells drilled for this project (MGW12 and MGW14), and existing shallow groundwater wells (MGW02 and MGW07) will be sampled according to the plan outlined in Table 6-1. SCS3 may specify alternate groundwater sampling locations and sampling frequencies for the PISC period, if obtaining samples from MGW02 and MGW07 is not feasible.

Analytes and sampling procedures for all soil gas and groundwater monitoring activities conducted during the PISC period are anticipated to be the same as what is presented in the Soil Gas Monitoring QASP and Groundwater Monitoring QASP within Section 5.0 of this application. SCS3 anticipates 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.

KJ HINTZ/SLASH LAZY H 5

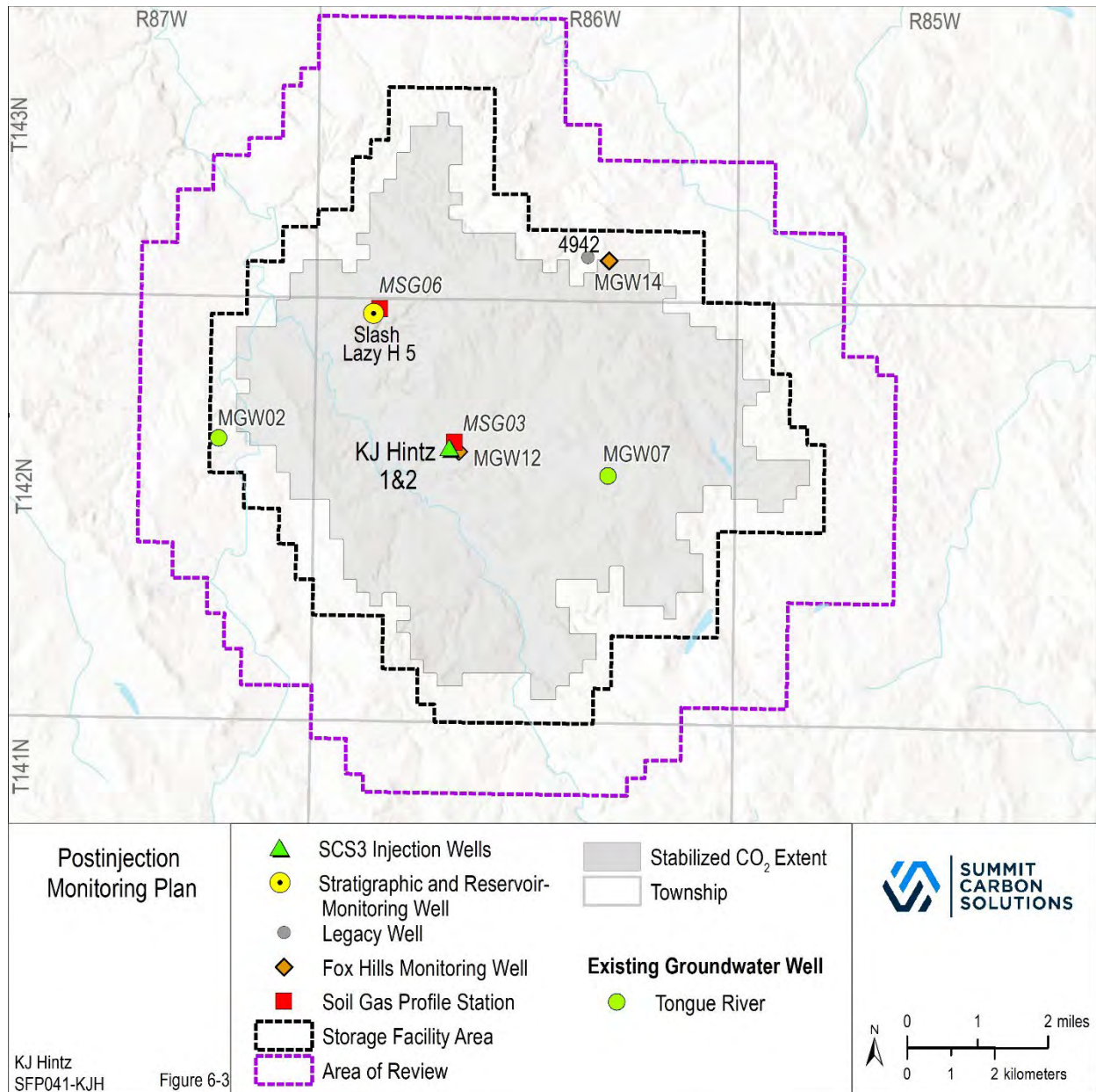


Figure 6-3. Soil gas station and groundwater well sampling locations included in the PISC period.

6.2.3 Deep Subsurface Monitoring

Table 6-1 describes the deep subsurface monitoring strategy during the PISC period. Monitoring methods include a combination of geophysical monitoring (e.g., time-lapse 3D/2D seismic) and formation monitoring (i.e., downhole P/T) for tracking CO₂ saturation and associated pressure, respectively, over the entire storage complex.

The design and frequency of the time-lapse seismic survey will depend on how the CO₂ plume is migrating during the operational phase of the project and the results of the adaptive

management approach discussion described in Section 5.0 of this application. The seismic survey design will be reevaluated and updated according to monitoring data results gathered in the operational phase.

SCS3 will follow the Above-Zone Monitoring Interval QASP, Direct Reservoir Monitoring QASP, and Indirect Reservoir Monitoring QASP described within Section 5.0 of this application for the set of deep subsurface postinjection monitoring activities presented in Table 6-1.

6.3 Postinjection Site Care Plan

At the start of the PISC period, Flowline NDL-326, if not in use or projected use at this time, will be permanently disconnected, purged, and capped at both ends below grade, in accordance with the abandonment of flowlines pursuant to N.D.A.C. § 43-02-03-34.1. Main line valves (MLVs), launcher receivers, and other associated flowline infrastructure at grade or buried at a depth of 3 feet or less will be removed, whereas the NDL-326 flowline will be abandoned in place as the pipe bury depth will be 4 feet top of pipe and will be permanently disconnected, purged, and capped pursuant to N.D.A.C. § 43-02-03-34.1. The cost estimate for flowline segment NDL-326 abandonment can be found in Table 12-3b.

As required by N.D.A.C. § 43-05-01-19(5), PISC activities will include the P&A (plugging and abandonment) of the CO₂ injection wells (KJ Hintz 1 and 2) and reclamation of the injection well pad. Storage facility equipment, appurtenances, and structures not associated with monitoring will be removed, and the surface will be reclaimed to the DMR-O&G's specifications to return the land as close as practicable to its original condition. Injection well pad reclamation activities may occur contemporaneously with flowline removal and do not include the soil gas profile station (MSG03) and the Fox Hills monitoring well (MGW12).

SCS3 intends to use the Slash Lazy H 5 wellbore for deep subsurface monitoring during the PISC period. The postinjection testing and monitoring activities for the Slash Lazy H 5 and near-surface sampling are described earlier 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

Where possible, PISC-monitoring data and results will be submitted to DMR-O&G within 45 days following the end of the calendar year in which CO₂ 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

SCS3 will notify DMR-O&G prior to its intent to close the site, and the facility closure plan will describe a set of activities that will be performed, following approval by DMR-O&G, 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 and removal of aboveground storage facility equipment, appurtenances, and structures (e.g., buildings, gravel pads, access roads, etc.) not associated with monitoring or another deemed use; 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, SCS3 will work with DMR-O&G to determine which wells and monitoring equipment will remain and transfer to the state for continued postinjection monitoring. P&A of the Slash Lazy H 5 and well pad reclamation are costs factored into Section 12.0, but DMR-O&G may choose to retain this reservoir-monitoring well into the postclosure period. The Fox Hills monitoring well (MGW12) drilled adjacent to the CO₂ injection wells (KJ Hintz 1 and 2), the Fox Hills monitoring well (MGW14) drilled adjacent to NDIC File No. 4942, and the soil gas profile stations (MSG03 and MSG06) may also transfer ownership to the state or a third party, pending DMR-O&G review and approval of the PISC plan and final assessment pursuant to N.D.A.C. § 43-05-01-19.11. 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 entity does not occur.

6.4.1 Submission of Facility Closure Report, Survey, and Deed

A facility closure report will be prepared and submitted to DMR-O&G within 90 days following the execution of the PISC and facility closure plan. This report will provide DMR-O&G with a final assessment that documents the location of the stored CO₂ in the reservoir, describes its characteristics, and demonstrates the stability of the CO₂ plume in the reservoir over time. The facility closure report will also document the following:

- Plugging records of the CO₂ injection wells and reservoir-monitoring well.
- Location of the sealed CO₂ injection wells and reservoir-monitoring well on a plat survey that has been submitted to the county recorder's office.
- Notifications to state and local authorities as required by N.D.A.C. § 43-05-01-19.
- Records regarding the nature, composition, and volume of the injected CO₂.
- Postinjection monitoring records.

At the same time, SCS3 will also provide DMR-O&G with a copy of an accurate plat certified by a registered surveyor that has been submitted to the county recorder's office designated by DMR-O&G. The plat will indicate the location of the injection well relative to permanently surveyed benchmarks pursuant to N.D.A.C. § 43-05-01-19.

Lastly, SCS3 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 N.D.A.C. § 43-05-01-19.11.

SECTION 7.0

EMERGENCY AND REMEDIAL RESPONSE PLAN

7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN

Summit Carbon Storage #3, LLC (SCS3) requires all employees, contractors, and agents to follow the company emergency and remedial response plan (ERRP) for KJ Hintz. The purpose of the ERRP is to provide guidance for quick, safe, and effective response to an emergency to protect the public, all responders, company personnel, and the environment.

This 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 (USDW) during the construction, operation, and postinjection site care phases 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 to USDWs. In addition, this ERRP describes the emergency response team and command structure, injection 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 company’s nearest operational office and at the geologic storage facility.

7.1 Background

SCS3 is the owner and operator of KJ Hintz, located in Oliver County, approximately 12 miles southeast of Beulah, North Dakota. SCS3 is requesting a commercial permit for the operation of the storage facility for the injection of a CO₂ stream that will range from 95% CO₂ to ≤99.9% CO₂. This CO₂ stream range will provide flexibility to receive CO₂ from a variety of industrial sources (Table 7-1). This anticipated average CO₂ stream composition will ensure the safe and economic operation of the storage facility, including such factors as consistency with the design and materials of transport and storage equipment.

Table 7-1. Anticipated Average CO₂ Stream Composition

Chemical Content	System Specification
Carbon Dioxide, CO ₂	≥98.25%
Inert, N ₂	≤1.44%
Oxygen, O ₂	≤0.31%
Water, H ₂ O*	≤20 lb/MMscf
Total Hydrocarbons*	≤1800 ppm by volume
Hydrogen Sulfide, H ₂ S*	≤10 ppm by volume
Total Sulfur, S*	≤10 ppm by volume
Glycol	≤0.3 gallons/MMscf

* Denotes trace constituents that do not make up notable percentages of stream composition

Figure 7-1 identifies the planned pipeline, flowlines, injection wells (KJ Hintz 1 and KJ Hintz 2), and the stratigraphic and reservoir-monitoring well (Slash Lazy H 5). The well locations, including latitudes and longitudes, are listed in Table 7-2. At the time SCS3 filed this application, it has not applied for any other permits from state, federal, or local agencies.

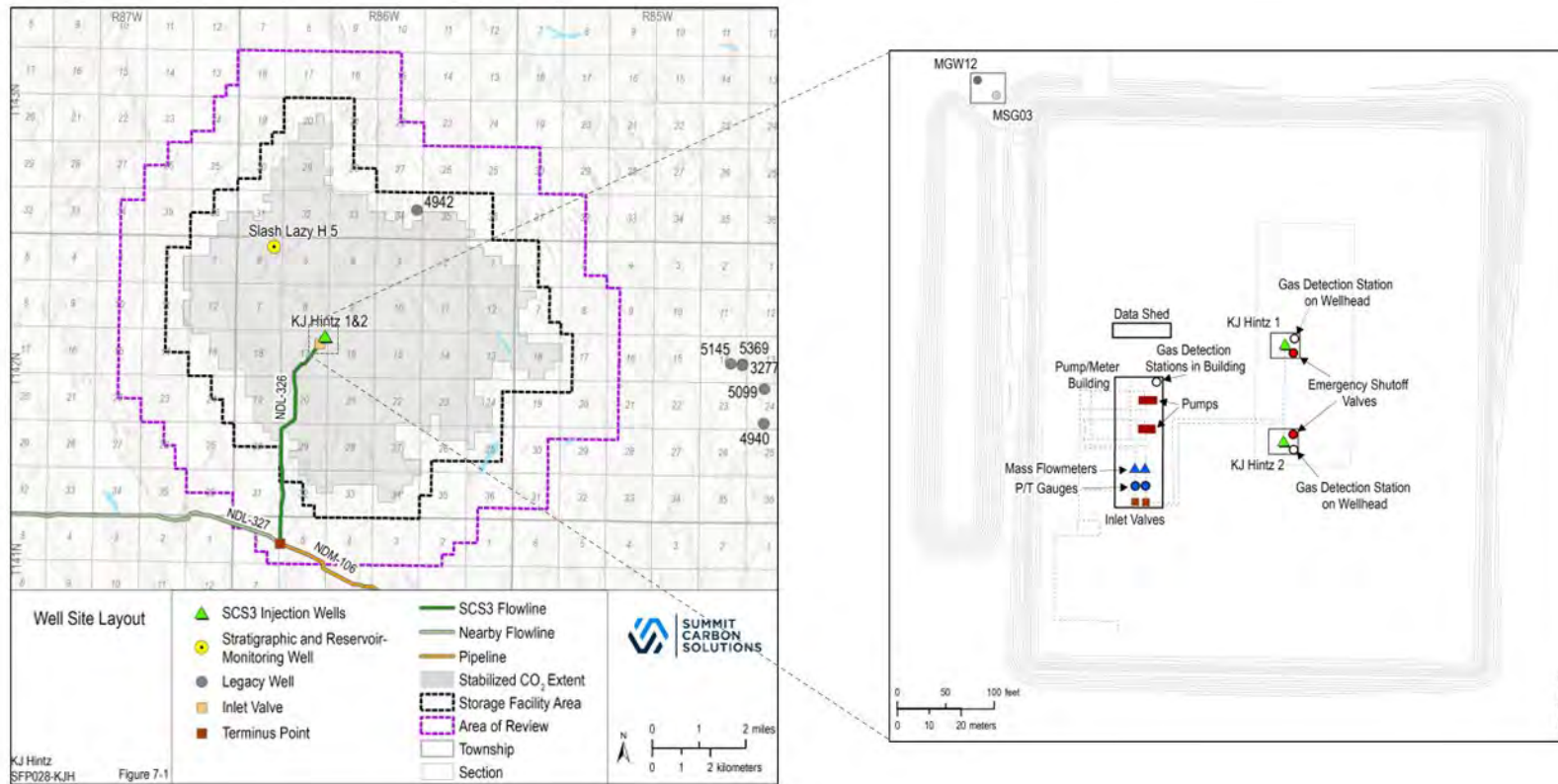


Figure 7-1. Site map detailing the on-pad CO₂ flowline(s) and the CO₂ injection wellsite. Also shown are the flowline(s) and pipeline associated with the Midwest Carbon Express (MCE) project. Inset map illustrates a layout of surface facilities with key leak detection and monitoring equipment identified.

Table 7-2. Well Names and Location Information for the Injection Wells and Reservoir-Monitoring Well of the Geologic Storage Operations

Well Name	Purpose	NDIC ¹		Section	Township	Range	Latitude ²	Longitude ²
		File No.	Quarter/Quarter					
KJ Hintz 1	CO ₂ injection	40127	NE/NE	17	142	86	47.124661	-101.597686
KJ Hintz 2	CO ₂ injection	40128	NE/NE	17	142	86	47.124386	-101.597689
Slash Lazy H 5	Reservoir monitoring	38701	Lot 1	6	142	86	47.151633	-101.620606

¹ North Dakota Industrial Commission.

² North American Datum 83 (NAD 83) geographic coordinate system.

The primary SCS3 contacts for the geologic storage project and their contact information are listed in Table 7-3.

Table 7-3. Primary SCS3 Contacts

Individual	Title	Contact Information Office Phone Number
Wade Boeshans	Executive Vice President	515.531.2608
Jay Volk	Sequestration – Director of Health, Safety & Environmental	515.207.3563
Jeff Skaare	Director of Land & Legal Affairs	515.531.2615

Contact names and information for key local emergency organizations/agencies are provided in Figures 7-2 through 7-5 and Table 7-4.

7.2 Local Resources and Infrastructure

Land use near KJ Hintz comprises primarily agricultural activities. Local resources in the vicinity of the geologic storage project that may be impacted as a result of an emergency event include existing groundwater wells, a legacy well (Figure 4-3), and 11 gravel pits (Figure 4-2).

The infrastructure in the area of review (AOR) that may be impacted as a result of an emergency event include 1) KJ Hintz 1 and 2 (CO₂ injection wells), SCS3 flowline NDL-326, and Slash Lazy H 5 (stratigraphic and reservoir-monitoring well); 2) surface features and occupied structures (Figure 4-2); and 3) public roads (Figures 7-3 through 7-5). Additional infrastructure nearby includes TB Leingang (SCS1), comprising two CO₂ injection wells, respective NDL-327 flowline, and Milton Flemmer 1 (stratigraphic and reservoir-monitoring well); BK Fischer (SCS2), comprising two CO₂ injection wells and respective NDL-325 flowline; and Archie Erickson 2 (stratigraphic and reservoir-monitoring well) and the MCE pipeline (Figures 7-3 through 7-5).

7.3 Identification of Potential Emergency Events

7.3.1 Definition of an Emergency Event

An emergency event is an event that poses an immediate, or acute, risk to human health, resources, or infrastructure and requires a rapid, immediate response. This ERRP focuses on emergency events that have the potential to move injection fluid or formation fluid in a manner that may endanger USDWs or lead to an accidental release of CO₂ to the atmosphere during the construction, operation, or postinjection site care project phases.

KJ HINTZ/SLASH LAZY H 5

Storage Facility Area	Location	County	EMS District	Fire District	Law Enforcement	LEPC Jurisdiction
TB Leingang	Monitoring Site Milton Flemmer 1	Mercer	Glen Ullin EMS	Glen Ullin Fire Department	Mercer County Sheriff's Department	Mercer County LEPC
	Injection Site TB Leingang 1 and 2	Oliver	Beulah EMS Mercer County Ambulance	Beulah Rural Fire Dept.	Oliver County Sheriff's Department	Oliver County LEPC
	TB Leingang SFA	Mercer/Oliver/Morton	New Salem Ambulance Service	New Salem Fire Department	Morton County Sheriff's Department	Mercer County LEPC
			Glen Ullin EMS	Glen Ullin Fire Department	Mercer County Sheriff's Department	Morton County LEPC
BK Fisher	Monitoring Site Archie Erickson 2	Mercer	Beulah EMS Mercer County Ambulance	Beulah Rural Fire Dept.	Mercer County Sheriff's Department	Mercer County LEPC
	Injection Site BK Fisher 1 and 2					
	BK Fisher SFA	Mercer/Oliver			Oliver County Sheriff's Department	Oliver County LEPC
KJ Hintz	Monitoring Site Slash Lazy H 5	Oliver	Hazen EMS Mercer County Ambulance	Hazen Fire & Rescue	Oliver County Sheriff's Department	Oliver County LEPC
	Injection Site KJ Hintz 1 and 2			New Salem Fire Dept.		
	KJ Hintz SFA		Beulah EMS Mercer County Ambulance	Oliver Fire Dept.		
			Oliver EMS	Beulah Rural Fire Dept.		

Figure 7-2. Off-site emergency notification list. Emergency management service (EMS) districts, fire districts, law enforcement agencies, and Local Emergency Planning Committee (LEPC) jurisdictions with response jurisdictions intersecting with the KJ Hintz storage facility area (SFA) will be provided a copy of this ERRP.

KJ HINTZ/SLASH LAZY H 5

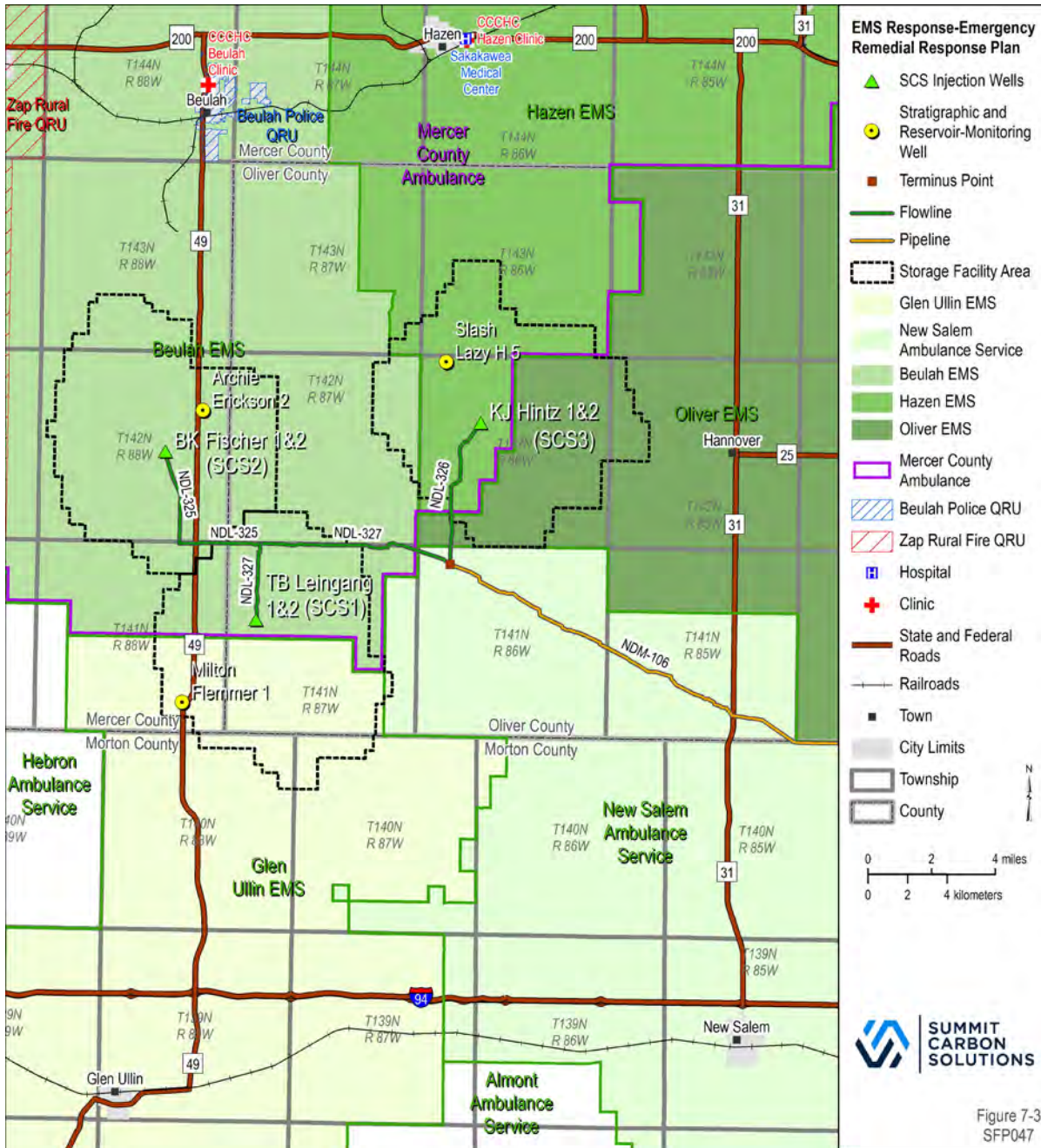


Figure 7-3. Map showing emergency management service (EMS) response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

KJ HINTZ/SLASH LAZY H 5

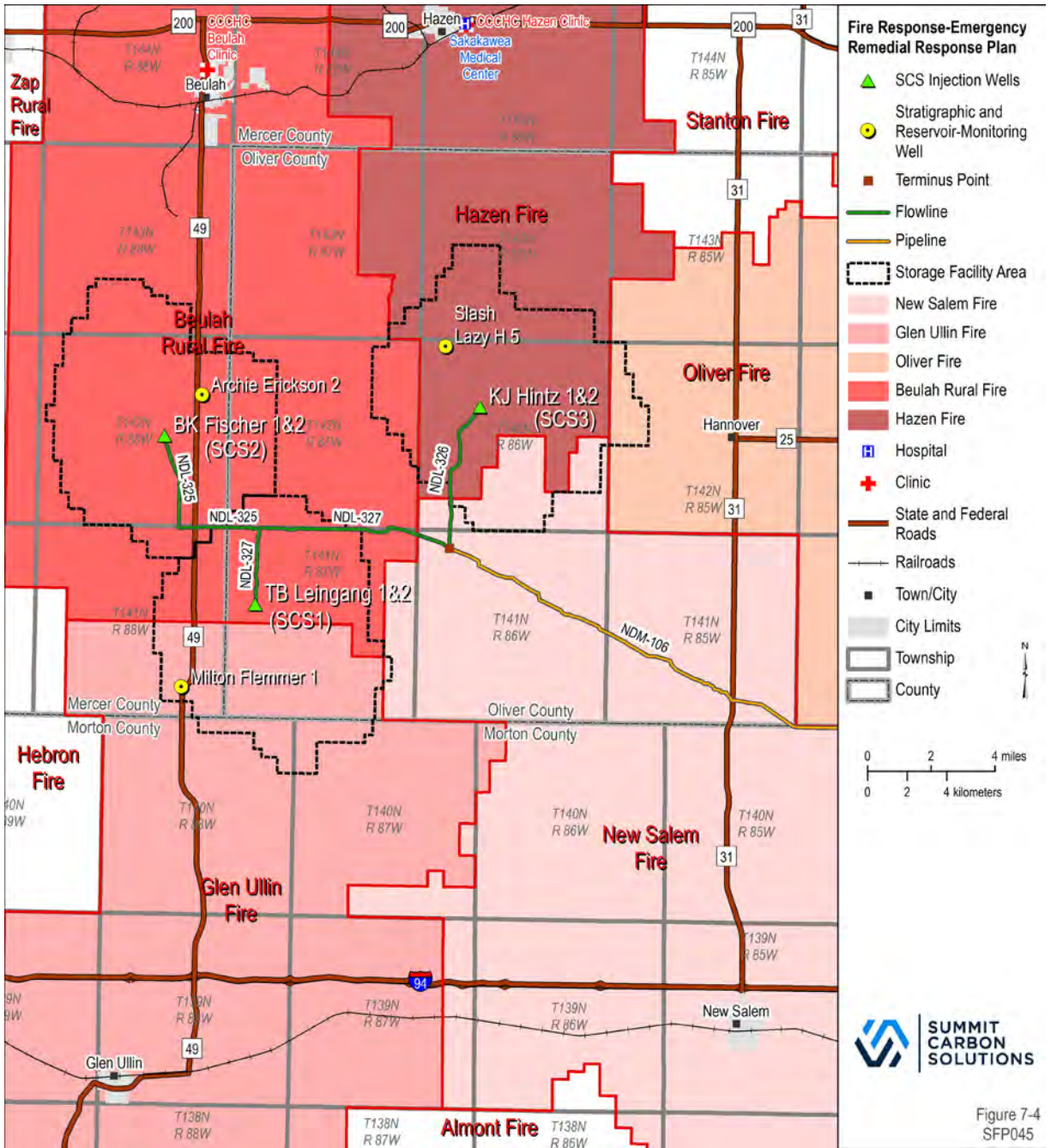


Figure 7-4. Map showing fire response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

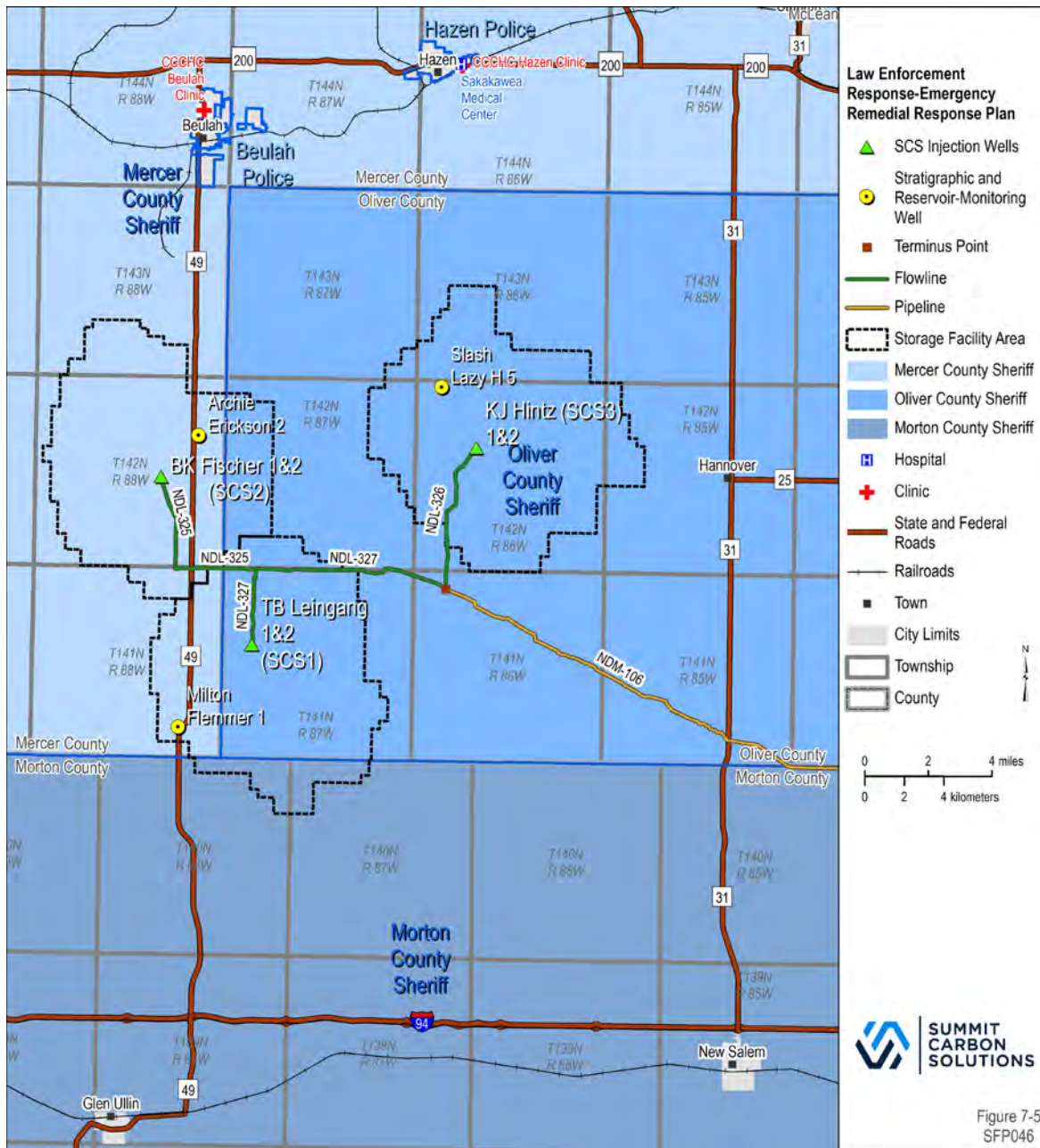


Figure 7-5. Map showing law enforcement response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads.

Table 7-4. Off-Site Emergency Notification/PSAP Phone List

Agency	Phone	Alternate Contact/ Notes
Almont Ambulance Service	701.943.2355	
Beulah Police Department	701.873.5252	Quick Response Unit (QRU)
Beulah Rural Fire Department	701.873.2121	
Coal Country Community Health Center – Beulah Clinic	701.873.4445	
Coal Country Community Health Center – Hazen Clinic	701.748.2256	
Coal Country Community Health Center – Center Clinic	701.794.8798	
Emergency Manager – Mercer County	701.745.3333	
Emergency Manager – Morton County	701.667.3307	
Emergency Manager – Oliver County	701.745.3302	
Glen Ullin Ambulance	701.348.3507	
Glen Ullin Fire Department	701.348.3113	
Hazen Police Department	701.748.2414	
Hazen Fire & Rescue	701.745.3332	
Hebron Ambulance Service District	701.878.4600	
Hebron Fire Department	701.878.4353	State Radio Dispatch at 701.328.9921 / 800.472.2121
Mercer County Ambulance – Beulah EMS	701.748.7241	
Mercer County Ambulance – Hazen EMS	701.748.5558	
Mercer County Sheriff’s Department	701.745.3333	
Morton County Sheriff’s Department	701.667.3330	
ND Department of Emergency Services	1.833.997.7458	
ND Highway Department	701.327.9921	
ND Highway Patrol	State Radio Dispatch 701.328.9921/ 800.472.2121	Office: 701.328.2447
ND Poison Control	1.800.222.1222	
New Salem Ambulance Services	701.843.7828	
New Salem Fire Department	701.843.7111	
Oliver County Ambulance Service	701.794.3555	
Oliver Fire Department	701.794.3450	
Oliver County Sheriff Department	701.794.3450	Mercer County Dispatch 701.745.3333
Sanford AirMed	844.424.7633	Sanford AirMed Dispatch Sioux Falls, SD 1.800.437.6886
Sanford Emergency and Trauma Center – Bismarck	701.323.6150	
Sakakawea Medical Center – Hazen	701.748.2225	Emergency Services
Stanton Fire Department	701.748.2591	
Zap Rural Fire Department	Mercer County Dispatch 701.745.3333	QRU
Western Plains Public Health	701.667.3370/ 1.888.667.3370	Formerly Custer Health District

7.3.2 Potential Project Emergency Events and Their Detection

The SLRA for the project developed a list of potential technical project risks (i.e., a risk register) which were placed into the following six technical risk categories:

1. Injection operations
2. Storage capacity
3. Containment – lateral migration of CO₂
4. Containment – pressure propagation
5. Containment – vertical migration of CO₂ or formation water brine via injection wells, other wells, or inadequate confining zones
6. Natural disasters (induced seismicity)

Based on a review of these technical risk categories, SCS3 developed, to include in this ERRP, a list of the geologic storage project events that could potentially result in the movement of injection fluid or formation fluid in a manner that may endanger a USDW and, in turn, require an emergency response. These events and means for their detection are provided in Table 7-5.

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 also addressed in this ERRP.

7.4 Emergency Response Actions

7.4.1 General Emergency Response Actions

The response actions that will be taken to address the events listed in Table 7-5, 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), as found in Section 7.5, will be immediately notified and will make an initial assessment of the severity of the event (i.e., does it represent an emergency event?). The QI must make this assessment as soon as is practicable but must do so within 24 hours of the notification. This protocol will ensure SCS3 has taken all reasonable and necessary steps to identify and characterize any release pursuant to North Dakota Administrative Code (N.D.A.C.) § 43-05-01-13(2)(b).
- If an emergency event exists, the QI or designee shall notify, within 24 hours of the emergency event determination, the Department of Mineral Resources Oil and Gas Division (DMR-O&G) Director (see Sections 7.5 and 7.6 and Table 7-6). N.D.A.C. § 43-05-01-13(2)(c). The QI shall also implement the emergency communications plan (N.D.A.C. § 43-05-01-13[2][d]).

Table 7-5. Potential Project Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Events
Failure of CO ₂ Flowline NDL-326	<ul style="list-style-type: none"> • Computational flowline continuous monitoring and leak detection system (LDS). <ul style="list-style-type: none"> – Instrumentation at the flowline for each injection well on the well pad collects pressure, temperature, and flow data. – Pressure, temperature, and flow measurements will be measured at the MCE terminus point. – The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. – By monitoring deviations between the real-time model and the predictive model, the software detects flowline leaks. • Frozen ground at leak site may be observed. • CO₂ monitors located inside and outside of the process buildings detect a release of CO₂ from the flowline, connection, and/or wellhead.
Integrity Failure of Injection or Monitoring Well	<ul style="list-style-type: none"> • Pressure monitoring reveals wellhead pressure exceeds the shutdown pressure specified in the permit. • Annulus pressure indicates a loss of external or internal well containment. • Mechanical integrity test results identify a loss of mechanical integrity. • CO₂ monitors located inside and outside of the enclosed wellhead building detect a release of CO₂ from the wellhead.
Monitoring Equipment Failure of Injection Well	<ul style="list-style-type: none"> • Failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure is detected.
Storage Reservoir Unable to Contain the Formation Fluid or Stored CO ₂	<ul style="list-style-type: none"> • Elevated concentrations of indicator parameter(s) in soil gas, groundwater, and/or surface water sample(s) are detected.

Following these actions, the company will:

- Initiate a project shutdown plan and immediately cease CO₂ injection. However, in some circumstances, the company may determine whether gradual or temporary cessation of injection is more appropriate in consultation with the DMR-O&G Director.
- Shut in the CO₂ injection well (close the flow valve).
- Vent CO₂ from the surface facilities.
- Limit access to the wellhead to authorized personnel only, who will be equipped with appropriate personal protection equipment (PPE).
- If warranted, initiate the evacuation of the injection facilities, and communicate with local emergency authorities to initiate evacuation plans of nearby residents (Figure 7-2 and Table 7-4).
- Perform the necessary actions to determine the cause of the event; identify and implement the appropriate emergency response actions in consultation with the DMR-O&G Director. Table 7-6 provides 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 7-5.

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions

Failure of CO ₂ Flowline NDL-326	<ul style="list-style-type: none"> • The CO₂ release and its location will be detected by the LDS and/or CO₂ wellhead monitors, which will trigger a Pipeline Control* alarm, alerting system operators to take necessary action. • If warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program, situated near the location of the failure, to monitor the presence of CO₂ and its natural dispersion following the shutdown of the flowline. • Inspect the flowline failure to determine the root cause. • 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	<ul style="list-style-type: none"> • 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 downhole equipment or wellhead (in consultation with the DMR-O&G 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 DMR-O&G Director).
Monitoring Equipment Failure of Injection Well	<ul style="list-style-type: none"> • 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 DMR-O&G Director).

* Pipeline Control refers to the controller monitoring MCE, SCS1, SCS2, and SCS3 flowline operations (see Section 7.5.8).

Continued . . .

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

<p>Storage Reservoir Unable to Contain the Formation Fluid or Stored CO₂</p>	<ul style="list-style-type: none"> • Collect a confirmation sample(s) of groundwater from the Fox Hills monitoring well(s) and soil gas profile station(s), and analyze the samples for indicator parameters (Section 5.0). • If the presence of indicator parameters is confirmed, develop (in consultation with the DMR-O&G Director) a case-specific work plan to: <ol style="list-style-type: none"> 1. Install additional monitoring points near the impacted area to delineate the extent of impact: <ol style="list-style-type: none"> 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 CO₂ to the atmosphere is confirmed, and, if warranted, initiate an evacuation plan in tandem with an appropriate workspace and/or ambient air-monitoring program situated at the appropriate incident boundary to monitor the presence of CO₂ and its natural dispersion following the termination of CO₂ injection. c. If surface release of CO₂ to surface waters is confirmed, implement the appropriate surface water-monitoring program to determine if water quality standards are exceeded. 2. Proceed with efforts, if necessary, to: <ol style="list-style-type: none"> a. Remediate the USDW to achieve compliance with drinking water standards (e.g., install a system to intercept/extract brine or CO₂ or “pump and treat” the impacted drinking water to mitigate CO₂/brine impacts), and/or b. Manage surface waters using natural attenuation (i.e., natural processes, such as biological degradation, active in the environment that can reduce contaminant concentrations), or c. Activate treatment to achieve compliance with applicable water quality standards. • Continue all remediation and monitoring at an appropriate frequency (as determined by company management designee and the DMR-O&G Director) until unacceptable adverse impacts have been fully addressed.
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Continued . . .

Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response Actions (continued)

Natural Disasters (seismicity)	<ul style="list-style-type: none"> • Identify when the event occurred and the epicenter and magnitude of the event. • If the magnitude is greater than 2.7 (Section 5.0), then: <ol style="list-style-type: none"> 1. Determine whether there is a connection with injection activities. 2. Demonstrate all project wells have maintained mechanical integrity. 3. If a loss of CO₂ containment is determined, proceed as described above to evaluate and, if warranted, mitigate the loss of containment.
Natural Disasters	<ul style="list-style-type: none"> • Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure. • If warranted, perform additional monitoring of groundwater, surface water, and/or workspace/ambient air to delineate the 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 DMR-O&G Director).

7.4.2 Incident-Specific Response Actions

If notification is received of a high-risk incident, the following procedures will be followed:

1. Accidental/Uncontrolled Release of CO₂ from the Injection Facility or Associated Flowline(s)

- On-scene personnel shall confirm that Pipeline Control is aware of the incident. If appropriate, Pipeline Control will effectuate the shutdown of the pipeline and the closure of mainline valves to isolate the release and to minimize the amount of released CO₂.
- Consideration should be given to notifying and evacuating the public downwind of the release and closing roads. Coordinate with nearby fire departments and law enforcement to aid in any evacuation efforts.
- Pipeline Control will call the appropriate public safety answering point (PSAP) and nearby fire departments, law enforcement, and other appropriate agencies. Table 7-4 provides a listing of PSAPs. Personnel on-scene during an incident may call 911 directly.
- Pipeline Control dispatches the company response crew (CRC) to investigate the incident and notifies the QI.

- CRC arrives at the incident site and completes initial response actions. A designated CRC member will fill the initial incident commander (IC) position.
- The IC will conduct a risk assessment and coordinate with the QI to determine what National Incident Management System Incident Command System (ICS) positions need to be filled for the local response team (LRT).
- The QI or IC will establish liaison with the local emergency coordinating agencies, such as the 911 emergency call centers or county emergency managers in lieu of communicating individually with each fire, police, or other public entities.
- If the response exceeds local capabilities, the IC will coordinate with the QI to determine the need for mobilization of a company support team (CST).

2. Fire or Explosion Occurring near or Directly Involving the Injection Facility or Associated Flowline(s).

Note: CO₂ is not flammable, combustible, or explosive.

- Call for assistance from nearby fire departments and company personnel, as needed. Take all possible actions to keep fire from spreading.
- Shut down the pipeline for an explosion involving the injection facility.
- The IC will conduct a preliminary assessment of the situation upon arrival at the scene, evaluate the scene for potential hazards, and determine what product is involved.
- Assemble the LRT at the command post.
- Coordinate response efforts with on-scene fire department.

3. Operational Failure Causing a Hazardous Condition.

- On-scene personnel will confirm that Pipeline Control is aware of the incident which will, if appropriate, effectuate the shutdown of the pipeline, injection well(s), and closure of mainline valves to isolate the release and minimize a hazardous condition.
- Consideration should be given to evacuating the public downwind of the release and closing roads. Coordinate with nearby fire departments and law enforcement to aid in any evacuation efforts.
- Pipeline Control will call the appropriate PSAP and nearby fire departments, law enforcement, and other appropriate agencies (Figure 7-2 and Table 7-4). Personnel on-scene during an incident may call 911 directly.

- Pipeline Control dispatches LRT to investigate the incident and notifies the QI.
- CRC arrives at the incident site and completes initial response actions. A designated CRC member will fill the initial IC position.
- The IC will conduct a risk assessment and coordinate with the QI to determine what ICS positions need to be filled for the LRT.
- The QI or IC will establish liaison with the local emergency coordinating agencies, such as the 911 emergency call centers or county emergency managers in lieu of communicating individually with each fire, police, or other public entity.
- If the response exceeds local capabilities, the IC will coordinate with the QI to determine the need for mobilization of a CST.

7.5 Response Personnel/Equipment and Training

7.5.1 Response Personnel and Equipment

Designated company personnel will undergo hazardous waste operations and emergency response training (HAZWOPER) 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 emergency services to implement this ERRP as shown in Figures 7-2 through 7-5.

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 is required (such as a drilling rig, logging equipment, or potable water hauling, etc.), one of the primary contacts listed in Table 7-3 is responsible for procurement of this equipment. One of the primary contacts listed in Table 7-3 is also responsible to maintain a list of contractors and equipment vendors (Section 7.6).

The company will provide personnel, training, equipment, instruments, tools, and material as needed to respond to an emergency incident.

- All local company personnel are available for callout as needed for duty on a 24-hour basis to support public safety agencies.
- Additional personnel, if required, will be acquired from agency responders from public safety agencies and/or response contractors.
- If public authorities are involved, they will be given full cooperation and assistance. In no event shall such cooperation and assistance violate safety rules or consist of actions that would endanger the public or employees.

- Company employees, contractors, and agency responders will be equipped with tools, supplies, and equipment available to be used in cases of emergency conditions existing on or near the injection facility and associated flowline(s). CO₂/O₂ monitoring devices should be used in the event of an accidental/uncontrolled release of CO₂. Self-contained breathing apparatus may be required pending results from on-site-specific hazards and monitoring results.

7.5.2 Staff Training and Exercise Procedures

The company will integrate the training of the emergency response personnel of the geologic storage project into the standard operating procedures and facility operations training programs. Periodic training will be provided, at least annually, to protect all necessary facility- and project-personnel. The training efforts will be documented in accordance with the requirements of company 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. The company will also work with local emergency response personnel to perform coordinated training exercises associated with potential emergency events such as a significant release of CO₂ to the atmosphere.

7.5.3 Emergency Response Procedures

This section describes organization features and duties of the company's QI, LRT, and CST. The company's initial response to an incident will be provided by the LRT, once activated by the QI. The IC will activate a CST if an incident exceeds the local capabilities. In some cases, the initial responders to an incident may include local law enforcement, ambulance, and/or local fire department(s). The company will work with these agencies to manage a coordinated response effort.

The ICS will be used to manage emergency response activities. Because ICS is a management tool that is readily adaptable to incidents of varying magnitude, it will be used for all emergency incidents. Staffing levels will be adjusted to meet specific response team needs based on incident size, severity, and type of emergency. Local agencies are also trained to use ICS and may fill roles during a coordinated response effort. ICS principles include the following:

- Common terminology
- Manageable span of control
- Management by objectives
- Incident action planning
- Comprehensive resource management
- Established incident facilities
- Integrated communications

As a component of an ICS, the unified command (UC) is a structure that brings together the company and agencies at the command level. The UC links the organizations responding to the incident and provides a forum for the responsible party and responding agencies to make consensus decisions. Under the UC, the various responding agencies and company personnel may blend together throughout the organization to create an integrated response team. The ICS process requires the UC to set clear objectives to guide the on-scene response resources. The primary entities of a UC may be two or more of the following:

- Federal on-scene coordinator
- State on-scene coordinator
- Local on-scene coordinator
- Company IC (responsible party IC)

7.5.4 *Qualified Individual (QI)*

The QI is defined by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) as a company employee who has been given authority to fund response efforts without consulting company leadership for further authorization and knows how to commence the response procedures of this plan. The QI is responsible for activating the ICS response organization, including the LRT and CST.

The QI will be an English-speaking company employee who is available on a 24-hour basis with the full authority to activate and deploy the necessary emergency-response contractors. The QI or alternate QI will activate personnel and equipment, act as a liaison with the UC, and obligate any funds required to carry out all the required or direct emergency-response activities.

7.5.4.1 *Communicating to Appropriate Operator Personnel*

If notification of an event relating to a potential emergency requires immediate response, the emergency notification flowchart in Figure 7-6 provides guidance regarding notification of appropriate operator personnel, contractors, and emergency and public officials.

7.5.5 *Local Response Team (LRT)*

The first company person on scene will function as the IC and person-in-charge until relieved by an authorized person who will then assume the position of IC. The number of positions/personnel required to staff the LRT will depend on the size and complexity of the incident. The duties of each position may be performed by the IC directly or delegated as the situation demands. The IC is always responsible for directing response activities and will assume the duties of all the primary positions until the duties can be delegated to other qualified personnel.

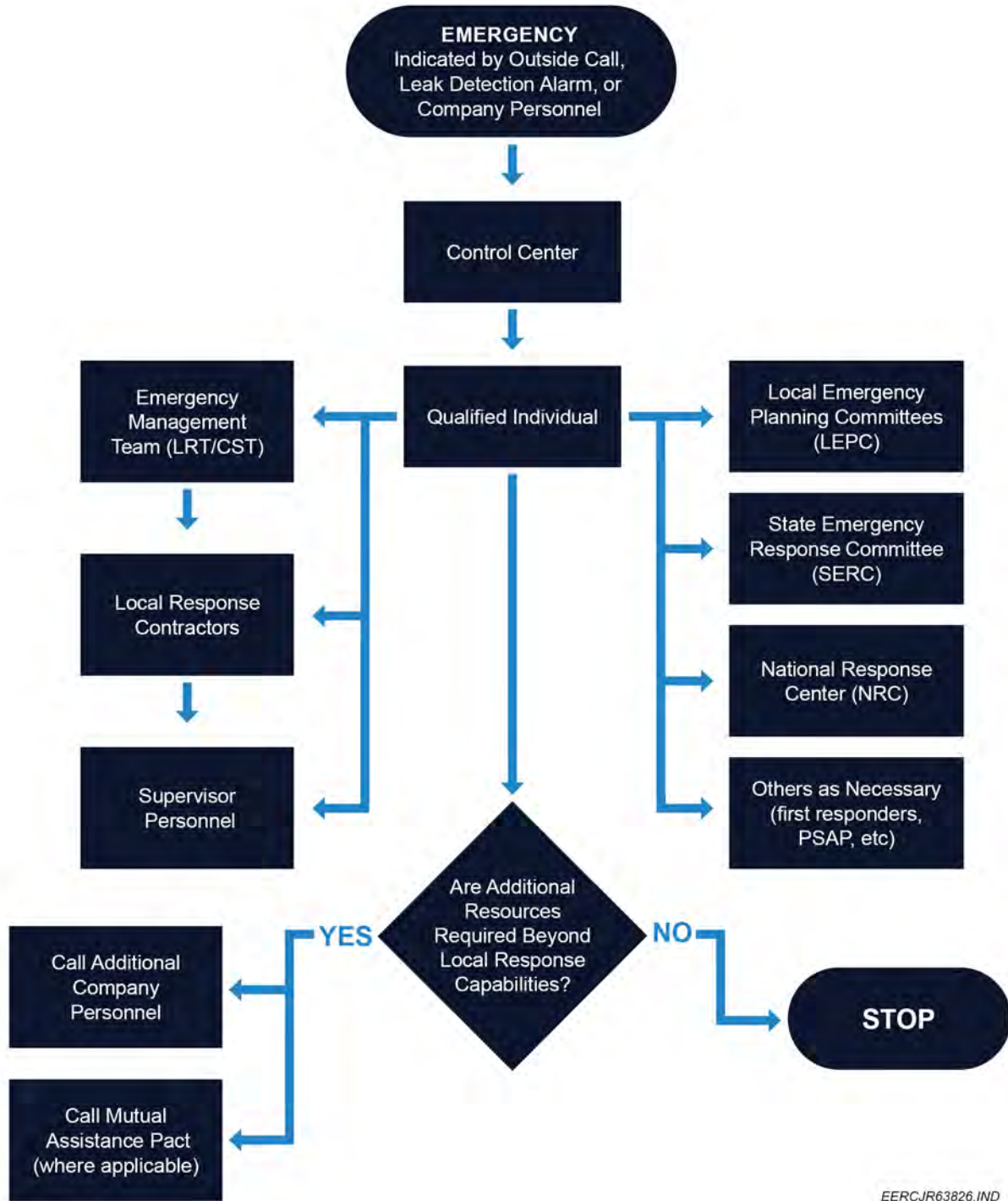
The LRT will fill the necessary positions and request additional support from the CST (defined below) to fill/back up any additional positions necessitated by the incident. Detailed job descriptions of the response team positions are provided within this plan.

7.5.6 *Company Support Team (CST)*

The QI and IC may decide to mobilize a CST if there are any response operations outside the LRT's capabilities. The members of the LRT will typically become members of the CST.

The CST, once fully staffed, is designed to cover all aspects of a comprehensive and prolonged incident response. The number of positions/personnel required to staff the CST will depend on the size and complexity of the incident. During a prolonged response, additional personnel may be cascaded in to fill additional ICS positions or relieve responding personnel.

The CST is staffed by trained personnel from various company locations and by various contract resources as the situation requires.



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Figure 7-6. Emergency notification flowchart.

7.5.7 Preplanning Emergency Response Activities with Public Safety Answering Point, Fire, Police, and Other Public Officials

To enhance cooperation during an incident response, the company will liaise with agency responders and public officials, including participating in emergency tabletop exercises, coordinating meetings to discuss hazards and emergency response, and conducting facility tours or open houses. These and other public outreach activities will be included in the Public Awareness Program that will be developed and implemented prior to commencing operation of the pipeline.

7.5.8 Required Controller Actions

Pipeline Control actions during emergency response actions will be detailed in the control room management plan that will be developed and implemented prior to commencing pipeline operations. Generally, the actions will include:

- Identifying abnormal operating conditions – including potential pipeline ruptures.
- Confirmation of abnormal conditions.
- Specific steps to take in response to certain abnormal conditions, including closing valves, notifications internal to the company, and notifications external to agency responders.
- Specific steps to take following pipeline shutdown to reestablish pipeline operations.

7.6 Emergency Communications Plan

In the event of an emergency, the facility response plan contains an ICS which specifies the organization of a facility response team, team member roles, and team member responsibilities. The company organizational structure is still in development. The company will provide updated specific identification and contact information for each member of the facility response team. In the event of an emergency, as outlined in N.D.A.C. § 43-05-01-13(2), DMR-O&G will be notified within 24 hours (Table 7-7).

Table 7-7. DMR-O&G UIC Program Management Contact

Company	Service	Location	Phone
DMR-O&G	Class VI/CCUS	Bismarck, ND	701.328.8020

The QI or QI designee is responsible for establishing and maintaining communications with appropriate off-site persons and/or agencies as provided in Figure 7-2 and Table 7-4. Table 7-8 lists available contractors and service providers.

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 (Figure 7-2 and Table 7-4) are provided a copy of the facility response plan, the QI or QI 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 company to focus time and resources on response measures.

Table 7-8. Potential Contractor and Services Providers

Company	Service	Location	Phone
4th Dimension Surveying & Consulting	Land surveying and drone mapping	Williston, ND	701.580.5267
Baranko Brothers, Inc.	Excavation, dirt work/hauling	Dickinson, ND	701.690.7279
Barr Engineering	Engineering services	Bismarck, ND	701.255.5460
Basin Concrete, Inc.	Trucking and rentals	Williston, ND	701.774.3085
Dakota Outlaw Services	Fencing	Glen Ullin, ND	701.870.5303
Dryland Enterprises LLC	Waste hauler	Belfield, ND	701.559.3232
Environmental Solutions	Cuttings disposal	Belfield, ND	701.300.1156
Farmers Union Oil (Cenex)	Propane, seed, soil fertility testing	Beulah, ND	701.873.4363
Flowserve	Injection pump manufacturer	Irving, TX	972.443.6500
Industrial Contractors Inc.	Mechanical	Bismarck, ND	701.258.9908
J&S Sanitation	Sanitation	Beulah, ND	701.873.5577
Lake View Services LLC	Crane services and dirt work/hauling	Beulah, ND	701.873.2719
Meadowland Services	Spraying	Zap, ND	701.880.0996
Minnesota Valley Testing Laboratories, Inc.	Formation fluids collection and analysis	Bismarck, ND	701.204.5478
Neuberger Oil	Fuel	Beulah, ND	701.873.2188
Pale Horse Services, Inc	Cuttings hauling and rentals	Dickinson, ND	701.690.6408
Roughrider Disposal LLC	Cuttings disposal	Fairfield, ND	701.638.8053
Roughrider Electric	Power provider	Hazen, ND	701.748.2293
Siemens	Variable-frequency drive and motor manufacturer	Alpharetta, GA	800.333.7421
Unruh Trucking	Fresh water hauling	Zap, ND	701.891.2875
Waste Management	Trash	Bismarck, ND	701.214.9741
Western Steel Builders	Metal building contractor	Hazen, ND	701.748.6305
Wild Well Control	Well control emergency responders	Greeley, CO	281.784.4700
YES LLC	Electrical	Dickinson, ND	701.483.8330

7.7 ERRP Review and Updates

This ERRP shall be reviewed:

- At least annually following its approval by DMR-O&G.
- Within 1 year of an AOR reevaluation.
- Within a prescribed period (to be determined by DMR-O&G) following any significant changes to the project (e.g., injection process, the injection rate).
- As required by DMR-O&G.

If the review indicates that no amendments to the ERRP are necessary, the company will provide the documentation supporting the “no amendment necessary” determination to the DMR-O&G Director.

If the review indicates that amendments to the ERRP are necessary, SCS3 will make and submit amendments to the DMR-O&G as soon as reasonably practicable. In no event, however, shall it do so more than 1 year following the commencement of a review.

SECTION 8.0

WORKER SAFETY PLAN

8.0 WORKER SAFETY PLAN

Summit Carbon Storage #3, LLC (SCS3) requires all employees and contractors to follow the SCS3 Worker Safety Plan (WSP) for KJ Hintz. SCS3 maintains and implements a safety program that meets all state and federal requirements for worker safety protections, including the Occupational Safety and Health Administration (OSHA) and the National Fire Protection Association (NFPA). The safety program is described in this WSP. SCS3 will periodically review the WSP, and if substantive changes are warranted, the revised WSP will be provided to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G). Controlled copies of the WSP are available at SCS3's nearest operational office and at the geologic storage facility (North Dakota Administrative Code [N.D.A.C.] § 43-05-01-13).

The WSP outlines steps to protect the health and safety of employees, contractors, and visitors while working near and around CO₂. Specific topics included in the WSP are, but are not limited to, the following:

- A list of safety training programs, including annual CO₂ safety training, annual safe-working procedures training, and annual Emergency and Remedial Response Plan (ERRP) training, as well as the review frequency for the safety training programs and, if necessary, updates. A record of training completions, including the trainee's name, date and type of training, and the signatures (or other acceptable acknowledgment/documentation) of the trainee and trainer are maintained and available upon request.
- A site-specific list of potential hazards of working near and around CO₂.
- Processes for determining causes of incidents and implementing appropriate emergency response actions.
- Requirements for employees to perform duties in ways that prevent the discharge of CO₂.
- Personal protective equipment (PPE) policies for employees while performing their duties, including guidelines for selecting, using, and maintaining PPE.
- New-hire, contractor, and visitor protocols to ensure all on-site individuals are appropriately trained and are aware of the potential hazards of CO₂.
- Drug, alcohol, and controlled substances policy complying with all governmental laws and regulations in the workplace and consequences for those who violate the policy.
- Reporting guidelines for all injuries; equipment or property damages; leaks, spills, or releases; or other health, safety, and environmental (HSE)-related incidents.

Only SCS3 employees and contractor personnel who have been properly trained can participate in the on-site activities of drilling, construction, operations, and equipment repair.

SECTION 9.0

WELL CASING AND CEMENTING PROGRAM

9.0 WELL CASING AND CEMENTING PROGRAM

Summit Carbon Storage #3, LLC (SCS3) plans to construct two CO₂ injection wells, KJ Hintz 1 (API No. 33-065-00024, North Dakota Industrial Commission [NDIC] File No. 40127) and KJ Hintz 2 (API No. 33-065-00025, NDIC File No. 40128) and convert the Slash Lazy H 5 stratigraphic test well (API No. 33-065-00021, NDIC File No. 38701) into a reservoir-monitoring well. The following information represents the current proposed state for KJ Hintz 1 (Figures 9-1 and 9-2, Tables 9-1 through 9-4) and KJ Hintz 2 (Figures 9-3 and 9-4, Tables 9-5 through 9-8), the current, as-completed state for Slash Lazy H 5 (Figure 9-5, Tables 9-9 through 9-12), and a radial cement bond log (RCBL) evaluation summary for Slash Lazy H 5 (Figure 9-6).

9.1 KJ Hintz 1: Proposed Injection Well Casing and Cementing Programs

The proposed state of KJ Hintz 1 is provided in Figure 9-1. KJ Hintz 1 is a deviated well. The well surface location, well trajectory, and bottomhole target location are provided in Figure 9-2. This fieldwork information may change based on field conditions and operational challenges. The information below is the best knowledge available at the time of drafting this permit application.

Table 9-1 provides well information for KJ Hintz 1. Tables 9-2 through 9-4 provide the casing and cement programs for KJ Hintz 1 and have been updated according to the proposed drilling estimate for 2025. The tables demonstrate compliance with North Dakota Administrative Code (N.D.A.C.) § 43-05-01. In addition, the materials used for construction satisfy the requirements of N.D.A.C. § 43-05-01-11 for a CO₂ injection well.

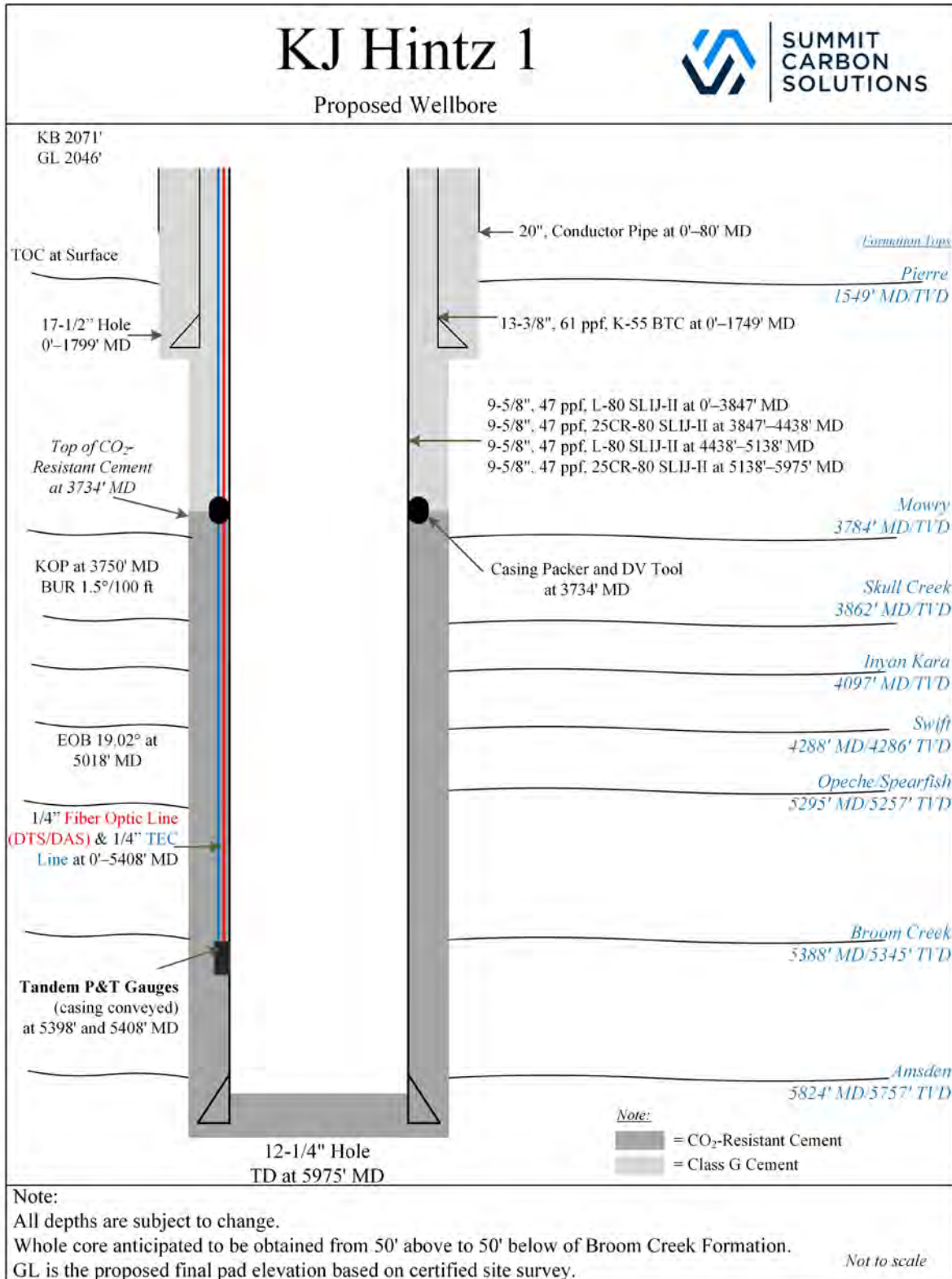


Figure 9-1. KJ Hintz 1 proposed wellbore schematic.

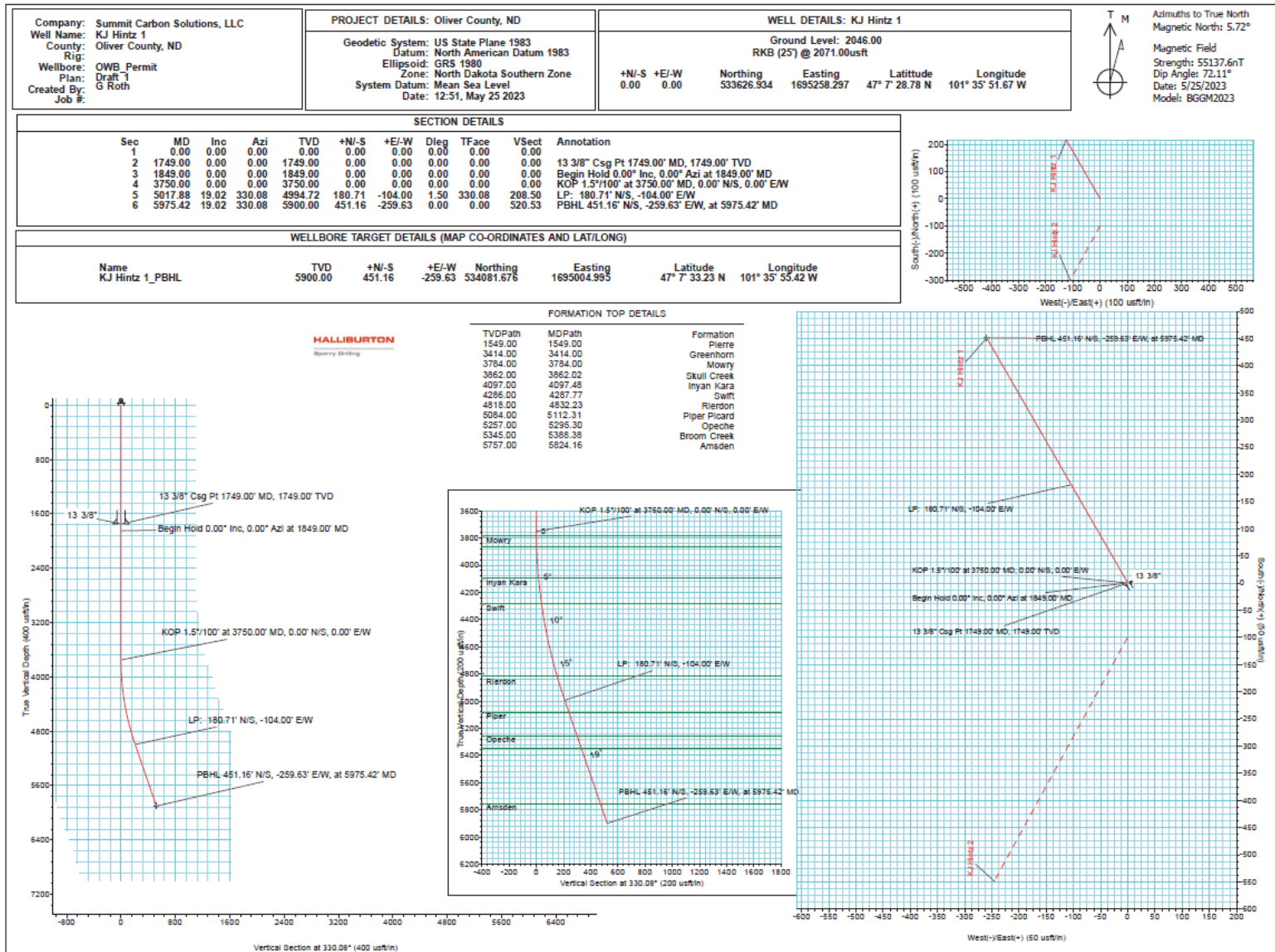


Figure 9-2. KJ Hintz 1 proposed wellbore trajectory.

