NORTH DAKOTA INTEGRATED CARBON STORAGE COMPLEX FEASIBILITY STUDY

Final Report

(for the period June 9, 2017 – February 8, 2020)

Prepared for:

AAD Document Control

National Energy Technology Laboratory
U.S. Department of Energy
626 Cochrans Mill Road
PO Box 10940, MS 921-107
Pittsburgh, PA 15236-0940

Cooperative Agreement No. DE-FE0029488
DUNS No. 102280781

Prepared by:

Wesley D. Peck
Nicholas A. Azzolina
David V. Nakles
Kyle A. Glazewski
Ryan J. Klapperich
Charlene R. Crocker
Benjamin S. Oster
Daniel J. Daly
Amanda J. Livers-Douglas
Shane K. Butler
Steven A. Smith
Barry W. Botnen
Ian K. Feole
Jun He
Neil Dotzenrod
Arelys Y. Salazar
Santosh B. Patil
Janet L. Crossland

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
Phone (701) 777-5195; Fax (701) 777-5181
wpeck@undeerc.org

Shelia Hanson

Gamble Hall Room 365
293 Centennial Dr Stop 8363
Grand Forks, ND 58202-8363

Wesley D. Peck

Digitally signed by Wesley D. Peck
DN: cn=Wesley D. Peck, o=UND, ou=EERC, email=wpeck@undeerc.org, c=US
Date: 2020.03.24 12:57:52 -05'00'

Wesley D. Peck, Principal Investigator

March 24, 2020
2020-EERC-03-19

EERC DISCLAIMER

LEGAL NOTICE This research report was prepared by the Energy & Environmental Research Center (EERC), an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy (DOE) National Energy Technology Laboratory. Because of the research nature of the work performed, neither the EERC nor any of its employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the EERC.

DOE DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

This material is based upon work supported by the U.S. Department of Energy under Award No. DE-FE0029488.

NDIC DISCLAIMER

This report was prepared by the EERC pursuant to an agreement partially funded by the Industrial Commission of North Dakota, and neither the EERC nor any of its subcontractors nor the North Dakota Industrial Commission nor any person acting on behalf of either:

(A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

(B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the North Dakota Industrial Commission. The views and opinions of authors expressed herein do not necessarily state or reflect those of the North Dakota Industrial Commission.

ACKNOWLEDGMENTS

The authors would like the thank the following companies for allowing the use of their software packages in support of this work:

Computer Modelling Group, Ltd. (CMG-GEM, CMG-CMOST, CMG-WinProp, CMG-Builder, CMG-Results)
CGG (HampsonRussel)
ESRI (ArcMap)
HIS Markit (Petra and Kingdom)
Neuralog (Neuralog)
Schlumberger (Petrel and Techlog)

TABLE OF CONTENTS

LIST OF FIGURES iii

LIST OF TABLES v

EXECUTIVE SUMMARY vi

INTRODUCTION 1

STORAGE COMPLEX GEOLOGIC CHARACTERIZATION 2
- Structural Correlation 5
  - Summary of Stratigraphic Well Test Results 7

GEOLOGIC MODELING AND SIMULATION 12
- Introduction 12
- Geologic Model Construction and Numerical Simulation of CO_2 Injection 14
- Results of Numerical Simulations of CO_2 Injection 14
  - Scenario 1 – GPSP Injection into Broom Creek Formation 14
  - Scenario 2 – MRYS Injection into Broom Creek Formation 15
  - Scenario 3 – MRYS Injection into the Inyan Kara, Broom Creek, and Deadwood Formations 16
  - Scenario 4 – MRYS Injection into the Broom Creek and Deadwood Formations 17
- Simulation Scenario Summary 18
- Delineation of Area of Review 19

REGULATORY AND ECONOMIC ASSESSMENT 22
- Regulatory Considerations 22
- Economic Analysis 24
  - Commercial Project Path Forward 24
  - Cumulative PV10 per Ton of CO_2 Stored by Project Year 27

SITE DEVELOPMENT PLAN 29
- Site Characterization Plan 29
  - CO_2 Management Strategy 31
  - Risk Assessment and Mitigation Strategies 31

OUTREACH 33
- Approach 34
- Methodology 35
  - Establish an Outreach Advisory Board 35
  - Prepare and Implement an Outreach Plan 35
- Results and Discussion 38
  - Outreach Advisory Board 38
  - Outreach Plan 38

Continued . . .

TABLE OF CONTENTS (continued)

Regional Characterization 38
Audience Engagement Activities and Assessment 39
Outreach Tool Kit 41
Public Perceptions Study 42
Focus Groups 45
Conclusions 46

NRAP TOOLS OVERVIEW 47

OVERALL CONCLUSIONS 49

NEXT STEPS 50

REFERENCES 50

SITE CHARACTERIZATION ACTIVITIES: DOWNHOLE AND LABORATORY ANALYSES ..... Appendix A

GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION ..... Appendix B

NORTH DAKOTA CARBON DIOXIDE STORAGE FACILITY AND INJECTION WELL PERMIT APPLICATIONS CHECKLIST ..... Appendix C

COST MODEL FOR ESTIMATING INCREMENTAL COSTS FOR DEDICATED GEOLOGIC STORAGE OF CARBON DIOXIDE IN NORTH DAKOTA ..... Appendix D

OUTREACH ..... Appendix E
CCUS PUBLIC PERCEPTIONS STUDY RESULTS ..... Appendix E-1
INFOGRAPHICS ..... Appendix E-2

NATIONAL RISK ASSESSMENT PARTNERSHIP ..... Appendix F

LIST OF FIGURES

1 Location of the two energy complexes being evaluated for commercial geologic storage of 50 Mt of CO_2 2

2 Williston Basin stratigraphic column 3

3 Geophysical log correlation of the Flemmer-1 and BNI-1 wells 6

4 Pressure test data collected from the Flemmer-1 and BNI-1 wells plotted against standard freshwater and saline pressure gradients as well as a calculated local gradient for the BNI-1 location 8

5 Section of sandstone core from the Broom Creek Formation 9

6 Laboratory measurements of porosity and permeability from Flemmer-1 core samples correlated with the core GR log and lithologic interpretations 9

7 Laboratory measurements of porosity and permeability from BNI-1 core samples correlated with the core GR log and lithologic interpretations 11

8 Map showing the North Dakota CarbonSAFE study area, which includes two North Dakota coal-based power plants 13

9 Scenario 1 – CO_2 plume map for two potential vertical wells for the GPSP site in the Broom Creek Formation after the injection of 2 Mt per year of CO_2 for a period of 25 years 15

10 Scenario 2 – CO_2 plume from simulation results at the end of 25 years CO_2 injection for four vertical wells for MRYS site in Broom Creek Formation 16

11 Generalized well configuration under investigation for the stacked storage of CO_2 in the Inyan Kara, Broom Creek, and Deadwood Formations at the MRYS site 17

12 Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt into the Broom Creek Formation and 25 Mt into each of the Inyan Kara and Deadwood Formations 18

13 Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt each into the Brown Creek and Deadwood Formations 19

14 Calculated AOR for injection into the Deadwood Formation based on standard critical pressure calculation methods 21

15 Permit acquisition time line for the Class VI permits of a CO_2 geologic storage site 23

Continued . . .

LIST OF FIGURES (continued)

16 Conceptual business model for Project Tundra 25

17 Cumulative present value of the estimated costs for a generic geologic storage project 28

18 Cumulative PV10 of storage costs per ton of CO_2 stored per project year 29

19 Risk management process adapted from the ISO 31000 standard 32

20 Two-county study area, which contains most of the existing coal-based energy facilities in North Dakota 34

21 Local high school class visits the drilling site for one of the stratigraphic test wells 40

22 Students at a STEM event using bicycle pumps to push air through cores of rock 42

23 Opinions on taking actions on climate change 43

24 Opinions on associated and dedicated permanent CO_2 storage 44

25 Public perception of CO_2 capture and permanent storage 45

LIST OF TABLES

1 Cored and Logging Intervals for Stratigraphic Test Wells 5

2 Depth and Thickness of Formations in the Stratigraphic Test Wells 5

3 Relative Reservoir Quality as a Function of Porosity and Permeability 11

4 Summary of CO_2 Injection Scenarios 19

5 Cross Reference of Major Site Development Activities Needed to Acquire a North Dakota CO_2 Storage Facility Permit 30

6 Relating Outreach Plan Content to Key Project Story Questions 35

7 NRAP Tools Assessed Using Site-Specific Data from This Project 48

NORTH DAKOTA INTEGRATED CARBON STORAGE COMPLEX FEASIBILITY STUDY

EXECUTIVE SUMMARY

In spring 2017, the Energy & Environmental Research Center (EERC) initiated an effort to determine the feasibility of developing a commercial-scale CO_2 geologic storage complex able to store 50+ million tonnes (Mt) of CO_2 in central North Dakota safely, permanently, and economically. The objective was to fulfill the goals of the U.S. Department of Energy (DOE) Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative and address technical and nontechnical challenges specific to commercial-scale deployment of a CO_2 storage project. The findings clearly show that the concept of capturing CO_2 from a lignite-fired electrical generation facility in central North Dakota and safely and permanently storing the CO_2 in the deep subsurface is indeed technically, economically, and socially feasible.

This project evaluated two study areas and their respective geologic storage complexes located adjacent to separate coal-fired facilities in North Dakota: the Basin Electric Power Cooperative (BEPC)-owned Great Plains Synfuels Plant (GPSP) and the Minnkota Power Cooperative (Minnkota)-owned Milton R. Young Station (MRYS). These locations, one with CO_2 capture in place and an existing CO_2 pipeline, are bolstered by progressive North Dakota pore space ownership and long-term liability laws. These elements and a motivated team created an ideal synergistic scenario for ensuring success of the CarbonSAFE Initiative and promoting North Dakota's statewide vision for carbon management.

The project included drilling two new geologic characterization wells, integrating an existing 3-D seismic survey, creating a geologic model subsequently used for injection simulation, a risk assessment, public outreach, and generating a site development plan based on results. In addition, the performance of select National Risk Assessment Partnership tools was evaluated.

The geologic characterization wells were drilled ~5600 feet deep to the Broom Creek Formation; ~350 feet of core was retrieved from each well. The core included the Broom Creek (targeted injection zone) and a portion of the overlying Opeche Shale (seal). The Flemmer-1 well, west of Beulah, North Dakota, yielded 169 feet of sandstone. The BNI-1 well located south of Center, North Dakota, yielded 124 feet of sandstone. In each case, laboratory analysis of the sandstone showed permeability in the 300–1000-mD range, with porosity of 20%–30%. The Flemmer-1 well was sited within the boundaries of an existing 3-D seismic survey. Colocating the well with the seismic survey maximized the relationship between new and legacy data and developed a first-of-its-kind interpretation of the geologic fabric of the Broom Creek.

Geologic characterization data were integrated into a 5544-mi^2 geocellular model that encompassed both new wells and stratigraphy from the surface to the Amsden Formation (underlying the Broom Creek). The model was later expanded vertically to include the deeper Black Island–Deadwood interval to examine its potential viability as a storage target. The geocellular model provided the foundation for dynamic simulation of CO_2 into the Broom Creek. Results of the simulation suggest that the Broom Creek could accept the DOE target rate of 2 Mt/yr of CO_2 into as few as two wells. To bracket the expected capture from MRYS, simulations were

also investigated for a 4-Mt/yr rate near MRYS. Although more wells are needed (two additional), the Broom Creek still has the storage resource to accept the CO_2 at the increased rate.

A risk assessment exercise was conducted to identify and assess technical and nontechnical risks that could prevent potential candidate storage complexes within the study area from serving as commercial storage sites. The assessment identified and evaluated six technical risk categories: 1) CO_2 injectivity, 2) storage capacity, 3) lateral migration of CO_2, 4) lateral pressure propagation, 5) vertical migration of CO_2 or formation brine, and 6) induced seismicity. Following two rounds of analysis and scoring, no risks were determined to preclude continued efforts to develop carbon capture, utilization, and storage (CCUS) in central North Dakota. The risk assessment results will be used to guide future site characterization, modeling and simulation, and monitoring activities. A specific nontechnical strategic risk based on challenges that may be realized in amalgamation of pore space resulted in vertically expanding the geologic model to incorporate the potential for stacked storage in multiple saline reservoirs. By including the Black Island–Deadwood interval (the basal sedimentary reservoir in this region), the amalgamated areal extent could be reduced by as much as 45%. Working with a smaller geographic area reduces risks and costs associated with monitoring and pore space leasing.

An economic evaluation incorporating capture; transport (<5 mi); Class VI wells; permitting; and monitoring, verification, and accounting suggests implementing commercial-scale CCUS is economically attractive if the federal tax benefits of 45Q are included. This is validated by Minnkota's continued pursuit of CO_2 capture and geologic storage at MRYS through its Project Tundra initiative, indicating that there is a business case for CCUS in central North Dakota.

Currently, North Dakota is the only state with underground injection control (UIC) Class VI primacy. Built into the North Dakota Century Code is a series of regulatory requirements that guide the process to obtain a Class VI CO_2 storage facility permit. As part of this project, a site development plan was compiled to assure compliance with North Dakota's requirements to permit a commercial-scale CO_2 storage operation and includes a prospective time line encompassing a general breakdown of activities. In total, an estimated 30 months would be needed to execute the necessary steps to attain a North Dakota CO_2 storage facility permit.

Outreach was an integral part of the project and encompassed any project-related activity that had contact or exposure beyond the project team. The goals of outreach were to foster an environment from which stakeholders could make informed decisions about the project and gauge community receptiveness to a CCUS project. A consistent set of messages and outreach products were developed in conjunction with an outreach advisory board that integrated project partners and team members. To gauge public acceptability of geologically storing CO_2, 5611 households in the project area were invited to participate in an online survey. The survey results indicate that the public attitude regarding CCUS is neutral to positive, with strong sentiment that CO_2 capture and storage may be an approach to maintain the economic vitality of the region.

To achieve project objectives, critical support in the form of financial backing, engineering evaluations, site access, outreach collaboration, operations data, risk assessment/evaluation, and software access was provided by BEPC, the North Dakota Industrial Commission Lignite Research Council, ALLETE Clean Energy, BNI Energy, North American Coal Corporation, Minnkota, Prairie Public Broadcasting, Computer Modelling Group Ltd., and Schlumberger.

NORTH DAKOTA INTEGRATED CARBON STORAGE COMPLEX FEASIBILITY STUDY

INTRODUCTION

The Energy & Environmental Research Center (EERC) has conducted a feasibility study for two commercial-scale carbon dioxide (CO_2) geologic storage complexes, each capable of safely, permanently, and economically storing 50+ million tonnes (Mt) of CO_2 in central North Dakota. This feasibility project was executed as Phase II of the U.S. Department of Energy (DOE) Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative, a multiphase initiative to support the deployment of large-scale carbon capture and storage (CCS) projects. Each CarbonSAFE project is required to demonstrate the potential to capture and store at least 50 Mt of CO_2 over a 25-year operational period. The storage complexes evaluated in this investigation are located adjacent to separate coal-fired facilities in North Dakota: the Basin Electric Power Cooperative (BEPC)-owned Great Plains Synfuels Plant (GPSP) and the Minnkota Power Cooperative (Minnkota)-owned Milton R. Young Station (MRYS) (Figure 1). These locations, one with readily available CO_2 and an existing CO_2 pipeline, are bolstered by progressive North Dakota pore space ownership and long-term liability laws and North Dakota's primacy to administer the underground injection control (UIC) Class VI program.

This study focused on GPSP and MRYS for the CarbonSAFE Initiative because of existing CO_2 capture at GPSP and Minnkota's plan to capture CO_2 from MRYS through its ongoing Project Tundra initiative. Annually, these two facilities produce about 6 Mt and 3 Mt of CO_2, respectively. Much of the CO_2 captured from GPSP is currently transported via existing pipeline for 205 miles to the Weyburn and Midale oil fields of southern Saskatchewan for enhanced oil recovery (EOR). Each of these facilities overlies one or more extensive geologic formations with characteristics well-suited for storing CO_2.

What Is Project Tundra:
Minnkota is leading a commercial-scale CCS effort known as Project Tundra. The postcombustion CO_2 capture system will be incorporated at MRYS Unit 2, a 477-MW power plant fueled by North Dakota lignite. The nominally 3.1 Mt/yr of captured CO_2 will be stored in deep saline formations near MRYS.

To address the challenges of the CarbonSAFE Phase II project, the EERC assembled a diverse and committed team: the North Dakota Industrial Commission (NDIC) Lignite Research Council (LRC), BEPC, ALLETE Clean Energy (ACE), BNI Energy (BNI), North American Coal Corporation, Minnkota, Schlumberger Carbon Services (Schlumberger), Computer Modelling Group Ltd. (CMG), and Prairie Public Broadcasting.

The Phase II project was organized into the following component tasks:

- Storage Complex Geologic Characterization
- Geologic Modeling and Simulation
- Regulatory and Economic Assessment
- Site Development Plan
- Public Outreach

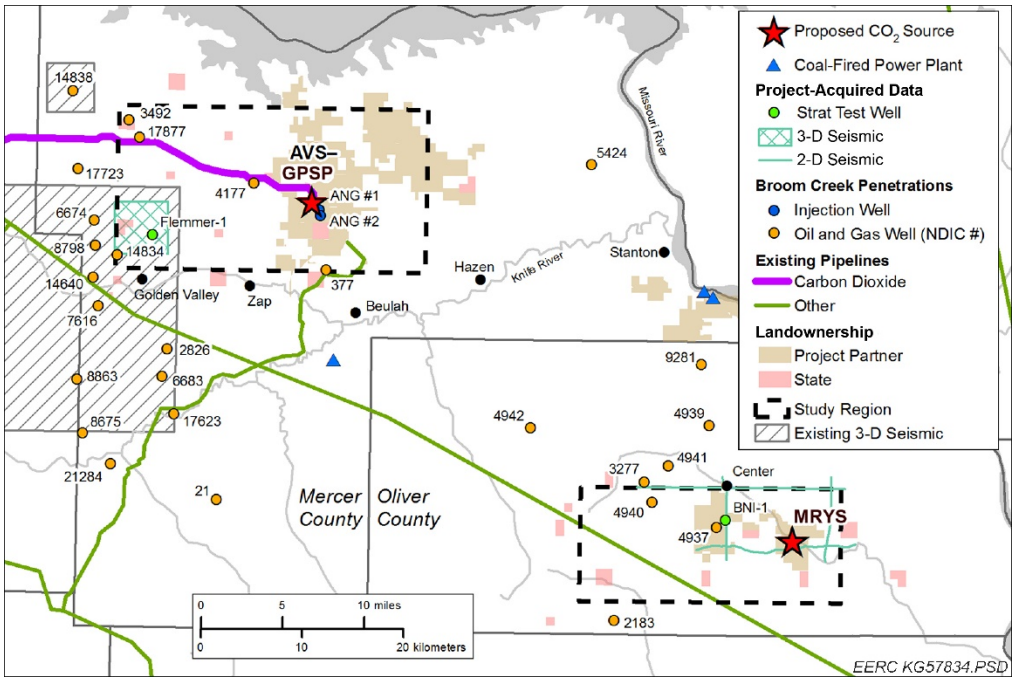


Figure 1. Location of the two energy complexes being evaluated for commercial geologic storage of 50 Mt of CO_2.

In addition, a separate task was dedicated to review a select number of National Risk Assessment Partnership (NRAP) software tools. A key outcome of the Phase II project is the determination that commercial-scale carbon capture, utilization, and storage (CCUS) in central North Dakota is feasible from a technical, economic, and societal standpoint.

STORAGE COMPLEX GEOLOGIC CHARACTERIZATION

The primary technical challenge facing the implementation of commercial-scale CCUS in the area around North Dakota's coal-fired energy generation facilities is making site-specific recommendations and assessments for the region's promising geologic storage complex(es). A CO_2 geologic storage complex includes one or more storage formations, each with at least one, or usually multiple, regionally continuous confining layers called cap rocks or seals.

Previous regional assessments show substantial potential for CO_2 storage in North Dakota, particularly within the sandstones of the Broom Creek Formation, (Sorensen and others, 2009; Peck and others, 2014; Glazewski and others, 2015). Accordingly, the geologic characterization efforts for the North Dakota CarbonSAFE project focused on a geologic storage complex comprising the Broom Creek Formation (storage formation) and the overlying Opeche Formation (cap rock) (Figure 2). Before this project, only a very limited amount of Broom Creek Formation core had been collected in North Dakota, presenting a significant challenge to performing site-specific assessments. The nearest existing core to the study areas was collected from the ANG #1 well (Figure 1), but this core represents only about 15 feet of the Broom Creek Formation. To

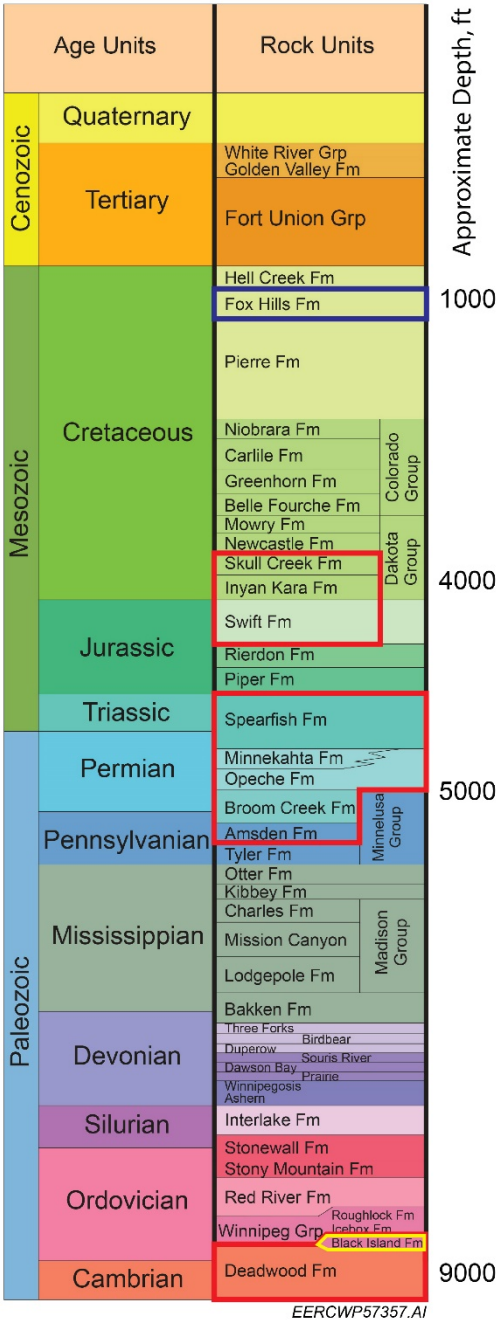


Figure 2. Williston Basin stratigraphic column. Intervals investigated in this work are highlighted in red, including the Inyan Kara, Broom Creek, Black Island, and Deadwood Formations.

provide the necessary site-specific data to assess the feasibility of the Broom Creek to accommodate and store at least 2 Mt of CO_2 within 25 years, two new stratigraphic test wells, the Flemmer-1 and the BNI-1, were drilled to collect core, sample fluids, and conduct in situ testing (Figure 1). One stratigraphic test well was drilled for each area of interest. Approximately 350 feet of 4-inch core was collected from each well. The core comprised the lower portion of the Opeche Formation and the entirety of the Broom Creek Formation. After the sampling and logging processes were completed, these wells were plugged and abandoned according to procedures established by NDIC.

A consequence of North Dakota's lignite-mining and power generation industry being located outside of the state's prime oil exploration and production region is the relative lack of well-drilling history and associated subsurface knowledge. The scattered distribution of wells that penetrate the prospective storage complex provide some point location information. However, having a greater comprehension of the geologic fabric (3-D distribution of porosity and permeability and/or internal structure) of the Broom Creek Formation was needed to properly characterize the storage complex and reduce uncertainty. As such, the Flemmer-1 well was drilled inside the boundary of a large area of preexisting 3-D seismic data and a 10-square-mile block of that data was acquired for reprocessing and interpretation (Figure 1). During the openhole wireline geophysical logging of the Flemmer-1 well, a dipole sonic log was collected to tie together the core, other geophysical logs, and acquired 3-D seismic data.

The BNI-1 stratigraphic test well was drilled on a parcel of BNI-owned reclaimed mine land approximately 5 miles west of the MRYS (Figure 1). The proximity of this well to the town of Center, North Dakota, provided an educational outreach opportunity for the local schools to visit the site.

Openhole wireline conveyed geophysical well logs were acquired in both stratigraphic test wells along the entire open section (no casing) of each wellbore. Table 1 shows the logging intervals for each stratigraphic test well. Multiple wireline runs were used to collect data on each stratigraphic test well. Collected data included gamma ray (GR) (total and spectral), caliper, density, porosity (neutron, density, and sonic), spontaneous potential, resistivity, sonic (compressional and shear), and lithologic properties.

Interpretations derived from the newly acquired geophysical logs were used to develop a geologic model of the storage complex in the study area. Well log interpretations of the stratigraphic test wells were also used to guide the integration of existing well logs in the study area to develop a more complete understanding of the subsurface geology. The geophysical logs from the existing wellbores in the area were acquired from the databases of NDIC and the North Dakota Department of Environmental Quality (NDDEQ).

Well logs provided formation top depths, lithology interpretation, petrophysical properties, and time–depth shifting of the seismic data. Well log interpretation efforts focused on the Broom Creek Formation, along with the overlying cap rocks of the Opeche, Minnekahta, and Spearfish Formations. The Inyan Kara, Black Island, and Deadwood Formations were also investigated to determine the feasibility as a stacked storage interval to augment Broom Creek Formation storage or as an alternate primary storage target (Figure 2).

Table 1. Cored and Logging Intervals for Stratigraphic Test Wells

	Flemmer-1	BNI-1
Total Depth, ft	6790	5316
Cored Interval, ft	6235–6575	4893–5208
Geophysical Logging Interval, ft	1930–6790	1390–5316

Structural Correlation

Logs collected from the stratigraphic test wells were used to pick formation tops based on well log signatures throughout the Williston Basin (Bluemle and other, 1986). Formation tops were picked from the top of the Pierre Formation to the top of the Amsden Formation (Table 2). These top picks were correlated with the 205 existing wells throughout the study area to interpret the geologic extent, depth, and thickness of the subsurface geologic formations of interest. Structural surfaces created from the stratigraphic top picks were used as input for structural geologic modeling.

Table 2. Depth and Thickness of Formations in the Stratigraphic Test Wells

	Flemmer-1		BNI-1	
Formation	**Depth, ft**	**Thickness, ft**	**Depth, ft**	**Thickness, ft**
Pierre	1826	2166	1228	1952
Greenhorn	3992	423	3180	388
Mowry	4415	93	3568	59
Newcastle	4508	14	3627	11
Skull Creek	4522	248	3638	227
Inyan Kara	4770	321	3865	178
Swift	5091	402	4043	476
Rierdon	5493	259	4519	144
Spearfish	5963	137	4865	42
Minnekahta	6100	8	N/A	N/A
Opeche	6108	165	N/A	?
Broom Creek	6273	263	4907	273
Amsden	6536		5180	

The top of the Broom Creek Formation was picked across the study area based on the transition from the high GR signature of the shale/siltstone of the overlying Opeche–Spearfish cap rock to the low GR signature of the sandstone/dolostone lithologies in the Broom Creek (Figure 3). The top of the Amsden Formation was placed at the top of a high-GR argillaceous dolostone that could be correlated across the entire study area (Figure 3).

As originally defined, the Opeche Formation lies between the Minnekahta and Broom Creek Formations (Darton, 1901; Benison and Goldstein, 2000). The interpretation of the geophysical

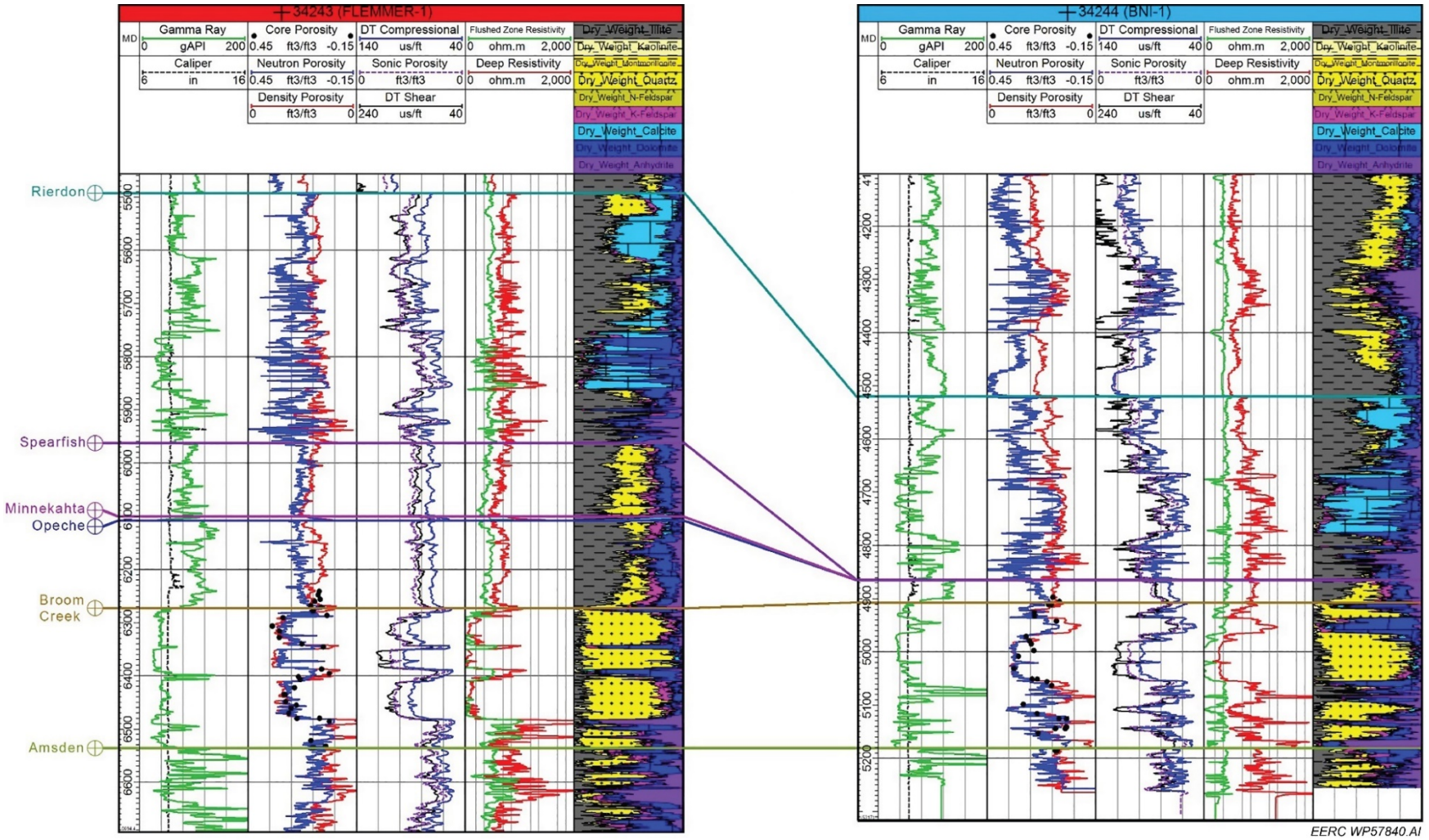


Figure 3. Geophysical log correlation of the Flemmer-1 and BNI-1 wells. Corresponding geologic formation tops are indicated with the labeled horizontal lines. The logs show thickness and characteristics similar to the Broom Creek in both wells. However, not all of the individual sealing layers (formations) above the Broom Creek at the Flemmer-1 well are present in the BNI-1 well. The Opeche and Minnekata Formations pinch out in the area between the two wells. The sealing layers present in BNI-1 (Spearfish and Rierdon) are of appropriate thickness to contain injected CO_2.

logs from Flemmer-1 and BNI-1 concludes that the Minnekahta Formation pinches out somewhere between the two well locations (Figure 3). The geophysical log signature of the Opeche and Spearfish Formations are nearly indistinguishable, and without the defining aspect of the Minnekahta to delineate the Opeche, there is uncertainty as to what formation is present directly above the Broom Creek Formation in the BNI-1 well. This uncertainty is reflected in Table 2. Regardless of the formal name, the package of shale and siltstone overlying the Broom Creek represents a viable and widespread cap rock to ensure CO_2 containment at both locations and throughout the study area.

Summary of Stratigraphic Well Test Results

Flemmer-1 Well

A single pressure test was conducted in the Inyan Kara Formation. The measured pressure was used to calculate a gradient of 0.426 psi/ft (Figure 4), which indicates slightly underpressured conditions in comparison to a normal freshwater hydrostatic gradient. Fluid samples were collected and analyzed, and a salinity of 21,300 mg/L total dissolved solids (TDS) was measured. An associated permeability estimate of 109 mD was calculated.

Pressure testing in the Broom Creek Formation included six pore pressure measurements. All six tests showed relatively good agreement, resulting in a calculated pressure gradient of 0.488 psi/ft. This pressure gradient suggests that the Broom Creek Formation is overpressured with respect to a freshwater hydrostatic gradient (Figure 4). Broom Creek fluid samples were collected; however, an unusually slow recovery precluded the team from conducting a thorough initial pump-out to confidently rid the interval of invaded drilling mud. An analysis of the sample yielded a salinity measurement of 263,000 mg/L TDS, but concerns remained that the acquired sample may not have been representative of native brine.

Resistivity measured salinity values were compared with formation water samples taken with the MDT (modular formation dynamics tester) tool. Log-estimated salinity for the Broom Creek Formation at the Flemmer-1 well was approximately 54,000 mg/L, with a range of 32,000 to 77,000 mg/L.

Resistivity log-based estimates of salinity for the Broom Creek Formation at the Flemmer-1 well ranged from 32,000 to 77,000 mg/L. This range of salinity estimates exceeds the 10,000-mg/L minimum salinity criteria established by the U.S. Environmental Protection Agency (EPA) for a prospective CO_2 storage formation

Microfracture tests were performed in the Opeche and Broom Creek Formations. The test was performed in the Opeche Formation at a depth of 6261 feet, yielding results with good confidence in terms of mechanical integrity: a breakdown pressure of 5320 psi and a calculated fracture pressure gradient of 0.847 psi/ft. The results of the microfracture test in the Broom Creek Formation (6358 ft depth) provided less confidence. An initial breakdown pressure of 4950 psi was measured; however, subsequent tests resulted in fracture reopening pressures increasing to 5214, 6255, and finally 7293 psi. Fracture reopening pressures should generally be lower than the initial breakdown pressure. These anomalous results indicate a possible plugging of the tool's probe by solids as the test was performed.

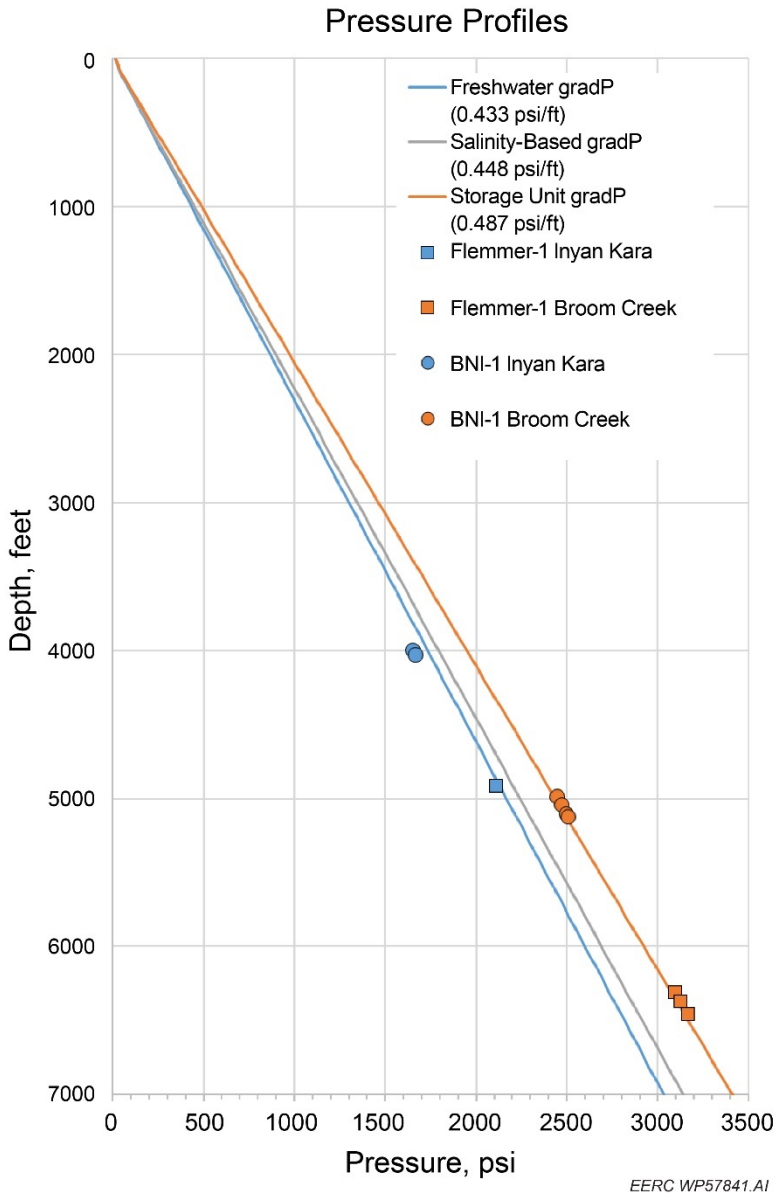
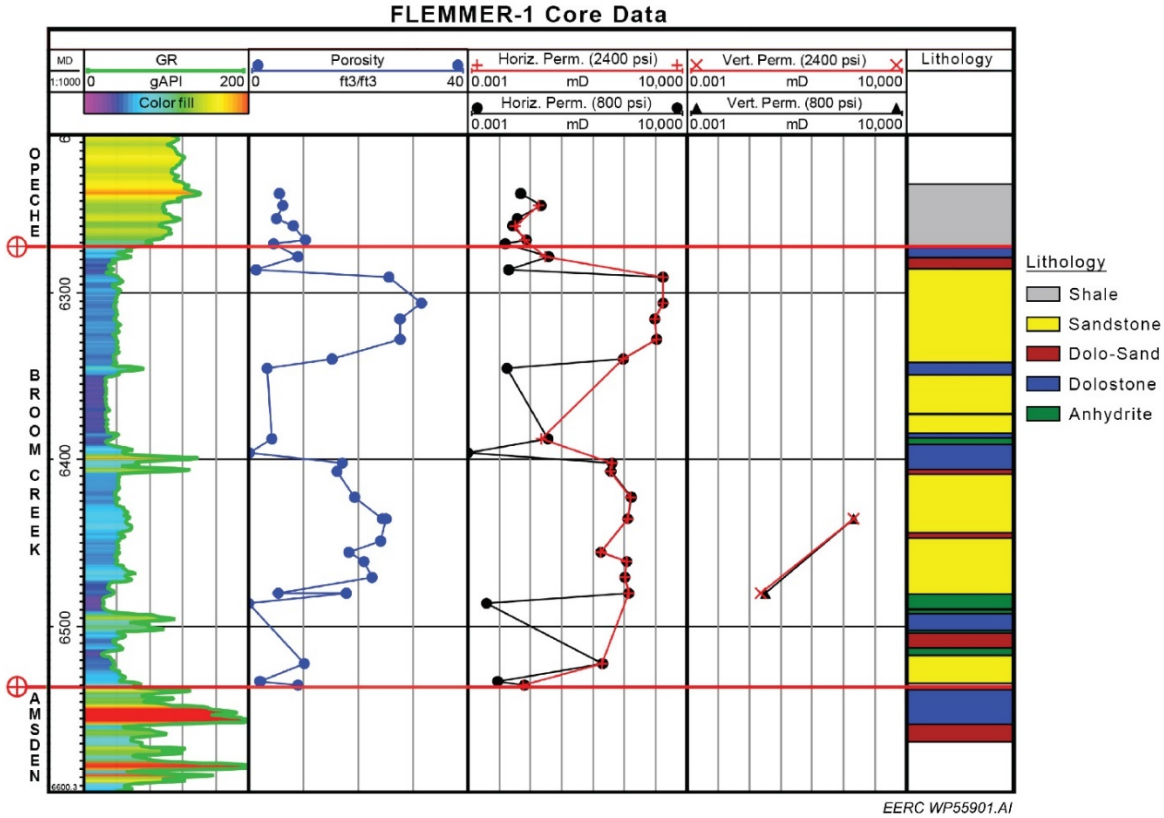


Figure 4. Pressure test data collected from the Flemmer-1 and BNI-1 wells plotted against standard freshwater and saline pressure gradients as well as a calculated local gradient for the BNI-1 location.

At the Flemmer-1 well location, the Broom Creek Formation is nearly 265 feet thick with approximately 170 feet of sandstone (Figure 5) comprising four separate layers ranging 17 to 53 feet in thickness. Laboratory tests on core samples from the sandstone horizons of the Broom Creek Formation show an average porosity of nearly 24% (ranging from 18% to 32%) and an average permeability of 400 mD (ranging from 144 to 1811 mD) (Figure 6) (Appendix A).

EERC WP57843.AI

Figure 5. Section of sandstone core from the Broom Creek Formation.



EERC WP55901.AI

Figure 6. Laboratory measurements of porosity and permeability from Flemmer-1 core samples correlated with the core GR log and lithologic interpretations. Permeability data are plotted on a logarithmic scale.

BN-1 Well

Six pressure tests were conducted in the BNI-1 well: two in the Inyan Kara Formation, one in the Opeche Formation, and three in the Broom Creek Formation. The Inyan Kara tests were conducted at depths of 3996 and 4030 feet and yielded pressure measurements of 1652 and 1666 psi, respectively. These measurements showed relatively good agreement with the calculated pore pressure gradient, both within the round-off error of 0.410 psi/ft (Figure 4). As with the Flemmer-1 well, the BNI-1 Inyan Kara pressure measurements indicate a subnormally pressured formation in comparison to a freshwater hydrostatic gradient. Permeability estimates from the tests ranged from 155 to 229 mD. A pressure test conducted at a depth of 4897 feet, within the Opeche Formation (near the contact with the Broom Creek Formation), yielded a pressure measurement of 2446 psi and a pressure gradient of 0.488 psi/ft. The three pressure tests conducted in the Broom Creek Formation (depths of 5041, 5104, and 5124 ft) yielded pressure measurements of 2471, 2499, and 2508 psi, all agreeing with a pressure gradient of 0.487 psi/ft (Figure 4).

Analysis of a fluid sample from the Inyan Kara Formation showed brine salinity to be approximately 20,000 mg/L TDS. An analysis of four fluid samples from the Broom Creek Formation yielded salinities ranging from 60,800 to 65,700 mg/L TDS. Salinity estimates derived from the resistivity log ranged from 40,000 to 60,000 mg/L. The measured salinity values are in close agreement with the derived salinity values for the Broom Creek Formation. This agreement suggests the derived salinity values for the Broom Creek at the Flemmer-1 well are close to true values and that salinity of the Broom Creek Formation is well above the EPA minimum 10,000-mg/L criteria for a prospective CO_2 storage horizon.

Resistivity measured salinity values were compared with formation water samples taken with the MDT tool. Log-estimated salinity for the Broom Creek Formation at the BNI-1 well was approximately 57,800 mg/L, with a range of 40,000 to 60,000 mg/L.

As with the Flemmer-1 well, microfracture tests were performed in the Opeche and Broom Creek Formations. Two tests were performed in the Opeche at depths of 4873 and 4897 feet, just above the contact with the Broom Creek. The test at 4873 feet resulted in a maximum applied pressure of 7560 psi, but no discernable formation breakdown was observed. The test near the Opeche–Broom Creek contact (4897-ft depth) showed formation breakdown occurred at a pressure of 5897 psi, yielding an unusually high fracture pressure gradient of 1.201 psi/ft.

The Broom Creek Formation at the BNI-1 well is nearly 275 feet thick, of which approximately 125 feet of sandstone comprises three separate layers ranging from 16 to 90 feet in thickness. Laboratory tests on samples from the sandstone horizons of the Broom Creek at the BNI-1 well show an average porosity of nearly 23% (ranging from 19% to 30%) and an average permeability of 700 mD (ranging from ~360 to over 2600 mD) (Figure 7) (Appendix A).

Based on reservoir quality parameters compiled by Shogenova and others (2015), the Broom Creek Formation falls into the high-quality or preferred-quality classification of CO_2 storage reservoirs (Table 3).

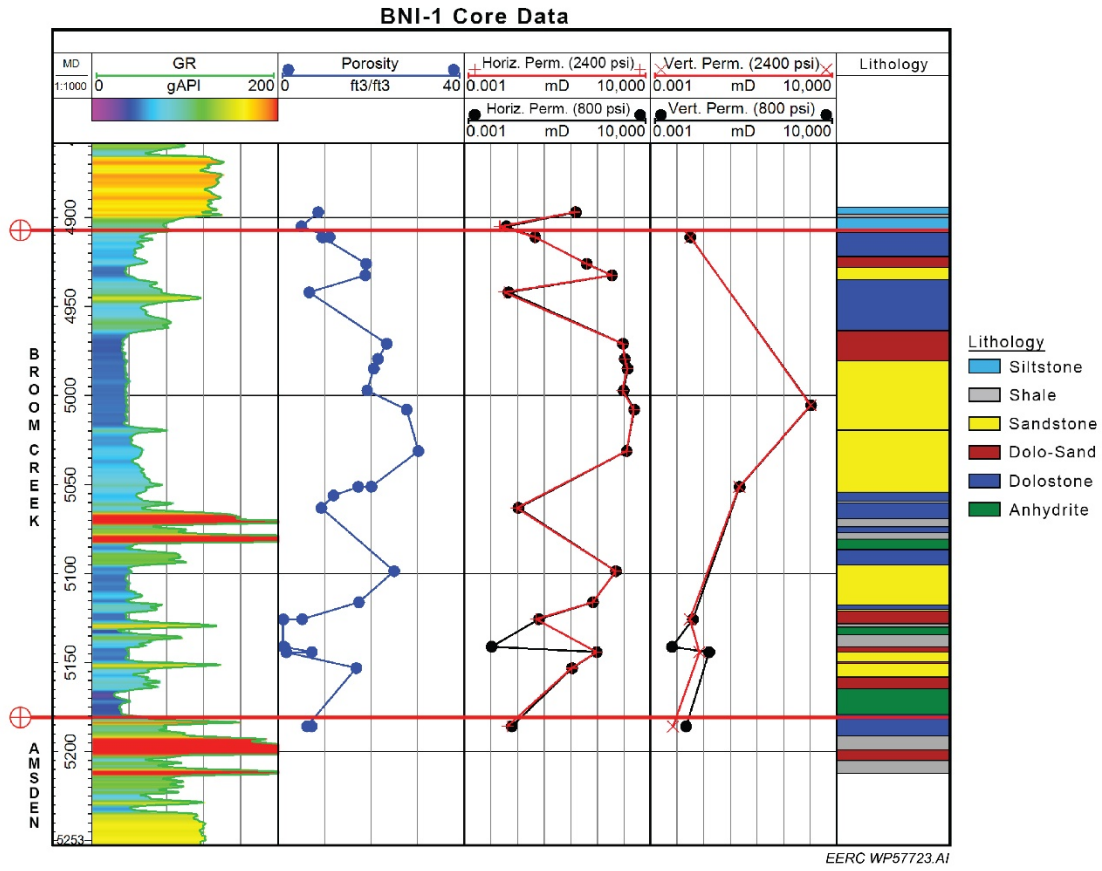


Figure 7. Laboratory measurements of porosity and permeability from BNI-1 core samples correlated with the core GR log and lithologic interpretations. Permeability data are plotted on a logarithmic scale.

Table 3. Relative Reservoir Quality as a Function of Porosity and Permeability (modified from Shogenova and others, 2015)

			Average Values for the Broom Creek Formation			
General CO_2 Storage Reservoirs			**Flemmer-1**		**BNI-1**	
Reservoir Quality	**Permeability, mD**	**Porosity, %**	**Permeability, mD**	**Porosity, %**	**Permeability, mD**	**Porosity, %**
High	≥500	≥25				
Preferred	>300	>20	400	24	700	23
Good	50–250	15–20				
Moderate	50–250	10–15				
Cautionary	<200	<10				
Low	<10	<15				

Siesmic Source Testing

In an effort to tie existing 2-D seismic lines to geophysical log and core analysis data from the BNI-1 stratigraphic test well, a new 5-mile-long 2-D seismic line was acquired. The data for the new seismic line were generated using an 850-lb accelerated weight drop source and autonomous three component geophones. Although this approach has been previously used to image sandstone reservoirs at depths of up to 6000 feet, the results of this seismic survey were of low quality. Examination of the data revealed a lack of direct signal arrivals and visible reflections after image stacking, indicating significant attenuation of the seismic signal. This attenuation is likely due to the 2-D survey being conducted across reclaimed mine land that has nearly 80 feet of near-surface fill. The nature of the acquired data highlighted the need to better understand the impacts of reclaimed mine land on seismic signal attenuation. To that end, a seismic source test Spearfish, and Piper Formations. Subsequent geologic models were built to investigate stacked storage potential. The later models incorporated the Inyan Kara Formation and overlying Skull Creek Formation seal and the Deadwood and Black Island Formations and overlying Icebox was conducted near the MRYS site in fall 2019 to assess the feasibility of acquiring 3-D seismic data over reclaimed mine land and to determine what type of seismic source is needed to do so. The source test involved evaluating vibroseis trucks and dynamite shots of different weights, 5.5, 7.7, and 11 lb, and depths at two test sites, one on reclaimed mine land and the other on unmined land. Signals from dynamite shots at depths of 20 feet or more below the reclaimed interval were less affected by the reclaimed interval than data from shallower dynamite shots and data from the vibroseis trucks.

Results of the source test indicated that to collect quality 3-D seismic data over reclaimed mine land with ~80 feet of fill requires using dynamite shots with 11-lb charges placed at a depth of at least 20 feet. This configuration produces sufficient signal to image formations at least 9600 feet below the land surface. North Dakota’s major coal-fired electric generation facilities are minemouth plants. There are promising geologic storage targets directly below the proximity of these power plants and their associated coal mines. Understanding the effort needed to properly characterize promising storage formations beneath reclaimed land will inform the creation of site development and monitoring, verification, and accounting (MVA) plans in North Dakota and elsewhere with similar mining practices.

GEOLOGIC MODELING AND SIMULATION

Introduction

A geologic model, based on geophysical and geological observations and interpretations, was created comprising a 3-D representation of the subsurface geology and hydrogeology of the prospective CO_2 storage complex (Figure 8). The resulting geologic model is the foundation for reservoir simulation and depicts the storage reservoir formation(s) and confining zones (seals). The necessary distributed geologic properties for dynamic reservoir simulations of CO_2 injection include 1) facies/lithology (bodies of rock with similar geologic characteristics), which is used to assign relative permeability data; 2) effective porosity; 3) matrix permeability; 4) temperature, and 5) pressure.

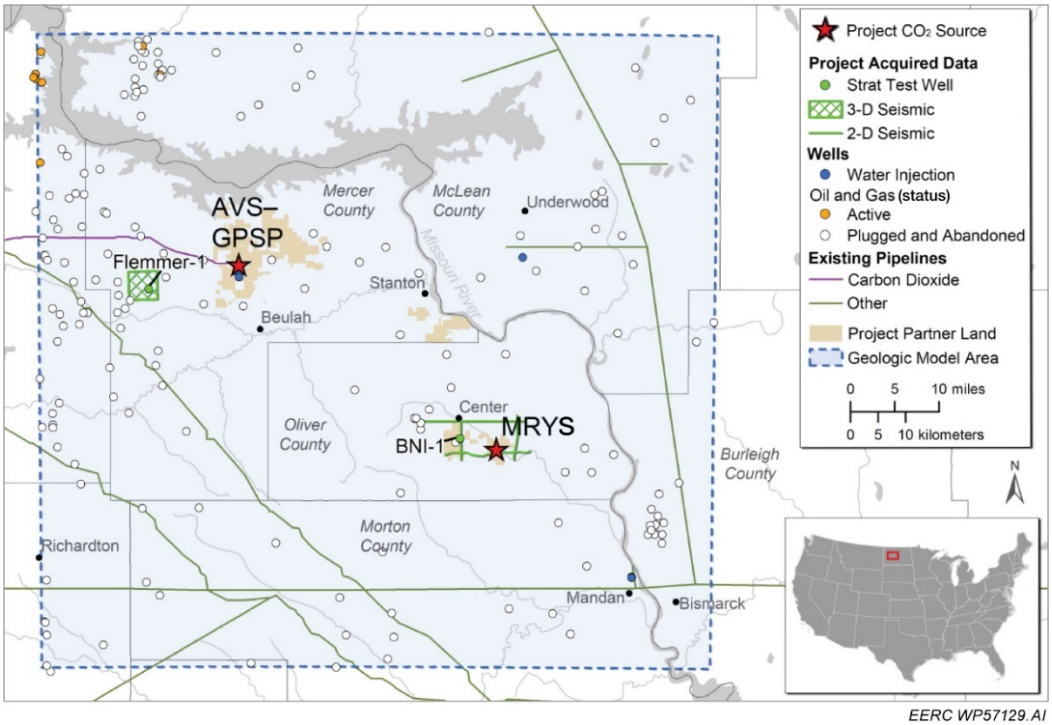


Figure 8. Map showing the North Dakota CarbonSAFE study area, which includes two North Dakota coal-based power plants: BEPC's GPSP in northwestern Mercer County and MRYS in central Oliver County. GPSP sits directly adjacent to AVS. The extent of the geologic model created for this study is depicted by a blue rectangle that encompasses an area of 5544 square miles.

Dynamic reservoir simulations enable greater insight on storage capacity, formation injectivity (how fast the CO_2 can be injected), and containment (risks associated with potential leakage from the reservoir or storage complex). The primary purposes for developing reservoir injection simulations are to investigate project development alternatives, estimate future operational capabilities or constraints, and predict the movement or behavior of injected CO_2 and other fluids in the subsurface. Examples of activities supported by simulation results are surface facility design, optimization of operational scenarios to increase capacity or minimize risks, and development of effective monitoring strategies.

Geologic models were built for use in numerical simulation of CO_2 injection to evaluate the potential of storing at least 50 Mt of CO_2 over a 25-year time frame. The geologic models covered a study area over 5500 square miles that include both GPSP in northwestern Mercer County and MRYS in central Oliver County (Figure 8). Model construction and numerical simulation efforts focused primarily on the Broom Creek Formation and overlying seals of the Opeche, Minnekahta, Spearfish, and Piper Formations. Subsequent geologic models were built to investigate stacked storage potential. The later models incorporated the Inyan Kara Formation and overlying Skull Creek Formation seal and the Deadwood and Black Island Formations and overlying Icebox Formation seal. Numerical simulations of CO_2 injection evaluated the feasibility of CO_2 storage near GPSP and MRYS in multiple injection scenarios, including single-formation and multiple-formation stacked storage. Additionally, geochemical simulation investigated CO_2-trapping mechanisms within the Broom Creek Formation over a 100-year postinjection period.

Geologic Model Construction and Numerical Simulation of CO_2 Injection

An initial Broom Creek model was constructed during the early stages of the project with formation top depths, well logs, and 2-D and 3-D seismic horizons. The model was used during preliminary simulation scenarios and for an independent evaluation of NRAP tools. The model was later updated to include core analysis results and 3-D seismic interpretations. The final updated model was used for all reported simulation results, including the history-match of two existing Broom Creek water disposal wells (ANG #1 and ANG #2) near GPSP.

Using Schlumberger's Petrel software (Schlumberger, 2016), construction of geologic models for the Inyan Kara, Broom Creek, and Deadwood–Black Island Formations and their overlying seal formations used project-acquired data sets (e.g., stratigraphic test well data, 3-D surface seismic survey) and publicly available data (e.g., well logs, formation top depths, core samples). The geologic models provide the basis for subsequent numerical simulation of CO_2 injection. Model construction for each formation is described in more detail in Appendix B.

Numerical simulations of CO_2 injection evaluated the feasibility of CO_2 storage at the GPSP and MRYS sites using Computer Modelling Group Ltd. (CMG) GEM and CMOST software (Computer Modelling Group, 2018). GEM simulation offers insight into the physical and geochemical processes that are expected to occur in the subsurface during injection of CO_2 into the three geologic formations. CMOST helps optimize the potential well locations and the number of wells required to meet storage target goals while also offering a sensitivity analysis of geologic parameters.

The simulated injection scenarios investigate the feasibility of reaching a cumulative CO_2 injection target of 50 Mt near GPSP and 100 Mt near MRYS over 25 years of injection. The numerical simulations investigate 1) optimization of potential well locations and number of wells required to reach the storage target and 2) estimation of the areal extent of CO_2 plumes at the conclusion of 25 years of CO_2 injection.

CO_2 injection was simulated at a constant rate of 2 Mt/year for GPSP and 2 and 4 Mt/yr for MRYS. The 2-Mt/yr rate meets the minimum requirement for commercial scale as defined by the CarbonSAFE program. The higher rate of 4 Mt/yr ensures bracketing the rate that may be captured from MRYS through Project Tundra.

Results of Numerical Simulations of CO_2 Injection

Several simulation scenarios evaluated the feasibility of CO_2 storage and successfully met the storage target near each coal-fired power plant. Multiple models were generated with varying geologic properties (e.g., facies distributions, porosity, permeability) in an effort to account for geologic uncertainties. The results reported in this document represent the median of expected geologic properties within the reservoir.

Scenario 1 – GPSP Injection into Broom Creek Formation

The primary target for CO_2 injection for GPSP is the Broom Creek Formation. Numerical simulation results indicated that two vertical injection wells could achieve the injection target of

50 Mt over 25 years. The optimum well locations for these two vertical wells (Figure 9) required a significant distance between them and the ANG water disposal wells to minimize any pressure and/or injectivity effects from simulated CO_2 injection. The simulated CO_2 plume extent is approximately 14 square miles for the two injector wells for the GPSP site (light blue-shaded area in Figure 9).