Table 9-1. KJ Hintz 1: Proposed Well Information

Well Name:	KJ Hintz 1	NDIC File No.:	40127	API No.:	33-065-00024
County:	Oliver	State:	ND	Operator:	SUMMIT CARBON STORAGE #3, LLC
Location:	Sec. 17, T142N, R86W	Footages*:	426 ft FNL, 546 ft FEL	Total Depth:	5975 ft, MD

* From the north line (FNL), from the east line (FEL).

Table 9-2. KJ Hintz 1: Proposed Casing Program

Section	Hole Size, in.	Casing OD,* in.	Weight, lb/ft	Grade	Connection**	Top Depth,*** ft	Bottom Depth,*** ft	Objective
Surface	17.5	13.375	61	K-55	BTC	0	1749	Protects underground source of drinking water (USDW) Fox Hills Formation
Long-String	12.25	9.625	47	L-80	SLIJ-II	0	3847	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	3847	4438	CO ₂ -resistant across Inyan Kara Formation
	12.25	9.625	47	L-80	SLIJ-II	4438	5138	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	5138	5975	CO ₂ -resistant across Broom Creek Formation

* Outside diameter.

** BTC: buttress, SLIJ-II: VAM SLIJ-II: gastight premium connection.

*** Depths are in measured depth (MD) based on proposed wellbore trajectory and formation top prognosis.

Table 9-3. KJ Hintz 1: Proposed Casing Properties

Section	OD, in.	Grade	Weight, lb/ft	Connection	ID,* in.	Drift ID,* in.	Collapse, psi	Burst, psi	Yield Strength, klb	
									Body	Connection
Surface	13.375	K-55	61	BTC	12.515	12.359	1537	3088	963	1170
Long-String	9.625	L-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780
	9.625	25Cr-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780

* Inside diameter.

Table 9-4. KJ Hintz 1: Proposed Cement Program

Section	Casing OD, in.	Cement Class/Type	Lead/Tail/ Single	Stage	Slurry Weight, ppg	Slurry Yield, ft ³ /sack	Interval,* ft	Excess %	Volume, sacks
Surface	13.375	Class G	Single	NA	12.5	2.220	0–1749	100	1140
Long-String	9.625	Class G	Single	Stage 2	12.2	2.214	0–3734	100	845
	9.625	CO ₂ -resistant	Single	Stage 1	13	1.541	3734–5975	100	920

* The cement top will be confirmed once the RCBL is performed. Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

** Differential valve.

9.2 KJ Hintz 2: Proposed Injection Well Casing and Cementing Programs

The proposed state of KJ Hintz 2 is provided in Figure 9-3. KJ Hintz 2 is a deviated well. The well surface location, well trajectory, and bottomhole target location are provided in Figure 9-4. This fieldwork information may change based on field conditions and operational challenges. The information below is the best knowledge available at the time of drafting this permit application.

Table 9-5 provides well information for KJ Hintz 2. Tables 9-6 through 9-8 provide the casing and cementing programs for KJ Hintz 2 and have been updated according to the proposed drilling estimate for 2025. The tables demonstrate compliance with N.D.A.C. § 43-05-01. In addition, the materials used for construction satisfy the requirements of N.D.A.C. § 43-05-01-11 for a CO₂ injection well.

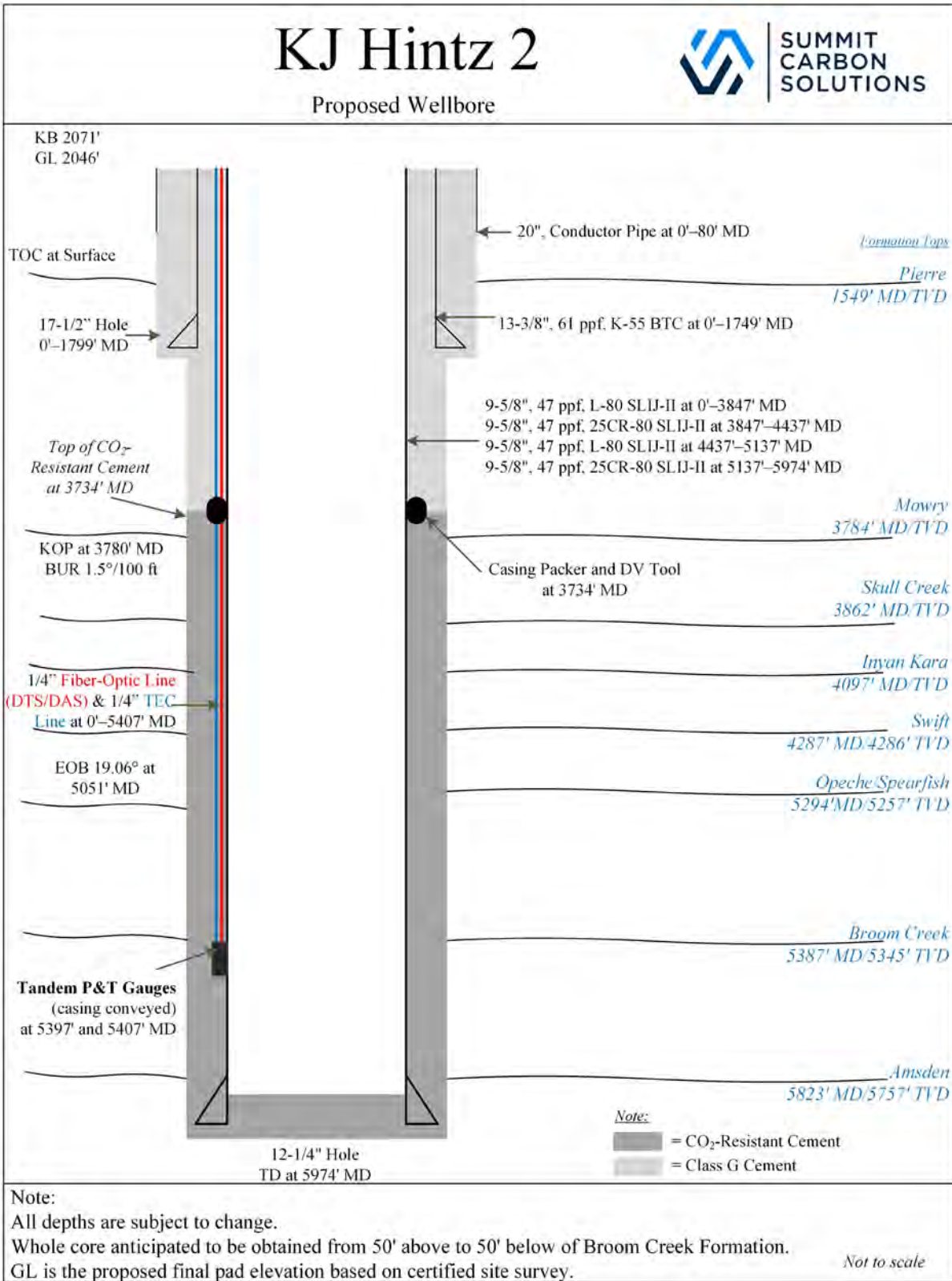


Figure 9-3. KJ Hintz 2 proposed wellbore schematic.

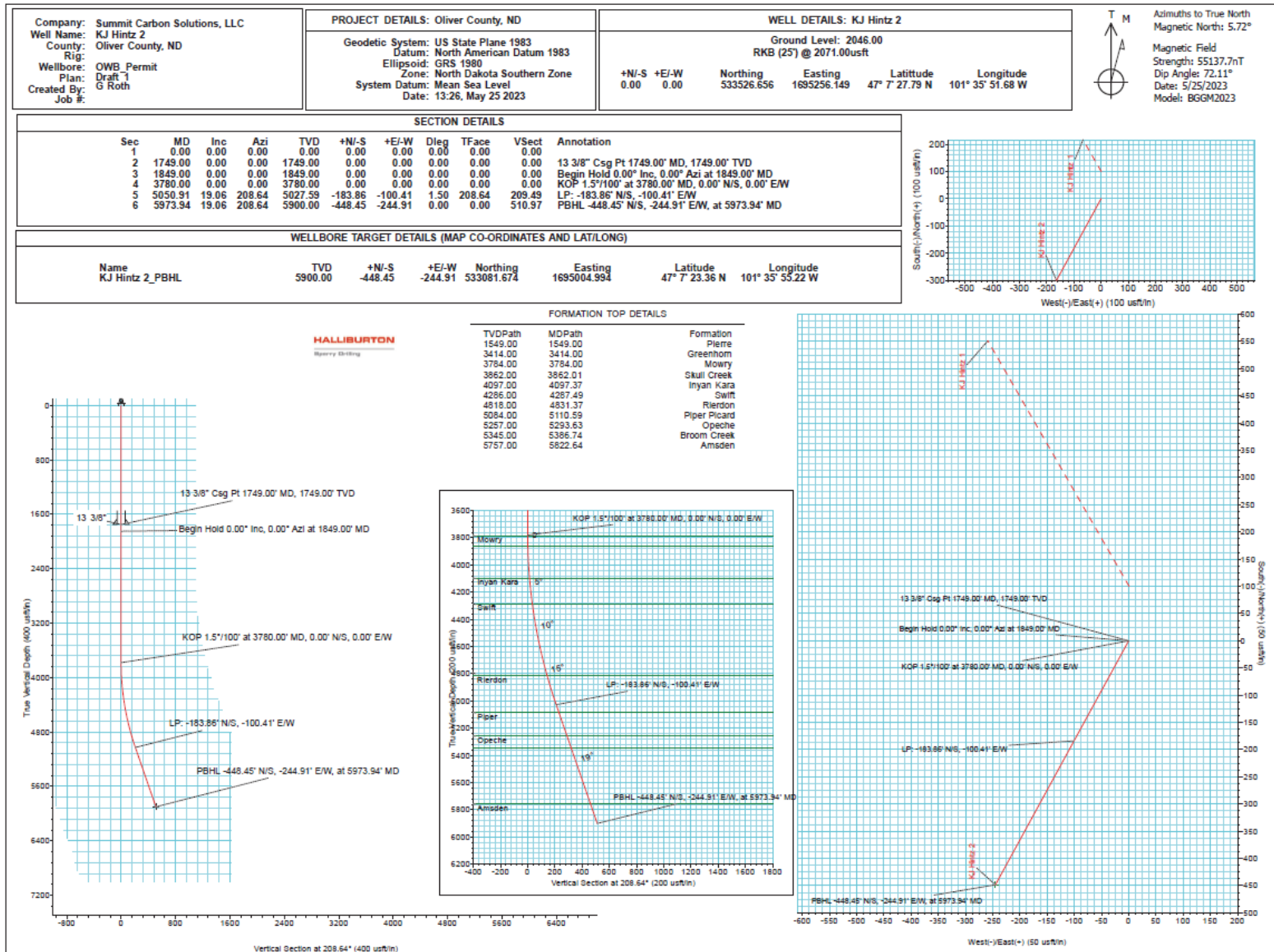


Figure 9-4. KJ Hintz 2 proposed wellbore trajectory.

Table 9-5. KJ Hintz 2: Proposed Well Information

Well Name:	KJ Hintz 2	NDIC File No.:	40128	API No.:	33-065-00025
County:	Oliver	State:	ND	Operator:	SUMMIT CARBON STORAGE #3, LLC
Location	Sec. 17, T142N, R86W	Footages:	526 ft FNL, 546 ft FEL	Total Depth:	5974 ft, MD

Table 9-6. KJ Hintz 2: Proposed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection	Top Depth,* ft	Bottom Depth,* ft	Objective
Surface	17.5	13.375	61	K-55	BTC	0	1749	Protects USDW Fox Hills Formation
Long-String	12.25	9.625	47	L-80	SLIJ-II	0	3847	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	3847	4437	CO ₂ -resistant across Inyan Kara Formation
	12.25	9.625	47	L-80	SLIJ-II	4437	5137	Long-string casing
	12.25	9.625	47	25Cr-80	SLIJ-II	5137	5974	CO ₂ -resistant across Broom Creek Formation

* Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

9-6

Table 9-7. KJ Hintz 2: Proposed Casing Properties

Section	OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Yield Strength, klb	
									Body	Connection
Surface	13.375	K-55	61	BTC	12.515	12.359	1537	3088	963	1170
Long-String	9.625	L-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780
	9.625	25Cr-80	47	SLIJ-II	8.681	8.525	4756	6858	1087	780

Table 9-8. KJ Hintz 2: Proposed Cement Program

Section	Casing OD, in.	Cement Class/Type	Lead/Tail/Single		Stage	Slurry Weight, ppg	Slurry Yield, ft ³ /sack	Interval,* ft	Excess %	Volume, sacks
			Single	NA						
Surface	13.375	Class G	Single	NA	12.5	2.220	0-1749	100	1140	
Long-String	9.625	Class G	Single		Stage 2	12.2	2.214	0-3734	100	845
	9.625	CO ₂ -resistant	Single		Stage 1	13	1.541	3734-5974	100	920

* The cement top will be confirmed once the RCBL is performed. Depths are in MD based on proposed wellbore trajectory and formation top prognosis.

9.3 Slash Lazy H 5: As-Completed CO₂ Monitoring Well Casing and Cementing Programs

The Slash Lazy H 5 well was permitted and drilled as a stratigraphic test well in February 2022 by the original operator, Summit Carbon Solutions, LLC (SCS). The Slash Lazy H 5 was constructed and operated in compliance with N.D.A.C. § 43-05-01 requirements, bonded in accordance with N.D.A.C. § 43-02-03-15, and temporarily abandoned, drilled to total depth (TATD) in accordance with N.D.A.C. § 43-02-03-55. As of December 2023, SCS has transferred ownership and operation of the Slash Lazy H 5 (API No. 33-065-00021, NDIC File No. 38701) to SCS3 in accordance with N.D.A.C. § 43-02-03-15. Future plans for the Slash Lazy H 5 include utilizing the well as a reservoir-monitoring well. The as-completed state of Slash Lazy H 5 is shown in Figure 9-5. The isolation scanner log, generally called an ultrasonic imaging tool (USIT), was deployed to determine the cement bond quality radially and provide a casing inspection log. The isolation scanner log result is provided in Figure 9-6.

Table 9-9 provides well information for Slash Lazy H 5. Tables 9-10 through 9-12 provide the casing and cementing programs for Slash Lazy H 5 and have been updated according to the drilling performed in February 2022.

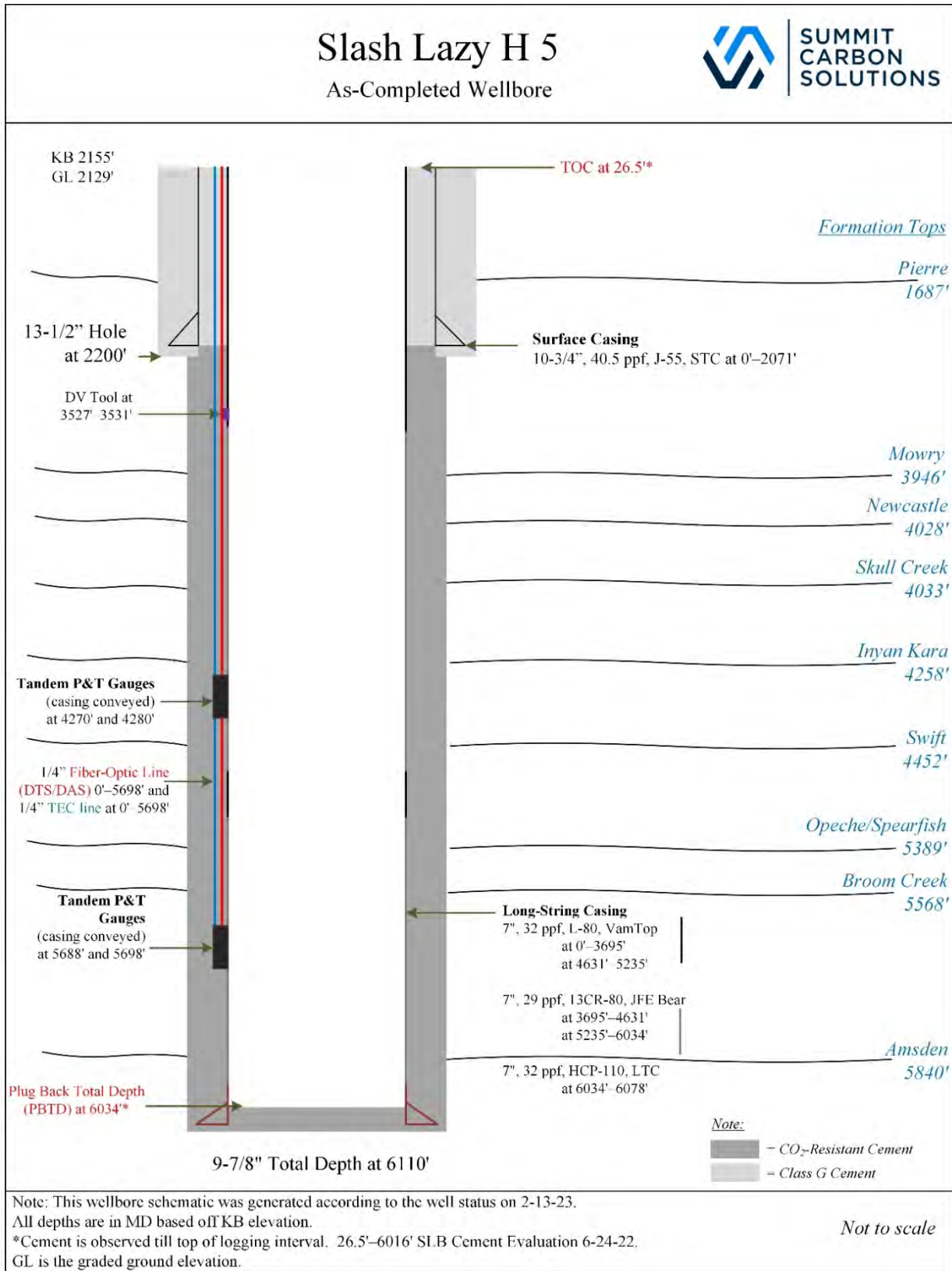


Figure 9-5. Slash Lazy H 5 as-completed wellbore schematic.

Table 9-9. Slash Lazy H 5: As-Completed Well Information

Well Name:	Slash Lazy H 5	NDIC File No.:	38701	API No.:	33-065-00021
County:	Oliver	State:	ND	Original Operator:	SUMMIT CARBON SOLUTIONS, LLC
				Current Operator:	SUMMIT CARBON STORAGE #3, LLC
Location:	Sec. 6, T142N, R86W	Footages:	1122 ft FNL, 932 ft FEL	Total Depth:	6110 ft, MD

Table 9-10. Slash Lazy H 5: As-Completed Casing Program

Section	Hole Size, in.	Casing OD, in.	Weight, lb/ft	Grade	Connection*	Top Depth,** ft	Bottom Depth,** ft	Objective
Surface	13.50	10.75	40.5	J-55	STC	0	2071	Protects USDW Fox Hills
Long-String	9.875	7.00	32	L-80	VAM TOP	0	3695	Long-string casing
	9.875	7.00	29	13Cr-80	JFE BEAR	3695	4631	CO ₂ -resistant across Inyan Kara Formation
	9.875	7.00	32	L-80	VAMTOP	4631	5235	Long-string casing
	9.875	7.00	29	13Cr-80	JFE BEAR	5235	6034	CO ₂ -resistant across Broom Creek Formation
	9.875	7.00	32	HCP-110	LTC	6034	6078	Long-string casing

* STC: short-thread and coupled; LTC: long-thread and coupled; VAM TOP and JFE BEAR: gastight premium connection.

** Depths are in MD.

Table 9-11. Slash Lazy H 5: As-Completed Casing Properties

Section	OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Yield Strength, klb	
									Body	Connection
Surface	10.75	J-55	40.5	STC	10.050	9.894	1580	3130	629	420
	7.00	L-80	32	VAM TOP	6.094	5.969	8610	9060	745	745
Long-String	7.00	13Cr-80	29	JFE BEAR	6.184	6.059	7030	8160	676	676
	7.00	HCP-110	32	LTC	6.094	5.969	10,760	12,460	1025	897

Table 9-12. Slash Lazy H 5: As-Completed Cement Program

Section	Casing OD, in.	Type	Lead/Tail/Single	Stage	Slurry Weight, ppg	Interval,* ft, MD	Volume, sacks
Surface	10.75	VariCem GS1	Single	NA	12.5	0–2071	775
Long-String	7.00	EconoCem	Lead	Stage 2	12.2	0–3527	265
	7.00	CorrosaCem	Tail	Stage 2	12.2		555
Stage 2 Through DV Tool at 3527–3531 ft, MD							
	7.00	CorrosaCem	Single	Stage 1	13.0	3527–6078	770

* The cement intervals are based on designed volumes in the cementing postjob report. According to Halliburton, it is not possible to distinguish where CorrosaCem ends and EconoCem begins, but the isolation scanner illustrates isolation in the CO₂ injection zone (Figure 9-6), confining zones and USDWs.

KJ HINTZ/SLASH LAZY H 5

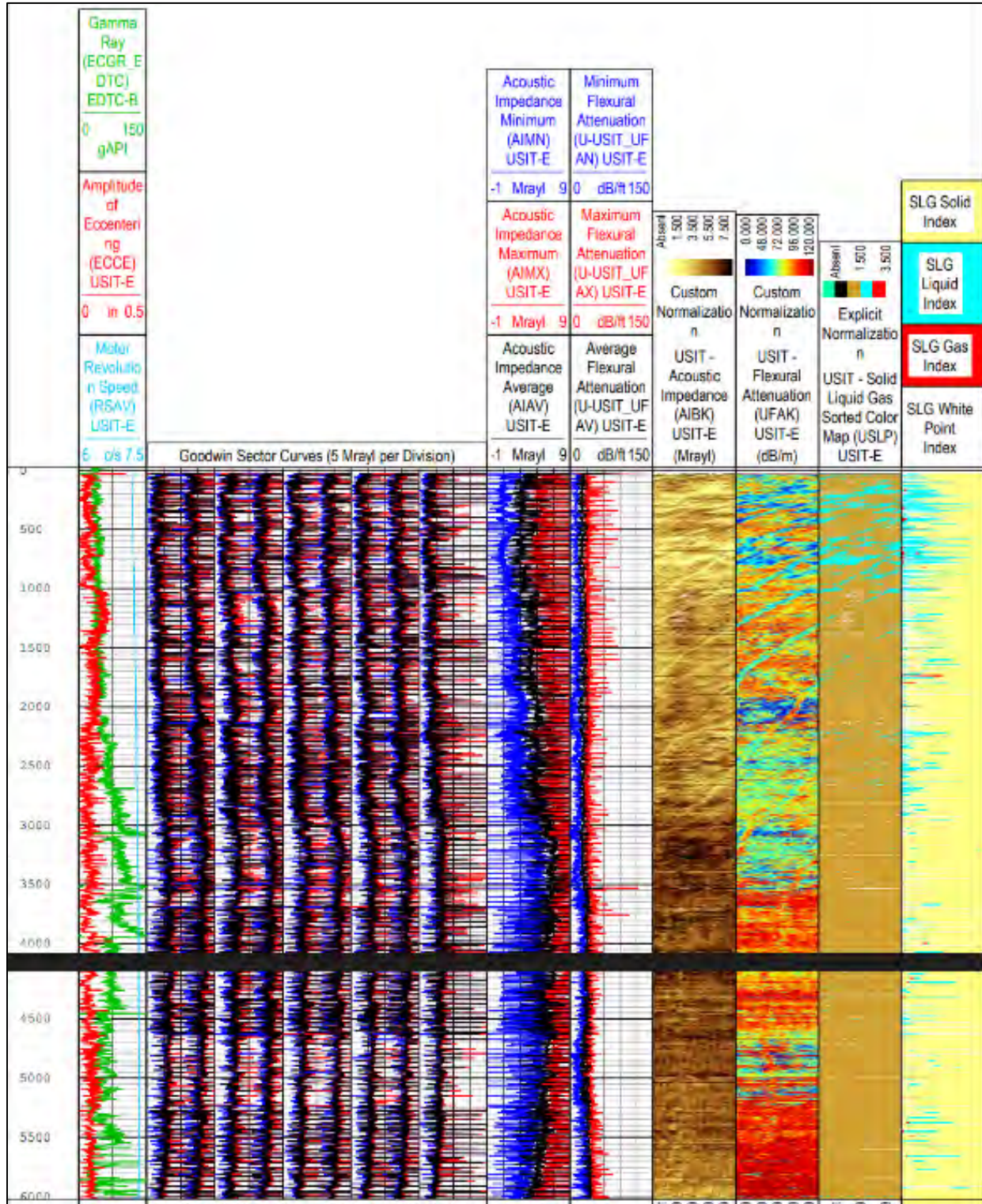


Figure 9-6. Slash Lazy H 5 cement evaluation—RCBL from Slash Lazy H 5 verifies the cement-bond quality. Using a high-resolution image, the analyst can assess isolation in the CO₂ injection zone, confining zones, and USDWs.

SECTION 10.0
PLUGGING PLAN

10.0 PLUGGING PLAN

The proposed plug and abandonment (P&A) procedures for the KJ Hintz 1 and KJ Hintz 2 wells are intended to be interpreted as proposed conditions and do not reflect the current as-proposed state for the wells. The proposed plugging procedure for the Slash Lazy H 5 does not reflect the current as-completed state but the anticipated completion state at the time of abandonment during site closure. Plugging operations will likely occur at different times in the life cycle of the injector wells, KJ Hintz 1 and KJ Hintz 2, and the reservoir-monitoring well, Slash Lazy H 5. The injection wells, KJ Hintz 1 and KJ Hintz 2, are planned for P&A once the CO₂ injection operation ceases. The reservoir-monitoring well, Slash Lazy H 5, is planned for P&A after verification and North Dakota Industrial Commission (NDIC) Department of Mineral Resources, Oil and Gas Division (DMR-O&G) approval that the CO₂ plume has stabilized.

A proposed P&A procedure will be provided to DMR-O&G. Final procedures and requirements will be determined and approved at the time of abandonment. A CO₂-resistant cement plug will be placed across the CO₂ storage reservoir in addition to cement across other zones, as deemed necessary for isolation of oil-bearing zones, nitrogen zones, etc. After approval, ample notification will be given to allow a DMR-O&G 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 CO₂-compatible materials and complete isolation of the injection zone as per North Dakota underground injection control (UIC) Class VI requirements.

10.1 KJ Hintz 1: Proposed Injection Well P&A Program

The KJ Hintz 1 CO₂ injection well proposed completion schematic is provided in Figure 10-1. The proposed schematic is based on current information. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.

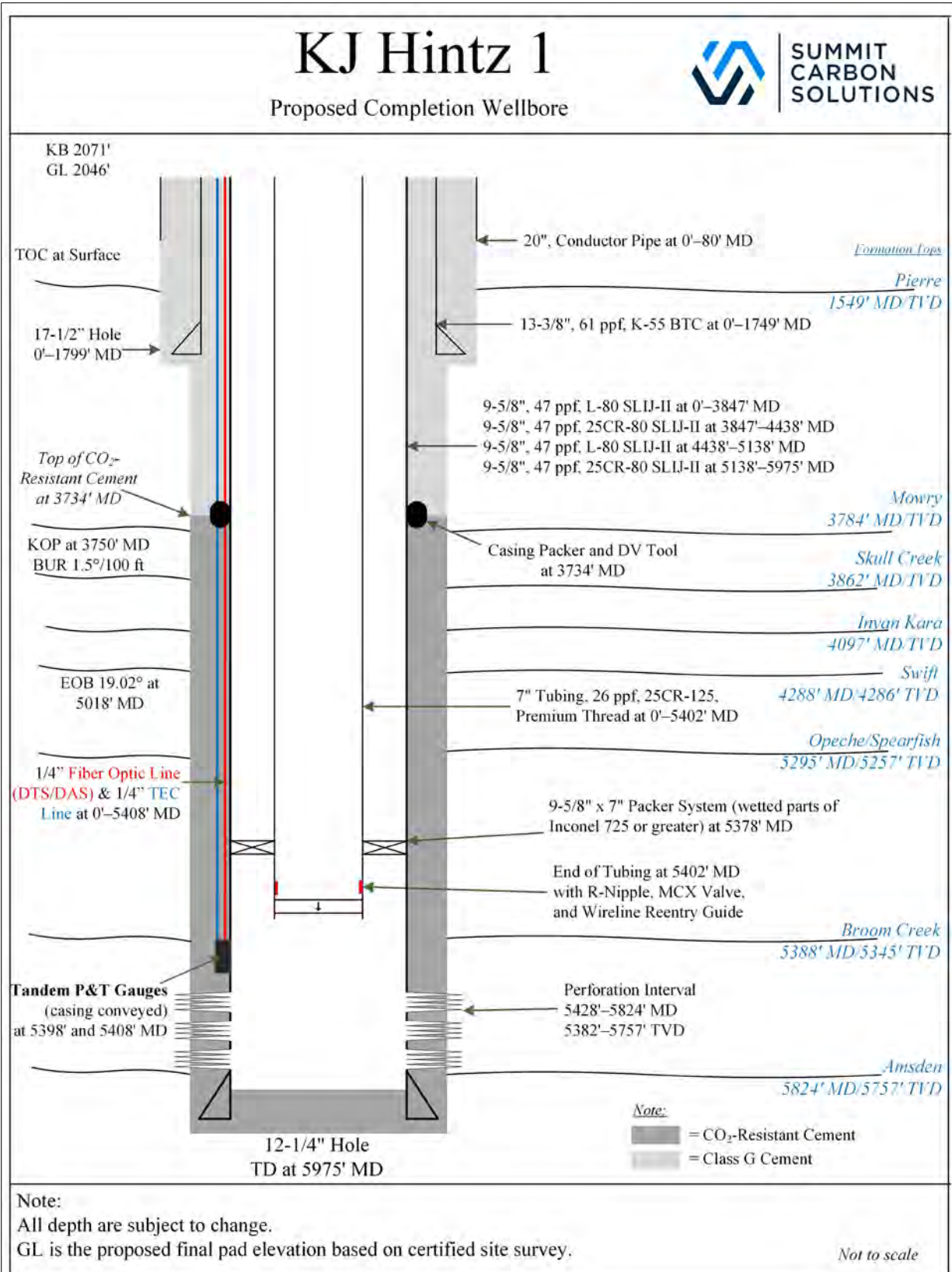


Figure 10-1. KJ Hintz 1 proposed completion wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for KJ Hintz 1 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.
2. After injection operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.
3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hours (hr) prior to moving onto location.
4. Dig out surface casing valve and bleed off. Confirm most recent date of pull test. Pull test deadman anchors, if required. May require installing new deadman anchors depending on results.
5. Move-in and rig up (MIRU) workover rig and surface equipment onto the KJ Hintz 1 well. All CO₂ flowlines and valves will be marked and noted by the rig supervisor prior to MIRU.
6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.
7. Nipple up (NU) lubricator, and install backpressure valve (BPV) in tubing hanger. Nipple down (ND) Christmas tree, NU blowout preventer (BOP). Recover BPV, and install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.
8. Recover test plug. Connect a 7-in. work joint to the tubing hanger, and POOH (pull out of hole) until tubing hanger is unseated.
9. Release tubing from packer following the packer manufacturer instructions. Trip out of hole (TOOH) with 7-in corrosion resistant alloy (CRA) tubing string, and lay down.

Contingency: If unable to release tubing from packer, rig up (RU) electric line, and make a cut on the tubing string just above the packer. Pull the tubing string out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan.

10. Pick up (PU) 2⁷/₈-in. work string, and stand in derrick. PU bit and scraper, and trip in hole (TIH) to top of packer. Perform reverse circulation, pump down casing annulus and up the work string to clean hole. TOO H with work string, bit, and scraper.
11. PU cast iron cement retainer (CICR) and stinger, and TIH to depth. Set CICR 20 ft above packer.
12. Spot cement equipment, and RU preparing to squeeze across Broom Creek Formation perforations and balance plugs.
13. Conduct and document a safety meeting prior to pumping cement. Ensure all materials are on location and accounted for. Confirm volumes, tests, procedures, operating equipment, and setting times with cement provider. Ensure **CO₂-resistant cement** is used for Broom Creek and Inyan Kara intervals. All other cement should be of Class G grade or equivalent.
14. Pressure-test lines prior to pumping. Sting in, and establish injection rate. Proceed with squeezing Broom Creek Formation perforations per cementer's planned procedures with 280 sacks (sx) of 15.2 pounds per gallon (ppg), 0.92ft³/sx **CO₂-resistant cement** and under displace 5 barrels of cement. Sting out of retainer, and finish displacing the last 5 barrels on top of the cement retainer. Check for flow. Pull work string above the plug.
15. Pressure-test casing to 1000 psi for 30 minutes or as approved by DMR-O&G. Record mechanical integrity test on casing. Circulate wellbore clean. TOO H with stinger and work string standing in derrick, and rig down (RD) stinger.

Contingency: If pressure test failed, a cast iron bridge plug (CIBP) will be set below each subsequent plug until casing test passes.

16. If needed, RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options, and RD logging truck:
 - Activated neutron log
 - Noise log
 - Production logging tool (PLT)
 - Tracers
 - Temperature log
 - DTS (distributed-temperature sensing) survey (no required logging unit)

Note: If external failure in long-string casing is identified, the operator will adjust the P&A plan with DMR-O&G's approval.

17. If pressure test failed, set a CIBP prior to pumping balanced plug. TIH with work string and diffuser to depth of Plug 2. Pump 270 sx of 15.2 ppg, 0.92 ft³/sx **CO₂-resistant cement** balanced plug as designed from cementer's proposed procedures across Inyan Kara interval.
18. Pull up work string above the top of the plug, and test casing. Circulate wellbore clean.

19. Set a CIBP prior to pumping Plug 3 if previous test failed. TOOH to depth of Plug 3. Pump 95 sx of 15.8 ppg, 1.15 ft³/sx Class G cement at 1849 ft. Pull up work string above the top of the plug, and circulate wellbore clean.
20. TOOH laying down work string to 90 ft. Pump 40 sx of 15.8 ppg, 1.15 ft³/sx Class G cement plug at 90 ft. Lay down all work string.

Contingency: Perform top job as necessary to ensure good cement on both sides.

21. RD all equipment, and move out.
22. Dig out wellhead and cut off casing 5-ft below ground level (GL). Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO₂ injection.
23. Dig out deadman anchors. Report photos of steel cap to DMR-O&G.
24. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).
25. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for KJ Hintz 1 is summarized in Table 10-1 and provided in Figure 10-2. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-1. Summary of P&A Plan for KJ Hintz 1

Cement Plug Number	Cement Type	Weight, ppg	Yield, ft³/sack	Interval, ft, MD	Thickness, ft	Volume, sacks	Notes
Plug 4	Class G	15.8	1.15	0–90	90	40	Surface plug
Plug 3	Class G	15.8	1.15	1599–1849	250	95	Isolate Fox Hills Formation at base of surface casing
Plug 2	CO ₂ -resistant	15.2	0.92	3897–4497	600	270	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 1	CO ₂ -resistant	15.2	0.92	5358–5975	617	280	Squeeze perforations and mechanically isolate Broom Creek Formation

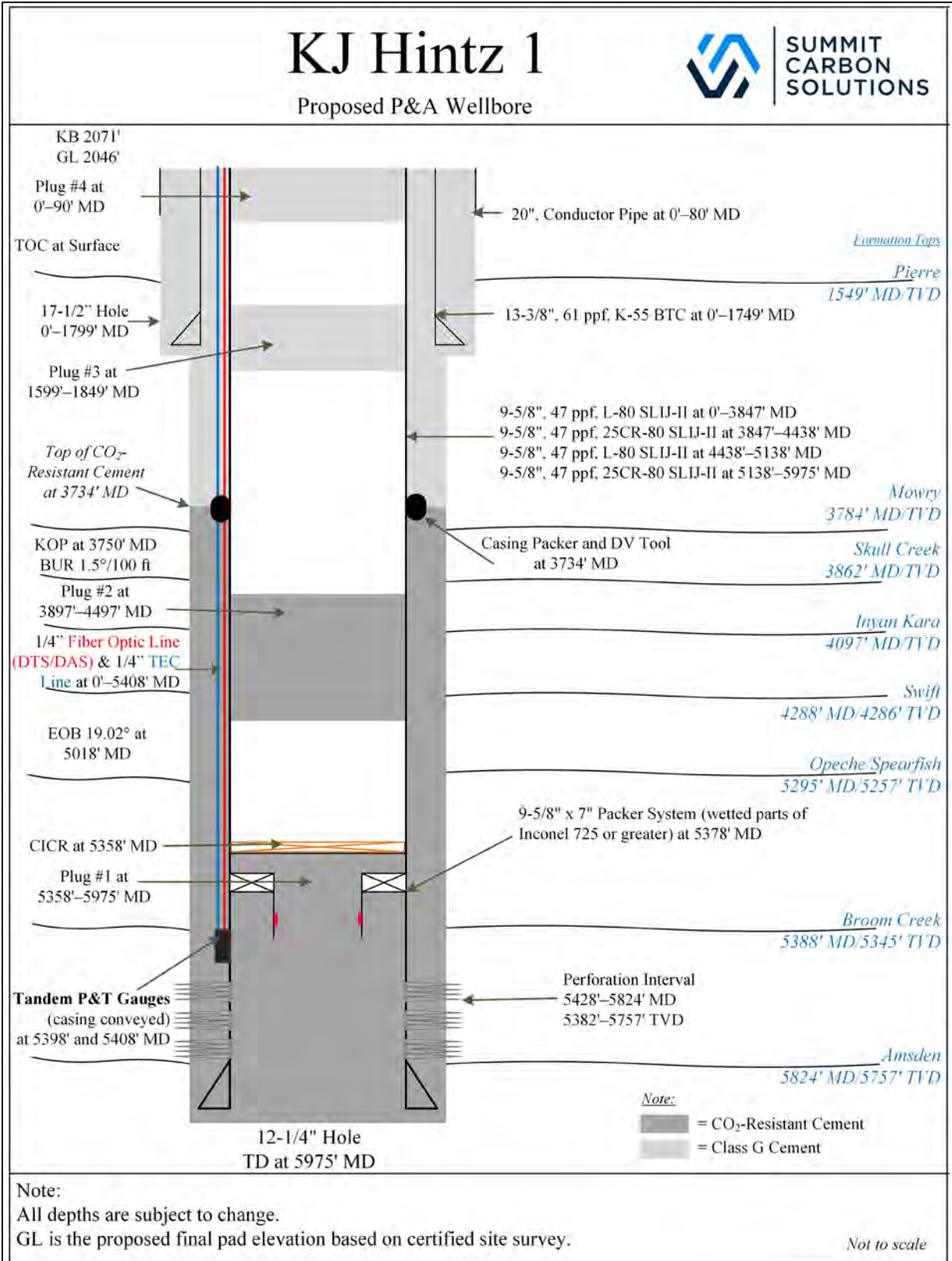


Figure 10-2. KJ Hintz 1 proposed P&A wellbore schematic.

10.2 KJ Hintz 2: Proposed Injection Well P&A Program

The KJ Hintz 2 CO₂ injection well proposed completion schematic is provided in Figure 10-3. The proposed schematic is based on current information. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.

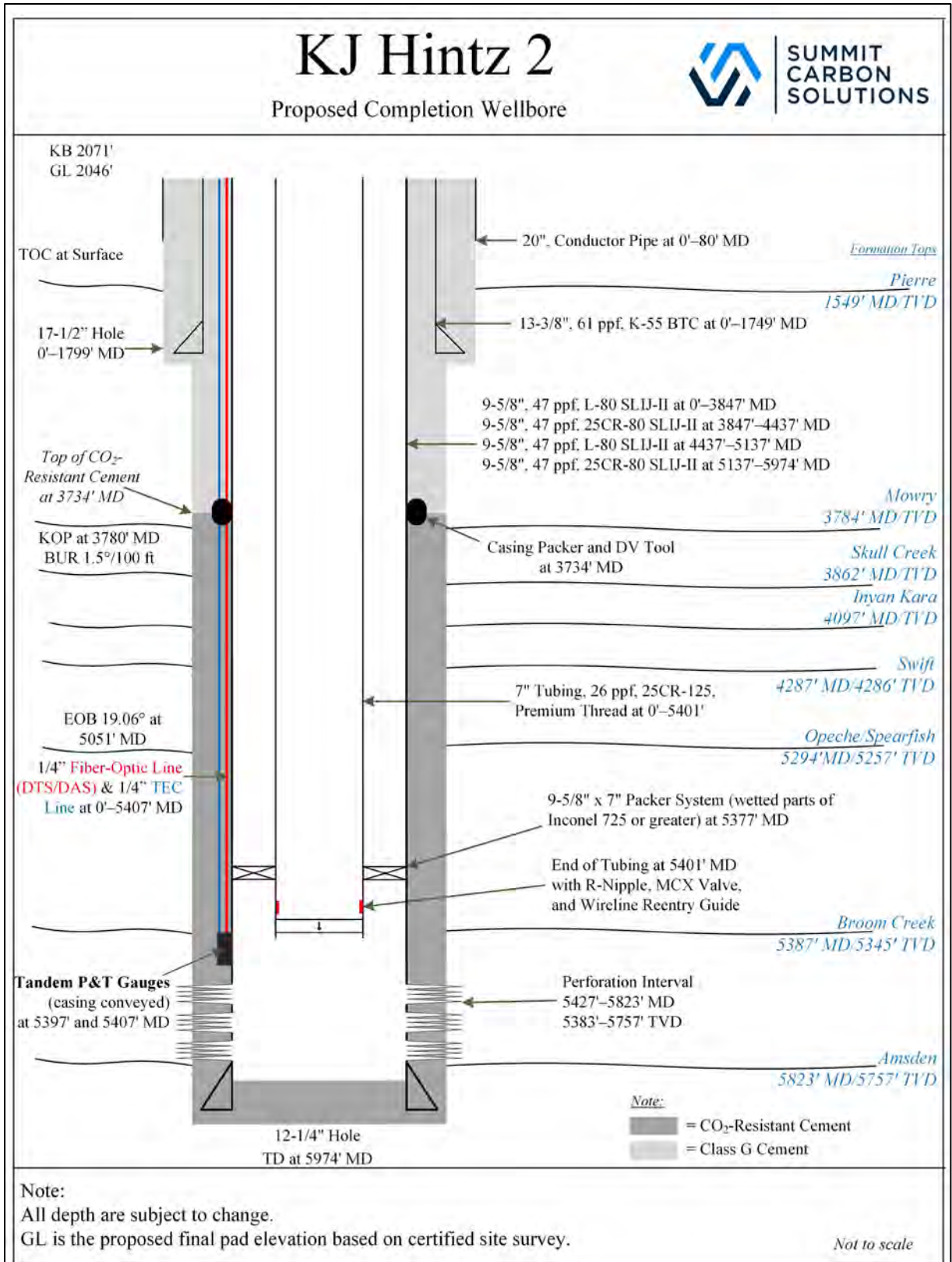


Figure 10-3. KJ Hintz 2 proposed completion wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for KJ Hintz 2 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.
2. After injection operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.
3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hr prior to moving onto location.
4. Dig out surface casing valve, and bleed off. Confirm most recent date of pull test. Pull test deadman anchors, if required. May require installing new deadman anchors depending on results.
5. MIRU workover rig and surface equipment onto the KJ Hintz 2 well. All CO₂ flowlines and valves will be marked and noted by the rig supervisor prior to MIRU.
6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.
7. NU lubricator, and install BPV in tubing hanger. ND Christmas tree, NU BOP. Recover BPV, and install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.
8. Recover test plug. Connect a 7-in. work joint to the tubing hanger, and POOH until tubing hanger is unseated.
9. Release tubing from packer following packer manufacturer instructions. TOO H with 7-in. CRA tubing string, and lay down.

Contingency: If unable to release tubing from packer, RU electric line, and make a cut on the tubing string just above the packer. Pull the tubing string out of hole, and proceed to the next step. If problems are noted, update the cement remediation plan.

10. PU 2⁷/₈-in. work string, and stand in derrick. PU bit and scraper, and TIH to top of packer. Perform reverse circulation, pump down casing annulus and up the work string to clean hole. TOO H with work string, bit, and scraper.

11. PU CICR and stinger, and TIH to depth. Set CICR 20 ft above packer.
12. Spot cement equipment, and RU preparing to squeeze across Broom Creek Formation perforations and balance plugs.
13. Conduct and document a safety meeting prior to pumping cement. Ensure all materials are on location and accounted for. Confirm volumes, tests, procedures, operating equipment, and setting times with cement provider. Ensure **CO₂-resistant cement** is used for Broom Creek and Inyan Kara intervals. All other cement plugs should be of Class G grade or equivalent.
14. Pressure-test lines prior to pumping. Sting in, and establish injection rate. Proceed with squeezing Broom Creek Formation perforations per cementer's planned procedures with 280 sx of 15.2 ppg, 0.92 ft³/sx **CO₂-resistant cement** and under displace 5 barrels of cement. Sting out of retainer, and finish displacing the last 5 barrels on top of the cement retainer. Check for flow. Pull work string above the plug.
15. Pressure-test casing to 1000 psi for 30 minutes or as approved by DMR-O&G. Record mechanical integrity test on casing. Circulate wellbore clean. TOOH with stinger and work string standing in derrick and RD stinger.

Contingency: If pressure test failed, a CIBP will be set below each subsequent plug until casing test passes.

16. If needed, RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options, and RD logging truck:
 - Activated neutron log
 - Noise log
 - PLT
 - Tracers
 - Temperature log
 - DTS survey (no required logging unit)

Note: If external failure in long-string casing is identified, the operator will adjust the P&A plan with DMR-O&G approval.

17. If pressure test failed, set a CIBP prior to pumping balanced plug. TIH with work string and diffuser to depth of Plug 2. Pump 270 sx of 15.2 ppg, 0.92 ft³/sx **CO₂-resistant cement** balanced plug as designed from cementer's proposed procedures across Inyan Kara interval.
18. Pull up work string above the top of the plug, and test casing. Circulate wellbore clean.
19. Set a CIBP prior to pumping Plug 3 if previous test failed. TOOH to depth of Plug 3. Pump 95 sx of 15.8 ppg, 1.15 ft³/sx Class G cement at 1849 ft. Pull up work string above the top of the plug, and circulate wellbore clean.

20. TOOH laying down work string to 90 ft. Pump 40 sx of 15.8 ppg, 1.15 ft³/sx Class G cement plug at 90 ft. Lay down all work string.

Contingency: Perform top job as necessary to ensure good cement on both sides.

21. RD all equipment, and move out.
22. Dig out wellhead, and cut off casing 5-ft below GL. Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO₂ injection.
23. Dig out deadman anchors. Report photos of steel cap to DMR-O&G.
24. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).
25. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for KJ Hintz 2 is summarized in Table 10-2 and provided in Figure 10-4. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-2. Summary of P&A Plan for KJ Hintz 2

Cement Plug Number	Cement Type	Weight, ppg	Yield, ft³/sx	Interval, ft, MD	Thickness, ft	Volume, sx	Notes
Plug 4	Class G	15.8	1.15	0–90	90	40	Surface plug
Plug 3	Class G	15.8	1.15	1599–1849	250	95	Isolate Fox Hills Formation at base of surface casing
Plug 2	CO ₂ -resistant	15.2	0.92	3897–4497	600	270	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 1	CO ₂ -resistant	15.2	0.92	5357–5974	617	280	Squeeze perforations and mechanically isolate Broom Creek Formation

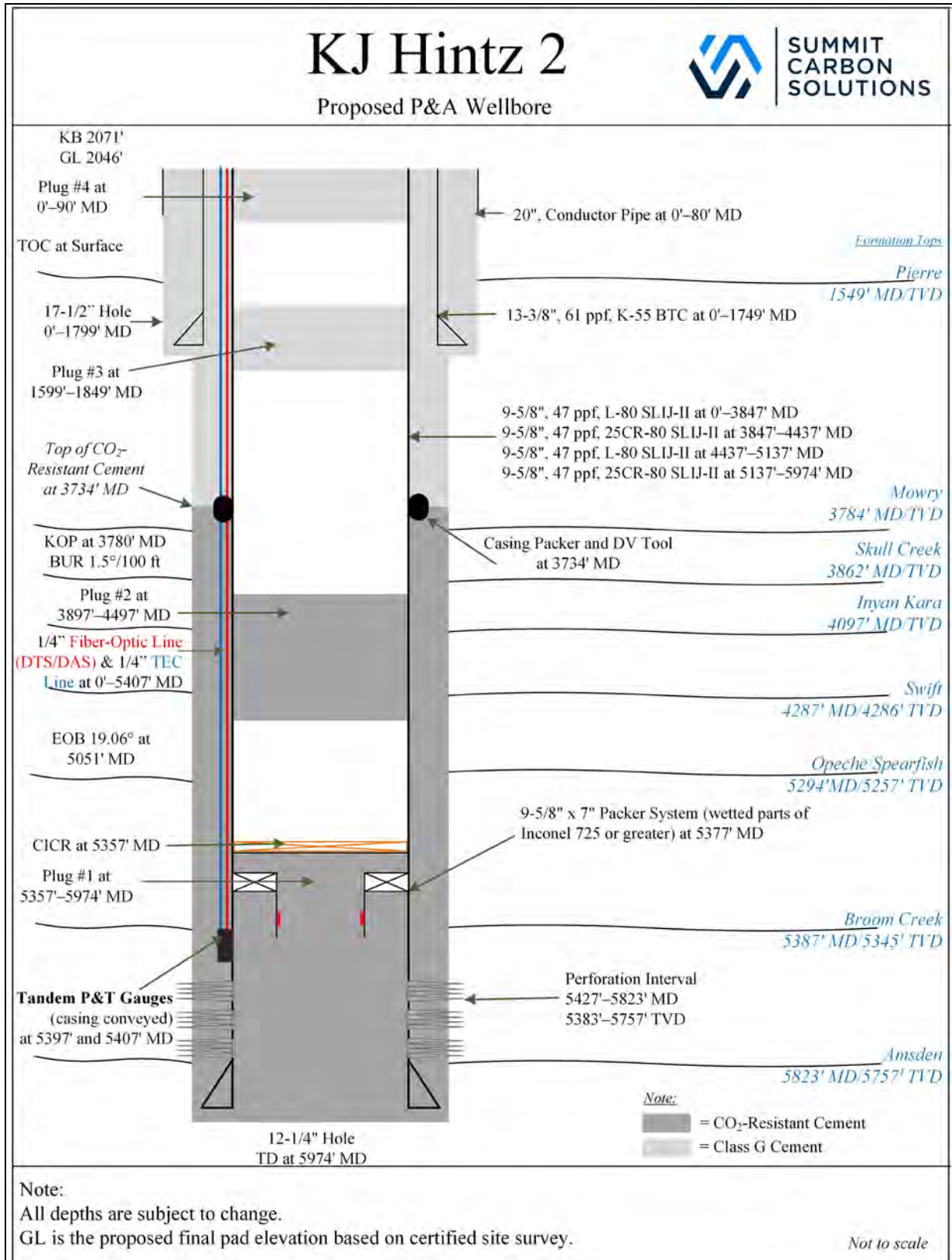


Figure 10-4. KJ Hintz 2 proposed P&A wellbore schematic.

10.3 Slash Lazy H 5: Proposed Reservoir-Monitoring Well P&A Program

The Slash Lazy H 5 wellbore is to be P&A when the CO₂ plume has stabilized and monitoring of the plume extent is no longer necessary. An as-completed reservoir-monitoring well schematic of Slash Lazy H 5 is provided in Figure 10-5. The proposed P&A program may change based on the best knowledge available at the time of execution. The proposed P&A program may also change based on well response during the actual P&A procedures.

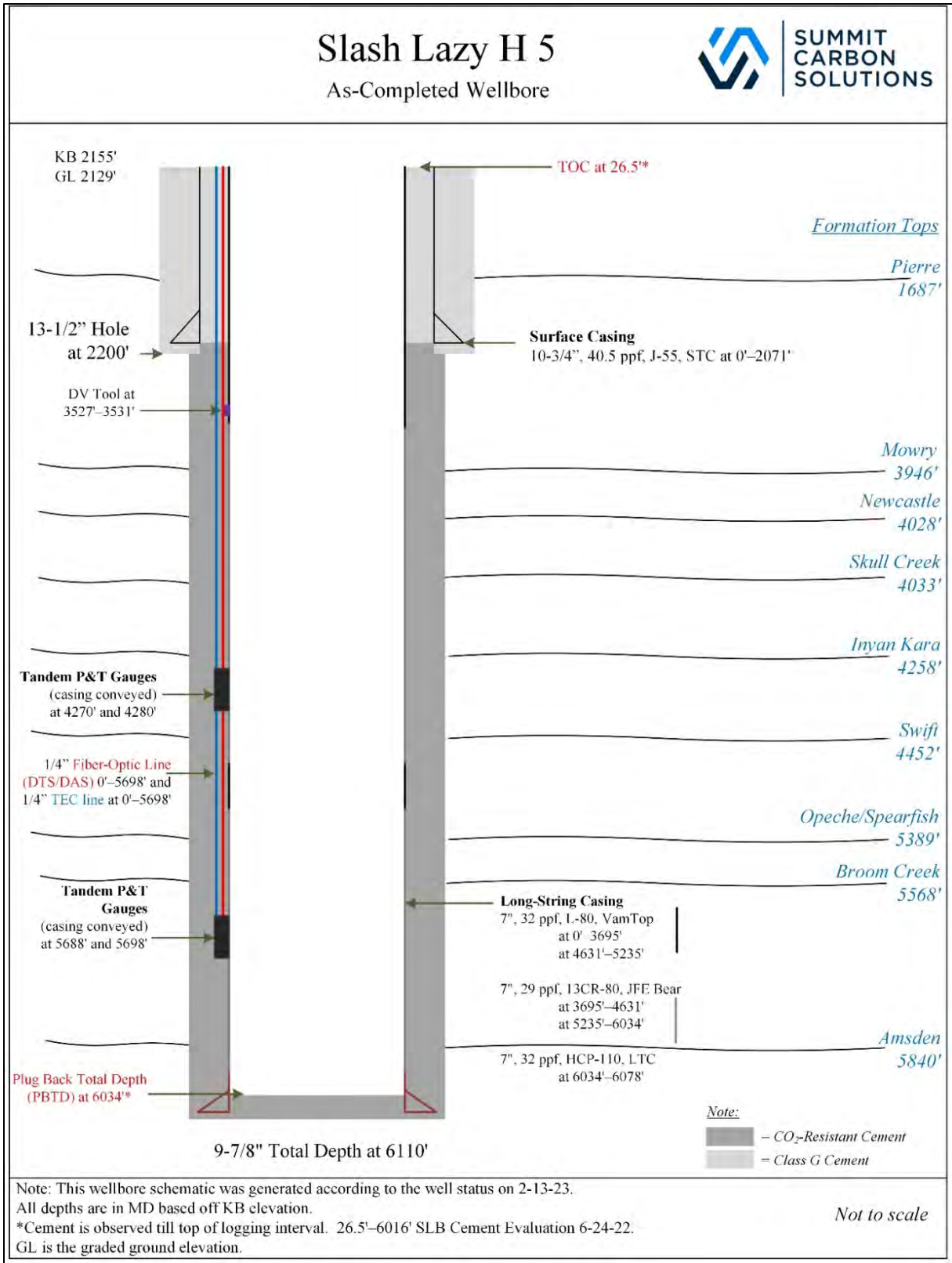


Figure 10-5. Slash Lazy H 5 as-completed wellbore schematic.

DMR-O&G will be contacted, and an intent to P&A for Slash Lazy H 5 will be filed in NorthSTAR for approval. Final adjustments to the proposed P&A procedure will be made based on current wellbore conditions and DMR-O&G field inspector recommendations. Currently, the proposed P&A procedure for the well is as follows.

Proposed P&A Procedure:

1. The procedures described below are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications, as per DMR-O&G approval, due to unforeseen circumstances will be described in the plugging report.
2. After monitoring operations have been terminated, the well will be flushed with kill fluid, which should be calculated from downhole gauges for proper fluid weight. A sufficient volume will be pumped to kill the well while remaining below the fracture pressure and ensuring control of the well.
3. Contact DMR-O&G supervisor and/or DMR-O&G field inspector 24 hr prior to moving onto location.
4. Dig out surface casing valve, and bleed off. Confirm most recent date of pull test. Pull test deadman anchors, if required. May require installing new deadman anchors depending on results.
5. MIRU workover rig and surface equipment onto the Slash Lazy H 5 well.
6. Conduct and document a safety meeting. Check pressure at wellhead, and ensure pressure is off prior to starting work. Additional kill fluid may be needed.
7. ND wellhead, NU BOP. Install test plug. Test BOP for functionality. Pressure-test BOP to 80% of working pressure. Document BOP test.
8. PU 2 $\frac{7}{8}$ -in. work string and stand in derrick. Pick up bit and scraper and TIH. Perform reverse circulation, pump down casing annulus and up the work string to clean hole. TOOH with work string, bit and scraper.
9. Pressure-test casing to 1000 psi for 30 minutes or as approved by DMR-O&G. Record mechanical integrity test on casing.

Contingency: If pressure test failed, a CIBP will be set below each subsequent plug until casing test passes.

10. If needed, RU logging unit. Confirm external mechanical integrity by running one of the tests listed below as options, and RD logging truck:

- Activated neutron log
- Noise log
- PLT
- Tracers
- Temperature log
- DTS survey (no required logging unit)

Note: If external failure in long-string casing is identified, the operator will adjust the P&A plan with DMR-O&G approval.

11. TIH with work string and diffuser to depth as in cementer's proposed procedures for Broom Creek interval.
12. MIRU cementing equipment to perform cement balanced plug across Broom Creek.
13. Conduct and document a safety meeting prior to pumping cement. Ensure all materials are on location and accounted for. Confirm volumes, tests, procedures, operating equipment, and setting times with the cement provider. Ensure **CO₂-resistant cement** will be used for the Broom Creek and Inyan Kara intervals. All other cement should be of Class G grade or equivalent.
14. Pressure-test lines prior to pumping. Proceed with pumping 135 sx of 15.2 ppg, 0.92 ft³/sx **CO₂-resistant cement** balanced plug as designed from cementer's proposed procedures across Broom Creek interval.
15. Pull work string above the plug, and test casing. Circulate wellbore clean.
16. If pressure test failed, set a CIBP prior to pumping balanced plug. TOOH with work string and diffuser to depth of Plug 2. Pump 135 sx of 15.2 ppg, 0.92 ft³/sx **CO₂-resistant cement** balanced plug as designed from cementer's proposed procedures across Inyan Kara interval.
17. Pull up work string above the top of the plug, and test casing. Circulate wellbore clean. Wait on setting time, and tag top of the plug.
18. Set a CIBP prior to pumping balanced Plug 3 if previous test failed. TOOH to depth of Plug 3. Pump 50 sx of 15.8 ppg, 1.15 ft³/sx Class G cement at 2171 ft. Pull up work string above the top of the plug, and circulate wellbore clean. Wait on setting time, and tag top of the plug.
19. TOOH laying down work string to 90 ft. Pump 25 sx of 15.8 ppg, 1.15 ft³/sx Class G cement plug at 90 ft. Lay down all work string.

Contingency: Perform top job as necessary to ensure good cement on both sides.

20. RD all equipment, and move out.
21. Dig out wellhead, and cut off casing 5 ft below GL. Weld ½-in. steel cap on casing with well name, date inscribed, and information that it was used for CO₂ monitoring.
22. Dig out deadman anchors, and report photo of steel cap to DMR-O&G.
23. Within 60 days, submit Form 7 plugging report after plugging operations are complete (N.D.A.C. § 43-05-01-11.5[4]).
24. Submit notice of intent to reclaim to DMR-O&G 30 days in advance prior to reclamation (N.D.A.C. § 43-05-01-18[10][d]).

The proposed P&A plan for Slash Lazy H 5 is summarized in Table 10-3 and provided in Figure 10-6. These values are estimated; final volume and thickness of plugs will be determined by design at time of plugging.

Table 10-3. Summary of P&A Plan for Slash Lazy H 5

Cement Plug Number	Cement Type	Weight, ppg	Yield, ft³/sx	Interval, ft, MD	Thickness, ft	Volume, sx	Notes
Plug 4	Class G	15.8	1.15	0–90	90	25	Surface plug
Plug 3	Class G	15.8	1.15	1921–2171	250	50	Isolate Fox Hills Formation at base of surface casing
Plug 2	CO ₂ -resistant	15.2	0.92	4058–4658	600	135	Isolate Inyan Kara Formation from Fox Hills Formation
Plug 1	CO ₂ -resistant	15.2	0.92	5368–5968	600	135	Set balanced plug and mechanically isolate Broom Creek Formation

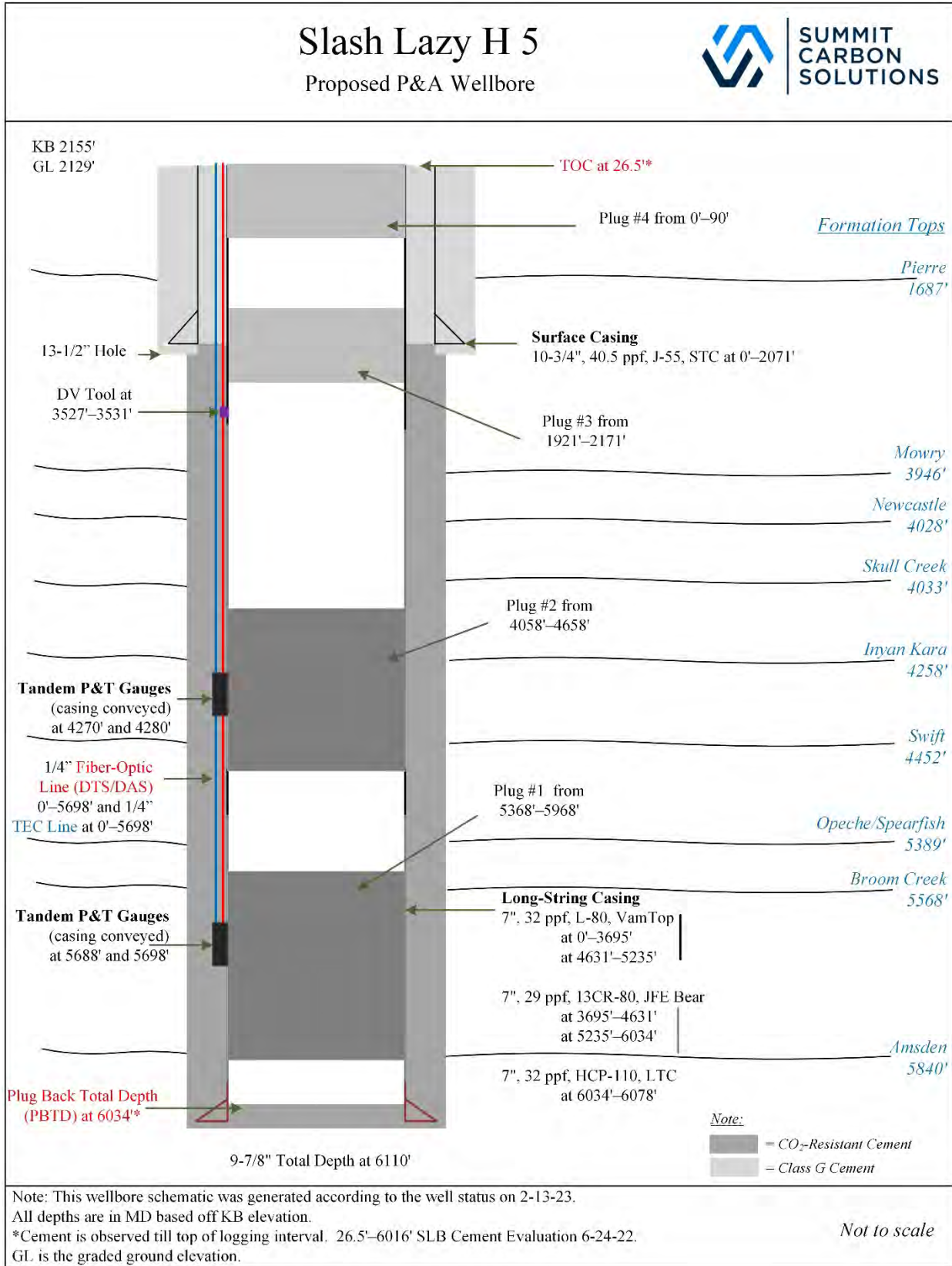


Figure 10-6. Slash Lazy H 5 proposed P&A wellbore schematic.

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 (USDWs). 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 (N.D.A.C.) § 43-05-01-05 and § 43-05-01-11.3. Planned well logging and testing activities and monitoring activities can be found in Sections 5.0 and 6.0.

Table 11-1. KJ Hintz 1 and KJ Hintz 2: Proposed Injection Wells Operating Parameters

Item	Values		Description/Comments
Injected Volume			
Total Injected Mass/Volume	129.7 MMt 2,451,470 MMcf		Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint
Injection Rates			
	KJ Hintz 1	KJ Hintz 2	Description/Comments
Average Injection Rate	9000 tonnes/day (170.1 MMscf/day) 3.29 MMt/yr 1,241,801 MMcf 65.7 MMt	8767 tonnes/day (165.7 MMscf/day) 3.20 MMt/yr 1,209,669 MMcf 64.0 MMt	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Average Maximum Injection Rate*	29,548 tonnes/day (558.5 MMscf/day) 10.79 MMt/yr 4,076,963 MMcf 215.7 MMt	27,027 tonnes/day (510.9 MMscf/day) 9.87 MMt/yr 3,729,183 MMcf 197.3 MMt	Based on maximum BHP with only one well injecting at a time: KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi
Depth			
	KJ Hintz 1	KJ Hintz 2	Description/Comments
Depth (true vertical depth [TVD]) of the Top Perforation Used in the BHP Calculation	5426	5397	Depths are for simulation modeling, taken prior to final site survey
Pressure (psi)			
	KJ Hintz 1	KJ Hintz 2	Description/Comments
Formation Fracture Pressure at Top Perforation	4253	4231	Based on geomechanical analysis of formation fracture gradient as 0.784 psi/ft
Average Surface Injection Pressure	2100	2100	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Maximum Surface Injection Pressure*	6500	5800	Based on maximum BHP with only one well injecting at a time (using the designed 7-in. tubing): KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi

Continued . . .

Table 11-1. KJ Hintz 1 and KJ Hintz 2: Proposed Injection Wells Operating Parameters (continued)

Item	Values		Description/Comments
	KJ Hintz 1	KJ Hintz 2	Description/Comments
Average BHP	3600 psi	3622 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint
Calculated Maximum BHP	3828 psi	3808 psi	Based on 90% of the formation fracture pressure: KJ Hintz 1: 4253 psi KJ Hintz 2: 4231 psi

*Maximum injection pressure during operations will be limited to the surface equipment pressure ratings and maximum BHP constraint.

11.1 KJ Hintz 1: Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the KJ Hintz 1 well will be drilled and completed as a CO₂ injector (Figures 11-1 and 11-2 and Tables 11-2, 11-3, and 11-4). The following proposed completion procedure outlines the steps necessary to complete and test the well for injection purposes. The procedures described below are subject to change during execution as necessary to ensure successful completion and/or testing.