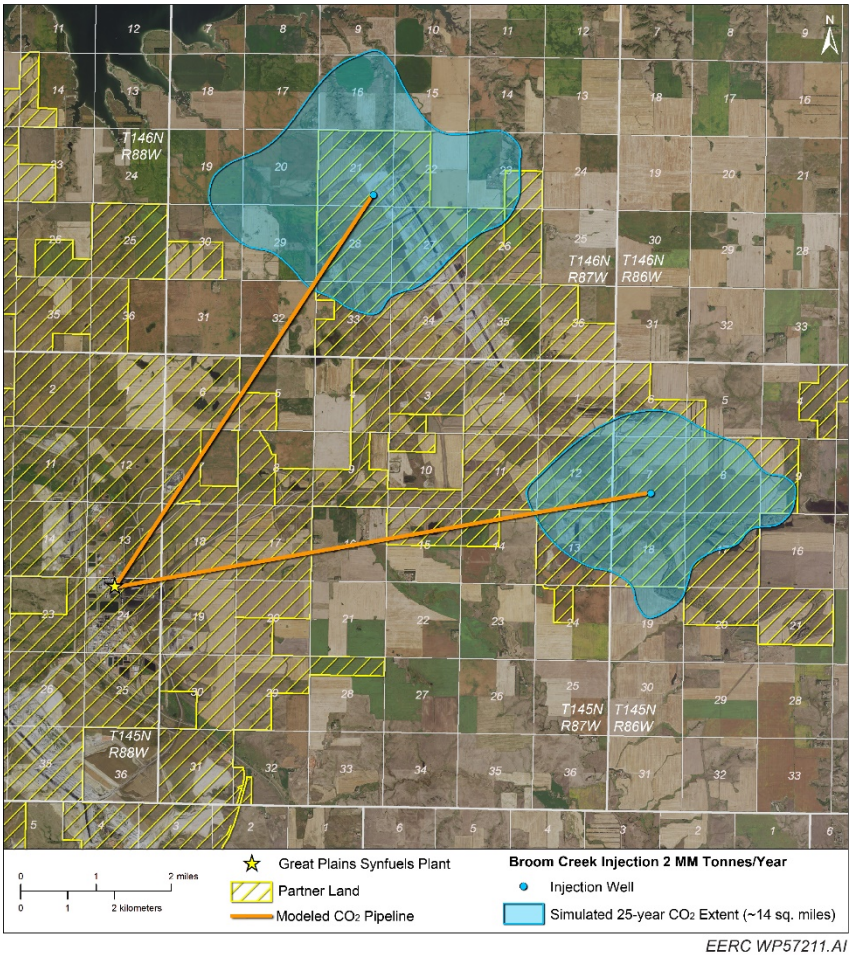


Figure 9. Scenario 1 – CO_2 plume map for two potential vertical wells for the GPSP site in the Broom Creek Formation after the injection of 2 Mt per year of CO_2 for a period of 25 years.

Scenario 2 – MRYS Injection into Broom Creek Formation

Numerical simulations for the MRYS site targeting the Broom Creek Formation showed that at least four vertical wells would be needed to reach the CO_2 injection target of 100 Mt over 25 years (i.e., injection rate approximately 1 Mt per well, per year). Multiple simulations helped select the optimal locations for four vertical wells based on the most favorable geologic conditions (e.g., permeability) while attempting to maximize partner land (Figure 10). The well locations were selected to also avoid pressure interference between wells during injection. The total CO_2 plume area is just under 20 square miles.

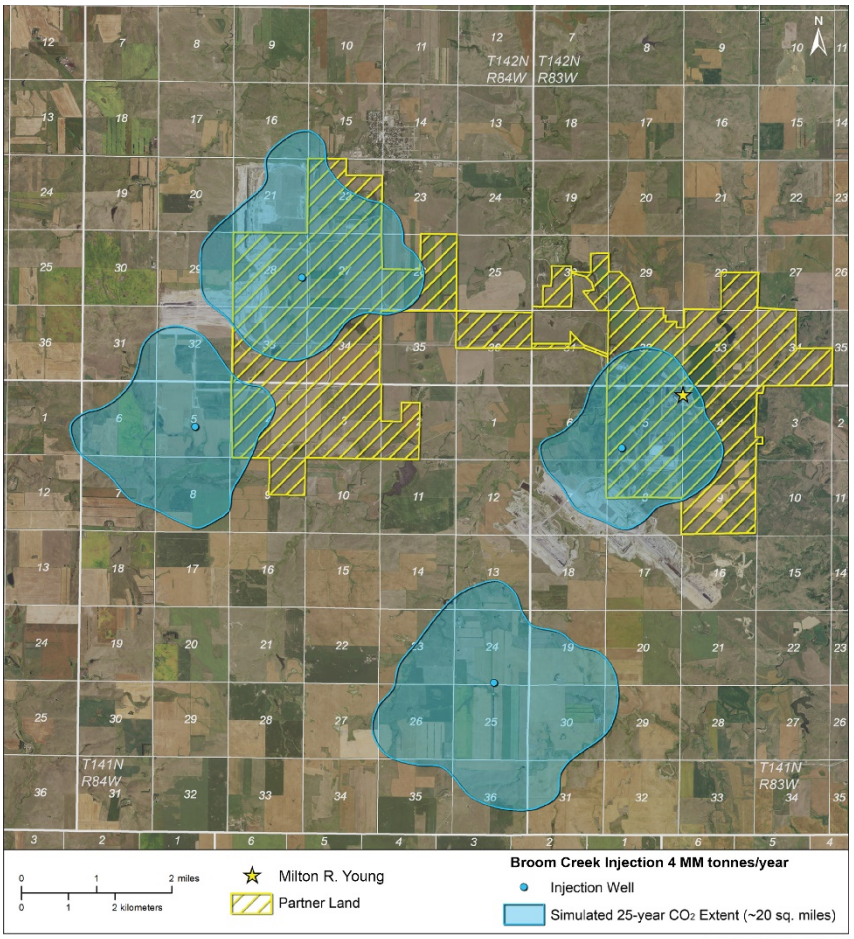


Figure 10. Scenario 2 – CO_2 plume from simulation results at the end of 25 years CO_2 injection for four vertical wells for MRYS site in Broom Creek Formation. Pipelines were not modeled for this scenario.

Scenario 3 – MRYS Injection into the Inyan Kara, Broom Creek, and Deadwood Formations (Stacked Storage Concept 1)

The stacked storage concept to meet the 25-year CO_2 injection target of 100 Mt (i.e., 4 Mt/yr) at the MRYS site aims to minimize the areal extent of the CO_2 plume through injection into multiple geologic formations (Figure 11). The primary objective is to try to keep as much of the areal CO_2 plume under partner-owned land as compared to the single formation plume generated in Scenario 2 for the Broom Creek Formation. This stacked storage scenario evaluated the Inyan Kara, Broom Creek, and Deadwood Formations and comprised two separate well pads (Figure 12). The first pad consisted of a vertical injection well into the Broom Creek Formation, two horizontal injection wells into the Inyan Kara Formation, and one horizontal well into the Deadwood Formation. The second pad consisted of a vertical injection well into the Broom Creek Formation and a horizontal injection well into the Deadwood Formation.

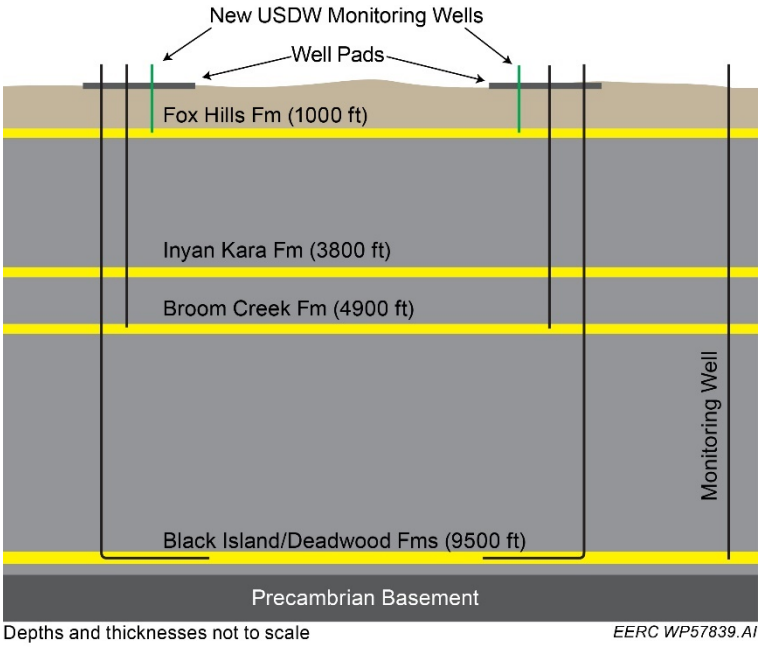


Figure 11. Generalized well configuration under investigation for the stacked storage of CO_2 in the Inyan Kara, Broom Creek, and Deadwood Formations at the MRYS site (depths and thicknesses not to scale).

Figure 12 shows the simulated CO_2 plume map for this stacked storage scenario, with a total CO_2 mass injection rate of 4.0 Mt/year. The green, blue, and red shading represents the areal extent of the CO_2 plume in the Inyan Kara, Broom Creek, and Black Island–Deadwood Formations, respectively. The total simulated CO_2 plume area for this well configuration and injection strategy is approximately 21.3 square miles for a cumulative CO_2 mass of 25 Mt in the Inyan Kara, 50 Mt in the Broom Creek, and 25 Mt in the Deadwood Formation.

Scenario 4 – MRYS Injection into the Broom Creek and Deadwood Formations (Stacked Storage Concept 2)

A second stacked storage scenario at the MRYS site comprised two wells pads, each having a vertical injection well into the Broom Creek Formation and a horizontal injection well into the Deadwood Formation. The Inyan Kara Formation was not considered a viable storage target as part of this scenario because of the large areal extent of the CO_2 plume that was observed in the formation during the investigation of the previous stacked storage scenario (see Figure 12).

The simulated CO_2 extent for this stacked storage scenario involving 2.0 Mt/year into the Broom Creek Formation and 2.0 Mt/year into Deadwood Formation (total of 100 Mt CO_2 stored over 25 years of injection) is shown in Figure 13. The total areal extent of the CO_2 plume for this injection strategy is approximately 16.2 square miles, which is smaller than Scenarios 2 and 3 for the MRYS site and best utilizes the pore space beneath partner-owned land.

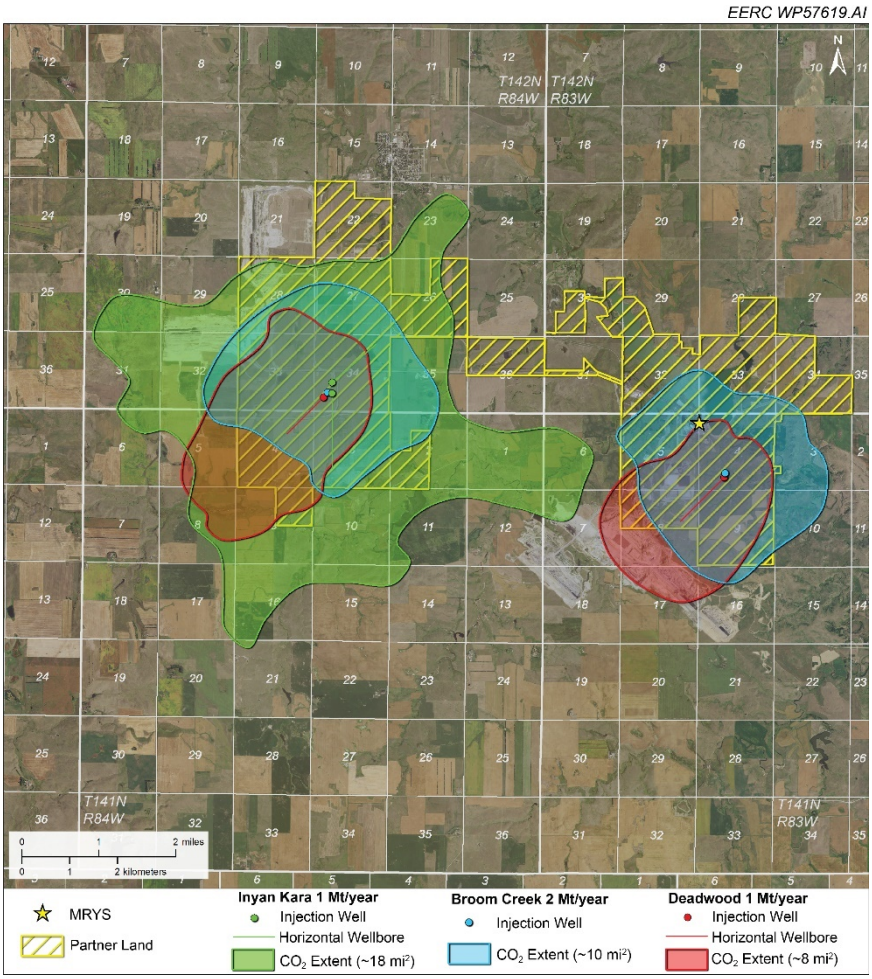


Figure 12. Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt into the Broom Creek Formation and 25 Mt into each of the Inyan Kara and Deadwood Formations. Pipelines were not modeled for this scenario.

To move forward with this stacked storage scenario, collection of new geologic core from the Deadwood Formation and collection of additional 3-D seismic data are necessary to reduce the uncertainties in defining the optimal number and configuration of injection wells that are needed.

Simulation Scenario Summary

The numerical simulation efforts have shown that the storage resource of the different formations targeted by the North Dakota CarbonSAFE project are more than adequate to accept between 50 and 100 Mt of CO_2 over a 25-year period (i.e., CO_2 injection rates of 2 Mt to 4 Mt per year). The investigation revealed that Scenario 1 provided a satisfactory approach for the GPSP site and Scenario 4, using stacked storage in the Broom Creek and Deadwood Formations, provided an optimal approach for the MRYS site, i.e., achieved the required storage capacity and injectivity while at the same time maximizing the amount of pore space that was associated with partner-owned land. Table 4 provides a summary of the injection scenarios that were investigated in this study.

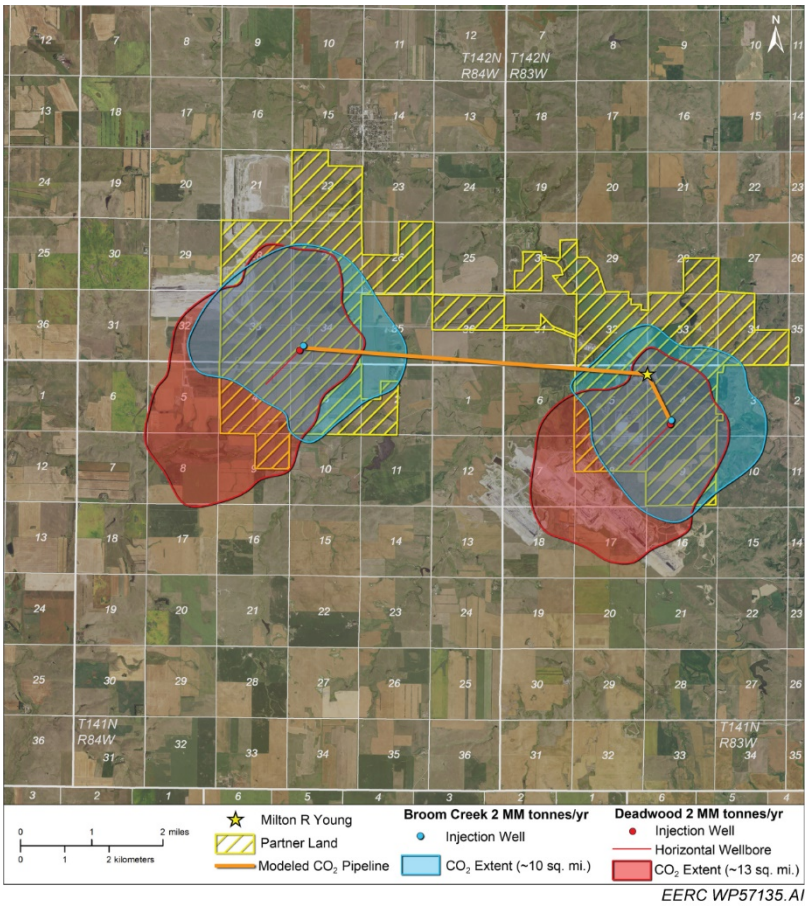


Figure 13. Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt each into the Broom Creek and Deadwood Formations.

Table 4. Summary of CO_2 Injection Scenarios

Scenario	Formation	Site	No. Wells and Configuration	CO_2 Stored, Mt	CO_2 Plume Area, mi^2
1	Broom Creek	GPSP	Two verticals	50	14.0
2	Broom Creek	MRYS	Four verticals	101	19.9
3	Inyan Kara Broom Creek Deadwood	MRYS	Two horizontals Two verticals Two horizontals	25 50 25	21.3
4	Broom Creek Deadwood	MRYS	Two verticals Two horizontals	50 50	16.2

Delineation of Area of Review (AOR)

The North Dakota CO_2 storage regulations require that each storage facility permit delineate an AOR, which is defined as the region surrounding the geologic storage project where underground sources of drinking water (USDWs) may be endangered by the injection activity

(North Dakota Administrative Code [NDAC] § 43-05-01-05). The concern about endangerment of USDWs is related to the potential vertical migration of CO_2 and/or brine associated with every CO_2 storage project. Therefore, the AOR encompasses the region overlying free-phase CO_2, and the region overlying the extent of fluid pressure increase sufficient to drive formation fluids (e.g., brine) into a USDW, assuming pathways (e.g., abandoned wells or fractures) are present. The minimum pressure increase that results in a sustained flow of brine upward into an overlying drinking water aquifer is referred to as the "critical threshold pressure increase," and the resultant pressure as the "critical threshold pressure."

Based on in situ pressure measurements, the Broom Creek Formation is an overpressurized formation. Overpressured formations have pore pressures higher than the hydrostatic pressure expected for a horizon at a specific depth. The implication of an overpressured formation is that reservoir fluids already have the potential to reach the lowermost USDW (i.e., Fox Hills Formation [Figures 2 and 11]) in an open wellbore, even prior to planned CO_2 injection, resulting in an infinite AOR based on EPA definition (U.S. Environmental Protection Agency, 2013). To mitigate this situation, CO_2 storage site developers in this region will need to adapt a risk-based approach to AOR delineation as supported by recent literature (Birkholzer and others, 2014; Siirila-Woodburn and others, 2017; Bandilla and others, 2012). A risk-based approach uses leakage pathway models (i.e., reduced-order models [ROMs]) to evaluate the magnitude of leakage and potential severity of impact on the groundwater resources. The ROMs quantify the resultant leakage impacts to the lowermost USDW and delineate a detectable impact threshold based on measurements of pH or TDS. The quantification of leakage impacts results in a gradual decreasing level of risk as one moves away from the planned CO_2 injection well and determines what flux of formation water would be required to exceed the detectable threshold in the lowermost USDW at a given location. In determining this flux of formation fluid, one can introduce a reasonably conservative permeability in place of the open conduit dictated by the regulations and introduce non-USDW porous zones between the Broom Creek and Fox Hills Formations that will act as thief zones. These thief zones have the capacity to accommodate potential upward-moving formation fluids, thus reducing or eliminating the leakage flux into the Fox Hills caused by a specific formation pressure, and, thereby, increasing the allowable "critical pressure" (Dilmore, 2019). These thief zones, not accounted for in typical AOR delineations, will reduce the AOR extent for the CO_2 storage project and aid in defining a defensible AOR for overpressured formations.

A key aspect underlying the risk-based approach is determining a no-impact threshold concentration for the USDW. Using TDS as an example, two options have been considered:

1) Assume that most detection limits can only discern a 10% difference in concentration, which would yield a no-impact threshold concentration equal to 10% greater than the observed concentration. For example, if the baseline USDW TDS concentration was 1000 ppm, then the no-impact concentration would be (1000 + 10%) or 1100 ppm TDS.

2) The no-impact threshold concentration could be defined based on background/baseline groundwater concentrations using the background/baseline upper tolerance limit (UTL) with 95% confidence and 95% coverage, sometimes referred to as the UTL95/95. The no-impact threshold determined using this approach can be interpreted as being an approximation to the upper 95th percentile of the background/baseline distribution. It is designed to be a reasonable maximum on the likely range of background/baseline concentrations.

Having determined the no-impact threshold concentration, the "critical pressure" of the formation is then determined as being the pressure that would produce a flux of formation water into the USDW that would result in its TDS concentration exceeding the no-impact threshold value. Critical pressure would likely be determined using analytical or semianalytical models. Unfortunately, none of the current NRAP "leaking well" tools (Wellbore Leakage Analysis Tool [WLAT]) are good fits for the site-specific conditions of the North Dakota CarbonSafe projects. As an alternative, one could use the analytical solution compiled in FORTRAN by Cihan and others (2011). This approach would permit the use of site-specific permeabilities for the vertical migration conduit as well as introduce potential thief zones (e.g., the underpressured Inyan Kara Formation) that lie between the Broom Creek Formation and the lowest USDW.

Because the risk-based approach is still in development, an AOR has not been calculated for the Broom Creek Formation at the time of publication. Additional site-specific data will be collected during future site characterization activities (see Site Development Plan), which will provide supporting evidence for delineating a risk-based AOR for injection into the Broom Creek. Until in situ measurements can be collected, the Deadwood Formation is assumed to be normally pressured. As such, the critical pressure and corresponding AOR can be was calculated for the Deadwood Formation (Figure 14) using the approach prescribed by EPA. The relatively few (two) deep well penetrations (potential artificial leakage pathways) in the derived AOR greatly mitigate the level of effort to assess leakage risk within the AOR.

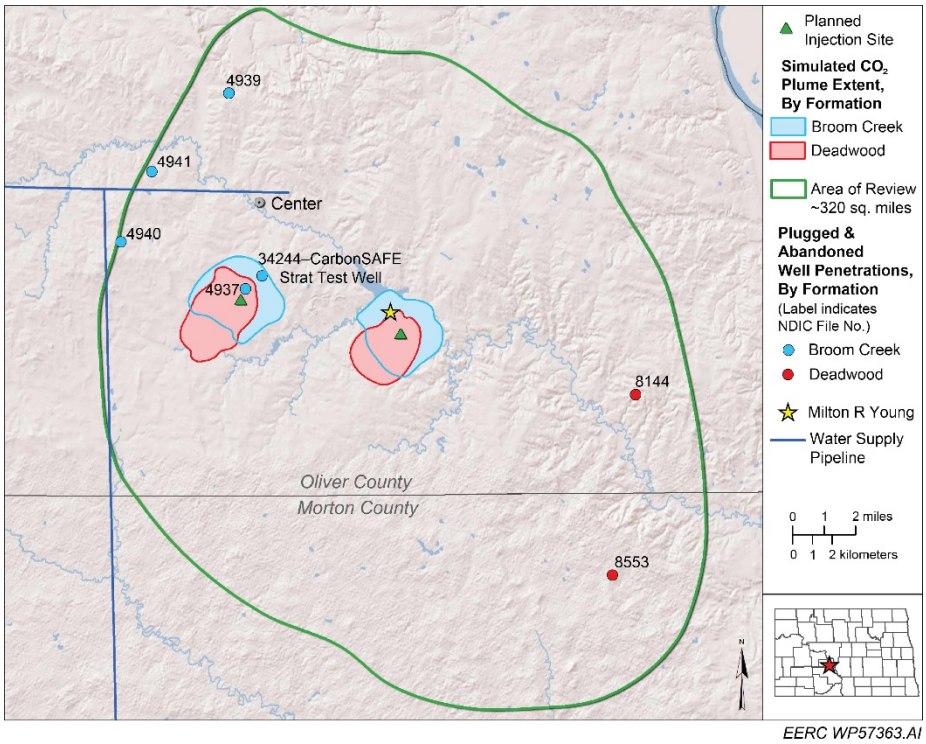


Figure 14. Calculated AOR for injection into the Deadwood Formation based on standard critical pressure calculation methods.

REGULATORY AND ECONOMIC ASSESSMENT

Regulatory Considerations

In December 2010, EPA finalized federal requirements for the geologic storage of CO_2 under the authority of the federal Safe Drinking Water Act UIC Program, creating a new class of injection well, Class VI. In April 2018, the NDIC Oil and Gas Division was granted primary regulatory authority (primacy) over Class VI injection well activities in the state of North Dakota. To receive primacy, North Dakota demonstrated, through application to EPA, that its Class VI UIC Program is at least as stringent as the federal standards. North Dakota Century Code (NDCC) Chapter 38-22 and NDAC Chapter 43-05-01 lay out the necessary pathway for securing a storage facility permit and a permit to construct a Class VI injection well. Guidelines for the storage facility and injection well permits are provided in Appendix C.

The geologic storage of CO_2 in North Dakota requires a storage facility permit as well as permits to drill and operate the CO_2 injection wells. Discussions with NDIC representatives revealed that the pursuit of a stacked storage concept may require multiple storage facility permits, i.e., at least one storage facility permit per storage formation (Helms and Fried, 2019). In addition, separate storage facility permits may be required for an individual formation depending on the location of the injection wells and the potential for the injected plumes of CO_2 to act independently of each other (rather than coalesce and act as a single plume). Given the current vision of stacked storage for Project Tundra, multiple storage facility permits will be required, i.e., a minimum of two storage facility permits (one for the Broom Creek Formation and one for the Black Island–Deadwood Formations) to as many as four storage facility permits (two for the Black Island–Deadwood Formations and two for the Broom Creek Formation). In addition, there will be a need to secure at least four drilling and operating permits to store the required amount of CO_2 (assuming injection rates of ~1 Mt per year of CO_2 injected per well). Although a multiple formation stacked storage permitting effort may extend the overall permitting time line, minimizing the areal extent of the CO_2 plume will minimize the AOR and the number of landowners required to secure the amalgamation of the pore space required for the storage operations.

A detailed time line for acquiring the permits for a CO_2 geologic storage site in North Dakota, which includes securing a storage facility permit as well as drilling and operating permits for the Class VI injection wells, is provided in Figure 15. The permitting time line comprises three groups of activities: 1) select and characterize site, acquire pore space rights, and perform baseline monitoring; 2) prepare plans and submit North Dakota storage facility and injection permits; and 3) receive NDIC approval of storage facility and injection permits, and amalgamate pore space. The 30-month permitting schedule represents a generic time line for securing the necessary permits for a dedicated storage site for CO_2 and includes an update of the project-specific risk assessment, which can be altered by project-specific circumstances. For example, should either of the proposed commercial storage projects in North Dakota elect to pursue the stacked storage of CO_2 into two or more of the candidate storage formations, i.e., the Inyan Kara, Broom Creek and Black Island–Deadwood Formations, multiple storage facility permits may be required, one for each of the target storage formations. This permitting requirement would dictate the drilling of a deeper stratigraphic well, one that would penetrate the Black Island–Deadwood Formation, as well as the collection and characterization of core samples from these formations. In addition, geologic models would

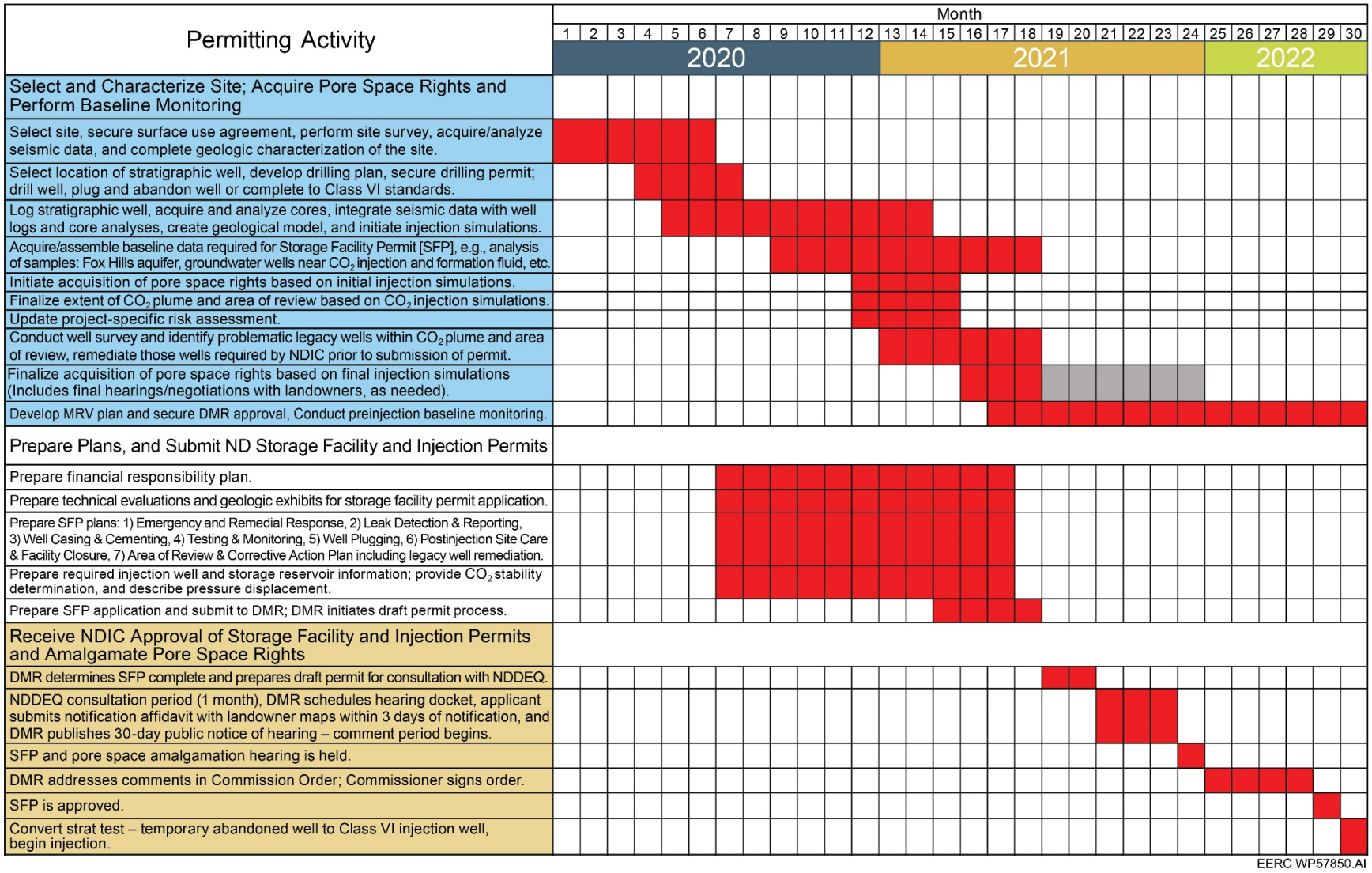


Figure 15. Permit acquisition time line for the Class VI permits of a CO_2 geologic storage site, which includes a storage facility permit and Class VI injection well-drilling and operating permits.

have to be developed to simulate the injection of the CO_2 into each of the formations and a monitoring program would be required to monitor CO_2 and brine movement in each of them. Lastly, the specific plans enumerated in the North Dakota regulations would have to be developed for each of the individual permits. Such an expansion of the permitting activities has the potential to significantly alter the schedule presented in Figure 15. However, the extent to which the schedule is impacted would, among other factors, depend upon the available resources of both the commercial operator and the governing regulatory agencies. The final permitting schedules for each of the proposed commercial storage projects will be derived from Figure 15 after the details regarding the CO_2 injection strategies for each project have been finalized.

Economic Analysis

Commercial Project Path Forward

Project Tundra is currently moving forward with the planning of a commercial dedicated geologic storage site for the CO_2 that is captured from MRYS Unit 2. Given this commitment, this discussion of a commercial project path forward for the dedicated geologic storage of CO_2 in North Dakota is focused on the commercial business model currently being pursued by Project Tundra, with an emphasis on the development of a cost framework for the dedicated storage of CO_2 in North Dakota within the context of that business model.

Given the data limitations associated with feasibility study projects (i.e., the general absence of detailed regional- and project-specific data), this dedicated storage cost model was populated with economic information that was gathered from several different sources: 1) literature values and cost-estimating algorithms for similar CCS projects that were developed by other organizations such as the DOE National Energy Technology Laboratory (NETL) (U.S. Department of Energy, 2014; 2018); 2) extrapolation of cost estimates that had been developed as part of other similar EERC projects; and 3) preliminary project-specific cost estimates that were available from the proposed North Dakota CarbonSAFE projects combined with recent federal/state regulatory developments.

The cost model was used as a preliminary screening tool to 1) estimate the cumulative present value of the costs for a generic storage project over a project lifetime of 25 years of operation and a 10-year postinjection period; 2) assess the importance of the various individual elements of the cost of storage; and 3) examine the normalized cost of storage, expressed as cumulative present value per ton of CO_2 stored per project year. As the project moves forward beyond the feasibility stage toward final design and construction, this cost framework will be populated with more project-specific data, permitting both an update of the dedicated storage costs as well as sensitivity analyses to identify those cost elements that offer the best opportunities for cost reduction of dedicated storage at the commercial scale.

The details of the cost model and the initial estimates of the cost of dedicated storage in North Dakota are provided in Appendix C; a brief summary of these results is presented here.

Conceptual Business Model of Project Tundra

The conceptual business model envisioned for Project Tundra is shown in Figure 16 and comprises the following four, independent operating entities:

- Electric power generation facility that produces electricity and generates a flue gas containing CO_2. The plant also produces excess steam, power, and water, which are available for sale.

- The CO_2 capture facility, which removes the CO_2 from the power plant flue gas prior to emitting it to the atmosphere and either sells the captured CO_2 to an EOR operator, where associated geologic storage of the CO_2 occurs, or provides it to a dedicated storage operator.

- The EOR operator buys the CO_2 from the CO_2 capture facility and then acquires the 45Q tax credits of $35 per tonne, which it provides back to the capture facility operator.

- The dedicated storage operator, which is likely to be the CO_2 generator in the CarbonSAFE projects, stores the CO_2 in a saline formation, acquiring 45Q tax credits of $50 per tonne, which is returned to the capture facility operator.

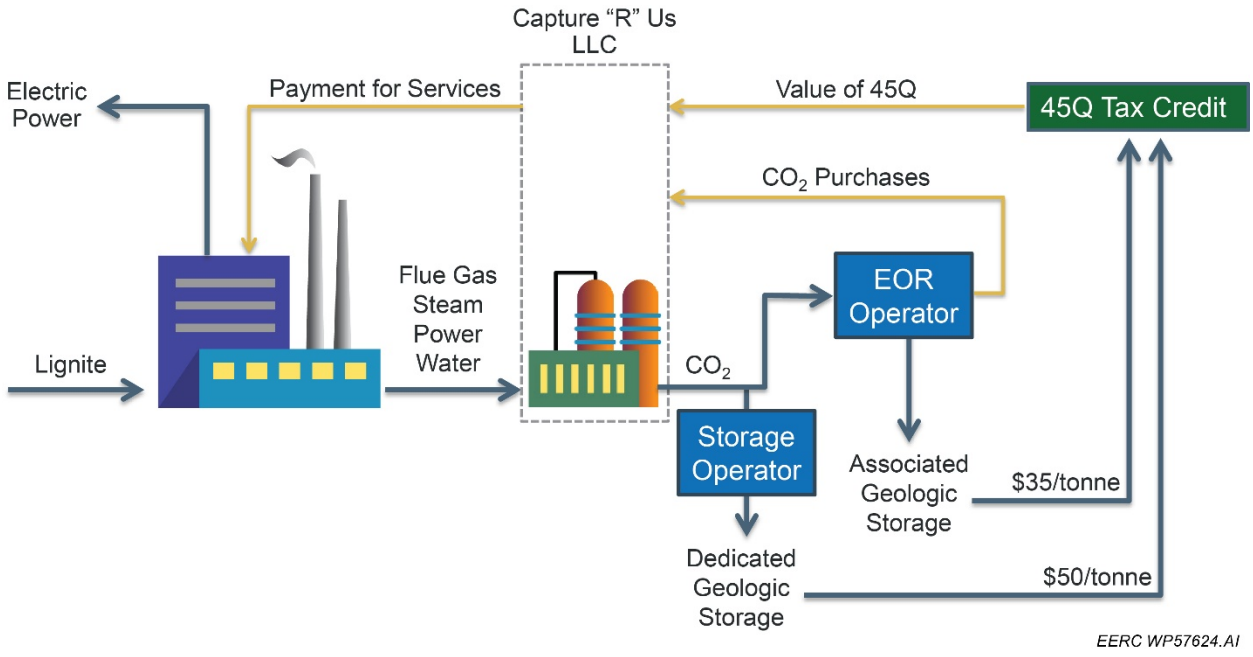


Figure 16. Conceptual business model for Project Tundra, which comprises the power generation facility, a carbon capture facility, an EOR operator, and a dedicated storage operator.

In summary, the flow of money associated with this business model has the electric power generation facility receiving payment for support services (i.e., power, steam, and water) from the capture facility, while the capture facility receives payment from the EOR operator for the CO_2 as well as 45Q tax credits from both the EOR and dedicated storage operator. In most cases, it is likely that the dedicated storage operator will be the source of the CO_2, which in the case of Project Tundra, is the power plant operator.[1] In this business model, the operator of the dedicated storage facility is the same as the capture facility.

Overview of Cost Framework for the Dedicated Storage of CO_2

Project Tundra is in the process of evaluating the economics of a CCS project in North Dakota as depicted in Figure 16. In general, at a feasibility study level, the project developer believes that constructing and operating a capture system can be profitable within the current 45Q tax credits of $35 per tonne for associated storage and $50 per tonne for dedicated storage. To complement this cost exercise, a cost model framework for estimating storage-related costs associated with implementing a commercial-scale CO_2 geologic storage project under the North Dakota UIC Program Class VI primacy regulations has been developed as part of the North Dakota CarbonSAFE project (see Appendix C).

The design basis for this storage cost framework assumes that CO_2 is captured at a coal-fired (lignite) power plant located in North Dakota and that the dedicated geologic storage of the captured CO_2 occurs via injection into deep saline formations. For the purposes of this document, "commercial scale" denotes a CO_2 capture rate of at least 2 Mt per year over an operational lifetime of at least 25 years, which is consistent with the goals of the North Dakota CarbonSAFE project. The modeling framework used in this study does not include the capital or operating costs associated with the CO_2 capture system; rather, it focuses solely on the incremental costs for 1) constructing and operating a pipeline for the transport of the CO_2 from the source to the dedicated storage site and 2) the associated activities involved with the permitting, operation, and closure of a CO_2 geologic storage site under the North Dakota Class VI primacy regulations.

Present Value Calculations

The costs for each year are expressed as a present value (PV) using a discount rate of 10% per year and Year 1 as the reference year, according to Equation 1.[2]

$$PV10 = \frac{R_t}{(1+i)^t} \qquad \text{[Eq. 1]}$$

Where:
R_t = Total cost during a single period *t*.
i = Discount rate, assumed to be 10% for the current work.
t = Number of time periods, years in the current work.

[1] Not shown in Figure 16 is the revenue that the CO_2 EOR operator will receive for its production and sale of the incremental oil that it generates as part of its EOR operations.
[2] A discount rate of 10% was chosen as a reasonable discount rate based on a review of literature sources (IHS Energy, 2016; U.S. Department of Energy, 2017),

This study uses "PV10" to denote the fact that a 10% discount rate is used in the analysis. The cumulative PV10 for the project is determined by summing the PV10s for each year of the project over the entire project lifetime (Equation 2).

$$PV10_{cumulative} = \sum_{t=1}^{n} \frac{R_t}{(1+i)^t} \quad \text{[Eq. 2]}$$

Where *n* represents the number of years included in the summation, which can range from $t = 1$ to $t = 41$ years.

It should be noted that economic models typically express the results as "net present value," or NPV10, which sums the PV of cash inflows and the PV of cash outflows over a period of time. Since this study focuses solely on incremental costs (PV of cash outflows), the term PV10 is used throughout the document. However, this quantity would be analogous to NPV10 and therefore consistent with other economic models.

Preliminary Model Results – Cumulative PV10 of Incremental Dedicated Storage Costs in North Dakota

An illustrative example of applying the cost model to a dedicated storage site in North Dakota is provided in Appendix C and is summarized here. As previously noted, these results represent feasibility-level estimates of the various cost items that are identified in Appendix C.

The cumulative present value (PV10) of the estimated incremental costs for the dedicated geologic storage of CO_2 in North Dakota is presented in Figure 17. These costs reflect the generic time line of 5 years of project planning and preparations (yellow), 25 years of CO_2 injection (blue), 10 years of PISC (green), and 1 year for compliance certification (red). As shown in the figure, the PV10 of the storage costs rises steeply from \$7.7MM to \$21.4MM during the project planning and preparation period (i.e., 2020 to 2024), with the dominant costs attributable to the characterization of the site and the drilling of a combination of wells, including a stratigraphic test well, two CO_2 injection wells, and a monitoring well. Following the initiation of CO_2 injection (2025), the PV10 of the costs continues to rise, but at a much slower rate, plateauing at \$28.8MM at the end of the 25 years of CO_2 injection, i.e., 2049. The primary storage costs during this period are dominated by the leasing of the pore space in combination with the cost of monitoring and the payment of fees to the North Dakota Administrative and Trust Funds. During the PISC phase, the PV10 of the storage costs edges slowly towards \$29.2MM, with the primary costs attributable to site monitoring, which is required by state regulations.

Cumulative PV10 per Ton of CO_2 Stored by Project Year

The cumulative PV10 cost of storage by year, normalized per ton of CO_2 stored, is presented over the project lifetime in Figure 18. As would be expected, the cumulative PV10 cost per ton is highest at the beginning of the project, as cost outlays are large and storage is nonexistent prior to the CO_2 injection phase. Consequently, the \$/ton at the first year of injection is approximately \$11.14/ton (2025). As injection continues, the cumulative PV10 per ton of CO_2 stored steadily decreases, approaching a value of approximately \$2.47, \$1.33, and \$0.58 per ton of CO_2 stored at

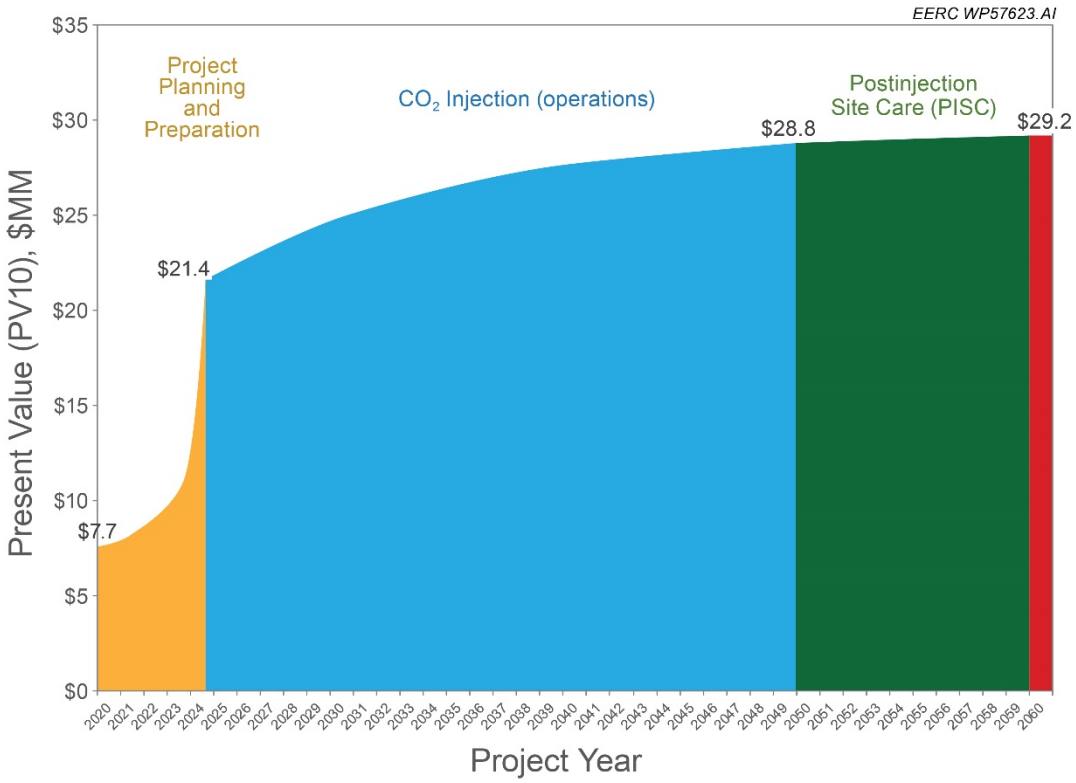


Figure 17. Cumulative present value (PV10) of the estimated costs for a generic geologic storage project injecting 2 Mt per year and comprised of project planning and preparation (5 years – yellow), CO_2 injection (25 years – blue), postinjection site care (PISC) (10 years – green), and compliance certification (1 year – red).

5, 10, and 25 years into the operations phase, respectively. This decrease reflects the fact that initial, up-front site characterization and well-drilling costs have been replaced with lower annual operating costs, i.e., pore space lease fees and monitoring costs, while the cumulative quantity of CO_2 that is stored continues to increase, i.e., 2 Mt per year. The decreasing numerator and increasing denominator therefore act to decrease the cost per ton.

After injection ceases, the PV10 cost per ton of CO_2 stored is projected to slightly increase as PISC-monitoring costs continue to be incurred but with no additional storage of CO_2. However, as shown in Figure 18, the approximate cost at the end of the project lifetime (2060) is estimated to be \$0.59 per ton of CO_2 stored, which is virtually indistinguishable from the \$0.58 per ton of CO_2 stored at the end of injection. These price-per-ton-of-CO_2-stored estimates are dependent upon the individual cost elements and how those cost elements are mapped onto the project time line. Therefore, the estimates shown in Figure 18 should be considered illustrative and not directly applicable to a specific storage site. However, the cost model can be used to conduct cost sensitivity analyses in support of commercial cost optimization studies, identifying future cost elements that have the greatest potential to impact the projected cost of CO_2 storage.

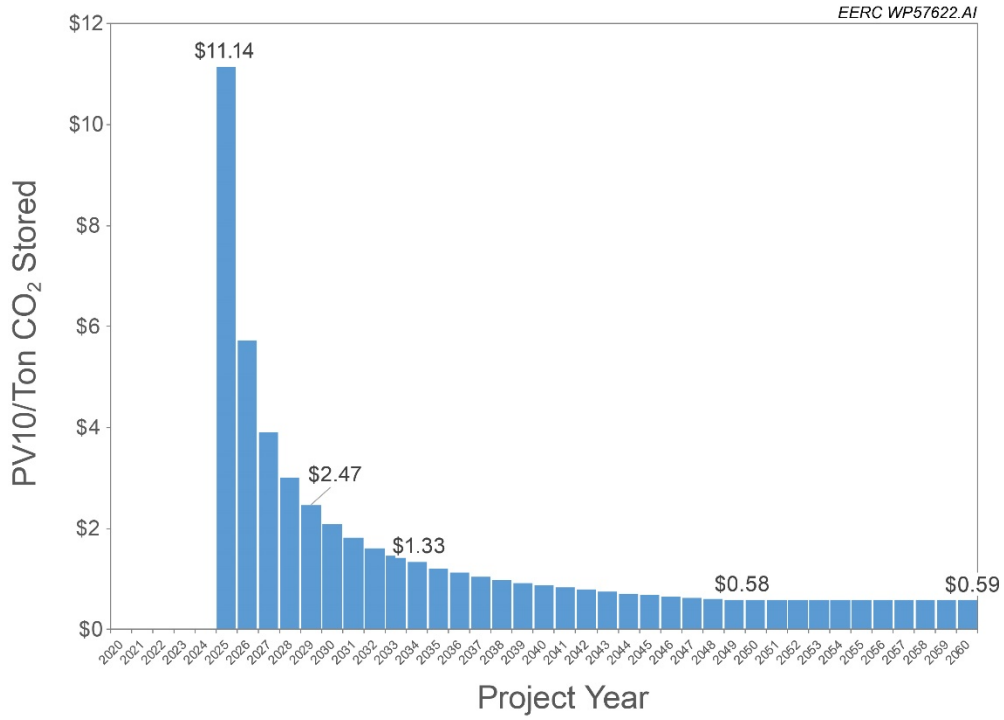


Figure 18. Cumulative PV10 of storage costs per ton of CO_2 stored per project year.

SITE DEVELOPMENT PLAN

This section summarizes the site development plan (Peck and others, 2019) that presented specific activities vital for the commercial development of a dedicated geologic storage site for CO_2 in North Dakota as well as identified actions needed beyond feasibility studies to inform site development. The plan examined the two potential storage sites, one near GPSP and the other near MRYS. The development plan contained three main components for each storage site: a site characterization plan, a CO_2 management strategy, and risk assessment and mitigation.

Site Characterization Plan

Site characterization activities aim to generate the site-specific data to address North Dakota regulatory requirements described in NDCC 38-22 and NDAC 43-05-01. Meeting the regulatory requirements for a storage facility permit will also address the requirements needed for approval of a Class VI permit to construct via EPA. Table 5 depicts the major proposed characterization activities and the permit requirements they address.

Table 5. Cross Reference of Major Site Development Activities Needed to Acquire a North Dakota CO_2 Storage Facility Permit

	Major Proposed Characterization Activities								
Major NDIC Permitting Requirements	**Core**	**Logging**	**Downhole Testing**	**Lab Testing**	**Modeling**	**Simulation**	**Seismic Collection**	**Baseline Sampling**	**New Fox Hills Wells**
Determine Plume Extent	X	X	X	X	X	X	X		
Determine Pore Space Amalgamation	X	X	X	X	X	X	X		
Geologic Properties of Injection and Confining Zones	X	X	X	X			X		
Regional Faulting Assessment	X						X		
Potential for Seismic Activity			X	X	X		X		
Geologic Maps and Cross Sections	X	X			X		X		X
Geomechanics of Confining Zones(s)	X	X	X	X	X				
Identify and Characterize Secondary Confining Zones		X	X		X		X		
Determine Area of Review		X	X	X	X	X	X	X	X
Baseline Geochemical Data	X			X				X	X
Baseline Water and Soil Data				X				X	X

Little CO_2 storage site-specific characterization data exist near MRYS because of limited local commercial oil/gas activity that has occurred within the target storage formations. Available regional data suggest that injectivity into the target storage formations is likely sufficient for the desired amount of CO_2; however, the limited nearby data elevate the degree of uncertainty. As a result, rigorous site characterization data collection will be required to move forward with MRYS to meet storage facility permit requirements, and these data collection activities are discussed in greater detail in D6 (Peck and others, 2019). Similarly, the GPSP project site will require further characterization activities to improve interpretations and reduce uncertainty. A future site characterization program for GPSP is discussed in greater detail in D6 (Peck and others, 2019).

CO_2 Management Strategy

MRYS and GPSP each generate enough CO_2 to meet the goals of DOE's CarbonSAFE program. Proposed capture at MRYS Unit 2 would nominally provide 3.1 Mt/yr for dedicated storage or EOR, with a composition suitable for either scenario as described in the site development plan (Peck and others, 2019). GPSP is currently capturing between 2.5 to 3 Mt/yr of CO_2, with a composition that is suitable for dedicated geologic storage or EOR.

Both project locations will require pipeline transport of CO_2 to injection sites. MRYS, assuming a dedicated storage scenario as described in the site development plan (Peck and others, 2019), would require pipelines to two injection well locations, with approximate distances of 4.5 miles and 0.2 miles, with each transporting nominally 1.8 Mt/year of CO_2 to single well pads. The GPSP project site could proceed under two different scenarios. One scenario involves constructing two new pipelines to transport captured CO_2 approximately 20 miles to target the Broom Creek Formation under a dedicated storage scenario. The second scenario uses the existing CO_2 pipeline to move CO_2 to operators in western North Dakota that are planning to develop EOR projects in sour oil fields.

Risk Assessment and Mitigation Strategies

Risk assessment is an integral part of the risk management process (see steps highlighted in blue in Figure 19) and comprises three components: 1) risk identification, 2) risk analysis, and 3) risk evaluation. A risk assessment was conducted for both the MRYS and the GPSP project storage sites in accordance with the international standard presented in ISO 31000 (International Organization for Standardization, 2009), with adaptations specific to conducting subsurface technical risk assessments of geologic CO_2 storage projects (Canadian Standards Association, 2012; Azzolina and others., 2017).

The results of this risk assessment are summarized in the site development plan (Peck and others, 2019) along with risk mitigation strategies that may be required moving forward with the commercial project.

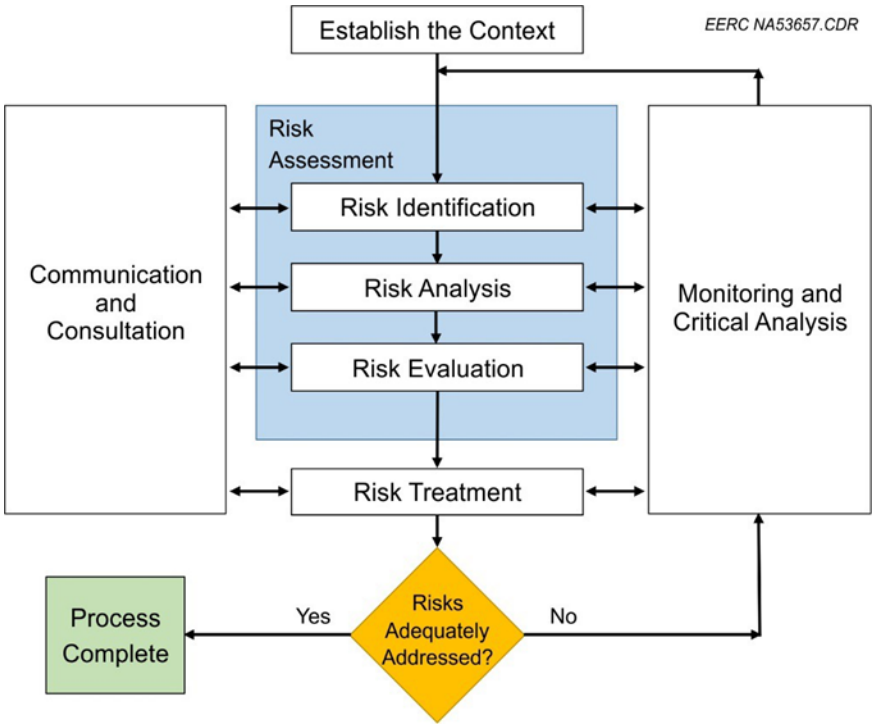


Figure 19. Risk management process adapted from the ISO 31000 (International Organization for Standardization, 2009) standard (Azzolina and others, 2017).

The MRYS and GPSP risk assessment was completed through a series of work group meetings from May 2018 through April 2019. The participants of these work group meetings included representatives of both the project developers and NDIC as well as subject matter experts from the EERC. During these meetings, both technical and nontechnical risks were identified and evaluated. The technical and nontechnical risks were grouped into the following principal risk categories:

Technical Risks	**Nontechnical Risks**
CO_2 Injectivity	Negative public reaction to geologic CO_2 storage project
Storage Capacity	Inability to adequately secure rights/access to pipelines and/or injection site
Containment – lateral migration of CO_2	Noncompliance with local/state/federal regulations and policies
Containment – lateral pressure propagation	Resource limitations prevent the project from proceeding
Containment – vertical migration of CO_2 or formation brine	
Induced Seismicity	

The risk assessment results revealed that there are currently no known potential risks, either technical or nontechnical, that would prevent the Broom Creek Formation from serving as the commercial-scale geologic CO_2 storage site near MRYS or GPSP. (Note: The stacked storage concept was not envisioned at the time that this risk assessment was conducted. See additional discussion below.) The available data and information suggest that the Broom Creek Formation has the potential to accommodate commercial-scale storage of 50 or 100 Mt of CO_2 (for GPSP and MRYS, respectively) and represents an excellent storage candidate for further investigation.

Although the risk assessment did not identify any risks that required immediate treatment, it was determined that all of the identified technical and nontechnical risks either required no action or were recommended for continued monitoring to ensure that they remained at acceptable levels. As such, a risk-based MVA program will need to be developed for either the MRYS or the GPSP project that will monitor these risks over time to determine whether any of them require the application of mitigation strategies over the course of the project lifetime.

It is important to note that prior to receiving a storage facility permit from NDIC, the Class VI regulations of North Dakota require that a corrective action plan be developed to identify, evaluate, and if necessary, remediate all legacy wells within the CO_2 plume that have the potential to be a source of CO_2 leakage to USDWs or the surface (NDCC § 38-22, Carbon Dioxide Underground Storage). Conversations with NDIC have indicated that legacy well remediation efforts can be addressed over time based on when the CO_2 plume is expected to reach those legacy wells that represent a potential pathway for CO_2 leakage (Helms and Fried, 2019).

OUTREACH

Outreach was an integral part of the overall North Dakota CarbonSAFE project and encompassed any project-related activity that involved contact or exposure beyond the project team. Just as the Phase II technical teams were charged with evaluating the technical feasibility of CCUS in the project area, so the Phase II outreach team was charged with evaluating the social feasibility of CCUS in the project area. At the same time, the research effort of North Dakota CarbonSAFE required interaction with various stakeholders where value was added by a dedicated and systematic outreach effort.

The goals of North Dakota CarbonSAFE outreach were to 1) foster an environment in which stakeholders could make informed decisions regarding their attitude toward the project within their community and the region through education and engagement and 2) gauge community receptiveness to a CCUS project. Thus outreach efforts during Phase II introduced the North Dakota CarbonSAFE project concept and Phase II activities to a variety of audiences, providing focused outreach in support of field activities and general information on the project and on permanent geologic storage of CO_2 captured from coal-fired energy facilities. The outreach team also sought to gauge the attitudes, perceptions, and concerns of residents of the study area, shown in Figure 20, and to build relationships and communication pathways within the overall project team to ensure effective outreach if the Phase II efforts found CCUS to be technically and socially feasible in the project area.