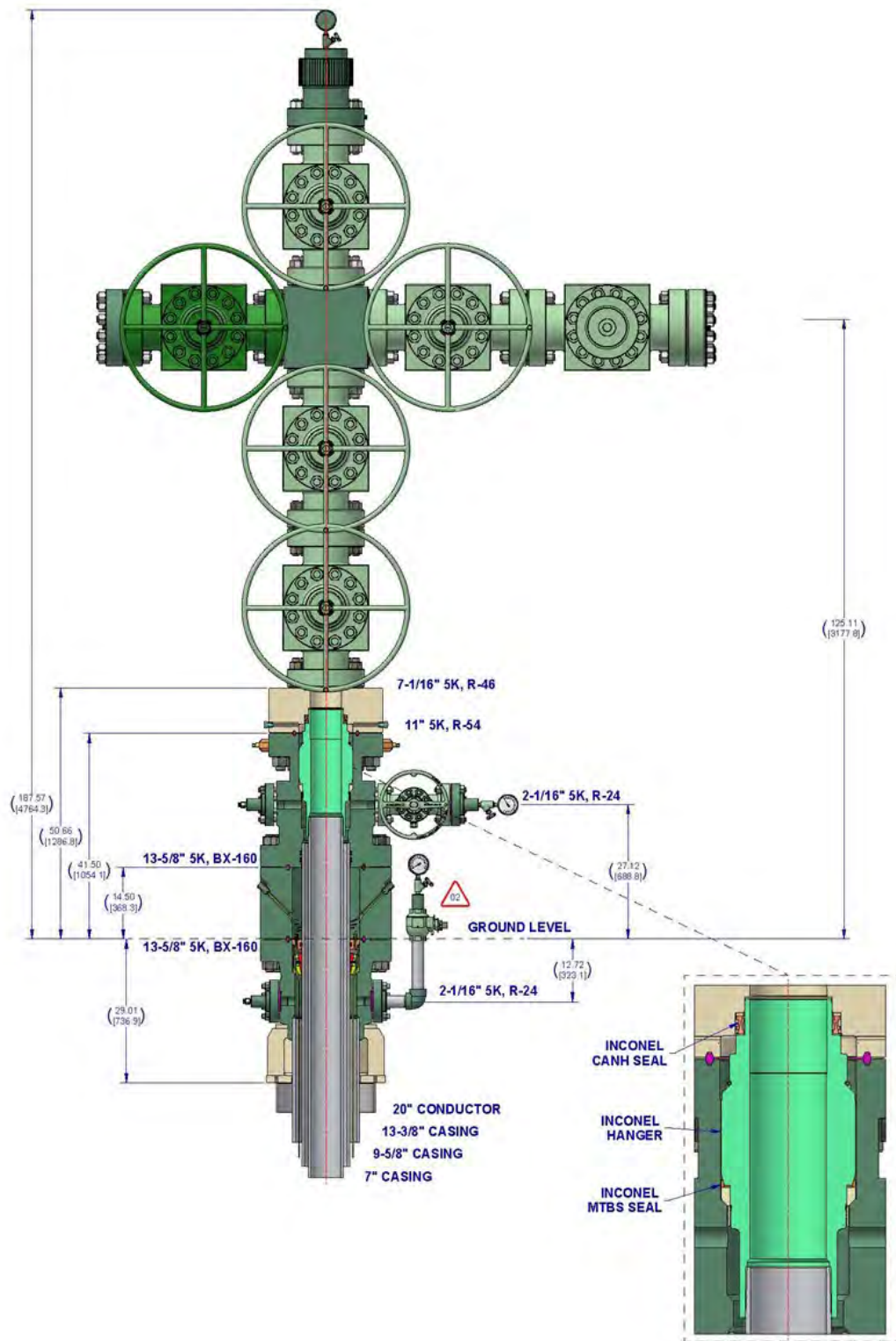


Figure 11-1. KJ Hintz 1 proposed CO₂-resistant wellhead schematic. The lowest manual valve of injection tree will be of Class HH material, and tubing hanger mandrel will be of CRA (corrosion-resistant alloy) material, while the rest of the tree will consist of Class FF and equivalent.

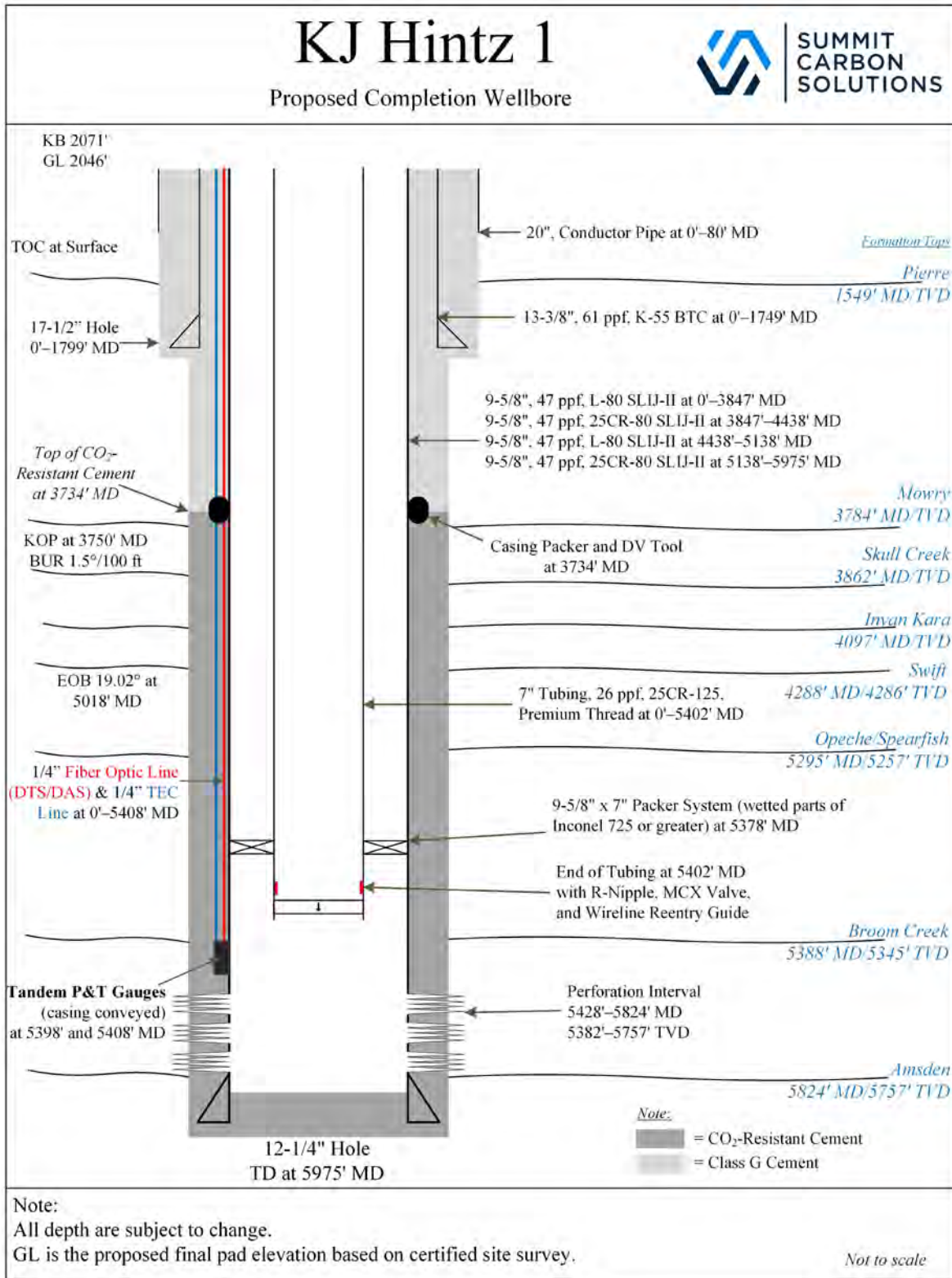


Figure 11-2. KJ Hintz 1 proposed completion wellbore schematic.

Table 11-2. KJ Hintz 1: Tubing Properties

OD*, in.	Grade	Weight, lb/ft	Connection	ID, ** in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, klb
7.000	25Cr-125	26	Sentinel	6.276	6.151	6233	10,239	943

* Outer diameter.

** Inside diameter.

Table 11-3. KJ Hintz 1: Tubing Accessories

Description	OD, in.	Depth, ft, MD	Material	ID, in.	Drift ID, in.
Ratch Latch Assembly	7.765	5374	CRA	5.98	5.95
Packer	8.220	5378	CRA	5.98	5.95
Pup Joint	7.000	5385	25Cr-125	6.276	6.151
LN Profile	7.954	5391	CRA	5.875	5.875
Pup Joint	7.000	5393	25Cr-125	6.276	6.151
LN Profile	7.733	5399	CRA	5.750	5.750
Wireline Reentry Guide	8.250	5401	CRA	6.230	6.200
MCX Valve**	5.620	TBD	CRA	2.620	–

* Estimated, will be adjusted with actual tally; TBD: to be determined.

** MCX valve will be run with slickline after installation of tubing assembly.

Table 11-4. Cased-Hole Logging Plan for the KJ Hintz 1

	Logging	Justification	Frequency	N.D.A.C. § 43-05-01-
Long-String Section without Tubing	Sonic array logging (inclusive of radial cement bond log [RCBL], variable-density log [VDL], casing collar locator [CCL], gamma ray (GR), and temperature log	Identify cement bond quality radially and evaluate cement top and zonal isolation. Establish baseline temperature profile for distributed temperature sensing (DTS) fiber-optic cable calibration.	Baseline and repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved casing inspection log [CIL])	Acquire baseline and demonstrate external mechanical integrity.		11.2(1)(c)(2) and (d)
Through-Tubing	Pulsed-neutron log (PNL)	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if DTS fails	11.2(1)(c)(2) and (d)

Site Well Work Preparations

- Contact Department of Mineral Resources, Oil and Gas Division (DMR-O&G), and provide schedule to perform DMR-O&G-approved well work.
 - Work road and location as needed for safe operations.
 - Install rig anchors and test to 20,000 lbf (pounds-force), or as required by rig contractor. If installed, confirm recent anchor test date and that testing has been performed according to contractor policy.
 - Confirm actual casing depths and casing-conveyed gauges with the contractor representative and designated contractor field engineer.
 - Conduct safety meetings prior to shifts and treatments/operations.
 - Move in (MI) pipe racks, pipe wranglers, tanks, and portable toilet.
 - MI and unload 7-in., 25Cr-125 injection string and 2⁷/₈-in. PH6 work string.
 - Fill tanks with compatible testing fluid for all well work.
1. Move in and rig up (MIRU) workover (WO) rig capable of 200,000 lb and equipment, check the casing pressure, and release pressure if any. Ensure no pressure buildup before proceeding to the next step.
 2. Remove nightcap and nipple up (NU) a blowout preventer (BOP) with variable rams capable of 2⁷/₈ to 7-in.
 3. Test BOP to maximum anticipated surface pressure (MASP).
 4. Tally and pick up (PU) 2⁷/₈-in. PH6 work string and 8¹/₂-in. bit to drill out differential valve (DV) tool and clean out residual cement down to float collar. Pull out of hole (POOH).
 5. Run in the hole and work string with bit and scraper in front of the injection zone and at the depth where the packer will be set.
 6. Tag plug back total depth (PBTD).
 7. Circulate the wellbore with completion fluid, estimated at 9.8 ppg, compatible with the formation. Circulate until clean returns.
 8. Trip out of hole (TOOH) work string with bit and scraper.
 9. Close blind rams and test casing for 30 min to 1000 psi or as approved by DMR-O&G. If the pressure decreases more than 10% in 30 min, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it. Document all test results.
 10. MIRU logging truck.
 11. Conduct safety meeting to discuss logging and perforating operations.

12. Install and test lubricator.
13. Perform logs as per cased-hole logging plan shown in Table 11-4.

Note: Run radial cement bond log (RCBL) with 500-psi pressure. If the RCBL result shows poor cement bonding or a low top of cement, the results should be communicated to DMR-O&G and an action plan will be prepared.

14. Perforate the Broom Creek Formation (ensure shots do not penetrate fiber-optic cable or downhole gauges. Perforations should be at least 10 ft away from gauge and fiber-optic cable). Actual perforation depths and design will be determined by designated geologists and engineers and based on the log analysis review and selected contractor.

Note: DTS/DAS (distributed temperature sensing/distributed acoustic sensing) fiber-optic cable and casing conveyed gauges 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.

15. TOOH with perforating guns.
16. Tally and PU retrievable testing packer with surface readout downhole gauges and run in the hole with work string to the top of the perforations.
17. Set packer above, at least 50 ft, top perforations to isolation and test the annulus to ensure seal and no communication with backside.
18. RU pump truck. Perform an injectivity test/step rate test (SRT) and pressure falloff test with fluid compatible with the formation. The SRT and pressure falloff test will be designed at a later time.

Note: If the well shows poor injectivity, perform a near-wellbore/perforation cleanout using a designed concentration of acid. Adjust acid formulation and volumes with water samples and compatibility test. Maximum injection pressure is not to exceed formation fracture pressure. Ensure correct acid and additives are used and the acid formula is determined based on not only the acid/formation compatibility test result but also installed CRA material.

19. Release packer. TOOH, lay down (LD) retrievable packer, and LD work string.
20. Prepare rig floor to install injection string assembly (injection tubing and packer).
21. RU wireline. PU wireline-set permanent packer to desired depth.
22. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and DMR-O&G requirements.

Note: Avoid setting packer within 10 ft of casing-conveyed gauges.

23. Tally, PU, and run completion assembly in accordance with program. Displace the well with inhibited packer fluid prior to latching 7-in., 25Cr-125 injection string into permanent packer.
24. Test packer to 1000 psi for 30 min. Ensure good seal.
25. Install tubing hanger.
26. Install backpressure valve (BPV), and nipple down (ND) BOP.
27. NU injection tree. Recover BPV.
28. Install test plug, and pressure-test injection tree to pressure rating. Recover test plug.
29. RDMO (rig down and move out) WO rig and equipment.
30. Schedule mechanical integrity test (MIT) with DMR-O&G inspector. Perform and record MIT with DMR-O&G representative present. Document MIT and submit to DMR-O&G.

11.2 KJ Hintz 2: Proposed Completion Procedure to Conduct Injection Operations

As described in Section 9.1, the KJ Hintz 2 well will be drilled and completed as a CO₂ injector (Figures 11-3 and 11-4 and Tables 11-5, 11-6, and 11-7). The following proposed completion procedure outlines the steps necessary to complete and test the well for injection purposes. The procedures described below are subject to change during execution as necessary to ensure successful completion and/or testing.

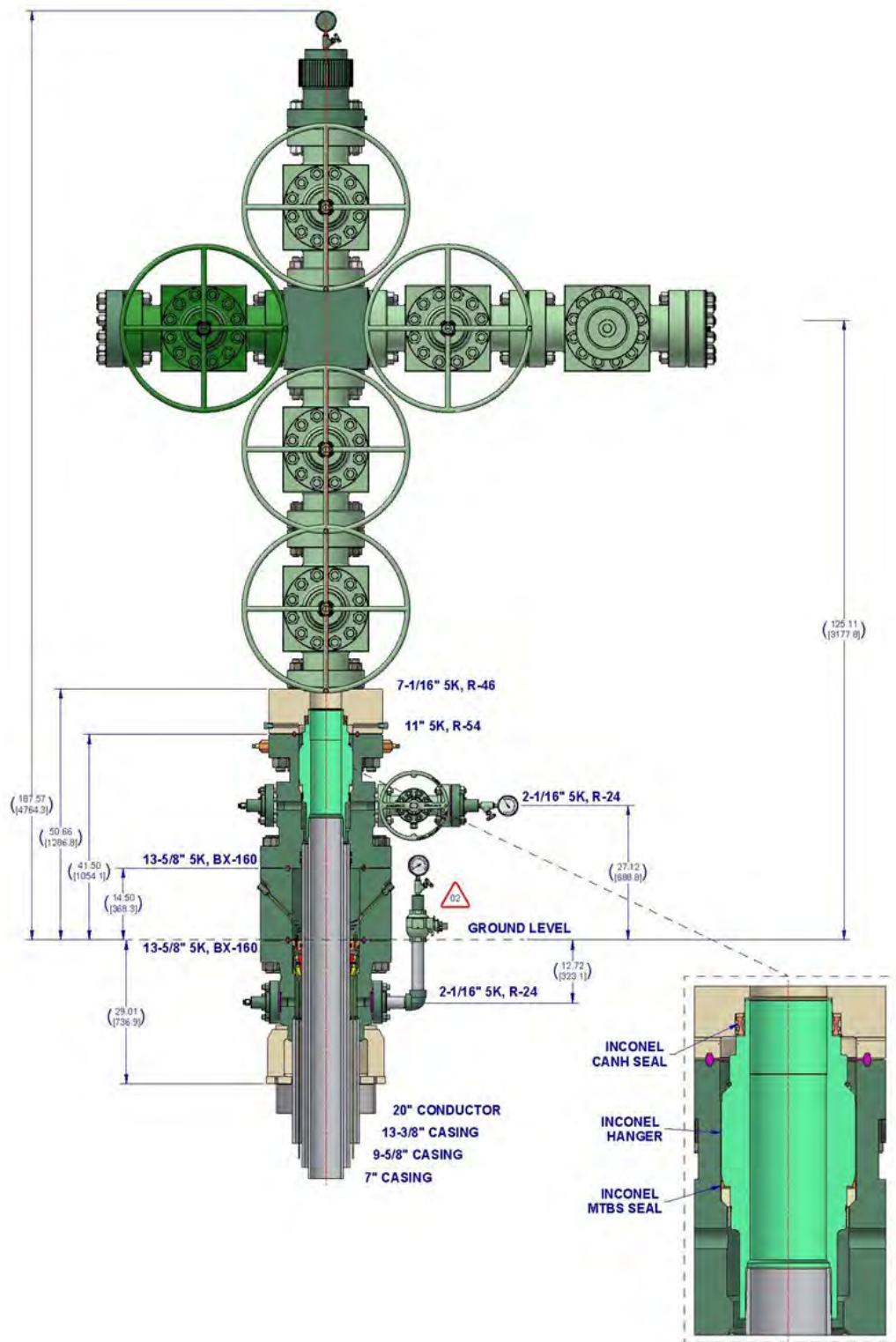


Figure 11-3. KJ Hintz 2 proposed CO₂-resistant wellhead schematic. The lowest manual valve of injection tree will be of Class HH material, and tubing hanger mandrel will be of corrosion-resistant material, while the rest of the tree will consist of Class FF and equivalent.

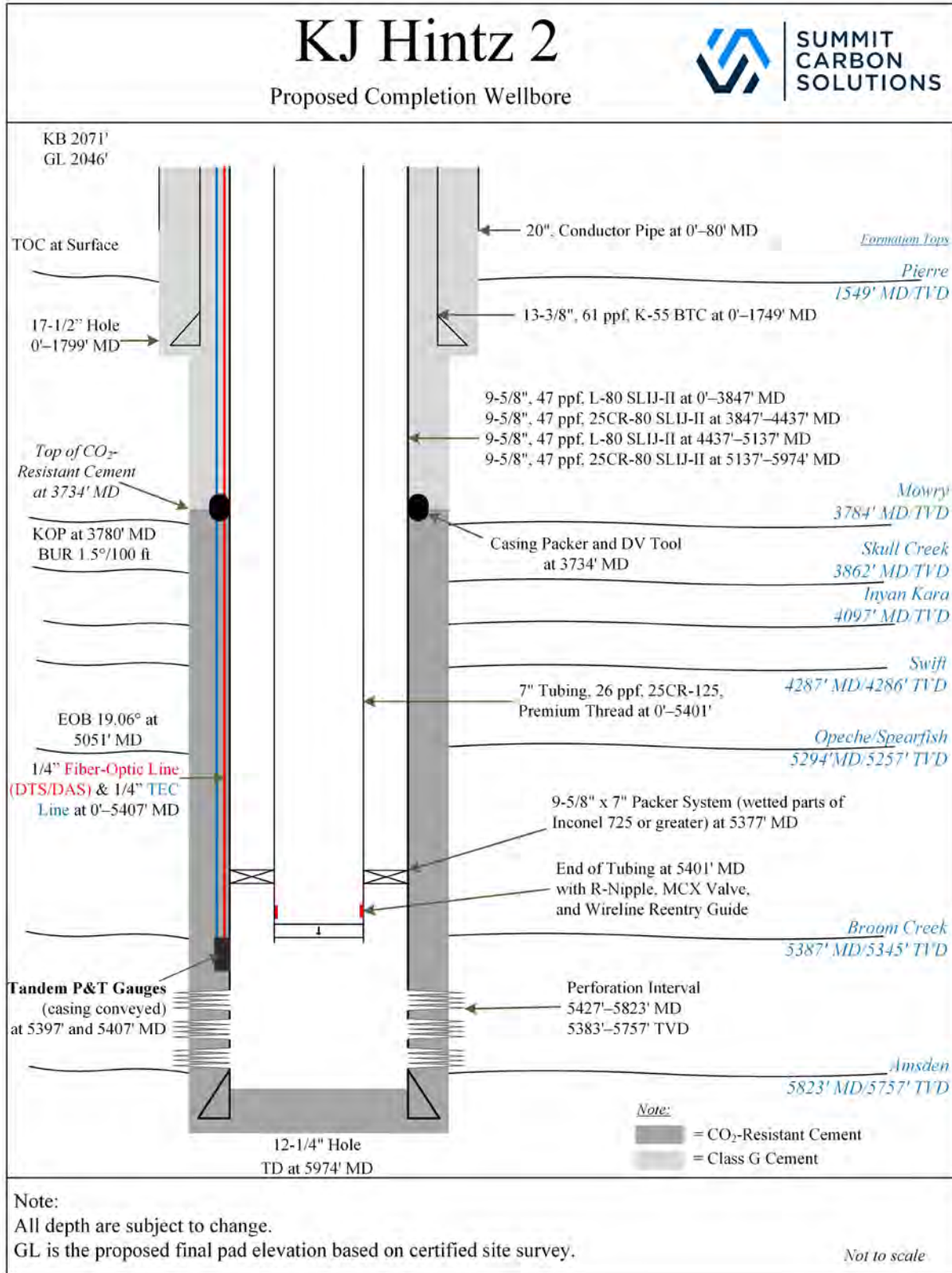


Figure 11-4. KJ Hintz 2 proposed completion wellbore schematic.

Table 11-5. KJ Hintz 2: Tubing Properties

OD, in.	Grade	Weight, lb/ft	Connection	ID, in.	Drift ID, in.	Collapse, psi	Burst, psi	Tension, klb
7.000	25Cr-125	26	Sentinel	6.276	6.151	6233	10,239	943

Table 11-6. KJ Hintz 2: Tubing Accessories

Description	OD, in.	Depth,* ft, MD	Material	ID, in.	Drift ID, in.
Ratch Latch Assembly	7.765	5373	CRA	5.980	5.950
Packer	8.220	5377	CRA	5.980	5.950
Pup Joint	7.000	5384	25Cr-125	6.276	6.151
LN Profile	7.954	5390	CRA	5.875	5.875
Pup Joint	7.000	5392	25Cr-125	6.276	6.151
LN Profile	7.733	5398	CRA	5.750	5.750
Wireline Reentry Guide	8.250	5400	CRA	6.230	6.200
MCX Valve**	5.620	TBD	CRA	2.620	–

* Estimated, top connection depth will be adjusted with actual tally, TBD: to be determined.

** MCX valve will be run with slickline after installation of tubing assembly.

Table 11-7. Cased-Hole Logging Plan for the KJ Hintz 2

	Logging	Justification	Frequency	N.D.A.C. § 43-05-01-
Long-String Section Without Tubing	Sonic array logging (inclusive of RCBL, VDL, CCL), GR, and temperature log	Identify cement bond quality radially and evaluate cement top and zonal isolation. Establish baseline temperature profile for DTS fiber-optic cable calibration.	Baseline and repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved CIL)	Acquire baseline and demonstrate external mechanical integrity prior to injection.		11.2(1)(c)(2) and (d)
Through-Tubing	PNL	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if DTS fails	11.2(1)(c)(2) and (d)

Site Well Work Preparations

- Contact DMR-O&G and provide schedule to perform DMR-O&G-approved well work.
 - Work road and location as needed for safe operations.
 - Install rig anchors and test to 20,000 lbf, or as required by rig contractor. If installed, confirm recent anchor test date and that testing has been performed according to contractor policy.
 - Confirm actual casing depths and casing-conveyed gauges with the contractor representative and designated contractor field engineer.
 - Conduct safety meetings prior to shifts and treatments/operations.
 - MI pipe racks, pipe wranglers, tanks, and portable toilet.
 - MI and unload 7-in. 25Cr-125 injection string and 2⁷/₈-in. PH6 work string.
 - Fill tanks with compatible testing fluid for all well work.
1. MIRU WO rig capable of 200,000 lb and equipment, check the casing pressure, and release pressure if any. Ensure no pressure buildup before proceeding to the next step.
 2. Remove nightcap, and NU a BOP with variable rams capable of 2⁷/₈ to 7-in.
 3. Test BOP to MASP.
 4. Tally and PU 2⁷/₈-in. PH6 work string and 8¹/₂-in. bit to drill out DV tool and clean out residual cement down to float collar. POOH.
 5. Run in the hole and work string with bit and scraper in front of the injection zone and at the depth where the packer will be set.
 6. Tag PBTD.
 7. Circulate the wellbore with completion fluid, estimated at 9.8 ppg, compatible with the formation. Circulate until clean returns.
 8. TOOH work string with bit and scraper.
 9. Close blind rams and test casing for 30 min to 1000 psi or as approved by DMR-O&G. If the pressure decreases more than 10% in 30 min, bleed pressure, check surface lines and surface connections, and repeat test. If the failure persists, the operator will be required to assess the root cause and correct it. Document all test results.
 10. MIRU logging truck.
 11. Conduct safety meeting to discuss logging and perforating operations.
 12. Install and test lubricator.
 13. Perform logs as per cased-hole logging plan shown in Table 11-7.

Note: Run RCBL with 500-psi pressure. If the RCBL result shows poor cement bonding or a low top of cement, the results should be communicated to DMR-O&G and an action plan will be prepared.

14. Perforate the Broom Creek Formation (ensure shots do not penetrate fiber-optic cable or downhole gauges. Perforations should be at least 10 ft away from gauge and fiber-optic cable). Actual perforation depths and design will be determined by designated geologists and engineers and based on the log analysis review and selected contractor.

Note: DTS/DAS fiber-optic cable and casing conveyed gauges 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.

15. TOO H with perforating guns.
16. Tally and PU retrievable testing packer with surface readout downhole gauges, and run in the hole with work string to the top of the perforations.
17. Set packer above, at least 50 ft, top perforations to isolation and test the annulus to ensure seal and no communication with backside.
18. RU pump truck. Perform an injectivity test/SRT and pressure falloff test with fluid compatible with the formation. The SRT and pressure falloff test will be designed at a later time.

Note: If the well shows poor injectivity, perform a near-wellbore/perforation cleanout using a designed concentration of acid. Adjust acid formulation and volumes with water samples and compatibility test. Maximum injection pressure is not to exceed formation fracture pressure. Ensure correct acid and additives are used and the acid formula is determined based on not only the acid/formation compatibility test result but also installed CRA material.

19. Release packer. TOO H, LD retrievable packer, and LD work string.
20. Prepare rig floor to install injection string assembly (injection tubing and packer).
21. RU wireline. PU wireline-set permanent packer to desired depth.
22. Set injection packer within 50 ft above the top perforations, according to manufacturer recommendations and DMR-O&G requirements.

Note: Avoid setting packer within 10 ft of casing-conveyed gauges.

23. Tally, PU, and run completion assembly in accordance with program. Displace the well with inhibited packer fluid prior to latching 7-in. 25Cr-125 injection string into permanent packer.
24. Test packer to 1000 psi for 30 min. Ensure good seal.
25. Install tubing hanger.
26. Install BPV and ND BOP.
27. NU injection tree. Recover BPV.
28. Install test plug, and pressure-test injection tree to pressure rating. Recover test plug.
29. RDMO WO rig and equipment.
30. Schedule MIT with DMR-O&G inspector. Perform and record MIT with DMR-O&G representative present. Document MIT and submit to DMR-O&G.

11.3 Slash Lazy H 5: Proposed Completion Procedure for Monitoring Well Operations

Slash Lazy H 5 completion meets the requirements for a reservoir-monitoring well (Figures 11-5 and 11-6 and Table 11-8) to support deep subsurface monitoring of KJ Hintz 1 and KJ Hintz 2, the CO₂ injection wells. Monitoring of the CO₂ plume extent and the storage reservoir pressure will be conducted continuously through a casing-conveyed fiber-optic cable with DTS and pressure temperature gauges installed outside the long-string casing. Monitoring will be conducted during injection operations as well as during the postinjection site care (PISC) period (Section 6.0).

Slash Lazy H 5 has been drilled, logged, and completed as a monitoring well. This well is capable of being the reservoir-monitoring well for KJ Hintz 1 and KJ Hintz 2 injection wells.

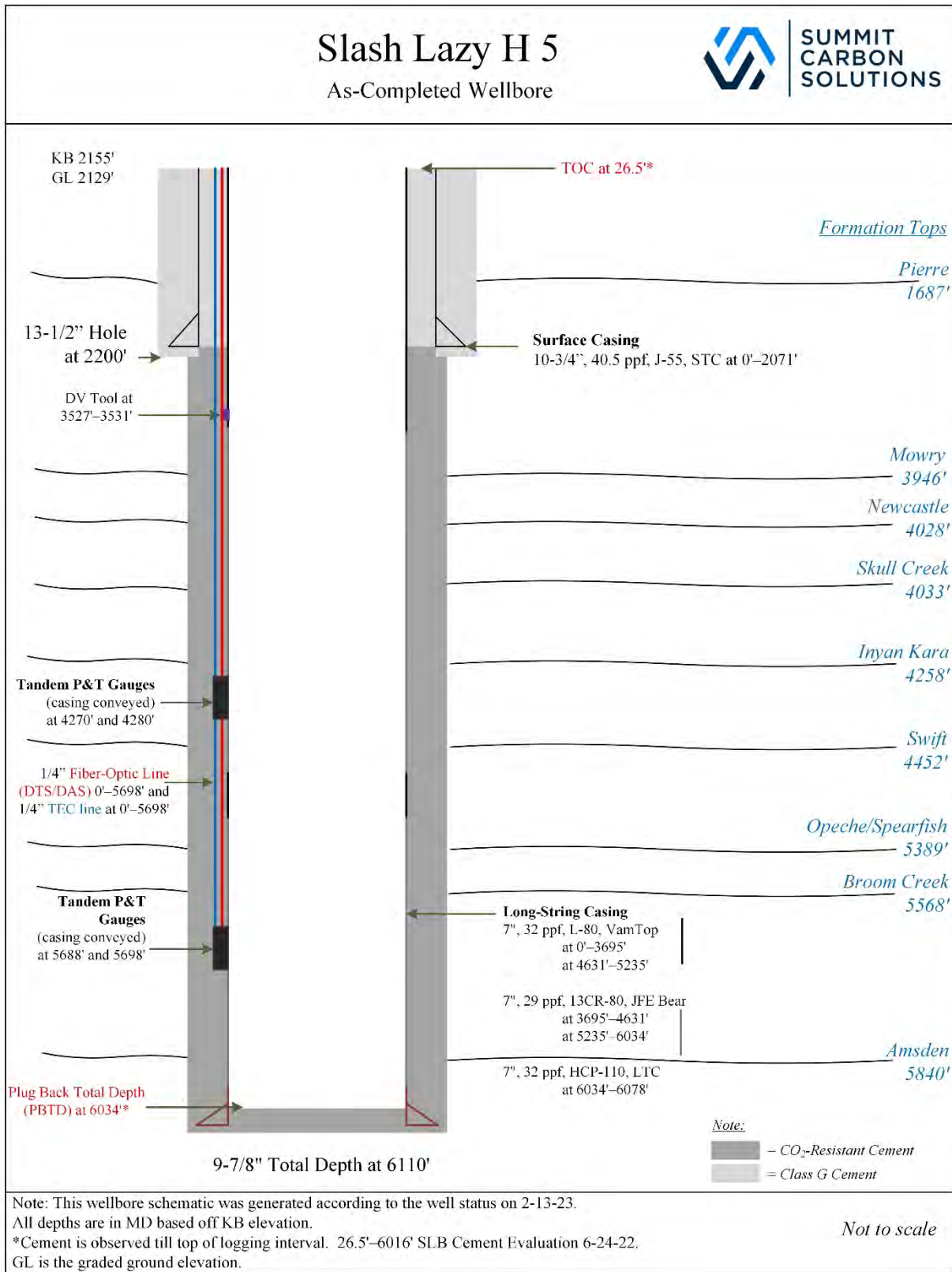


Figure 11-5. Slash Lazy H 5 as-completed wellbore schematic.

KJ HINTZ/SLASH LAZY H 5

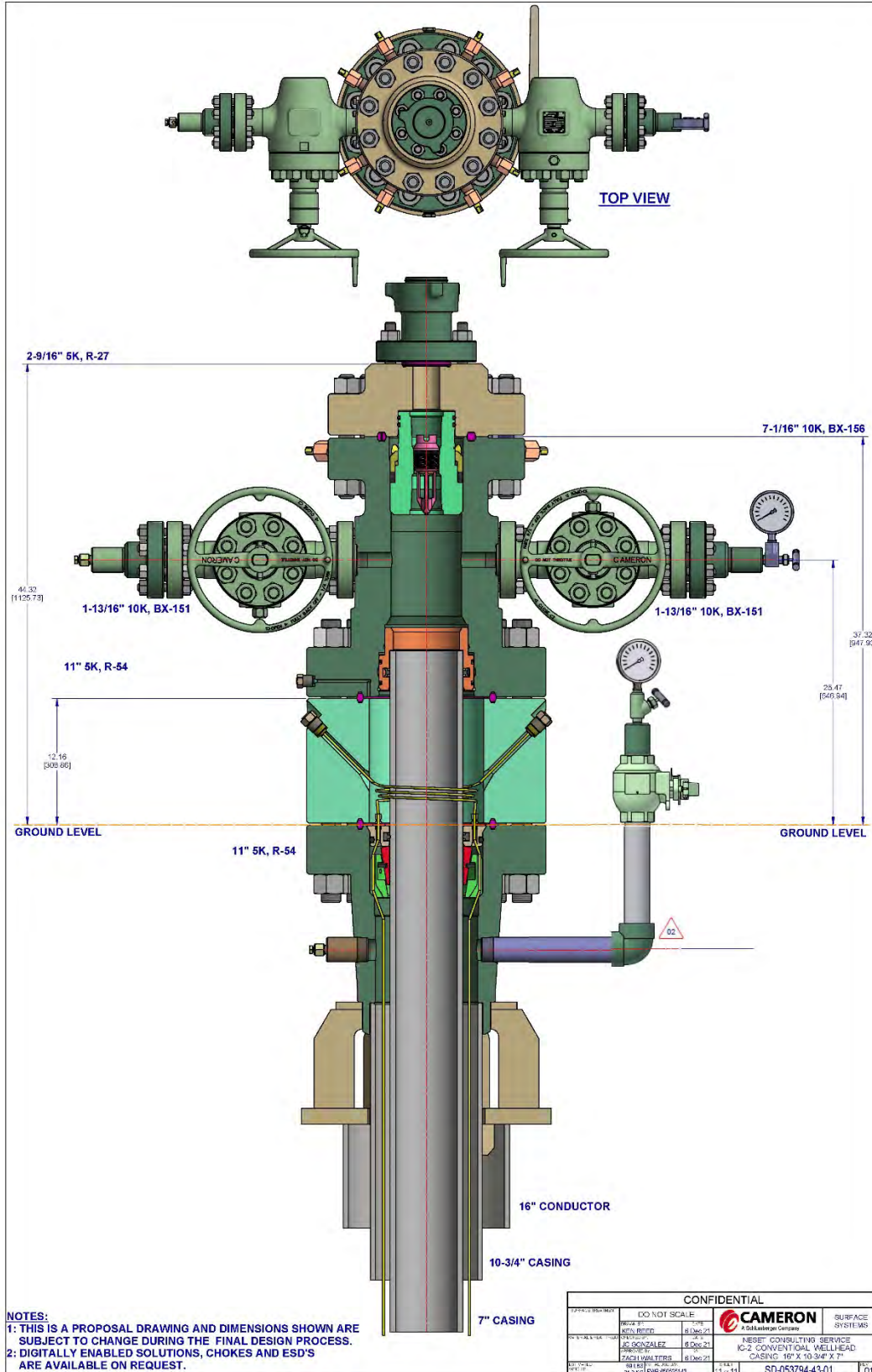


Figure 11-6. Slash Lazy H 5 wellhead schematic.

Table 11-8. Cased-Hole Logging Plan for the Slash Lazy H 5

	Logging	Justification	Frequency	N.D.A.C. § 43-05-01
Long-String Section – No Tubing	Sonic array logging (inclusive of RCBL, VDL, CCL), GR, and temperature log	Baseline already acquired to identify cement bond quality radially and evaluate cement top and zonal isolation.	Repeat when required and when tubing is pulled during workovers	11.2(1)(c)(2) and (d)
	Ultrasonic logging tool (or other approved CIL)	Baseline already acquired. Run log to demonstrate external mechanical integrity.		11.2(1)(c)(2) and (d)
	PNL	Confirm internal and external mechanical integrity from Opeche/Spearfish Formation to surface.	Baseline and Year 1, Year 3, and at least once every 3 years thereafter (e.g., Years 6, 9, 12, etc.)	11.4(g)(1)
	Temperature logging	Confirm external mechanical integrity and acquire baseline temperature profile.	Baseline and annually only if DTS fails	11.2(1)(c)(2) and (d)

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 CO₂ as prescribed by the state of North Dakota in North Dakota Administrative Code (N.D.A.C.) § 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 Summit Carbon Storage #3, LLC (SCS3) has taken and shall take to assure state and federal regulators that sufficient financial support is in place to cover the cost of any corrective action (N.D.A.C. § 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 (N.D.A.C. § 43-05-01-11.5); postinjection site care (PISC) and facility closure (N.D.A.C. § 43-05-01-19); emergency and remedial response plan (ERRP) (N.D.A.C. § 43-05-01-13); and endangerment to underground sources of drinking water (USDW).

This FADP provides cost estimates for each of the above actions (Section 12.0) 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 KJ Hintz.

As the FADP was prepared, U.S. Environmental Protection Agency (EPA) guidance (2011) was also considered to assess the effectiveness of multiple qualifying financial instruments in the context of SCS3, 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, the FADP financial instruments were considered in evaluating the assurance approach during each of the operational periods.

SCS3 will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations. The applicant will provide a surety bond to ensure funds are available for PISC and facility closure activities in accordance with N.D.A.C. § 43-05-01-09.1(1)(a). SCS3 will also provide a third-party pollution liability insurance policy to cover emergency and remedial response costs, including endangerment to USDWs, in accordance with N.D.A.C. § 43-05-01-13, and a financial instrument to cover the costs of plugging the injection wells in accordance with N.D.A.C. § 43-05-01-11.5. No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time.

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 ensure 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, ERRP, and endangerment of USDWs. The estimated total costs of these activities are presented in Table 12-1.

Table 12-1. Potential Future Costs Covered by Financial Assurance

Phase	Activity	Total Cost	Covered by Surety	Covered by Pollution Liability Policy	Details in Supporting Table
Preinjection, Active Injection, and PISC	Corrective Action on Wells in Area of Review (AOR)	\$0	\$0	\$0	N/A
Cessation of Injection	Plugging of Injection Wells	\$1,166,000	\$1,166,000	\$0	Table 12-2
PISC	PISC Storage Facility Monitoring and Injection Well Site Reclamation	4,731,800	\$4,731,800	\$0	Table 12-3a
PISC	Flowline Plugged and Abandoned (P&A)	\$243,000	\$243,000	\$0	Table 12-3b
PISC	Site Closure and Remediation	\$672,000	\$672,000	\$0	Table 12-4
Active Injection/PISC	ERRP	\$11,100,000	\$0	\$11,100,000	Table 12-6
Active Injection/PISC	Endangerment of USDWs	\$2,905,000	\$0	\$2,905,000	Table 12-7
Total		\$20,817,800	\$6,812,800	\$14,005,000	

If there are any changes, updated information related to the financial instruments will be provided on an annual basis to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G) for review and evaluation as required under N.D.A.C. § 43-05-01-09.1.

12.1 Facility Information

The facility name, facility contact, and injection well locations are provided below:

Facility Name: Summit Carbon Storage #3, LLC
 Facility Contact: Wade Boeshans
 Injection Well Locations: KJ Hintz 1 and 2; NE¼ of Section 17 T142, R86W

12.2 Approach to Financial Responsibility Cost Estimates

In accordance with the requirements contained in N.D.A.C. § 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, ERRP, and endangerment of USDWs (Table 12-1). The following provides a summary description of the considerations and assessment approach for each activity.

12.2.1 Corrective Action

According to N.D.A.C. § 43-05-01-05.1, corrective action involves inventorying and characterizing existing wells in the proposed AOR. The objective of a corrective action assessment is to describe the actions SCS3 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. SCS3 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 CO₂ and require no corrective action.

SCS3 has determined no wells in the proposed AOR require corrective action prior to or during the project operation, PISC, or postclosure period (Section 4.2). One legacy wellbore is located within the AOR boundary, Raymond Jenson 1-34 (well file no. 4942), but it is located outside the projected stabilized CO₂ plume boundary. Likewise, the only other identified wellbore within the AOR boundary is the stratigraphic test and reservoir-monitoring well, Slash Lazy H5. SCS3 will employ a proactive monitoring approach to track the CO₂ 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 CO₂ injection wells and reservoir-monitoring well (Section 5.7). For the avoidance of doubt, if injection or monitoring wells proposed as part of the SCS3 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

SCS3 will include the costs associated with plugging injection wells during site program closure within the project cost, the FADP, and the proposed instruments that SCS3 will use for plugging (N.D.A.C. § 43-05-01-11.5[2]). The injection wells will be plugged at cessation of the injection operation as discussed in Section 6.0 of this SFP application. The estimate covers the aggregated plugging and abandonment (P&A) cost of SCS3 injector wells KJ Hintz 1 and 2, including rig mobilization, workover rig and rentals, labor, cementing, logging, trucking, supervision, and project management (Table 12-2). The specifics of the plugging program of the KJ Hintz 1 and 2 wells can be found in Section 10.0. Reservoir-monitoring well plugging is separately accounted for as part of facility closure.

Table 12-2. Injection Well Plugging

Activity	Total Cost
Plugging KJ Hintz 1	\$583,000
Plugging KJ Hintz 2	\$583,000
Total	\$1,166,000

12.2.3 Implementation of the PISC 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 in 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 \$5,646,800, including \$4,731,800 for implementing the PISC (Table 12-3a), \$243,000 for flowline P&A (Table 12-3b), and \$672,000 for facility closure activities (Table 12-4). The PISC includes the following: a) formation monitoring (i.e., pulsed-neutron logs

KJ HINTZ/SLASH LAZY H 5

[PNL]), 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,

Table 12-3a. Cost Estimate¹ for PISC Activities for the KJ Hintz Assuming a 10-year PISC Period

Activity	Frequency	Unit Cost	Total
Injection Pad Reclamation			
Reclamation Costs of the Injection Well Pad and Aboveground Structure Removal	Perform prior to facility closure (anticipated in Year 10 of postinjection).	\$255,000	\$255,000
Wellbore Monitoring (Slash Lazy H 5)			
Overhead and Management	Overhead and management of monitoring activities for the whole duration of the PISC period.	\$60,000	\$600,000
PNL (saturation monitoring)	Repeat PNL in Year 4 and Year 9 during the PISC period.	\$45,000	\$90,000
Ultrasonic Logging (or other approved CIL [casing inspection log])	Repeat when required (assumes two occurrences).	\$43,000	\$86,000
Annulus Pressure Testing (internal mechanical integrity)	Repeat during workover operations in cases where the tubing must be pulled (assumes two occurrences).	\$8,000	\$16,000
Monitoring Surface Equipment Maintenance and Power	Quarterly inspections of wellhead and surface monitoring equipment.	\$5,000	\$50,000
Near-Surface Monitoring			
MSG03 and 06 – Sampling and Analysis	Collect three to four seasonal samples at each station (MSG03 and MSG06) in Years 1 and 3 of postinjection and every 3 years thereafter (e.g., Years 6 and 9) and perform concentration analyses on all samples.	\$2,150	\$68,800
Existing Groundwater Wells (MGW02 and MGW07) – Sampling and Analysis	Collect three to four seasonal samples from MGW07 in Years 1 and 3 of postinjection and at least once every 3 years thereafter until facility closure (anticipated in Year 10 of postinjection). Collect three to four seasonal samples from MGW02 in Year 4 of postinjection and prior to facility closure (anticipated in Year 10 of postinjection).	\$1,500	\$36,000
Dedicated Fox Hills Well (MGW12) – Sampling and Analysis	Collect annually until facility closure (anticipated in Year 10 of postinjection).	\$1,500	\$15,000
Dedicated Fox Hills well (MGW14) near NDIC File No. 4942	Collect annually until facility closure (anticipated in Year 10 of postinjection).	\$1,500	\$15,000
Storage Complex Monitoring			
Time-Lapse Seismic Survey Acquisition and Processing	Collect multiple repeat time-lapse seismic surveys during postinjection, with the first survey occurring by Year 4 of postinjection. (assumes two occurrences).	\$1,750,000	\$3,500,000
Total for PISC Activities			\$4,731,800

¹ Does not include interpretation and reporting. Costs are based on 2023 pricing and do not account for inflation.

which are required to be carried out at 5-year intervals to validate models, which are expected to cover an area up to 75 mi². Additionally, at the start of the PISC period, determined by cessation of injection operations, SCS3 will P&A the KJ Hintz 1 and 2 injection wells (Table 12-2) and conduct reclamation of injection well pad and aboveground structures, if no other beneficial use is determined at that time. SCS3 would leave intact for the period of the PISC the reservoir-monitoring well and the dedicated Fox Hills monitoring wells (MGW12 and MGW14). These costs for plugging and surface facility reclamation are included in Table 12-4.

12.2.3.1 Plugging and Abandonment of Flowlines

The application must demonstrate that a financial instrument is in place sufficient to cover the costs associated with abandonment of \$100,000 or an amount determined by the Director of the DMR-O&G. This document describes the abandonment cost of the flowline and associated structures to be \$243,000 (Table 12-3b).

The FADP describes actions the operator has taken and shall take to assure state and federal regulators that sufficient financial support is in place to cover the cost of abandonment which includes:

- a) Disconnect and physically isolate the pipeline from any operating facility or other pipeline.
- b) Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.
- c) Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.
- d) Remove cathodic protection from the pipeline.
- e) Permanently plug or cap all open ends by mechanical means or welded means.

Table 12-3b. Cost Estimate for Flowline Segment NDL-326 Abandonment

Activity	Timing	Description	Total
Closure and Reclamation Costs			
Isolation of Flowline from Operating Facility or Other Pipeline	Prior to facility closure	Disconnect and physically isolate the pipeline from any operating facility or other pipeline.	\$20,000
Cut of Flowline to Be Abandoned	Prior to facility closure	Cut off the pipeline or the part of the pipeline to be abandoned below surface at pipeline level.	\$50,000
Purge Flowline	Prior to facility closure	Purge the pipeline with fresh water, air, or inert gas in a manner that effectively removes all fluid.	\$10,000
Cathodic Protection Removal	Prior to facility closure	Remove cathodic protection from the flowline.	\$10,000
Remove Launcher/Receivers	Prior to facility closure	Remove three launcher and/or receiver sites associated with NDL-326.	\$150,000
Site Reclamation	Prior to facility closure	Main line valves (MLVs)/launcher receiver sites based on 0.06 ac × 2 sites (seed, seeding, soil prep, and mobilization).	\$3,000
Total for Flowline P&A Activities			\$243,000

12.2.3.2 Facility Closure

SCS3 will prepare and apply for facility closure to the DMR-O&G and, upon authorization from the DMR-O&G, will proceed with plugging the reservoir-monitoring wells and well pad reclamation as discussed in Section 6.0 of this SFP application. The specifics of the plugging program of the reservoir-monitoring well can be found in Section 10.0. The estimate covers the aggregated P&A and reclamation cost of SCS3 reservoir-monitoring well, Slash Lazy H 5, including rig mobilization, Fox Hills monitoring well P&A, soil gas profile station P&A, workover rig and rentals, equipment and labor, cementing, logging, trucking, dirt work, supervision, and project management (Table 12-4). SCS3 is planning that the Fox Hills monitoring wells (MGW12 & MGW14) will remain in place because the groundwater monitoring locations may be wanted by DMR-O&G or SCS3 for future use; however, SCS3 has set aside funds in case P&A is required.

Table 12-4. Cost Estimate¹ for Site Closure and Remediation Activities for KJ Hintz CO₂ Storage Project

Activity	Timing	Description	Total
Closure and Reclamation Costs			
Plugging of the Slash Lazy H 5	During facility closure	Plugging activities described in Section 10 plugging plan	\$382,500
Reclamation Costs of Slash Lazy H 5 Well Pad	During facility closure	Wellhead removal, sump removal, pad reclamation (rock removal and soil coverage), fencing removal, reseeding, general labor	\$255,000
Fox Hills Monitoring Wells P&A ²	During facility closure	Pipe removal, pad reclamation (rock removal and soil coverage), reseeding, general labor of MGW12 & MGW14	\$32,000 (\$16,000 per well)
MSG P&A ²	During facility closure	P&A of MSG03 and MSG06	\$2,500 (\$1,250 per well)
Total for Closure Activities			\$672,000

¹ Does not include interpretation and reporting. Costs are based on 2023 pricing and do not account for inflation.

² P&A assumed unless DMR-O&G requests transfer of ownership.

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 of this SFP application. The ERRP assessment supports a determination that the likelihood of release of significant volumes of CO₂ 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) Continuous monitoring of transportation and injection systems.
- b) Routine measurement and reporting of CO₂ volumes.
- c) Physical security, barriers, and signage around injection facilities.
- d) Primary and secondary containment for leaked fluids at injection well pads.

A review of the ERRP technical risk categories for SCS3 identified a list of events that could potentially result in the movement of injected CO₂ 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 CO₂
- d) Containment loss – pressure propagation
- e) Containment loss – vertical migration of CO₂ 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 has occurred, the emergency response actions that will be implemented are described in the ERRP (Section 7.0) of this SFP application. SCS3 planned response actions are summarized in Table 7-6.

12.2.4.2 Estimation of Costs of Emergency Response Actions

Estimating the costs of implementing the emergency response actions in Table 7-6 is challenging since remediation measures specifically dedicated to CO₂ 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 CO₂ 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 CO₂ 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.

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/USDW, 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.

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

However, it is important to note that, at this time, no methodology is widely accepted for designing intervention and remediation plans for CO₂ geologic storage projects. In an effort to establish SCS3’s site-specific financial assurance obligation, three areas were evaluated, as follows:

- 1) Cost estimates specific to remediation within SCS3’s AOR,
- 2) Methodologies and estimates from permitted North Dakota storage facilities, and
- 3) Existing literature (Manceau and others, 2014; Bielicki and others, 2014).

12.2.4.2.2 Estimation of Costs for Implementing Emergency Event Responses

SCS3 has compiled cost estimates regarding a conservative hypothetical emergency event scenario to provide for future financial assurance. This conservative outer-limit cost estimate was calculated and used as a basis for this FADP.

Emergency Remedial Response Scenarios

The applicant formed a team to evaluate and quantify project risks based upon the scenarios described in the ERRP. The team consisted of members with relevant professional qualifications and experience in subsurface analysis, drilling engineering, facilities engineering, operations, well control events, and finance. The team evaluated and considered hypothetical scenarios for costs estimates in this document and identified site-specific financial risks.

Following the identification of financial risks, the applicant compiled cost estimates associated with a conservative hypothetical scenario wherein a failure of well integrity in an injection well causes a loss of containment in which a significant volume of CO₂ and briny water

migrates to the surface during injection operations through one of the injection wells. The conservative hypothetical scenario response action includes potential responses including but not limited to securing the location, diagnostics, well control and containment activities, remediation of injection well integrity, evaluation of environmental impacts, installation of monitoring equipment, and execution of surface remediation. The remediation plan would be discussed with DMR-O&G. The scenario contemplates a reactive response approach, e.g., mobilization of response personnel and equipment upon discovery of such an event to diagnose and develop a remediation plan. 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 ERRP 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 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

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 North Dakota Century Code (N.D.C.C.) § 43-02-05-03 west of the 83W range line, and this formation is mostly targeted for water disposal wells in those areas. Approximately 1116 ft of cap rock acts as a main seal between the Inyan Kara zone and the Broom Creek.

Inside the AOR, 38 domestic water wells, 45 stock water wells, one industrial water well, and 3 water observation wells are located in shallow aquifers, providing water for the associated farms, livestock, irrigation, and localized consumption (Figure 4-3). Two new Fox Hills monitoring wells (MGW12 and MGW14) will monitor the lowest USDW within the AOR, as shown in Figure 5-4 and discussed in the testing and monitoring strategy (Section 5.7).

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 4.0) for the SCS3 storage reservoir, two deep wells penetrate the storage complex

(one oil and gas exploration, one stratigraphic) within or in proximity to the plume boundaries and the identified pressure front. These wells are identified in Section 4.2.

12.2.4.2.3 Cost Estimates

The tables in Section 12 provide a detailed estimate, in current dollars (2023), of the cost for performing corrective actions on wells in the AOR, plugging the injection well, PISC and facility closure, endangerment to USDWs, flowline abandonment and ERRP. Table 12-1 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.

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. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, and overhead during the postinjection period. 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. SCS3 will adjust the value of the financial instruments if the cost estimates change, and it will submit any adjustment to DMR-O&G for approval (N.D.A.C. § 43-05-01-09.1[3] and N.D.A.C. § 43-05-01-19).

Tables 12-6 and 12-7 provide additional information for the future cost estimates provided in Table 12-1.

Table 12-6. Cost Estimate for Emergency and Remedial Response Plan*

Activity/Item	Cost
General Incident Response and Diagnostics	\$600,000
Well Control and Containment Activities	\$8,100,000
Well Integrity and Site Remediation Activities	\$2,400,000
Total	\$11,100,000

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence.

Table 12-7. Cost Estimate for Endangerment of USDWs*

Description	Total Estimated Amount
General Response, Delineation, and Water Replacement	\$2,100,000
Quarterly Groundwater Monitoring (10 years) and Reporting	\$750,000
P&A of Groundwater-Monitoring Wells	\$55,000
Total	\$2,905,000

* These costs are based on activities in response to a hypothetical scenario with remote risk of occurrence. Costs are based on estimates of current (2023) contract rates.

12.3 Financial Instruments

The applicant will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations (N.D.A.C. § 43-05-01-09.1. The applicant will provide financial assurance in the form of a surety bond to ensure funds are available for PISC and facility closure activities (N.D.A.C. § 43-05-01-09.1[1][a] and N.D.A.C. § 43-05-01-19). The applicant will also obtain a pollution liability policy(s) to cover emergency and remedial response costs and endangerment of USDWs under (N.D.A.C. § 43-05-01-13), and a financial instrument (surety bond) to cover the costs of plugging the injection wells (N.D.A.C. § 43-05-01-11.5). No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time.

This application presents the estimated total costs (\$20,817,800) of these activities and a breakdown apportionment across proposed financial instruments in Table 12-1. 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 DMR-O&G determines that the storage operator has fulfilled its financial obligations.

The third-party insurance, which identifies SCS3 as the covered party, will be provided by one or a combination of the companies meeting the creditworthiness and other requirements of N.D.A.C. §43-05-01-09.1. However, the greatest hypothetical exposure evaluated would be an acute upward migration through a CO₂ injection well, which would have an estimated cost of \$14,005,000 for emergency and remedial response actions, as well as identified in the endangerment of USDWs.

Coverage terms are of an indicative/estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of injection operations; however, final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations. The actual third-party insurance companies will be determined closer to the proposed injection start date and will meet both of the following criteria, as specified in N.D.A.C. §43-05-01-09.1(1)(g):

1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor's (AAA, AA, A, or BBB) or Moody's (Aaa, Aa, A, Baa).

2. The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor’s (AAA, AA, A, or BBB) or Moody’s (Aaa, Aa, A, Baa), when applicable.

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 CO₂ 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., de Lary, L., Jensen, N.B., and Réveillère, A., 2014, Mitigation and remediation technologies and practices in case of undesired migration of CO₂ from a geological storage unit—current status: *International Journal of Greenhouse Gas Control*, v. 22, p. 272–290.
- U.S. Environmental Protection Agency, 2011, Geologic sequestration of carbon dioxide—underground injection control (UIC) Program Class VI financial responsibility guidance: www.epa.gov/sites/default/files/2015-06/documents/uicfinancialresponsibilityguidancefinal072011v.pdf (accessed November 2023).

APPENDIX A

**WELL AND WELL FORMATION FLUID
SAMPLING LAB ANALYSIS**



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1201 Lincoln Hwy. ~ Nevada, IA 50201 ~ 800-362-0855 ~ Fax 515-382-3885
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Account #: 74217 **Client:** Nenet Consulting
Workorder: Slash Lazy H 5 (444)

Jean Datahan
Nenet Consulting
6844 Hwy 40
Tioga, ND 58852

Certificate of Analysis

Approval

All data reported has been reviewed and approved by:

A handwritten signature in blue ink that reads "C. Carroll".

Claudette Carroll, Lab Manager Bismarck, ND

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

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Report Date: Wednesday, April 13, 2022 1:01:11 PM

Corrected 444 - 555810



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Account #: 74217

Client: Naset Consulting

Workorder Summary

Batch Comments

METb/92 - 200.8/6020 Bis Dis DP Inst

All analytes with elevated RLs that were analyzed by method 200.8 or 6020B required dilution due to matrix. Reporting limits have been raised to account for dilution.

METb/101 - 200.8/6020 Bis Dis DP Inst

All analytes with elevated RLs that were analyzed by method 200.8 or 6020B required dilution due to matrix. Reporting limits have been raised to account for dilution.

METb/104 - 200.8/6020 Bis Dis DP Inst

All analytes with elevated RLs that were analyzed by method 200.8 or 6020B required dilution due to matrix. Reporting limits have been raised to account for dilution.

Task Comments

444001 - 541118 - WATb/76

The reporting limit for alkalinity analytes has been raised to account for matrix interference.

444001 - 541132 - METb/89

All analytes with elevated RLs that were analyzed by method 200.7 or 6010D required dilution due to matrix. Reporting limits have been raised to account for dilution.

444001 - 541136 - METb/71

Sample required dilution due to matrix. Reporting limit has been raised.

Analysis Results Comments

444001 (Broom Creek)

Sample required dilution due to matrix. Reporting limit has been raised.
(Ammonia as N)

Sample required dilution due to matrix. Reporting limit has been raised.
(Calcium)

Sample required dilution due to matrix. Reporting limit has been raised.
(Magnesium)

Sample required dilution due to matrix. Reporting limit has been raised.
(Potassium)

Sample required dilution due to matrix. Reporting limit has been raised.
(Sodium)

444001 (Broom Creek)

Sample analyzed beyond holding time.(pH)

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**Account #:** 74217**Client:** Nenet Consulting**Analytical Results**

Lab ID: 444001 **Date Collected:** 03/30/2022 10:02 **Matrix:** Groundwater
Sample ID: Broom Creek **Date Received:** 03/30/2022 11:51 **Collector:** MVTL Field Service
Temp @ Receipt (C): 7.1 **Received on Ice:** Yes

Calculated**Method: SM1030F**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	1280	meq/L		1	04/13/2022 12:59	04/13/2022 12:59	CW		
Anion Summation	1600	meq/L		1	04/13/2022 12:59	04/13/2022 12:59	CW		
Percent Difference	-11	%		1	04/13/2022 12:59	04/13/2022 12:59	CW		

Inorganic Chemistry**Method: ASTM D516-11**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	2980	mg/L	200	40	04/06/2022 13:20	04/06/2022 13:20	SRD	MA,NDA	

Method: EPA 350.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Ammonia as N	0.95	mg/L	0.2	5	04/05/2022 14:01	04/05/2022 14:01	SRD		*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrate + Nitrite as N	66.8	mg/L	8	40	03/31/2022 11:24	03/31/2022 11:24	SRD	MA,NDA	

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Organic Carbon	11.0	mg/L	0.5	20	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	99	mg/L as CaCO3	20.5	1	03/31/2022 16:20	03/31/2022 16:20	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 16:20	03/31/2022 16:20	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 16:20	03/31/2022 16:20	RAA		
Bicarbonate	99	mg/L as CaCO3	20.5	1	03/31/2022 16:20	03/31/2022 16:20	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 16:20	03/31/2022 16:20	RAA		

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**Account #:** 74217**Client:** Naset Consulting**Analytical Results**

Lab ID: 444001 **Date Collected:** 03/30/2022 10:02 **Matrix:** Groundwater
Sample ID: Broom Creek **Date Received:** 03/30/2022 11:51 **Collector:** MVTL Field Service
Temp @ Receipt (C): 7.1 **Received on Ice:** Yes

Inorganic Chemistry**Method: SM2510 B-2011 EC**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	95820	umhos/cm	1	1	04/11/2022 15:07	04/11/2022 15:07	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	7.1	units	0.1	1	03/30/2022 14:54	03/30/2022 14:54	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	54200	mg/L	2000	1000	04/05/2022 10:37	04/05/2022 10:37	EJV	MA,NDA	

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	83100	mg/L	10	1	04/01/2022 09:08	04/01/2022 09:08	RAA	MA,NDA	

Metals**Method: EPA 245.1**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Mercury, Dissolved	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA	

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Calcium	1870	mg/L	5	5	03/30/2022 16:53	04/01/2022 11:57	MDE	MA,NDA	*
Magnesium	313	mg/L	5	5	03/30/2022 16:53	04/01/2022 11:57	MDE	MA,NDA	*
Sodium	26400	mg/L	20	20	03/30/2022 16:53	04/01/2022 14:17	MDE	MA,NDA	*
Potassium	596	mg/L	5	5	03/30/2022 16:53	04/01/2022 11:57	MDE	MA,NDA	*
Iron	3.19	mg/L	0.1	1	03/30/2022 16:53	03/31/2022 13:08	SLZ	MA,NDA	
Manganese	0.12	mg/L	0.05	1	03/30/2022 16:53	03/31/2022 13:08	SLZ	MA,NDA	
Barium, Dissolved	<5	mg/L	5	50	04/05/2022 08:37	04/05/2022 12:34	SLZ	MA,NDA	
Strontium, Dissolved	67.8	mg/L	5	50	04/05/2022 08:37	04/05/2022 12:34	SLZ	MA,NDA	

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**Account #:** 74217**Client:** Naset Consulting**Analytical Results**

Lab ID: 444001 **Date Collected:** 03/30/2022 10:02 **Matrix:** Groundwater
Sample ID: Broom Creek **Date Received:** 03/30/2022 11:51 **Collector:** MVTL Field Service
Temp @ Receipt (C): 7.1 **Received on Ice:** Yes

Metals**Method: EPA 6020B**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Arsenic, Dissolved	<0.008	mg/L	0.008	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Chromium, Dissolved	0.0140	mg/L	0.008	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Lead, Dissolved	0.0046	mg/L	0.002	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Selenium, Dissolved	0.1629	mg/L	0.02	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Silver, Dissolved	<0.004	mg/L	0.004	40	04/05/2022 08:37	04/07/2022 11:26	MDE	MA,NDA	
Cadmium, Dissolved	0.0100	mg/L	0.002	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Molybdenum, Dissolved	0.8668	mg/L	0.008	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	
Copper, Dissolved	0.3068	mg/L	0.008	20	04/05/2022 08:37	04/06/2022 17:01	MDE	MA,NDA	

Sampling Information**Method: 120.1**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance - Field	109591	umhos/cm	1	1	03/30/2022 10:02	03/30/2022 10:02	DJN		

Method: 150.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH - Field	6.83	units	0.01	1	03/30/2022 10:02	03/30/2022 10:02	DJN		

Method: 170.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Temperature - Field C	11.55	degrees C		1	03/30/2022 10:02	03/30/2022 10:02	DJN		

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Account #: 74217

Client: Neset Consulting

Minnesota Valley Testing Laboratories
2616 E. Broadway Ave
Bismarck, ND 58501
(701) 258-9720

Neset Consulting
WO: 444



Chain of Custody Record

444

Report To: Neset Consulting
Attn: Jean Datahan
Address: 6844 Hwy 40
Tioga, ND 58852
Phone: 701-664-1492
Email: jeandatahan@nesetconsulting.com

CC:

Project name: **Slash Lazy H 5**
Event:
Sampled By: *Darren Nieswager*

Lab Number	Sample Information				Sample Containers					Field Readings			Analysis Required	
	Sample ID	Date	Time	Sample Type	1 Liter Raw	500 mL HNO3	500 mL HNO3 (filtered)	250 mL H2SO4	TOC (set of 3)	Temp (°C)	Spec. Cond.	pH		
001	Broom Creek	30 Mar 22	1002	GW	2	X	X	X	X	11.55	109591	6.83	See Attachment	

Comments:

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
<i>Jean Datahan</i>	30 Mar 22	Log in	TM562 / 7M805	<i>Ely Datahan</i>	30 Mar 22
	1151	Walk in #2	ROE 7.1		1151

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Account #: 74217

Client: Naset Consulting

Metal Digestion
pH
Conductivity (EC)
pH - Field
Temperature - Field
Total Alkalinity
Phenolphthalein Alk
Bicarbonate
Carbonate
Hydroxide
Conductivity - Field
Total Organic Carbon
Sulfate
Chloride
Nitrate-Nitrite as N
Ammonia-Nitrogen as N
Mercury - Dissolved
Total Dissolved Solids
Calcium - Total
Magnesium - Total
Sodium - Total
Potassium - Total
Iron - Total
Manganese - Total
Barium - Dissolved
Copper - Dissolved
Molybdenum - Dissolved
Strontium - Dissolved
Arsenic - Dissolved
Cadmium - Dissolved
Chromium - Dissolved
Lead - Dissolved
Selenium - Dissolved
Silver - Dissolved

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Account #: 74217 **Client:** Naset Consulting
Workorder: Slash Lazy H 5 (470)

Jean Datahan
Naset Consulting
6844 Hwy 40
Tioga, ND 58852

Certificate of Analysis

Approval

All data reported has been reviewed and approved by:

Claudette Carroll, Lab Manager Bismarck, ND

Analyses performed under Minnesota Department of Health Accreditation conforms to the current TNI standards.

NEW ULM LAB CERTIFICATIONS:
MN LAB # 027-015-125 ND WW/DW # R-040

BISMARCK LAB CERTIFICATIONS:
MN LAB # 038-999-267 ND W/DW # ND-016 SD SDWA

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Account #: 74217

Client: Nese Consulting

Workorder Summary

Batch Comments

METb/92 - 200.8/6020 Bis Dis DP Inst

All analytes with elevated RLs that were analyzed by method 200.8 or 6020B required dilution due to matrix. Reporting limits have been raised to account for dilution.

METb/101 - 200.8/6020 Bis Dis DP Inst

All analytes with elevated RLs that were analyzed by method 200.8 or 6020B required dilution due to matrix. Reporting limits have been raised to account for dilution.

Task Comments

470001 - 542991 - WATb/76

The reporting limit for alkalinity analytes has been raised to account for matrix interference.

470001 - 543005 - METb/89

All analytes with elevated RLs that were analyzed by method 200.7 or 6010D required dilution due to matrix. Reporting limits have been raised to account for dilution.

470001 - 543008 - METb/94

Sample required dilution due to matrix. Reporting limit has been raised.

470001 - 543009 - METb/88

All analytes with elevated RLs that were analyzed by method 200.7 or 6010D required dilution due to matrix. Reporting limits have been raised to account for dilution.