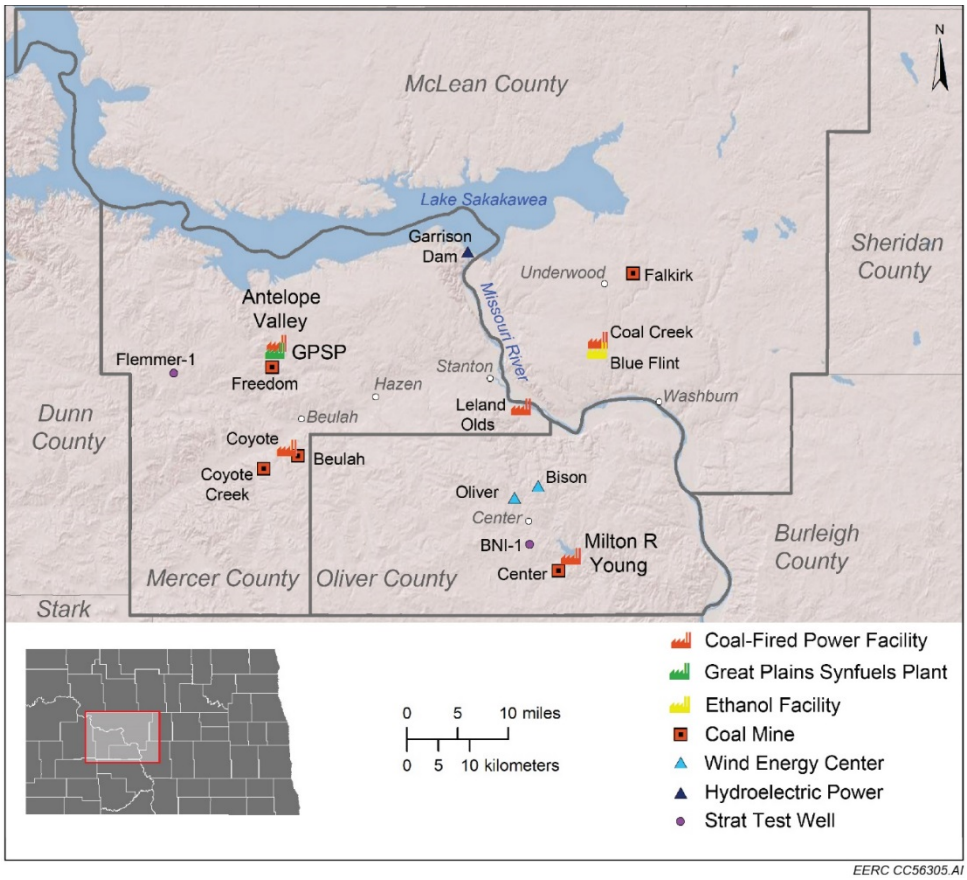


Figure 20. Two-county study area (Mercer and Oliver Counties), which contains most of the existing coal-based energy facilities in North Dakota and, along with McLean County, comprises "Coal Country."

Approach

Trust is the basic element in healthy relationships. Outreach actions were geared to build trust in the North Dakota CarbonSAFE project among a variety of audiences. At the heart of these efforts were ascertaining audience attitudes, perceptions, and concerns as well as providing accurate information that responded to the needs of the audience. Whether for the North Dakota CarbonSAFE project outreach as a whole or for individual components, the outreach process required building consensus on the objectives, learning about the audiences, developing a plan, creating materials, engaging the audiences, and documenting and assessing the engagement for improvement in the future.

Outreach was a coordinated effort that encompassed 1) North Dakota CarbonSAFE project team outreach, including members from both the EERC and partner organizations, 2) internal outreach beyond the project team to all EERC and project partners, and 3) external outreach. Internal outreach efforts created effective, informed team members who can act as knowledgeable spokespeople for the project. External outreach was triggered by any project-related activity that had public contact or exposure.

For North Dakota CarbonSAFE, outreach was guided by experiences in CCUS outreach developed under efforts such as the Plains CO_2 Reduction (PCOR) Partnership Program, part of DOE's Regional Carbon Sequestration Partnership's (RCSP's) Initiative (e.g., Daly and others, 2009; 2017; 2018), the RCSP Outreach Best Practices Manual, reflecting the collective experience of the DOE RCSP Initiative (U.S. Department of Energy, 2017); experiences for EOR and saline projects (e.g., Sacuta and others, 2016); and knowledge from commercial practices such as the models for evaluating public relations actions developed by Jim Macnamara (Macnamara, 2016).

Methodology

Establish an Outreach Advisory Board (OAB)

An OAB was established at the outset of the project to facilitate collaboration and a common vision and to coordinate outreach actions across the project with partners. OAB members included representatives of the EERC project outreach team, the EERC North Dakota CarbonSAFE project manager, and representatives of each of the North Dakota CarbonSAFE project partners.

Prepare and Implement an Outreach Plan

Effective outreach addresses five key questions developed by the PCOR Partnership Program outreach effort. An outreach plan answers those questions by defining goals, identifying audiences and engagement strategies, and laying out the time line for everything that needs to happen (Table 6). This living document was updated to respond to feedback and new information over the course of the project.

Table 6. Relating Outreach Plan Content to Key Project Story Questions

	Outreach Development Questions	North Dakota CarbonSAFE Outreach Plan Content
1	What are we trying to achieve and how do we best work together to achieve it?	• Goal, approach, and success measures • Partners' roles • Audiences • Implementation considerations and guidelines
2	What is our story?	• Outreach narrative, themes, and messages
3	How will audiences hear our story?	• Engagement strategies • Outreach tool kit
4	When do we need to tell the story?	• Preliminary outreach time line matched to technical time line and partner considerations
5	Who heard the story, and what do they think about it?	• Success measures/tracking/review and assessment

For the North Dakota CarbonSAFE project, an outreach plan was developed at the outset of the project in collaboration with the OAB. Methodology for key elements is outlined below. Outcomes of three elements are presented in the results section.

Characterize the Study Region

The DOE Best Practices: Public Outreach and Education for Geologic Storage Projects (U.S. Department of Energy, 2017) document describes the value of social characterization to:

- Understand how individuals perceive the need for, risks of, and tradeoffs of carbon storage.
- Provide insights about the different stakeholders and their levels of interest, information needs, and perspectives.
- Suggest appropriate ways to address those differing needs.

For the North Dakota CarbonSAFE project, social characterization was undertaken as a baseline assessment of stakeholders to help define, quantify, and provide context to the social picture in the study area; develop the outreach approach; and identify elements influencing the social feasibility of CCUS in the region. Social characterization entailed locating, reviewing, and compiling key existing sources. The results of this activity were incorporated into outreach messaging and assessment. Although the research undertaken in Phase II focused on the two-county study area, the information provided context for the surrounding counties as well as the state of North Dakota.

Identify Target Audiences

Seven target audience categories were identified for engagement during Phase II. These include partners (and their industry peers), media, elected officials and regulators, the education community, the general public, technical (peer-to-peer) personnel, and environmental nongovernment organizations (NGOs).

Construct Project Narrative, Themes, and Messages

Having a single coherent story was essential to create effective, informed team members acting as knowledgeable spokespeople for the project. The story needed to be consistent whether presented as a one-sentence sound bite, a paragraph synopsis, or a project fact sheet. The messages provided a foundation for expansion and customization over the course of the project. Regional characterization, known concerns, and audience attitudes and perceptions were key inputs to message development.

Implement Tracking and Assessment Techniques

The tracking and assessment practices were based on PCOR Partnership Program outreach protocols under the following:

Identify Engagement Strategies. The engagement strategies used to reach target audiences comprise three categories: 1) in-person one-on-one conversations, and group presentations; 2) mass communications via mailings, traditional print and broadcast media, social media,

and Internet interactions; and 3) indirect engagement through partner outreach activities. Within each category, strategies were customized for specific audiences and the objective of the communication.

Develop Materials. Outreach materials development involved preparing information necessary to understand the basics of CCUS technology and the North Dakota CarbonSAFE CS project and translating jargon and technical information into verbiage both familiar and relevant to the layperson. Reflecting outreach team experience, the process addressed the following questions:

- Who is the audience?
- What is the format, i.e., how will the materials be used?
- What are the messages we want to convey?
- How/why is the content relevant to the audience?
- What else does the audience need to know to understand the messages (e.g., key technical information)?
- What jargon can be replaced for clarity and readability, and what must remain and be defined?
- What illustrations enhance the content?

Input to content development came from technical materials, researchers, social characterization, OAB communications, and the experience of the outreach and graphic design teams. Materials were tested through an iterative process of review involving combinations of project team members, project partners via the OAB, EERC editors and upper management, and community members via focus groups. The products developed in this process comprised the outreach tool kit included in the updated outreach plan (Daly and others, 2019).

Public Perception Study of North Dakota Residents

Knowledge of public perception of CCUS greatly facilitated effective engagement with audiences and the capacity to gauge public support and concerns and, thereby, evaluate the social feasibility of implementing a CCUS project. Through social science research during Phase II, North Dakota CarbonSAFE outreach moved beyond regional characterization baseline to better understand public knowledge, opinion, and concerns regarding CCUS in North Dakota. The study used a mixed-method design, consisting of both quantitative (online survey) and qualitative (focus groups) market research, to explore public perceptions of carbon management strategies and North Dakota CarbonSAFE. Research methodology was approved by the University of North Dakota Institutional Review Board with prior acceptance of online survey content (included in Appendix D) by the OAB.

Launched in June 2019, the online survey ran 90 days and focused on households in Mercer and Oliver Counties (Appendix E-1). Invitations to participate in the survey were mailed to the ~4440 households in Oliver and Mercer Counties based on postal route information. Project partners e-mailed invitations to employees. A letter to the editor and advertisements invited participation in two of the local newspapers and on Facebook. The online survey also provided the

means to populate the focus groups in Oliver and Mercer Counties; respondents were offered the option to express interest in participating in subsequent focus groups at the end of the survey.

Qualitative research took place in two stages: with the initial focus group in Grand Forks followed by two focus groups in the two-county study area. The 2-hour-long focus groups were held in three locations on the following dates: Grand Forks, North Dakota, on June 26, 2019; Beulah, North Dakota, on September 12, 2019; and Center, North Dakota, on September 29, 2019.

Results and Discussion

Outreach Advisory Board

Formed in April 2017, six partners provided 12 representatives, and meetings were held monthly. Over the course of the project, the OAB provided input and feedback on outreach activities, outreach planning, common language for outreach products and personnel, and in-kind as well as opportunities for project outreach and to communicate information on the project through their own communications networks.

Outreach Plan

The outreach plan provided a conceptual and temporal framework for delivering timely, accurate information to key stakeholder audiences regarding CCUS, current North Dakota CarbonSAFE activities, and the long-term potential of North Dakota CarbonSAFE in the context of CCUS in general and in related activities in the region and beyond. The outreach plan was updated in May 2019 to include the experience of nearly two project years and submitted to DOE (Daly and others, 2019). Included in this report are highlights of the following:

1. Regional characterization
2. Audience engagement throughout the period of performance
3. Elements of the tool kit—the outreach materials developed to support the story

Regional Characterization

For the North Dakota CarbonSAFE project, the regional and social characterization findings were based on available reports and personal conversations with residents. Based on the social characterization work, messaging to the general population in the two-county study area should incorporate the following considerations:

- Coal mining and the industries that use the coal (electricity generation, coal gasification) are as important as agriculture to the economy. Because coal mines and energy facilities employ nearly 40% of the area workers and operate for decades, offering steady long-term employment and high wages; median wages in Mercer and Oliver Counties are above the state median wage and the median wages in nearby counties that are dependent on agriculture alone. Much of the current population has grown up in households supported by the coal industry or in an economic environment expanded by coal.

- Entry points for discussing CCUS include two related activities: the successful GPSP CO_2 capture facility and CO_2 pipeline and an abandoned proposal for a geologic storage site for CO_2 in neighboring Dunn County (pore space-leasing agreements initiated in 2010, but all have expired). Lack of public opposition to these projects suggested a neutral-to-positive starting point for engagement. Global warming is probably not an effective concern in discussing the merits of CCUS projects. A majority of surveyed residents believe in global warming, but less than half believe it will affect them or that strict emission controls for CO_2 are needed.

- Residents self-identify as good stewards and believe their environment to be protected.

- Environmental concerns about energy development should be considered and further investigated for outreach activities. Public outreach messages to the study area should address both environmental protection and economic development/stability.

Audience Engagement Activities and Assessment

As laid out by the outreach plan, the project team engaged with the major audiences over the course of the project. Altogether, 176 outreach activities and events were documented, 40% of which involved direct contact in Oliver and Mercer County. The bulleted list below highlights major engagement efforts and summarizes the breadth of activities undertaken throughout the project. Where possible, estimates of audience exposure and general attitude of audiences are described. Feedback for outreach activities was collected from audiences as indicated below.

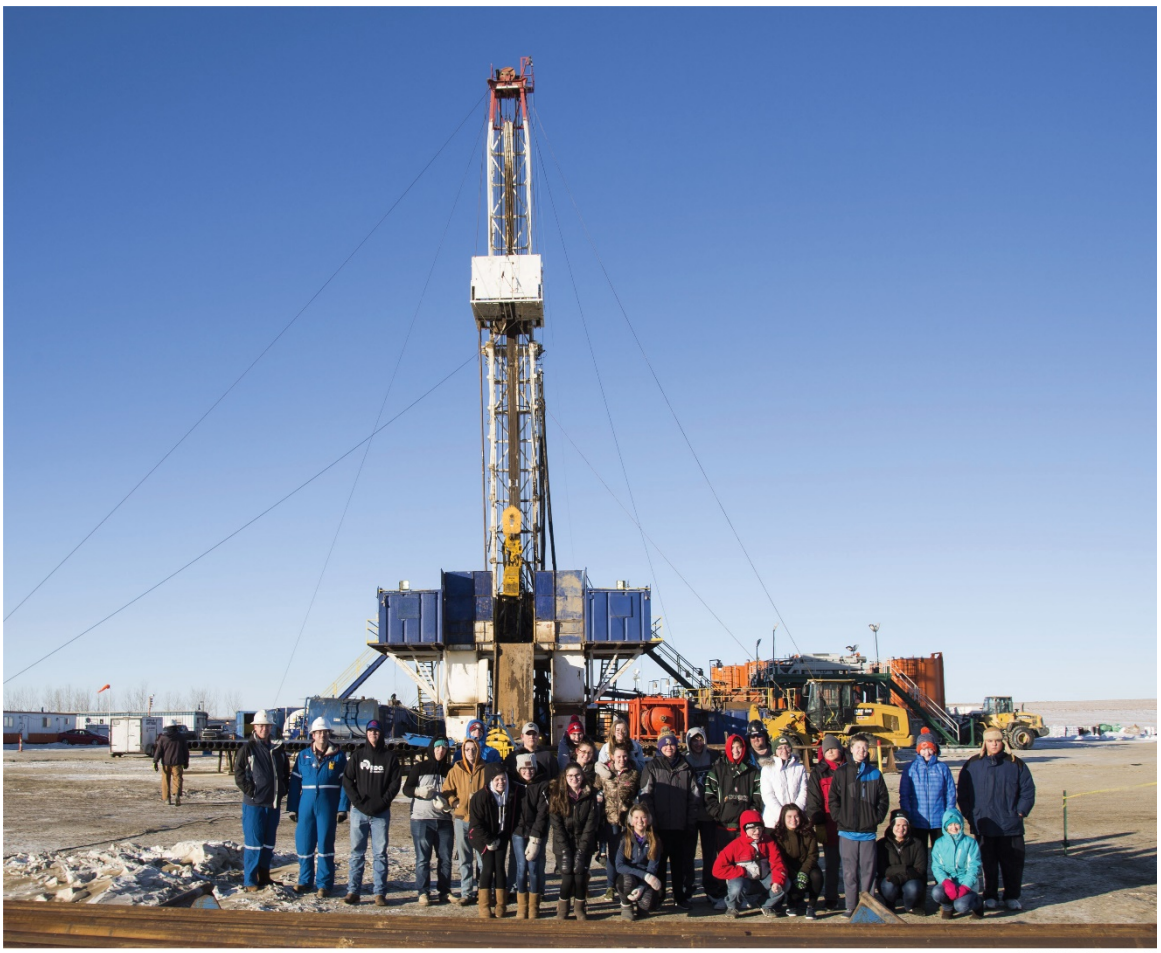
- Partners – Project partners from coal mines, electrical cooperatives, oil producers, and advocacy groups were engaged at the start of the project, participated in the OAB (32 meetings), and provided venues (two employee presentations) and their own messaging outlets (company newsletters, websites) to help spread the project narrative. Partners provided feedback on product development. As a result, information about the project was disseminated to employees and cooperative members across North Dakota and surrounding states.

- Media – Media coverage was initiated by six EERC and two DOE press releases and three one-on-one interviews with field crew members, generating 32 news articles, 23 social media postings, five TV news broadcasts, and three radio broadcasts. Additionally, the region's public television produced and broadcasted an 8-minute documentary short, "Low-Carbon Energy for North Dakota," based on eight face-to-face interviews. As a result, these stories had the potential to reach 37,000 individuals from print and online news articles, 150,000 households (western North Dakota, including the Dickinson and Bismarck areas) from TV news reports, 45,000 individuals from radio broadcasts and 315,000 North Dakota households from the 8-minute documentary short that premiered on prime-time television on April 19, 2019.

- Elected Officials and Regulators – Through a combination of eight county commission meeting appearances and one dedicated mayoral meeting, 28 elected officials were briefed early in the project and at key junctures as the project progressed. Through hearings and community events, local officials were kept informed about the project, and

feedback on the proactive nature of engagement as well as the format, level, and timeliness of the information provided were both positive and complimentary.

- Educators and Students – Outreach engagement occurred both locally and regionally. Within the project area, science classes at Center–Stanton High School and Hazen High School received site tours (Figure 21) and presentations (annually), reaching six teachers and 141 students. Regionally, more than 340 educators from North Dakota and adjacent states were engaged through presentations and materials provided by the North Dakota CarbonSAFE project at the annual Lignite Energy Council (LEC) teacher seminar; 5% of attending teachers currently use materials distributed at LEC seminars or that are accessible online, reaching an additional 1020 students directly.



EERC WP57843.AI

Figure 21. Local high school class visits the drilling site for one of the stratigraphic test wells.

- General Public – The 10,500 residents of the two-county project area represent the study's largest, most diverse, and most dispersed audience. Example activities include meetings with individuals, class or group interactions, community open houses, maintaining a web

presence, and participation in events outside of the two-county area (e.g., the North Dakota State Fair, STEM events, career fairs).

- Technical – The North Dakota CarbonSAFE team presented the project at 23 international, national, and regional meetings focused on CCUS technology and technical issues. These included the International Energy Agency Greenhouse Gas (IEAGHG) Greenhouse Gas Technologies 14th International (GHGT-14) Meeting in Australia, the national DOE contractor meeting and the national Pittsburgh Coal Conference, and the regional Lignite Energy Conference meetings held in Bismarck, North Dakota. As a result, 21 presentations and four poster exhibits reached over 5300 individuals directly (69% of attendees based on reported attendance). This peer-to-peer contact kept the technical audience informed with respect to the concept, status, and results of the project.

Outreach Tool Kit

Developed in collaboration with the OAB, the outreach products comprise a tool kit of materials available for use by project participants and partners alike. Items from the tool kit were included in packets to county commissioners; offered at public outreach events such as the open houses, STEM night, and county fairs; given to field crews to share with the public; used during educational presentations; and distributed at conference booths. Example technical activities for which specific materials were produced include the geophysical survey in Center, North Dakota, and the drilling and geologic sampling activities at the sites in Mercer and Oliver Counties. The tool kit was included with the updated outreach plan (Daly and others, 2019). New items added to the tool kit contents since that report include the following:

- One-page (front and back) handout/PDF focused on a single topic
  - Project fact sheet: North Dakota CarbonSAFE –Feasibility Study Results
  - Project FAQs: Why Investigate CCUS?
  - Activity FAQs: Geophysical Source Test near Center, North Dakota
  - North Dakota Is a Great Place to Do CCUS (infographic) (see Appendix E-2)
  - Enhanced Oil Recovery from CO_2 Captured from Energy (infographic) (see Appendix E-2)
  - Monitoring: Keeping an Eye on Injected CO_2 (infographic) (see Appendix E-2)

- Updated Web content (https://undeerc.org/NDCarbonSafe) and partner blog (Basin Electric Power Cooperative, 2019a,b).

- Hands-on demonstrations for reservoir permeability/pressure (see Figure 22) and chemical trapping in the reservoir.

Figure 22. Students at a STEM event using bicycle pumps to push air through cores of rock. Bubbles are formed as the compressed air escapes the rock core. Variations in porosity in the rock cores translates into easier (higher porosity and permeability) and harder (lower porosity and permeability) pumping.

Public Perceptions Study

Online Survey

The survey provided a snapshot of public opinion on CCUS—concept, context, and value, for which the sample majority was positive—and some direction on messaging. Key findings are included in this section. The survey questions and evaluation of responses are included in Appendix D.

Survey Participants

The sample consisted of 163 respondents. More than 3% of households completed all or part of the survey, which is an adequate response rate for a single mailing. In terms of generalizability, the survey sample is comparable to both Oliver and Mercer Counties and to the state of North Dakota for age and gender. The sample was higher in education and income than the county

averages. Thus the sample represents individuals with similar profiles and may tend to underrepresent lower levels of income and educational attainment.

Employment and Landownership

Of particular value for the North Dakota CarbonSAFE project were the opinions of residents with no direct interest in coal-related industry and agricultural landowners whose livelihood may appear to be impacted by permanent geologic storage projects. Two-thirds of the sample stated they did not work (67.2%) for an organization in the coal or coal-fired electricity industry, and 30.7% indicated that someone in their household was a landowner of agricultural land.

Awareness of CCUS Projects and Process

The survey polled familiarity with the North Dakota CarbonSAFE scenario. Nearly half (45.6%) of the sample had heard of North Dakota CarbonSAFE, which speaks to the success of the public outreach efforts. When asked if they had heard of any other carbon-related projects, 34.4% of respondents had.

Awareness of Coal Characteristics and Impact on the Region

When asked about coal use and electricity generation in North Dakota, the majority of respondents had a good grasp of the role coal plays in electricity generation (70% of respondents estimated coal at 60% to 80% as the primary source of generation) and a favorable attitude toward the associated cost (66% ranked coal as most and second most affordable). For messaging, this suggests that the role of coal in electricity is a useful springboard for discussing the benefits of CCUS opinions on climate change and energy. When asked about climate change statements, the majority of respondents recognized the existence of climate change (77.0%), although fewer acknowledged anthropogenic elements (63.2%). Less than half of the respondents agreed (48.6%) with the statement that evidence shows climate change is occurring because of human activity, and more than a quarter (28.5%) disagreed, the influence of which was observed in subsequent responses related to climate change and reasons to investigate CCUS. Messages focused on the need for actions to mitigate climate change and to expand energy options received a divided response. Figure 23 shows 36.9% in favor of and 40.4% opposed to addressing climate change now. Given the divided responses, messages focused on CCUS as a means to continue to use coal

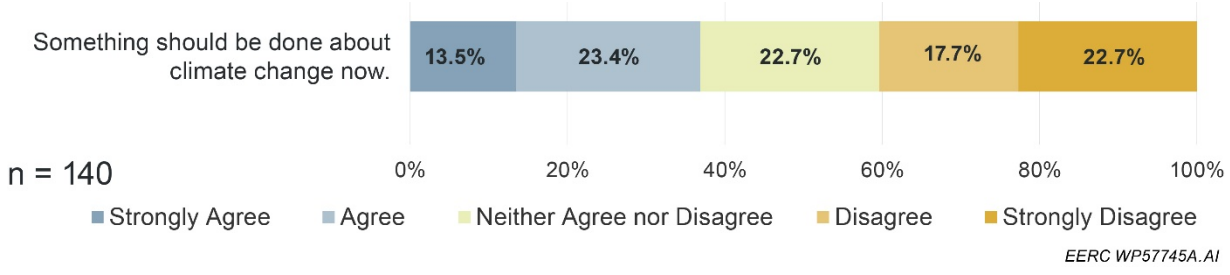


Figure 23. Opinions on taking actions on climate change.

resources as well as for the "all of the above" energy messaging may resonate better with this sample.

Perceptions of and Reasons to Investigate CO_2 Capture and Permanent Storage

Respondents overwhelmingly saw CCUS as providing value to the region (91%); 77.0% favored dedicated permanent storage, and even more (90.7%) favored using captured CO_2 to produce additional oil (Figure 24). Among four proffered reasons to investigate CCUS, economics ranked the highest (90.0%), followed closely by environmental stewardship (87.9%) and continued use of fossil fuels to supply energy in our modern lifestyle (87.8%). A smaller majority felt that regulation to manage carbon resources was at least somewhat important (60.1%). The data suggest that audiences will be more receptive to reasons rooted in economic gain, concern for the environment, and continued use of fossil fuel than "to meet a regulatory requirement," regardless of the benefit intended by the regulation. These responses indicate that the sample does not view fossil energy and environmental stewardship as opposing values.

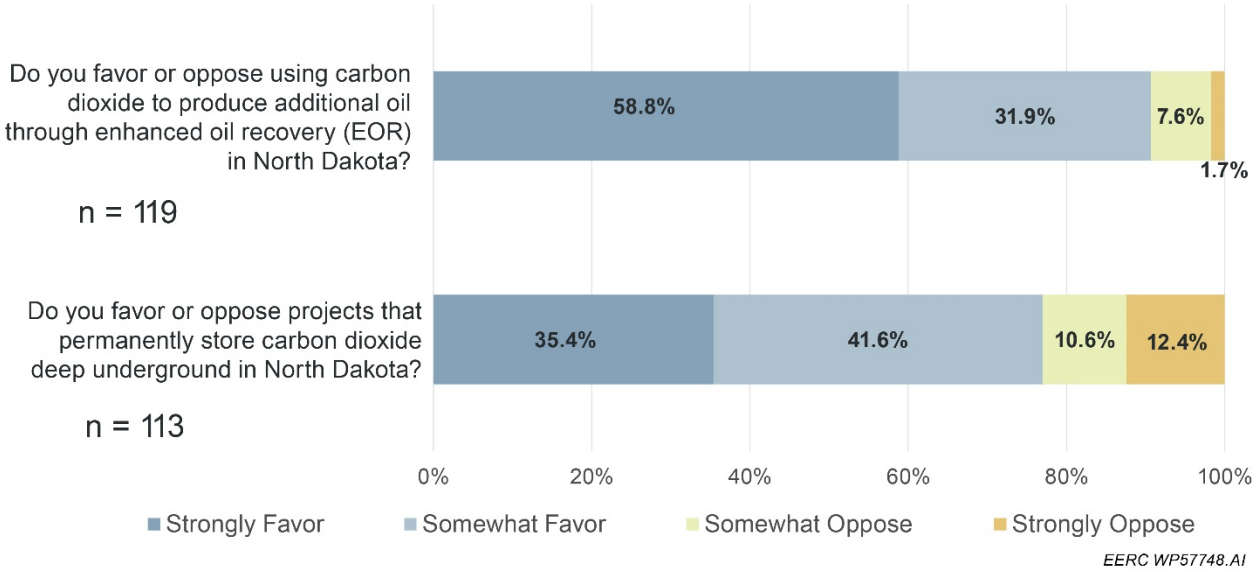


Figure 24. Opinions on associated and dedicated permanent CO_2 storage.

Over half of respondents saw CCUS as a mature technology, but even so, nearly half described CCUS as dangerous (only 19.4% described it as safe) indicating that "value" and "maturity" do not translate into "safe" in the minds of respondents. This dichotomy in responses is echoed in the responses to questions dealing with CCUS as an "opportunity" or "area of concern" for North Dakota—81.4% saw CCUS as an opportunity, and nearly half (48.6%) saw CCUS as an area of concern (Figure 25). The ability to elaborate yielded insight into the sample's concerns, which included risk and safety, pore space management and compensation, overall economic impacts (e.g., cost of electricity, future generation of electricity, etc.), impact of leaks on water quality, and potential for induced seismicity as well as articulating the need for more information).