Analysis Results Comments

470001 (Inyan Kara)

Sample required dilution due to matrix. Reporting limit has been raised.
(Ammonia as N)

Sample required dilution due to matrix. Reporting limit has been raised.
(Nitrate + Nitrite as N)

Sample required dilution due to matrix. Reporting limit has been raised.
(Sulfate)

470001 (Inyan Kara)

Sample analyzed beyond holding time.(pH)

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Report Date: Wednesday, April 13, 2022 12:50:15 PM

Corrected 470 - 555821

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**Account #:** 74217**Client:** Naset Consulting**Analytical Results**

Lab ID: 470001 **Date Collected:** 03/31/2022 00:38 **Matrix:** Groundwater
Sample ID: Inyan Kara **Date Received:** 03/31/2022 08:06 **Collector:** MVTL Field Service
Temp @ Receipt (C): 0.2 **Received on Ice:** Yes

Calculated**Method: SM1030F**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Cation Summation	230	meq/L		1	04/13/2022 12:38	04/13/2022 12:38	CW		
Anion Summation	252	meq/L		1	04/13/2022 12:38	04/13/2022 12:38	CW		
Percent Difference	-4.7	%		1	04/13/2022 12:38	04/13/2022 12:38	CW		

Inorganic Chemistry**Method: ASTM D516-11**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Sulfate	115	mg/L	25	5	04/06/2022 14:05	04/06/2022 14:05	SRD	MA,NDA	*

Method: EPA 350.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Ammonia as N	6.05	mg/L	0.2	5	04/05/2022 13:53	04/05/2022 13:53	SRD		*

Method: EPA 353.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Nitrate + Nitrite as N	<1	mg/L	1	5	04/07/2022 10:58	04/07/2022 10:58	SRD	MA,NDA	*

Method: SM 5310C-2014

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Organic Carbon	28.9	mg/L	0.5	40	04/01/2022 10:04	04/01/2022 10:04	NS	MA,NDA	

Method: SM2320 B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Alkalinity, Total	778	mg/L as CaCO3	20.5	1	03/31/2022 22:12	03/31/2022 22:12	RAA	MA,NDA	
Alkalinity, Phenolphthalein	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 22:12	03/31/2022 22:12	RAA		
Carbonate	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 22:12	03/31/2022 22:12	RAA		
Bicarbonate	778	mg/L as CaCO3	20.5	1	03/31/2022 22:12	03/31/2022 22:12	RAA		
Hydroxide	<20.5	mg/L as CaCO3	20.5	1	03/31/2022 22:12	03/31/2022 22:12	RAA		

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**Account #:** 74217**Client:** Neset Consulting**Analytical Results**

Lab ID: 470001 **Date Collected:** 03/31/2022 00:38 **Matrix:** Groundwater
Sample ID: Inyan Kara **Date Received:** 03/31/2022 08:06 **Collector:** MVTL Field Service
Temp @ Receipt (C): 0.2 **Received on Ice:** Yes

Inorganic Chemistry**Method: SM2510 B-2011 EC**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance	19490	umhos/cm	1	1	03/31/2022 22:12	03/31/2022 22:12	RAA	MA,NDA	

Method: SM4500 H+ B-2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH	8.0	units	0.1	1	03/31/2022 22:12	03/31/2022 22:12	RAA	MA,NDA	*

Method: SM4500-Cl-E 2011

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Chloride	8300	mg/L	200	100	04/05/2022 10:56	04/05/2022 10:56	EJV	MA,NDA	

Method: USGS I-1750-85

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Total Dissolved Solids	12800	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, Dissolved	<0.0002	mg/L	0.0002	1	04/05/2022 10:00	04/05/2022 16:06	AMC	MA,NDA	

Method: EPA 6010D

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Calcium	86.3	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:38	MDE	MA,NDA	
Magnesium	15.0	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:38	MDE	MA,NDA	
Sodium	5120	mg/L	10	10	03/31/2022 17:20	04/06/2022 14:20	MDE	MA,NDA	
Potassium	39.1	mg/L	1	1	03/31/2022 17:20	04/06/2022 10:38	MDE	MA,NDA	
Iron	3.29	mg/L	0.5	5	03/31/2022 17:20	04/05/2022 11:20	SLZ	MA,NDA	
Manganese	<0.25	mg/L	0.25	5	03/31/2022 17:20	04/05/2022 11:20	SLZ	MA,NDA	
Barium, Dissolved	2.93	mg/L	0.5	5	04/05/2022 08:37	04/05/2022 13:27	SLZ	MA,NDA	
Strontium, Dissolved	3.66	mg/L	0.5	5	04/05/2022 08:37	04/05/2022 13:27	SLZ	MA,NDA	

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**Account #:** 74217**Client:** Naset Consulting**Analytical Results**

Lab ID: 470001 **Date Collected:** 03/31/2022 00:38 **Matrix:** Groundwater
Sample ID: Inyan Kara **Date Received:** 03/31/2022 08:06 **Collector:** MVTL Field Service
Temp @ Receipt (C): 0.2 **Received on Ice:** Yes

Metals**Method: EPA 6020B**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Arsenic, Dissolved	0.0059	mg/L	0.004	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Chromium, Dissolved	<0.004	mg/L	0.004	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Lead, Dissolved	<0.001	mg/L	0.001	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Selenium, Dissolved	<0.01	mg/L	0.01	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Silver, Dissolved	<0.001	mg/L	0.001	10	04/05/2022 08:37	04/07/2022 10:27	MDE	MA,NDA	
Cadmium, Dissolved	<0.001	mg/L	0.001	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Molybdenum, Dissolved	0.0056	mg/L	0.004	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	
Copper, Dissolved	0.0207	mg/L	0.004	10	04/05/2022 08:37	04/06/2022 15:57	MDE	MA,NDA	

Sampling Information**Method: 120.1**

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Specific Conductance - Field	22207	umhos/cm	1	1	03/31/2022 00:38	03/31/2022 00:38	DJN		

Method: 150.2

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
pH - Field	7.59	units	0.01	1	03/31/2022 00:38	03/31/2022 00:38	DJN		

Method: 170.1

Parameter	Results	Units	RDL	DF	Prepared	Analyzed	By	Cert	Qual
Temperature - Field C	15.42	degrees C		1	03/31/2022 00:38	03/31/2022 00:38	DJN		

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Account #: 74217

Client: Neset Consulting

	Minnesota Valley Testing Laboratories 2616 E. Broadway Ave Bismarck, ND 58501 (701) 258-9720	Neset Consulting WO: 470 	Chain of Custody Record

Report To: Neset Consulting Attn: Jean Datahan Address: 6844 Hwy 40 Tioga, ND 58852 Phone: 701-664-1492 Email: jeandatahan@nesetconsulting.com	CC:	Project Name: Slash Lazy H 5 Event: Sampled By: <i>Danica N. Harvey</i>
--	-----	--

Lab Number	Sample ID	Date	Time	Sample Type	Sample Containers						Field Readings			Analysis Required	
					1 Liter Raw	500 mL HNO3	500 mL HNO3 (filtered)	250 mL H2SO4	TOC (set of 3)	Temp (°C)	Spec. Cond.	pH			
001	Injan kara	31Mar22	0038	GW	2	X	X	X	X		15.42	22207	7.59	See Attachment	

Comments:

Relinquished By		Sample Condition		Received By	
Name	Date/Time	Location	Temp (°C)	Name	Date/Time
<i>Danica N. Harvey</i>	31Mar22 0806	Log In Walk In #2	TM562 / TM805 0.2 ROT	<i>Sely Ardan</i>	31Mar22 0800

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Account #: 74217

Client: Naset Consulting

Metal Digestion
pH
Conductivity (EC)
pH - Field
Temperature - Field
Total Alkalinity
Phenolphthalein Alk
Bicarbonate
Carbonate
Hydroxide
Conductivity - Field
Total Organic Carbon
Sulfate
Chloride
Nitrate-Nitrite as N
Ammonia-Nitrogen as N
Mercury - Dissolved
Total Dissolved Solids
Calcium - Total
Magnesium - Total
Sodium - Total
Potassium - Total
Iron - Total
Manganese - Total
Barium - Dissolved
Copper - Dissolved
Molybdenum - Dissolved
Strontium - Dissolved
Arsenic - Dissolved
Cadmium - Dissolved
Chromium - Dissolved
Lead - Dissolved
Selenium - Dissolved
Silver - Dissolved

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APPENDIX B

FRESHWATER WELL FLUID SAMPLING

B-1. FRESHWATER WELL FLUID SAMPLING

Table B-1 summarizes the results from existing groundwater wells for ranges of pH, electrical conductivity (EC), total dissolved solids (TDS), and total alkalinity measured from 2 monitoring sites within KJ Hintz area of review (AOR). Monitoring sites were selected to supplement forthcoming groundwater sampling to establish baseline conditions. Figure B-1 is a map showing the locations of the selected monitoring sites. Water chemistry results are included below.

Table B-1. Summary of Water Chemistries¹ at Two Sampling Locations Within the Area of Review (AOR) at KJ Hintz

Number of Wells	Water Samples	Data Vintage	Sampling Horizon	pH	EC, mS/cm	TDS, mg/L	Total Alkalinity, mg/L CaCO₃
1	1	1967	Fox Hills	8.1	3200	1940	1020
1	1	1994	Unknown	7.83	1190	839–4260	NA

KJ HINTZ/SLASH LAZY H 5

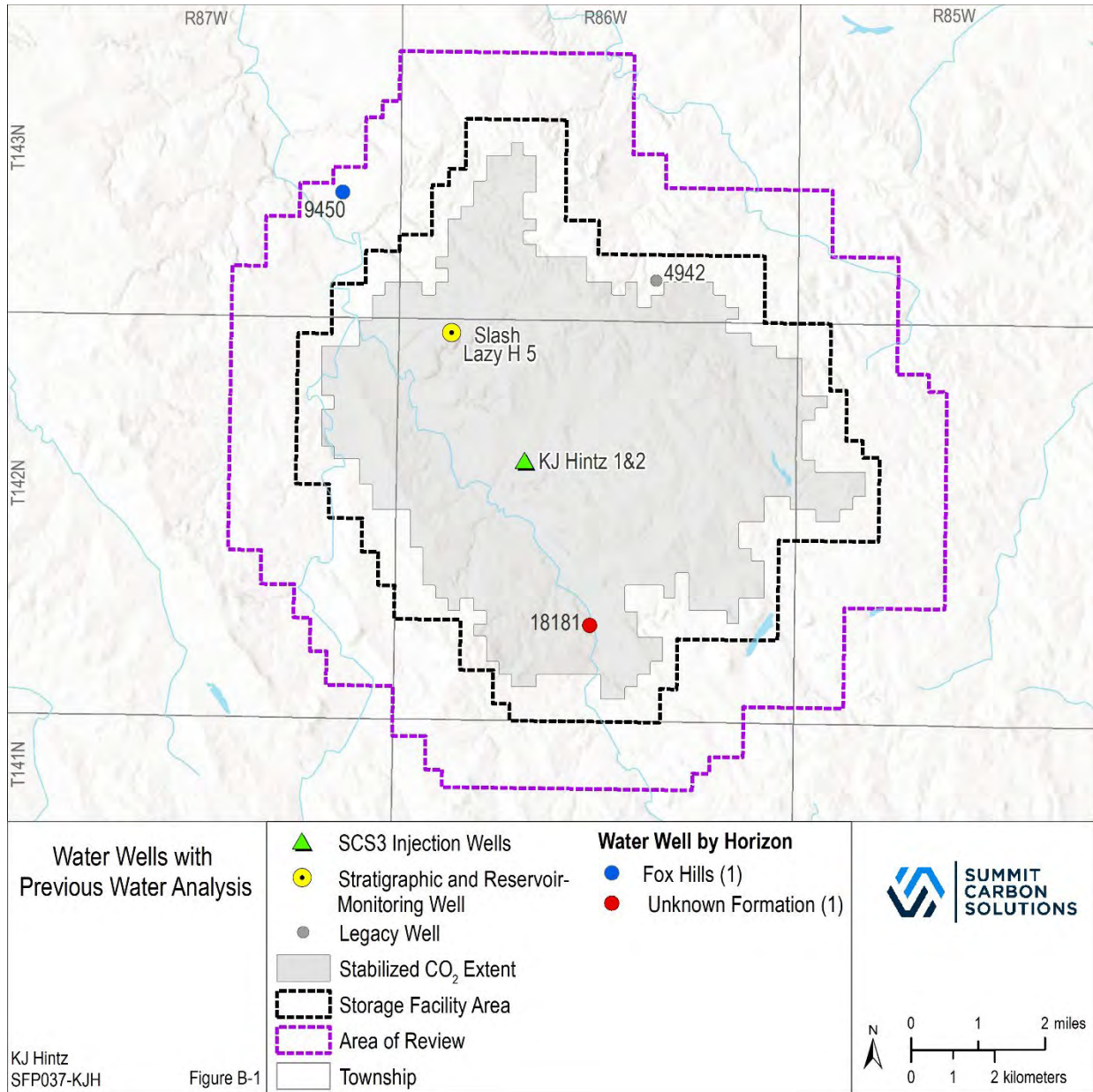


Figure B-1. Locations of the two water wells with previous water analysis results within the AOR.

APPENDIX C
GEOCHEMICAL INTERACTIONS

C.1 GEOCHEMICAL INTERACTIONS

C.1.1 Geochemical Interaction of Injection Zone (Broom Creek Formation)

Geochemical simulation has been performed to calculate the effects of introducing the CO₂ stream to the injection zone. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). GEM is also the primary simulation software used for evaluation of the reservoir's dynamic behavior resulting from the expected CO₂ injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum bottomhole pressure (BHP) and maximum wellhead pressure (WHP) constraints of 3828 and 2100 psi, respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO₂ injection is stopped.

The anticipated average CO₂ stream composition is 98.25% CO₂, 1.44% N₂, and 0.31% O₂, with a trace amount of H₂S. The CO₂ stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O₂ (2%). The modeled stream containing ~95% CO₂ and 2% O₂ was used to represent a conservative scenario where the oxygen concentration is highest, potentially triggering more geochemical reactions in the formation. This simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figures C-1 and C-2).

The case with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (78% of bulk reservoir volume) and average formation brine composition (22% of bulk reservoir volume). X-ray diffraction (XRD) data from the Slash Lazy H 5 core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table C-2). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the Broom Creek Formation water, derived from the state-certified analysis reported in Appendix A, is listed in Table C-3.

Table C-1. CO₂ Stream Composition Used for Geochemical Modeling

Component	mol%
CO ₂	94.999
N ₂	3
O ₂	2
H ₂ S	1.0E-3

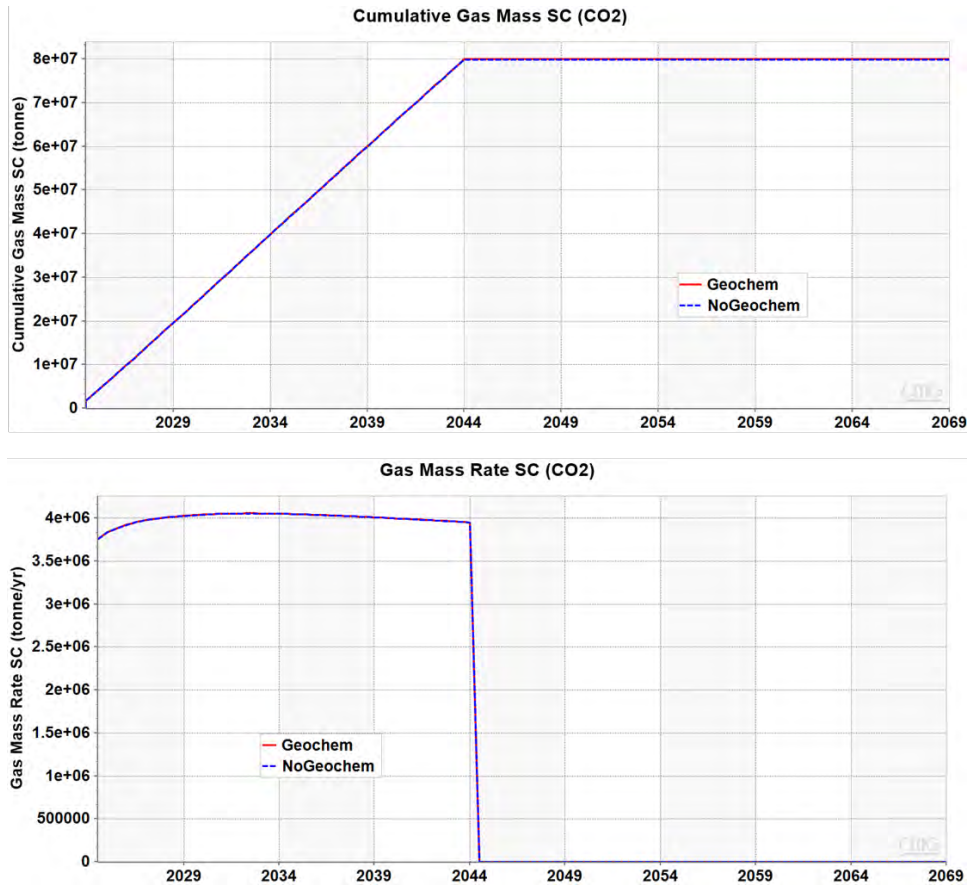


Figure C-1. Top graph shows cumulative injection vs. time; bottom graph shows gas injection rate vs. time. There is no observable difference in injection volume and gas rate due to geochemical reactions.

KJ HINTZ/SLASH LAZY H 5

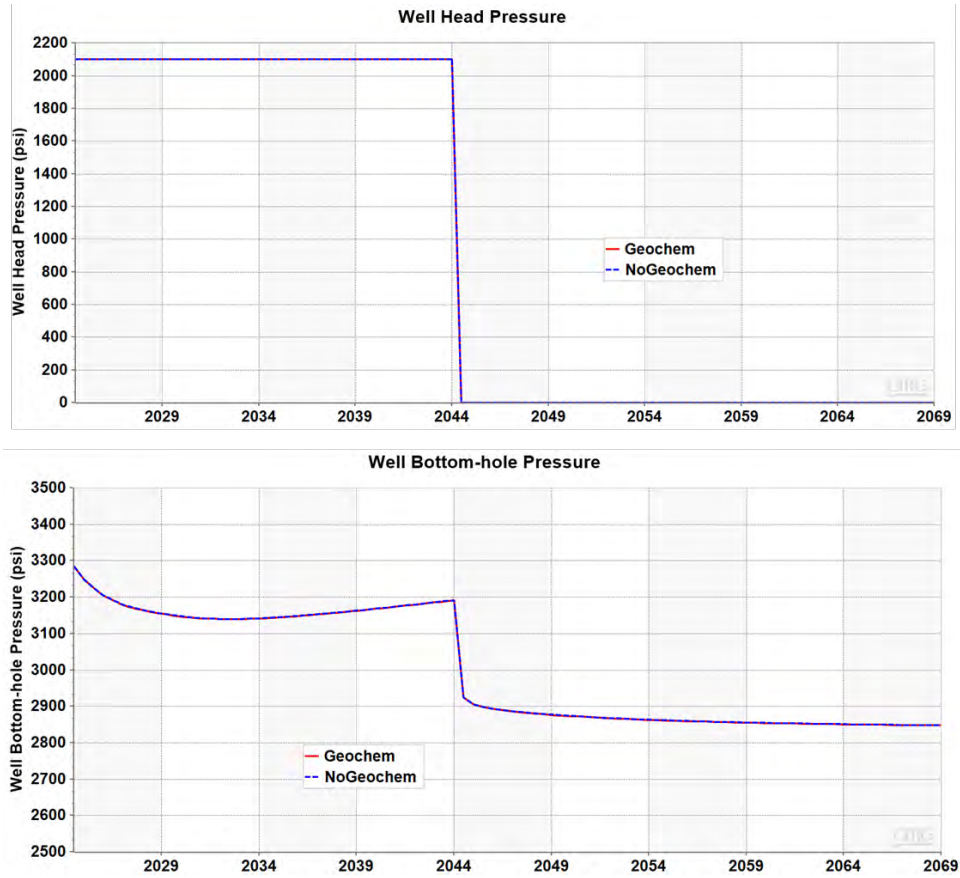


Figure C-2. Top graph shows WHP vs. time; bottom graph shows BHP vs. time. There is no observable difference in pressures due to geochemical reactions.

**Table C-2. Averaged XRD data for
(Slash Lazy H 5) Broom Creek
Core Sample**

Mineral Data	wt%
Illite	4.67
K-Feldspar	5.99
Albite	0.81
Quartz	44.77
Dolomite	34.37
Anhydrite	9.33
Siderite	1.00E-08
Hematite	0.05
Ankerite	1.00E-08
Fe(OH) ₃	1.00E-08

Table C-3. Slash Lazy H5 Broom Creek Formation Water Ionic Composition

Component	mg/L	Molality
Na ⁺	26,400	1.185627
K ⁺	596	0.015739
Ca ²⁺	1870	0.048175
Mg ²⁺	313	0.013296
Fe ²⁺	3.19	5.9E-05
SO ₄ ²⁻	2980	3.20E-02
Cl ⁻	54,200	1.578444
HCO ₃ ⁻	99	1.68E-03
H ⁺	8.0068E-05	8.2E-08
Al ³⁺	1E-10	3.83E-15
OH ⁻	0.01073132	6.51E-07
SiO ₂ (aq)	1.00E-10	1.72E-15
CO ₃ ²⁻	0.00001	1.72E-10
Fe ³⁺	1.00E-10	1.86E-15

The results do not show an evident difference in the CO₂ gas molality fraction between both cases as seen in Figures C-1 and C-2 for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection rate have no observable difference between the geochemical and nongeochemical cases. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.

Figure C-3 shows the location of the cross sections and Layer 30 used in Figures C-4a and C-4b to depict the geochemical modeling results. Figures C-4a and C-4b show the concentration of CO₂, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model and nongeochemistry model, respectively.

The pH of the reservoir brine changes in the vicinity of the CO₂ accumulation, as shown in Figure C-5a. The pH of the Broom Creek Formation native brine sample is 7.1 whereas the fluid pH goes down to approximately 4.7 in the CO₂-flooded areas near the well as a result of CO₂ dissolution in the native formation brine (Figure C-5b).

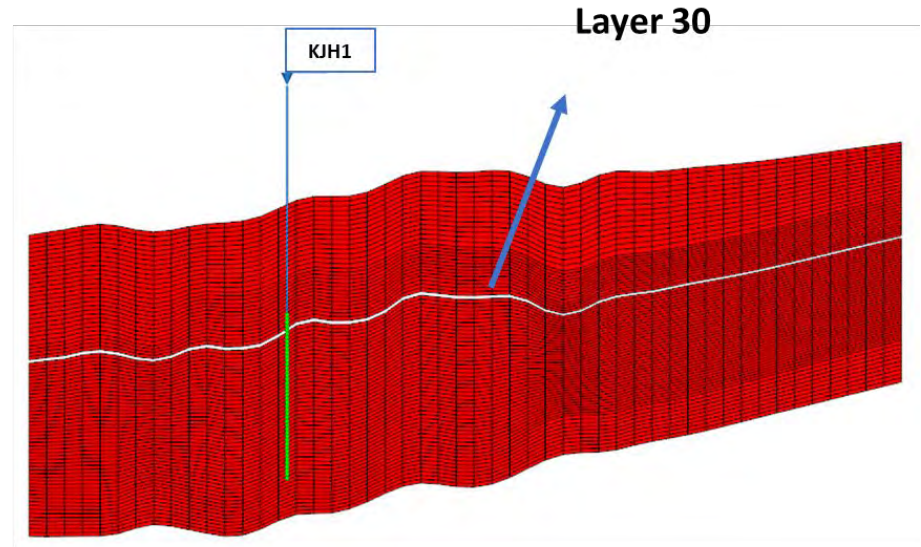
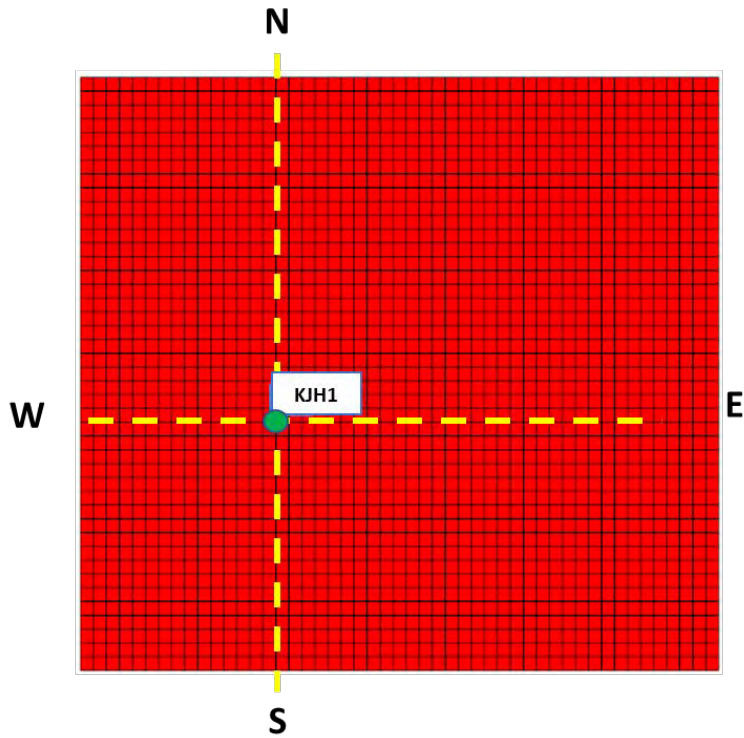
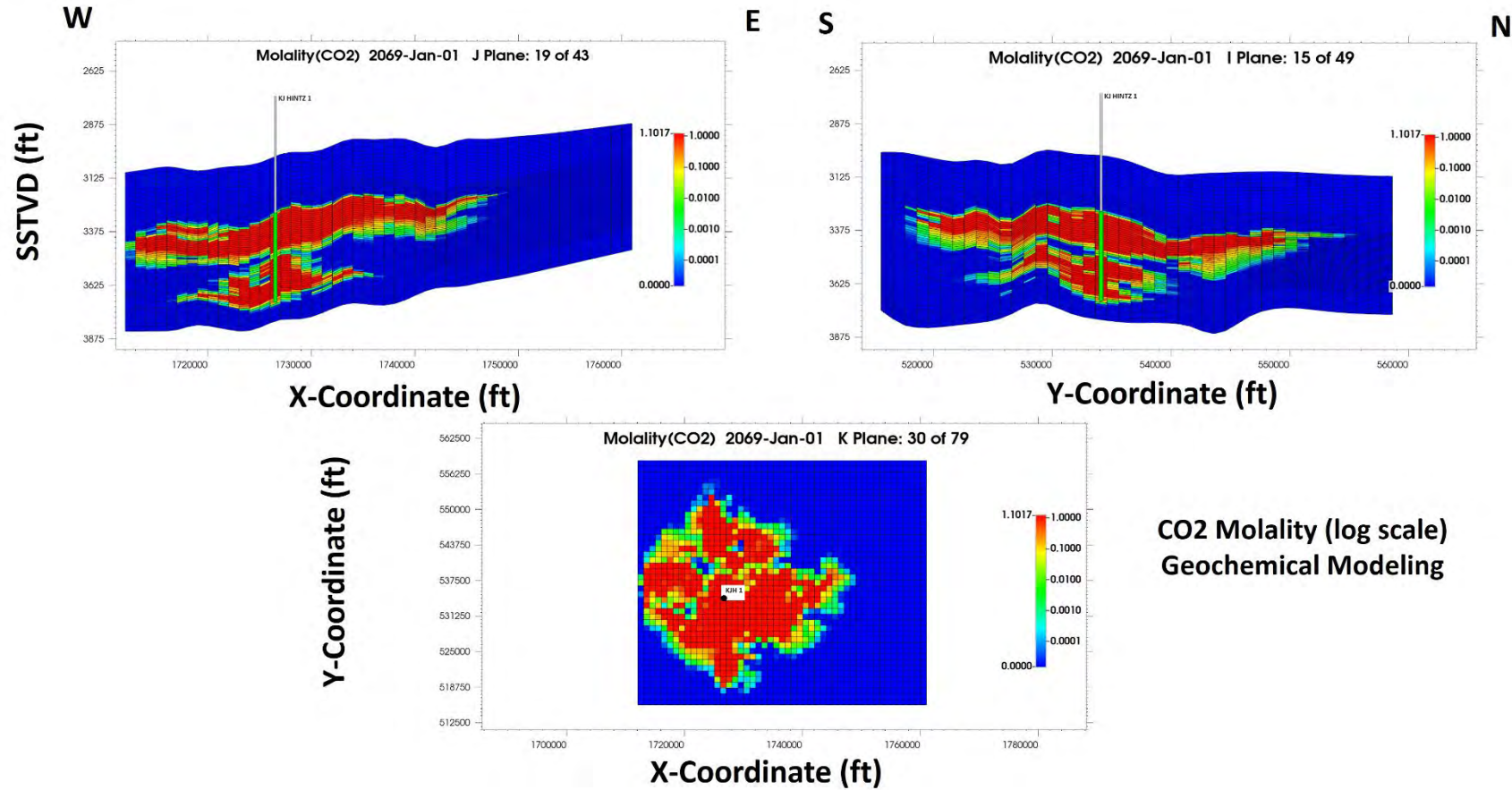


Figure C-3. Index map of west-east and south-north cross sections and simulation Layer 30 at 3332.7 ft (SSTVD, subsea true vertical depth).



CO₂ Molality (log scale)
Geochemical Modeling

Figure C-4a. CO₂ molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO₂ molality in 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 30 at 3332.7 ft (SSTVD).

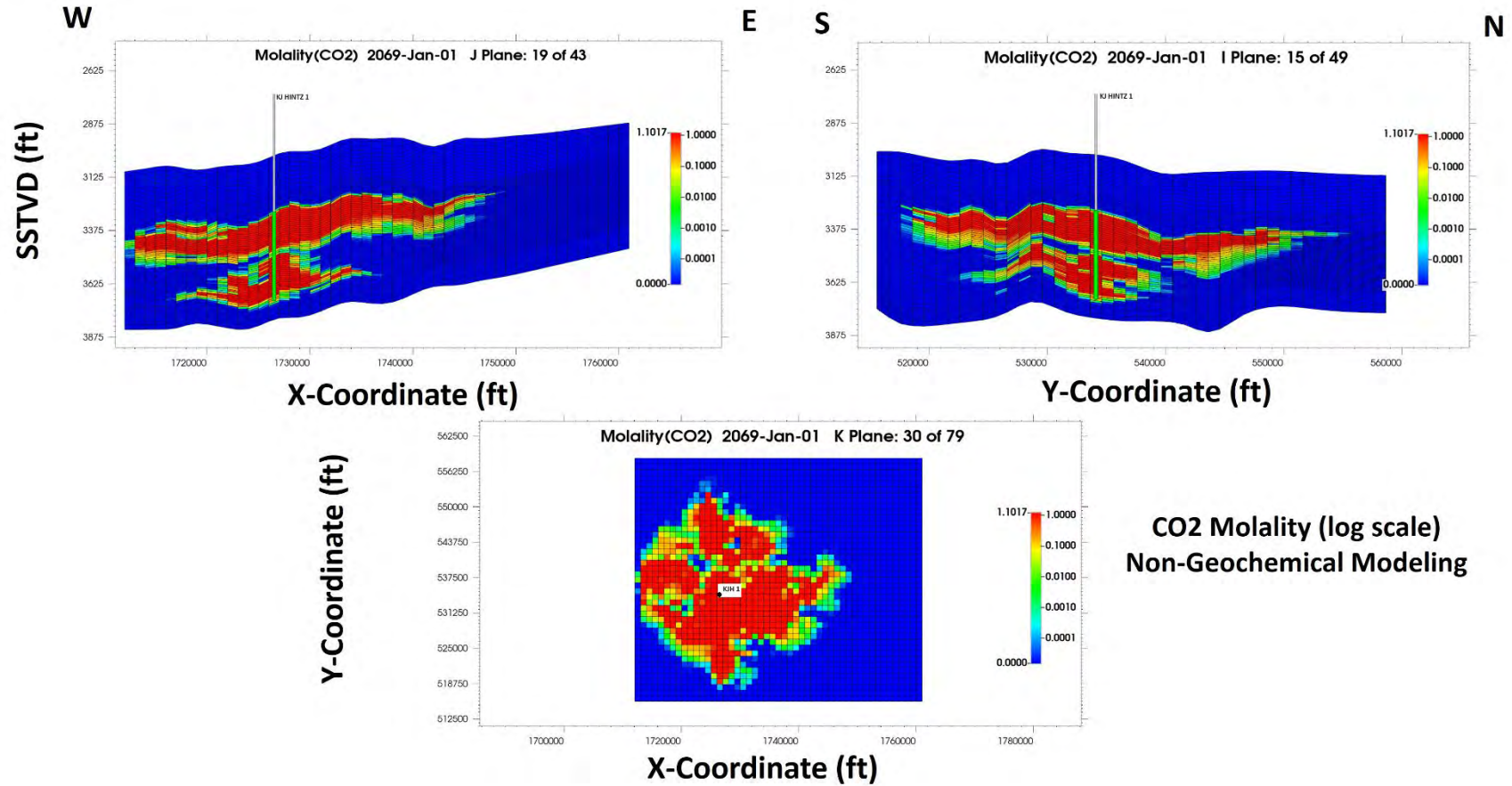


Figure C-4b. CO₂ molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO₂ molality in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD).

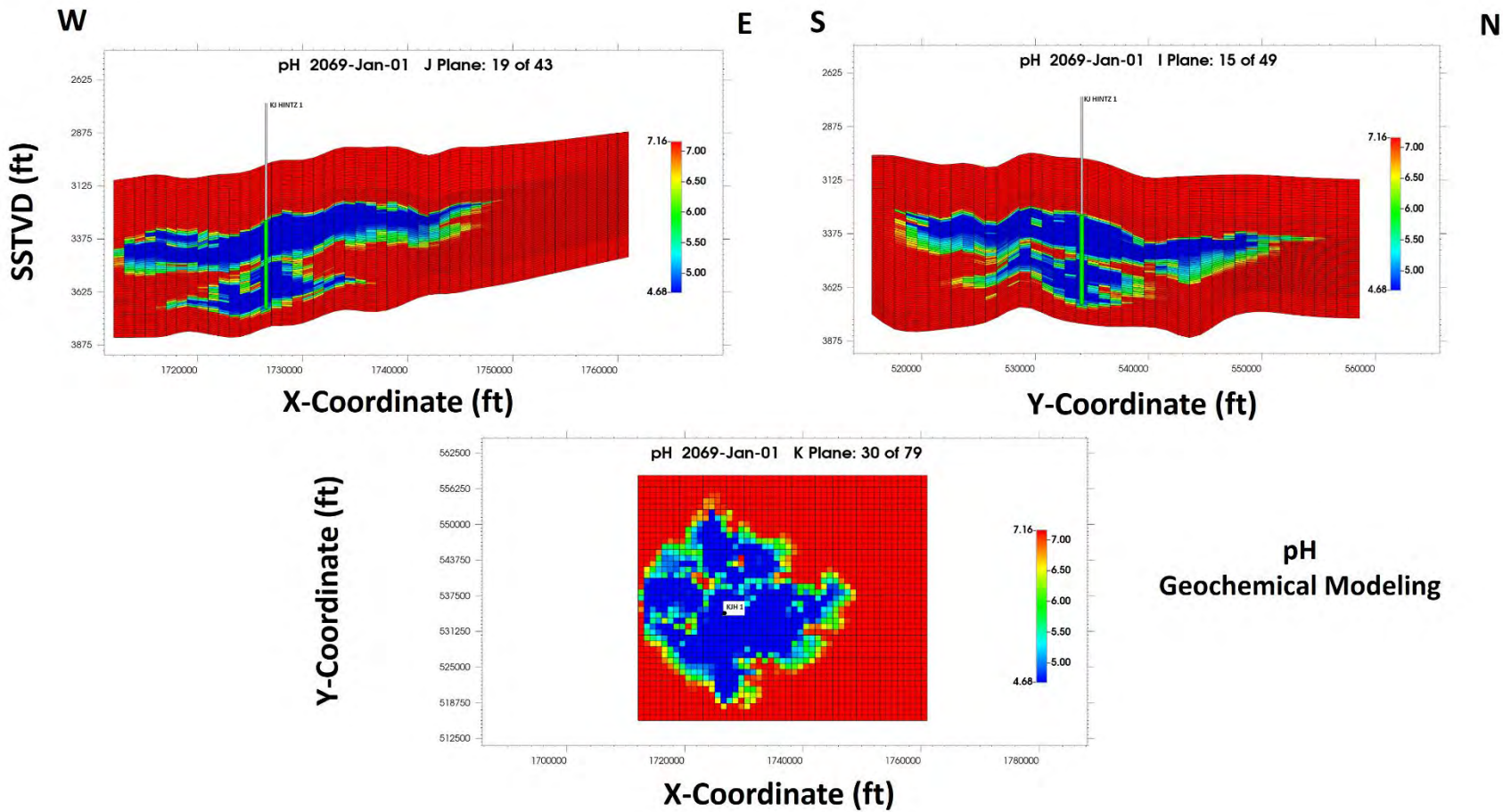


Figure C-5a. Geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the pH of formation brine in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD).

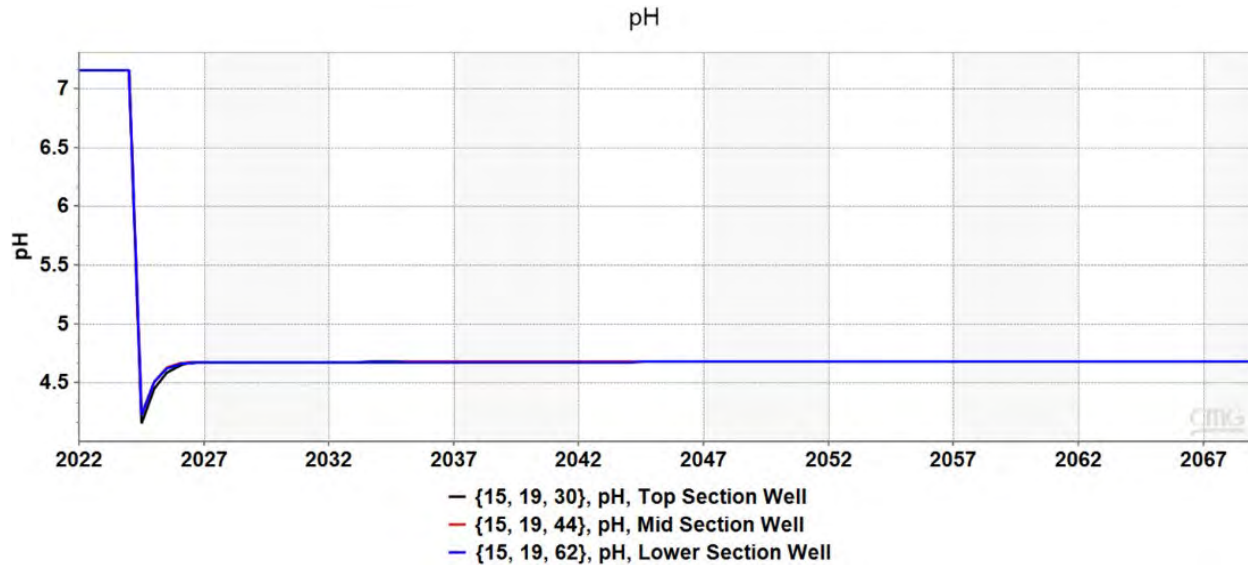
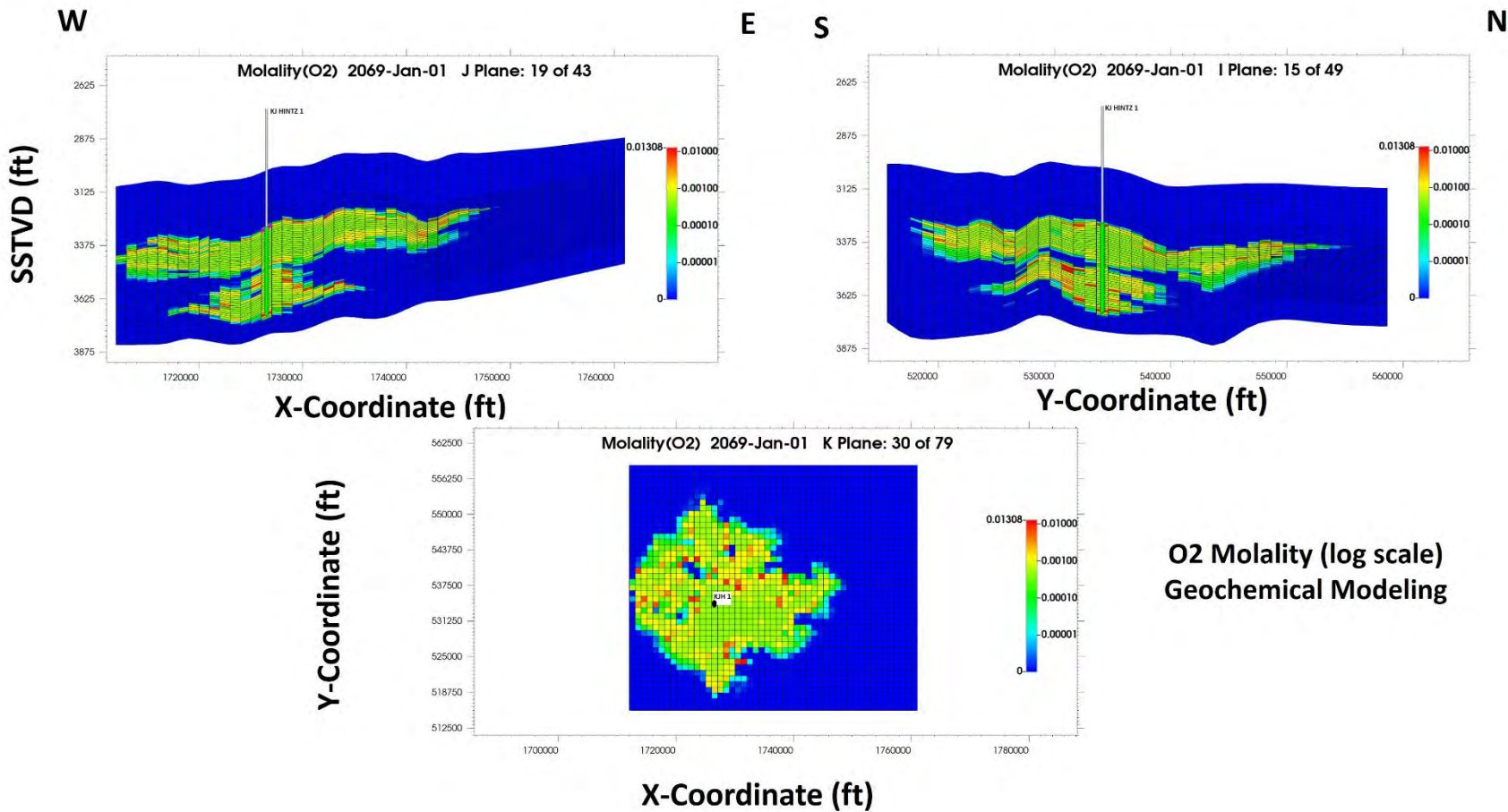


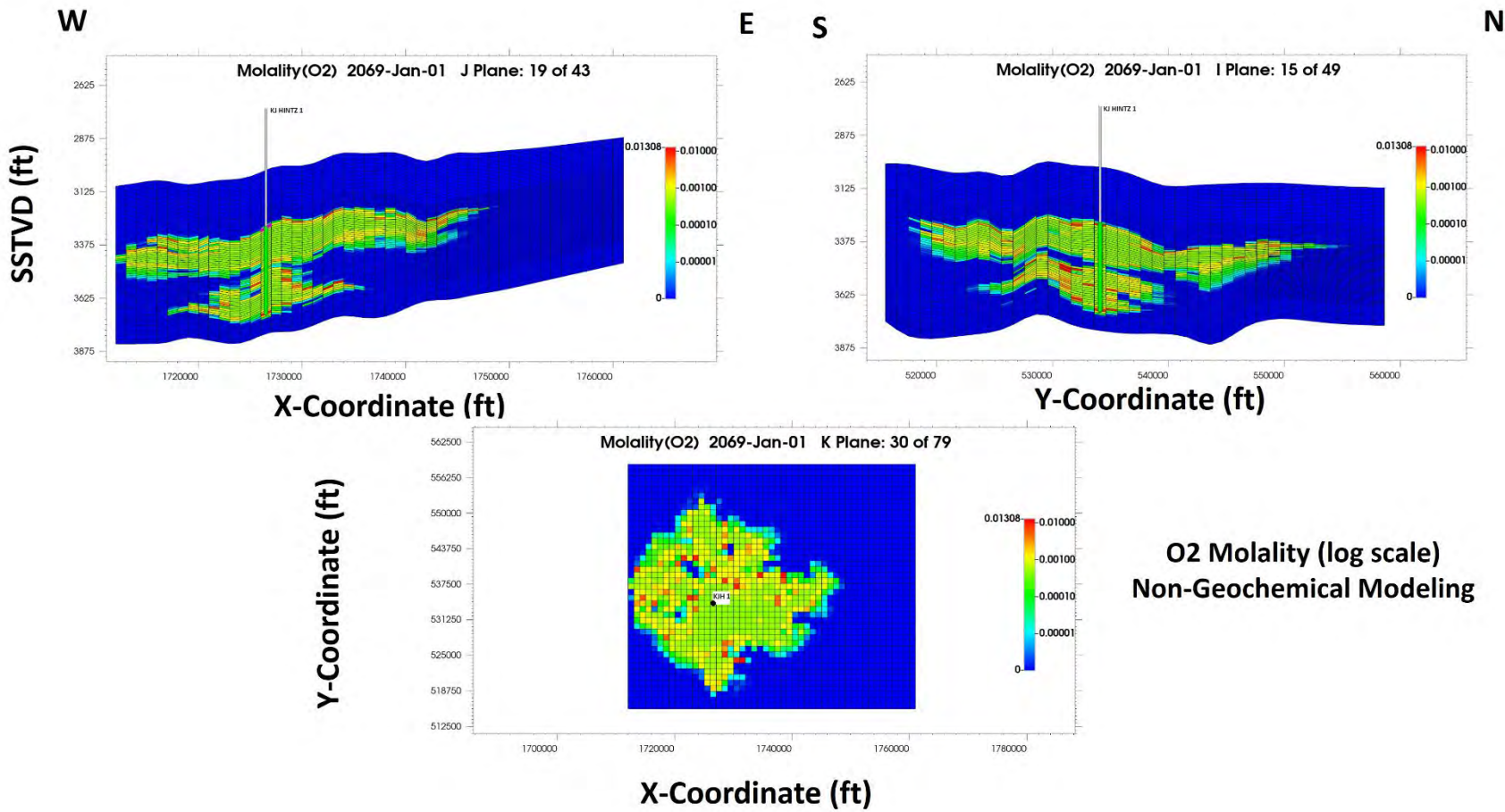
Figure C-5b. Geochemistry case simulation results through 20 years of injection plus 25 years postinjection showing the pH of the Broom Creek Formation brine at the wellbore vs. time for Layer 30 at 3332.7 ft (SSTVD), Layer 44 at 3463.3 ft (SSTVD), and Layer 62 at 3631.3 ft (SSTVD).

Figures C-6a and C-6b show the cross section for O_2 molality in the Broom Creek Formation. Figure C-6a 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 C-6b shows the same information for the nongeochimistry simulation case for comparison. The results do not show an evident difference in the O_2 gas molality fraction between both cases. After being injected, the 2% molar oxygen content in the injection 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 C-2.



O₂ Molality (log scale)
Geochemical Modeling

Figure C-6a. Cross section for O₂ molality for the geochemistry case simulation results after 20 years of injection plus 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 30 at 3332.7 ft (SSTVD).



O₂ Molality (log scale)
Non-Geochemical Modeling

Figure C-6b. Cross section for O₂ molality for the nongeochemistry case simulation results after 20 years of injection plus 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 30 at 3332.7 ft (SSTVD).

Figure C-7 shows the mass of mineral dissolution and precipitation due to CO₂ injection in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral, while anhydrite is the most prominent precipitated mineral. All other minerals showed very limited variations.

Simulation results show that, during CO₂ injection, the supercritical CO₂ (free-CO₂ gas) remains dominant. CO₂ dissolution in the formation water and residual trapping of CO₂ slowly increased over time, while CO₂ mineralization is negligible at the plot scale in Figure C-7 it can be observed at the plot scale in Figure C-8. Once CO₂ injection ceases in 2044, injected concentrated CO₂ begins to expand, resulting in more CO₂ that is capillary-trapped or dissolved into fresh brine, as evidenced by the crossover in Figure C-8. Figures C-9 and C-10, respectively, provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most precipitation, anhydrite. Considering the apparent net dissolution of minerals in the system, as indicated in Figure C-7, there is an associated net increase in porosity in the affected areas, as shown in Figure C-11. Del Porosity Mineral (DPORMNR) output calculates the porosity change due to mineral dissolution/precipitation. It is calculated as Initial Porosity – Porosity at Time “t.” Negative values of this output indicate net mineral dissolution (porosity increase), while positive values indicate net mineral precipitation (porosity decrease). However, the porosity change is small, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years of postinjection.

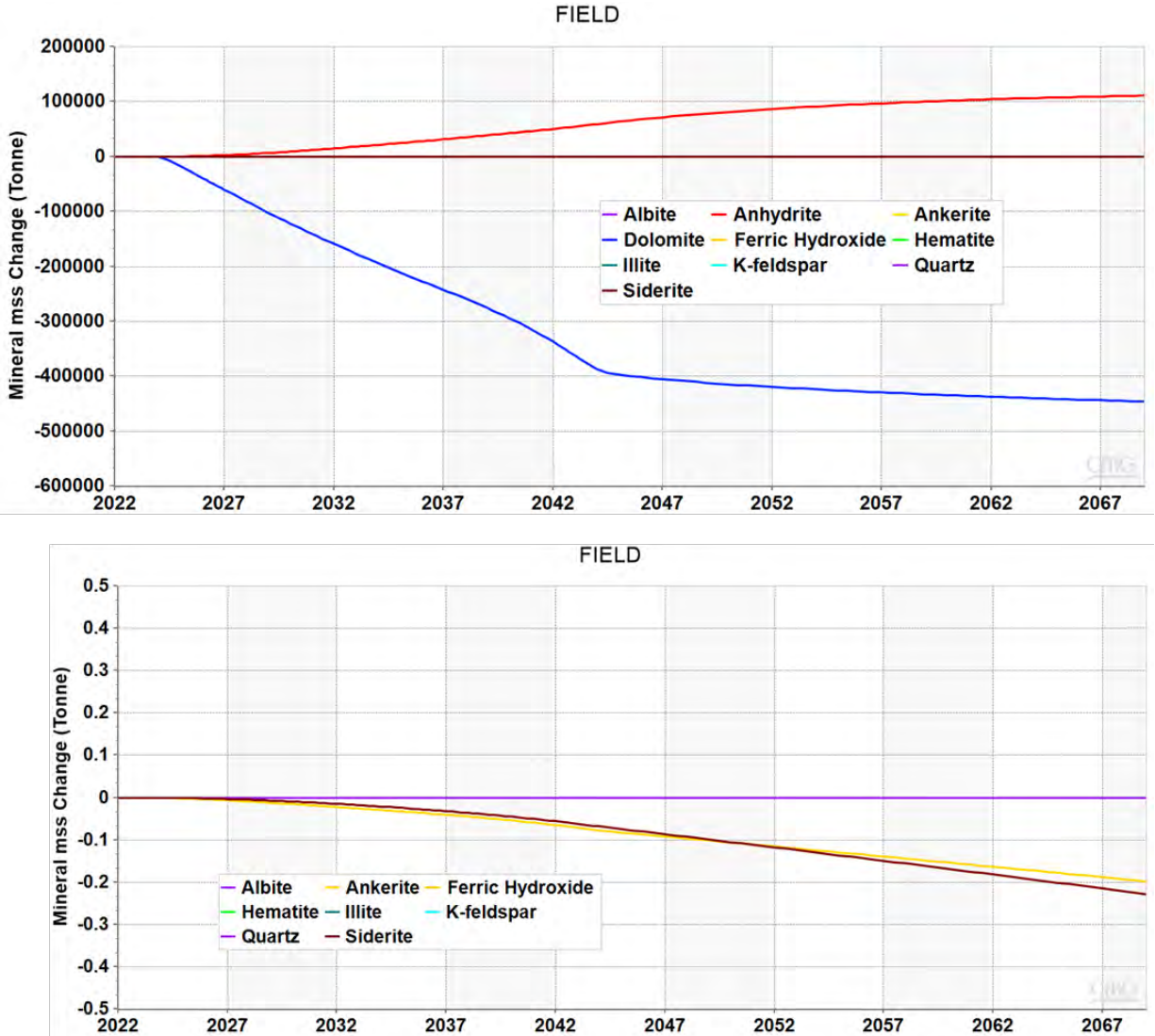


Figure C-7. Modeled change in the mineral masses (minus values show dissolution and positive values show precipitation) due to CO₂ injection (top: all minerals; bottom: zoomed-in after removing anhydrite and dolomite). Dissolution of dolomite with precipitation of anhydrite was observed. All of the other minerals showed very small values and account as net zero in this figure.



Figure C-8. Top image: mineral mass changes, in metric tons (tonnes), for the different CO₂-trapping mechanisms present during CO₂ injection with geochemical modeling in the injection zone for the Broom Creek Formation; bottom image: CO₂ mineral trapping.

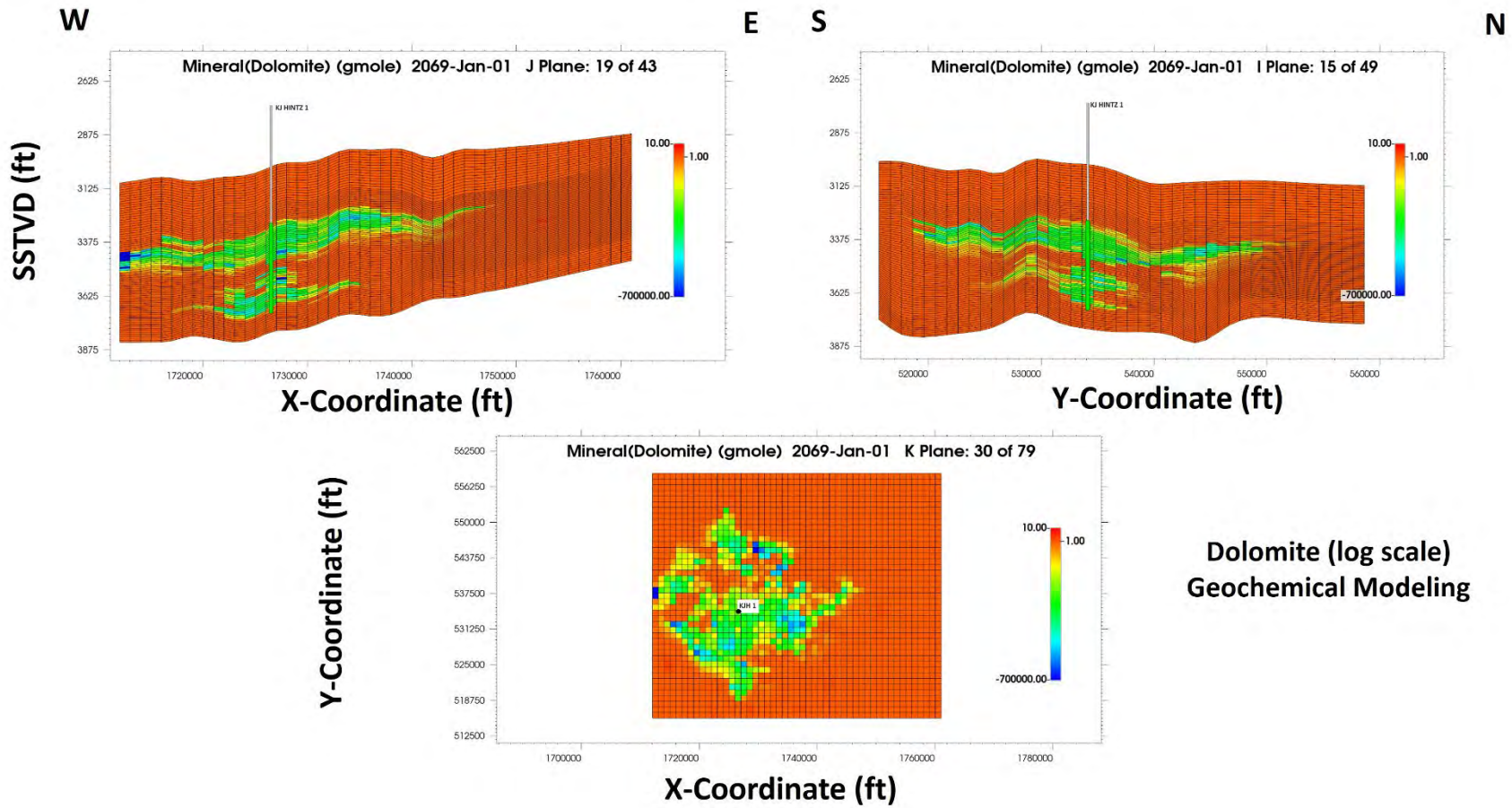


Figure C-9. Modeled change in molar distribution of dolomite, the most prominent dissolved mineral after 20 years of injection plus 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD).

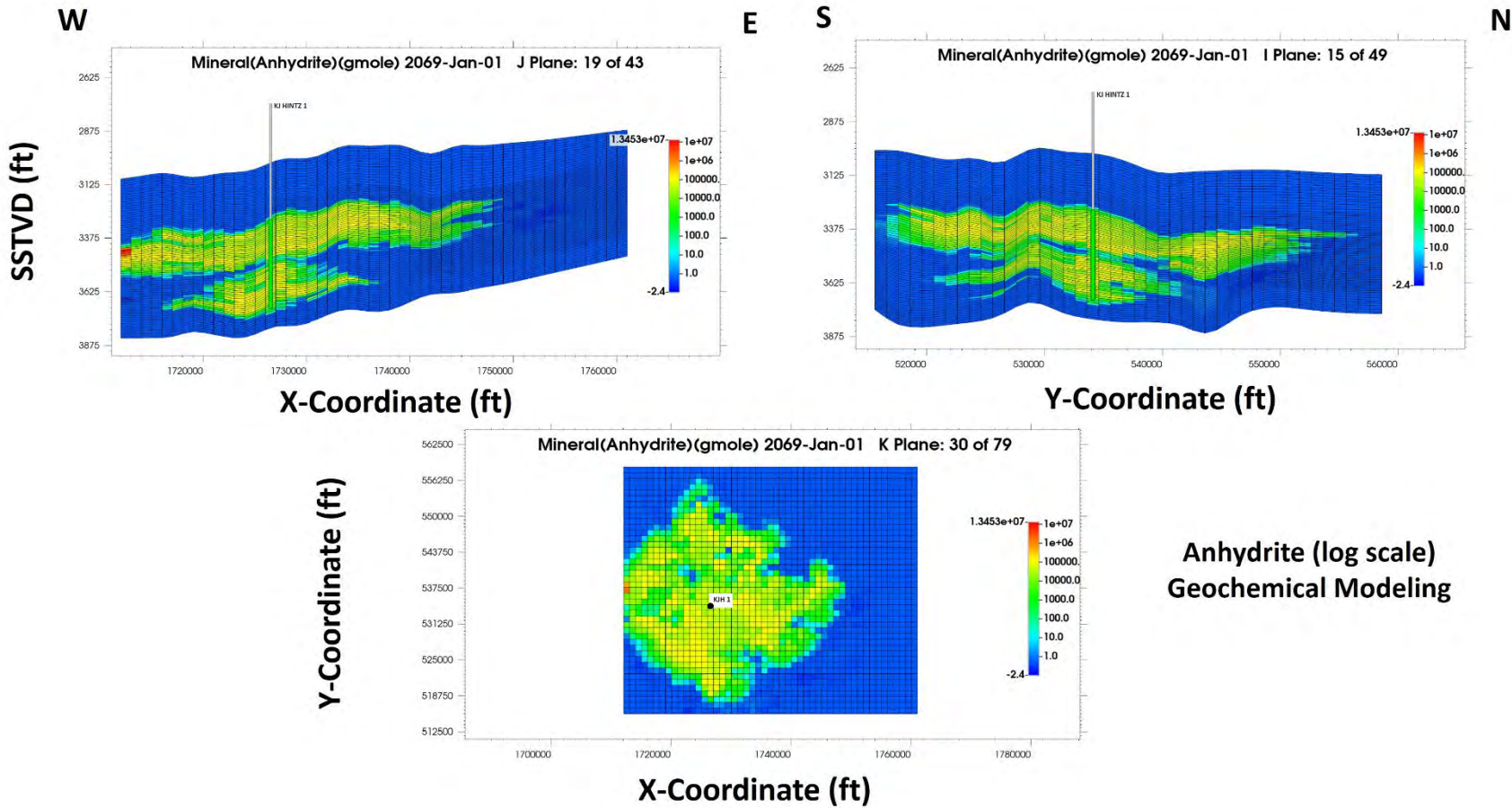


Figure C-10. Modeled change in molar distribution of anhydrite, the most prominent precipitated mineral after 20 years of injection plus 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD).

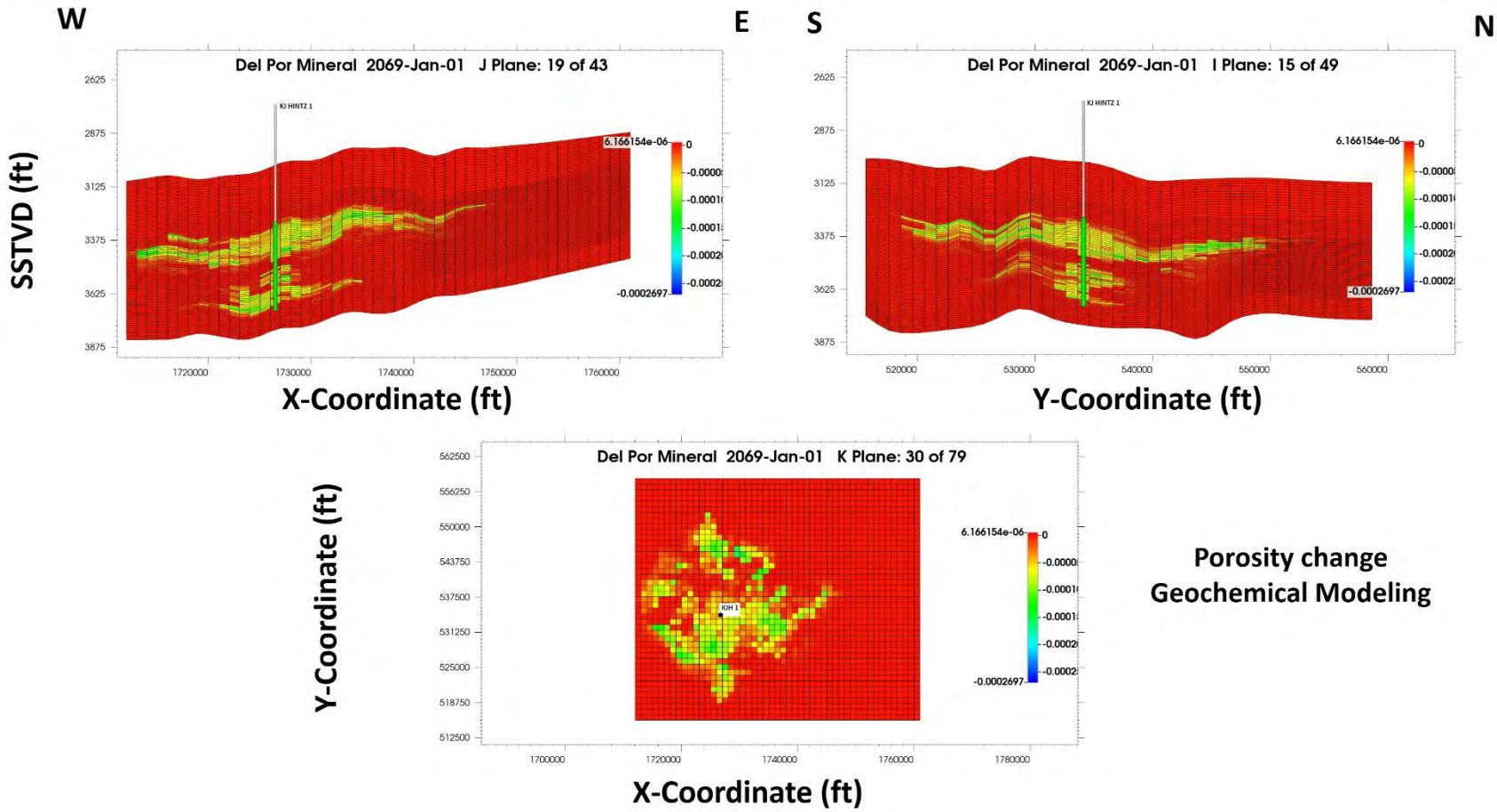


Figure C-11. Modeled change in porosity due to net geochemical dissolution after 20 years of injection plus 25-year postinjection period. The top-left image is west-east, and the top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD).

C.1.2 Geochemical Interaction of the Upper Confining Zone (Cap Rock, Opeche/Spearfish Formation)

Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO₂ 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 injection stream mixture 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, 2.5, and 3.5 meters above the cap rock–CO₂ exposure boundary. The mineralogical composition calculated from the XRD results of the deepest sample from the Opeche/Spearfish Formation was honored (Table C-4). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table C-5).

The anticipated average CO₂ stream composition is 98.25% CO₂, 1.44% N₂, and 0.31% O₂, with a trace amount of H₂S. The CO₂ stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O₂ (2%). The modeled stream containing ~95% CO₂ and 2% O₂, described in Table C-1, was used to represent a conservative scenario where the higher oxygen concentration may trigger more geochemical reactions in the formation. The exposure level, expressed in moles per year, of the CO₂ stream to the confining layer was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). Again, this conservative overestimation was done 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 obtained from the dynamic reservoir simulation.

Table C-4. Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of Slash Lazy H 5 Core Sample at a Depth of 5570 ft MD

Minerals, wt%	
Anhydrite	9.60
Dolomite	83.70
Illite	0.50
K-feldspar	4.00
Pyrite	0.30
Quartz	1.90

Table C-5. Formation Water Chemistry from Broom Creek Formation Fluid Sample from Slash Lazy H 5

pH	6.8	TDS	83,100 mg/L
Total Alkalinity	99 mg/L CaCO ₃	Calcium	1,870 mg/L
Bicarbonate	99 mg/L CaCO ₃	Magnesium	313 mg/L
Carbonate	20.5 mg/L CaCO ₃	Sodium	26,400 mg/L
Hydroxide	20.5 mg/L CaCO ₃	Potassium	596 mg/L
Sulfate	2,980 mg/L	Strontium	67.8 mg/L
Chloride	54,200 mg/L	Nitrate	66.8 mg/L

Results showed geochemical processes at work. Figures C-12 through C-16 show results from geochemical modeling. Figure C-12 shows a change in fluid pH over time as CO₂ diffuses into the system. For the cell at the CO₂ interface, Cell 1 (C1), the pH starts declining from an initial pH of 6.6 after 5 years of injection time and continues to decrease to a level of 5.1 by the end of 25 years of postinjection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH begins to change after Year 4 and goes down to 5.5 by the end of simulation. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH begins to change after Year 33. Lastly, the pH is unaffected in C4, indicating CO₂ does not penetrate this cell within the 45 years of simulation.

Figures C-13 shows the modeled change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. In C1, K-feldspar starts to dissolve from the beginning of the simulation period, while illite, quartz, and calcite start to precipitate at the same time. Dissolution of dolomite in C1 is minimal, which is 0.01% of initial dolomite (83.7%). The net change due to precipitation or dissolution in C2 is less than 1.15 kg per cubic meter, with little dissolution or precipitation taking place at the later year of simulation. Any effects in C3 are too small to represent at this scale.

Figures C-14 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table C-4. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar is the primary mineral that dissolves. Dissolution (%) in C2 is minimal (<0.01%) and not significant to represent at the scale in Figure C-14.

Figure C-15 represents minerals expected to be precipitated in weight (%) shown for C1 and C2 of the model. In C1 and C2, illite, quartz, and calcite are the minerals to be precipitated.

Figure C-16 shows the modeled change in porosity of the cap rock for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal. Initially C1 experiences up to a 0.011% increase in porosity because of dissolution upon first CO₂ exposure and initial model equilibration, but the change is temporary. No significant porosity changes were observed for C2 and C3. These results suggest that geochemical change from exposure to CO₂ is minor and therefore the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes.

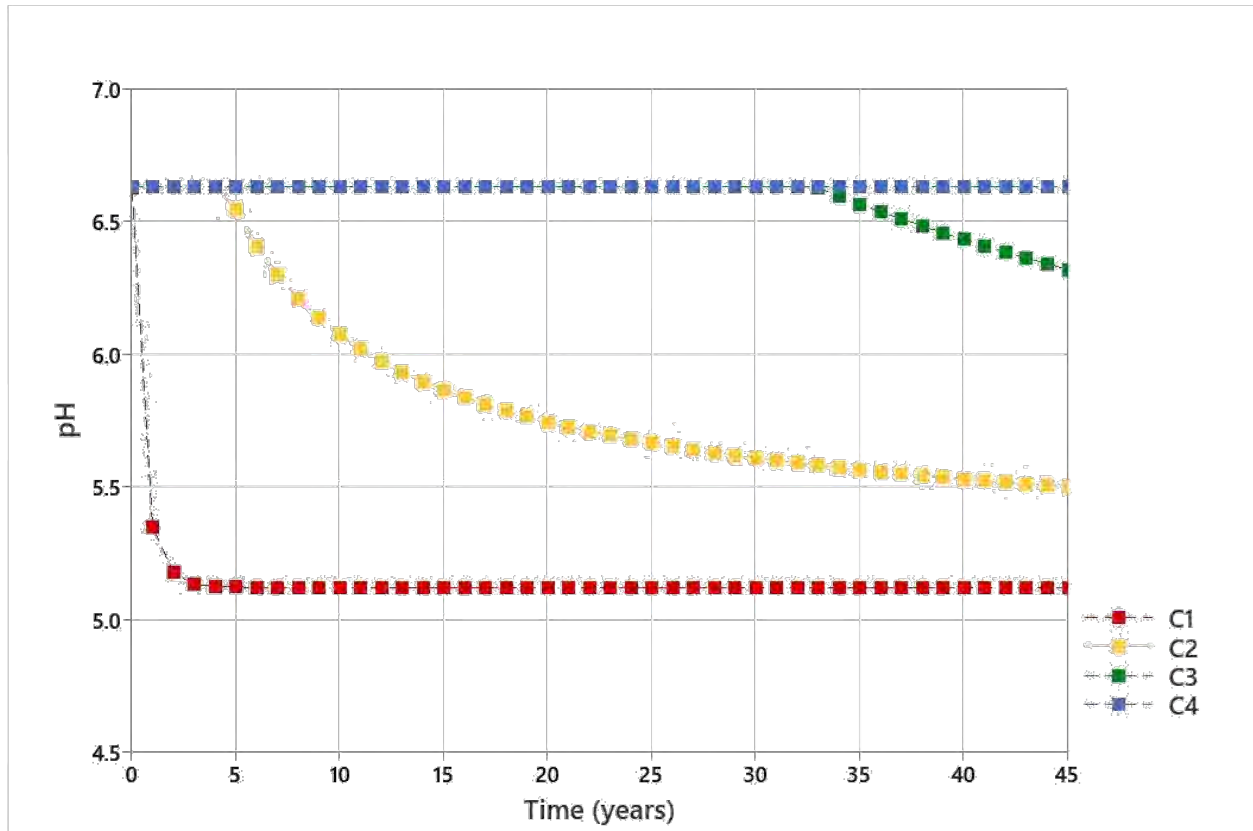


Figure C-12. Modeled change in fluid pH vs. time. Red line shows pH for the center of C1, 0.5 meters above the Opeche/Spearfish Formation cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. Blue line shows C4, 3.5 meters above the cap rock base.

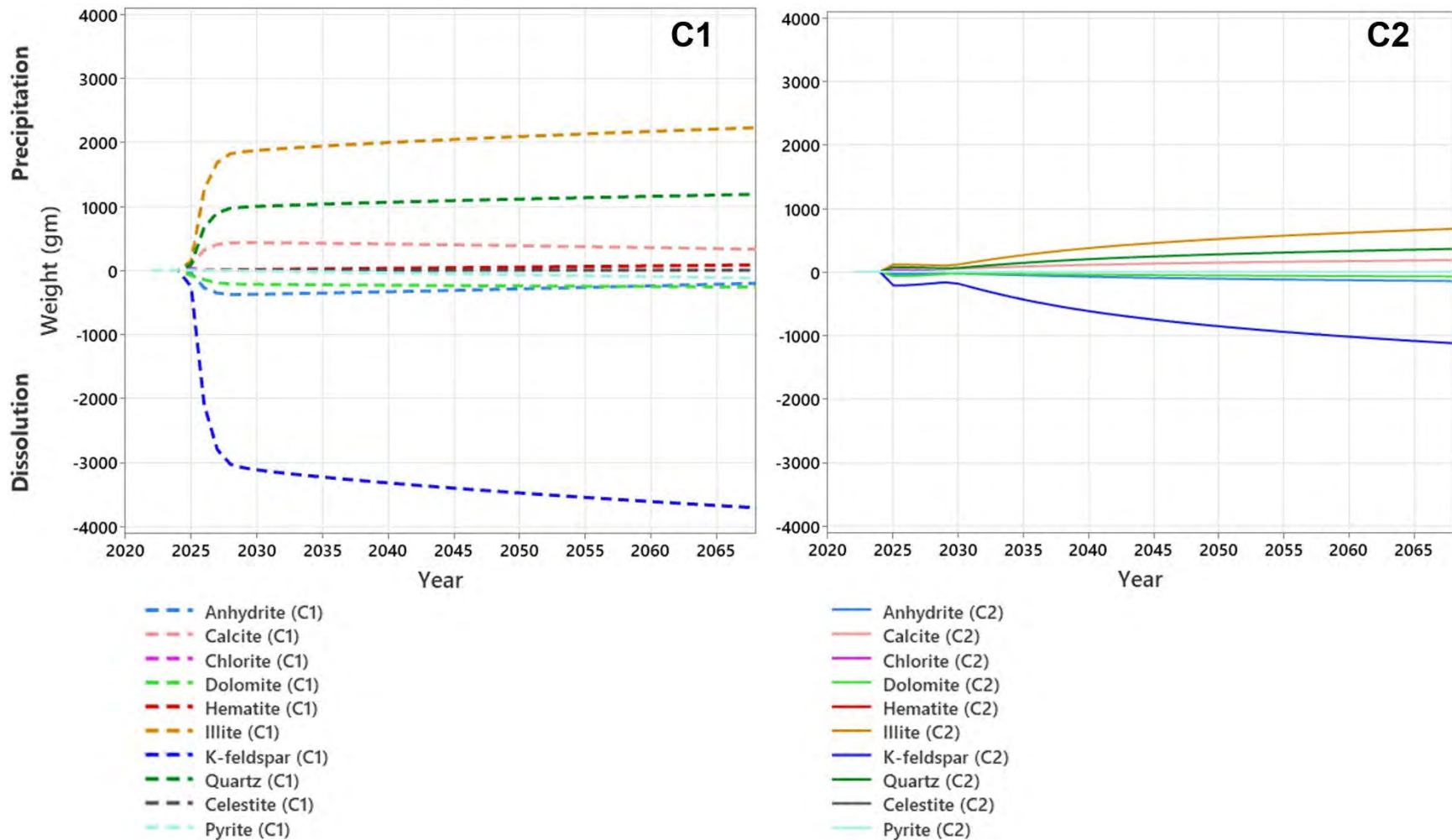


Figure C-13. Modeled dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1, 0.5 meters above the cap rock base. Solid lines show results for C2, 1.5 meters above the cap rock base, and these changes are smaller compared to the changes observed for C1. Results from C3, 2.5 meters above the cap rock base, are similar to the change observed for C2.

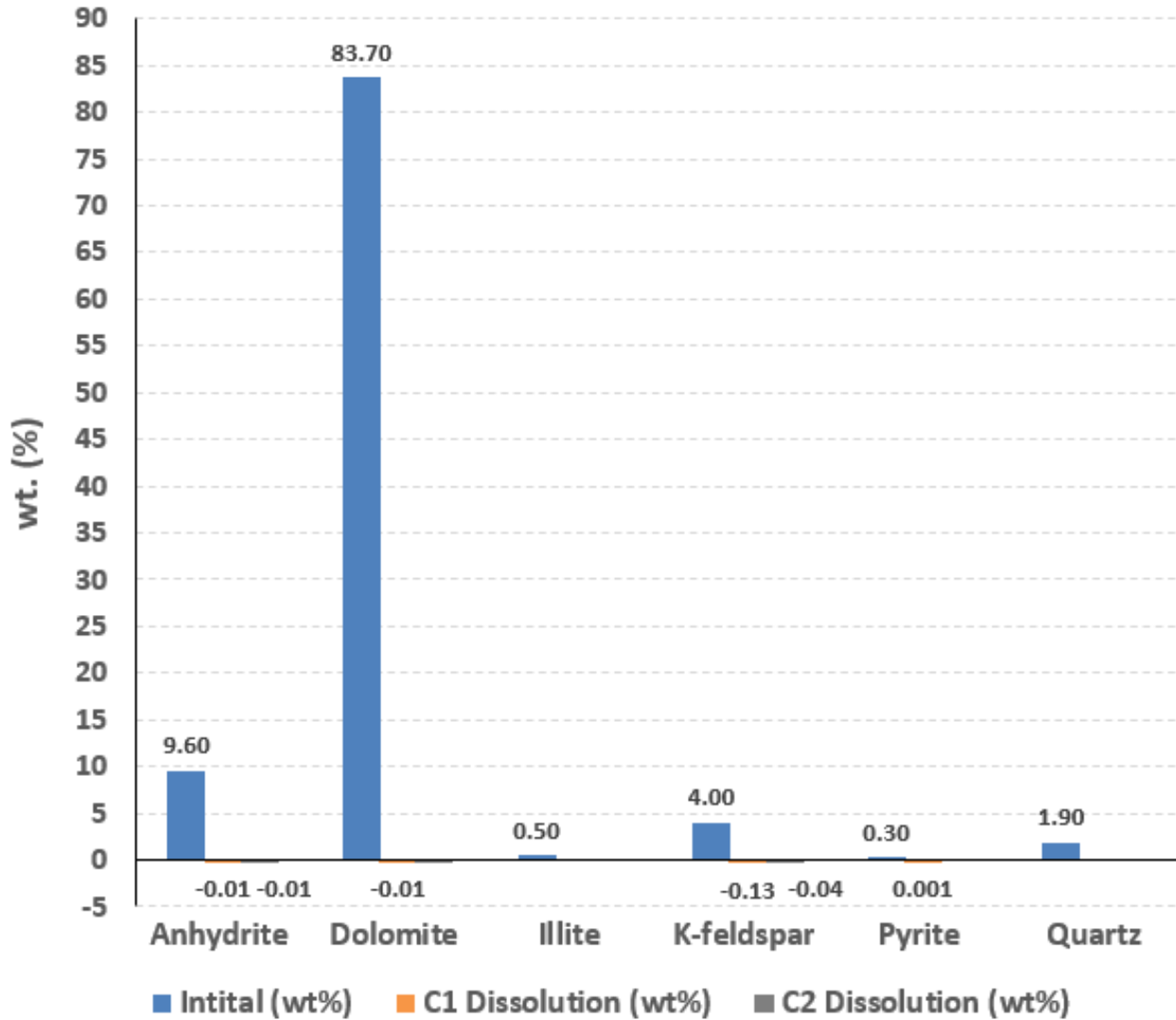


Figure C-14. Weight percentage (wt%) of potentially reactive minerals present in the Opeche/Spearfish Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange, too small to see in the figure) and C2 (gray, too small to see in the figure) after 20 years of injection plus 25 years of postinjection. Negative values represent total wt% associated with dissolution.

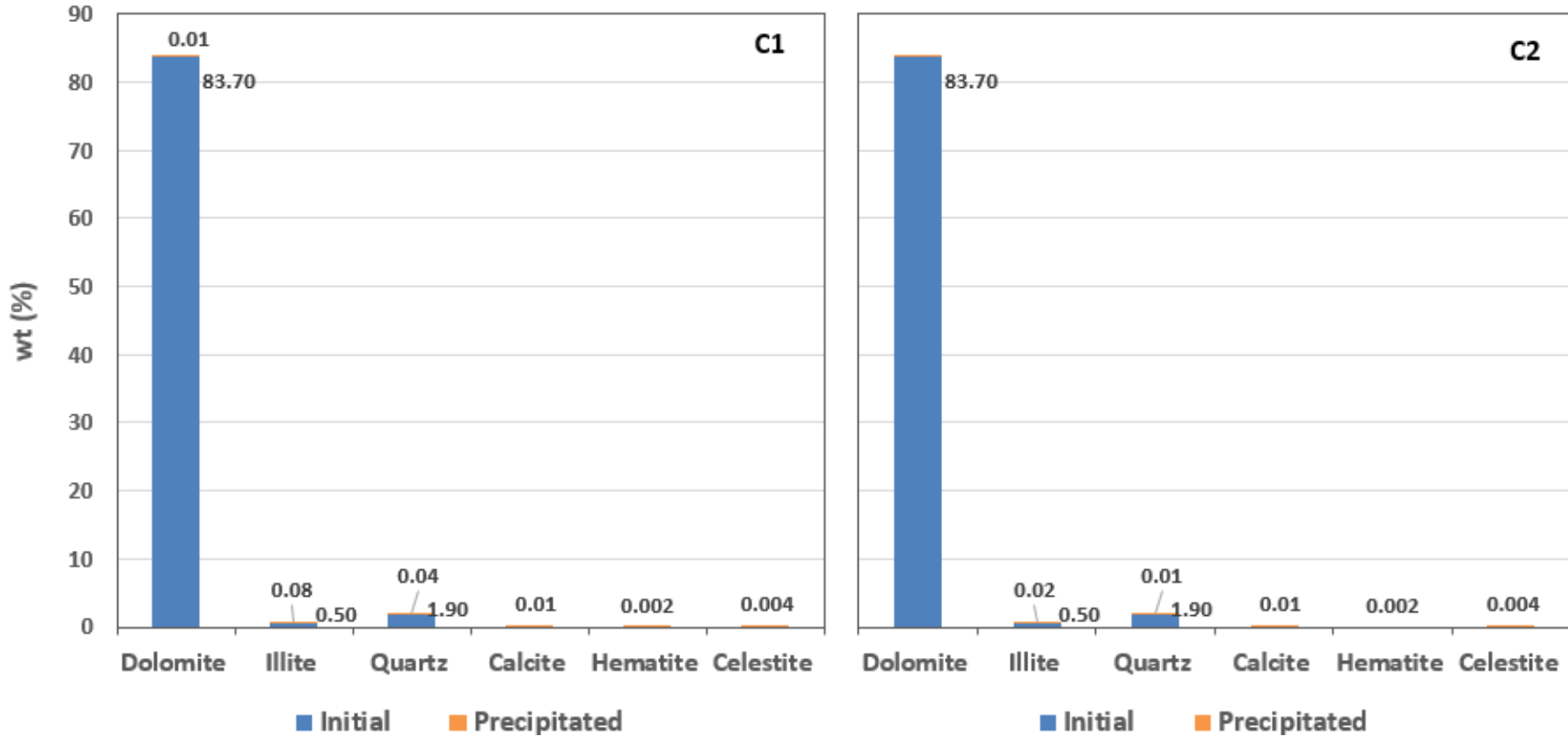


Figure C-15. Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of the Opeche/Spearfish Formation in C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years of postinjection. Minerals precipitated in C1 and C2 are too small to be seen in the figure.

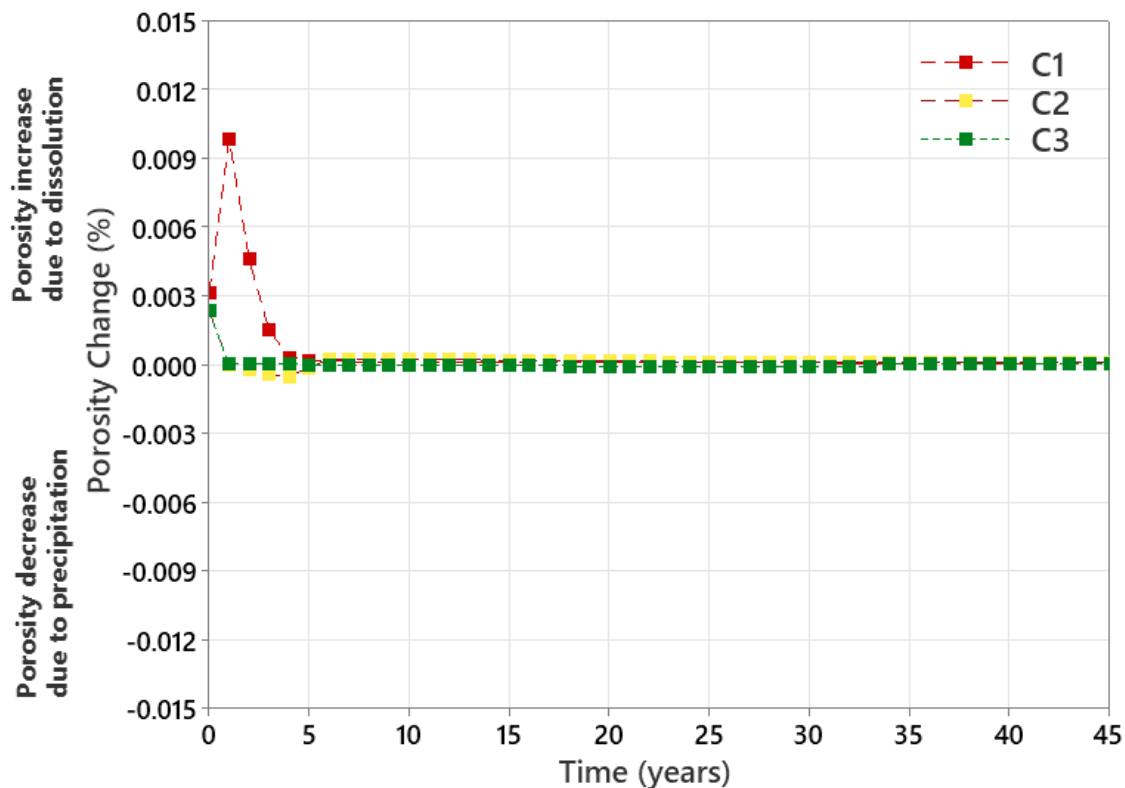


Figure C-16. Modeled change in percent porosity of the Opeche/Spearfish Formation cap rock. Red line shows porosity change calculated for C1, 0.5 meters above the cap rock base. Yellow line shows C2, 1.5 meters above the cap rock base. Green line shows C3, 2.5 meters above the cap rock base. Long-term 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.

C.1.3 Geochemical Interaction of the Lower Confining Zone (Amsden Formation)

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 16 cells, each cell 1 meter in thickness. The formation was exposed to CO₂ stream components at the top boundary of the simulation, and CO₂ 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–CO₂ exposure boundary. The average mineralogical composition calculated from the results of four samples from the Amsden Formation was honored (Table C-6). The formation brine composition was assumed to be the same as the known composition from the overlying Broom Creek Formation injection zone (Table C-5). A CO₂ stream containing ~95% CO₂ and 2% O₂, shown in Table C-1, was used in the geochemical modeling to represent a conservative scenario, where higher oxygen concentration may trigger more geochemical reactions in the formation. 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.

Table C-6. Averaged Mineral Composition of the Amsden Formation Derived from XRD Analysis of Slash Lazy H 5 Core Samples at Depths of 5839.5, 5846.0, 5855.4, and 5861 ft MD

Minerals, wt%	
Illite	6.2
K-Feldspar	11.2
Anhydrite	5.6
Quartz	13.3
Dolomite	63.3
Others	0.4

The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. This simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.

Modeling results show geochemical processes at work. Figures C-17 through C-22 show results from the geochemical modeling. Figure C-17 shows change in fluid pH over 45 years (representing 20 years of injection and 25 years of postinjection) as CO₂ enters the system. Initial change in pH in all of the cells, for C1 to C16, is related to initial equilibration of the model. For the cell at the CO₂ interface, C1, the pH declines to a level of 5.0 after 8 years of injection, further declining to 4.6 by the end of the modeled injection period, and hits 4.4 by the end of simulation period. Progressively lower or slower pH changes occur for each cell that is more distant from the CO₂ interface. The pH for C13-16 declines to 5.8 over the 45 years of simulation time because of the transport and mixing process of formation brine that results in a CO₂ concentration below 0.01 molality. Figure C-18 shows that CO₂ penetration greater than 0.01 molality is limited to C1-C12 and does not penetrate in higher amount (>0.01 molality) more than 12 meters (represented by C13) over the 20 years of injection and 25 years of postinjection.

Figure C-19 shows the modeled changes in mineral dissolution and precipitation in grams per cubic meter over simulation years. For C1, K-feldspar starts to dissolve from the beginning of the simulation period while quartz and illite start to precipitate. Dolomite and anhydrite show initial precipitation and dissolution, respectively, during the injection period which is reversed during 25 years of postinjection. C2 shows the same trends, but the major geochemical process begins approximately 10 years after Cell C1.

Figure C-20 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table C-6. The expected dissolution of the minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar and dolomite are the primary minerals that dissolve, and initial fractions of K-feldspar have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals.

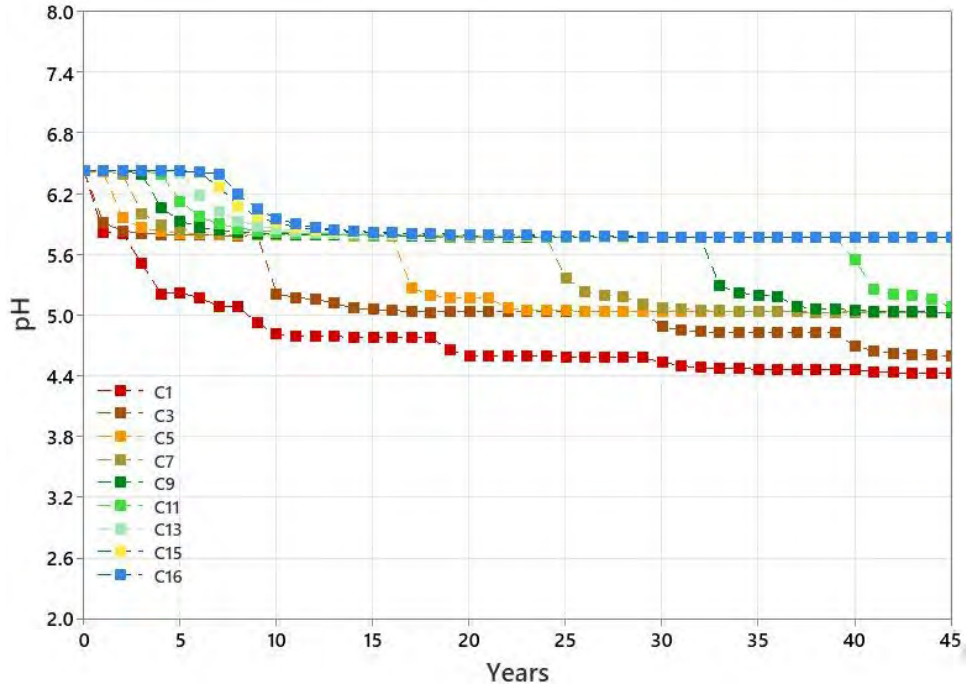


Figure C-17. Modeled change in fluid pH for C1–C16 (odd numbered cells through C15 plus C16) in the Amsden Formation underlying confining layer.

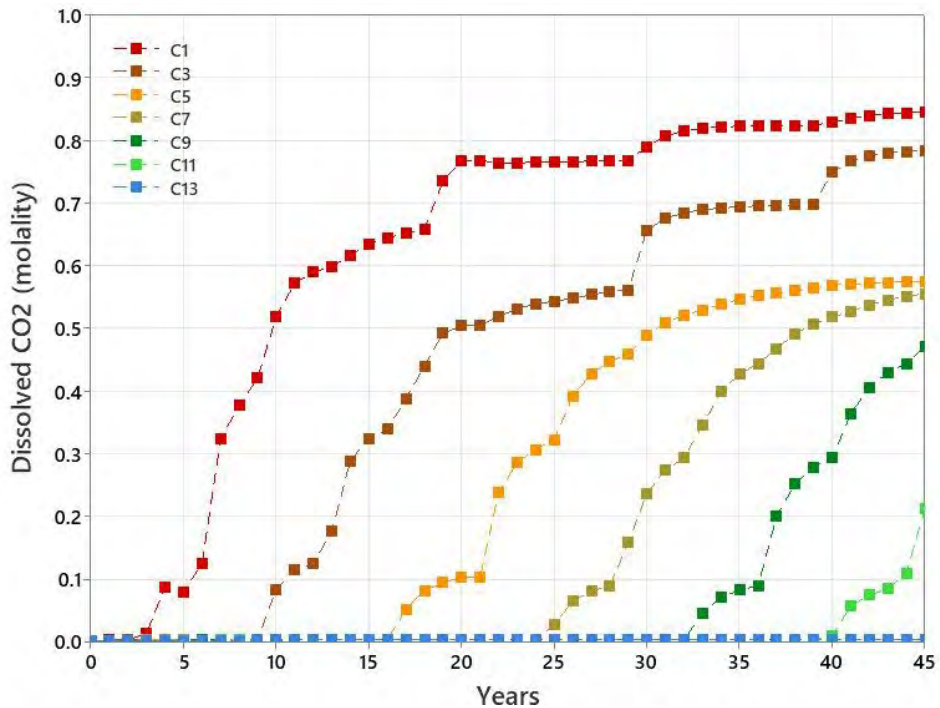


Figure C-18. Modeled CO₂ concentration (molality) of the odd-numbered cells, C1–C13, in the Amsden Formation underlying confining layer. CO₂ penetration in C13 is less than 0.01 molality.

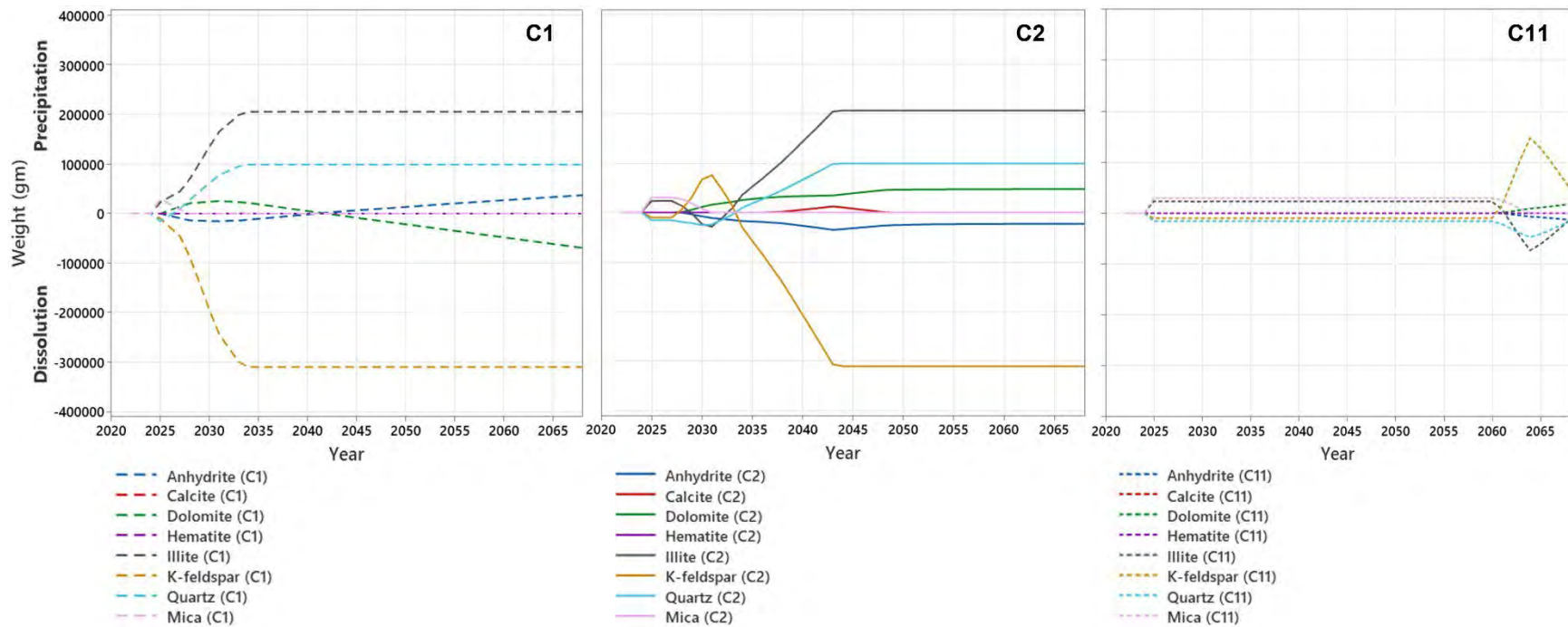


Figure C-19. Modeled dissolution and precipitation of minerals in the Amsden Formation underlying confining layer. Dashed lines show results for C1, 0 to 1 meter below the Amsden Formation top. Solid lines show results for C2, 1 to 2 meters below the Amsden Formation top. Dotted lines show results for C11, 10 to 11 meters below the Amsden Formation top. C11 shows minimal dissolution and precipitation at the end of 25 years of postinjection because of smaller amount of CO₂ penetration in C11 by the end of 45 years of simulation.

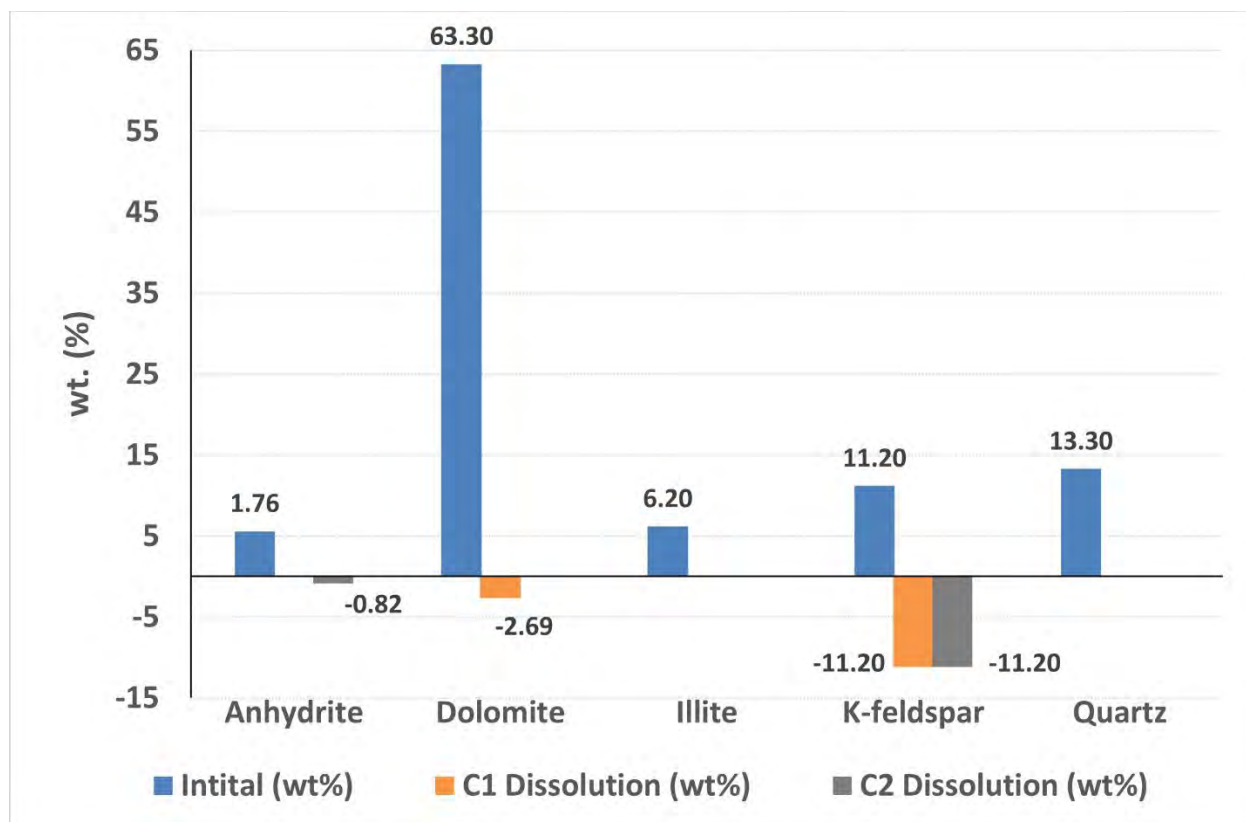


Figure C-20. Weight percentage (wt%) of potentially reactive minerals present in the Amsden Formation geochemistry model before simulation (blue) and expected dissolution of minerals in C1 (orange) and C2 (gray) after 20 years of injection plus 25 years of postinjection. Negative values represent total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

Figure C-21 represents this replacement with the minerals expected to be precipitated in weight percentage (wt%) shown for C1 and C2 of the model. In C1 and C2, illite and quartz are the key primary minerals expected to be precipitated. Anhydrite and dolomite precipitate as secondary minerals in C1 and C2, respectively.

The modeled change in porosity (% units) of the Amsden Formation underlying confining layer is displayed in Figure C-22 for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal, less than 2% change during the life of the simulation. C1 shows an initial porosity increase, but this change is temporary, and the cell returns to its near-initial porosity after Year 9. For C2 and C3, a cyclic pattern of porosity increase and subsequent decrease with low amplitude is observed. No significant porosity changes were observed in C2–C3 after 20 years of modeled simulation time. Cells C4–C11 showed similar results, with porosity change being less than 0.3% at each time step (not shown in Figure C-22).

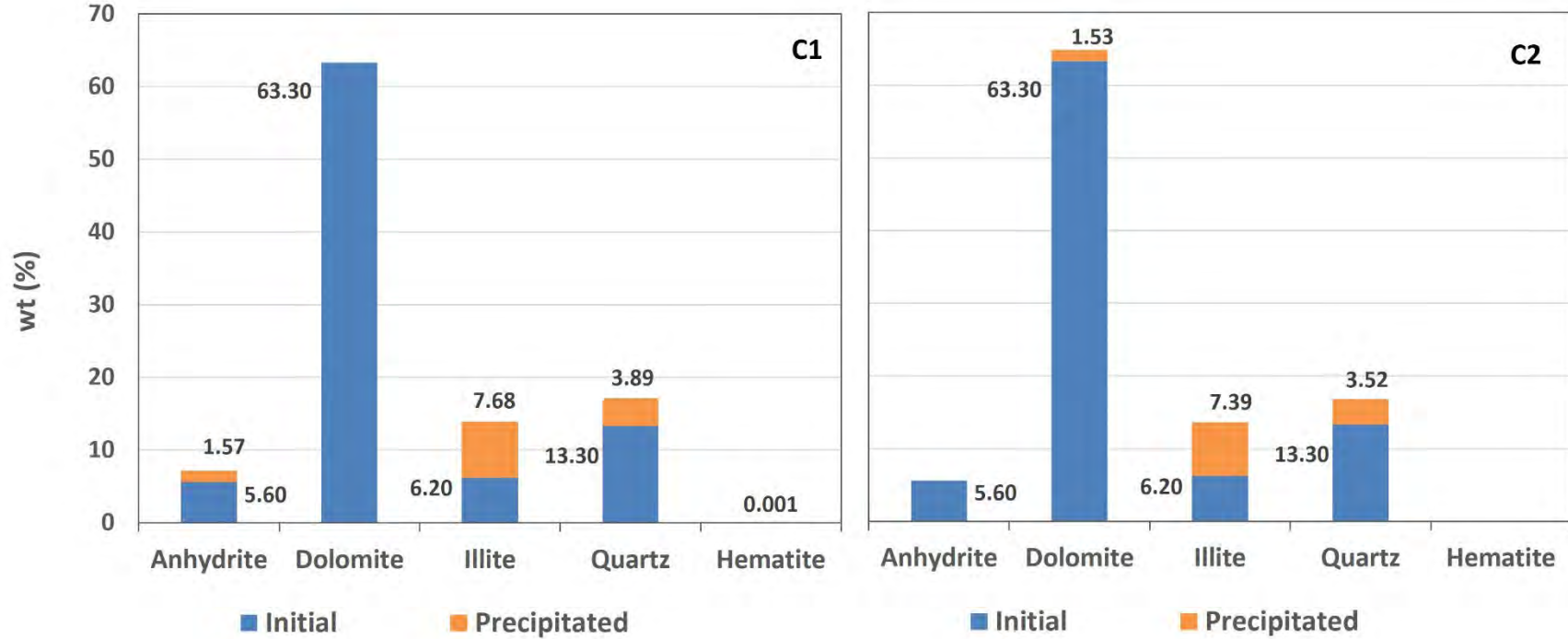


Figure C-21. Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of Amsden Formation in C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years of postinjection. Very little hematite and anhydrite precipitation is observed in C1. Hematite precipitation in C2 is too small to be seen in the figure.

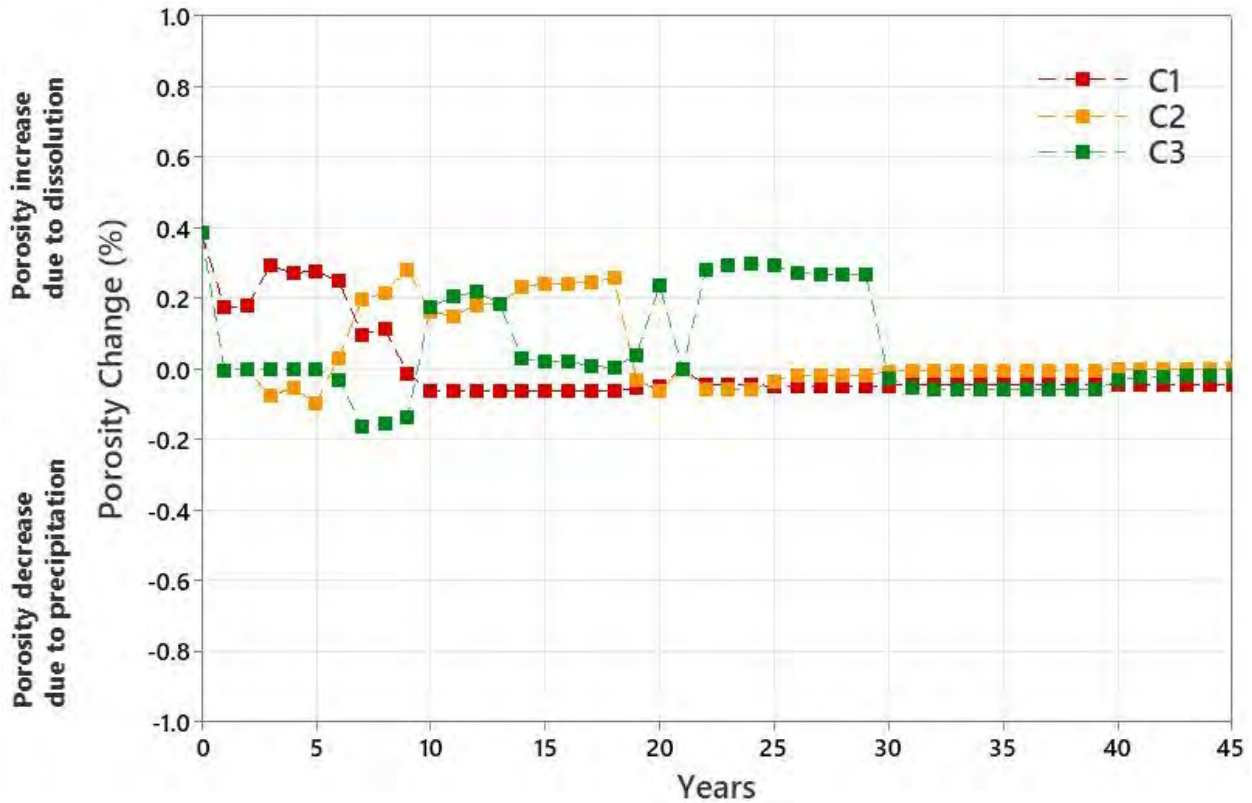


Figure C-22. Modeled change in percent porosity in the Amsden Formation underlying confining layer. Red line shows porosity change for C1, 0 to 1 meter below the Amsden Formation top. Orange line shows C2, 1 to 2 meters below the Amsden Formation top. Green line shows C3, 2 to 3 meters below the Amsden 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.

C.1.4 REFERENCES

Espinoza, D.N., and Santamarina, J.C., 2017, CO₂ breakthrough—caprock sealing efficiency and integrity for carbon geological storage: *International Journal of Greenhouse Gas Control*, v. 66, p. 218–229.

APPENDIX D

**MONITORING EQUIPMENT
SPECIFICATION INFORMATION**

Attachment D-1 – Gas Chromatograph Specification Sheet



Envent Model 132S

Process Gas Chromatograph

The Model 132S Process Gas Chromatograph (GC) is a simple approach to energy measurement, created and designed for many different applications. Envent provides a Process Gas Chromatograph platform that is efficiently manufactured to ensure industry leading delivery, while providing a GC that allows for ease of serviceability.

Features

- High performance GC columns packed in our Envent GC Lab
- Reduced carrier usage due to efficient column design
- Environmental chamber tested prior to shipment

Field-Serviceability

- Easy access Electronics Enclosure with single board technology
- Easy access GC Detector/Column Oven for easy GC valve diaphragm replacement and column change
- Typical downtime for diaphragm and column change: approx. 30 minutes
- No modules to maintain or un-planned downtime due to non-serviceability and high cost of competitor’s module technology
- Returns ownership to the measurement technician rather than the GC manufacturer

Natural Gas Applications

- Energy Measurement
- Pipeline Monitoring
- Custody Transfer
- Biogas/Landfill
- Power Generation
- Turbine Control

Gas Processing Applications

- Cryogenic gas plant
- NGL/LPG (methanol ethanol)
- LNG
- Fractionation/ Hydrocarbon Purity
- Gas Sweetening
- Methanol in NGL
- Methanol in Natural Gas

Electronics

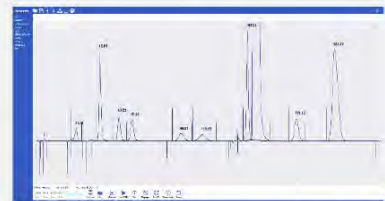
- Non-incendive electronic circuit design approved for Class I Division 2 electrical areas
- Eliminates the need for explosion proof enclosures or purge-air
- Includes all CPU, Memory, and I/O functions on a single board that operates together with the Envent Gas Chromatograph software
- Low-cost, simplified electronic troubleshooting approach

Software

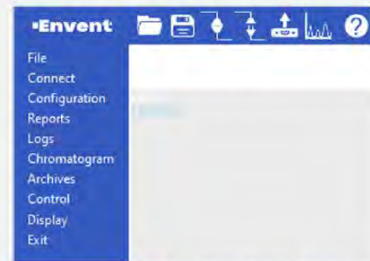
- Archived custody stream chromatogram/chart storage
- Auto-storage of most recent calibration chromatogram/chart
- 18 months of archived analysis reports
- 6 months of archived calibration reports



132S Process Configuration



Envent Gas Chromatograph Software (GCS)



Envent GCS User Interface Menu

www.enventengineering.com

CD-19-0.2.3_R0_10 May 22

Continued...

Attachment D-1 – Gas Chromatograph Specification Sheet (continued)



Easily Accessible GC Oven



1. Thermal Conductivity Detector (Max 2)
2. GC Valve (Max 6)
3. Column Dish
4. Sample Pre-Heat Coil (Max 4)



High performance micro-packed GC columns manufactured at our Envent GC lab in Houston, TX

Specifications

Environmental Temperature	-18° to 54°C (0° to 130°F) Quoted per application
Dimensions	Standard Configuration: 72" H x 24" W x 16" D (183cm H x 61cm W x 41cm D)
Mounting	Wall mount or floor mount
Enclosure	NEMA 4X
Electrical Classification	Class I, Division 2, Groups B, C, D
Power	120 +/- 10% VAC 50/60 Hz Standard 240 +/- 10% VAC 50/60 Hz Available
Power Consumption	Start up: 150 watts Steady State: 60 - 80 watts nominal
Oven	Airless Heat Sink
GC Valves	Six-port and ten-port diaphragm chromatograph valves Thermal Conductivity Detector (TCD) Single or Dual TCD Capabilities (2-min application)
Stream Valves	Double Block and Bleed
Carrier Gas	UHP Helium (99.999%) or UHP Hydrogen (99.999%)
Actuation Gas	Helium, Nitrogen, Instrument Air (GC Valves/Stream Valves Regulated to 65 psig)
Detector	Thermal Conductivity Detector: Single or Dual TCD capabilities Advanced TCD allows for low ppm measurement
Peak Gating	Auto-Slope detection
Streams	Up to 4 Custody streams (plus auto-calibration stream)
Input/Output	2 analog outputs 4 dry contact relay outputs 4 digital inputs 4 solenoid outputs
Communications	SIM 2251 Modbus mapping User Modbus mapping 1 RS-232 serial communication ports (Modbus capable) 2 RS-485 serial communication ports (Modbus capable) 1 Ethernet communication port RJ-45 (Modbus capable)
Measurement Calculations	Latest GPA 2145, GPA 2172, AGA 8, and ISO 6976 calculations

www.enventengineering.com

CD-19-0.2.3_RO_10 May 22

Attachment D-2 – Gas Detection Station Specification Sheet

ULTIMA® X5000 Gas Monitor

The future looks bright.



Simple retrofits have identical footprint and wiring to ULTIMA X Gas Monitor series.

Bluetooth® wireless technology allows mobile device to act as HMI screen and controller.

Intuitive display features new design equipped with organic LED (OLED) display, with full word text in 9 languages. Bright green, yellow, and red status LEDs for extreme visibility.

Industry-first, touch-button interface provides intuitive, tool-free user experience.

Instrument status indicators illuminate power, fault, and alarm conditions.

X/S Connect App
Reduce setup time by at least 50% with the X/S Connect App.

GET IT ON Google Play | Download on the App Store

Advanced Sensor Technology

POWERED BY
XCell
SENSORS

WITH
TruCal
TECHNOLOGY

- Patented XCell H₂S 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.
- 3-year warranty and 5-year expected life for XCell Sensors.
- **Dual sensor capability** doubles sensing power with half the footprint of a single gas sensor transmitter.
- **SafeSwap** enables safe and quick XCell Sensor replacement without powering off gas detector.

Applications

- Chemical
- Petrochemical
- Wastewater
- Oil and gas
- Utilities
- General industry



Continued...

Attachment D-2 – Gas Detection Station Specification Sheet (continued)

ULTIMA X5000 Gas Monitor: Sensor Specifications



Electrochemical Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min.	Max.				
Ammonia - 100	0 - 100 ppm	25 - 100 ppm	0.1 ppm	< 20 Sec	< 60 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Ammonia - 1000	0 - 1000 ppm	190 - 1000 ppm	10 ppm	< 20 Sec	< 300 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Carbon Monoxide - 100	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 1000	0 - 1000 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide - 500	0 - 500 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Carbon Monoxide H ₂ Resistant	0 - 100 ppm	10 - 1000 ppm	1 ppm	< 3 Sec	< 9 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Chlorine - 5	0 - 5 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 10	0 - 10 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine - 20	0 - 20 ppm	1 - 20 ppm	0.1 ppm	< 5 Sec	< 12 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2
Chlorine Dioxide	0 - 3 ppm	0.5-3.0 ppm	0.01 ppm	< 12 Sec	< 30 Sec	< ±15%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	XCell	5 Years	3 Years	Div/Zone 2
Ethylene Oxide	0 - 10 ppm	1 - 10 ppm	0.1 ppm	< 50 Sec	< 140 Sec	< ±15%	< 2% FS/Month	-20°C (-4°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen	0 - 1000 ppm	250 - 1000 ppm	10 ppm	< 40 Sec	< 185 Sec	< ±10%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Chloride	0 - 50 ppm	25 - 50 ppm	1 ppm	< 30 Sec	< 120 Sec	< ±35%	< 1% FS / Month	-30°C (-22°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Cyanide	0 - 50 ppm	25 - 50 ppm	1 ppm	< 8 Sec	< 30 Sec	< ±15%	< 1% FS / Month	-20°C (-4°F)	40°C (104°F)	Echem	2 Years	1 Year	Div/Zone 1
Hydrogen Fluoride	0 - 10 ppm	5 - 10 ppm	0.1 ppm	< 60 Sec	< 90 Sec	< ±15%	< 2% FS / Month	0°C (32°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Hydrogen Sulfide - 10	0 - 10 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 50	0 - 50 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 100	0 - 100 ppm	10 - 100 ppm	0.1 ppm	< 7 Sec	< 23 Sec	< ±1%	< 1% FS / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen Sulfide - 500	0 - 500 ppm	20 - 500 ppm	1 ppm	< 20 Sec	< 60 Sec	< ±10%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Nitrogen Dioxide	0 - 10 ppm	1.5 - 10 ppm	0.1 ppm	< 30 Sec	< 60 Sec	< ±10%	< 1% FS / Month	-40°C (-40°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Nitrogen Oxide	0 - 100 ppm	2.5 - 100 ppm	0.5 ppm	< 5 Sec	< 20 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Oxygen	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< ±1% Vol	< 0.2 % Vol / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen (FM)	0 - 25%	5 - 25%	0.10%	< 6 Sec	< 11 Sec	< ±1% Vol	< 0.2 % Vol / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Oxygen, Low	0 - 25%	2 - 25%	0.10%	< 10 Sec	< 30 Sec	< ±10%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 1
Sulfur Dioxide - 100	0 - 100 ppm	25 - 100 ppm	1 ppm	< 10 Sec	< 30 Sec	< ±15%	< 1% FS / Month	-30°C (-22°F)	50°C (122°F)	Echem	2 Years	1 Year	Div/Zone 2
Sulfur Dioxide - 25	0 - 25 ppm	5 - 25 ppm	0.1 ppm	< 3 Sec	< 6 Sec	< ±1%	< 1% FS / Month	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 2

*Typical response at standard temperature and pressure test conditions

Continued...

D-4

KJ HINTZ/SLASH LAZY H 5

Attachment D-2 – Gas Detection Station Specification Sheet (continued)

ULTIMA X5000 Gas Monitor: Sensor Specifications



XCell Catalytic Bead Sensors													
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Type	Sensor Life	Warranty	Classification
				T50	T90			Min.	Max.				
Methane (5.0%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Propane (2.1%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Heptane (1.05%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Nonane (0.8%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Hydrogen (4.0%)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Methane (4.4% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Propane (1.7% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Heptane (0.85% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1
Nonane (0.7% EN)	0 - 100% LEL	20 - 100% LEL	1%	< 10 Sec	< 22 Sec	< ±1% LEL	< 5% LEL / Year	-40°C (-40°F)	60°C (140°F)	XCell	5 Years	3 Years	Div/Zone 1

ULTIMA XIR Plus Infrared Sensors												
Gas	Default Range	Selectable Full Scale Range	Resolution	Response Time*		Repeatability	Zero Drift	Operating Temperature		Sensor Life	Warranty	Classification
				T50	T90			Min.	Max.			
XIR+ 0-100% LEL Ethanol	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethylene Oxide	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Gasoline Hexane	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Hexane	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Isopropanol	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methane (5%)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methyl Methacrylate	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Propane (2.1%)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethanol EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Ethylene Oxide EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Gasoline Hexane EN	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Methane (4.4% EN)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ 0-100% LEL Propane (1.7% EN)	0 - 100% LEL	20 - 100% LEL	1%	—	< 2 Sec	< ±1% LEL	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ Carbon Dioxide (2%)	0 - 2% Vol	0.4 - 2%	0.05%	< 3 Sec	< 6 Sec	< ±1%	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1
XIR+ Carbon Dioxide (5%)	0 - 5% Vol	1 - 5%	0.05%	< 3 Sec	< 6 Sec	< ±1%	N/A	-40°C (-40°F)	60°C (140°F)	10+ Years	10 Years	Div/Zone 1

*Typical response at standard temperature and pressure test conditions

Continued...

Attachment D-2 – Gas Detection Station Specification Sheet (continued)

ULTIMA® X5000 Gas Monitor



Specifications

Product Specifications	
COMBUSTIBLE GAS SENSOR TYPE	Catalytic Bead (XCell combustible) Infrared (XIR Plus)
TOXIC GAS & OXYGEN SENSOR TYPE	<p>XIR PLUS Carbon Dioxide (CO₂)</p> <p>XCell Toxic Ammonia (NH₃), Carbon Monoxide (CO), Carbon Monoxide (CO) H₂-resistant, Hydrogen Sulfide (H₂S), Chlorine (Cl₂), Chlorine Dioxide (ClO₂), Sulfur Dioxide (SO₂)</p> <p>XCell O₂ Oxygen (O₂)</p> <p>Electrochem. Ammonia (NH₃), Ethylene Oxide (ETO), Hydrogen (H₂), Hydrogen Chloride (HCl), Hydrogen Cyanide (HCN), Hydrogen Fluoride (HF), Nitric Oxide (NO), Nitrogen Dioxide (NO₂), Sulfur Dioxide (SO₂)</p>
SENSOR MEASURING RANGES	<p>Combustible 0-100% LEL</p> <p>CO₂ 0-2%, 0-5% Vol</p> <p>CO 0-100, 0-500, 0-1000 ppm</p> <p>CO, H₂-resistant 0-100 ppm</p> <p>Cl₂ 0-5, 0-10, 0-20 ppm</p> <p>ClO₂ 0-3 ppm</p> <p>ETO 0-10 ppm</p> <p>H₂ 0-1000 ppm</p> <p>HCl 0-50 ppm</p> <p>HCN 0-50 ppm</p> <p>HF 0-10 ppm</p> <p>H₂S 0-10, 0-50, 0-100, 0-500 ppm</p> <p>NH₃ 0-100, 0-1000 ppm</p> <p>NO 0-100 ppm</p> <p>NO₂ 0-10 ppm</p> <p>O₂ 0-25%</p> <p>SO₂ 0-25, 0-100 ppm</p>
APPROVALS CLASSIFICATION	<i>Markings vary by component. See manual for specific component markings.</i>
DIVISIONS (US/CAN)	Class I, II, III; Div 1 & 2, T4/T5/T6
ZONES (GLOBAL)	Ex db nA IIC T5 Gb (Class I, Zone 1/Zone2) Ex tb IIIC T85°C Db (Class II, Zone 2I)
ENCLOSURE RATING	Type 4X, IP66
WARRANTY	<p>X5000 transmitter 2 years</p> <p>XIR PLUS 10 years source, 5 years electronics</p> <p>XCell Sensors 3 years</p> <p>Electrochemical Sensors Varies by gas</p>
APPROVALS	CSA, FM*, ATEX, IECEx, INMETRO, DNV-GL Marine, CE Marking. SIL 2 suitable. Complies with C22.2 No. 152, FM 6320

Environmental Specifications																															
OPERATING TEMPERATURE RANGE	<p>XCell -40°C to +60°C</p> <p>Electrochem. See page 2</p> <p>XIR PLUS -40°C to +60°C</p>																														
RELATIVE HUMIDITY (NON-CONDENSING)	<p>XCell toxics & O₂ 10-95%</p> <p>XCell combustible 0-95%</p> <p>XIR PLUS 15-95%</p>																														
Mechanical Specifications																															
INPUT POWER	11 to 30 VDC, 3 wire																														
SIGNAL OUTPUT	Dual 4-20 mA current source, HART																														
BLUETOOTH (OPTIONAL)	Bluetooth Low Energy (BLE) v4.3 or higher																														
RELAY RATINGS	5 A @ 30 VDC; 5 A @ 220 VAC (3X) SPDT - fault, warn, alarm																														
RELAY MODES	Common, discrete, horn																														
NORMAL MAX POWER	<table border="1"> <thead> <tr> <th></th> <th>Without Relays</th> <th>With Relays</th> </tr> </thead> <tbody> <tr> <td>XIR PLUS</td> <td>5.7 W</td> <td>6.7 W</td> </tr> <tr> <td>XCell combustible</td> <td>3.9 W</td> <td>4.9 W</td> </tr> <tr> <td>XCell Toxic & O₂</td> <td>1.8 W</td> <td>2.8 W</td> </tr> <tr> <td>XIR PLUS & XCell combustible</td> <td>9.9 W</td> <td>10.9 W</td> </tr> <tr> <td>XIR PLUS & XCell toxic or O₂</td> <td>6.0 W</td> <td>7.0 W</td> </tr> <tr> <td>Dual XIR PLUS</td> <td>10.6 W</td> <td>11.6 W</td> </tr> <tr> <td>Dual XCell toxic & O₂</td> <td>2.6 W</td> <td>3.6 W</td> </tr> <tr> <td>Dual XCell combustible</td> <td>9.6 W</td> <td>10.6 W</td> </tr> <tr> <td>Dual XCell comb. & XCell toxic or O₂</td> <td>4.3 W</td> <td>5.3 W</td> </tr> </tbody> </table>		Without Relays	With Relays	XIR PLUS	5.7 W	6.7 W	XCell combustible	3.9 W	4.9 W	XCell Toxic & O₂	1.8 W	2.8 W	XIR PLUS & XCell combustible	9.9 W	10.9 W	XIR PLUS & XCell toxic or O₂	6.0 W	7.0 W	Dual XIR PLUS	10.6 W	11.6 W	Dual XCell toxic & O₂	2.6 W	3.6 W	Dual XCell combustible	9.6 W	10.6 W	Dual XCell comb. & XCell toxic or O₂	4.3 W	5.3 W
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Dual XCell combustible	9.6 W	10.6 W																													
Dual XCell comb. & XCell toxic or O₂	4.3 W	5.3 W																													
EMC DIRECTIVE	Complies with EN 50270, EN 61000-6-4, EN 61000-6-3																														
DISPLAY	Organic LED (multi-lingual) with contrast ratio of 2000:1 and view angle of 160°																														
HART	HART 7, HART device description language available																														
FAULTS MONITORED	Low supply voltage, RAM checksum error, flash checksum error, EEPROM error, internal circuit error, relay, invalid sensor configuration, sensor faults, general system																														
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 mm ² . Refer to manual for mounting distances.																														
Dimensions																															
HOUSING (W x H)	5.88" x 5.71" (150 x 145 mm)																														
W/XCELL SENSOR	5.88" x 10.15" (150 x 258 mm)																														
W/XCELL & XIR SENSORS	13.42" x 10.15" (341 x 258 mm)																														
LID (DEPTH)																															
W/RELAY BOARD	4.86" (123 mm)																														
W/O RELAY BOARD	3.86" (98 mm)																														
WEIGHT	8.8 lb. (4 kg), 316 SS																														

See manual for FM approved sensors.

Note: This Bulletin contains only a general description of the products shown. While product uses and performance capabilities are generally described, the products shall not, under any circumstances, be used by untrained or unqualified individuals. The products shall not be used until the product instructions/user manual, which contains detailed information concerning the proper use and care of the products, including any warnings or cautions, have been thoroughly read and understood. Specifications are subject to change without prior notice. MSA is a registered trademark of MSA Technology, LLC in the US, Europe, and other Countries. For all other trademarks visit <https://us.msasafety.com/Trademarks>.

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Attachment D-3 – SCADA System and Leak Detection Software

Supervisory Control and Data Acquisition (SCADA) System

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 CO₂ geologic storage project injection operations in real time. This supervisory system collects data at an assigned time interval and stores the data in the historian server. Using Summit Carbon Storage #3, LLC (SCS3) process control selections, the SCADA system 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 SCS3 control room, which is staffed 24/7, of near or excessive violations of set parameters within the system.

Leak Detection Software

The leak detection system (LDS) will monitor the CO₂ flowline from the point of transfer to each of the injection wellheads. Instrumentation at both ends of the CO₂ flowline and each injection well collects pressure, temperature, and flow data. The LDS software uses the pressure readings and flow rates in and out of the line to produce a real-time model and predictive model. By monitoring deviations between the real-time model and the predictive model, the software is able to detect leaks along the CO₂ flowline.

Attachment D-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.

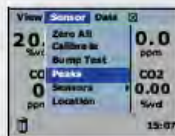
And a color display is more than eye-catching. It allows the user to step through instrument settings and functions with an intuitive menu and the instrument's five-way navigation button. It even supports the option of on-board graphing for easily interpreted direct readings and recorded data.

Plus, the MX6 iBrid is our most rugged instrument ever. It is compatible with our DSX™ Docking Station and iNet

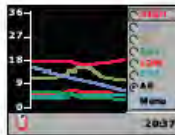
MX6 IBRID COLOUR SCREEN



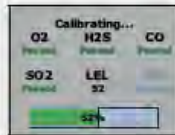
The MX6 clearly shows real-time readings in PPM or % by volume.



An intuitive menu provides easy access to features and setup.



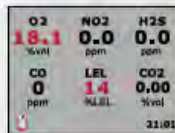
Datalog trends and direct readings can be viewed graphically.



Calibration progress and results are shown for each sensor.



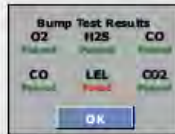
A "calibration due" warning appears for each relevant sensor.



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 menu-driven navigation
- Five-way navigation button
- Durable, concussionproof over-mold
- 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



Continued...

Attachment D-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/ Hydrogen Sulfide (COSH)	CO: 0-1,500 ppm H2S: 0-500 ppm	1 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:	-20°C to 55°C (-4°F to 131°F)
OPERATING HUMIDITY RANGE:	15% to 95% non-condensing (continuous)

Attachment D-5 – Electrical Resistance (ER) Probe Specification Sheet

Roxar Retrievable ER Probes
FA-T218-A

Product Data Sheet
06.07.2015

Roxar Electrical Resistance (ER) Probes 2" Retrievable System



High Accuracy ER Probes

Corrosion is a serious industrial problem, and corrosion control is important in order to avoid damage and loss of integrity in a plant or production site. Efficient corrosion mitigation requires fast and reliable tools for control and verification of protection programs, such as the use of corrosion inhibitors.

Electrical Resistance (ER) Probes are probably the most commonly used technology used for internal corrosion monitoring. ER Probes provide a high resolution and sensitivity compared to other technologies available, and changes in corrosion rates can be identified within hours or days ¹⁾.

ER Probes measure corrosion and corrosion rates as an increase in electrical resistance over time for a steel element in the probe face. The increase in electrical resistance is proportional to the accumulated corrosion of the probe element over the exposure period. Since resistance is also dependent on temperature, a reference element (not exposed to corrosion) is buried inside the probe body for temperature correction.

ER Probes can generally be used in most common environments, like oil, gas and water. The ER Probes described in this data sheet are of the 2" high pressure retrievable type, typically used in upstream, high pressure applications.

Quality of information and measurement accuracy depend on measurement frequency and instruments used. For best results, it is recommended that Roxar ER Probes are used with Roxar CorrLog or Roxar CorrLog Wireless high accuracy instruments, covering a wide range of configuration options.

Operating conditions vary from case to case, and it is important to choose the right probe for the specific application. For this reason, a range of ER Probes is available with flush or projecting design.

The useful life of an ER Probe is normally defined as half the measurement element thickness.

¹⁾ Depending on probe type, measurement frequency and corrosion rates.

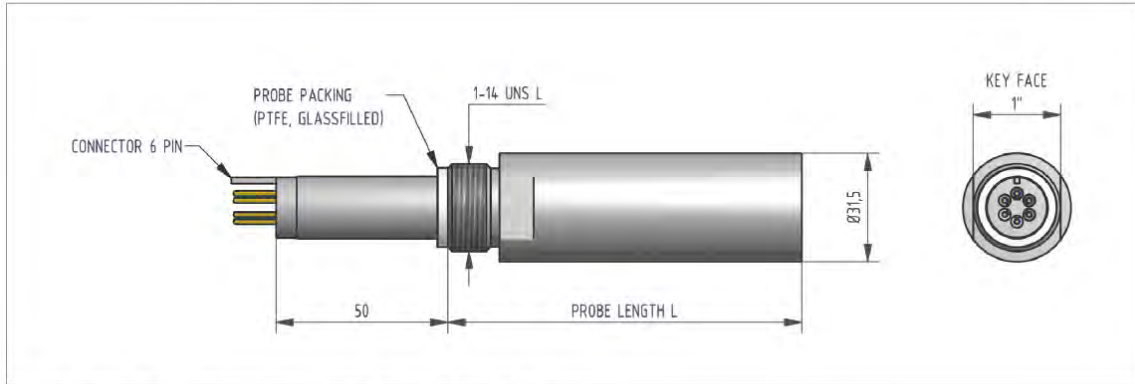


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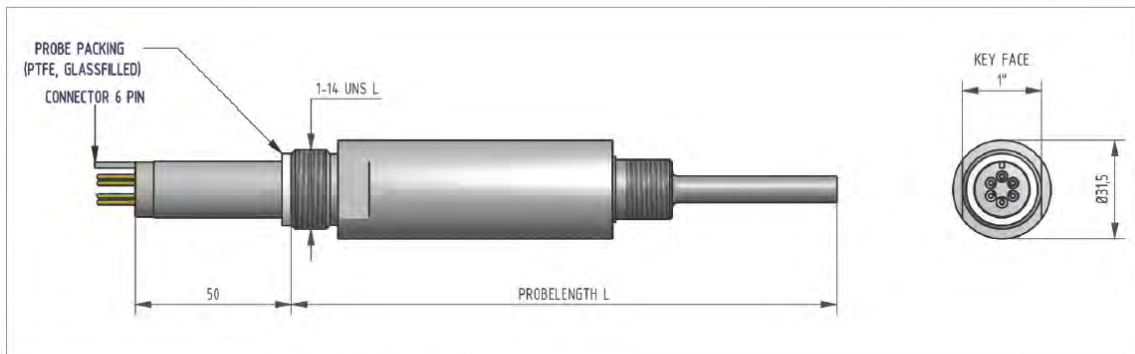
Attachment D-5 – ER Probe Specification Sheet (continued)

Roxar Retrievable ER Probes

06.07.2015



Drawing shows flush probe outline and basis for probe length calculations.



Drawing shows tubular probe outline and basis for probe length calculations.



A special reinforced probe design is available for conditions where velocities are high, sometimes in combination with a need for long probes. Need for reinforced design probes is normally evaluated based on wake frequency calculations. Picture shows reinforced probe body with reinforced hollow plug.

Attachment D-5 – ER Probe Specification Sheet (continued)

06.07.2015

Roxar Retrievable ER Probes

Repro D Probe



Repro D Probe front

The design of the Repro D Probe ensures a high resistance, and thus, highly accurate measurements, even if probe has a thick element. This design is therefore suitable for corrosion monitoring where corrosion rates are assumed to be from moderate to high, maintaining a high measurement resolution and accuracy. Repro D Probe is available with element thicknesses 1, 2 and 4 mm (40, 80 and 160 mil).

Repro E Probe



Repro E Probe front

The simple design of the probe makes it suitable in conditions where conductive deposits could cause short circuits between sections of the probe element for more sophisticated probe element designs (e.g. in sour production environments).

Repro F Probe



Repro F Probe front

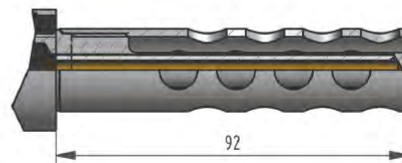
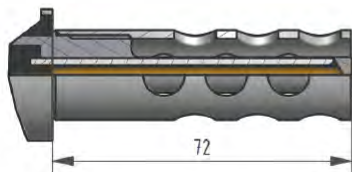
The Repro F Probe has an element with an optimized shape, and is available with a 0,1 mm (4 mil) measurement element. The design gives the probe a very high sensitivity, however, a limited life for many field applications. The probe is mostly recommended for conditions where corrosion is expected to be low, or for test/research applications where fast response is required.