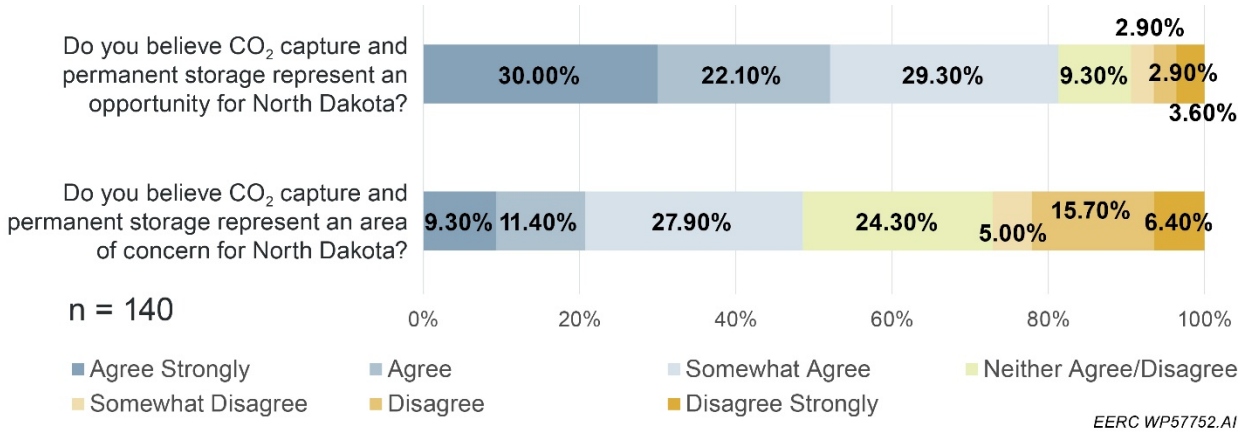


Figure 25. Public perception of CO_2 capture and permanent storage as opportunity and as area of concern.

This information can be used as jumping-off points to continue to explore ways to improve messaging, particularly regarding safety and concern and to improve content and methods of delivery in future projects in the area.

Focus Groups

The Grand Forks focus group was used to test outreach materials and to gauge an initial "pulse" regarding risk and benefit with citizens of eastern North Dakota. In contrast, the coal country focus groups occurred after preliminary online survey results were reviewed, allowing for more focus on concerns and risk. A secondary outcome of the focus groups was giving residents an opportunity for their voices to be heard. Future interaction may determine whether this unanticipated outcome was as effective as it appeared at the time of the encounters.

Participants

Eighteen people participated in the three groups, with six participants per group. Among the focus group participants were eight males and ten females ranging in age from 22 to 73 years old. In Grand Forks, the participants were a mix of professionals and students. None had ties to the coal industry. In Beulah and Center, participants included retired professionals; business, education, and local government professionals; landowners; and community members. Coal-related industry employees and agricultural producers comprised a minority of the participants. All participants were clearly engaged in the process and the topic.

Risks, Concerns, and Opportunities

The focus group conversations gave researchers the opportunity to gain a deeper understanding of participants concerns, how they would like their concerns to be addressed, by whom (e.g., scientists, regulators), how best to communicate with residents and communities (e.g., in-person, social media), and how to tailor messaging to meet the needs of specific communities (e.g., Beulah vs. Center). Universally expressed among the groups were concerns related to risk to humans and the environment (e.g., drinking water and induced seismicity); cost, economic value,

and mineral rights; and the time line. Less universally, members of the focus group wanted to tie CCUS to broader energy context: the actual impact on CO_2 emissions, permanence of the solution, and contrasting continued use of fossil fuels versus migration to all renewable energy sources. Based on the discussions, topics for future public outreach messaging would be a combination of the following: CCUS in the greater energy context, coal/CCUS as part of an all-of-the-above energy strategy, CCUS can and would be done safely, cost/benefit explanations, and the long-term plan for monitoring and risk mitigation.

Preferred Messengers

Focus group members preferred multiple sources to one source of information. Other than uniform distrust of social media outlets, no clear trusted authority was agreed on in the discussions.

Preferred Messages

The coal country focus groups wanted both information and reassurance to be comfortable supporting permanent geologic storage. Fact sheets, web pages, and talking points seemed to be good starting points for more in-depth conversation.

Conclusions

The main finding of the outreach work is that a full-scale CCUS project in the region is socially feasible at this time. This is based on the findings of social characterization, public perception research, the neutral-to-positive nature of media coverage during the project period, and the overall neutral-to-positive tone of interactions members of the audiences during the course of the project.

The last point cannot be over stressed. Given the close-knit communities in the study region, all interactions will be evaluated and shared among community members. Developing opportunities to offer community voices to be heard as well as learn will produce positive outcomes.

With that said, public perception research, including focus groups and surveys as well as conversations with individuals indicate that important areas of concern will need to be discussed and resolved moving forward as this first-of-its-kind facility in this region moves forward. These concerns are centered on clarity and full disclosure regarding the process, transparency as the process moves forward, and the trustworthiness of the project team and regulatory oversight. Key concerns expressed by the public include the following:

- How do we know that the site you choose will be safe?
- How do you know it will stay where you put it?
- How will you protect my drinking water, and what happens if it leaks?
- How do we know that the regulators overseeing this work are trustworthy?

Future messaging needs to help audiences understand how the technology can be made safe (starting with good location, monitoring/response systems, and worst-case scenario in the specific

location and communication transparency) and how all the facets of "mature technology" contribute to "safety of the technology."

With respect to the goal of creating an environment for effective engagement, feedback from the audiences has been overall neutral to positive and overall interactions have been constructive. If a specific project is proposed, then focused outreach using the approach, products, and framework detailed in the updated outreach plan (Daly and others, 2019) can provide a foundation for that effort.

NRAP TOOLS OVERVIEW

NRAP is a multinational laboratory effort led by NETL. The goal of NRAP is to develop quantitative, science-based methods for estimating long-term environmental risks related to potential leakage and induced seismicity regarding the long-term storage of CO_2. To address this goal, NRAP has developed a suite of risk assessment tools based on ROM approaches.

As part of the risk assessment activities of this investigation, the EERC tested several of the NRAP tools with data inputs derived from the GPSP and MRYS sites. The NRAP tools provided assessments of the project storage complex similar to the characterization, modeling, and simulation assessments described earlier in this report. The five NRAP tools tested using project-specific data were the following:

- RROM-Gen (Reservoir Reduced-Order Model – Generator), Version 2017.03-1.2.1
- REV (Reservoir Evaluation and Visualization), Version 2017.03-1.2.1
- WLAT (Wellbore Leakage Analysis Tool), Version 2016.11-1.0.0.3
- GMPIS (Ground Motion Prediction applications to potential Induced Seismicity) Version 2016.11-1.0.0.3
- NRAP-Open-IAM (open-source Integrated Assessment Model [IAM] for Phase II of NRAP)

A summary of the tools tested and the key challenges or recommendations to improve the applicability of the tools is presented in Table 7. An in-depth discussion of each of the tools, the testing procedures, and the challenges encountered during testing is available in Appendix F.

Table 7. NRAP Tools Assessed Using Site-Specific Data from This Project

Tool	Purpose	Key Challenges or Recommendations
RROM-Gen	Used to convert reservoir simulation results at the reservoir–seal interface layer into a usable input format for Open-IAM.	Visual comparison of RROM-Gen outputs to CMG-GEM reservoir simulation outputs shows that these two outputs are in general agreement. However, the perturbations introduced in the RROM-Gen gridding process may affect the subsequent use of RROM-Gen output in NRAP tools like Open-IAM. Future versions of RROM-Gen should allow for inputs from more than one model layer to accommodate geologic models that do not contain a uniform number of cap rock layers (e.g., proportional gridding).
REV	Used to transform the outputs of reservoir simulations into three simple metrics for studying reservoir performance as it relates to risk for carbon storage. The three metrics are CO_2 plume size, differential pressure plume size, and pressure profiles at specified locations.	The utility for calculating the pressure threshold within the threshold parameters page of REV generated incorrect values as compared to the EPA-recommended approach for estimating critical pressure. The graphical output from REV resulted in a banding and feathering along with the elongated aspect ratio due to a nonsquare model grid size in the CMG-GEM reservoir simulation.
WLAT	Includes four separate ROMs for estimating CO_2 or brine leakage through a wellbore that penetrates the seal and therefore provides a potential leakage pathway from the storage unit to overlying formations. The three WLAT ROMs tested were 1) cemented wellbore model, 2) multisegmented well model, and 3) open wellbore model.	Future versions of the cemented wellbore model should accommodate site-specific depth inputs for the thief zone and shallow aquifer, which would allow for the tool to more closely approximate the site-specific stratigraphy of a storage complex. A recommendation for improving the WLAT multisegmented wellbore model is that future versions should allow for additional graphical outputs to permit comparisons of leakage rates, given variable distances between the injection well and the leaky well. The open wellbore model dashboard provides a compact and easy-to-use interface for entering input values. However, the depth and thickness of the aquifer are fixed at 0 and 500 m, respectively, which did not allow for the use of site-specific depths and thicknesses for this project.

Continued . . .

Table 7. NRAP Tools Assessed Using Site-Specific Data from This Project (continued)

Tool	Purpose	Key Challenges or Recommendations
GMPIS	Designed to calculate ground motion predictions and generate ShakeMaps to assess potential risks associated with induced seismicity.	The user manual should include more detailed descriptions, including 1) how the tool reads input files, 2) minimum and maximum values accepted for each parameter, and 3) file formats for input and output data including information about units. More constraints should be added to input parameter selections such as data validation or error messages.
Open-IAM	Integrates inputs from a reservoir simulation and allows the user to simulate leakage of CO_2 or brine through the storage complex using stochastic simulation within different modules (open wellbore and cemented wellbore). Open-IAM testing was regarded as a theoretical exercise as no evidence exists for the presence of a leaking wellbore in the project study areas.	To use the cemented wellbore module, the site-specific stratigraphy needed to be altered from the actual stratigraphy. Using the graphical user interface, it can become difficult to troubleshoot input errors. Some erroneous inputs (values outside of ranges, incorrect parameter file entries, etc.) cause the console window to close immediately, imparting little feedback to the user.

OVERALL CONCLUSIONS

Through the execution of the North Dakota CarbonSAFE feasibility study, the EERC has demonstrated the technical, economic, and social feasibility of developing a commercial-scale CO_2 geologic storage complex in central North Dakota. In the course of doing so, the EERC fulfilled the goals of DOE's CarbonSAFE Initiative and addressed technical and nontechnical challenges specific to commercial-scale deployment of a CO_2 storage project.

Geologic characterization of the Broom Creek Formation based on full-formation cores from two stratigraphic test wells generated results supporting an earlier prognosis that the Broom Creek is a high-quality reservoir for CO_2 storage. Computer simulations, based on geologic models of the Broom Creek Formation incorporating measured permeability as high as 1500 mD and porosity values in excess of 20% support a CO_2 injection rate of nearly 1 Mt/yr per injection well.

Acquisition of geologic data specific to the goal of confirming the feasibility of establishing a certifiable large-scale CO_2 storage site reduced the technical and nontechnical uncertainty with respect to the ultimate implementation of the commercial-scale operation. A risk assessment exercise to identify and assess technical and nontechnical risks that could prevent the candidate storage complexes from serving as commercial storage sites concluded there are no risks to

preclude continued efforts to develop CCUS in central North Dakota. However, a specific nontechnical strategic challenge that may be realized in amalgamation of pore space was identified. This challenge was addressed by vertically expanding the geologic model to incorporate the potential for stacked storage in multiple saline reservoirs. By including the Black Island–Deadwood Formations as CO_2 storage intervals, the amalgamated areal extent could be reduced by as much as 45%. In addition to reducing the number of landowners with whom to establish pore space-leasing agreements, working within a smaller geographic area reduces risks and costs associated with monitoring.

The availability of the 45Q tax credit is a major driver in establishing economic feasibility for CO_2 capture and storage. In North Dakota, the 45Q federal incentive is augmented by financial incentives established by the state of North Dakota. North Dakota Governor Doug Burgum signed legislation in April 2019 that will incentivize the capture of CO_2 from the state's coal-based generation facilities. The legislation created various tax exemptions for the use of coal-based CO_2 in the process of EOR. Also included was a sales and property tax exemption for secure geologic storage of CO_2. Although the specific details are business confidential, Minnkota views Project Tundra as being financially feasible considering federal and state incentives and has initiated work to pursue the necessary federal and state permits required to build the CO_2 capture facility and to store the CO_2 in deep geologic formations.

Outreach was an integral part of the overall project and encompassed any project-related activity that had contact or exposure beyond the project team. The goals of outreach were to provide information with which stakeholders could make informed decisions about the project and gauge community receptiveness to a CCUS project. Results of an online survey conducted through the project indicate that the public attitude regarding CCUS is neutral to positive, with strong sentiment that CO_2 capture and storage may be an approach to maintain the economic vitality of the region.

NEXT STEPS

The next steps in realizing a commercial-scale CO_2 capture and storage project in North Dakota is the execution of the site development plan, compiled as part of this project, and to apply for a storage facility permit from NDIC Department of Mineral Resources (DMR). The site development plan is designed to gather the necessary geologic, financial, and operational data necessary to obtain a storage facility permit. Securing the substantial financial backing necessary for a commercial-scale CCUS project will likely depend on showing that the proposed geologic storage complex is viable. Viability will be demonstrated through the successful acquisition of a state-issued storage facility permit.

REFERENCES

Azzolina, N.A., Nakles, D.V., Ayash, S.C., Wildgust, N., Peck, W.D., and Gorecki, C.D., 2017, PCOR Partnership best practices manual for subsurface technical risk assessment of geologic CO_2 storage projects: Plains CO_2 Reduction (PCOR) Partnership Phase III Task 9 Deliverable

D103 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2017-EERC-10-21, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Bandilla, K.W., Kraemer, S.R., and Birkholzer, J.T., 2012, Using semi-analytical solutions to approximate the area of potential impact for carbon dioxide injection: International Journal of Greenhouse Gas, v. 8, p. 196–204.

Basin Electric Power Cooperative, 2019a, Scientists sample rock one mile below the surface near Basin Electric facilities, www.basinelectric.com/news-center/publications/basin-today/scientists-sample-rock-one-mile-below-surface-near-basin (accessed February 2020).

Basin Electric Power Cooperative, 2019b, Basin electric, EERC representatives meet to review North Dakota CarbonSAFE findings, www.basinelectric.com/news-center/news-briefs/basin-electric-eerc-representatives-meet-review-north-dakota-carbonsafe (accessed February 2020).

Benison, K.C., and Goldstein, R.H., 2000, Sedimentology of ancient saline pans—an example from the Permian Opeche Shale, Williston Basin, North Dakota, USA: Journal of Sedimentary Research, v. 70, no. 1, p. 159–169.

Birkholzer, J., Cihan, A., and Bandilla, K., 2014, A tiered area-of-review framework for geologic carbon sequestration: Greenhouse Gases—Science and Technology, v. 4, p. 20–35, http://dx.doi.org/10.1002/ghg.1393.

Bluemle, J.P., Anderson, S.B., Andrew, J.A., Fischer, D.W., and LeFever, J.A., 1986, North Dakota Stratigraphic Column MS 66: North Dakota Geological Survey.

Bradley, C., Coblentz, D., and Lee, R., 2016, Ground motion prediction applications to potential induced seismicity (GMPIS) tool user's manual, Version 2016.11-1.1: NRAP Technical Report Series, NRAP-TRS-III-018-2016, Morgantown, West Virginia, U.S. Department of Energy National Energy Technology Laboratory, p. 28.

Canadian Standards Association, 2012, Z741-12 – Geological Storage of Carbon Dioxide.

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S., and Zweigel, P., 2006, Best practice for the storage of CO_2 in saline aquifers—Keyworth, Nottingham: British Geological Survey Occasional Publication, v. 14, p. 1–277.

Cihan, A., Zhou, Q., and Birkholzer, J.T., 2011, Analytical solutions for pressure perturbation and fluid leakage through aquitards and wells in multilayered aquifer systems: Water Resources Research, v. 47, no. 10, 2011.

Computer Modelling Group, 2018, GEM user guide.

Daly, D.J., Crocker, C.R., and Gorecki, C.D., 2017, Regionwide outreach in a project-level world – lessons from the PCOR Partnership: 13th International Conference on Greenhouse Gas Control Technologies (GHGT-13), Lausanne, Switzerland, November 13–18, 2016, Energy Procedia, v. 114, p. 7224–7236.

Daly, D.J., Crocker, C.R., Crossland, J.L., and Gorecki, C.D., 2018, PCOR Partnership outreach—an evolving regional capability based on RCSP outreach best practices: Paper presented at the 14th International Conference on Greenhouse Gas Control Technologies (GHGT-14), Melbourne, Australia, October 21–25, 2018.

Daly, D.J., Crossland, J.L., Crocker, C.R., Glazewski, K.A., Massmann, N.M., and Peck, W.D., 2019, North Dakota CarbonSAFE outreach plan (updated) Phase II: Prepared for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0029488, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

Daly, D.J., Hanson, S.K., Steadman, E.S., and Harju, J.H., 2009, Best practices manual: outreach. Deliverable D48 Task 8 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, May.

Darton, N.H., 1901, Preliminary description of the geology and water resources of the southern half of the Black Hills and adjoining regions in South Dakota and Wyoming: U.S. Geological Survey Annual Report, v. 21, no. 4, p. 489–599.

Dilmore, R., 2019, National risk assessment partnership Task 6—risk-based approach to post-injection site closure, carbon capture, utilization, storage and oil and gas technologies integrated review meeting, National Energy Technology Laboratory, David L. Lawrence Convention Center, Pittsburgh, PA, August 26–30, 2019.

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

Halland, E.K., Johansen, W.T. and Riss, F., 2013, CO_2 Storage Atlas – Norwegian Sea. The Norwegian Petroleum Directorate, www.npd.no/globalassets/1-npd/publikasjoner/atlas-eng/co2-atlas-north-sea.pdf (accessed February 2020).

Helms, L., and Fried, S., 2019, North Dakota Industrial Commission, personal communication, May 30, 2019.

Huerta, N.J. and Vasylkivska, V.S., 2016, Well leakage analysis tool (WLAT) user's manual, Version 2016.11-1.0.0.3: NRAP Technical Report Series, NRAP-TRS-III-011-2016, Albany, Oregon, U.S. Department of Energy National Energy Technology Laboratory, p. 44.

International Organization for Standardization, 2009, Risk management—principles and guidelines: ISO 31000:2009(E).

King, S., 2016a, Reservoir evaluation and visualization (REV) tool user's manual, Version 2016.11-1.2.0: NRAP Technical Report Series, NRAP-TRS-III-013-2016, Morganton, West Virginia, U.S. Department of Energy National Energy Technology Laboratory, p. 20.

King, S., 2016b, Reservoir reduced-order model – generator (RROM-Gen) tool user's manual, Version 2016.11-1.2: NRAP Technical Report Series, NRAP-TRS-III-014-2016, Morgantown, West Virginia, U.S. Department of Energy National Energy Technology Laboratory, p. 16.

Macnamara, J., 2016, PR Measurement Summit 2016: Jim Macnamara's keynote speech presentation, www.slideshare.net/CARMA_Global/pr-measurement-summit-2016-jim-macnamaras-keynote-speech-presentation (accessed April 30, 2018).

Peck, W.D., Glazewski, K.A., Braunberger, J.R., Grove, M.M., Bailey, T.P., Bremer, J.M., Gorz, A.J., Sorensen, J.A., Gorecki, C.D., and Steadman, E.N., 2014, Broom Creek Formation

outline: Plains CO_2 Reduction (PCOR) Partnership Phase III value-added report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-09-09, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Peck, W.D., Nakles, D.V., Glazewski, K.A., and Pekot, L.J., 2019, North Dakota integrated carbon storage complex feasibility study—site development plan Deliverable D6: Research performance progress report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0029488, Grand Forks, North Dakota, Energy & Environmental Research Center, December.

Sacuta, N., Daly, D., Botnen, B., and Worth, K., 2016, Communicating about the geological storage of carbon dioxide – comparing public outreach for CO_2 EOR and saline storage projects: Presented at the 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2015, Lausanne, Switzerland.

Schlumberger, 2016, Petrel 2016: Petrel E&P Software Platform.

Shogenova, K., Shogenova, A., Vizika-Kavvadias, O., and Nauroy, J., 2015, Reservoir quality and petrophysical properties of Cambrian sandstones and their changes during the experimental modelling of CO_2 storage in the Baltic Basin. Estonian Journal of Earth Sciences 64(3):199; DOI: 10.3176/earth.2015.27

Siirila-Woodburn, E.R., Cihan, A., Birkholzer, J.T., 2017, A risk map methodology to assess the spatial and temporal distribution of leakage into groundwater from Geologic Carbon Storage. International Journal of Greenhouse Gas Control, v 59, p 99–109. DOI 10.1016/j.ijggc.2017.02.003

Sorensen, J., Bailey, T., Dobroskok, A., Gorecki, C., Smith, S., Fisher, D., Peck, W., Steadman, E., and Harju, J., 2009, Characterization and modeling of the Broom Creek Formation for potential storage of CO_2 from coal-fired power plants in North Dakota: Search and Discovery Article #80046.

Stauffer, P., Chu, S., Tauxe, C., and Pawar, R., 2016, NRAP integrated assessment model-carbon storage (NRAP-IAM-CS) tool user's manual, Version: 2016.11-1.1; NRAP-TRS-III-010-2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p. 64.

U.S. Department of Energy, 2014, FE/NETL CO_2 Transport Cost Model: Description and User's Manual, National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2014/1660, Pittsburgh, PA, July 11.

U.S. Department of Energy, 2017, FE/NETL CO_2 Saline Storage Cost Model: User's Manual, National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2018/1873, Pittsburgh, PA, 2017.

U.S. Department of Energy, 2018, FE/NETL CO_2 Transport Cost Model, National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL 2018-1894.

U.S. Environmental Protection Agency, 2013, Geologic sequestration of carbon dioxide underground injection control (UIC) program Class VI well area of review evaluation and corrective action guidance: May 2013, www.epa.gov/sites/production/files/2015-07/documents/epa816r13005.pdf (accessed March 2020).

APPENDIX A

SITE CHARACTERIZATION ACTIVITIES: DOWNHOLE AND LABORATORY ANALYSES

NORTH DAKOTA CARBONSAFE PHASE 2 SITE CHARACTERIZATION ACTIVITIES: DOWNHOLE AND LABORATORY ANALYSES

1.0 INTRODUCTION

The Broom Creek Formation in west central North Dakota is being considered as a subsurface CO_2 storage target (Sorensen and others, 2009). The Broom Creek is composed primarily of sandstone, with local areas of dolomite, anhydrite, chert, and shale. The Broom Creek unconformably overlies the Amsden Formation (Fischer and others, 2008; Ziebarth, 1972; Hoda, 1977; Rygh, 1990) and is unconformably overlain by muddy shales of the Opeche and undifferentiated Opeche–Spearfish Formations (Murphy and others, 2009).

This storage target was investigated in Task 2 – Storage Complex Characterization of Phase 2 of the North Dakota CarbonSAFE Project. Characterization activities included acquisition of multiple forms of geologic data, including stratigraphic test well data from two wells that were drilled between December 2017 and February 2018 (i.e., Flemmer-1 and BNI-1, respectively); a 10-mi^2 3-D seismic survey; and 28 miles of 2-D seismic lines (Figure A-1). Samples collected

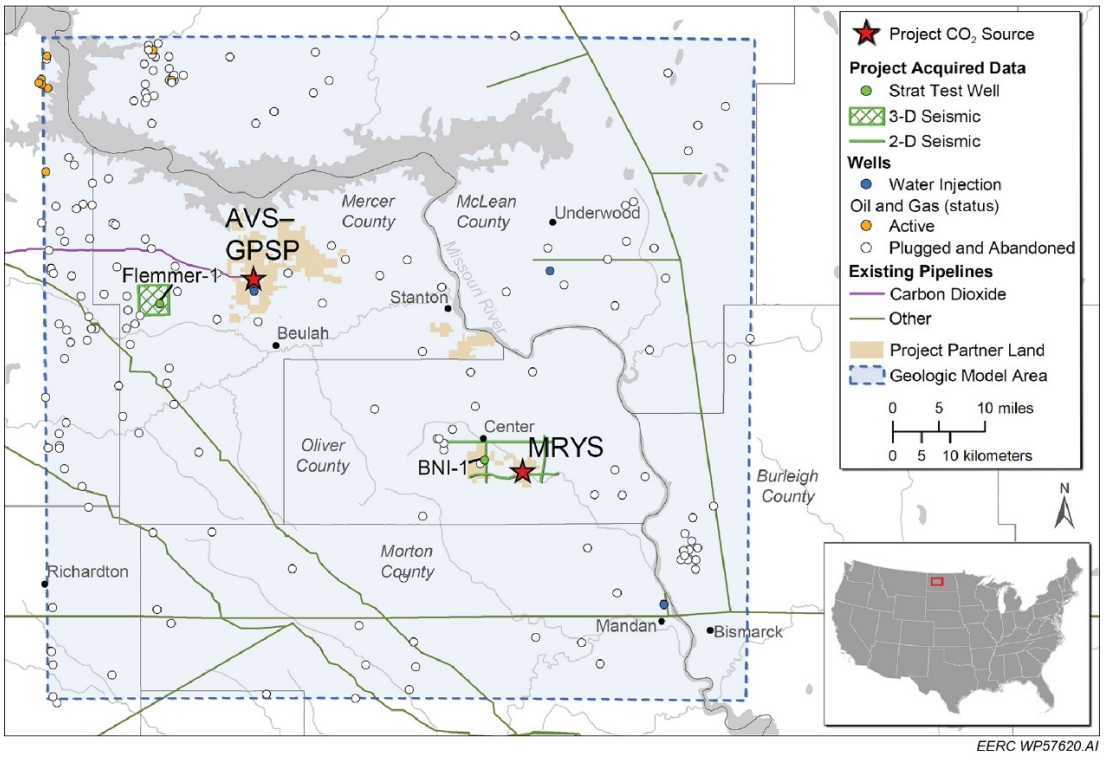


Figure A-1. Map showing North Dakota CarbonSAFE Project sites (Antelope Valley Station [AVS]–Great Plains Synfuels Plant [GPSP] and Milton R. Young Station [MRYS]), including CO_2 sources, CO_2 injection well locations for dedicated storage, geologic data acquired during Phase 2 of the project, and existing CO_2 and other pipelines. Areal extent of the geologic model (blue rectangle comprising 5544 mi^2) and land owned by project partners (yellow-shaded areas) are also delineated in this figure.

during drilling and analysis of the two stratigraphic test wells included drill cuttings collected along the entire wellbore and 645 ft of core samples (325 ft from Flemmer-1 and 315 ft from BNI-1) from the Amsden, Broom Creek, Opeche, and Spearfish–Piper Formations. At the same time, multiple measurements were made including openhole geophysical well log measurements, fracture measurements, and formation fluid sample and pressure measurements. The core samples obtained from the wells were later analyzed in Energy & Environmental Research Center (EERC) laboratories to determine their geologic properties, which were used to construct geologic models for the predictive simulation of CO_2 injection in the storage complex.

2.0 GEOLOGIC CHARACTERIZATION DATA

2.1 Geophysical Well Logs

Openhole wireline-conveyed geophysical well logs were acquired in both stratigraphic test wells (Flemmer-1 and BNI-1) along the entire open section (no casing) of each wellbore at the conclusion of drilling. Table A-1 shows the logging intervals for each stratigraphic test well. Multiple wireline runs were used to collect data on each stratigraphic test well. Geophysical data included gamma ray (GR) (total and spectral), caliper, density, porosity (neutron, density, and sonic), spontaneous potential, resistivity, sonic (compressional and shear), and lithologic properties.

Table A-1. Openhole Geophysical Logging Intervals

Well	Log Depth, ft
Flemmer-1	1930–6790
BNI-1	1390–5316

Geophysical logs collected in each stratigraphic test well were used to gain a better understanding of the subsurface geologic formations in the study area. Well logs provided formation top depths, lithology interpretation, petrophysical properties, and time–depth shifting of the seismic data. Well log interpretation efforts focused on the primary storage target, the Permian Broom Creek Formation, along with the overlying cap rocks of the Opeche, Minnekahta, and Spearfish Formations. The Cretaceous Inyan Kara Formation was also investigated to determine the feasibility as a stacked storage interval to augment Broom Creek storage or as an alternate primary storage target.

Well log interpretations of stratigraphic test wells were applied to the 205 existing wellbores (where available) in the study area to provide a better understanding of subsurface geology. Well logs from the 205 existing wellbores were acquired from the databases of the North Dakota Industrial Commission (NDIC) and the North Dakota Department of Environmental Quality (NDDEQ).

2.1.1 Structural Correlation

Logs collected from the stratigraphic test wells were used to pick formation tops based on well log signatures throughout the Williston Basin (Bluemle and other, 1986). Formation tops were picked from the top of the Pierre Formation to the top of the Amsden Formation (Table A-2). These top picks were used in addition to the 205 existing wells throughout the study area to understand the geologic extent, depth, and thickness of the subsurface geologic formations. Structural surfaces created from the stratigraphic top picks were used as input for structural geologic modeling.

Table A-2. Depth and Thickness of Formation in the Stratigraphic Test Wells

	Flemmer-1		BNI-1	
Formation	**Depth, ft**	**Thickness, ft**	**Depth, ft**	**Thickness, ft**
Pierre	1826	2166	1228	1952
Greenhorn	3992	423	3180	388
Mowry	4415	93	3568	59
Newcastle	4508	14	3627	11
Skull Creek	4522	248	3638	227
Inyan Kara	4770	321	3865	178
Swift	5091	402	4043	476
Rierdon	5493	259	4519	144
Spearfish	5963	137	4865	42
Minnekahta	6100	8	N/A	N/A
Opeche	6108	165	N/A	N/A
Broom Creek	6273	263	4907	273
Amsden	6536	101	5180	

The top of the Broom Creek Formation was picked across the study area based on the transition from the high GR signature of the shale/siltstone of the overlying Opeche–Spearfish cap rock to the low GR signature of the sandstone/dolostone lithologies in the Broom Creek (Figure A-2). The top of the Amsden Formation was placed at the top of a high-GR argillaceous dolostone that could be correlated across the entire study area (Figure A-2).

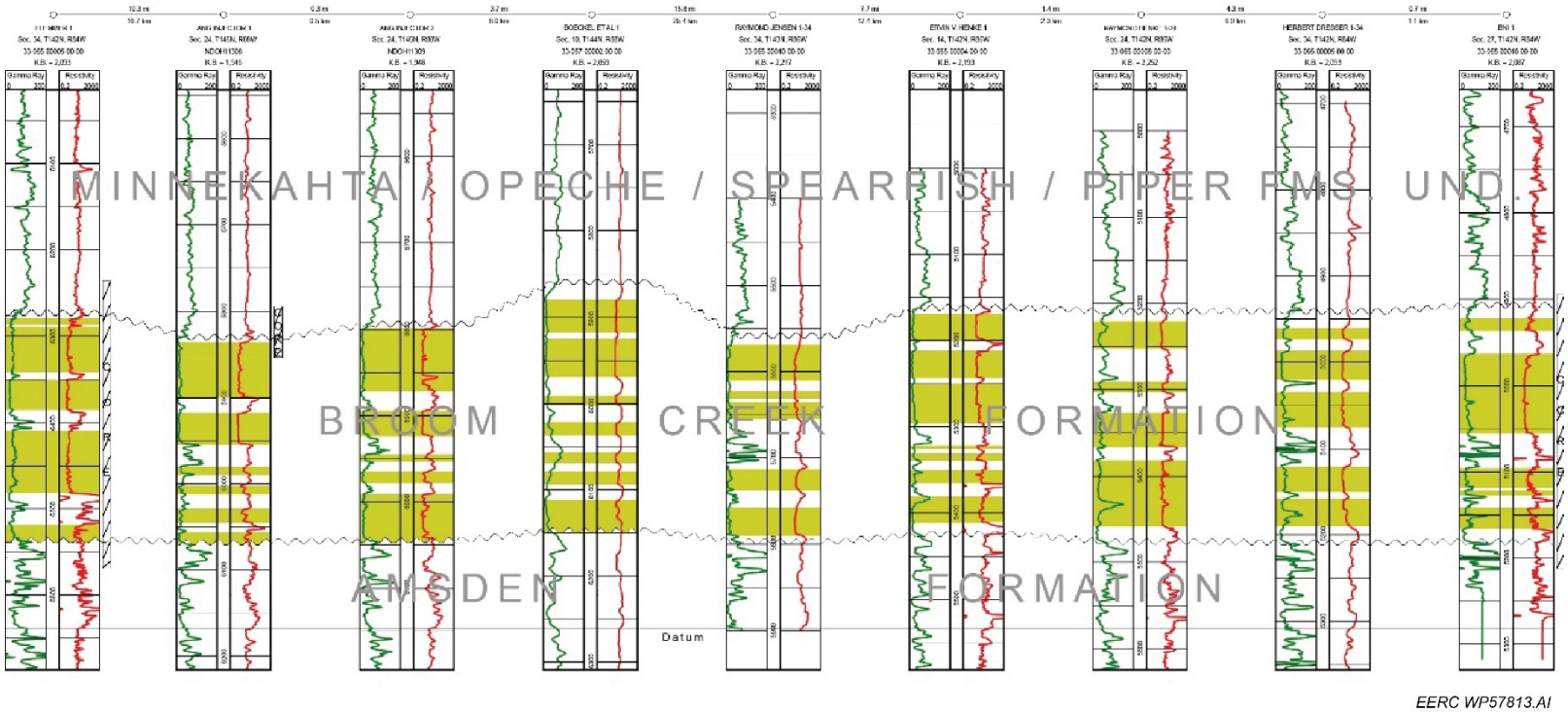


Figure A-2. Cross section of the Broom Creek Formation from the Flemmer-1 well to the BNI-1 well. Each wellbore contains a GR log (left) and a resistivity log (right); sandstone intervals are shaded yellow.

2.1.2 Lithology Interpretation

Core sample and well log data collected from both Phase 2 stratigraphic test wells (Flemmer-1 and BNI-1), as well as existing Broom Creek cores (NDIC #90383, 658, ANG #1 [NDDEQ]), were analyzed to better understand the lithologies of the Broom Creek Formation. The Broom Creek interval was assigned four lithofacies: sandstone, dolostone, dolomitic sandstone, and anhydrite (Figure A-3). The sandstone and dolomitic sandstone lithofacies represent the reservoir lithologies within the Broom Creek Formation because they have the best reservoir properties relative to CO_2 storage. The nonreservoir dolostone and anhydrite lithofacies represent poor reservoir properties, thus creating internal baffles within the Broom Creek.

The interpreted depositional environment of the Broom Creek Formation is eolian and nearshore marine sandstone–carbonate cycles (Willis, 1959). Sandstone and dolostone are the two dominate lithologies in the Broom Creek and can be easily separated on well logs based on their contrasting well log signatures (Figure A-3). The sandstone intervals in the Broom Creek are associated with a low-GR, low-density, high-porosity (neutron, density, and sonic), low-resistivity, and high-sonic log signature. The dolostone intervals in the formation are associated with an increased GR compared to the sandstone interval high-density, low-porosity (neutron, density, and sonic), high-resistivity, and low-sonic log signature. The dolomitic sandstone lithofacies was defined as a transition facies found primarily between the sandstone and dolostone intervals. Anhydrite intervals are easily identifiable on well logs because of their low GR signature and their very high density and resistivity.

Learnings from the core and well log associations in the stratigraphic test wells were used to determine Broom Creek lithologies in existing wellbores throughout the study area that did not contain core data. Lithologies assigned to each wellbore were then used in the creation of the Broom Creek geologic facies model.

In addition to the Broom Creek Formation, the Inyan Kara Formation was also assessed for CO_2 storage potential. Well log interpretations of the Inyan Kara in the stratigraphic test wells were used to understand the lithologies in the formation. Lithology logs were generated from well logs using GR log cutoffs that were chosen by comparing various well logs, including elemental log analysis results and GR logs (Figure A-4). The Inyan Kara was assigned two main lithologies: sandstone and shale.

2.1.3 Petrophysical Properties

Derived ELAN logs included porosity and permeability logs for each of the stratigraphic test wells. Since very few porosity and permeability core analysis data exist for the Broom Creek Formation, the addition of ELAN porosity and permeability logs allowed for an increased petrophysical data set. These logs along with core analysis data were used in petrophysical property modeling within the study area.

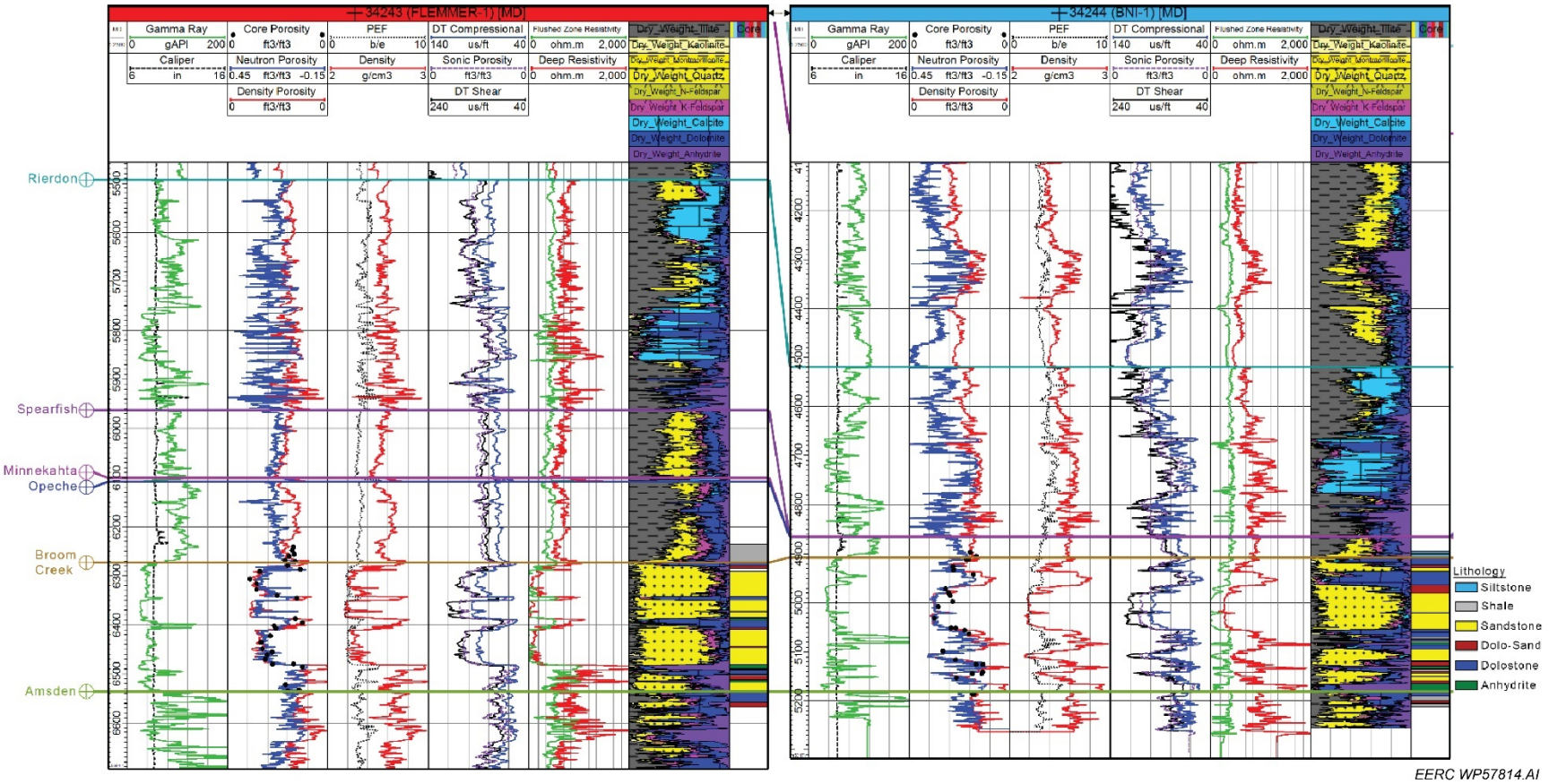


Figure A-3. Stratigraphic test well logs of the Broom Creek Formation (Flemmer-1 [NDIC #34243] and BNI-1 [NDIC #34244]). Data shown for each well, from left to right, are 1) caliper and GR; 2) core, neutron, and density porosity; 3) photoelectric factor (PEF) and density; 4) compressional sonic travel time (DT compressional), sonic porosity, and shear sonic travel time (DT shear); 5) deep resistivity and flushed zone resistivity; and 6) derived elemental log analysis (ELAN) and lithology.

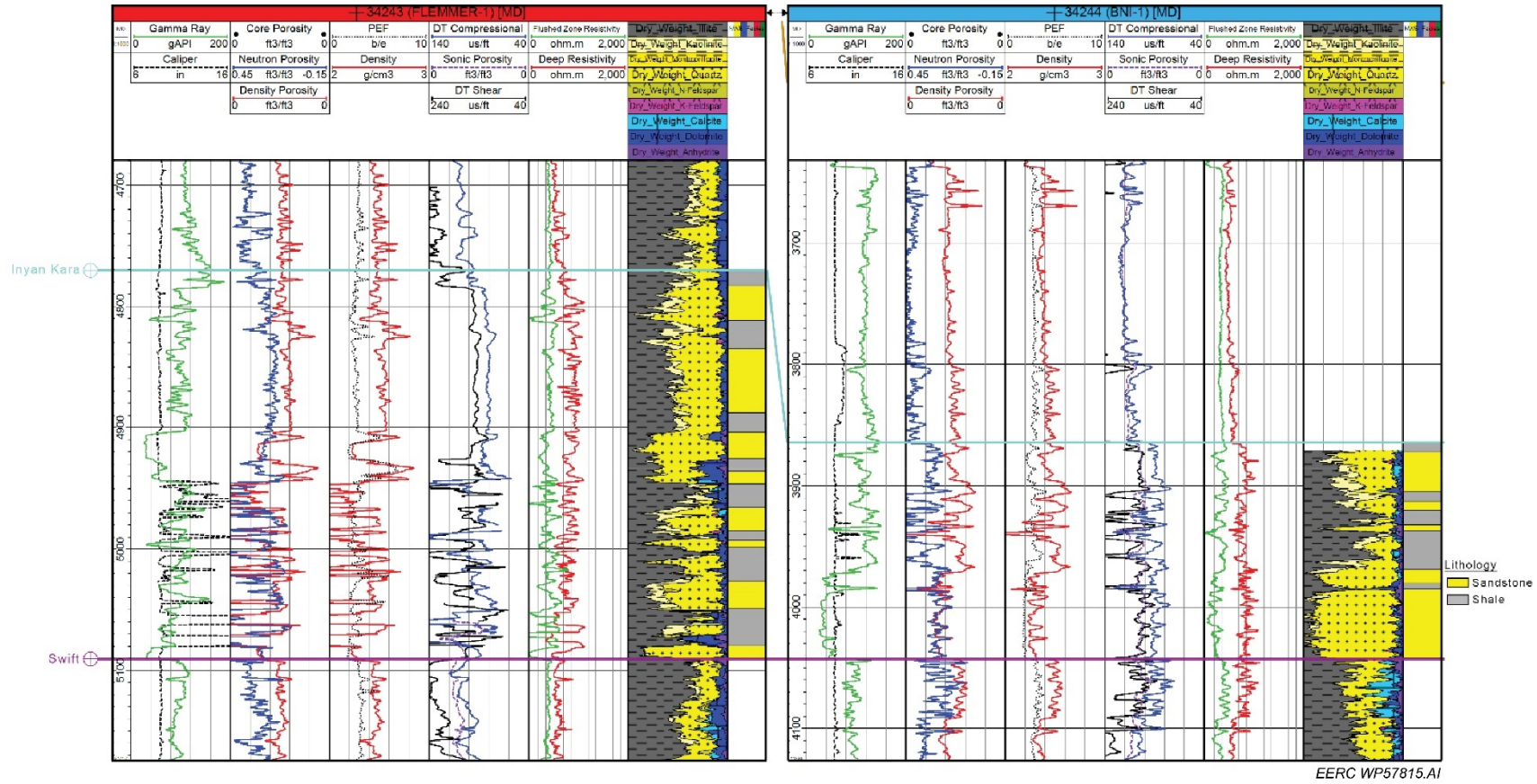


Figure A-4. Stratigraphic test well logs of the Inyan Kara Formation (Flemmer-1 [NDIC #34243] and BNI-1 [NDIC #34244]). Data shown for each well, from left to right, are 1) caliper and GR; 2) core, neutron, and density porosity; 3) PEF and density; 4) compressional sonic travel time (DT compressional), sonic porosity, and shear sonic travel time (DT shear); 5) deep resistivity and flushed zone resistivity; and 6) derived ELAN and lithology.

2.1.4 Formation Water Salinity

During the data acquisition phase (after completion of drilling) of the Flemmer-1 and BNI-1 wells, formation water was collected from the Broom Creek and Inyan Kara Formations. Water chemistry analysis of formation water measured the salinity of the native formation fluid. Because of possible contamination of the Broom Creek water sample from the Flemmer-1 well, resistivity well logs were used to estimate the formation water salinity in both test wells. Resistivity-measured salinity values were compared with formation water samples taken with the MDT (modular formation dynamics tester) tool. Log estimated salinity at the BNI-1 well was approximately 57,800 mg/L, with a range of 40,000 to 60,000 mg/L. Salinity estimates at the Flemmer-1 well were approximately 54,000 mg/L, with a range of 32,000 to 77,000 mg/L.

2.1.5 Summary of Stratigraphic Well Test Results

Flemmer-1 Well

A single pressure test was conducted in the Inyan Kara Formation, which revealed slightly underpressured conditions in comparison to a normal freshwater hydrostatic gradient. Pressure was recorded with a calculated gradient of 0.426 psi/ft. Fluid samples were collected and analyzed, and a salinity of 21,300 mg/L total dissolved solids (TDS) was measured. An associated permeability estimate of 109 mD was calculated.

Pressure testing in the Broom Creek Formation included six pore pressure measurements. All six tests showed relatively good agreement, resulting in a calculated pressure gradient of 0.488 psi/ft. Broom Creek fluid samples were collected; however, an unusually slow recovery precluded the team from conducting a thorough initial pump-out to confidently rid the interval of invaded drilling mud. An analysis of the sample yielded a salinity measurement of 263,000 mg/L TDS, but concerns remained that the acquired sample may not have been representative of native brine. No estimate of permeability was performed.

Microfracture tests performed in the Opeche and Broom Creek Formations yielded results, although with some uncertainty as to the accuracy of the conclusions. The microfracture test performed in the Opeche Formation at a depth of 6261 ft yielded results with good confidence, a breakdown pressure of 5320 psi and a calculated fracture pressure gradient of 0.847 psi/ft. The results of the microfracture test in the Broom Creek Formation (6358-ft depth) were more perplexing, with an initial breakdown pressure of 4950 psi measured; however, additional fracture-reopening pressures increased to 5214, 6255, and finally 7293 psi. Fracture-reopening pressures, generally, should be lower than initial breakdown pressure. The anomalous results indicated something unexpected was occurring, possibly plugging of the tool's probe by solids as the test was performed. As a result, the project team modified the testing plan for the BNI-1 well to perform the tests and sampling with a different probe assembly on the MDT tool, which was expected to perform better because of its larger surface area.

BN-1 Well

Six pressure tests were conducted in the BNI-1 well, including two in the Inyan Kara Formation, one in the Opeche Formation, and three in the Broom Creek Formation. The Inyan Kara tests were conducted at depths of 3996 and 4030 ft and yielded pressure measurements of 1652 and 1666 psi, respectively. These measurements showed relatively good agreement in calculated pore pressure gradient, both within the round-off error of 0.410 psi/ft. Similar to the Flemmer-1 well Inyan Kara test results, the results indicate subnormal pressures in comparison to hydrostatic gradient. Permeability estimates from the tests ranged from 155 to 229 mD. A pressure test conducted at a depth of 4897 ft within the Opeche Formation but very close to the contact between the Opeche and Broom Creek Formations yielded a pressure measurement of 2446 psi and a pressure gradient of 0.488 psi/ft. The three pressure tests conducted in the Broom Creek Formation (depths of 5041, 5104, and 5124 ft) yielded pressure measurements of 2471, 2499, and 2508 psi, all agreeing with a pressure gradient of 0.487 psi/ft. Permeability estimates from these intervals were 119, 282, and 12 mD, respectively.

Analysis of a fluid sample from the Inyan Kara Formation showed brine salinity to be approximately 20,000 mg/L TDS. An analysis of four fluid samples from the Broom Creek Formation yielded salinities ranging from 60,800 to 65,700 mg/L TDS.

Similar to the Flemmer-1 well, microfracture tests were performed in the Opeche and Broom Creek Formations. Two tests were performed in the Opeche Formation at depths of 4873 and 4897 ft, just above the contact with the Broom Creek Formation. The test at 4873 ft resulted in a maximum applied pressure of 7560 psi, but no discernable formation breakdown was observed. The test near the Opeche–Broom Creek contact (4897-ft depth) showed formation breakdown occurred at a pressure of 5897 psi, yielding an unusually high fracture pressure gradient of 1.201 psi/ft. One microfracture test was attempted in the Broom Creek Formation at a depth of 5040 ft. Breakdown pressure was not able to be determined, but fracture closure pressure from the results appeared to be between 3025 and 3045 psi.

2.2 Seismic Data

2.2.1 Acquired 2-D and 3-D Seismic Data

Seismic data acquired during Phase 2 of the North Dakota CarbonSAFE project included an existing 10-mi^2 3-D seismic survey and 28 miles of existing 2-D seismic (Figure A-1). Seismic interpretations provided data that were used in the geologic modeling efforts, including structural control and a better understanding of interwell heterogeneity.

Amplitude interpretation of the 3-D seismic data was used for facies modeling of the Broom Creek and Inyan Kara Formations. Interpretation of the 3-D seismic in the Broom Creek identified southwest-to-northeast-trending ovular features using seismic attribute analysis. Core analysis and well log correlations coupled with synthetic modeling suggested these ovular features represent thin interdunal carbonate deposits. Interpreted geobodies including elongate eolian sand dunes

(reservoir) and ovular interdune carbonate (nonreservoir) beds were incorporated into the geologic model by using the dimensions of the interpreted reservoir and nonreservoir lithologies within the formation (Figure A-5).

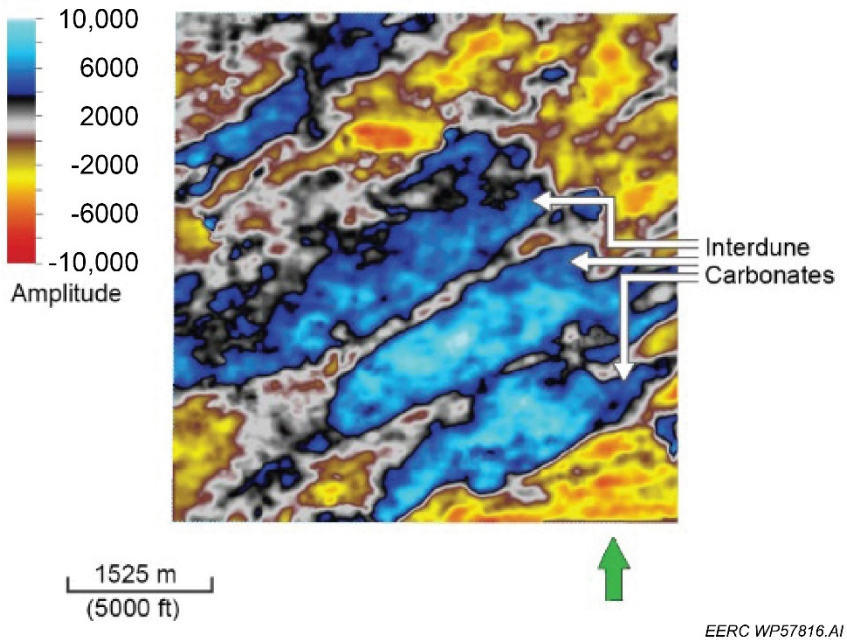


Figure A-5. Map view of seismic amplitude time slice through the Broom Creek Formation with interpreted geobodies. High amplitude values (blue) caused by thin bed tuning indicate the presence of interdunal carbonates.

2.2.2 Seismic Source Test

Seismic data acquisition efforts included the acquisition of a 5-mile-long seismic line across reclaimed mine land near MRYS that intersected the existing 2-D seismic lines and the BNI-1 stratigraphic test well. These data were acquired to tie the well log data to the existing seismic data. The low quality of the acquired data highlighted the need to better understand the impacts of reclaimed mine land on seismic signal attenuation. To that end, a seismic source test was conducted near the MRYS site in fall 2019 to assess the feasibility of acquiring 3-D seismic data over reclaimed mine land and to determine what type of seismic source is needed to do so. The source test involved evaluating vibroseis trucks and dynamite shots of different weights (5.5, 7.7, and 11 lb) and depths at two test sites, one on reclaimed mine land and the other on unmined land (North Dakota Industrial Commission, 2019). Signals from dynamite shots at depths of 20 ft or more below the reclaimed interval were less affected by the reclaimed interval than data from shallower dynamite shots and data from the vibroseis trucks. Results indicated that it is feasible to collect 3-D seismic data over reclaimed mine land using dynamite shots and that 11-lb charges would produce sufficient signal to image formations at least 9600 ft below the land surface.

3.0 LABORATORY ANALYSES OF CORE SAMPLES

Several laboratory analyses were performed on the Flemmer-1 and BN-1 core samples to further inform the development of geologic models for the simulation of CO_2 injection into the subsurface of the North Dakota CarbonSAFE project area. These analyses included the description of thin sections of the core using standard petrographic methods, mineralogy and bulk chemical assessments using x-ray diffraction (XRD) and x-ray fluorescence (XRF), electrical resistivity tests to aid in the interpretation of wireline resistivity log data collected in the field, relative permeability testing using high-pressure flow-through tests, and geomechanical tests such as triaxial and rebound testing. Several of these tests (i.e., electrical resistivity, relative permeability, and geomechanical tests) require the collection and characterization (i.e., grain volume and permeability to air) of subsamples from the core. A description of the core, the collection and characterization of core subsamples, and results of these laboratory analyses for the Flemmer-1 and BN-1 well core are summarized as follows.

3.1 Core Description and Collection of Subsamples for Testing

3.1.1 Core Description

The lithologies, features, and structures of nearly 650 ft of core material were described in detail for the Flemmer-1 (340 ft) and BNI-1 (315 ft) core. The core was also photographed. The Flemmer-1 and BNI-1 core both show a series of sabhka-type depositional environments with seas transgressing, resulting in dolomites overlain by sandy dolomites, which are in turn overlain by sands, which can be shallow marine beach sands to eolian dune sands (Figure A-6). In several instances, either the dolomite or the sandstones were capped with anhydrite.

The Flemmer-1 core displayed a primarily regressive sequence (approximate depth of 6480 to 6410 ft), with the sandstone depositional setting primarily shallow marine or reworked dune deposits (Figure A-6). From 6410 to 6390 ft, there is a transgressive sequence with an abrupt regression indicated by a thin dolomite with fossil fragments capped with anhydrite. From 6380 ft to the top of the core at 6235 ft, the Flemmer-1 core was primarily regressive, with shallow marine sandstone deposits giving way to eolian dune deposited sandstone and back to shallow marine beach deposited sandstone starting at around 6270 ft.

The lower portion of the BNI-1 core is similar to the lower portion of the Flemmer-1 core (Figure A-7). From the base of the BNI-1 core at 5208 to 5115 ft, sediments demonstrate a fluctuating shallow marine and sabhka environment with dolomite and anhydrite intervals, with some thin sandstones or sandy dolomites interbedded. This represents primarily a near-shore transgressive sequence. From 5115 to 5094 ft, there is a regressive sandstone deposited in a shallow marine-to-higher-energy beach environment. The second transgressive sequence consists of dolomites and anhydrites interbedded from 5094 to 5052 ft. A thick eolian sandstone deposit marks the second major regression from 5052 to 4978 ft. The upper portion of this sandstone appears to have been deposited in a shallow marine-to-beach environment. A transgressive sequence starts at 4978 to 4908 ft, with primarily dolomite and sandy dolomite from shallow marine deposition. These are in turn overlain by siltstones of the Opeche Formation.