Tubular T10 and T20 Probes



Roxar Tubular Probe front

Roxar tubular element probes are designed with a tubular shaped element protruding into the flow. The probes are available with 0.25 and 0.5 mm (10 and 20 mil) elements.



Protective shields for the tubular elements are available (T10 probe left, T20 probe right)

Attachment D-5 – ER Probe Specification Sheet (continued)

Roxar Retrievable ER Probes

06.07.2015

Specifications - Roxar Retrievable ER Probes

Item	Description
Mounting:	2" high pressure access fitting (mechanical or hydraulic system)
Probe body material:	316 SS (other materials available upon request)
Pressure rating:	Standard: 6,000 psi (420 bar) Optional: 10,000 psi (690 bar)
Connector:	6 pin Amphenol male
Temperature rating:	Operating Temperature up to 145 °C (293 °F) (Welded element tubular probes are option at higher temperature rating, please ask Roxar for details).

Model Code Selector - Roxar Retrievable ER Probes

Model	Product Description		
THCMPR	Corrosion Monitoring Probe		
Code	Measuring Method		
1	Electrical Resistance		
Code	Probe Body Type		
01	Standard Design Fixed Length		
02	Reinforced Design Fixed Length for Access Fitting Flareweld		
03	Reinforced Design Fixed Length for Access Fitting MECH ≤300#, HYD ≤1500#		
04	Reinforced Design Fixed Length for Access Fitting MEC ≥4/600#, HYD 2500#		
99 ⁵	Other Design		
Code	Probe Body Material		
2C6A	Stainless Steel A 479 Gr. 316L, bar	EN 10204 3.1 NACE MR0175	
2D6A	Duplex A 276 / A 479 UNS S31803, bar	EN 10204 3.1 NACE MR0175	
2C6C	Stainless Steel A 479 Gr. 316L, bar	EN 10204 3.1 NACE MR0175	NORSOK M630 MDS S01
2D6C	Duplex A 276 / A 479 UNS S31803, bar	EN 10204 3.1 NACE MR0175	NORSOK M630 MDS D47
9X9X ⁵	Project Specific Material		
Code	Element Type and Material		
00S ¹	Flush	Repro D 1.0 mm	St 52-3N
01S ¹	Flush	Repro D 2.0 mm	St 52-3N
02S ¹	Flush	Repro D 4.0 mm	St 52-3N
03S ¹	Flush	Repro E 0.25 mm	St 52-3N
04S ¹	Flush	Repro E 0.50 mm	St 52-3N

Attachment D-6 – ER Probe Data Transmitter Specification Sheet

Rosemount™ 4390 Series of Corrosion and Erosion Wireless Transmitters

Maximize your process performance with continuous online corrosion and erosion monitoring



Rosemount 4390 Series of Corrosion and Erosion Wireless Transmitters provide continuous, accurate and highly sensitive real time corrosion and erosion monitoring data, enabling maximum performance through process optimization and eliminate the need of costly walk-downs. The transmitter delivers superior corrosion management data by using top of the range instruments thus providing improved data processing, flexible data management solutions and friendly user interface.

- Best-in-class inline corrosion and erosion data monitoring by providing continuous, accurate and highly sensitive monitoring data
- Increase safety at your plant by reducing exposure to personnel in hazardous areas and eliminating walk-downs to gather data
- *WirelessHART®* – seamless compatibility with existing Emerson™ devices
- Self-organizing, self-healing, adaptive mesh network – no wireless expertise is required
- Better cost control by enabling maximum performance through process optimization



Easy to Deploy and Easy to Maintain



Corrosion monitoring system

- The transmitter is compatible with Electrical Resistance Probes (ER probes), Linear Polarization Probes (LPR probes) and Multi Element Sand probes from Emerson and other major vendors
- Various data formats (calculated metal loss data, corrosion and erosion rates or probe raw data) can be selected from the HART® terminal, or from the Emerson Asset Management System (AMS)
- The corrosion wireless transmitter can be seamlessly integrated with Plantweb™ Insight Inline Corrosion Application and provides actionable data right to your desk
- High resolution (24 bit) ensuring reliable and fast corrosion and erosion monitoring
- Optimized power consumption up-to 4 times more compared to previous generation
- 15 times better sampling rate compared to previous generation
- Delivers high reliability in challenging radio environments using Direct Sequence Spread Spectrum (DSSS) technology

For more information, visit Emerson.com/Corrosion-Erosion or contact your local Emerson Sales Representative



Continued...

Attachment D-6 – ER Probe Data Transmitter Specification Sheet (continued)

Rosemount 4390 Series of Corrosion and Erosion Wireless Transmitters

Product Specifications	
General	For connection with intrusive corrosion and erosion probes
Connection	Connected to probe via a probe cable - maximum 65 feet (20 m)
Humidity Limits	5 - 95% relative humidity
Instrument Resolution	24 bit
Measurement Intervals	Multiple Element probes and Electrical Resistance (ER) probes can be measured as fast as 1-minute interval Linear Polarization Resistance (LPR) probes can be measured as fast as 4-minutes intervals
Communication	WirelessHART 2.4 GHz DSSS (Discrete Sequential Spread Spectrum)
ER Probe	Actual accuracy 10-100 ppm of probe element thickness, depending on probe type and environmental conditions
LPR Probe	Accuracy of 100ppm for the resistance measured on the LPR port
Sand Probe	Actual accuracy 10-100 ppm of probe element thickness, depending on probe type and environmental conditions
Operating Temperature	-40 to 158 °F (-40 to +70 °C)
Power Module	Black power module, type 701PBKKF. Replaceable, non-rechargeable. Intrinsically safe Lithium-Thionyl Chloride power module pack with PBT/PC enclosure. 7.2 V
Housing & Weight	Painted aluminum, IP 66, NEMA® 4x, 5kg
Hazardous Location Protection Type	Intrinsically Safe (Ex ia) device

*See product data sheet for full specifications.

RELATED PRODUCTS



Emerson Automation Solutions
 North America
 6021 Innovation Blvd.
 Shakopee MN 55379
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 ☎ +1 952 949 7001
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Consider It Solved.

Emerson Automation Solutions supports you with innovative technologies and expertise to address your toughest challenges.

For more information, visit [Emerson.com/Corrosion-Erosion](https://www.emerson.com/Corrosion-Erosion)



Attachment D-7 – Example Ultrasonic Tool Specification Sheet



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

Flexural wave imaging is used by Isolation Scanner service as a significant complement to pulse-echo acoustic impedance measurement. It relies on the pulsed excitation and propagation of a casing flexural mode, which leaks deep-penetrating acoustic bulk waves into the annulus. Attenuation of the first casing arrival, estimated at two receivers, is used to unambiguously determine the state of the material coupled to the casing as solid, liquid, or gas (SLG). Third-interface reflection echoes arising from the annulus/formation interface yield additional characterization of the cased hole environment:

- acoustic velocity (*P* or *S*) of the annulus material
- position of the casing within the borehole or a second casing string
- geometrical shape of the wellbore.

Vertical sampling is selectable to as low as 0.6 in [1.52 cm], and the azimuthal resolution has a maximum of 10°. Because acoustic impedance and flexural attenuation are independent measurements, their combined analysis provides borehole fluid properties, not requiring a separate fluid property measurement.

Applications

- Differentiate high-performance lightweight cements (foam, LiteCRETE*, and Ultra LiteCRETE* systems) from liquids
- Map annulus material as SLG
- Confirm hydraulic isolation
- Image channels and defects in annular isolating material
- Visualize position of casing in the borehole
- Image wellbore shape
- Determine casing internal diameter and thickness
- Determine depth for sidetracking and casing milling.



Attachment D-7 – Example Ultrasonic Tool Specification Sheet (continued)



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

Isolation Scanner Service Measurement Specifications	
Output [†]	Solid-liquid-gas map of annulus material, hydraulic communication map, acoustic impedance, flexural attenuation, rugosity image, casing thickness image, internal radius image
Logging speed	Standard resolution (6 in, 10° sampling): 2,700 ft/h [823 m/h] High resolution (0.6 in, 5° sampling): 563 ft/h [172 m/h] Up to 13,000 ft/h [3,972 m/h] using SLB Power Transducers
Range of measurement	Min. casing thickness: 0.15 in [0.38 cm] Max. casing thickness: 0.79 in [2.01 cm]
Vertical resolution	High resolution: 0.6 in [1.52 cm] High speed: 6 in [15.24 cm]
Accuracy [‡]	Acoustic impedance: [§] 0 to 1.0 Mrayl (range); 0.2 Mrayl (resolution); 0 to 3.3 Mrayl = ±0.5 Mrayl, >3.3 Mrayl = ±15% (accuracy) Flexural attenuation: ^{††} 0 to 2 dB/cm (range), 0.05 dB/cm (resolution), ±0.01 dB/cm (accuracy)
Depth of investigation	Casing and annulus up to 3 in [7.62 cm]
Mud type or weight limitations ^{‡‡}	Conditions simulated before logging
Combinability	Bottom only, combinable with most wireline tools Telemetry: fast transfer bus (FTB) or enhanced FTB (EFTB)
Special applications	H ₂ S service

- † Investigation of annulus width depends on the presence of third-interface echoes. Analysis and processing beyond cement evaluation can yield additional answers through additional outputs, including the Variable Density log of the annulus waveform and polar movies in AVI format
- ‡ 8-mm calibration target
- § Differentiation of materials by acoustic impedance alone requires a minimum gap of 0.5 Mrayl between the fluid behind the casing and a solid
- †† For 0.3-in [8-mm] casing thickness
- ‡‡ Max. mud weight depends on the mud formulation, sub used, and casing size and weight, which are simulated before logging

Isolation Scanner Service Mechanical Specifications	
Temperature rating	350 degF [177 degC]
Pressure rating	20,000 psi [138 MPa]
Casing size—min. [†]	4 ½ in (min. pass-through restriction: 4 in [10.16 cm])
Casing size—max. [†]	13 ¾ in
Outside diameter	IBCS-A: 3.375 in [8.57 cm] IBCS-B: 4.472 in [11.36 cm] IBCS-C: 6.657 in [16.91 cm] IBCS-D: 8.736 in [22.19 cm]
Length	Without sub: 19.73 ft [6.01 m] IBCS-A sub: 2.01 ft [0.61 m] IBCS-B sub: 1.98 ft [0.60 m] IBCS-C sub: 1.98 ft [0.60 m] IBCS-D sub: 1.98 ft [0.60 m]
Weight	Without sub: 333 lbm [151 kg] IBCS-A sub: 16.75 lbm [7.59 kg] IBCS-B sub: 20.64 lbm [9.36 kg] IBCS-C sub: 23.66 lbm [10.73 kg] IBCS-D sub: 24.55 lbm [11.13 kg]
Sub max. tension	2,250 lbf [10,000 N]
Sub max. compression	12,250 lbf [50,000 N]

† Limits for casing size depend on the sub used. Data can be acquired in casing larger than 9½ in with low-attenuation mud (e.g., water, brine). If the chrome content of the tubing or casing is higher than 13%, contact your local SLB representative.

Attachment D-8 – Example Array Sonic Tool Specification Sheet



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

Array Sonic Tool (ASLT)

Acoustic, or sonic, tools provide a measurement of the formation integral travel time (Δt) in a variety of environments. Acoustic logs recognize secondary, or vugular, porosity in hard rock sediments. Acoustic tools can be run in conjunction with density and compensated neutron tools in bad borehole conditions to measure porosity, and this third porosity is also used to identify complex lithology.

The Array Sonic Tool (ASLT) is made up with a Sonic Array Logging Sonde (ASLT), which uses the Digital Telemetry System, to provide either compressional Δt measurements or Cement Bond Log (CBL) and Variable Density log (VDL) measurements and digital waveform recording and display. The conventional sonic measurements are borehole-compensated (BHC) (3- to 5-ft [0.91- to 1.52-m]) transit time and long-spacing depth-derived BHC (DDBHC) (5- to 7-ft [2.43- to 3.65-m]) and STC.

Applications

- 2 ft span BHC (3ft to 5ft) delta-T
- 2 ft span BHC (5ft to 7ft) delta-T (Compensated measurement for tool tilt and wash out)
- 6 in span BHC Compressional Δt
- Compressional and Shear slowness from multi receiver STC analysis
 - Gas detection
 - Seismic ties & Synthetics
 - Sonic Porosity
- ASLT has capability to obtain Shear Slowness in fast formation through STC Processing

ASLT Measurement Specifications	
Output	OH: BHC (3-5ft), DDBHC (5-7ft), STC CH: 1ft and 3ft CBL, VDL, Attenuation
Logging speed	3,600 ft/h [1,097 m/h]
Range of measurement	40 to 200 us/ft [131 to 656 us/m]
Maximum compressional slowness	155 (us/ft) with DT mud at 180 (us/ft)
Maximum shear slowness	DT mud – 50 (us/ft)
Tx – Rx Configuration	Upper and Lower Transmitter – 6 Receivers Array
Mud type or weight limitations	None
Combinability	Combinable with most services



Attachment D-8 – Example Array Sonic Tool Specification Sheet (continued)



Summit Carbon Solutions LLC
Cased-Hole Wireline Services RFP 7.6.2023

ASLT Mechanical Specifications	
Temperature rating	302 degF [150 degC]
Pressure rating	20,000 psi [138 MPa]
Borehole size—min.	OH: 5 in
	CH: 5 1/2 in
Borehole size—max.	OH: 13 5/8 in
	CH: 17 1/2 in
Outside diameter	3 5/8 in
Length	14.66 ft
Weight	100 kgf
Tension	20,000 lbs
Compression	3,000 lbs

Attachment D-9 – Example Pulsed-Neutron Logging Tool Specification Sheet



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 D-9 – Example Pulsed-Neutron Logging Tool Specification Sheet (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, CO₂ 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

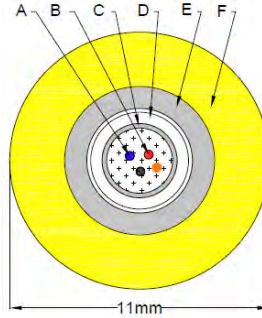
Tool specification	
Description	Specification
Tool diameter	180 in. (w/ Boron coating) 19 ft
Tool length	29.75 ft (w/ telemetry, GR and CCL)
Temperature	350°F
Pressure	20,000 psi
Minimum restriction	190 in.
Maximum hole size	12.25 in.
Tool compressive strength	570 lb
Tool tensile strength	22,000 lb
Maximum bend rate	30°/100 ft
Crystals	Brilliance 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

Attachment D-10 – DTS Fiber-Optic Cable Specification Sheet

Cable Engineered by Prysmian

**TEF w/ 4 OPTICAL FIBERS 825 ALLOY SHEATH TUBE ROUND ENCAPSULATION
CARBON CAPTURE AND STORAGE (CCS) APPLICATION**



Components

- A: 2 x Fibercore GIMM CMTDA 50/125 Graded Index Fiber; Colored Blue & Orange
- B: 2 x Fibercore SM1250 CMTDA Single Mode Fiber; Colored Red & Black
- C: FIMT: 3.2 mm x 2.8 mm Stainless Steel 316L, Filled with LA4000 EFL $\geq 0.30\%$
- D: Natural Polypropylene; O.D.: 4.57mm (0.180") Nominal – Belt OD run larger for CCS Application
- E: 825 Alloy Tube; Wall Thickness: 0.89 mm (0.035"); O.D.: 6.35 mm (0.250") Nominal
- F: Yellow Round Profile Polypropylene; OD.: 11 mm (0.433") Nominal

Print Legend

"FiberSight™" P/N: 103200010 (Batch Number) (month/year)" Plus Footage Markings

Physical Characteristics

- Tube Min Tensile Strength : 3546 lbs
- Tube Min Yield Strength : 2246 lbs
- Cable Breaking Strength, Theoretical : 4166 lbs Maximum
- Fiber Coating : 245 μ m \pm 15 μ m
- Cable Weight, kg/km (lbs/1000 ft) : 208 (140) Nominal
- Temperature Rating : 150°C

Optical Characteristics

- Optical Attenuation at 850 / 1300nm : ≤ 3.0 dB/km / ≤ 1.0 dB/km
- Optical Attenuation at 1310 / 1550nm : ≤ 0.5 dB/km / ≤ 0.3 dB/km
- Point Discontinuity MMF / SMF : ≤ 0.2 dB / ≤ 0.1 dB

R e v	DATE	CHANGE DETAIL		Prysmian Group	Prysmian Cable Systems USA, LLC 111 Chimney Rock Road Bridgewater, New Jersey 08807 Phone: 866-786-8823 Fax: 732-469-6363	
	0	09/11/23	New Issue			
	1	10/09/23	SCN 43522			
Approvals:		Created By:	Reviewed By:	Project Name:	Halliburton 103200010	
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Attachment D-11 – DTS Fiber-Optics Interrogator Specification Sheet

PINNACLE

Distributed Temperature Sensing (DTS) Interrogator

FiberWatch® DTS Hydrogen Tolerant (HT) System

The FiberWatch® DTS hydrogen tolerant (HT) system is designed to provide DTS results in the harshest upstream environments. This system incorporates our patented dual-laser technology to mitigate effects of degradation to capture meaningful data on multi-mode fiber that may have previously been unusable. The interrogator is designed for long-term monitoring to assess life of well performance.



FiberWatch® DTS HT System

Performance	
Nominal Range	5 km
Spatial Resolution	1 m
Sampling Resolution	0.5 m
Accuracy	±2°C
Temperature Resolution	See Performance Curves
Measurement Time per Channel	10-second minimum (See Performance Curves)

Specifications	
Operating Temperature	0°C to 40°C (32°F to 104°F)
Storage Temperature	-20°C to 70°C (-4°F to 158°F)
Data Storage	194 GB solid state drive
Fiber Compatibility	50 µm graded index multimode fiber
Optical Channels	1, 2, 4, 8, 12, or 16 with E2000/APC connectors. Single-ended configuration only.
Laser Safety	Lasers are certified as Class 1M per IEC 60825-1:2007
Certification	Low voltage safety: IEC 61010-1:2012, IEC 60825-1:2007 EMC: EN 61326-1:2005, CISPR 11:2003, IEC 61000-4-2:2001, IEC 61000-4-3:2002, IEC 61000-4-4:2004, IEC 61000-4-6:2003 Hazardous area: EN 60079-0:2012, EN 60079-28:2007 Output is inherently safe optical radiation. Suitable for Zone 1 and 2 areas.
Packaging	2U, Rackmount, w x d x h: 482x508x89 mm (19x20x3.5 in.)
Power (AC or DC options)	110 to 240 VAC: 90 W Peak, 70 W Typical 18 to 36 VDC: 90 W Peak, 70 W Typical
Weight	9 kg (19.8 lb)

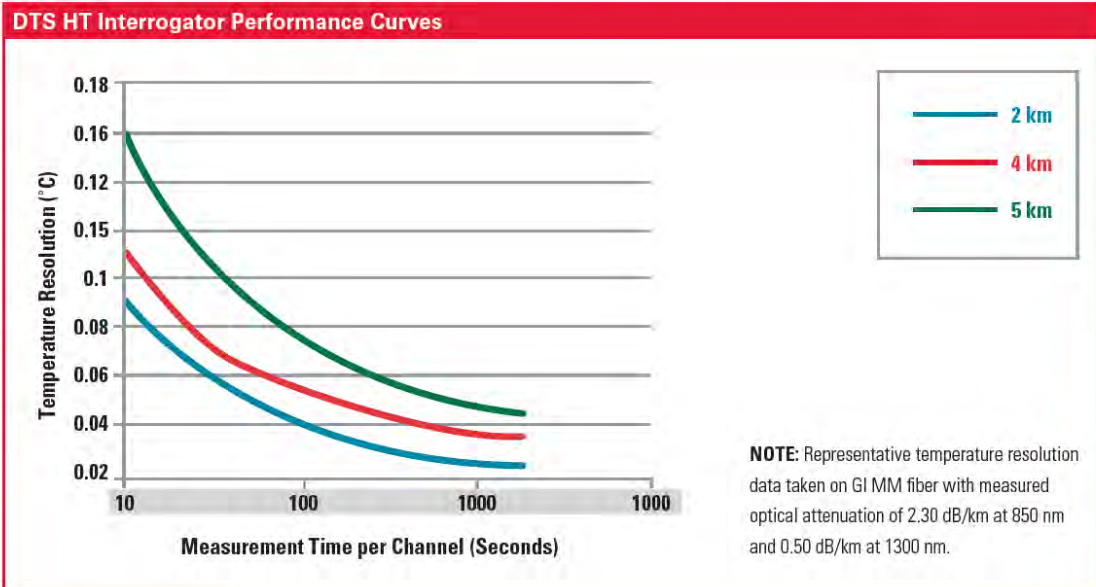


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Attachment D-11 – DTS Fiber-Optics Interrogator Specification Sheet

PINNACLE

Software and Communications	
Software	OS (Windows Embedded Systems 7), DTS Commander™, FiberView™ software
Communication Ports	Ethernet x 2 , USB x 2, DB9 x 1, VGA x 1
Data Protocols	Standard: Modbus (TCP/IP), Modbus (RS232), DNP3 (TCP/IP), DNP3 (RS232) Optional: OPC (TCP/IP)
Data Zones and Alarms	Multiple zoning with individual alarms per zone
Remote Access	Full operator remote control and data access capabilities
Diagnostics	Real-time diagnostics for remote support, system health alarms



Naming Convention

DTS-HT-XX-Y-WW-ZZ-SF

XX	Channels	01, 02, 04, 08, 12, or 16
Y	Packaging	R = Rackmount, S = Subsea, LP = Low Power
WW	Integral SPDT Relays	00 or 16
ZZ	Voltage	AC or DC
SF	SEAFOM Testing	SF

For more information on FiberWatch® DTS HT System, contact us at askanexpert@pinntech.com.

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Attachment D-12 – Example Annulus Pressure Test Procedure

The following is a checklist SCS3 will use as a guide for conducting an initial annulus pressure test. Annulus pressure tests are required prior to commencing injection and are requisite in reestablishing mechanical integrity following a workover that involves tubing removal. If necessary, a detailed annulus pressure test procedure can be provided with the written notification prior to conducting the test.

Pretest Protocol:

- Notify the Department of Mineral Resources, Oil and Gas Division (DMR-O&G) in writing at least 30 days prior to annulus pressure testing and again at least 48 hours in advance to witness the test.
- Prepare a well schematic that includes sufficient information to confirm the packer is set opposite a cemented interval of the long-string casing and no more than 50 feet above the uppermost perforation or at a location otherwise approved by DMR-O&G. If the test well was worked over and the tubing or tubing/packer retrieved from the well, provide a workover record to the DMR-O&G inspector for review and verification of packer depth.
- Provide the on-site DMR-O&G inspector with a well schematic confirming the test well packer is in an approved location.
- Provide the on-site DMR-O&G inspector with a calibration certificate for the mechanical or digital device used to record the annulus pressure test verifying calibration within 1 year of the test date.

Test Protocol:

- Install or select the wellhead pressure gauge and continuous recording device to measure pressure and serve as a record of the pressure data witnessed on the wellhead pressure gauge. Select a pressure gauge with an appropriate scale so that the anticipated testing pressure falls within 25% and 75% of the full gauge scale and that the gauge range is at a minimum twice the testing pressure. The pressure gauge and continuous recording device shall have sufficient accuracy and precision to identify a 10% pressure change.
- Fill the tubing-casing annulus with an approved liquid and confirm the annulus will remain full. Measure and record the liquid type and volume required to fill the annulus. Allow time for the temperature of the well and annulus liquid to equilibrate.
- Confirm that the annulus is liquid-filled.
- Build and maintain the annulus pressure at 1000 psig or a value previously approved by DMR-O&G.
- Isolate the well from the pressure source and confirm no leaks occur at shut-off valves. If present, consider disconnecting the seal pot or surge tank to also prevent leaks at their shut-off valves.

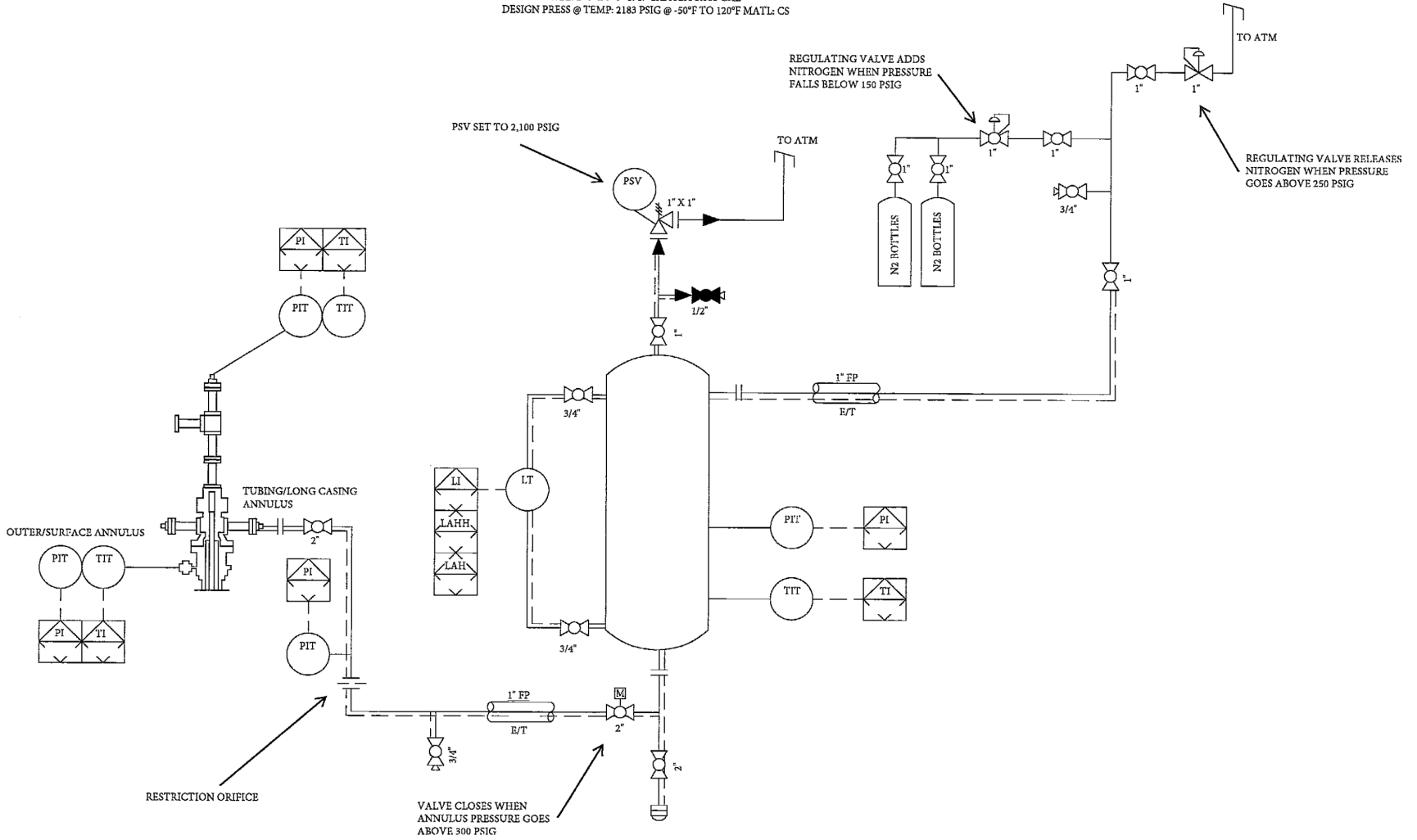
- Maintain a minimum pressure differential of 200 psi between the tubing pressure and annulus pressure. If a lower pressure differential is needed, the storage facility operator must obtain prior DMR-O&G approval.
- Record the annulus pressure for at least 30 minutes.
 - Note the time, the annulus pressure, and the tubing pressure at the start of the test and at least every 5 minutes thereafter to the end of the test.
 - The continuous recording device shall serve as a backup. A copy of the continuous pressure recording shall be submitted with the written reports to DMR-O&G.
 - A net pressure change of more than 10% constitutes a failed test.

Posttesting Protocol:

- Report to DMR-O&G within 30 days the results of any annulus pressure test.
- Publish the annulus pressure test results in the quarterly report in which the test was performed.

Attachment D-13 – Diagram of the Seal Pot System

ANNULUS VOLUME TANK
 SIZE: 2'-0" x 8'-0" T/T/ CAPACITY: 160 GAL
 DESIGN PRESS @ TEMP: 2183 PSIG @ -50°F TO 120°F MATL: CS



D-27

Attachment D-14 – Antimicrobial Biocide Specification Sheet

PRODUCT DATA SHEET

ALDACIDE® G

BIOCIDE

Product Description

ALDACIDE® G biocide is suitable for use in water-based drilling fluids and packer fluids. ALDACIDE G biocide is effective against aerobic and anaerobic bacteria and is compatible with all brine types. Use of ALDACIDE G biocide in conjunction with sulphite oxygen scavengers is not recommended.

Applications/Functions

- » Water-based drilling fluids
- » Completion and packer fluids
- » Aqueous waste treatment
- » Used as part of corrosion control systems

Advantages

- » Effective against a broad range of microbes, bacteria and fungi
- » Effective in small concentrations
- » Compatible with most water-based drilling fluids

Typical Properties

- » Appearance: Transparent liquid
- » Specific gravity: 1.06
- » pH: 3.1 - 4.5

Recommended Treatment

Initial additions around 0.4 lb/bbl (1.1. kg/m³) will achieve effective antimicrobial action. Packer fluids should be treated with ALDACIDE G along with other corrosion control additives. Circulating fluids require regular additions of ALDACIDE G in order to maintain protection.

Caution: ALDACIDE G biocide is incompatible with BARASCAV™ D and BARASCAV L oxygen scavengers.

Packaging

ALDACIDE G biocide is packaged in 5-gal (18.9-l) pails and 55-gal (208-l) drums.

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HALLIBURTON | Baroid

Attachment D-15 – Corrosion Inhibitor Specification Sheet

Baroid Fluid Services

BARACOR® 100

Corrosion Inhibitor

Product Data Sheet

Product Description

BARACOR 100 inhibitor is a highly active, film forming, water-dispersible corrosion inhibitor for use in solids-free brines.

Applications / Functions

- BARACOR 100 inhibitor is an effective corrosion inhibitor in solids-free packer fluids and other oil and gas industry applications. BARACOR 100 inhibitor is effective at temperatures up to 400°F (204°C) in monovalent (sodium and potassium) brines and up to 300°F (148°C) in divalent (calcium and zinc) brines. Typical results show over ninety percent corrosion inhibition.

Advantages

- Effective at low concentrations
- Convenient and easy to use
- Economical

Typical Properties

• Appearance	Dark liquid
• Flash point, TCC	92 °F
• Flash point, TCC	33 °C
• pH, (1% aqueous solution)	10.5
• Pour point	-10 °F
• Pour point	-23 °C
• Specific gravity	1

Recommended Treatment

Treatment recommendations should be based on area histories which indicate a need for an inhibited packer fluid and compatibility test of BARACOR 100 inhibitor with the packer fluid. Many producing companies require the use of inhibited packer fluids in areas known to have corrosion problems. This is low-cost insurance for production strings. The suggested treatment for solids-free freshwater or brine packer fluids is 0.5%-1% by volume. BARACOR 100 inhibitor should be mixed with the packer brine after filtration, then spotted in the hole.

Packaging

BARACOR 100 inhibitor is packaged in 55-gal (208-l) drums containing 462-lb (210-kg) net weight.

HALLIBURTON | Fluid Systems

Baroid Fluid Services • P.O. Box 1675 • Houston TX 77251 • 281-871-5516

Because the conditions of use of this product are beyond the seller's control, the product is sold without warranty either express or implied and upon condition that purchaser make its own test to determine the suitability for purchaser's application. Purchaser assumes all risk of use and handling of this product. This product will be replaced if defective in manufacture or packaging or if damaged. Except for such replacement, seller is not liable for any damages caused by this product or its use. The statements and recommendations made herein are believed to be accurate. No guarantee of their accuracy is made, however.

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April 2005

Attachment D-16 – Scaling Inhibitor (Oxygen Scavenger) Specification Sheet

OXYGON™ Scavenger

PRODUCT DATA SHEET

Fluid Additive

Product Description

OXYGON™ is a non-sulfite oxygen scavenger used to minimize the corrosive effects of soluble oxygen. Dissolved oxygen can be removed from drilling, completion and packer fluids. OXYGON works in conjunction with inhibitors, other scavengers and biocides to minimize corrosion and avoid damage to drilling and completion equipment.

Applications/Functions

- Removes soluble oxygen from drilling, completion and packer fluids
- Compatible with fresh water, mono- and divalent brines
- Used as part of corrosion control systems

Advantages

- Effective at low concentrations
- Rapid removal of dissolved oxygen
- Stable in solution to 250°F (121°C)
- Stability can be extended up to 500°F (260°C)

Typical Properties

- Appearance: White granular powder
- Solubility: Water Soluble
- Specific Gravity: 1.2

Recommended Treatment

Packer fluids should be treated with 0.1 lb/bbl (0.29 kg/m³) OXYGON, along with other corrosion control additives. Circulating fluids require regular additions of OXYGON. Service at temperatures above 250°F (121°C) requires treatment with 0.5 lb/bbl (1.45 kg/m³) CFS-635 OXYGON stabilizer.

Packaging

OXYGON is packed in 50lb and 25kg pails.

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Baroid

Attachment D-17 – Example Casing-Conveyed P/T Gauge Specifications

INTELLIGENT COMPLETIONS | Permanent Monitoring

DataSphere® Array System

RELIABLE MULTI-POINT RESERVOIR MONITORING



OVERVIEW

The DataSphere® Array system is the next step in the evolution of DataSphere permanent monitoring suite. The technology is built upon the reliability of ROC™ gauge hybrid technology and provides greater system customization by deploying multiple discrete sensors across challenging wellbore regions.

A system comprised of conventional gauges can communicate with multiple Array sensor systems distributed across different wellbore intervals. Each Array system provides discrete real-time annular downhole distributed multi-point temperature and pressure monitoring data. The Array system incorporates no cable terminations, which reduces installation time and eliminates risks associated with multiple terminations. Furthermore, the Array system uses internal short circuit protection circuitry that minimizes system line takedowns.

Based on an industry-standard, field-proven resonating quartz crystal sensor, the Array system can be used for distributed, single zone, or multi-zone monitoring applications.

In distributed monitoring, the use of Halliburton conventional downhole gauges can be enhanced by the Array system, allowing operators greater visibility into their operations efficiency in a cost-effective manner.

APPLICATIONS

- » ICD efficiency monitoring
- » Production monitoring
- » Injection monitoring
- » Field reservoir monitoring
- » SmartWell® completion system optimization
- » Artificial lift/gas lift optimization
- » Pressure gradient monitoring

FMJ CABLE TERMINATION

When connected to a conventional gauge, the DataSphere Array system uses a high-performance cable termination with a sealing arrangement based on our highly reliable intelligent completion FMJ connector. This cable termination incorporates a pressure-testable dual metal-to-metal ferrule seal arrangement for isolating the downhole cable outer metal sheath from the well fluid.

FEATURES

- » Can be deployed standalone
- » Up to 50 sensors per array
- » ROC-MODBUS communication protocol
- » Designed for harsh environments up to 16,000 psi and 175°C
- » AWES qualified
- » Reduced OD design
- » Multi-drop capability on single core tubing encased conductor (TEC)
- » Hermetically sealed electron beam-welded design
- » Application Specific Integrated Chip (ASIC) technology
- » Increased capabilities such as fault protection per sensor
- » Designed for a 10 year life at 185°C

BENEFITS

- » Quartz-sensors provide high accuracy and resolution and low drift
- » Can be deployed across the sandface for greater reservoir inflow/outflow understanding
- » Reduces rig time through faster installation times (up to eight hours saved per gauge)
- » Reduces need for cable terminations
- » Eliminates requirement for gauge mandrels in annular sensing applications
- » Validates/disproves reservoir models
- » Tool head voltage and gauge current measurement for diagnostics
- » Reduces potential leak points by minimizing system connections

Attachment D-17 – Example Casing-Conveyed P/T Gauge Specifications (continued)

INTELLIGENT COMPLETIONS | Permanent Monitoring

TESTING

The individual sensor design has gone through the Design for Reliability process, which includes a Highly Accelerated Lifetime Test (HALT) program. This program is a series of controlled environmental stresses designed to ensure that stringent criteria are met for thermal shock, mechanical shock, vibration and thermal aging. During manufacture, all gauges are also subjected to Environmental Stress Screening (ESS) to highlight any defect in functionality prior to installation at the well site. This method of screening has proven to be far more effective than "burn-in" techniques.

All of the individual sensors that make up the DataSphere Array system are independently calibration-checked in our manufacturing facility. During Factory Acceptance Testing (FAT), the DataSphere Array sensor welds are pressure tested for integrity as the array is being built and spooled onto the final drum.

DataSphere® Array System - Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	< 0.005
Repeatability (°C)	< 0.01
Drift at 177°C (°C/year)	< 0.1

DATASPHERE ARRAY SYSTEM DESIGNS

- » Quartz transducer and hybrid technology
- » ASIC technology
- » Maximum 175°C operating temperature
- » Can be used in conjunction with existing gauges
- » Improved shock and vibration performance
- » 0.625-in. OD ultra slim design
- » Less than 7-in. length per sensor
- » Does not need a gauge mandrel to be deployed
- » Short-circuit protection per sensor, prevents line takedowns



Temperature and Pressure Sensor > The DataSphere® Array system is comprised of multiple ultra slim, highly accurate quartz-based temperature and pressure sensors.

DataSphere® Array System - Pressure Performance

Pressure Range (psi / bar)	0 to 10,000 / 0 to 690	0 to 16,000 / 0 to 1,100
Accuracy (% FS)	0.015	0.02
Typical Accuracy (% FS)	0.012	0.015
Achievable Resolution (psi/sec)	< 0.006	< 0.008
Repeatability (% FS)	< 0.01	< 0.01
Response Time to FS Step (for 99.5% FS)	< 1 sec	< 1 sec
Acceleration Sensitivity (psi/g – any axis)	< 0.02	< 0.02
Drift at 14 psi and 25°C (%FS/year)	Negligible	Negligible
Drift at Max. Pressure and Temperature (%FS/year)	0.02	0.02

For more information, contact your local Halliburton representative or visit us on the web at www.halliburton.com

Sales of Halliburton products and services will be in accord solely with the terms and conditions contained in the contract between Halliburton and the customer that is applicable to the sale.

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APPENDIX E

**STORAGE FACILITY PERMIT REGULATORY
COMPLIANCE TABLE**

Subject	N.D.C.C. / N.D.A.C. 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	N.D.C.C. §§ 38-22-06(3) and (4) N.D.A.C. §§ 43-05-01-08(1) and (2)	<p>N.D.C.C. § 38-22-06</p> <p>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.</p>	<p>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;</p>	<p>1.0 PORE SPACE ACCESS Summit Carbon Storage #3, LLC (SCS3) will notify in accordance with N.D.A.C. § 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>	<p>The affidavit has not yet been prepared.</p>
		<p>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.</p> <p>N.D.A.C. § 43-05-01-08</p> <p>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:</p>	<p>b. A map showing the extent of the pore space that will be occupied by carbon dioxide over the life of the project;</p>	<p>1.0 PORE SPACE ACCESS (p. 1-1) North Dakota law explicitly grants title to pore space in all strata underlying the surface of lands and waters to the owner of the overlying surface estate; i.e., the surface owner owns the pore space (North Dakota Century Code [N.D.C.C.] § 47-31-03). Prior to issuance of the storage facility permit (SFP), North Dakota law mandates the storage operator obtain the consent of landowners who own at least 60% of the pore space of the storage reservoir for geologic storage of CO₂ (N.D.C.C. § 38-22-08[5]). The statute also mandates that a good faith effort be made to obtain consent from all pore space owners and that all nonconsenting pore space owners are, or will be, equitably compensated (N.D.C.C. §§ 38-22-08[4], [14]). North Dakota law grants the North Dakota Industrial Commission (NDIC) the authority to require pore space owned by nonconsenting owners to be included in a storage facility and subject to geologic storage through pore space amalgamation (N.D.C.C. § 38-22-10). Amalgamation of pore space will be considered at an administrative hearing as part of the regulatory process required for consideration of the SFP application. Surface access for any potential aboveground activities is not included in pore space amalgamation.</p> <p>Summit Carbon Storage #3, LLC (SCS3) has identified the owners (surface and mineral) (N.D.C.C. §§ 38-22-06[3], [4]; North Dakota Administrative Code [N.D.A.C.] § 43-05-01-08[1]). No mineral lessees or operators of mineral extraction activities are within the facility area or within 0.5 miles of its outside boundary. SCS3 will notify all owners of a pore space amalgamation hearing at least 45 days prior to the scheduled hearing and will provide information about the proposed CO₂ storage project and the details of the scheduled hearing. An affidavit of mailing will be provided to NDIC to certify that these notifications were made (N.D.C.C. §§ 38-22-06[3], [4]; N.D.A.C. §§ 43-05-01-08[1], [2]).</p> <p>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 (N.D.C.C. § 47-31-03). The review of pertinent county recorder records identified no severance of pore space from the surface estate or leasing of pore space to a third party prior to April 9, 2009. All surface owners and pore space owners and lessees are the same owner of record.</p> <p>The map in Figure 1-1 shows the extent of the pore space that will be occupied by CO₂ at the cessation of injection (20 years) and over the life of the project (the stabilized CO₂ extent) as well as the storage facility area boundary and 0.5 miles outside of the storage facility area boundary (the hearing notification area).</p>	<p>Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20 years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)</p>
		<p>a. Each operator of mineral extraction activities within the facility area and within one-half mile [.80 kilometer] of its outside boundary;</p> <p>b. Each mineral lessee of record within the facility area and within one-half mile [.80 kilometer] of its outside boundary;</p> <p>c. Each owner of record of the surface within the facility area and one-half mile [.80 kilometer] of its outside boundary;</p>	<p>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>		<p>Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20 years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)</p>
			<p>d. A map showing the storage reservoir boundary and one-half mile outside of its boundary with a description of each</p>		<p>Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20</p>

Subject	N.D.C.C. / N.D.A.C. 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)
		<p>d. Each owner of record of minerals within the facility area and within one-half mile [.80 kilometer] of its outside boundary;</p> <p>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</p> <p>f. Any other persons as required by the commission.</p> <p>2. The notice given by the applicant must contain:</p> <p>a. A legal description of the land within the facility area.</p> <p>b. The date, time, and place that the commission will hold a hearing on the permit application.</p> <p>c. A statement that a copy of the permit application and draft permit may be obtained from the commission.</p>	<p>operator of mineral extraction activities;</p> <p>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;</p> <p>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;</p> <p>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.</p>		<p>years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)</p> <p>Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20 years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)</p> <p>Figure 1-1. Map illustrating the pore space CO₂ extent at the cessation of injection (20 years), alongside the stabilized CO₂ extent over the life of the project. Map also depicts the storage facility area boundary, and 0.5 miles outside of the storage facility area boundary is the hearing notification area. Additionally, 0.5 miles outside the hearing notification area, the area of review boundary is depicted. (p. 1-2)</p>

Subject	N.D.C.C. / N.D.A.C. 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)																												
Geologic Exhibits	N.D.A.C. § 43-05-01-05 (1)(b)(1)	<p>N.D.A.C. § 43-05-01-05 (1)(b) (1) The name, description, and average depth of the storage reservoirs;</p>	<p>a. Geologic description of the storage reservoir: Name Lithology Average thickness Average depth</p>	<p>2.1 Overview of Project Area Geology (p. 2-1) The KJ Hintz is situated approximately 13 miles southeast of Beulah, North Dakota (Figure 2-1). This project site is on the eastern flank of the Williston Basin.</p> <p>Overall, the stratigraphy of the Williston Basin has been well studied, particularly the numerous oil-bearing formations. Through research conducted by the Energy & Environmental Research Center (EERC) via the Plains CO₂ Reduction (PCOR) Partnership, the Williston Basin has been identified as an excellent candidate for long-term CO₂ storage due, in part, to the thick sequence of clastic and carbonate sedimentary rocks and subtle structural character and tectonic stability of the basin (Peck and others, 2014; Glazewski and others, 2015).</p> <p>The CO₂ storage reservoir for this project is the Broom Creek Formation, a predominantly sandstone formation 5568 ft below kelly bushing (KB) elevation at the stratigraphic and reservoir-monitoring well (Slash Lazy H 5: NDIC File No. 38701) (Figure 2-2). Unconformably overlying the Broom Creek Formation is 179 ft of predominantly siltstone with interbedded dolostone and anhydrite of the undifferentiated Opeche and Spearfish Formations, hereafter referred to as the Opeche/Spearfish Formation. The Minnekahta Formation (limestone) is used to distinguish between the Spearfish Formation (above) and Opeche Formation (below); since the Minnekahta Formation is absent at the Slash Lazy H 5 location, and due to the similarity in lithology between the two formations, the Opeche and Spearfish are undifferentiated. The Opeche/Spearfish Formation serves as the primary upper confining zone (Figure 2-2). The Amsden Formation (dolostone, anhydrite, sandstone) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Figure 2-2). Together, the Opeche/Spearfish, Broom Creek, and Amsden Formations comprise the CO₂ storage complex for KJ Hintz (Table 2-1).</p> <p>Including the Opeche/Spearfish Formation, there are 1116 ft (thickness in Slash Lazy H 5) of impermeable rock formations between the Broom Creek Formation and the next overlying permeable zone, the Inyan Kara Formation. An additional 2571 ft (thickness at the Slash Lazy H 5) of impermeable intervals separates the Inyan Kara Formation and the lowest underground source of drinking water (USDW), the Fox Hills Formation (Figure 2-2).</p> <p style="text-align: center;">Table 2-1. Formations Comprising the KJ Hintz Storage Complex (simulation model values calculated from model extent shown in Figure 2-3)</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="text-align: left;">Formation</th> <th style="text-align: left;">Purpose</th> <th style="text-align: center;">Thickness at Slash Lazy H 5, ft</th> <th style="text-align: center;">Depth at Slash Lazy H 5, MD* ft</th> <th style="text-align: center;">Average Simulation Model Thickness, ft</th> <th style="text-align: center;">Average Simulation Model Depth, (TVD),** ft</th> <th style="text-align: left;">Lithology</th> </tr> </thead> <tbody> <tr> <td>Opeche/Spearfish</td> <td>Upper confining zone</td> <td style="text-align: center;">179</td> <td style="text-align: center;">5389</td> <td style="text-align: center;">138</td> <td style="text-align: center;">5106</td> <td>Siltstone, dolostone, anhydrite,</td> </tr> <tr> <td>Broom Creek</td> <td>Storage reservoir (i.e., injection zone)</td> <td style="text-align: center;">272</td> <td style="text-align: center;">5568</td> <td style="text-align: center;">280</td> <td style="text-align: center;">5244</td> <td>Sandstone, dolostone, anhydrite, siltstone</td> </tr> <tr> <td>Amsden</td> <td>Lower confining zone</td> <td style="text-align: center;">242</td> <td style="text-align: center;">5840</td> <td style="text-align: center;">257</td> <td style="text-align: center;">5524</td> <td>Dolostone, sandstone anhydrite</td> </tr> </tbody> </table> <p>* Measured depth (MD). ** True vertical depth. *** Thickness estimated based on offset well information.</p>	Formation	Purpose	Thickness at Slash Lazy H 5, ft	Depth at Slash Lazy H 5, MD* ft	Average Simulation Model Thickness, ft	Average Simulation Model Depth, (TVD),** ft	Lithology	Opeche/Spearfish	Upper confining zone	179	5389	138	5106	Siltstone, dolostone, anhydrite,	Broom Creek	Storage reservoir (i.e., injection zone)	272	5568	280	5244	Sandstone, dolostone, anhydrite, siltstone	Amsden	Lower confining zone	242	5840	257	5524	Dolostone, sandstone anhydrite	<p>Figure 2-1. Topographic map showing well locations and the KJ Hintz in relation to the city of Beulah, North Dakota. (p. 2-2)</p> <p>Figure 2-2. Stratigraphic column identifying the storage reservoir and confining zones (outlined in red) and the lowest USDW (outlined in blue). The Minnekahta Formation is not present at Slash Lazy H 5. (p. 2-3)</p> <p>Table 2-1. Formations Comprising the KJ Hintz Storage Complex (simulation model values calculated from model extent shown in Figure 2-3) (p. 2-4)</p>
	Formation	Purpose	Thickness at Slash Lazy H 5, ft	Depth at Slash Lazy H 5, MD* ft	Average Simulation Model Thickness, ft	Average Simulation Model Depth, (TVD),** ft	Lithology																										
Opeche/Spearfish	Upper confining zone	179	5389	138	5106	Siltstone, dolostone, anhydrite,																											
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Amsden	Lower confining zone	242	5840	257	5524	Dolostone, sandstone anhydrite																											
N.D.A.C. § 43-05-01-05(1)(b)(2)(k)	<p>N.D.A.C. § 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</p>	<p>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</p>	<p>SOURCE OF DATA 2.2 Data and Information Sources (p. 2-4) Several sets of data were used to characterize the injection and confining zones to establish their suitability for the storage and containment of injected CO₂. Data sets used for characterization included both existing data (e.g., from published literature, publicly available databases, purchased/leased digital well logs, existing 3D and 2D seismic) and site-specific data acquired specifically to characterize the storage complex.</p>	<p>Figure 2-3. Map showing the extent of the regional geologic model, distribution of well control points, 2D and 3D seismic, and extent of the simulation model. The wells shown penetrate the</p>																													

Subject	N.D.C.C. / N.D.A.C. 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)
		facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	<p>Mineralogy Porosity Permeability Capillary pressure Facies changes</p>	<p>2.2.1 Existing Data (p. 2-4) Well log data and interpreted formation top depths from 115 wellbores within the 4070-mi² (74-mi × 55-mi) area covered by the geologic model were used to characterize the depth, thickness, and extent of the subsurface geologic formations (Figure 2-3). Seismic interpretation products (seismic horizons and acoustic impedance volumes) from legacy 3D seismic data and 2D seismic data shown in Figure 2-3 were used to support generation of the 3D geologic model.</p> <p>In addition to data from the Slash Lazy H 5, existing laboratory measurements for core samples from the Broom Creek Formation and its confining zones were available from nine additional wells: ANG 1 (ND-UIC-101), Flemmer 1 (NDIC File No. 34243), BNI 1 (NDIC File No. 34244), J-LOC 1 (NDIC File No. 37380), 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), and Archie Erickson 2 (NDIC File No. 38622) (Figure 2-4). These measurements were compiled and used to establish relationships between measured petrophysical characteristics and estimates from well log data and were integrated with newly acquired site-specific data.</p> <p>2.2.2 Site-Specific Data (p. 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 3D seismic data. Slash Lazy H 5 was drilled to a depth of 6110 ft MD in 2022, specifically to gather subsurface geologic data to support the development of this CO₂ storage facility permit (SFP) application and serve as a future CO₂ reservoir-monitoring well. Downhole logs were acquired, and cores were collected from the associated storage complex (Opeche/Spearfish, Broom Creek, and Amsden Formations). Broom Creek Formation stress tests, a fluid sample, and temperature and pressure measurements were collected in the Slash Lazy H 5 (Figure 2-5).</p> <p>DATA ON THE INJECTION ZONE: 2.3 Storage Reservoir (injection zone) (p. 2-16) The Broom Creek Formation is laterally extensive across the simulation model area and surrounding region (Figure 2-9). The Broom Creek Formation comprises interbedded eolian/nearshore marine sandstone (permeable storage intervals) and dolostone layers (impermeable layers) with minor amounts of siltstone and 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).</p> <p>The top of the Broom Creek Formation is located at a depth of 5568 ft below KB elevation at Slash Lazy H 5 and the cored interval is made up of 186 ft of sandstone, 71 ft of dolostone, and 15 ft of anhydrite. The thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft. Cored wells within the extent of the simulation model show minor anhydrite and siltstone intervals are also present in the Broom Creek Formation. Across the simulation model area, the Broom Creek Formation ranges in thickness from 139 to 492 ft (Figures 2-10a and 2-10b), with an average thickness of 280 ft based on offset-well data and geologic model characteristics. The net sandstone thickness within the simulation model area ranges from 6 to 397 ft, with an average thickness of 140 ft.</p> <p>The top of the Broom Creek Formation was picked based on the stratigraphic transition from a relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation to a relatively high GR signature representing the siltstones of the Opeche/Spearfish Formation (Figure 2-11). This transition is also noted with a drop in bulk density (RHOB) and dipole sonic compressional slowness values (DTC) and an increase in neutron porosity (NEUT) and resistivity (RES_D, RES_S). The bottom of the Broom Creek Formation was placed at the base of a relatively low GR package representing a 10-ft package of anhydrite that can be correlated across much of the study area. This rock package divides the clean sandstones and dolostone lithologies of the Broom Creek Formation from the dolostone and anhydrite of the Amsden Formation. Seismic data collected as part of site characterization efforts (Figure 2-8) were used to reinforce structural correlation and thickness estimations of the storage reservoir. The combined structural correlation and seismic interpretation indicate that the formation is continuous across the area near Slash Lazy H 5 (Figures 2-12 and 2-13). A structure map of the Broom Creek Formation shows no detectable features with associated spill points in the simulation model area (Figures 2-14 and 2-15).</p> <p>Twenty-eight (28) 1-in.-diameter core plugs collected from the Broom Creek Formation were sampled and used to determine the distribution of porosity and permeability values throughout the formation (Table 2-6, Figure 2-16). All but four samples were successfully tested in the lab. Some of the samples tested were fractured or chipped which could have resulted in optimistic porosity and/or permeability measurements. The range in porosity and permeability predominantly captured the sandstone variability as this rock type was prominent in the sampling program over the dolostone.</p>	<p>storage reservoir and the upper and lower confining zones. (p. 2-5)</p> <p>Figure 2-4. Map showing the spatial relationship between the KJ Hintz and ten wells where core samples were collected from the formations comprising the storage complex. (p. 2-6)</p> <p>Figure 2-9. 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 dashed line has been modified based on new well control. (p. 2-16)</p> <p>Figure 2-10a. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6). (p. 2-17)</p> <p>Figure 2-10b. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6). (p. 2-18)</p>

Subject	N.D.C.C. / N.D.A.C. 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)																																																		
				<p>Core-derived measurements from Slash Lazy H 5 were used as the foundation for the generation of porosity and permeability properties within the 3D geologic model. The 1-in.-diameter core plug sample measurements showed good agreement with the geologic model property distribution at the location of Slash Lazy H 5. This agreement gave confidence to the geologic model, which is a spatially and computationally larger data set created with the extrapolation of porosity and permeability from offset well logs. The geologic model property distribution statistics shown in Table 2-6 are derived from a combination of the core plug analysis and the larger data set derived from offset well logs.</p> <p>Sandstone intervals in the Broom Creek Formation are associated with low GR, low density, high porosity (neutron, density, and sonic), low resistivity because of brine salinity, and high sonic slowness measurements (Figure 2-11). 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 slowness measurements. The dolomitic sandstone intervals in the formation are the transitions between sandstone and dolostone, where the porosity begins to decrease, and density begins to increase in a transition from predominantly sandstone to dolostone (Figure 2-16).</p> <p>2.3.1 Mineralogy of the Injection Zone (p. 2-26) Powder XRD for average bulk composition analysis of 32 finely ground, homogenized samples from the Broom Creek Formation shows quartz as the most common mineral (~44%) followed by carbonates (~34%, mostly dolomite with a minor contribution from ankerite), sulfates (~9%, mostly anhydrite with minor contributions from gypsum and barite), feldspar (~6%, mostly K-feldspar), and clay minerals (~5%, primarily illite) (Figure 2-17a). Minor amounts of halide (~0.2%) make up the rest of the mineralogy. The major constituents of the Broom Creek Formation obtained by XRD are also shown in Table 2-7a. These results align with the average elemental composition obtained by XRF which shows silica (Si) as the dominant element followed by calcium (Ca), magnesium (Mg), sulfur (S), aluminum (Al), potassium (K), and other trace elements (Figure 2-17a).</p> <p>XRF analysis of the Broom Creek Formation (Figure 2-17b) shows a high percentage of SiO₂ (1.5%–93.8%), CaO (0.8%–40%), and MgO (0.2%–23%) that confirms the dominance of sandstone and dolomite intervals in the Broom Creek Formation. A high percentage of CaO (~32%) and MgO (~20%) at the top of the formation indicates the presence of dolomite layer that isolates the Broom Creek Formation from the Opeche/Spearfish Formation. As the formation gets deeper, the mineralogy changes to anhydrite-rich as indicated by a higher percentage of CaO (~39%) and SO₃ (~49%) that separates the Broom Creek Formation from the bottom Amsden Formation. The Broom Creek Formation consists of a clay content ranging from 0.1% to 26%, with an average of ~5%, with illite being the dominant clay type.</p> <p>Table 2-6. Description of CO₂ Storage Reservoir (injection zone) at the Slash Lazy H 5</p> <table border="1" data-bbox="1320 1124 2517 1689"> <thead> <tr> <th colspan="4">Injection Zone Core Derived Properties</th> </tr> <tr> <th>Property</th> <th colspan="3">Description</th> </tr> </thead> <tbody> <tr> <td>Formation Name</td> <td colspan="3">Broom Creek</td> </tr> <tr> <td>Lithology</td> <td colspan="3">Sandstone, dolostone, anhydrite</td> </tr> <tr> <td>Formation Top Depth, (MD), ft</td> <td colspan="3">5568</td> </tr> <tr> <td>Thickness, ft</td> <td colspan="3">272 (sandstone 186, dolostone 71, anhydrite 15)</td> </tr> <tr> <td>Capillary Entry Pressure (brine/CO₂), psi</td> <td colspan="3">1.12</td> </tr> <tr> <th colspan="4">Geologic Properties</th> </tr> <tr> <th>Formation</th> <th>Property</th> <th>Laboratory Analysis</th> <th>Simulation Model Property Distribution</th> </tr> <tr> <td rowspan="2">Broom Creek (sandstone)</td> <td>Porosity, %*</td> <td>17.1 (6.6–27.2)</td> <td>22.0 (0.0–35.3)</td> </tr> <tr> <td>Permeability, mD**</td> <td>409.1194, 18.5984 (0.0599–2410)</td> <td>458.79, 136.96 (0.0–3401.2)</td> </tr> <tr> <td rowspan="2">Broom Creek (dolostone)</td> <td>Porosity, %*</td> <td>7.9 (4.6–10.6)</td> <td>4.4 (0.0–34.9)</td> </tr> <tr> <td>Permeability, mD**</td> <td>0.6995, 0.0328 (0.0013–6.51)</td> <td>2.07, 0.0221 (0.0–919.6)</td> </tr> </tbody> </table> <p>* Porosity values are reported as the arithmetic mean followed by the range of values in parentheses. Values are measured at 2400 psi. ** Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation. Values are measured at 2400 psi.</p>	Injection Zone Core Derived Properties				Property	Description			Formation Name	Broom Creek			Lithology	Sandstone, dolostone, anhydrite			Formation Top Depth, (MD), ft	5568			Thickness, ft	272 (sandstone 186, dolostone 71, anhydrite 15)			Capillary Entry Pressure (brine/CO ₂), psi	1.12			Geologic Properties				Formation	Property	Laboratory Analysis	Simulation Model Property Distribution	Broom Creek (sandstone)	Porosity, %*	17.1 (6.6–27.2)	22.0 (0.0–35.3)	Permeability, mD**	409.1194, 18.5984 (0.0599–2410)	458.79, 136.96 (0.0–3401.2)	Broom Creek (dolostone)	Porosity, %*	7.9 (4.6–10.6)	4.4 (0.0–34.9)	Permeability, mD**	0.6995, 0.0328 (0.0013–6.51)	2.07, 0.0221 (0.0–919.6)	<p>Figure 2-11. Well log display of the interpreted facies of the Opeche/Spearfish, Broom Creek, and Amsden Formations in Slash Lazy H 5. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) resistivity – deep (red) and resistivity – shallow (light blue); 5) delta time (black), NEUT (blue), and density (green); and 6) facies. (p. 2-19)</p> <p>Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20)</p> <p>Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B'</p>
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				<p>Appendix C C.1.1 Geochemical Interaction of Injection Zone (Broom Creek Formation) (p. C-1) Geochemical simulation has been performed to calculate the effects of introducing the CO₂ stream to the injection zone. The injection zone, the Broom Creek Formation, was investigated using the geochemical analysis option available in GEM, the compositional simulation software package from Computer Modelling Group Ltd. (CMG). GEM is also the primary simulation software used for evaluation of the reservoir’s dynamic behavior resulting from the expected CO₂ injection. For this geochemical modeling study, the injection scenario consisted of a single injection well injecting for a 20-year period with maximum bottomhole pressure (BHP) and maximum wellhead pressure (WHP) constraints of 3828 and 2100 psi, respectively. A postinjection period of 25 years was run in the model to evaluate any dynamic behavior and/or geochemical reaction after the CO₂ injection is stopped.</p> <p>The anticipated average CO₂ stream composition is 98.25% CO₂, 1.44% N₂, and 0.31% O₂, with a trace amount of H₂S. The CO₂ stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O₂ (2%). The modeled stream containing ~95% CO₂ and 2% O₂ was used to represent a conservative scenario where the oxygen concentration is highest, potentially triggering more geochemical reactions in the formation. This simulation scenario was run with and without the geochemical model analysis option included, and results from the two cases were compared (Figures C-1 and C-2).</p> <p>The case with geochemical analysis (geochemistry case) was constructed using the average mineralogical composition of the Broom Creek Formation rock materials (78% of bulk reservoir volume) and average formation brine composition (22% of bulk reservoir volume). X-ray diffraction (XRD) data from the Slash Lazy H 5 core samples were used to inform the mineralogical composition of the Broom Creek Formation (Table C-2). Illite was chosen to represent clay for geochemical modeling as it was the most prominent type of clay identified in the XRD data. Ionic composition of the Broom Creek Formation water, derived from the state-certified analysis reported in Appendix A, is listed in Table C-3.</p> <p>The results do not show an evident difference in the CO₂ gas molality fraction between both cases as seen in Figures C-1 and C-2 for volume injected and injection pressure simulation results. As a result of geochemical reactions in the reservoir, cumulative volume and injection rate have no observable difference between the geochemical and nongeochemical cases. The resulting BHP and WHP from the two cases are nearly identical, with no appreciable differences.</p> <p>Figure C-3 shows the location of the cross sections and Layer 30 used in Figures C-4a and C-4b to depict the geochemical modeling results. Figures C-4a and C-4b show the concentration of CO₂, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model and nongeochemistry model, respectively.</p> <p>The pH of the reservoir brine changes in the vicinity of the CO₂ accumulation, as shown in Figure C-5a. The pH of the Broom Creek Formation native brine sample is 7.1 whereas the fluid pH goes down to approximately 4.7 in the CO₂-flooded areas near the well as a result of CO₂ dissolution in the native formation brine (Figure C-5b).</p> <p>Figures C-6a and C-6b show the cross section for O₂ molality in the Broom Creek Formation. Figure C-6a shows the cross section for the concentration of O₂, in molality, in the reservoir after 20 years of injection plus 25 years of postinjection for the geochemistry model scenario, and Figure C-6b shows the same information for the nongeochemistry simulation case for comparison. The results do not show an evident difference in the O₂ gas molality fraction between both cases. After being injected, the 2% molar oxygen content in the injection 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 O₂ that would affect the CO₂ injection volume as demonstrated by the comparison in injection rates between the case with and without geochemical modeling shown in Figure C-2.</p> <p>Figure C-7 shows the mass of mineral dissolution and precipitation due to CO₂ injection in the Broom Creek Formation. Dolomite is the most prominent dissolved mineral, while anhydrite is the most prominent precipitated mineral. All other minerals showed very limited variations.</p> <p>Simulation results show that, during CO₂ injection, the supercritical CO₂ (free-CO₂ gas) remains dominant. CO₂ dissolution in the formation water and residual trapping of CO₂ slowly increased over time, while CO₂ mineralization is negligible at the plot scale in Figure C-7 it can be observed at the plot scale in Figure C-8. Once CO₂ injection ceases in 2044, injected concentrated CO₂ begins to expand, resulting in more CO₂ that is capillary-trapped or dissolved into fresh brine, as evidenced by the crossover in Figure C-8. Figures C-9 and C-10, respectively, provide an indication of the change in distribution of the mineral that experienced the most dissolution, dolomite, and the mineral that experienced the most</p>	<p>for image display purposes. Cross section is scaled in SSTVD. (p. 2-21)</p> <p>Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-22)</p> <p>Figure 2-15. Cross section of the KJ Hintz storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p. 2-23)</p> <p>Table 2-6. Description of CO₂ Storage Reservoir (injection zone) at the Slash Lazy H5 (p. 2-24)</p> <p>Figure 2-16. Vertical distribution of core-derived porosity and permeability values in the KJ Hintz storage complex from Slash Lazy H 5. Tracks from left to right are 1) SSTVD; 2) GR (black) and caliper (dark blue); 3) MD; 4) delta time (black), NEUT (blue), and bulk density (green); 5) core porosity</p>

Subject	N.D.C.C. / N.D.A.C. 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)
				<p>precipitation, anhydrite. Considering the apparent net dissolution of minerals in the system, as indicated in Figure C-7, there is an associated net increase in porosity in the affected areas, as shown in Figure C-11. Del Porosity Mineral (DPORMNR) output calculates the porosity change due to mineral dissolution/precipitation. It is calculated as Initial Porosity – Porosity at Time “t.” Negative values of this output indicate net mineral dissolution (porosity increase), while positive values indicate net mineral precipitation (porosity decrease). However, the porosity change is small, less than 0.01% porosity units, equating to a maximum increase in average porosity from 22.00% to 22.01% after the 20-year injection period plus 25 years of postinjection.</p>	<p>(2400 psi) and log porosity (light blue); 6) core permeability (2400 psi) and log permeability (black); 7) facies; and 8) upscaled facies. (p. 2-25)</p> <p>Figure 2-17a Bar charts showing a) average mineralogy (wt%), and b) average elemental composition (wt%) of the Broom Creek Formation at Slash Lazy H 5 (note: elemental data by XRF were determined as oxides of the respective elements). (p. 2-26)</p> <p>Table 2-7a. XRD Analysis of the Opeche/Spearfish Formation at Slash Lazy H 5. Only major constituents are shown. (p. 2-27)</p> <p>Figure 2-17b. Elemental composition by XRF as a function of depth in the Broom Creek Formation at Slash Lazy H 5. (p. 2-28)</p> <p>Figure 2-18. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Broom Creek Formation at Slash Lazy H 5. The most porous sample has a total porosity and permeability of 32% and >2000 mD, respectively, which notably reduced to 1.3% and 0.0265 mD in the least porous sample. The blue color in the thin sections a and b</p>

Subject	N.D.C.C. / N.D.A.C. 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)
					<p>represents porosity. (p. 2-29)</p> <p>Figure 2-19. Change in the mineralogy of the target reservoir Broom Creek Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red). (p. 2-30)</p> <p>Table C-1 CO₂ Stream Composition Used for Geochemical Modeling (p. C-1)</p> <p>Table C-2 Averaged XRD data for (Slash Lazy H5) Broom Creek Core Sample (p. C-3)</p> <p>Table C-3 Broom Creek Formation Water Ionic Composition (p. C-4)</p> <p>Figure C-1 Top graph shows cumulative injection vs. time; bottom graph shows gas injection rate vs. time. There is no observable difference in</p>

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					<p>injection volume and gas rate due to geochemical reactions. (p. C-2)</p> <p>Figure C-2 Top graph shows WHP vs. time; bottom graph shows BHP vs. time. There is no observable difference in pressures due to geochemical reactions. (p. C-3)</p> <p>Figure C-3 Index map of west-east and south-north cross sections and simulation Layer 30 at 3332.7 ft (SSTVD, subsea true vertical depth). (p. C-5)</p> <p>Figure C-4a. CO₂ molality for the geochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO₂ molality in 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 30 at 3332.7 ft (SSTVD). (p. C-6)</p> <p>Figure C-4b. CO₂ molality for the nongeochemistry case simulation results after 20 years of injection plus 25 years postinjection, showing the distribution of CO₂ molality in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of</p>

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					<p>simulation Layer 30 at 3332.7 ft (SSTVD). (p. C-7)</p> <p>Figure C-5a. Geochemistry case simulation results after 20 years of injection plus 25 years postinjection showing the pH of formation brine in log scale. The top-left image is west-east, and top-right image is a south-north cross section. The bottom image is a planar view of simulation Layer 30 at 3332.7 ft (SSTVD). (p. C-8)</p> <p>Figure C-5b. Geochemistry case simulation results through 20 years of injection plus 25 years postinjection showing the pH of the Broom Creek Formation brine at the wellbore vs. time for Layer 30 at 3332.7 ft (SSTVD), Layer 44 at 3463.3 ft (SSTVD), and Layer 62 at 3631.3 ft (SSTVD). (p. C-9)</p> <p>Figure C-6a. Cross section for O₂ molality for the geochemistry case simulation results after 20 years of injection plus 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</p>

Subject	N.D.C.C. / N.D.A.C. 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)
					<p>Layer 30 at 3332.7 ft (SSTVD). (p. C-10)</p> <p>Figure C-6b. Cross section for O₂ molality for the nongeochimistry case simulation results after 20 years of injection plus 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 30 at 3332.7 ft (SSTVD). (p. C-11)</p> <p>Figure C-7 Modeled change in the mineral masses (minus values show dissolution and positive values show precipitation) due to CO₂ injection (top: all minerals; bottom: zoomed-in after removing anhydrite and dolomite). Dissolution of dolomite with precipitation of anhydrite was observed. All of the other minerals showed very small values and account as net zero in this figure. (p. C-13)</p> <p>Figure C-8. Top image: mineral mass changes, in metric tons (tonnes), for the different CO₂-trapping mechanisms present during CO₂ injection with geochemical modeling in the injection zone for the Broom Creek Formation;</p>

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					<p>bottom image: CO₂ mineral trapping. (p. C-14)</p> <p>Figure C-9. Modeled change in molar distribution of dolomite, the most prominent dissolved mineral after 20 years of injection plus 25-year postinjection period. 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 30 at 3332.7 ft (SSTVD). (p. C-15)</p> <p>Figure C-10 Modeled change in molar distribution of anhydrite, the most prominent precipitated mineral after 20 years of injection plus 25-year postinjection period. 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 30 at 3332.7 ft (SSTVD). (p. C-16)</p> <p>Figure C-11 Modeled change in porosity due to net geochemical dissolution after 20 years of injection plus 25-year postinjection period. 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 30 at 3332.7 ft (SSTVD). (p. C-17)</p>

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			<p>c. Data on the confining zone and source of the data which may include geologic cores, outcrop data, seismic surveys, and well logs:</p> <ul style="list-style-type: none"> Depth Areal extent Thickness Mineralogy Porosity Permeability Capillary pressure Facies changes 	<p>SOURCE OF THE DATA: <i>See discussion above under 2.2.1 Existing Data (p. 2-4)</i></p> <p>AND</p> <p>2.4 Confining Zones (p. 2-31) The confining zones for the Broom Creek Formation are the overlying Opeche/Spearfish Formation and the underlying Amsden Formation (Figure 2-2, Table 2-7b). Both the overlying and underlying confining formations consist primarily of impermeable rock layers.</p> <p>Table 2-7b. Properties of Upper and Lower Confining Zones at the Slash Lazy H 5</p> <table border="1" data-bbox="1286 566 2554 832"> <thead> <tr> <th>Confining Zone Properties</th> <th>Upper Confining Zone</th> <th>Lower Confining Zone</th> </tr> </thead> <tbody> <tr> <td>Stratigraphic Unit</td> <td>Opeche/Spearfish</td> <td>Amsden</td> </tr> <tr> <td>Lithology</td> <td>Siltstone/anhydrite/dolostone</td> <td>Dolostone/anhydrite/sandstone</td> </tr> <tr> <td>Formation Top Depth (MD), ft</td> <td>5389</td> <td>5840</td> </tr> <tr> <td>Thickness, ft</td> <td>179</td> <td>242</td> </tr> <tr> <td>Capillary Entry Pressure (brine/CO₂), psi</td> <td>61.04</td> <td>307.61</td> </tr> <tr> <td>Depth below Lowest Identified USDW, ft</td> <td>3702</td> <td>4153</td> </tr> </tbody> </table> <table border="1" data-bbox="1286 862 2554 1187"> <thead> <tr> <th>Formation</th> <th>Property</th> <th>Laboratory Analysis</th> <th>Simulation Model Property Distribution</th> </tr> </thead> <tbody> <tr> <td rowspan="2">Opeche/Spearfish</td> <td>Porosity, % *</td> <td>7.7 (3.1–12.1)</td> <td>2.1 (0.0–14.6)</td> </tr> <tr> <td>Permeability, mD **</td> <td>0.0512, 0.0126 (0.0004–0.3620)</td> <td>0.1088, 0.0021 (0.00–6.37)</td> </tr> <tr> <td rowspan="2">Amsden</td> <td>Porosity, % *</td> <td>4.7 (0.3–13.3)</td> <td>2.9 (0.0–35.1)</td> </tr> <tr> <td>Permeability, mD **</td> <td>15.6259, 0.0045 (0.0006–125.0000)</td> <td>0.7056, 0.0070 (0.00–156.05)</td> </tr> </tbody> </table> <p>* Porosity values recorded at 2400-psi confining pressure. Porosity values from the model are reported as the arithmetic mean followed by the range of values in parentheses. ** Permeability values recorded at 2400-psi confining pressure. Permeability values are reported as the arithmetic mean and geometric mean, respectively, followed by the range of values in parentheses and do not have the 2.5 permeability calibration factor applied during simulation.</p> <p>2.4.1 Upper Confining Zone (p. 2-32) In KJ Hintz, the upper confining zone, the Opeche/Spearfish Formation, consists of predominantly siltstone with interbedded dolostone and anhydrite (Table 2-7b). The upper confining zone is laterally extensive across the simulation model area (Figure 2-20) and is 5389 ft below KB elevation and 179 ft thick as observed in Slash Lazy H 5 (Figures 2-20 and 2-21). The contact between the underlying Broom Creek Formation and the upper confining zone is an unconformity that can be correlated across the Broom Creek Formation extent where the resistivity and GR logs show a significant change across the contact. A relatively low GR signature of sandstone and dolostone lithologies within the Broom Creek Formation changes to a relatively high GR signature representing the siltstones of the Opeche/Spearfish Formation (Figure 2-11).</p> <p>2.4.1.1 Mineralogy of the Upper Confining Zone (p.2-35) Powder XRD for average bulk composition analysis of nine finely ground, homogenized samples from the Opeche/Spearfish Formation shows quartz as the most common mineral (~38%) followed by carbonates (~23%, mostly dolomite with minor contributions from ankerite and calcite), feldspar (~15%, mostly K-feldspar), clay minerals (~14%, mostly illite with minor contributions from chlorite and kaolinite), and sulfates (~9%, mostly anhydrite) (Figure 2-22a). Minor amounts of oxide/hydroxide (~0.5%) and sulfide (~0.1%) minerals make up the rest of the mineralogy. The major constituents of the Opeche/Spearfish Formation obtained by XRD are also shown in Table 2-7c. XRD data align with the average</p>	Confining Zone Properties	Upper Confining Zone	Lower Confining Zone	Stratigraphic Unit	Opeche/Spearfish	Amsden	Lithology	Siltstone/anhydrite/dolostone	Dolostone/anhydrite/sandstone	Formation Top Depth (MD), ft	5389	5840	Thickness, ft	179	242	Capillary Entry Pressure (brine/CO ₂), psi	61.04	307.61	Depth below Lowest Identified USDW, ft	3702	4153	Formation	Property	Laboratory Analysis	Simulation Model Property Distribution	Opeche/Spearfish	Porosity, % *	7.7 (3.1–12.1)	2.1 (0.0–14.6)	Permeability, mD **	0.0512, 0.0126 (0.0004–0.3620)	0.1088, 0.0021 (0.00–6.37)	Amsden	Porosity, % *	4.7 (0.3–13.3)	2.9 (0.0–35.1)	Permeability, mD **	15.6259, 0.0045 (0.0006–125.0000)	0.7056, 0.0070 (0.00–156.05)	<p>Table 2-7b. Properties of Upper and Lower Confining Zones at Slash Lazy H5 (p. 2-32)</p> <p>Figure 2-20. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-33)</p> <p>Figure 2-21. Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-34)</p> <p>Figure 2-22a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Opeche/Spearfish Formation at the Slash Lazy H 5 (note: elemental data by XRF were determined as oxides of the respective elements). (p. 2-35)</p> <p>Table 2-7c. XRD Analysis of the Opeche/Spearfish Formation at Slash Lazy H 5. Only major constituents are shown. (p. 2-36)</p>
Confining Zone Properties	Upper Confining Zone	Lower Confining Zone																																										
Stratigraphic Unit	Opeche/Spearfish	Amsden																																										
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				<p>elemental composition obtained by XRF, which shows silica (Si) as the dominant element followed by calcium (Ca), aluminum (Al), magnesium (Mg), sulfur (S), potassium (K), iron (Fe), and other trace elements (Figure 2-22b).</p> <p>XRF analysis of the Opeche/Spearfish Formation (Figure 2-22b) identifies SiO₂ (55%–72%), CaO (6%–13%), Al₂O₃ (2%–11%), and MgO (2%–9%), correlating well with the silicate, carbonate, and aluminum-rich mineralogy determined by XRD. A high percentage of CaO (~32%) and MgO (~20%) with SO₃ (5%) at the base of the Opeche/Spearfish Formation indicates the presence of a dolomite and anhydrite interval separating the Opeche/Spearfish Formation from the Broom Creek Formation. The Opeche/Spearfish Formation consists of clay content ranging from 0.5% to 28%, with an average of ~14%, with illite being the most dominant clay type.</p> <p>Thin-section and SEM–EDS micrographs of the most porous sample at the core depth of 5523.5 ft – KB elevation of 5524 ft show tightly associated, moderately sorted fine-grained subrounded to subangular quartz and feldspar grains. Contacts between the grains are mostly long, sutured, and concavo-convex grain creating isolated and discontinuous pore spaces (Figures 2-23a and 2-23c). The least porous sample at the core depth of 5552.7 ft – KB elevation of 5553.2 ft is mainly composed of highly cemented, poorly sorted quartz and feldspar grains (Figures 2-23b and 2-23d) creating an ultralow permeable layer. Figure 2-24 shows changes in the mineralogy at the Slash Lazy H 5 well as a function of depth next to the core sample porosity and permeability data. The Opeche/Spearfish Formation is highlighted in gray.</p> <p>Appendix C <i>C.1.2 Geochemical Interaction of the Upper Confining Zone (Cap Rock, Opeche/Spearfish Formation) (p.C-18)</i> Geochemical simulation using the PHREEQC geochemical software was performed to calculate the potential effects of an injected multicomponent CO₂ 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 injection stream mixture 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, 2.5, and 3.5 meters above the cap rock–CO₂ exposure boundary. The mineralogical composition calculated from the XRD results of the deepest sample from the Opeche/Spearfish Formation was honored (Table C-4). Formation brine composition was assumed to be the same as the known composition from the Broom Creek Formation injection zone below (Table C-5).</p> <p>The anticipated average CO₂ stream composition is 98.25% CO₂, 1.44% N₂, and 0.31% O₂, with a trace amount of H₂S. The CO₂ stream, shown in Table C-1 that was used for geochemical modeling, contains a higher amount of O₂ (2%). The modeled stream containing ~95% CO₂ and 2% O₂, described in Table C-1, was used to represent a conservative scenario where the higher oxygen concentration may trigger more geochemical reactions in the formation. The exposure level, expressed in moles per year, of the CO₂ stream to the confining layer was 4.5 moles/yr. This value is considerably higher than the expected actual exposure level of 2.3 moles/year (Espinoza and Santamarina, 2017). Again, this conservative overestimation was done 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 obtained from the dynamic reservoir simulation.</p> <p>Results showed geochemical processes at work. Figures C-12 through C-16 show results from geochemical modeling. Figure C-12 shows a change in fluid pH over time as CO₂ diffuses into the system. For the cell at the CO₂ interface, Cell 1 (C1), the pH starts declining from an initial pH of 6.6 after 5 years of injection time and continues to decrease to a level of 5.1 by the end of 25 years of postinjection. For the cell occupying the space 1 to 2 meters into the cap rock, C2, the pH begins to change after Year 4 and goes down to 5.5 by the end of simulation. For the cell occupying the space 2 to 3 meters into the cap rock, C3, the pH begins to change after Year 33. Lastly, the pH is unaffected in C4, indicating CO₂ does not penetrate this cell within the 45 years of simulation.</p> <p>Figures C-13 shows the modeled change in mineral dissolution and precipitation in grams per cubic meter of rock for C1 and C2. In C1, K-feldspar starts to dissolve from the beginning of the simulation period, while illite, quartz, and calcite start to precipitate at the same time. Dissolution of dolomite in C1 is minimal, which is 0.01% of initial dolomite (83.7%). The net change due to precipitation or dissolution in C2 is less than 1.15 kg per cubic meter, with little dissolution or precipitation taking place at the later year of simulation. Any effects in C3 are too small to represent at this scale.</p> <p>Figures C-14 represents the initial fractions of potentially reactive minerals in the Opeche/Spearfish Formation based on XRD data shown in Table C-4. The expected dissolution of these minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar is the primary mineral that dissolves. Dissolution (%) in C2 is minimal (<0.01%) and not significant to represent at the scale in Figure C-14.</p>	<p>Figure 2-22b. Elemental composition by XRF as a function of depth in the Opeche/Spearfish Formation at Slash Lazy H 5. (p. 2-36)</p> <p>Figure 2-23. Thin-section (a, b) and SEM (c, d) micrographs of the most porous (a, c) and the least porous (b, d) samples from the Opeche/Spearfish Formation at the Slash Lazy H 5 well. The most porous sample has a total porosity and permeability of 12.42% and 0.46 mD, respectively, which is notably reduced to 4.31% and 0.0367 mD in the least porous sample. The blue color in thin sections a and b represents porosity. (p. 2-37)</p> <p>Figure 2-24. Change in the mineralogy of the upper-confining Opeche/Spearfish Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Very low total porosity and permeability with a high clay content make the Opeche/Spearfish Formation an ultralow permeable formation. Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1)</p>

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				<p>Figure C-15 represents minerals expected to be precipitated in weight (%) shown for C1 and C2 of the model. In C1 and C2, illite, quartz, and calcite are the minerals to be precipitated.</p> <p>Figure C-16 shows the modeled change in porosity of the cap rock for C1–C3. The overall net porosity changes from dissolution and precipitation are minimal. Initially C1 experiences up to a 0.011% increase in porosity because of dissolution upon first CO₂ exposure and initial model equilibration, but the change is temporary. No significant porosity changes were observed for C2 and C3. These results suggest that geochemical change from exposure to CO₂ is minor and therefore the ability of the Opeche/Spearfish Formation to maintain its sealing integrity will not be compromised by geochemical processes.</p> <p>C1.3 Geochemical Interaction of the Lower Confining Zone (Amsden Formation) (p. C-24) 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 16 cells, each cell 1 meter in thickness. The formation was exposed to CO₂ stream components at the top boundary of the simulation, and CO₂ 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–CO₂ exposure boundary. The average mineralogical composition calculated from the results of four samples from the Amsden Formation was honored (Table C-6). The formation brine composition was assumed to be the same as the known composition from the overlying Broom Creek Formation injection zone (Table C-5). A CO₂ stream containing ~95% CO₂ and 2% O₂, shown in Table C-1, was used in the geochemical modeling to represent a conservative scenario, where higher oxygen concentration may trigger more geochemical reactions in the formation. 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.</p> <p>The higher-pressure results are shown here to represent a potentially more rapid pace of geochemical change. This simulation was run for 45 years to represent 20 years of injection plus 25 years of postinjection.</p> <p>Modeling results show geochemical processes at work. Figures C-17 through C-22 show results from the geochemical modeling. Figure C-17 shows change in fluid pH over 45 years (representing 20 years of injection and 25 years of postinjection) as CO₂ enters the system. Initial change in pH in all of the cells, for C1 to C16, is related to initial equilibration of the model. For the cell at the CO₂ interface, C1, the pH declines to a level of 5.0 after 8 years of injection, further declining to 4.6 by the end of the modeled injection period, and hits 4.4 by the end of simulation period. Progressively lower or slower pH changes occur for each cell that is more distant from the CO₂ interface. The pH for C13-16 declines to 5.8 over the 45 years of simulation time because of the transport and mixing process of formation brine that results in a CO₂ concentration below 0.01 molality. Figure C-18 shows that CO₂ penetration greater than 0.01 molality is limited to C1–C12 and does not penetrate in higher amount (>0.01 molality) more than 12 meters (represented by C13) over the 20 years of injection and 25 years of postinjection.</p> <p>Figure C-19 shows the modeled changes in mineral dissolution and precipitation in grams per cubic meter over simulation years. For C1, K-feldspar starts to dissolve from the beginning of the simulation period while quartz and illite start to precipitate. Dolomite and anhydrite show initial precipitation and dissolution, respectively, during the injection period which is reversed during 25 years of postinjection. C2 shows the same trends, but the major geochemical process begins approximately 10 years after Cell C1.</p> <p>Figure C-20 represents the initial fractions of potentially reactive minerals in the Amsden Formation based on the XRD data shown in Table C-6. The expected dissolution of the minerals in weight percentage is also shown for C1 and C2 of the model. In C1 and C2, K-feldspar and dolomite are the primary minerals that dissolve, and initial fractions of K-feldspar have almost completely dissolved. No dissolution is observed for illite and quartz. The minerals that experience dissolution in the model are almost completely replaced by the precipitation of other minerals.</p> <p>2.4.2 Additional Overlying Confining Zones (p. 2-38) Several other formations provide additional confinement above the Opeche/Spearfish Formation. Impermeable rocks above the primary seal include the Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-8a). At the Slash Lazy H 5, together with the Opeche/Spearfish Formation, these intervals are 1116 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-25). Above the Inyan Kara Formation, 2571 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and the lowermost USDW, the Fox Hills Formation (Figure 2-26). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-8a).</p>	<p>GR (black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red). (p. 2-38)</p> <p>Table C-4. Mineral Composition of the Opeche/Spearfish Derived from XRD Analysis of Slash Lazy H 5 Core Sample at a Depth of 5570 ft MD (p. C-18)</p> <p>Table C-5. Formation Water Chemistry from Broom Creek Formation Fluid Sample from Slash Lazy H5 (p. C-19)</p> <p>Figure C-12. Modeled 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. (p. C-20)</p> <p>Figure C-13. Modeled dissolution and precipitation of minerals in the Opeche/Spearfish Formation cap rock. Dashed lines show results calculated for C1, 0.5 meters above the cap rock base. Solid lines</p>

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				<p>The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).</p> <p style="text-align: center;">Table 2-8a. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the Slash Lazy H 5)</p> <table border="1" style="margin-left: auto; margin-right: auto;"> <thead> <tr> <th>Name of Formation</th> <th>Lithology</th> <th>Formation Top Depth MD, ft</th> <th>Thickness, ft</th> <th>Depth below Lowest Identified USDW, ft</th> </tr> </thead> <tbody> <tr> <td>Pierre</td> <td>Mudstone</td> <td>1687</td> <td>1429</td> <td>0</td> </tr> <tr> <td>Niobrara</td> <td>Mudstone</td> <td>3116</td> <td>389</td> <td>1429</td> </tr> <tr> <td>Carlile</td> <td>Mudstone</td> <td>3505</td> <td>49</td> <td>1818</td> </tr> <tr> <td>Greenhorn</td> <td>Mudstone</td> <td>3554</td> <td>105</td> <td>1867</td> </tr> <tr> <td>Belle Fourche</td> <td>Mudstone</td> <td>3659</td> <td>287</td> <td>1972</td> </tr> <tr> <td>Mowry</td> <td>Mudstone</td> <td>3946</td> <td>82</td> <td>2259</td> </tr> <tr> <td>Skull Creek</td> <td>Mudstone</td> <td>4033</td> <td>225</td> <td>2346</td> </tr> <tr> <td>Swift</td> <td>Mudstone</td> <td>4452</td> <td>535</td> <td>2765</td> </tr> <tr> <td>Rierdon</td> <td>Mudstone</td> <td>4987</td> <td>208</td> <td>3300</td> </tr> <tr> <td>Piper (Kline Member)</td> <td>Carbonate</td> <td>5195</td> <td>108</td> <td>3508</td> </tr> <tr> <td>Piper (Picard Member)</td> <td>Mudstone</td> <td>5303</td> <td>86</td> <td>3616</td> </tr> </tbody> </table> <p>Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability stratigraphically above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensor data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5.0). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO₂ would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Slash Lazy H 5 location is 4258 ft below KB elevation, and the interval itself is 194 ft thick.</p> <p>2.4.3 Lower Confining Zones (p. 2-42) The lower confining zone of the storage complex is the Amsden Formation, which comprises primarily dolostone, and anhydrite. The Amsden Formation does include some thin sandstone intervals on the order of 1 to 8 in. thick. The sandstone intervals in the Amsden Formation are isolated from the sandstones of the Broom Creek Formation by thick impermeable dolostone and anhydrite intervals. The top of the Amsden Formation was placed at the top of an argillaceous dolostone, which has relatively high GR character that can be correlated across the simulation model area (Figure 2-11). The Amsden Formation is 5840 ft below KB elevation and 242 ft thick at the KJ Hintz as determined at the Slash Lazy H 5 (Figures 2-27 and 2-28).</p> <p>The contact between the underlying Amsden Formation and the overlying Broom Creek Formation is evident on wireline logs as there is a lithological change from the dolostone and anhydrite beds of the Amsden Formation to the porous sandstones of the Broom Creek Formation (Figure 2-11). The top of the Amsden in Slash Lazy H 5 is picked at the base of a 10-ft anhydrite bed in the Broom Creek Formation, which can be correlated across much of the study area. This lithologic change is also recognized in the core from Slash Lazy H 5. The lithology of the cored section of the Amsden Formation from Slash Lazy H 5 is predominantly dolostone and anhydrite with lesser predominant lithologies of sandstone.</p> <p>2.4.3.1 Mineralogy of the Lower Confining Zone (p. 2-44)</p>	Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft	Pierre	Mudstone	1687	1429	0	Niobrara	Mudstone	3116	389	1429	Carlile	Mudstone	3505	49	1818	Greenhorn	Mudstone	3554	105	1867	Belle Fourche	Mudstone	3659	287	1972	Mowry	Mudstone	3946	82	2259	Skull Creek	Mudstone	4033	225	2346	Swift	Mudstone	4452	535	2765	Rierdon	Mudstone	4987	208	3300	Piper (Kline Member)	Carbonate	5195	108	3508	Piper (Picard Member)	Mudstone	5303	86	3616	<p>show results for C2, 1.5 meters above the cap rock base, and these changes are smaller compared to the changes observed for C1. Results from C3, 2.5 meters above the cap rock base, are similar to the change observed for C2. (p. C-21)</p> <p>Figure C-14. 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, too small to see in the figure) 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. C-22)</p> <p>Figure C-15. Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of the Opeche/Spearfish Formation in C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years of postinjection. Minerals precipitated in C1 and C2 are too small to be seen in the figure. (p. C-23)</p> <p>Figure C-16 Modeled change in percent porosity of the</p>
Name of Formation	Lithology	Formation Top Depth MD, ft	Thickness, ft	Depth below Lowest Identified USDW, ft																																																													
Pierre	Mudstone	1687	1429	0																																																													
Niobrara	Mudstone	3116	389	1429																																																													
Carlile	Mudstone	3505	49	1818																																																													
Greenhorn	Mudstone	3554	105	1867																																																													
Belle Fourche	Mudstone	3659	287	1972																																																													
Mowry	Mudstone	3946	82	2259																																																													
Skull Creek	Mudstone	4033	225	2346																																																													
Swift	Mudstone	4452	535	2765																																																													
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				<p>Powder XRD for average bulk composition analysis of nine finely ground, homogenized samples from the Amsden Formation shows carbonates as the most common minerals (~45%, mostly dolomite with a minor contribution from ankerite) followed by quartz (~25%), sulfates (~13%, mostly anhydrite with a minor amount of gypsum), clay (~10%, mostly illite), and feldspar (~6%, mostly K-feldspar) (Figure 2-29a[a]). Minor amounts of halide (~0.2%), oxide (~0.1%), and sulfide (~0.03%) make up the rest of the mineralogy. The major constituents of the Amsden Formation obtained by XRD are also shown in Table 2-8b. These data align with the average elemental composition obtained by XRF, which shows silica (Si) as the dominant element followed by calcium (Ca), magnesium (Mg), sulfur (S), aluminum (Al), potassium (K), iron (Fe), and other trace elements (Figure 2-29a[b]).</p> <p>XRF analysis of the Amsden Formation (Figure 2-29b) shows that the contact between the Amsden and Broom Creek Formations is dominated by SiO₂, CaO, and MgO, indicating the presence of sandstone and dolomite. As the formation gets deeper, the chemistry changes to more anhydrite-rich, as shown by the high percentage of CaO (~37%) and SO₃ (~40%). The Amsden Formation contains clay as high as 34%, with an average of ~10%, with illite being the dominant clay type.</p> <p>Similar to the Opeche/Spearfish Formation, the higher content of anhydrite (up to 70% with an average of ~13%) and clay minerals (up to 34% with an average of ~10%) makes the Amsden Formation less porous and more impermeable compared to the target Broom Creek Formation. The thin-section and SEM-EDS micrographs of the most porous sample at the core depth of 5873.5 ft – KB elevation of 5874 ft show moderately sorted, fine-grained subangular quartz and very fine-grained feldspar grains with some anhydrite (Figures 2-30a and c). Iron oxide is also present frequently as a filling material (Figure 2-30c). Contacts between the grains are mostly tangential, long, and sutured as well as concavo-convex creating isolated and discontinuous pore spaces (Figure 2-30c).</p> <p>The least porous sample located at the bottom of the section at the core depth of 5881.6 ft – KB elevation of 5882.1 ft, predominantly consists of anhydrite with dolomite clasts (Figures 2-30b and d) constituting ~70% and ~21% of the mineralogy, respectively. Figure 2-31 shows changes in the mineralogy at the Slash Lazy H 5 well as a function of depth next to the core sample porosity and permeability data. Although core sample porosity and permeability show a porous and permeable interval between the core depth of 5873.5 (KB elevation of 5874 ft) and 5879.5 ft (KB elevation of 5880 ft) in the Amsden Formation, it must be noted that this layer is isolated and confined between an ultralow permeable dolomite-rich clay layer above and an anhydrite-rich quartz layer below.</p>	<p>Opeche/Spearfish Formation cap rock. Red line shows porosity change calculated for C1, 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. C-24)</p> <p>Table C-6 Averaged Mineral Composition of the Amsden Formation Derived from XRD Analysis of Slash Lazy H 5 Core Samples at Depths of 5839.5, 5846.0, 5855.4, and 5861 ft MD (p. C-25)</p> <p>Figure C-17 Modeled change in fluid pH for C1–C16 (odd numbered cells through C15 plus C16) in the Amsden Formation underlying confining layer. (p. C-26)</p> <p>Figure C-18 Modeled CO₂ concentration (molality) of the odd-numbered cells, C1–C13, in the Amsden Formation underlying confining layer. CO₂ penetration in C13 is less than 0.01 molality. (p. C-26)</p> <p>Figure C-19 Modeled dissolution and precipitation of minerals in the Amsden Formation</p>

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					<p>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 results for C11, 10 to 11 meters below the Amsden Formation top. C11 shows minimal dissolution and precipitation at the end of 25 years of postinjection because of smaller amount of CO₂ penetration in C11 by the end of 45 years of simulation. (p. C-27)</p> <p>Figure C-20 Weight percentage (wt%) 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. C-28)</p> <p>Figure C-21 Weight percentage (wt%) of initial (blue) and precipitated (orange) minerals of Amsden Formation in C1 and C2 normalized based on total solid (initial – dissolution + precipitation) present in C1 and C2 after 20 years of injection and 25 years</p>

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					<p>of postinjection. Very little hematite and anhydrite precipitation is observed in C1. Hematite precipitation in C2 is too small to be seen in the figure. (p. C-29)</p> <p>Figure C-22 Modeled 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. Orange 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. (p. C-30)</p> <p>Table 2-8a. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Slash Lazy H5) (p. 2-39)</p> <p>Figure 2-25. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation</p>

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					<p>tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-40)</p> <p>Figure 2-26. 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 creation of this map. (p. 2-41)</p> <p>Figure 2-27. Structure map of the Amsden Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-42)</p> <p>Figure 2-28. Isopach map of the Amsden Formation across the simulation model area. The convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-43).</p> <p>Figure 2-29a. Bar charts showing a) average mineralogy (wt%) and b) average elemental composition (wt%) of the Amsden Formation at the Slash Lazy H 5 well. Elemental data by XRF were determined as</p>

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					<p>oxides of the respective elements. (p. 2-44)</p> <p>Table 2-8b. XRD Analysis of the Amsden Formation at Slash Lazy H 5. Only major constituents are shown. (p. 2-45)</p> <p>Figure 2-29b. Elemental composition by XRF as a function of depth in the Amsden Formation at Slash Lazy H 5. (p. 2-46)</p> <p>Figure 2-30. Thin-section (a, b) and SEM (c, d) micrographs of the most porous samples (a, c) and the least porous samples (b, d) of the Amsden Formation at Slash Lazy H 5. The most porous sample has a total porosity and permeability of 13.93% and 129 mD, respectively, which notably reduced to 1.58% and 0.00786 mD in the least porous sample. The blue color in thin section a represents porosity. (p. 2-46)</p> <p>Figure 2-31. Change in the mineralogy of the lower confining Amsden Formation (highlighted in gray) at Slash Lazy H 5 as a function of depth based on XRD in comparison to GR, facies, core sample total porosity (%), and permeability (mD). Data gaps in the porosity and permeability plots are due to the inability to obtain testable samples as solid plugs (e.g., samples too soft/brittle). Tracks from left to right are 1) GR</p>

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					(black), 2) MD, 3) total feldspar (orange), 4) quartz (blue), 5) anhydrite (yellow green), 6) dolomite (green), 7) total clay (light blue), 8) other (light green), 9) facies, 10) core porosity (2400 psi) (dark blue), and 11) core permeability (2400 psi) (red). (p. 2-47)																																																						
	N.D.A.C. § 43-05-01-05(1)(b) N.D.A.C. § 43-05-01-05(1)(b)(2)	(2) A geologic and hydrogeologic evaluation of the facility area, including an evaluation of all existing information on all geologic strata overlying the storage reservoir, including the immediate caprock containment characteristics and all subsurface zones to be used for monitoring. The evaluation must include any available geophysical data and assessments of any regional tectonic activity, local seismicity and regional or local fault zones, and a comprehensive description of local and regional structural or stratigraphic features. The evaluation must describe the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, structural features, and adsorption characteristics with regard to the ability of that confinement to prevent migration of carbon dioxide beyond the proposed storage reservoir. The evaluation	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	<p>2.2.2.3 Formation Temperature and Pressure (p. 2-9) Temperature measurements from Slash Lazy H 5 were used to derive a temperature gradient for the proposed injection site (Table 2-2b). In combination with depth, the temperature property was used primarily to inform predictive simulation inputs and assumptions. Temperature data were also used as inputs for geochemical modeling.</p> <p>Formation pressure testing at Slash Lazy H 5 was performed with the SLB (formerly Schlumberger) MDT (modular formation dynamics tester) tool. The MDT tool's 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 CO2 injection.</p> <p>Table 2-2b. Description of Slash Lazy H 5 Temperature Measurements and Calculated Temperature Gradients</p> <table border="1"> <thead> <tr> <th>Formation</th> <th>Sensor Depth MD, ft</th> <th>Sensor Depth TVD, ft</th> <th>Temperature, °F</th> </tr> </thead> <tbody> <tr> <td>Opeche/Spearfish</td> <td>5514.45</td> <td>5514.29</td> <td>—*</td> </tr> <tr> <td rowspan="5">Broom Creek</td> <td>5630.00</td> <td>5629.84</td> <td>115.43</td> </tr> <tr> <td>5630.00</td> <td>5629.84</td> <td>116.39</td> </tr> <tr> <td>5630.00</td> <td>5629.84</td> <td>119.07</td> </tr> <tr> <td>5660.12</td> <td>5659.97</td> <td>120.36</td> </tr> <tr> <td>5693.88</td> <td>5693.72</td> <td>121.96</td> </tr> <tr> <td></td> <td>5797.93</td> <td>5797.77</td> <td>123.72</td> </tr> <tr> <td>Mean Broom Creek Temperature, °F</td> <td></td> <td></td> <td>119.49</td> </tr> <tr> <td>Broom Creek Temperature Gradient, °F/ft</td> <td></td> <td></td> <td>0.014**</td> </tr> </tbody> </table> <p>* Dry test. Temperature measurement is unreliable because it was impacted by tool temperature rather than fluid. ** The temperature gradient is an average of the measured temperature minus the average annual surface temperature (40°F), divided by the associated test depth.</p> <p>Table 2-3. Description of Slash Lazy H 5 Formation Pressure Measurements and Calculated Pressure Gradients</p> <table border="1"> <thead> <tr> <th>Formation</th> <th>Sensor Depth MD, ft</th> <th>Sensor Depth TVD, ft</th> <th>Sensor Formation Pressure, psia</th> </tr> </thead> <tbody> <tr> <td>Opeche/Spearfish</td> <td>5514.45</td> <td>5514.29</td> <td>—*</td> </tr> <tr> <td rowspan="3">Broom Creek</td> <td>5630.00</td> <td>5629.84</td> <td>2713.37</td> </tr> <tr> <td>5630.00</td> <td>5629.84</td> <td>2713.36</td> </tr> <tr> <td>5630.00</td> <td>5629.84</td> <td>2713.29</td> </tr> </tbody> </table>	Formation	Sensor Depth MD, ft	Sensor Depth TVD, ft	Temperature, °F	Opeche/Spearfish	5514.45	5514.29	—*	Broom Creek	5630.00	5629.84	115.43	5630.00	5629.84	116.39	5630.00	5629.84	119.07	5660.12	5659.97	120.36	5693.88	5693.72	121.96		5797.93	5797.77	123.72	Mean Broom Creek Temperature, °F			119.49	Broom Creek Temperature Gradient, °F/ft			0.014**	Formation	Sensor Depth MD, ft	Sensor Depth TVD, ft	Sensor Formation Pressure, psia	Opeche/Spearfish	5514.45	5514.29	—*	Broom Creek	5630.00	5629.84	2713.37	5630.00	5629.84	2713.36	5630.00	5629.84	2713.29	<p>Table 2-2b. Description of Slash Lazy H5 Temperature Measurements and Calculated Temperature Gradients (p. 2-9)</p> <p>Table 2-3. Description of Slash Lazy H5 Formation Pressure Measurements and Calculated Pressure Gradients (p. 2-9)</p>
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		<p>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:</p>		<table border="1" data-bbox="1476 278 2368 506"> <tr> <td></td> <td>5660.12</td> <td>5659.97</td> <td>2727.20</td> </tr> <tr> <td></td> <td>5693.88</td> <td>5693.72</td> <td>2742.29</td> </tr> <tr> <td></td> <td>5797.93</td> <td>5797.77</td> <td>2789.43</td> </tr> <tr> <td>Mean Broom Creek Pressure, psi</td> <td></td> <td></td> <td>2733.16</td> </tr> <tr> <td>Broom Creek Pressure Gradient, psi/ft</td> <td></td> <td></td> <td>0.48**</td> </tr> </table> <p>* Dry test. No fluid was withdrawn because of low permeability. ** The pressure gradient is an average of the sensor measured pressures minus standard atmospheric pressure at 14.7 psi, divided by the associated test depth.</p> <p>2.3.2 Mechanism of Geologic Confinement (p. 2-31) For the KJ Hintz, the initial mechanism for geologic confinement of CO₂ injected into the Broom Creek Formation will be the upper confining formation (Opeche/Spearfish Formation), which will contain the initially buoyant CO₂ in the reservoir under the effects of relative permeability and capillary pressure. Lateral movement of the injected CO₂ will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the CO₂ into the native formation brine), confining the CO₂ within the proposed storage reservoir. After injected CO₂ becomes dissolved in the formation brine, the brine density will increase. This higher-density brine will ultimately sink in the storage formation (convective mixing). Over a much longer period (>100 years), mineralization of the injected CO₂ will ensure long-term, permanent geologic confinement. Injected CO₂ is not expected to adsorb to any of the mineral constituents of the target formation; therefore, this process is not considered to be a viable trapping mechanism in this project.</p> <p>2.4.4.2 Core-Fracture Analysis (p. 2-48) The fractures observed in the Opeche/Spearfish Formation were tectonic, vertical to subvertical, closed, and cemented with anhydrite. The Amsden Formation was determined to be a nonfractured interval. A few discontinuous closed fractures were noted. The presence of stylolites was also noted in the dolomitic intervals of the Amsden Formation.</p>		5660.12	5659.97	2727.20		5693.88	5693.72	2742.29		5797.93	5797.77	2789.43	Mean Broom Creek Pressure, psi			2733.16	Broom Creek Pressure Gradient, psi/ft			0.48**	
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	<p>N.D.A.C. § 43-05-01-05(1)(b)(2)(g)</p>	<p>N.D.A.C. § 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;</p>	<p>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</p>	<p>2.2.2.6 Seismic Survey (p. 2-14) A 208-square-mile 3D seismic survey was conducted from November 2021 to February 2022 south of Beulah, North Dakota (Figure 2-8). The Beulah 3D seismic data provided visualization of deep geologic formations at lateral-spatial intervals as short as 82.5 ft. Additionally, seismic data from nearby 3D surveys to the east, namely, the Center 3D and Minnkota 3D, and a connecting 2D line were used to interpret and evaluate the subsurface (Figure 2-8). The seismic data were used for assessment of the geologic structure and reservoir properties.</p> <p>Data products generated from the interpretation of the Beulah 3D were used as inputs for the geologic model that was used to simulate migration of the CO₂ plume. The Beulah 3D seismic data and the Slash Lazy H 5 well logs were used to interpret surfaces for the formations of interest within the survey area. These surfaces were converted to depth using the time-to-depth relationship derived from Archie Erickson 2, Milton Flemmer 1, and Slash Lazy H 5 dipole sonic logs. The depth-converted surfaces for the storage reservoir and upper and lower confining zones were used as inputs for the geologic model. Detailed information about the structure and varying thickness of the formations away from well control was derived from these surfaces. A prestack seismic inversion was generated from the 3D seismic data and well logs from the Milton Flemmer 1, Archie Erickson 2, and Slash Lazy H 5 stratigraphic test wells. Depth-converted surfaces and poststack seismic inversion results from the Center 3D and Minnkota 3D were also used as inputs for the geologic model.</p> <p>Interpretation of the 3D seismic data suggests there are no major stratigraphic pinch-outs or structural features with associated spill points (e.g., folds, domes, or fault traps) in KJ Hintz. No structural features, faults, or discontinuities that would cause a concern about seal integrity in the strata above the Broom Creek Formation extending to the deepest USDW, the Fox Hills Formation, were observed in the 3D seismic data in KJ Hintz.</p> <p>2.3.2 Mechanism of Geologic Confinement (p. 2-31) <i>See discussion above under 2.3.2 Mechanism of Geologic Confinement</i></p>	<p>Figure 2-8. Map showing the 2D and 3D seismic surveys used to characterize the KJ Hintz 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. (p. 2-15)</p> <p>Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and</p>																				

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					<p>5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20)</p> <p>Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21)</p> <p>Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-22)</p> <p>Figure 2-15. Cross section of the KJ Hintz storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p.2-23)</p>

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	N.D.A.C. § 43-05-01-05(1)(b)(2)(c)	N.D.A.C. § 43-05-01-05(1)(b)(2) (c) Any regional or local faulting;	f. Any regional or local faulting;	2.5 Faults, Fractures, and Seismic Activity (First two paragraphs on p. 2-63) This section discusses local and regional faults including a regional structural feature, the Stanton Fault and interpreted basement faults. In the area of review (AOR), none of these known or suspected faults or fractures has sufficient permeability and vertical extent to allow fluid movement out of the storage reservoir. The absence of transmissive faults is supported by fluid sample analysis results from Slash Lazy H 5 that suggest the injection interval, the Broom Creek Formation (83,100 mg/L), is isolated from the next permeable interval, the Inyan Kara Formation (12,800 mg/L) (Appendix A). This section also discusses the seismic history of North Dakota and the low probability that seismic activity will interfere with containment.	Figure 2-43. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12. (p. 2-70)																																																																																																																
	N.D.A.C. § 43-05-01-05(1)(b)(2)(j)	N.D.A.C. § 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;	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	<i>See discussion above under 2.5 Faults, Fractures, and Seismic Activity (p. 2-63)</i>	Figure 2-43. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12. (p. 2-70)																																																																																																																
	N.D.A.C. §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(m)	N.D.A.C. § 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,	h. Information on any regional tectonic activity, and the seismic history, including: The presence and depth of seismic sources; Determination of the probability that seismicity would interfere with containment;	2.5.4 Seismic Activity (p. 2-68) 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, 2022). Between 1870 and 2015, 13 earthquakes were detected within the North Dakota portion of the Williston Basin (Table 2-12) (Anderson, 2016). Of these 13 earthquakes, only three occurred along one of the eight Precambrian basement faults interpreted by Anderson (2016) in the North Dakota portion of the Williston Basin (Figure 2-43). The earthquake recorded closest to the project area occurred in 1927, located 28.37 miles southwest of the KJ Hintz 2 injection well, near Hebron, North Dakota (Table 2-12). The magnitude of this earthquake is estimated to have been 3.2. Table 2-12. Summary of Earthquakes Reported to Have Occurred in North Dakota (from Anderson, 2016) <table border="1" data-bbox="1174 1300 2660 1804"> <thead> <tr> <th>Map Label</th> <th>Date</th> <th>Magnitude</th> <th>Depth, miles</th> <th>Longitude</th> <th>Latitude</th> <th>City or Vicinity of Earthquake</th> <th>Distance to KJ Hintz 2 injection well, miles</th> </tr> </thead> <tbody> <tr> <td>A</td> <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>107.22</td> </tr> <tr> <td>B</td> <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>135.57</td> </tr> <tr> <td>C</td> <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>126.16</td> </tr> <tr> <td>D</td> <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>50.71</td> </tr> <tr> <td>E</td> <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>138.97</td> </tr> <tr> <td>F</td> <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>78.10</td> </tr> <tr> <td>G</td> <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>150.03</td> </tr> <tr> <td>H</td> <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>148.27</td> </tr> <tr> <td>I</td> <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>54.86</td> </tr> <tr> <td>J</td> <td>May 13, 1947</td> <td>3.7**</td> <td>U***</td> <td>-100.90</td> <td>46.00</td> <td>Selfridge</td> <td>84.45</td> </tr> <tr> <td>K</td> <td>Oct. 26, 1946</td> <td>3.7**</td> <td>U</td> <td>-103.70</td> <td>48.20</td> <td>Williston</td> <td>123.11</td> </tr> <tr> <td>L</td> <td>April 29, 1927</td> <td>3.2**</td> <td>U</td> <td>-102.10</td> <td>46.90</td> <td>Hebron</td> <td>28.37</td> </tr> <tr> <td>M</td> <td>Aug. 8, 1915</td> <td>3.7**</td> <td>U</td> <td>-103.60</td> <td>48.20</td> <td>Williston</td> <td>119.43</td> </tr> </tbody> </table>	Map Label	Date	Magnitude	Depth, miles	Longitude	Latitude	City or Vicinity of Earthquake	Distance to KJ Hintz 2 injection well, miles	A	Sept. 28, 2012	3.3	0.4*	-103.48	48.01	Southeast of Williston	107.22	B	June 14, 2010	1.4	3.1	-103.96	46.03	Boxelder Creek	135.57	C	March 21, 2010	2.5	3.1	-103.98	47.98	Buford	126.16	D	Aug. 30, 2009	1.9	3.1	-102.38	47.63	Ft. Berthold southwest	50.71	E	Jan. 3, 2009	1.5	8.3	-103.95	48.36	Grenora	138.97	F	Nov. 15, 2008	2.6	11.2	-100.04	47.46	Goodrich	78.10	G	Nov. 11, 1998	3.5	3.1	-104.03	48.55	Grenora	150.03	H	March 9, 1982	3.3	11.2	-104.03	48.51	Grenora	148.27	I	July 8, 1968	4.4	20.5	-100.74	46.59	Huff	54.86	J	May 13, 1947	3.7**	U***	-100.90	46.00	Selfridge	84.45	K	Oct. 26, 1946	3.7**	U	-103.70	48.20	Williston	123.11	L	April 29, 1927	3.2**	U	-102.10	46.90	Hebron	28.37	M	Aug. 8, 1915	3.7**	U	-103.60	48.20	Williston	119.43	Table 2-12. Summary of Seismic Events Reported to Have Occurred in North Dakota (from Anderson, 2016) (p. 2-69) Figure 2-43. Location of major faults, tectonic boundaries, and earthquakes in North Dakota (modified from Anderson, 2016). The black dots indicate earthquake locations listed in Table 2-12. (p. 2-70) Figure 2-44. Probabilistic map showing how often scientists expect damaging earthquake shaking around the United States (U.S. Geological Survey, 2019). The map shows there is a low probability of damaging earthquake
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		<p>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:</p> <p>N.D.A.C. § 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;</p>		<p>* Estimated depth. ** Magnitude estimated from reported modified Mercalli intensity (MMI) value. *** Unknown.</p> <p>Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of earthquake events occurring in North Dakota that would cause damage to infrastructure, with less than two damaging earthquake events predicted to occur over a 10,000-year time period (Figure 2-44) (U.S. Geological Survey, 2019). A 1-year seismic forecast (including both induced and natural seismic events) released by USGS in 2016 determined North Dakota has very low risk (less than 1% chance) of experiencing any seismic events resulting in damage (U.S. Geological Survey, 2016). Frohlich and others (2015) states there is very little seismic activity near injection wells in the Williston Basin. They noted only two historic earthquake events in North Dakota that could be associated with nearby oil and gas activities. Additionally, no earthquakes occurring along the Stanton Fault have been reported. This indicates stable geologic conditions in the region surrounding the potential injection site. The results from the USGS studies, the low risk of induced seismicity due to the basin stress regime, and the depth of the target reservoir in proximity to the basement and vertical extents of the interpreted faults suggest the probability that seismicity interfering with CO₂ containment is low.</p>	<p>events occurring in North Dakota. (p. 2-71)</p>
	<p>N.D.A.C. §§ 43-05-01-05(1)(b)(2) and (1)(b)(2)(n)</p>	<p>N.D.A.C. § 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</p>	<p>i. Illustration of the regional geology, hydrogeology, and the geologic structure of the storage reservoir area:</p> <p>Geologic maps Topographic maps Cross sections</p>	<p>2.1 Overview of Project Area Geology (p. 2-1) <i>See discussion above under 2.1 Overview of Project Area Geology</i></p> <p>4.4.3 Hydrology of USDW Formations (p. 4-15) The aquifers of the Fox Hills and Hell Creek Formations are hydraulically connected and function as a single confined aquifer system (Fischer, 2013). The Bacon Creek Member of the Hell Creek Formation forms a regional aquitard for the Fox Hills–Hell Creek aquifer system, isolating it from the overlying aquifer layers. Recharge for the Fox Hills–Hell Creek aquifer system occurs in southwestern North Dakota along the Cedar Creek Anticline and discharges into overlying strata under central and eastern North Dakota (Fischer, 2013). Flow through the AOR is to the east (Figure 4-9).</p> <p>Water sampled from the Fox Hills Formation is a sodium bicarbonate type with a total dissolved solids (TDS) content of approximately 1500–1600 ppm. Previous analysis of Fox Hills Formation water has also noted high levels of fluoride in excess of 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> <p>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 4-10. 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</p>	<p>Figure 2-1. Topographic map showing well locations and the KJ Hintz in relation to the city of Beulah, North Dakota. (p. 2-2)</p> <p>Figure 2-9. 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 dashed line has been modified based on new</p>

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		<p>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:</p> <p>N.D.A.C. § 43-05-01-05(1)(b)(2) (n) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the facility area; and</p>		<p>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 it 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).</p> <p>The Sentinel Butte Formation, a silty fine-to-medium-grained sandstone with claystone and lignite interbeds, overlies the Tongue River Formation in western portions of the AOR. The Sentinel Butte Formation is predominantly sandstone with lignite interbeds. While the Sentinel Butte Formation is another important source of groundwater in the region, primarily to the west of the AOR, the Sentinel Butte Formation is not a source of groundwater within the AOR. TDS in the Sentinel Butte Formation range from approximately 400 to 1000 ppm (Croft, 1973). Above these are undifferentiated alluvial and glacial drift Quaternary aquifer layers.</p>	<p>well control. (p. 2-16)</p> <p>Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20)</p> <p>Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21)</p> <p>Figure 2-15. Cross section of the KJ Hintz storage complex from the geologic model showing facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the</p>

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					<p>blue box in the inset map in the upper-left corner. (p. 2-23)</p> <p>Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013). (p. 4-16)</p> <p>Figure 4-10. West-east 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 (NDIC File No. 4942 is Raymond Jensen 1-34.) (p. 4-17)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(2)(d)	N.D.A.C. § 43-05-01-05(1)(b)(2) (d) An isopach map of the storage reservoirs;	j. An isopach map of the storage reservoir(s);	See Figure 2-10a and Figure 2-10b on p. 2-17 & p. 2-18	<p>Figure 2-10a. Isopach map of the Broom Creek Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in the creation of this map (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6). (p. 2-17)</p> <p>Figure 2-10b. Isopach map of the Broom Creek Formation focused around the three stratigraphic and reservoir-monitoring wells (thickness of the Broom Creek Formation at Slash Lazy H 5 is 272 ft, see Table 2-6). (p. 2-17)</p>

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	N.D.A.C. § 43-05-01-05(1)(b)(2)(e)	<p>N.D.A.C. § 43-05-01-05(1)(b)(2) (e) An isopach map of the primary and any secondary containment barrier for the storage reservoir;</p>	<p>k. An isopach map of the primary containment barrier for the storage reservoir;</p>	<p>See Figure 2-21 on p. 2-34</p>	<p>Figure 2-21. Isopach map of the Opeche/Spearfish Formation in the simulation model area. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-34)</p>
			<p>l. An isopach map of the secondary containment barrier for the storage reservoir;</p>	<p>See Figure 2-25 on p. 2-40 and Figure 2-26 on p. 2-41</p>	<p>Figure 2-25. Isopach map of the interval between the top of the Broom Creek Formation and the top of the Swift Formation. This interval represents the primary and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-40)</p> <p>Figure 2-26. 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 creation of this map. (p. 2-41)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(2)(f)	<p>N.D.A.C. § 43-05-01-05(1)(b)(2) (f) A structure map of the top and base of the storage reservoirs;</p>	<p>m. A structure map of the top of the storage formation;</p>	<p>See Figure 2-14 on p. 2-22 and Figure 2-20 on page 2-33.</p>	<p>Figure 2-14. Structure map of the Broom Creek Formation in the simulation model referenced in feet below mean sea level. A convergent interpolation gridding algorithm was</p>

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					used with well formation tops, 3D seismic, and 2D seismic in the creation of this map. (p. 2-22) Figure 2-20. Structure map of the Opeche/Spearfish Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-33)
			n. A structure map of the base of the storage formation;	See Figure 2-27 on p. 2-42	Figure 2-27. Structure map of the Amsden Formation across the simulation model area in feet below mean sea level. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-42)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(i)	N.D.A.C. § 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 2-13 on p. 2-21 and Figure 2-15 on p. 2-23.	Figure 2-13. Regional well log cross sections showing the structure of the upper confining zone and injection zone. Displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-21) Figure 2-15. Cross section of the KJ Hintz storage complex from the geologic model showing

Subject	N.D.C.C. / N.D.A.C. 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)
					facies distribution in the Broom Creek Formation. Depths are referenced as feet below mean sea level. Geologic model extent is displayed by the blue box in the inset map in the upper-left corner. (p. 2-23)
			p. Stratigraphic cross sections that describe the geologic conditions at the storage reservoir;	See Figure 2-12 on p. 2-20	Figure 2-12. Regional well log stratigraphic cross sections of the upper confining zone and injection zone flattened on the top of the Amsden Formation. Logs displayed in tracks from left to right are 1) SSTVD, 2) GR (black) and caliper (dark blue), 3) MD, 4) NEUT (blue) and bulk density (green), and 5) facies. The different depth scales are used between A-A' and B-B' for image display purposes. Cross section is scaled in SSTVD. (p. 2-20)
	N.D.A.C. § 43-05-01-05(1)(b)(2)(h)	N.D.A.C. § 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;	<p>3.4 Simulation Results (p. 3-16)</p> <p>The maximum WHP constraint of 2100 psi was one of the constraints on the injection wells for the entire 20 years of simulated injection. The maximum BHP constraint of 3828 psi for KJ Hintz 1 and 3808 psi for KJ Hintz 2 (equal to 90% of the product when multiplying the fracture gradient by top perforation depth) was approached near year 20 of injection but was never reached (Figure 3-10), translating to a cumulative combined 129.7 MMt of CO₂ injected into the Broom Creek Formation by KJ Hintz 1 and 2 (Figure 3-11). Simulations of CO₂ injection with the given well constraints, listed in Table 3-4, predicted the injection rate would decline from a maximum initial injection rate of approximately 3.7 MMt/yr per well to a final rate of approximately 3.2 MMt/yr per well (with a 20-year combined average of approximately 3.24 MMt/yr per injection well) (Figure 3-12).</p> <p>WHP and BHP responses depend on several factors, including predicted injection rate, injection tubing parameters (tubing internal radius and relative roughness), and surface injection temperature. For the designed tubing size of 7 in., the wells are operated at the maximum WHP of 2100 psi during the 20-year injection period (Figure 3-10).</p> <p>During and after injection, supercritical CO₂ (free-phase CO₂) accounts for the majority of CO₂ observed in the modeled pore space. Throughout the injection operation, a portion of the free-phase CO₂ is trapped in the pore space through a process known as residual trapping. Residual trapping can occur as a function of low CO₂ saturation and inability to flow under the effects of relative permeability. CO₂ 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 CO₂ during the postinjection period, resulting in a decline in the mass of free-phase CO₂. The relative portions of supercritical, trapped, and dissolved CO₂ can be tracked throughout the duration of the simulation (Figure 3-13).</p>	<p>Figure 3-14a. Average pressure increase within the Broom Creek Formation after 5 years of simulated CO₂ injection operation. (p. 3-20)</p> <p>Figure 3-14b. Average pressure increase within the Broom Creek Formation after 10 years of simulated CO₂ injection operation. (p. 3-21)</p> <p>Figure 3-14c. Average pressure increase within the Broom Creek Formation after 20 years of simulated CO₂ injection operation (end</p>

Subject	N.D.C.C. / N.D.A.C. 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)
				<p>The pressure front (Figures 3-14a–d) show the distribution of average pressure increase throughout the Broom Creek Formation after 5, 10, and 20 years of injection as well as 10 years postinjection. A maximum increase of approximately 1024 psi was estimated in the near-wellbore area at the end of the 20-year injection period (Figure 3-14c).</p> <p>6.1.1 Pre- and Postinjection Pressure Differential (p. 6-4) Model simulations were performed to predict the change in pressure in the Broom Creek Formation during and after the cessation of CO₂ injection. The simulations were conducted for 20 years of CO₂ injection in the Broom Creek Formation at an average total rate of 6.49 MMt/yr, followed by a postinjection period of 10 years. Figure 6-1 illustrates the predicted pressure differential at the cessation of CO₂ injection. At the time that CO₂ injection ceases, the models predict an increase in the pressure of the reservoir, with a maximum pressure differential of 1023 psi at the KJ Hintz CO₂ injection well pad. There is insufficient pressure increase caused by CO₂ injection to move more than 1 m³ 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 discussion within Section 3.0 of this application.</p> <p>Figure 6-2 illustrates the predicted gradual pressure decrease in the storage reservoir, over a 10-year period following the cessation of CO₂ injection. The pressure at the KJ Hintz CO₂ injection well pad at the end of the 10-year period is anticipated to decrease 600–650 psi as compared to the pressure in the storage reservoir at the time CO₂ 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.</p>	<p>of injection operation). (p. 3-22)</p> <p>Figure 3-14d. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO₂ injection. (p. 3-23)</p> <p>Figure 6-1. Predicted pressure increase in the storage reservoir following 20 years of injection of an average 6.49 MMt/yr of CO₂. (p. 6-5)</p> <p>Figure 6-2. Predicted decrease in pressure in the storage reservoir over a 10-year period following the cessation of CO₂ injection. (p. 6-6)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(2)(l)	<p>N.D.A.C. § 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;</p>	<p>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:</p> <ul style="list-style-type: none"> Fractures Stress Ductility Rock strength In situ fluid pressure 	<p>2.4.4 Geomechanical Information of Confining Zone (p. 2-48)</p> <p>2.4.4.1 Fracture Analysis Fractures within the overlying confining zone (the Opeche/Spearfish Formation) and the underlying confining zone (Amsden Formation) were assessed during the description of the Slash Lazy H 5 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 Slash Lazy H 5.</p> <p>2.4.4.2 Core-Fracture Analysis The fractures observed in the Opeche/Spearfish Formation were tectonic, vertical to subvertical, closed, and cemented with anhydrite. The Amsden Formation was determined to be a nonfractured interval. A few discontinuous closed fractures were noted. The presence of stylolites was also noted in the dolomitic intervals of the Amsden Formation.</p> <p>2.4.4.3 Borehole Image- Fracture Analysis Natural fractures and in-situ stresses were assessed through the interpretation of borehole image log, dipole shear sonic slowness (DTS), and DTC (compressional) logs acquired during the drilling of the Slash Lazy H 5 well. A borehole image log provides a 360-degree image of the formation of interest and is oriented to provide an understanding of the general orientation of the observed features.</p> <p>Fractures within Opeche/Spearfish Formation are primarily resistive continuous fractures, anastomosed without preferential orientation. They are commonly filled with anhydrite (Figure 2-32). No microfaults were found in the Opeche/Spearfish interval. The fractures vary in orientation and exhibit horizontal, oblique, and vertical trends. The aperture varies from closed to millimeter-scale (Figure 2-33a and Figure 2-33b).</p> <p>The Amsden Formation is considered a nonfractured interval; however, eleven (11) discontinuous resistive fractures are highlighted with the presence of horizontal compaction features (stylolites). These fractures are filled with quartz and considered closed. The fractures are oriented mainly to N-S, with the presence of NE-SW and NW-SE fracture sets (Figure 2-34). The fractures vary in orientation and exhibit oblique and vertical trends. The aperture varies from closed to millimeter-scale (Figure 2-35, and Figure 2-36a and Figure 2-36b). One conductive partially resistive fracture is highlighted oriented E-W and filled with quartz and clay. Also, five (05) conductive noncontinuous fractures were underlined, oriented N-S, NW-SE, and E-W, and are filled with clay. These fractures are closed and do not constitute any risk for fluid leakage. In addition, one minor fault was present in the Amsden interval at a depth of 6024 ft MD and is located around 190 feet below the bottom of the Broom Creek</p>	<p>Figure 2-32. Strike orientation per type of fracture that characterizes the Opeche/Spearfish Formation: resistive continuous fractures (orange) and conductive partially resistive fractures (green). Colored dots represent the dip value for corresponding type of fracture and the dip azimuth of the fracture. (p. 2-49)</p> <p>Figure 2-33a. Sedimentary and tectonic features in the Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and</p>

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				<p>Formation. Oriented NNE-SSW and dipping to the west with a dip angle equal to 50 degrees, this minor fault shows normal faulting, with an offset of 0.05 ft (Figure 2-36c). The analysis of the different attributes such as the fault's depth, length, strike, dip, offset, and aperture demonstrates that the minor fault appears isolated and does not interact with any fracture network and will not act as a conduit for fluid migration.</p> <p>Drilling-induced fractures (DIF) were identified in the Swift and Piper Kline Formations and oriented NNE-SSW (Figure 2-37). Because the wellbore is vertical, mainly tensile fractures were observed. The tensile fractures might indicate that the maximum horizontal stress (SHmax) has an orientation of N025°.</p> <p><i>2.4.4.4 Stress, Ductility and Rock Strength</i></p> <p>The dynamic elastic properties (dynamic Young's modulus and Poisson's ratio) for Opeche/Spearfish, Broom Creek, and Amsden Formations were calculated by using DTC, DTS, and density log collected from Slash Lazy H 5. These dynamic elastic properties were converted to static elastic properties with calibrations of geomechanical laboratory core measurements.</p> <p>A 1D MEM in the Broom Creek section was built for Slash Lazy H 5 using the available wireline data such as GR logs, caliper logs, density logs (RHOB), dipole sonic logs (DTC, DTS), and image logs. The 1D MEM consists of pore pressure, the vertical in situ stress (Sv, overburden), minimum and maximum horizontal in situ stresses (Shmin, SHmax), static and dynamic Young's moduli (E), static and dynamic Poisson's ratio (ν), bulk modulus (K), shear modulus (G), unconfined compressive strength (UCS), tensile strength (To), and friction angle (FA or FANG) (Tables 2-9 and 2-10).</p> <p>Sv is one of the three principal stresses that act upon a rock. It is defined as the stress applied by the overlying lithostatic column, at the depth (z), and is estimated using the Plumb and others (1991) equation. Sv is calculated using the RHOB log as an input. For the pore pressure, porosity proxy logging data based on a normal compaction trendline concept were used (for hydraulic static pressure, 1.03 g/cm³ = 0.44675 psi/ft = 8.6 ppg). For the Broom Creek Formation, the MDT data taken in sand bodies show pore pressure equivalent to 9.2 ppg equivalent to 0.48 psi/ft, which is slightly overpressured. The pore pressure estimation honored the MDT measurement. Dynamic to static Young's modulus function used a linear conversion where a dynamic Young's modulus log was calculated from the available sonic (DTC, DTS) and density log. For Poisson's ratio, dynamic and static parameters were assumed to be equal. The Biot factor was estimated using the formula Biot's factor = 1 - (K0/Kmineral); where K0 is the bulk modulus of the porous medium and Kmineral is the bulk modulus of solid parts of the porous medium. It is a function of mineral volumes and minerals' bulk modulus. For rock properties, Young's modulus, and Poisson's ratio, were estimated from well logs and were calibrated with the triaxial core laboratory measurements (Figure 2-38).</p> <p>Unconfined compressive strength (UCS) was calculated using empirical correlations between UCS and DTC for shale, sandstone, and dolostone: the Chang (2006) method was used for shale formation, the McNally (1987) method was used for sandstone formation, and Golubev and Rabinovich (1976) was used for dolostone formation. The tensile strength was assumed to be 10% of the calculated UCS. The friction angle (FA or FANG) was estimated using an empirical correlation between the internal angle of friction and DTC: Lal's approach (1999) was used to calculate the friction angle in the Opeche/Spearfish and Amsden Formations, and Weingarten and Perkins (1995) in the Broom Creek Formation. Horizontal stresses (Shmin and SHmax) were estimated using the poroelastic equations (Plumb et al, 2000). The orientations of Shmin and SHmax were estimated with the help of a borehole image log (Figure 2-37). The magnitude of Shmin was calibrated by the closure pressures which were measured with a mini-frac stress test. In addition, the 1D MEM shows that the stress regime observed in the Opeche/Spearfish, Broom Creek, and Amsden Formations is normal (Sv>SHmax>Shmin).The analysis of the pore pressure measured in the Broom Creek Formation attests that it could be considered an overpressured reservoir, with a gradient of 0.48 psi/ft.</p> <p>Triaxial test (static elastic properties), ultrasonic velocity (dynamic elastic properties), destructive test (compressive strength) at reservoir conditions, and pore volume compressibility (PVC) for reservoir samples were conducted on nine core samples acquired from the Opeche/Spearfish, Broom Creek, and Amsden Formations in Slash Lazy H 5 well. These values were used to calibrate the static and dynamic Young's modulus and Poisson's ratio generated from well logs (Table 2-11).</p>	<p>sedimentary tadpole orientation in the interval between 5389 and 5483 ft, MD. (p. 2-50)</p> <p>Figure 2-33b. Sedimentary and tectonic features in the Opeche/Spearfish Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5477 and 5571 ft MD. (p. 2-51)</p> <p>Figure 2-34. Strike orientation per type of fracture that characterizes the Amsden Formation: resistive noncontinuous fractures (red), conductive partially resistive fractures (teal), conductive noncontinuous fractures (blue), and minor fault (green). Colored dots represent the dip value for the corresponding type of fracture and the dip azimuth of the fracture. (p. 2-53)</p> <p>Figure 2-35. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log;</p>

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					<p>and 6) tectonic and sedimentary tadpole orientation in the interval between 5836 and 5930 ft MD. (p. 2-54)</p> <p>Figure 2-36a. Sedimentary and tectonic features in Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; 6) tectonic and sedimentary tadpole orientation in the interval between 5928 and 6023 ft MD. (p. 2-55)</p> <p>Figure 2-36b. Sedimentary and tectonic features in the Amsden Formation observed on the borehole image log. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) tectonic and sedimentary tadpole orientation in the interval between 5990 and 6083 ft MD. (p. 2-56)</p> <p>Figure 2-36c. Minor fault and its attribute in the Amsden Formation observed on the borehole image log. The tracks from left to right are 1) MD; 2) formation; 3) HSGR, HCal; 4) borehole dynamic image log; 5) borehole static image log; and 6) minor fault and bed boundary tadpole orientation in the interval</p>

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					<p>between 6 023.6 and 6026.4 ft MD. (p. 2-57)</p> <p>Figure 2-37. Orientation of the tensile drilling-induced fractures in the Slash Lazy H 5 well observed in Swift and Piper Kline Formations showing maximum horizontal stress (SHmax) direction about N025°. (p. 2-58)</p> <p>Figure 2-38 Geomechanical parameters in the Opeche/Spearfish, Broom Creek, and Amsden Formations. The tracks from left to right show 1) MD; 2) formation; 3) HSGR, (HCal); 4) TNPH (neutron porosity), RHOZ (bulk density); 5) dynamic Young's modulus (E_dyn), static Young's modulus (E_Stat)_calibrated with core measurements (E_Core); 6) Dynamic Poisson's ratio (PR_dyn) calibrated with core measurements (PR_Core); 7) cohesion, bulk modulus (K_dyn), and Biot's factor; 8) UCS, tensile strength, friction angle; 9) pore pressure, hydropressure calibrated with MDT pressure data; 10) vertical stress (Sv), SHmax, Shmin, calibrated with the MDT stress test; and 11) pore pressure, Shmin, and Eaton fracture gradients. (p. 2-61)</p> <p>Table 2-9. Ranges and Averages of the Elastic</p>

Subject	N.D.C.C. / N.D.A.C. 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)
					<p>Properties Estimated from 1D MEM in Opeche/Spearfish, Broom Creek, and Amsden Formations: Static Young's Modulus (E_Stat), Static Poisson's Ratio (v_Stat), Static Bulk Modulus (K), Static Shear Modulus (G), Unconfined Compressive Strength (UCS), Dynamic Young's Modulus (E_Dyn), and Dynamic Poisson's ratio (v_Dyn) (p. 2-59)</p> <p>Table 2-10. Ranges and Averages of the Sv, Pore Pressure, Shmin, and FA Estimated from 1D MEM in the Opeche/Spearfish, Broom Creek, and Amsden Formations (p. 2-59)</p> <p>Table 2-11. Formation, Lithology, Sample Depth (MD), Vertical Stress, Pore Pressure, Effective Vertical Stress, Horizontal Stress, Static Young's modulus, Poisson's ratio, and Compressive Strength in Opeche/Spearfish, Broom Creek, and Amsden Formations (p. 2-62)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(2)(o)	<p>N.D.A.C. § 43-05-01-05(1)(b)(2)</p> <p>(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.</p>	<p>s. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement:</p> <ul style="list-style-type: none"> Free of transmissive faults Free of transmissive fractures Effect on pressure dissipation Utility for monitoring, mitigation, and remediation. 	<p>2.4.2 Additional Overlying Confining Zones (p. 2-39)</p> <p>Several other formations provide additional confinement above the Opeche/Spearfish Formation. Impermeable rocks above the primary seal include the Piper, Rierdon, and Swift Formations, which make up the first additional group of confining formations (Table 2-8a). At the Slash Lazy H 5, together with the Opeche/Spearfish Formation, these intervals are 1116 ft thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation (Figure 2-25). Above the Inyan Kara Formation, 2571 ft of impermeable rocks acts as an additional seal between the Inyan Kara sandstone interval and the lowermost USDW, the Fox Hills Formation (Figure 2-26). Confining layers above the Inyan Kara sandstone interval include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (Table 2-8a).</p> <p style="text-align: center;">Table 2-8a. Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on the Slash Lazy H 5)</p>	<p>Table 2-8a Description of Zones of Confinement above the Immediate Upper Confining Zone (data based on Slash Lazy H5) (p. 2-39)</p> <p>Figure 2-25. 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</p>

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				<table border="1" data-bbox="1401 278 2436 687"> <thead> <tr> <th rowspan="2">Name of Formation</th> <th rowspan="2">Lithology</th> <th colspan="2">Formation Top Depth</th> <th rowspan="2">Depth below Lowest Identified USDW, ft</th> </tr> <tr> <th>MD, ft</th> <th>Thickness, ft</th> </tr> </thead> <tbody> <tr> <td>Pierre</td> <td>Mudstone</td> <td>1687</td> <td>1429</td> <td>0</td> </tr> <tr> <td>Niobrara</td> <td>Mudstone</td> <td>3116</td> <td>389</td> <td>1429</td> </tr> <tr> <td>Carlile</td> <td>Mudstone</td> <td>3505</td> <td>49</td> <td>1818</td> </tr> <tr> <td>Greenhorn</td> <td>Mudstone</td> <td>3554</td> <td>105</td> <td>1867</td> </tr> <tr> <td>Belle Fourche</td> <td>Mudstone</td> <td>3659</td> <td>287</td> <td>1972</td> </tr> <tr> <td>Mowry</td> <td>Mudstone</td> <td>3946</td> <td>82</td> <td>2259</td> </tr> <tr> <td>Skull Creek</td> <td>Mudstone</td> <td>4033</td> <td>225</td> <td>2346</td> </tr> <tr> <td>Swift</td> <td>Mudstone</td> <td>4552</td> <td>535</td> <td>2765</td> </tr> <tr> <td>Rierdon</td> <td>Mudstone</td> <td>4987</td> <td>208</td> <td>3300</td> </tr> <tr> <td>Piper (Kline Member)</td> <td>Carbonate</td> <td>5195</td> <td>108</td> <td>3508</td> </tr> <tr> <td>Piper (Picard Member)</td> <td>Mudstone</td> <td>5303</td> <td>86</td> <td>3616</td> </tr> </tbody> </table> <p data-bbox="1177 747 2660 834">The formations between the Broom Creek and Inyan Kara Formations and between the Inyan Kara Formation and lowest USDW have demonstrated the ability to prevent the vertical migration of fluids throughout geologic time and are recognized as impermeable flow barriers in the Williston Basin (Downey, 1986; Downey and Dinwiddie, 1988).</p> <p data-bbox="1177 864 2660 1036">Sandstones of the Inyan Kara Formation comprise the first unit, with relatively high porosity and permeability stratigraphically above the injection zone and the primary sealing formation. The Inyan Kara represents the most likely candidate to act as an overlying pressure dissipation zone. Monitoring distributed temperature sensor data for the Inyan Kara Formation using the downhole fiber-optic cable provides an additional opportunity for mitigation and remediation (Section 5.0). In the unlikely event of out-of-zone migration through the primary and secondary sealing formations, CO₂ would become trapped in the Inyan Kara Formation. The depth to the Inyan Kara Formation at the Slash Lazy H 5 location is 4258 ft below KB elevation, and the interval itself is 194 ft thick.</p>	Name of Formation	Lithology	Formation Top Depth		Depth below Lowest Identified USDW, ft	MD, ft	Thickness, ft	Pierre	Mudstone	1687	1429	0	Niobrara	Mudstone	3116	389	1429	Carlile	Mudstone	3505	49	1818	Greenhorn	Mudstone	3554	105	1867	Belle Fourche	Mudstone	3659	287	1972	Mowry	Mudstone	3946	82	2259	Skull Creek	Mudstone	4033	225	2346	Swift	Mudstone	4552	535	2765	Rierdon	Mudstone	4987	208	3300	Piper (Kline Member)	Carbonate	5195	108	3508	Piper (Picard Member)	Mudstone	5303	86	3616	<p data-bbox="2685 278 2958 510">and secondary confinement zones. A convergent interpolation gridding algorithm was used with well formation tops, 3D seismic, and 2D seismic in creation of this map. (p. 2-40)</p> <p data-bbox="2685 540 2958 949">Figure 2-26. 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 creation of this map. (p. 2-41)</p>
Name of Formation	Lithology	Formation Top Depth		Depth below Lowest Identified USDW, ft																																																															
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Pierre	Mudstone	1687	1429	0																																																															
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Piper (Kline Member)	Carbonate	5195	108	3508																																																															
Piper (Picard Member)	Mudstone	5303	86	3616																																																															
Area of Review Delineation	N.D.A.C. §§ 43-05-01-05(1)(j) and (1)(b)(3)	<p data-bbox="453 1072 752 1243">N.D.A.C. § 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;</p> <p data-bbox="453 1274 752 1800">N.D.A.C. § 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:</p>	<p data-bbox="777 1072 1153 1332">The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of the storage reservoir boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:</p>	<p data-bbox="1177 1072 2660 1276">4.1 Area of Review (AOR) Delineation (p. 4-1) North Dakota regulations for geologic storage of CO₂ 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 [N.D.A.C.] § 43-05-01-01[4]). Concern regarding the endangerment of USDWs is related to the potential vertical migration of CO₂ and/or brine from the injection zone to the USDW. Therefore, the AOR encompasses the region overlying the injected free-phase CO₂ plume and the region overlying the extent of formation fluid pressure increase that is sufficient to drive formation fluids (e.g., brine) into USDWs, assuming pathways for this migration (e.g., abandoned wells or transmissive faults) are present.</p> <p data-bbox="1177 1306 2660 1566">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 Slash Lazy H 5 (NDIC File No. 38701) shows that the storage reservoir in the project area is overpressured with respect to the lowest USDW (i.e., the allowable increase in pressure is less than zero. The storage reservoir is calculated to be overpressured, with a value of -251 psi calculated using data from the Slash Lazy H 5 well at the KJ Hintz simulation well location. The maximum vertically averaged storage reservoir change in pressure at the end of the simulated injection period was 1004 psi in the raster cell intersected by the injection well, which corresponds to less than 0.015 m³ of flow over 20 years (Section 3.5). Based on the computational methods used to simulate CO₂ injection activities and associated pressure front (Figure 4-1), the resulting AOR for KJ Hintz is delineated as being 1 mi beyond the storage facility area boundary. This extent ensures compliance with existing state regulations.</p> <p data-bbox="1177 1596 2660 1683">In accordance with N.D.A.C. § 43-05-01-05(1)(b)(3), a geologist or engineer reviewed the data of public record for all wells within the storage facility area, including those which penetrate the storage reservoir or primary or secondary seals overlying the reservoir and all wells within 1 mi of the storage facility area boundary (Table 4-1).</p> <p data-bbox="1177 1713 2660 1800">This section of the SFP application is accompanied by maps and tables that include information required and in accordance with N.D.A.C. § 43-05-01-05(1)(a) and (b) and § 43-05-01-05.1(2), such as the storage facility area; location of any proposed injection wells, presence of occupied structures or gravel pits (Figure 4-2); and location of water wells and any other wells within the AOR (Figure 4-3). Table 4-1 lists all the surface</p>	<p data-bbox="2685 1072 2958 1598">Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, brown crosses represent wind turbines and brown circles represent gravel pits (note: gravel pits were identified using the NDGISHUB Landmarks NDDOT [North Dakota Department of Transportation, 2002]). (p. 4-4)</p>																																																														

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				<p>and subsurface features that were investigated as part of the AOR evaluation. Surface features that were investigated but not found within the AOR boundary are also identified in Table 4-1.</p> <p>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 (Section 2.5) 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.</p>	
	<p>N.D.A.C. §§ 43-05-01- 05(1)(b)(3) and (1)(a)</p>	<p>N.D.A.C. § 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:</p> <p>N.D.A.C. § 43-05-01-05(1) a. A site map showing the boundaries of the storage reservoir and the location of all proposed wells, proposed cathodic protection boreholes, and surface facilities within the carbon dioxide storage facility area;</p>	<p>a. A map showing the following within the carbon dioxide reservoir area:</p> <ul style="list-style-type: none"> 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; 	<p>2.3 Storage Reservoir (injection zone) (p. 2-16) See Figure 2-9 on page 2-15.</p> <p>5.7.1 Soil Gas Monitoring (p. 5-23) See Figure 5-4 on page 5-23.</p> <p><i>3.5.5.2 Incremental Leakage Maps and AOR Delineation</i> (p. 3-40) See Figure 3-21 on page 3-43.</p> <p>5.2 Surface Facilities Leak Detection Plan (p. 5-10) See Figure 5-2 on page 5-11.</p> <p>4.1 Area of Review (AOR) Delineation (p. 4-1) See Figure 4-2 on page 4-4</p>	<p>Figure 2-9. 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 dashed line has been modified based on new well control. (p. 2-16)</p> <p>Figure 5-4. SCS3 baseline and operational near-surface sampling locations. (p. 5-23)</p> <p>Figure 3-21. Final AOR estimations and stabilized CO₂ extent of the project storage facility area in relation to nearby legacy wells. Shown is the storage facility area (black dashed line) and AOR (purple dashed line). The gray circles represent legacy oil and gas wells near the storage facility area. (p. 3-43)</p> <p>Figure 5-2. Map detailing CO₂ flowline path to CO₂ injection wellsite (left) and layout of surface facilities at the wellsite (right), illustrating key surface facilities leak detection and monitoring equipment. Soil gas station, MSG03, and</p>

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					<p>groundwater well, MGW12, off-pad monitoring locations are also shown. (p. 5-11)</p> <p>Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4)</p>
	<p>N.D.A.C. § 43-05-01-05(1)(b)(2)(a)</p>	<p>N.D.A.C. § 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;</p>	<p>b. A map showing the following within the storage reservoir area and within one mile outside of its boundary:</p> <ul style="list-style-type: none"> i. All wells, including water, oil, and natural gas exploration and development wells ii. All other manmade subsurface structures and activities, including coal mines; 	<p>4.1 Area of Review (AOR) Delineation (p. 4-1) See Figure 4-2 on page 4-4 and Figure 4-3 on page 4-5.</p> <p>2.6 Potential Mineral Zones (p. 2-71) See Figure 2-46a on page 2-74.</p>	<p>Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4)</p> <p>Figure 4-3. Map showing all wells located in the AOR. Shown are the stabilized CO₂ plume extent postinjection (gray-shaded area), storage facility area (dashed black boundary), and AOR (dashed purple</p>

Subject	N.D.C.C. / N.D.A.C. 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)
					<p>boundary). All groundwater wells in the AOR are identified based on data available from the Department of Water Resources (DWR). There are two existing Broom Creek Formation penetrations within the AOR, namely, the Slash Lazy H 5 well and Raymond Jensen 1-34 (NDIC File No. 4942). No other legacy oil and gas wells are present in the AOR (see Figure 2-46a for any nearby legacy wells outside of the AOR). No springs are present in the AOR (note: springs were evaluated using the National Map hosted by the U.S. Geological Survey [2023]). (p. 4-5)</p> <p>Figure 2-46a. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-74)</p>
	<p>N.D.A.C. § 43-05-01-05(1)(c) and N.D.A.C. § 43-05-01-05.1(1)(a)</p>	<p>N.D.A.C. § 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 and storage capacity of</p>	<p>c. A description of the method used for delineating the area of review, including:</p> <ul style="list-style-type: none"> 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; 	<p>3.5.2 Risk-Based AOR Delineation (p. 3-32) 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 overpressured 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.</p> <p>Several researchers have recognized the need for alternative methods for estimating the AOR for locations that are already overpressured 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.</p> <p>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 CO₂ injection) to the incrementally larger leakage that would occur in the CO₂ injection case. The modeling for the risk-based AOR used semianalytical solutions to single-phase flow equations to model reservoir</p>	<p>Figure 3-17. Workflow for delineating a risk-based AOR for a SFP (modified from Burton-Kelly and others, 2021). (p. 3-34).</p> <p>Table 3-5. EPA Method 1 Critical Threshold Pressure Increase Calculated at the KJ Hintz 1 Simulation Well Location (p. 3-35)</p> <p>Table 3-6. Simplified Stratigraphy and Average</p>

Subject	N.D.C.C. / N.D.A.C. 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)
		<p>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;</p> <p>N.D.A.C. § 43-05-01-05.1(1)</p> <p>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;</p>		<p>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”).</p> <p>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 overpressured relative to overlying aquifers.</p> <p>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 compositional simulator, GEM) provide the “gold standard” for estimating pressure buildup in response to CO₂ injection (e.g., Bosshart and others, 2018). However, these numerical reservoir simulations are typically limited to the storagereservoir 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 CO₂ plume domain can be reasonably described by a single-phase flow calculation by representing CO₂ injection as an equivalent-volume injection of brine (Oldenburg and others, 2014).</p> <p>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 CO₂ 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 3-17).</p> <p>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.</p> <p>3.5.3 Critical Threshold Pressure Increase Estimation (p. 3-34)</p> <p>For the purposes of delineating AOR for this permit, 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 Slash Lazy H 5 stratigraphic test well.</p> <p>Application of EPA Method 1 (Eq. 1) using model data from the KJ Hintz 1 simulation well shows that the injection zone is overpressured 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.</p> <p>In accordance with EPA (2013) guidance, the combination of a) a Method 1 negative $\Delta P_{i,f}$ value 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.</p> <p>3.5.4 Risk-Based AOR Calculations (p. 3-35)</p> <p>Complete details of the risk-based AOR model are found in Burton-Kelly and others (2021). The inputs, assumptions, and results discussed here provide the necessary details for reproducing and verifying the results. A macro-enabled Microsoft Excel file was used to define the inputs and calculations that were employed in the method (hereafter “ASLMA Workbook”).</p> <p>3.5.4.1 Initial Hydraulic Heads</p> <p>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</p>	<p>Properties Used to Represent the Storage Complex. (p. 3-36)</p> <p>Table 3-7. CO₂ Density and Injection Parameters Used for the ASLMA Model (p. 3-37)</p> <p>Figure 3-18. 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]). (p.3-38)</p>

Subject	N.D.C.C. / N.D.A.C. 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)
				<p>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 CO₂ injection.</p> <p>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. They illustrate the state of overpressure in the storage complex, because Aquifer 1 has a greater initial hydraulic head than Aquifer 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).</p> <p><i>3.5.4.2 CO₂ Injection Parameters</i> The ASLMA Model for the project used a Broom Creek CO₂ 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 CO₂ 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 CO₂ density from the storage reservoir pressure and temperature, which resulted in an estimated density, shown in Table 3-7. The CO₂ mass injection rate and CO₂ density are then used to derive the daily equivalent-volume injection rate, shown in Table 3-7.</p> <p><i>3.5.4.3 Hypothetical Leaky Wellbore</i> In the simulation model 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 CO₂ injection well. The pressure buildup in the storage reservoir at each distance, along with the recorded cumulative volume of formation fluid vertically migrating through the leaky wellbore from the storage reservoir to the USDW (i.e., from Aquifer 1 to Aquifer 3) throughout the 20-year injection period, provides the data set needed to derive the risk-based AOR.</p> <p>Published ranges for the effective permeability of a leaky wellbore (Figure 3-18) have included an “open wellbore” with an effective permeability as high as 10⁻⁵ m² (10¹⁰ mD) to values more representative of leakage through a wellbore annulus of 10⁻¹² to 10⁻¹⁰ m² (10³ to 10⁵ mD) (Watson and Bachu, 2008, 2009; Celia and others, 2011). Carey (2017) provides probability distributions for the effective permeability of potentially leaking wells at CO₂ storage sites and estimated a wide range from 10⁻²⁰ to 10⁻¹⁰ m² (10⁻⁵ to 10⁵ 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 CO₂ storage sites (Figure 3-18).</p> <p>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.</p> <p><i>3.5.4.4 Saline Aquifer Potential Thief Zone</i> As shown in Table 3-6, a saline aquifer (Aquifer 2, Inyan Kara Formation) exists between the storage reservoir primary seal and the 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, Aquifer 2 may act as a thief zone and reduce the potential for formation fluid impacts to the groundwater.</p> <p>The thief zone phenomenon was described by Nordbotten and others (2004) as an “elevator model” by analogy to 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 high-permeability zone encountered during drilling into which circulating fluids can be lost. Models with and without opening the leaky wellbore to Aquifer 2 were run and the results evaluated to quantify the effect of a thief zone on the risk-based AOR.</p> <p><i>3.5.4.5 Aquifer- and Aquitard-Derived Properties</i></p>	

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				<p>The ASLMA Model assumes homogeneous properties within each hydrostratigraphic unit (Table 3-6). For each unit shown in Table 3-6, pressure, temperature, porosity, permeability, and salinity are used to derive two key inputs for the ASLMA Model: HCON and specific storage (SS). Average porosity and permeability values were derived as follows: Broom Creek, from distributed properties in the geologic model; 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).</p> <p>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), potential thief zone (Aquifer 2), and USDW (Aquifer 3) are shown in Table 3-6. Details about the HCON and SS derivations are provided in supporting information for Burton-Kelly and others (2021).</p>	
	N.D.A.C. § 43-05-01-05.1(1)(b)(1-4)	<p>N.D.A.C. § 43-05-01-05.1(1)</p> <p>b. A description of:</p> <p>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;</p> <p>(2) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;</p> <p>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and</p> <p>(4) How corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are</p>	<p>d. A description of:</p> <p>(1) The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review;</p> <p>(2) Any monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date;</p> <p>(3) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation;</p> <p>(4) How corrective action will be conducted if necessary, including:</p> <p>a. What corrective action will be performed prior to injection</p> <p>b. How corrective action will be adjusted if there are changes in the area of review;</p>	<p>4.3 Reevaluation of AOR and Corrective Action Plan (p. 4-11)</p> <p>The AOR and corrective action plan will be reevaluated in accordance with N.D.A.C. § 43-05-01-05.1, with the first reevaluation taking place at a period not to exceed 5 years from the date the permit for CO₂ injection is issued (N.D.A.C. § 43-05-01-10) or when monitoring and operational conditions warrant a reevaluation. Each successive reevaluation shall take place at a period not to exceed 5 years from the date of the previous reevaluation (each referred to as a “Reevaluation Date”). The AOR reevaluations will address the following:</p> <ul style="list-style-type: none"> Monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model and the 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 the 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 delineation. <p>As part of the reevaluation, Summit Carbon Storage #3, LLC (SCS3) will either a) demonstrate to the Department of Mineral Resources, Oil and Gas Division (DMR-O&G) using monitoring data and modeling results that no plan amendment is necessary or b) submit an amended AOR and corrective action plan for DMR-O&G approval. Plan amendments must be incorporated into the permit and are subject to permit modification requirements.</p>	N/A

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		changes in the area of review; and how site access will be guaranteed for future corrective action.			
	N.D.A.C. § 43-05-01-05(1)(b)(2)	N.D.A.C. § 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;	4.1 Area of Review (AOR) Delineation (p. 4-1) See Figure 4-2 on page 4-4.	Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4)
	N.D.A.C. § 43-05-01-05(1)(b)(2)	N.D.A.C. § 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,	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. 2-71) See Figure 2-45, Figure 2-46a, Figure 2-46b, Figure 2-47, Figure 2-48, and Figure 2-49.	Figure 2-45. Drillstem test results indicating the presence of oil in the Spearfish Formation samples (modified from Stolldorf, 2020). (p. 2-72) Figure 2-46a. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-74) Figure 2-46b. Coal beds of the Sentinel Butte and Bullion Creek (Tongue River) Formations showing the lignite coals in western North Dakota (Zygarlicke and others, 2019). (p. 2-75) Figure 2-47. Beulah net coal isopach map and

Subject	N.D.C.C. / N.D.A.C. 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)
		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:			<p>resource area (modified from Ellis and others, 1999). (p. 2-76)</p> <p>Figure 2-48. Beulah overburden isopach map (modified from Ellis and others, 1999). (p. 2-77)</p> <p>Figure 2-49. Map showing the future mining area for the Coyote Creek Mine through 2040. (p. 2-78)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(3) and N.D.A.C. § 43-05-01-05.1(2)(b)	<p>N.D.A.C. § 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:</p> <p>N.D.A.C. § 43-05-01-05.1(2) b. Using methods approved by the commission, identify all penetrations, including active and</p>	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.	2.6 <i>Potential Mineral Zones</i> (p. 2-71) See Figure 2-46a on page 2-74.	Figure 2-46a. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-74)

Subject	N.D.C.C. / N.D.A.C. 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)
		abandoned wells and underground mines, in the area of review that may penetrate the confining zone. Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the commission may require;			
	N.D.A.C. § 43-05-01-05(1)(b)(3)(a)	N.D.A.C. § 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;	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;	See discussion in 4.1 Area of Review (AOR) Delineation (p. 4-1) See Figure 4-2 on page 4-4. 4.2 Corrective Action Evaluation (p. 4-6) See Table 4-2 on p. 4-7, Table 4-3 on p. 4-7, and Table 4-4 on p. 4-8. See Figure 4-4 on p. 4-9 and Figure 4-5 on p. 4-10 4.4 Protection of USDWs (p. 4-11) Table 4-5 on page 4-12, Figure 4-6 on page 4-13, Figure 4-7 on page 4-14, Figure 4-8 on page 4-15, Figure 4-9 on page 4-16, Figure 4-10 on page 4-17, Figure 4-11 on page 4-19, and Table 4-6 on page 4-19. 2.6 Potential Mineral Zones (p. 2-71) See Figure 2-46a on page 2-74 for nearby legacy wells.	Figure 4-2. Final AOR map showing the KJ Hintz storage facility area (dashed black boundary) and AOR (dashed purple boundary). Pink squares represent occupied structures, and brown circles represent gravel pits (note: gravel pits were identified using the North Dakota Geographic Information System [GIS] Hub landmarks data layer from the North Dakota Department of Transportation [2002]). (p. 4-4) Table 4-2. Well(s) in AOR Evaluated for Corrective Action* (p. 4-7) Table 4-3. Slash Lazy H 5 (NDIC File No. 38701) Well Evaluation (p. 4-7) Table 4-4. Raymond Jensen 1-34 (NDIC File No. 4942) Well Evaluation (p. 4-8) Figure 4-4. Slash Lazy H 5 (NDIC File No. 38701) well schematic. (p. 4-9) Figure 4-5. Raymond Jensen 1-34 (NDIC File No. 4942) well schematic
	N.D.A.C. § 43-05-01-05(1)(b)(3)(b)	N.D.A.C. § 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;	(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		
	N.D.A.C. § 43-05-01-05(1)(b)(3)(c)	N.D.A.C. § 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;	(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		
	N.D.A.C. §§ 43-05-01-05(1)(b)(3)(d) and (e)	N.D.A.C. § 43-05-01-05(1)(b)(3)			

Subject	N.D.C.C. / N.D.A.C. 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)
	N.D.A.C. § 43-05-01-05(1)(b)(3)(f)	<p>(d) Maps and cross sections of the area of review;</p> <p>N.D.A.C. § 43-05-01-05(1)(b)(3)</p> <p>(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;</p> <p>N.D.A.C. § 43-05-01-05(1)(b)(3)</p> <p>(f) A list of contacts, submitted to the commission, when the area of review extends across state jurisdiction boundary lines;</p>	<p>c. General vertical and lateral limits</p> <p>d. Water wells</p> <p>e. Springs</p> <p>(5) Map and cross sections of the area of review;</p> <p>(6) A map of the area of review showing the following:</p> <p>a. Number or name and location of all injection wells</p> <p>b. Number or name and location of all producing wells</p> <p>c. Number or name and location of all abandoned wells</p> <p>d. Number of name and location of all plugged wells or dry holes</p> <p>e. Number or name and location of all deep stratigraphic boreholes</p> <p>f. Number or name and location of all state-approved or United States Environmental Protection Agency-approved subsurface cleanup sites</p> <p>g. Name and location of all surface bodies of water</p> <p>h. Name and location of all springs</p> <p>i. Name and location of all mines (surface and subsurface)</p> <p>j. Name and location of all quarries</p> <p>k. Name and location of all water wells</p> <p>l. Name and location of all other pertinent surface features</p> <p>m. Name and location of all structures intended for human occupancy</p>		<p>showing the location of cement plugs. (p. 4-10)</p> <p>Table 4-5. Description of Zones of Confinement above the Immediate Upper Confining Zone (Opeche/Spearfish Formation) (data based on Slash Lazy H5) (p. 4-12)</p> <p>Figure 4-6. Major aquifer systems of the Williston Basin (modified from Downey and Dinwiddie, 1988). (p. 4-13)</p> <p>Figure 4-7. Upper stratigraphy of Mercer, Oliver, and Morton Counties showing the stratigraphic relationship of Cretaceous and Tertiary groundwater-bearing formations (modified from Croft, 1973). (p. 4-14)</p> <p>Figure 4-8. Depth to surface of the Fox Hills Formation in western North Dakota (Fischer, 2013). (p. 4-15)</p> <p>Figure 4-9. Potentiometric surface of the Fox Hills–Hell Creek aquifer system shown in feet of hydraulic head above sea level. Flow is to the east through the AOR in Mercer, Oliver, and Morton Counties (modified from Fischer, 2013). (p. 4-16)</p> <p>Figure 4-10. West-east cross section of the major aquifer layers in Oliver County. Wells used in the cross section are shown</p>

Subject	N.D.C.C. / N.D.A.C. 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)
			<p>n. Name and location of all state, county, or Indian country boundary lines</p> <p>o. Name and location of all roads</p> <p>(7) A list of contacts, submitted to the Commission, when the area of review extends across state jurisdiction boundary lines.</p>		<p>in the inset map and labeled with corresponding well names (NDIC File No. 4942 is Raymond Jensen 1-34.) (p. 4-17)</p> <p>Figure 4-11. Field-verified water wells located within the AOR. (p. 4-19)</p> <p>Table 4-6. DWR and SCS3 Well No. Correlation (p. 4-19)</p> <p>Figure 2-46a. Map showing stratigraphic wells for the project and nearest legacy wells. Gray circles indicate dry wells. The red circle indicates the closest oil and gas producing well (NDIC File No. 7616). (p. 2-74)</p>
	N.D.A.C. § 43-05-01-05(1)(b)(3)(g)	<p>N.D.A.C. § 43-05-01-05(1)(b)(3)</p> <p>(g) Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review; and</p>	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

Subject	N.D.C.C. / N.D.A.C. 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)
Required Plans	N.D.A.C. § 43-05-01-05(1)(k)	<p>N.D.A.C. § 43-05-01-05(1) k. The storage operator shall comply with the financial responsibility requirements pursuant to section 43-05-01-9.1;</p>	<p>a. Financial Assurance Demonstration</p>	<p>12.3 Financial Instruments (p.12-11) The applicant will establish a financial instrument(s) 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations (N.D.A.C. § 43-05-01-09.1. The applicant will provide financial assurance in the form of a surety bond to ensure funds are available for PISC and facility closure activities (N.D.A.C. § 43-05-01-09.1[1][a] and N.D.A.C. § 43-05-01-19). The applicant will also obtain a pollution liability policy(s) to cover emergency and remedial response costs and endangerment of USDWs under (N.D.A.C. § 43-05-01-13), and a financial instrument (surety bond) to cover the costs of plugging the injection wells (N.D.A.C. § 43-05-01-11.5). No estimates have been provided for corrective action (N.D.A.C. § 43-05-01-05.1) because no action is required at this time.</p> <p>This application presents the estimated total costs (\$20,817,800) of these activities and a breakdown apportionment across proposed financial instruments in Table 12-1. Section 12.2 of this FADP provides additional details of the financial responsibility cost estimates for each activity.</p> <p>The company providing insurance will meet all the following criteria:</p> <ol style="list-style-type: none"> 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 DMR-O&G determines that the storage operator has fulfilled its financial obligations. <p>The third-party insurance, which identifies SCS3 as the covered party, will be provided by one or a combination of the companies meeting the creditworthiness and other requirements of N.D.A.C. §43-05-01-09.1. However, the greatest hypothetical exposure evaluated would be an acute upward migration through a CO₂ injection well, which would have an estimated cost of \$14,005,000 for emergency and remedial response actions, as well as identified in the endangerment of USDWs.</p> <p>Coverage terms are of an indicative/estimated nature only at this time, as firm and bindable terms are not possible this far in advance of commencement of injection operations; however, final coverage terms and costs will be determined upon full underwriting and firm/bindable quotations to be issued by insurers 30–60 days prior to inception of coverage, which is expected to be at or just prior to the commencement of injection operations. The actual third-party insurance companies will be determined closer to the proposed injection start date and will meet both of the following criteria, as specified in N.D.A.C. §43-05-01-09.1(1)(g):</p> <ol style="list-style-type: none"> 1. The companies satisfy financial strength requirements based on credit ratings in the top four categories of either Standard & Poor’s (AAA, AA, A, or BBB) or Moody’s (Aaa, Aa, A, Baa). <p>The companies meet a minimum rating (minimum rating based on an issuer, credit, securities, or financial strength rating as a demonstration of financial stability) and minimum capitalization (i.e., demonstration that minimum thresholds are met for the following financial ratios: debt–equity, assets–liabilities, cash return on liabilities, liquidity, and net profit) and are able to pass bond rating in the top four categories of either Standard & Poor’s (AAA, AA, A, or BBB) or Moody’s (Aaa, Aa, A, Baa), when applicable.</p>	<p>Table 12-1. Potential Future Costs Covered by Financial Assurance (p. 12-2)</p> <p>Table 12-2. Injection Well Plugging (p. 12-3)</p> <p>Table 12-3a. Cost Estimate¹ for PISC Activities for KJ Hintz Assuming a 10-year PISC Period (p. 12-4)</p> <p>Table 12-3b. Cost Estimate for Flowline Segment NDL-326 Abandonment (p. 12-5)</p> <p>Table 12-4. Cost Estimate¹ for Site Closure and Remediation Activities for KJ Hintz CO₂ Storage Project (p. 12-5).</p> <p>Table 12-6. Cost Estimate for Emergency and Remedial Response Plan* (p. 12-10).</p> <p>Table 12-7. Cost Estimate for Endangerment of USDWs* (p. 12-10).</p>
	N.D.A.C. § 43-05-01-05(1)(d)	<p>N.D.A.C. § 43-05-01-05(1)(d) d. An emergency and remedial response plan pursuant to section 43-05-01-13;</p>	<p>b. An emergency and remedial response plan;</p>	<p>7.0 EMERGENCY AND REMEDIAL RESPONSE PLAN (p. 7-1) Summit Carbon Storage #3, LLC (SCS3) requires all employees, contractors, and agents to follow the company emergency and remedial response plan (ERRP) for KJ Hintz. The purpose of the ERRP is to provide guidance for quick, safe, and effective response to an emergency to protect the public, all responders, company personnel, and the environment.</p> <p>This 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 (USDW) during the construction, operation, and postinjection site care phases 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 to USDWs. In addition, this ERRP describes the emergency response team and command structure, injection facility evacuation plans, HazMat (hazardous materials) capabilities, and emergency communication plans. Lastly, procedures are presented for</p>	<p>Table 7-3. Primary SCS2 Contacts (p. 7-4)</p> <p>Figure 7-2. Off-site emergency notification list. Emergency management service (EMS) districts, fire districts, law enforcement agencies, and Local</p>

Subject	N.D.C.C. / N.D.A.C. 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)
				<p>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 company’s nearest operational office and at the geologic storage facility.</p>	<p>Emergency Planning Committee (LEPC) jurisdictions with response jurisdictions intersecting with the KJ Hintz storage facility area (SFA) will be provided a copy of this ERRP. (p. 7-5)</p> <p>Figure 7-3. Map showing emergency management service (EMS) response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads. (p. 7-6)</p> <p>Figure 7-4 Map showing fire response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads. (p.7-7)</p> <p>Figure 7-5. Map showing law enforcement response zones including, and within the vicinity of, KJ Hintz. Also included on this map are the planned CO₂ injection wells, stratigraphic and reservoir-monitoring wells, flowline(s), MCE pipeline, and state and federal roads. (p.7-8)</p> <p>Table 7-4. Off-Site Emergency</p>

Subject	N.D.C.C. / N.D.A.C. 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)
					<p>Notification/PSAP Phone List (p.7-9)</p> <p>Table 7-5. Potential Project Emergency Events and Their Detection (p.7-11)</p> <p>Table 7-6. Actions Necessary to Determine Cause of Events and Appropriate Emergency Response (p.7-13 through 7-15)</p> <p>Figure 7-6. Emergency notification flowchart. (p.7-20)</p> <p>Table 7-7. DMR-O&G UIC Program Management Contact (p.7-21)</p> <p>Table 7-8. Potential Contractor and Services Providers (p.7-23)</p>
	N.D.A.C. § 43-05-01-05(1)(e)	N.D.A.C. § 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
	N.D.A.C. § 43-05-01-05(1)(f)	N.D.A.C. § 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;	<p>5.3 CO₂ Flowline Corrosion Prevention and Detection Plan (p. 5-14) The purpose of this plan is to prevent and detect any signs of corrosion in the flowline.</p> <p>5.3.1 Corrosion Prevention To protect against corrosion, an external fusion-bonded epoxy coating will be applied to the ND-326 flowline. Flowline installed by trenchless methods, such as road crossings, will also have an abrasion-resistant overcoat installed as a secondary coating, over the fusion-bonded epoxy, prior to installation. SCS3 will install an impressed current cathodic protection (ICCP) system along the buried flowline to mitigate the threat of external soil corrosion on the line. The ICCP system, which will be continuously monitored, involves the installation of deep anode beds along the flowline that are connected to external power through a rectifier. The power provides the current needed to drive an electrochemical reaction whereby the anodes corrode instead of the flowline. Except for a rectifier, junction box, and small diameter vent pipe posted above the anode beds, the ICCP system will be buried. Because the CO₂ stream will contain only trace amounts of water (Table 5-3), SCS3 will operate the surface facilities above the saturation point of water to prevent corrosive conditions from forming.</p> <p>5.3.2 Corrosion Detection</p>	<p>Figure 5-2. Map detailing CO₂ flowline path to CO₂ injection wellsite (left) and layout of surface facilities at the wellsite (right), illustrating key surface facilities leak detection and monitoring equipment. Soil gas station, MSG03, and groundwater well, MGW12, off-pad monitoring locations are also shown. (p. 5-11)</p> <p>Figure 5-3. Generalized flow diagram from the</p>

Subject	N.D.C.C. / N.D.A.C. 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)
				<p>Real-time, continuous monitoring of the CO₂ flowline with P/T gauges and Coriolis mass flowmeter measurements from the pump/metering building to the point of transfer combined with continuous analysis of the CO₂ stream with the gas chromatograph will provide strong evidence that noncorrosive conditions are maintained in the flowline during injection operations. The equipment will be spliced to the SCADA system and have automated triggers and alarms for alerting SCS3 of any anomalous readings.</p> <p>The flowline segment from point of transfer to the pipeline inspection gauge (PIG) receiver (shown on Figure 5-3) will allow the passage of internal inspection devices (commonly referred to as “smart PIGs”), which are designed to detect certain internal and external anomalies in the line, such as loss of mass/wall thickness, dents, pitting, cracking, and scratches. The launchers and receiver facilities are designed to launch and receive these internal inspection devices along with other types of PIGs (e.g., maintenance pigs). The launchers and receivers will be located at standalone sites in Oliver County. The frequency for running PIGs in the flowline during operations is described in Table 5-2.</p> <p>In addition to the activities described above, SCS3 will install at least one electrical resistance (ER) probe along the CO₂ flowline upstream of the gas chromatograph to continuously monitor for loss of mass throughout the operational phase. The ER probe will be spliced to the SCADA system for real-time monitoring and will be removable for visual inspection and replacement, if required. The SCADA system will have automated triggers and alarms for alerting SCS3 of any anomalous readings.</p> <p>5.6 Wellbore Corrosion Prevention and Detection Plan (p. 5-21) 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 N.D.A.C. § 43-05-01-11.4(1)(c).</p> <p>5.6.1 Downhole Corrosion Prevention To prevent corrosion of the well materials in the KJ Hintz 1 and 2 wellbores, the following preemptive measures will be implemented: 1) cement opposite of the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation will be CO₂-resistant; 2) the well casing will also be CO₂-resistant from the bottomhole to just above the Opeche/Spearfish Formation and from below the top of the Swift Formation to just below the top of the Skull Creek 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. The tubing-casing annulus will be filled with the packer fluid system that is planned to be a brine-based fluid treated with antimicrobial biocide, corrosion inhibitor, and oxygen scavenger to minimize potential corrosive effects of soluble oxygen.</p> <p>To prevent corrosion of the well materials in the Slash Lazy H 5 wellbore, the following preemptive measures are implemented: 1) cement opposite the injection interval and extending to the differential valve (DV) staging tool above the top of the Mowry Formation is CO₂-resistant; 2) the well casing is CO₂-resistant from 194 feet below the top of the Amsden Formation to 154 feet above the top of the Opeche/Spearfish Formation and from 179 feet below the top of the Swift Formation to 250 feet above the top of the Mowry Formation; and 3) the long-string casing is filled with an industry standard corrosion inhibitor.</p> <p>Figures 11-2, 11-4, and 11-5 in Section 11.0 illustrate the downhole corrosion prevention measures in each of the wellbores.</p> <p>5.6.2 Downhole Corrosion Detection PNLs will be run in the KJ Hintz 1 and 2 and Slash Lazy H 5 wellbores to detect saturations of CO₂. Further investigative methods of inspecting for corrosion in the wellbore could include ultrasonic logging or other equivalent CIL when required. Tables 5-1 and 5-2 specify the sampling frequency for acquiring data related to this downhole corrosion detection plan.</p>	<p>point of transfer to the KJ Hintz 1 CO₂ injection well, illustrating key surface facilities’ connections and monitoring equipment. The flow diagram is identical for the KJ Hintz 2 CO₂ injection well (not shown). (p. 5-12)</p> <p>Table 5-3. CO₂ Stream System Specification (p. 5-9)</p>
	<p>N.D.A.C. § 43-05-01-05(1)(g)</p>	<p>N.D.A.C. § 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:</p> <p>(1) Identify the potential for release to the atmosphere;</p>	<p>e. A surface leak detection and monitoring plan for all wells and surface facilities pursuant to N.D.A.C. § 43-05-01-14;</p>	<p>5.2 Surface Facilities Leak Detection Plan (p. 5-10) The purpose of this leak detection plan is to specify the monitoring strategies SCS3 will use to quantify any losses of CO₂ from surface facilities during operations. Surface facilities include the CO₂ injection wellheads (KJ Hintz 1 and 2), the reservoir-monitoring wellhead (Slash Lazy H 5), and the NDL-326 CO₂ flowline, which begins at the first weld seam at the NDL-326/NDL-327 connection (i.e., point of transfer) and ends at the inlet valve upstream of the automated emergency shutoff valve at each CO₂ injection wellhead. Figure 5-2 illustrates the CO₂ flowline path to CO₂ injection wellsite, and Figure 5-3 is a generalized flow diagram from the point of transfer to the CO₂ injection wellheads, illustrating key surface facilities’ connections and monitoring equipment.</p> <p>As illustrated in Figure 5-3, leak detection equipment includes 1) P/T gauges along the flowline, 2) a Coriolis mass flowmeter placed near each of the injection wellheads, and 3) gas detection stations placed on the CO₂ injection wellheads pursuant to N.D.A.C. § 43-05-01-14(1) and inside the pump/metering building. The gas detection stations, which will detect gases such as CO₂, methane (CH₄), and hydrogen sulfide (H₂S), will have</p>	<p>N/A</p>

Subject	N.D.C.C. / N.D.A.C. 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)
		<p>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and</p> <p>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.</p>		<p>automated triggers and alarms to alert SCS3 of any anomalous readings. The SCADA system, which will continuously collect data streams from the leak detection equipment in real time, will also monitor for leaks with leak detection software.</p> <p>Field personnel from SCS3 will have multigas detectors with them for visiting wellsites or conducting flowline inspections. In addition, gas detection safety lights (part of the integrated alarm system) will be placed outside of the pump/metering building to warn field personnel of potential indoor air quality threats.</p>	
	<p>N.D.A.C. § 43-05-01-05(1)h</p> <p>N.D.A.C. § 43-05-01-05(1)(h)</p>	<p>N.D.A.C. § 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:</p> <p>(1) Identify the potential for release to the atmosphere;</p> <p>(2) Identify potential degradation of ground water resources with particular emphasis on underground sources of drinking water; and</p> <p>(3) Identify potential migration of carbon dioxide into any mineral zone in the facility area.</p>	<p>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;</p>	<p>5.7 Environmental Monitoring Plan (p. 5-22) To verify the injected CO₂ is contained in the storage reservoir, protect all USDW, and demonstrate hydrogeologic properties of the storage reservoir, multiple environments will be monitored.</p> <p>As required by N.D.A.C. § 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 and analyzing vadose-zone soil gas at two soil gas profile stations, two new Fox Hills monitoring wells, and up to two existing groundwater wells.</p> <p>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/Spearfish Formation to the Skull Creek Formation). The AZMI will be continuously monitored with DTS fiber optics in the KJ Hintz 1 and 2 wellbores as well as PNLs.</p> <p>Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), the storage reservoir will be monitored with both direct and indirect methods. Direct methods include continuous fiber optics (DTS) and downhole P/T measurements in the KJ Hintz 1 and 2 and Slash Lazy H 5 wells, and falloff tests and PNLs in the KJ Hintz 1 and 2 wellbores. Falloff testing analysis will provide reservoir pressure data and the completion condition including transmissibility, skin factor, and well flowing and static pressure data for technical adequacy to demonstrate no migration from the reservoir. Indirect methods include time-lapse seismic surveys. These efforts will provide assurance that surface and near-surface environments are protected and that the injected CO₂ is safely and permanently contained in the storage reservoir. In addition, SCS3 will install multiple seismometer stations for passively detecting and locating seismic events.</p> <p>5.7.1 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. Two permanent soil gas profile stations installed adjacent to both the CO₂ injection and Slash Lazy H 5 well pads will be sampled, as shown in Figure 5-4. Figure 5-5 is a typical wellbore schematic of a soil gas profile station.</p> <p>The sampling frequency for soil gas is summarized in Tables 5-1 and 5-2. During injection, SCS3 may install additional replacement or alternative soil gas sampling sites based on monitoring data results. SCS3 will notify DMR-O&G if either replacement or alternative soil gas sampling sites are added pursuant to N.D.A.C. § 43-05-01-18(2). The results of the baseline soil gas sampling program will be provided to DMR-O&G prior to injection.</p> <p>5.7.2 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. Figure 5-4 identifies the sampling locations associated with the near-surface baseline and operational monitoring plan, which includes two new Fox Hills monitoring wells and up to two existing groundwater wells.</p> <p>SCS3 will work with landowners of the two existing groundwater wells (MGW02 and MGW07) to attempt to collect samples as specified in Tables 5-1 and 5-2. The number of samples collected from each existing groundwater well may vary by location, since some of the groundwater wells may not be operated year-round or site accessibility may be limited (e.g., snow cover during winter months). If SCS3 is unable to access the</p>	

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				<p>wells because of operational status or access concerns, the reason why the sample is unable to be collected will be documented. An attempt was made to identify alternative wells that operate year-round with reduced access concerns but produced no results.</p> <p>SCS3 will install one Fox Hills monitoring well (MGW12) adjacent to the injection well pad (as shown in Figure 5-4). The Fox Hills monitoring well will be sampled according to the sampling frequency specified in Tables 5-1 and 5-2.</p> <p>NDIC File No. 4942 was plugged and abandoned with two cement plugs placed between the Broom Creek and Fox Hills Formations. In addition, NDIC File No. 4942 is outside the stabilized CO₂ plume boundary; therefore, the wellbore is not anticipated to come into contact with CO₂. SCS3 plans to monitor this legacy wellbore with a new Fox Hills monitoring well installed by SCS3 to provide additional assurance of nonendangerment to the lowest USDW. The Fox Hills monitoring well (MGW14) will be installed by Year 19 of injection. Seismic data acquisitions (described later in the Indirect Reservoir Monitoring section of the application) prior to Year 19 of injection will help track the migration of the CO₂ plume and may help determine timing of installation of MGW14. After the well is installed, SCS3 will sample wells according to the sampling frequency described in Tables 5-1 and 5-2.</p> <p>SCS3 reserves the right to evaluate and modify, if necessary, appropriate groundwater sampling locations and frequency based on conformance of the CO₂ plume extent in the subsurface. SCS3 will notify DMR-O&G if alternative or new water wells are added to the sampling program pursuant to N.D.A.C. § 43-05-01-18(2).</p> <p>Appendix B includes a supplemental baseline dataset of historic geochemistry results for two shallow groundwater wells within the area of review (AOR) boundary. The data were obtained from the Department of Water Resources (DWR). These shallow groundwater wells (DWR 9450 and 18181) were excluded from the baseline and operational monitoring plan primarily because they did not meet the depth criterion used to select wells for inclusion in the testing and monitoring plan.</p> <p>5.7.3 Deep Subsurface Monitoring Pursuant to N.D.A.C. § 43-05-01-11.4(1)(g), SCS3 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 this subsection 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.</p> <p>5.7.3.3 Direct Reservoir Monitoring DTS fiber optics installed in the KJ Hintz 1 and 2 and Slash Lazy H 5 wellbores will directly monitor the temperature of the storage reservoir. P/T readings from the casing-conveyed gauges in the CO₂ injection wells will also monitor conditions in the storage reservoir. To track the pressure front from CO₂ injection in the storage reservoir, pressure will be measured continuously from the casing-conveyed P/T gauge installed in the Slash Lazy H 5 well. To track the CO₂ plume in the storage reservoir, the DTS fiber-optic cable and temperature measurements from the casing-conveyed P/T gauge installed in the Slash Lazy H 5 well will be used to estimate the timing of arrival of the CO₂ plume at the reservoir-monitoring well. The pressure and temperature data will be used to ensure the monitoring data from the Broom Creek Formation (from Amsden through Opeche/Spearfish Formation) is conforming to the geologic model and numerical simulations. Pressure falloff tests will also be performed in the CO₂ injection to demonstrate the performance of the storage reservoir.</p> <p>5.7.3.5 Indirect Reservoir Monitoring SCS3 will acquire 3D time-lapse seismic surveys to track the extent of the CO₂ plume within the storage reservoir. The 200-mi² 3D Beulah seismic survey referenced in Section 2.0 will serve as the baseline survey. To demonstrate conformance between the reservoir model simulation and site performance, a localized 3D seismic survey will be collected to monitor the extent of the CO₂ plume, as shown in Figure 5-6 and detailed in Table 5-2.</p> <p>SCS3 will reevaluate the testing and monitoring plan, inclusive of the design and frequency of the repeat 3D seismic surveys, at least once every 5 years as required. If necessary, the time-lapse seismic monitoring strategy will be adapted based on updated simulations of the predicted extents of the CO₂ plume, including expanding the 3D survey area to capture additional data as the CO₂ plume expands in the storage reservoir.</p> <p>SCS3 plans to install multiple seismometer stations to continuously monitor for seismic events with a magnitude of >1.5 within the AOR boundary during injection. The 3D seismic survey data (e.g., velocity modeling) collected within the AOR boundary will provide supporting evidence for confidently locating seismic events. A traffic light system for detecting larger magnitude events (e.g., >2.7) is presented with the Indirect Reservoir Monitoring QASP section of this application.</p>	

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				<p>5.9 Adaptive Management Approach (p. 5-33) SCS3 will employ an adaptive management approach to implementing the testing and monitoring plan by completing periodic reviews of the testing and monitoring plan (Ayash and others, 2017) at least once every 5 years. During each 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 DMR-O&G for approval. Should amendments to the testing and monitoring plan be necessary, they will be incorporated into the permit following approval by DMR-O&G. Over time, monitoring methods and data collection may be supplemented or replaced as advanced techniques are developed.</p> <p>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.</p>	
	N.D.A.C. § 43-05-01-05(1)	<p>N.D.A.C. § 43-05-01-05(1) 1. A testing and monitoring plan pursuant to section 43-05-01-11.4;</p>	<p>g. A testing and monitoring plan pursuant to N.D.A.C. Section 43-05-01-11.4;</p>	<p>See Section 5.0 TESTING AND MONITORING PLAN</p> <p>Note: See Table 5-1 on p. 5-2; Table 5-2 on p. 5-4; Table 5-3 on p. 5-9; Table 5-4 on p. 5-14; Table 5-5 on p. 5-19; and Table 5-6 on p. 5-20, for detailed summaries of the testing and monitoring plan.</p>	<p>Table 5-1. Overview of Major Components of the Testing and Monitoring Plan – Preinjection (p. 5-2)</p> <p>Table 5-2. Overview of Major Components of the Testing and Monitoring Plan – Injection (p. 5-4)</p> <p>Table 5-3. CO₂ Stream System Specification (p. 5-9)</p> <p>Table 5-4. NDL-326 Flowline Design Specification (p. 5-14)</p> <p>Table 5-5. Completed Logging and Testing Activities for Slash Lazy H 5 (p. 5-19)</p> <p>Table 5-6. Logging and Testing Plan for the KJ Hintz 1 and KJ Hintz 2 Wellbores (p. 5-20)</p>
	N.D.A.C. § 43-05-01-05(1)(i)	<p>N.D.A.C. § 43-05-01-05 (1) i. The proposed well casing and cementing program detailing compliance with section 43-05-01-09;</p>	<p>h. The proposed well casing and cementing program;</p>	<p>9.0 WELL CASING AND CEMENTING PROGRAM (p. 9-1)</p>	<p>Figure 9-1. KJ Hintz 1 proposed wellbore schematic. (p. 9-2)</p>

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					<p>Figure 9-2. KJ Hintz 1 proposed wellbore trajectory. (p. 9-3)</p> <p>Figure 9-3. KJ Hintz 2-proposed wellbore schematic. (p. 9-7)</p> <p>Figure 9-4. KJ Hintz 2 proposed wellbore trajectory. (p. 9-8)</p> <p>Figure 9-5. Slash Lazy H5 as-constructed wellbore schematic. (p. 9-12)</p> <p>Figure 9-6. Slash Lazy H 5 cement evaluation – RCBL from Slash Lazy H 5 verifies the cement-bond quality. Using a high-resolution image, the analyst can assess isolation in the CO₂ injection zone, confining zones, and USDWs. (p. 9-15)</p>
	N.D.A.C. § 43-05-01-05(1)(m)	N.D.A.C. § 43-05-01-05(1) m. A plugging plan that meets requirements pursuant to section 43-05-01-11.5;	i. A plugging plan;	<p><i>Refer to Section 10.1 KJ Hintz 1: Proposed Injection Well P&A Program (p. 10-1)</i></p> <p><i>Refer to Section 10.2 KJ Hintz 2: Proposed Injection Well P&A Program (p. 10-8)</i></p> <p><i>Refer to Section 10.3 Slash Lazy H5: Proposed Reservoir-Monitoring Well P&A Program (p. 10-15)</i></p>	<p>Figure 10-1. KJ Hintz 1 proposed completion wellbore schematic. (p. 10-2)</p> <p>Figure 10-2. KJ Hintz 1 proposed P&A wellbore schematic. (p. 10-7)</p> <p>Figure 10-3. KJ Hintz 2 proposed completion wellbore schematic. (p. 10-9)</p> <p>Figure 10-4. KJ Hintz 2 proposed P&A wellbore schematic (p. 10-14)</p> <p>Figure 10-5. Slash Lazy H5 proposed completion wellbore schematic. (p. 10-16)</p>

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					Figure 10-6. Slash Lazy H5 proposed P&A wellbore schematic. (p. 10-21)
	N.D.A.C. § 43-05-01-05(1)(n)	N.D.A.C. § 43-05-01-05(1)n. A postinjection site care and facility closure plan pursuant to section 43-05-01-19; and	j. A post-injection site care and facility closure plan.	6.0 POSTINJECTION SITE AND FACILITY CLOSURE PLAN (p. 6-1) Note: Refer to Table 6-1 on p. 6-2	Table 6-1. Overview of Postinjection Testing and Monitoring Activities ¹ (p. 6-2)
Storage Facility Operations	N.D.A.C. § 43-05-01-05(1)(b)(4)	N.D.A.C. § 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;	The following items are required as part of the storage facility permit application:	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 (USDWs). 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 (N.D.A.C.) § 43-05-01-05 and § 43-05-01-11.3. Planned well logging and testing activities and monitoring activities can be found in Sections 5.0 and 6.0. Table 11-1. KJ Hintz 1 and KJ Hintz 2: Proposed Injection Well Operating Parameters	Table 11-1. KJ Hintz 1 and KJ Hintz 2: Proposed Injection Wells Operating Parameters (p. 11-1)
			a. The proposed average and maximum daily injection rates;		
			b. The proposed average and maximum daily injection volume;		
			c. The proposed total anticipated volume of the carbon dioxide to be stored;		
	N.D.A.C. § 43-05-01-05(1)(b)(5)	N.D.A.C. § 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	d. The proposed average and maximum bottom hole injection pressure to be utilized;		

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		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;	e. The proposed average and maximum surface injection pressures to be utilized;	<table border="1"> <thead> <tr> <th data-bbox="1177 276 1432 310">Item</th> <th colspan="2" data-bbox="1432 276 1687 310">Values</th> <th data-bbox="1687 276 2352 310">Description/Comments</th> </tr> </thead> <tbody> <tr> <td colspan="4" data-bbox="1177 310 2352 344">Injected Volume</td> </tr> <tr> <td data-bbox="1177 344 1432 459">Total Injected Mass/Volume</td> <td colspan="2" data-bbox="1432 344 1687 459">129.7 MMt 2,451,470 MMcf</td> <td data-bbox="1687 344 2352 459">Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint</td> </tr> <tr> <td colspan="4" data-bbox="1177 459 2352 493">Injection Rates</td> </tr> <tr> <td data-bbox="1177 493 1432 657">Average Injection Rate</td> <td data-bbox="1432 493 1687 657"> KJ Hintz 1 9000 tonnes/day (170.1 MMscf/day) 3.29 MMt/yr 1,241,801 MMcf 65.7 MMt </td> <td data-bbox="1687 493 1942 657"> KJ Hintz 2 8767 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simulation modeling, taken prior to final site survey</td> </tr> <tr> <td colspan="4" data-bbox="1177 993 2352 1028">Pressure (psi)</td> </tr> <tr> <td data-bbox="1177 1028 1432 1155">Formation Fracture Pressure at Top Perforation</td> <td data-bbox="1432 1028 1687 1155">4253</td> <td data-bbox="1687 1028 1942 1155">4231</td> <td data-bbox="1942 1028 2352 1155">Based on geomechanical analysis of formation fracture gradient as 0.784 psi/ft</td> </tr> <tr> <td data-bbox="1177 1155 1432 1241">Average Surface Injection Pressure</td> <td data-bbox="1432 1155 1687 1241">2100</td> <td data-bbox="1687 1155 1942 1241">2100</td> <td data-bbox="1942 1155 2352 1241">Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint</td> </tr> <tr> <td data-bbox="1177 1241 1432 1417">Maximum Surface Injection Pressure *</td> <td data-bbox="1432 1241 1687 1417">6500</td> <td data-bbox="1687 1241 1942 1417">5800</td> <td data-bbox="1942 1241 2352 1417">Based on maximum BHP with only one well injecting at a time (using the designed 7-in. tubing): KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi</td> </tr> <tr> <td colspan="4" data-bbox="1177 1417 2352 1451">Item</td> </tr> <tr> <td colspan="4" data-bbox="1177 1451 2352 1485">Values</td> </tr> <tr> <td colspan="4" data-bbox="1177 1485 2352 1520">Description/Comments</td> </tr> <tr> <td colspan="4" data-bbox="1177 1520 2352 1554">Pressure</td> </tr> <tr> <td data-bbox="1177 1554 1432 1588">KJ Hintz 1</td> <td data-bbox="1432 1554 1687 1588">KJ Hintz 2</td> <td colspan="2" data-bbox="1942 1554 2352 1588">Description/Comments</td> </tr> <tr> <td data-bbox="1177 1588 1432 1703">Average BHP</td> <td data-bbox="1432 1588 1687 1703">3600 psi</td> <td data-bbox="1687 1588 1942 1703">3622 psi</td> <td data-bbox="1942 1588 2352 1703">Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint</td> </tr> <tr> <td data-bbox="1177 1703 1432 1737">Calculated Maximum BHP</td> <td data-bbox="1432 1703 1687 1737">3828 psi</td> <td data-bbox="1687 1703 1942 1737">3808 psi</td> <td data-bbox="1942 1703 2352 1737">Based on 90% of the formation fracture pressure: KJ Hintz 1: 4253 psi KJ Hintz 2: 4231 psi</td> </tr> </tbody> </table>				Item	Values		Description/Comments	Injected Volume				Total Injected Mass/Volume	129.7 MMt 2,451,470 MMcf		Based on a maximum wellhead pressure (WHP) constraint of 2100 psi and maximum bottomhole pressure (BHP) constraint	Injection Rates				Average Injection Rate	KJ Hintz 1 9000 tonnes/day (170.1 MMscf/day) 3.29 MMt/yr 1,241,801 MMcf 65.7 MMt	KJ Hintz 2 8767 tonnes/day (165.7 MMscf/day) 3.20 MMt/yr 1,209,669 MMcf 64.0 MMt	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint	Average Maximum Injection Rate*	29,548 tonnes/day (558.5 MMscf/day) 10.79 MMt/yr 4,076,963 MMcf 215.7 MMt	27,027 tonnes/day (510.9 MMscf/day) 9.87 MMt/yr 3,729,183 MMcf 197.3 MMt	Based on maximum BHP with only one well injecting at a time: KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi	Depth				Depth (true vertical depth [TVD]) of the Top Perforation Used in the BHP Calculation	KJ Hintz 1 5426	KJ Hintz 2 5397	Depths are for simulation modeling, taken prior to final site survey	Pressure (psi)				Formation Fracture Pressure at Top Perforation	4253	4231	Based on geomechanical analysis of formation fracture gradient as 0.784 psi/ft	Average Surface Injection Pressure	2100	2100	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint	Maximum Surface Injection Pressure *	6500	5800	Based on maximum BHP with only one well injecting at a time (using the designed 7-in. tubing): KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi	Item				Values				Description/Comments				Pressure				KJ Hintz 1	KJ Hintz 2	Description/Comments		Average BHP	3600 psi	3622 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint	Calculated Maximum BHP	3828 psi	3808 psi	Based on 90% of the formation fracture pressure: KJ Hintz 1: 4253 psi KJ Hintz 2: 4231 psi	
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Average Maximum Injection Rate*	29,548 tonnes/day (558.5 MMscf/day) 10.79 MMt/yr 4,076,963 MMcf 215.7 MMt	27,027 tonnes/day (510.9 MMscf/day) 9.87 MMt/yr 3,729,183 MMcf 197.3 MMt	Based on maximum BHP with only one well injecting at a time: KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi																																																																																	
Depth																																																																																				
Depth (true vertical depth [TVD]) of the Top Perforation Used in the BHP Calculation	KJ Hintz 1 5426	KJ Hintz 2 5397	Depths are for simulation modeling, taken prior to final site survey																																																																																	
Pressure (psi)																																																																																				
Formation Fracture Pressure at Top Perforation	4253	4231	Based on geomechanical analysis of formation fracture gradient as 0.784 psi/ft																																																																																	
Average Surface Injection Pressure	2100	2100	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint																																																																																	
Maximum Surface Injection Pressure *	6500	5800	Based on maximum BHP with only one well injecting at a time (using the designed 7-in. tubing): KJ Hintz 1: 3828 psi KJ Hintz 2: 3808 psi																																																																																	
Item																																																																																				
Values																																																																																				
Description/Comments																																																																																				
Pressure																																																																																				
KJ Hintz 1	KJ Hintz 2	Description/Comments																																																																																		
Average BHP	3600 psi	3622 psi	Based on a maximum WHP constraint of 2100 psi and maximum BHP constraint																																																																																	
Calculated Maximum BHP	3828 psi	3808 psi	Based on 90% of the formation fracture pressure: KJ Hintz 1: 4253 psi KJ Hintz 2: 4231 psi																																																																																	
*Maximum injection pressure during operations will be limited to the surface equipment pressure ratings and maximum BHP constraint																																																																																				

Subject	N.D.C.C. / N.D.A.C. 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)												
	N.D.A.C. § 43-05-01-05(1)(b)(6)	N.D.A.C. § 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;	<p>f. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone;</p> <p>g. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the confining zone;</p>	<p>5.5 Baseline Wellbore Logging and Testing Plan (Site Characterization) (p. 5-18) Pursuant to N.D.A.C. § 43-05-01-11.2, SCS3 will collect baseline well-logging and -testing measurements from subsurface geologic formations in the CO₂ injection wellbores to 1) verify the depth, thickness, porosity, permeability, lithology, and salinity of the storage complex; 2) ensure conformance with the injection well construction requirements; and 3) establish accurate baseline data for making future time-lapse measurements. Baseline well-logging and -testing measurements will also be collected from the reservoir-monitoring well.</p> <p>Table 5-5 specifies baseline well-logging and -testing activities completed in the reservoir-monitoring well (Slash Lazy H 5), and Table 5-6 identifies the well-logging and -testing plan for the KJ Hintz 1. The plan for the KJ Hintz 2 wellbore will be the same as what is presented for the KJ Hintz 1 but may exclude dipole sonic logging (assuming dipole sonic logging is successful in the KJ Hintz 1).</p> <p>Tables 5-1 and 5-2 specify well-logging and -testing activities associated with establishing mechanical integrity and monitoring the deep subsurface, including the storage complex. Coring activities are described separately in the Section 9.0 as-drilled wellbore diagrams for KJ Hintz 1 and 2 and in the text in Section 2.0 for Slash Lazy H 5.</p> <p>SCS3 will provide DMR-O&G with an opportunity to witness all well-logging and -testing activities as required under N.D.A.C. § 43-05-01-11.2(6). See Appendix A: WELL AND WELL FORMATION FLUID SAMPLING LAB ANALYSIS</p> <p>2.0 GEOLOGIC EXHIBITS <i>Refer to 2.2 Data and Information Sources (p. 2-4)</i> <i>Refer to 2.2.2 Site-Specific Data (p. 2-6)</i></p> <p>2.2.2.2 Core Sample Analyses (p. 2-8) Three hundred seventy-nine (379) ft of 4-in whole core was recovered from the storage complex in the Slash Lazy H 5: 61 ft core from the Opeche/Spearfish Formation, 272 ft core from the Broom Creek Formation, and 46 ft core from the Amsden Formation. Core was analyzed to characterize the lithologies of the Opeche/Spearfish, Broom Creek, and Amsden Formations and correlated to the well log data. A core gamma ray log was acquired and matched to wireline gamma ray-to-depth correct core depth measurements (Table 2-2a). Core analyses included porosity and permeability measurements, x-ray diffraction (XRD), x-ray fluorescence (XRF), thin-section analysis, scanning electron microscopy (SEM), interfacial tension (IFT) and contact angle (CA), geomechanics and capillary entry pressure measurements. The results were used to inform geologic modeling and predictive simulation inputs and assumptions, geochemical modeling, and geomechanical modeling.</p> <p>Table 5-5. Completed Logging and Testing Activities for Slash Lazy H 5</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th style="width: 10%;"></th> <th style="width: 45%; text-align: center;">Logging/Testing</th> <th style="width: 45%; text-align: center;">Justification</th> </tr> </thead> <tbody> <tr> <td style="text-align: center; vertical-align: middle;">Surface Section</td> <td>Open-hole logs: triple combo (resistivity and neutron and density porosity), dipole sonic, spontaneous potential (SP), GR, caliper, and temperature</td> <td>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.</td> </tr> <tr> <td></td> <td>Cased-hole logs: ultrasonic and array sonic tools (inclusive of CCL, VDL, and RCBL), GR, and temperature</td> <td>Identified cement bond quality radially, evaluated the cement top and zonal isolation, and established external mechanical integrity. Established baseline temperature profile.</td> </tr> <tr> <td style="text-align: center; vertical-align: middle;">Long-String Section</td> <td>Open-hole logs: triple combo and spectral GR</td> <td>Quantified variability in reservoir properties, including resistivity, porosity, and lithology. Provided input for enhanced geomodeling and predictive simulation of CO₂ 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.</td> </tr> </tbody> </table>		Logging/Testing	Justification	Surface Section	Open-hole logs: triple combo (resistivity and neutron and density porosity), dipole sonic, spontaneous potential (SP), 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 and array sonic tools (inclusive of CCL, VDL, and RCBL), 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	Open-hole 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.	Table 5-6. Logging and Testing Plan for the KJ Hintz 1 and 2 Wellbores (p. 5-20)
	Logging/Testing	Justification															
Surface Section	Open-hole logs: triple combo (resistivity and neutron and density porosity), dipole sonic, spontaneous potential (SP), 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 and array sonic tools (inclusive of CCL, VDL, and RCBL), 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	Open-hole 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.															

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				<p>Open-hole log: dipole sonic Identified mechanical properties, including stress anisotropy.</p> <p>Open-hole log: fracture finder log Quantified fractures in the Broom Creek Formation and confining layers to ensure safe, long-term storage of CO₂.</p> <p>Open-hole log: combinable magnetic resonance (CMR) Interpreted reservoir properties (e.g., porosity and permeability) and determined the best location for pressure test depths, formation fluid sampling depths, and stress testing depths.</p> <p>Open-hole log: fluid sampling (modular formation dynamics tester) Collected fluid samples from the Inyan Kara and Broom Creek Formation for analysis. Collected in situ microfracture stress tests in the Broom Creek and Opeche/Spearfish Formation for formation breakdown pressure, fracture propagation pressure, and fracture closure pressure.</p> <p>Cased-hole logs: ultrasonic and array sonic tools (inclusive of CCL, VDL, RCBL), GR, and temperature Identified cement bond quality radially, evaluated the cement top and zonal isolation, confirmed mechanical integrity, and established baseline temperature profile.</p>	
	N.D.A.C. § 43-05-01-05(1)(b)(7)	N.D.A.C. § 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 (USDWs). 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 (N.D.A.C.) § 43-05-01-05 and § 43-05-01-11.3. Planned well logging and testing activities and monitoring activities can be found in Sections 5.0 and 6.0.	N/A
	N.D.A.C. § 43-05-01-05(1)(b)(8)	N.D.A.C. § 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 (USDWs). 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 (N.D.A.C.) § 43-05-01-05 and § 43-05-01-11.3. Planned well logging and testing activities and monitoring activities can be found in Sections 5.0 and 6.0. <i>Refer to Table 11-1. KJ Hintz 1 and KJ Hintz 2: Proposed Injection Wells Operating Parameters (p. 11-1)</i> <i>Refer to 11.1 KJ Hintz 1: Proposed Completion Procedure to Conduct Injection Operations (p. 11-2)</i> <i>Refer to 11.2 KJ Hintz 2: Proposed Completion Procedure to Conduct Injection Operations (p. 11-10)</i>	N/A