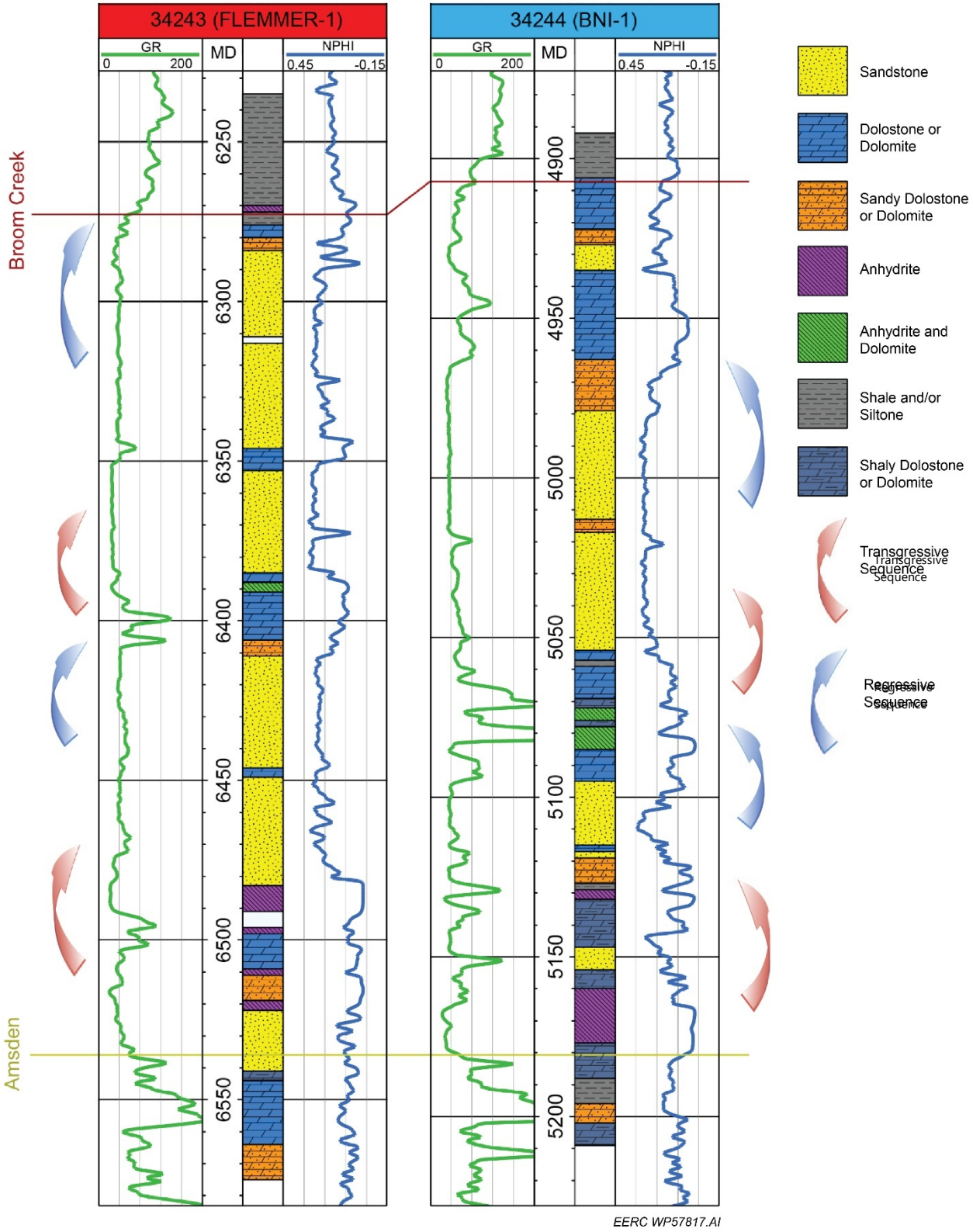
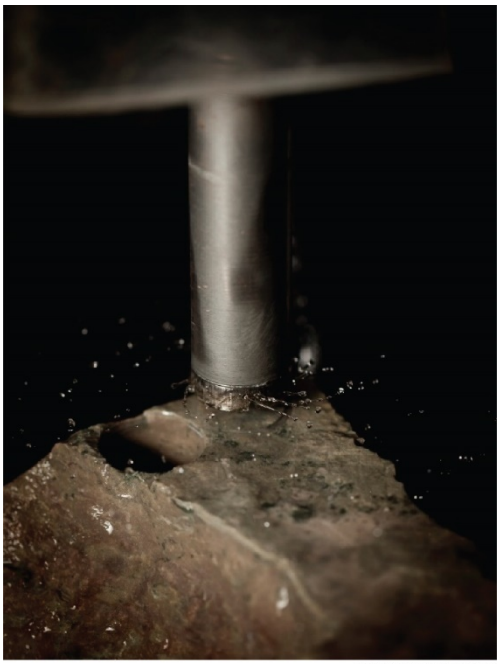


Figure A-6. Lithologic interpretation of the Flemmer-1 and BNI-1 core. GR and neutron logs are correlated with the lithologic interpretations.

The Flemmer-1 and BNI-1 cores both show two major transgression–regression events with several minor fluctuations, most notably in the lower portions of each core (Figure A-6). In the Flemmer-1 core, the basal Broom Creek Formation is an eolian sandstone overlaying dolomite and anhydrites of the upper Amsden Formation. This basal sandstone is about 20 ft thick capped by an anhydrite layer, which in turn is overlain by alternating dolomite and anhydrite beds. This interval represents a fluctuating shallow marine environment with carbonate deposition to subaerial exposed for evaporite deposition. From 6482 to 6411 ft is a thick sand primarily deposited in a shallow marine environment with laminated bedding and in several areas soft sediment deformation and fluid escape structures. The interval from 6411 to 6384 ft marks the start of the second major transgressive sequence, with marine dolomites capped with a sabhka-like dolomitic anhydrite. The second major regressive sequence starts at 6384 ft as a shallow marine deposited sandstone, which becomes a steep angle cross-bedded eolian-deposited sandstone from about 6335 to 6290 ft.

3.1.2 Subsample Collection, Preparation, and Screening

Representative subsamples from the Flemmer-1 and BNI-1 cores were required for conducting several of the laboratory tests, i.e., electrical resistivity, relative permeability, and geomechanical tests. These samples were obtained by drilling out a “core plug” from the core samples (See Figure A-7). Lists of the core plugs obtained from the BN-1 and Flemmer-1 cores are provided in Tables A-3 and A-4, respectively. These samples were prepared for laboratory testing by machining the ends flat. Basic physical attributes of the core plugs were



EERC WP57818.AI

Figure A-7. A rotary hole saw is used to drill out a core plug from the core recovered from the Flemmer-1 well for performing electrical resistivity, relative permeability, and geomechanical testing.

Table A-3. Core Plugs Obtained from the Core Samples of BNI-1 Stratigraphic Well

STAR #	Actual Depth, ft	Formation	Well	Plug Orientation	Notes
124353	4896	Piper–Spearfish–Opeche undifferentiated	BNI-1	Horizontal	
124354	4904	Piper–Spearfish–Opeche undifferentiated	BNI-1	Horizontal	**
124355	4910	Broom Creek	BNI-1	Horizontal	
124360	4925	Broom Creek	BNI-1	Horizontal	
124361	4931.5	Broom Creek	BNI-1	Horizontal	dmgAP
124362	4941	Broom Creek	BNI-1	Horizontal	**
124364	4970	Broom Creek	BNI-1	Horizontal	
124365	4977.5	Broom Creek	BNI-1	Horizontal	
124366	4983	Broom Creek	BNI-1	Horizontal	dmgAP
124368	4995.25	Broom Creek	BNI-1	Horizontal	dmgAP
124370	5006	Broom Creek	BNI-1	Horizontal	dmgAP
124373	5029	Broom Creek	BNI-1	Horizontal	dmgAP
124375	5049	Broom Creek	BNI-1	Horizontal	1" o.d.
124376	5054	Broom Creek	BNI-1	Horizontal	1" o.d.
124377	5061	Broom Creek	BNI-1	Horizontal	**
124381	5096.5	Broom Creek	BNI-1	Horizontal	
124382	5114	Broom Creek	BNI-1	Horizontal	
124383	5123.5	Broom Creek	BNI-1	Horizontal	
124387	5137	Broom Creek	BNI-1	Horizontal	*
124388	5140	Broom Creek	BNI-1	Horizontal	
124389	5149	Broom Creek	BNI-1	Horizontal	
124391	5181.75	Amsden	BNI-1	Horizontal	**
124355v	4910	Broom Creek	BNI-1	Vertical	**
124369v	5003.5	Broom Creek	BNI-1	Vertical	dmgAP
124375v	5049	Broom Creek	BNI-1	Vertical	
124383v	5123.5	Broom Creek	BNI-1	Vertical	**
124387v	5137	Broom Creek	BNI-1	Vertical	*
124388v	5140	Broom Creek	BNI-1	Vertical	**
124391v	5181.75	Amsden	BNI-1	Vertical	**

* Incomplete test. Permeability below 0.01 mD. Sample measured at one mean pore pressure, at 800 psi confining pressure.

** Incomplete test. Permeability below 1 mD. Sample measured at one mean pore pressure at 800 psi and 2400 psi confining pressure.

dmgAP = Sample damaged during air permeability measurement.

Table A-4. Core Plugs Obtained from the Core Samples of Flemmer-1 Stratigraphic Well

STAR#	Depth, ft	Formation	Well	Orientation	Notes
124173b	6241	Opeche*	Flemmer-1	Horizontal	*
124174b	6248	Opeche*	Flemmer-1	Horizontal	**
124175b	6256	Opeche*	Flemmer-1	Horizontal	*
124176b	6260	Opeche*	Flemmer-1	Horizontal	**
124177b	6268.5	Opeche*	Flemmer-1	Horizontal	**
124178b	6271	Broom Creek	Flemmer-1	Horizontal	*
124179b	6277.5	Broom Creek	Flemmer-1	Horizontal	
124180b	6285.5	Broom Creek	Flemmer-1	Horizontal	*
124181b	6293	Broom Creek	Flemmer-1	Horizontal	
124182b	6308.5	Broom Creek	Flemmer-1	Horizontal	
124183b	6318	Broom Creek	Flemmer-1	Horizontal	
124184b	6330	Broom Creek	Flemmer-1	Horizontal	
124185b	6343	Broom Creek	Flemmer-1	Horizontal	
124186b	6348.5	Broom Creek	Flemmer-1	Horizontal	*
124195b	6387.5	Broom Creek	Flemmer-1	Horizontal	
124196b	6396	Broom Creek	Flemmer-1	Horizontal	*
124197b	6402	Broom Creek	Flemmer-1	Horizontal	
124198b	6407	Broom Creek	Flemmer-1	Horizontal	
124200b	6423.5	Broom Creek	Flemmer-1	Horizontal	
124201b	6436.5	Broom Creek	Flemmer-1	Horizontal	
124201e	6436.5	Broom Creek	Flemmer-1	Vertical	
124202b	6449.5	Broom Creek	Flemmer-1	Horizontal	dmgP
124203b	6456.5	Broom Creek	Flemmer-1	Horizontal	
124204b	6462	Broom Creek	Flemmer-1	Horizontal	
124205b	6471.5	Broom Creek	Flemmer-1	Horizontal	
124206b	6481	Broom Creek	Flemmer-1	Horizontal	
124206d	6481	Broom Creek	Flemmer-1	Vertical	
124207b	6487	Broom Creek	Flemmer-1	Horizontal	*
124208b	6528	Broom Creek	Flemmer-1	Horizontal	
124209b	6538.5	Broom Creek	Flemmer-1	Horizontal	*
124210b	6541	Amsden	Flemmer-1	Horizontal	**

* Incomplete test. Permeability below 0.01 mD. Sample measured at one mean pore pressure, at 800 psi confining pressure.

** Incomplete test. Permeability below 1 mD. Sample measured at one mean pore pressure at 800 psi and 2400 psi confining pressure.

dmgP = Sample damaged during porosity measurement.

measured (i.e., mass, length, diameter, flatness and perpendicularity of the ends) in accordance with applicable ASTM International (ASTM) standards. Samples used for geomechanical testing were further screened based on a minimum length-to-diameter ratio of 2.5:1.

In addition to these basic physical attributes, the core plugs were also subjected to two low-cost standardized tests to determine base volumetric and flow parameters (i.e., unstressed porosity and permeability to air) that are used for screening the samples to identify those of interest for further evaluation. These tests are briefly described as follows.

Unstressed Porosity Measurements

A modified MetaRock PDP-300 gas porosimeter is used to measure skeletal, or grain, volume of each core plug. A simplified diagram of the instrument is shown in Figure A-8. Prior to testing, the sample is prepared with flat ends to create a near perfect cylinder in accordance with ASTM D4543 (ASTM International, 2008). The bulk volume is calculated from the measured length and diameter. For irregularly shaped samples, the bulk volume is measured using a 3-D laser scanner. Prior to testing, the calibration of the instrument is verified using precise volume standards. A core plug is then placed in the sample cup, and the system is sealed. The sample and system are given time to allow the temperature to equilibrate. The test is initiated by drawing a vacuum for several minutes to remove air from the sample and system. The reference chamber is then filled with helium at 200 psi and allowed to stabilize for several minutes. Valve C is then closed. Valve B is opened, and helium from the reference chamber enters the sample cup, penetrating the pore volume of the sample. The system is allowed several minutes to reach equilibrium, and the final pressure is measured.

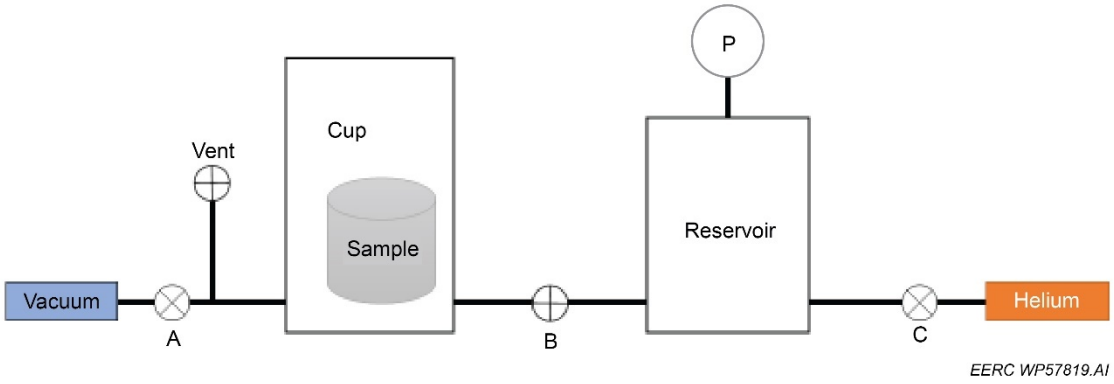


Figure A-8. Experimental setup for grain volume determination (helium porosity testing).

The grain volume of a sample is determined by applying Boyle's gas law equations as referenced in American Petroleum Institute (API) RP 40 (American Petroleum Institute, 1998a). The pore volume is calculated by subtracting grain volume from bulk volume; porosity is calculated by dividing the pore volume by the bulk volume. Porosity can also alternatively be calculated as (1-grain volume/bulk volume) Tables A-5 and A-6 present the unstressed porosity data for the BN-1 and Flemmer-1core plugs, respectively.

Table A-5. Unstressed Porosity of BN-1 Core Plugs

STAR #	Bulk Volume, mL	Bulk Density, g/mL	Grain Volume, mL	Grain Density, g/mL	Unstressed Porosity, %
124353	32.3	2.46	29.5	2.7	8.6
124354	33.3	2.59	31.7	2.73	5
124355	34.6	2.51	30.8	2.82	11
124360	34.4	2.25	27.8	2.78	19
124361	32.4	2.17	26.3	2.67	19
124362	37.3	2.61	34.7	2.8	6.7
124364	32	2.04	24.5	2.66	23
124365	35.4	2.12	27.8	2.7	21
124366	36.2	1.99	28.7	2.51	21
124368	29.5	2.03	23.9	2.52	19
124370	32.2	1.88	23.3	2.59	28
124373	33.4	1.83	23.3	2.62	30
124375	27	2.14	21.6	2.68	20
124376	25.8	2.5	22.7	2.84	12
124377	35.8	2.55	32.5	2.81	9.3
124381	30.7	1.99	23	2.66	25
124382	29.8	2.21	24.6	2.68	17
124383	34.9	2.59	33.1	2.73	5.2
124387	34.9	2.72	34.5	2.75	1.1
124388	35.2	2.52	32.6	2.72	7.3
124389	34.9	2.23	29	2.68	17
124391	35	2.6	32.9	2.77	6.2
124355v	35.8	2.54	32.4	2.81	9.5
124369v	–	–	–	–	–
124375v	34.6	2.21	28.7	2.67	17
124383v	35.4	2.71	35	2.75	1.1
124387v	35.2	2.71	34.7	2.75	1.4
124388v	35	2.7	34.4	2.75	1.8
124391v	35	2.57	32.5	2.77	7.2

Steady-State Air Permeability

Permeability to air is determined for each core plug utilizing a steady-state method as described in ASTM D4525 (ASTM International, 1990) and API RP-40 (American Petroleum Institute, 1998b). Using the apparatus shown in Figure A-9, steady-state gas permeability through the core material is measured. Prior to testing, the prepped samples are kept in a humidity-controlled oven at 40% humidity and 60°C until mass stability is achieved. Steady-state permeability tests are performed at two confining pressures to evaluate flow sensitivity to stress.

Table A-6. Unstressed Porosity of Flemmer-1 Core Plugs

STAR #	Bulk Volume, mL	Bulk Density, g/mL	Grain Volume, mL	Grain Density, g/mL	Unstressed Porosity, %
124173b	41.6	2.56	39.2	2.71	5.7
124174b	41.9	2.5	38.5	2.72	6.3
124175b	46.1	2.52	42.9	2.71	5.1
124176b	34.6	2.49	31.8	2.71	8.2
124177b	46.2	2.43	41.4	2.71	10
124178b	35.5	2.62	33.9	2.74	4.6
124179b	48	2.59	43.6	2.84	9.1
124180b	38.4	2.73	38.4	2.73	1.4
124181b	38.1	1.96	28.3	2.64	26
124182b	33.4	1.79	22.9	2.61	32
124183b	50.8	1.85	36.1	2.61	28
124184b	43.6	1.85	30.9	2.61	28
124185b	46.5	2.2	38.6	2.65	15
124186b	45	2.64	42.6	2.79	3.4
124195b	38.4	2.75	36.8	2.87	4.3
124196b	41.2	2.67	41.1	2.67	0.17
124197b	32.4	2.2	26.9	2.65	17
124198b	40	2.25	33.6	2.69	16
124200b	36.4	2.09	28.7	2.64	19
124201b	49.4	1.98	37	2.64	24
124201e	39.8	2	30.1	2.64	25
124202b	29.9	1.94	22.2	2.61	24
124203b	39.6	2.18	32.4	2.66	18
124204b	34	2.1	26.8	2.66	21
124205b	22.6	2.05	17.5	2.65	22
124206b	33.7	2.19	27.6	2.67	18
124206d	43.3	2.51	40.1	2.71	5.5
124207b	42.1	2.96	42.5	2.94	0.069
124208b	33.3	2.43	29.9	2.7	10
124209b	31	2.68	30.3	2.75	2.1
124210b	38.7	2.52	35.2	2.77	9.1

Testing is conducted by flowing dry nitrogen through the sample at a controlled pressure gradient. The pressure gradient across the sample is limited so as not to exceed the maximum recommendation described in API-RP 40 (American Petroleum Institute, 1998b) for the mean pore pressure being tested. Once steady-state flow is achieved at a given test condition, the mean pore pressure is increased to the next test condition. Multiple mean pore pressures between 15 and 100 psi are tested to allow calculation of Klinkenberg slip-corrected permeability. The permeability data for the BNI-1 and Flemmer-1 core plugs are presented in Tables A-7 and A-8, respectively.

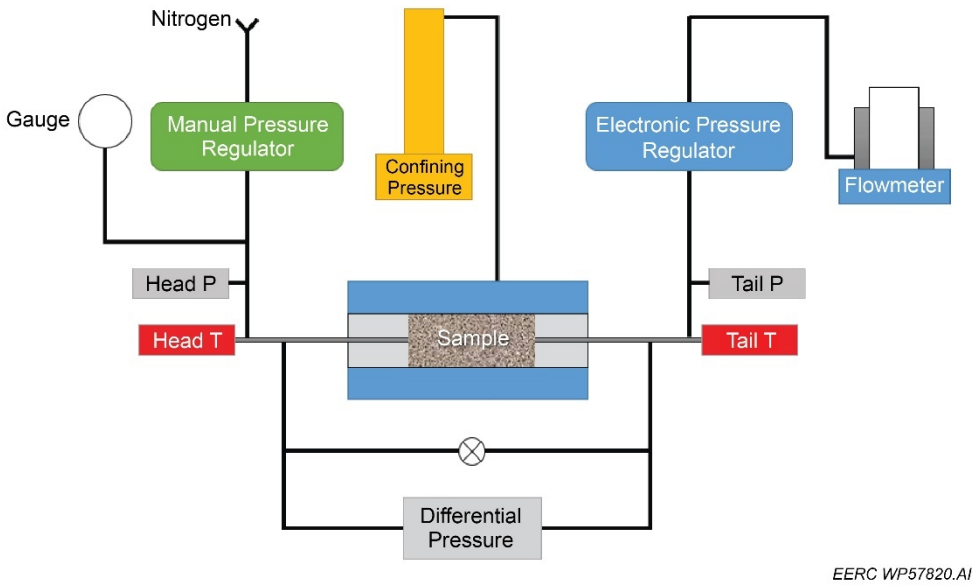


Figure A-9. Experimental setup to measure permeability of the core plug to air.

3.2 Laboratory Tests Performed on Core Samples/Subsamples

3.2.1 Thin-Section Image Analysis

To further interpret depositional environment and support core descriptions, thin sections of the core were described for lithology, grain size, sorting, roundness, and diagenetic alteration using standard petrographic methods. Sixty-four (64) thin sections, 35 from the BNI-1 core and 29 from the Flemmer-1 core, were created with blue epoxy dye for porosity, examined in plane polar and cross-polar light, and photographed in plane polar and reflected light.

Advanced image analysis was performed on the thin-section images with ImageJ (Rasband, 2016) and Ilastik (Sommer and others, 2011) to further assess grain size, shape, roundness, sorting, and size distributions. The combination of Image-J and Ilastik was used to manipulate, adjust, filter, analyze, and segment images. The workflow began by using Image-J to segment images into phases, followed by extracting binary images of each phase and performing operations on those images to extract information about size, shape, area, and border contacts.

Whereas many image analysis programs rely solely on gray scale for image segmentation, the Ilastik program has built-in advanced capabilities for efficient segmentation of image features based on several attributes, including texture and shape, in addition to gray scale. Together, the programs can be used to perform machine learning processes to interpret grain (or pore) size and shape, grain counts, and fractal analysis.

Table A-7. Steady-State Air Permeability (Kair) of BN-1 Core Plugs

STAR #	Plug Orientation	800 psi Klinkenberg, mD	2400 psi Klinkenberg, mD	800 psi Kair, mD	2400 psi Kair, mD	Average Kair, mD	Slippage, psi
124353	Horizontal	15.5	13.6	16	14.4	15.2	1.96
124354	Horizontal	–	–	0.037	0.0213	0.0292	–
124355	Horizontal	0.452	0.454	0.685	0.655	0.67	17.1
124360	Horizontal	39.7	39	42.6	41.3	42	2.33
124361	Horizontal	354	343	363	352	357	1.02
124362	Horizontal			0.045	0.031	0.038	–
124364	Horizontal	923	908	953	937	945	1.26
124365	Horizontal	1070	1060	1100	1080	1090	1.05
124366	Horizontal	1370	1340	1590	1490	1540	7.63
124368	Horizontal	966	860	1100	929	1010	1.57
124370	Horizontal	2420	2350	2750	2600	2670	4.69
124373	Horizontal	1270	1250	1420	1360	1390	4.06
124375	Horizontal	–	–	–	–	–	–
124376	Horizontal	–	–	–	–	–	–
124377	Horizontal	–	–	0.107	0.0915	0.099	–
124381	Horizontal	494	493	510	499	505	1.35
124382	Horizontal	68	66.6	71.9	69.7	70.8	2.04
124383	Horizontal	0.63	0.49	0.86	0.717	0.788	14.8
124387	Horizontal			0.0104		0.0104	–
124388	Horizontal	95.2	94.4	107	103	105	4.02
124389	Horizontal	11.2	10.7	12.4	12	12.2	4.17
124391	Horizontal	–	–	0.06	0.0411	0.0506	–
124355v	Vertical	–	–	0.0315	0.0318	0.0317	–
124369v	Vertical	1090	1050	1210	1140	1180	3.82
124375v	Vertical	2.23	2.16	2.85	2.75	2.8	10.1
124383v	Vertical	–	–	0.0392	0.03	0.0346	–
124387v	Vertical	–	–	0.0064	–	0.0064	–
124388v	Vertical	–	–	0.159	0.069	0.114	–
124391v	Vertical	–	–	0.0217	0.007	0.0144	–

Mineralogy was verified using light microscopy but was determined by XRD methods. The distribution of minerals in thin section was coupled with bulk mineralogy analyses to identify the cementing agents, if any, as well as determine indications of diagenetic events since burial.

The sandstone cements were variable and were found to be quartz overgrowths, authigenic clays, dolomite, and anhydrite (Figure A-10). Some of the eolian sands had little to no cement, and it was not possible to make a thin section from those intervals. Nearly all of the sandstones

Table A-8. Steady-State Air Permeability of Flemmer-1 Core Plugs

STAR#	Orientation	800 psi Klinkenberg, mD	2400 psi Klinkenberg, mD	800 psi Kair, mD	2400 psi Kair, mD	Average Kair, mD	Slippage, psi
124173b	Horizontal	–	–	0.0490	–	–	–
124174b	Horizontal	–	–	0.2200	0.1880	0.2040	–
124175b	Horizontal	–	–	0.0375	–	–	–
124176b	Horizontal	–	–	0.0265	0.0344	0.0305	–
124177b	Horizontal	–	–	0.0760	0.0664	0.0712	–
124178b	Horizontal	–	–	0.0160	–	–	–
124179b	Horizontal	0.2628	0.2955	0.8724	1.201	1.037	–
124180b	Horizontal	–	–	0.0200	–	–	–
124181b	Horizontal	1697	1677	1734	1710	1722	0.8272
124182b	Horizontal	1735	1675	1837	1786	1812	2.130
124183b	Horizontal	927.8	927.6	1041	1063	1052	4.576
124184b	Horizontal	1100	1036	1171	1131	1151	2.157
124185b	Horizontal	92.88	92.38	100.2	97.33	98.78	3.014
124186b	Horizontal	–	–	0.0176	–	0.0176	–
124195b	Horizontal	0.3664	0.2196	0.3966	0.3374	0.3670	4.218
124196b	Horizontal	–	–	0.0005	–	0.0005	–
124197b	Horizontal	41.14	40.67	44.53	43.08	43.80	3.590
124198b	Horizontal	36.67	35.98	42.05	40.16	41.10	5.419
124200b	Horizontal	157.3	158.8	170.4	166.3	168.3	3.060
124201b	Horizontal	208.6	204.6	214.0	211.5	212.8	0.9201
124201e	Vertical	128.5	127.4	137.3	134.6	135.9	2.597
124202b	Horizontal	–	–	–	–	–	–
124203b	Horizontal	17.94	17.62	21.01	19.65	20.33	6.369
124204b	Horizontal	119.5	117.1	128.1	123.4	125.7	2.814
124205b	Horizontal	101.7	101.3	112.1	107.0	109.6	3.963
124206b	Horizontal	136.5	137.0	145.6	143.0	144.3	2.540
124206d	Vertical	–	–	0.3260	0.2675	0.2968	–
124207b	Horizontal	–	–	0.0035	–	0.0035	–
124208b	Horizontal	19.87	19.66	22.19	21.42	21.80	4.242
124209b	Horizontal	–	–	0.0090	–	0.0090	–
124210b	Horizontal	–	–	0.0719	0.0634	0.0676	–

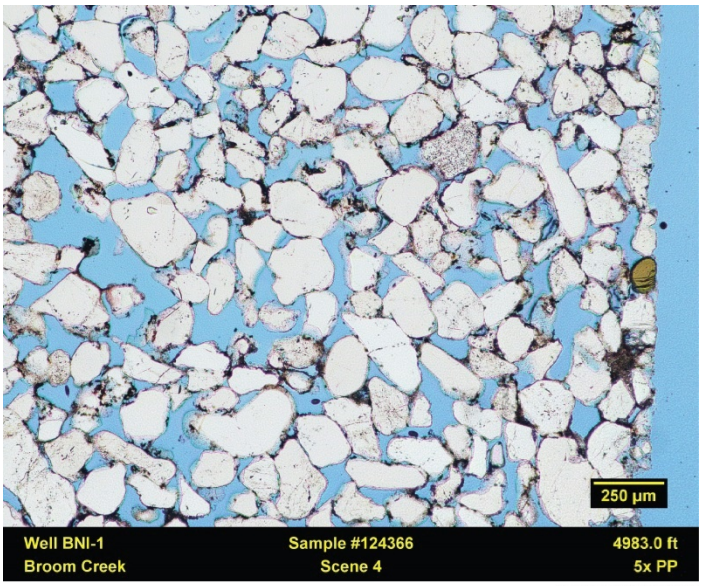


Figure A-10. Sandstone micrograph from BNI-1 core at 4983.0 ft showing some quartz overgrowths around many of the quartz grains. The very small, dark particles around the edges of some of the larger grains and as pore linings are iron oxide particles, giving the sand a reddish color.

showed a small amount of iron oxide precipitation, giving most of the sands a reddish color. Most of the sandstone samples also showed compaction. Some of the shallow marine sandstones contained a small amount of authigenic clays precipitated into pores, and several of the sandy dolomites had dolomite rhombs growing into pores (Figure A-11). Dolomitization occurred in samples where primary deposition was most likely carbonate mud. These intervals were also often associated with anhydrite. An evaporative model for the dolomitization of the mud is considered due to the association with anhydrite and lack of clay material to provide the Mg ions necessary for dolomitization of the carbonate muds.

3.2.2 XRD Analysis

The XRD data from 26 samples from the Flemmer-1 core supported facies interpretations from core descriptions and thin-section analysis. The Broom Creek units in the Flemmer-1 core were clay-poor. The core transition from the Amsden to the Broom Creek occurred between samples from 6541 to 6499.5 ft. Mineralogy demonstrated a regressive shift with quartz-rich sandstone subsequently overlain with a thick bed of anhydrite (6487 ft), most likely from a slight transgression as remnant deposits from a sahbka-type environment. The remainder of the Broom Creek unit consisted of quartz-dominated sandstones (~73% to ~93%), with potassium feldspars (~5% to ~15%) accounting for the other major siliciclastic phase. Dolomite acted as the most common cement in the sandstones. The interpretation of the carbonate-cemented sandstones was near-shore facies transitions. Dolomite units (6277.5, 6348.5, and 6387.5–6396 ft) represented transgressions in the sequence. Anhydrite also occurred as nodules in dolomite near facies margins. Anhydrite was also the predominant cement in the

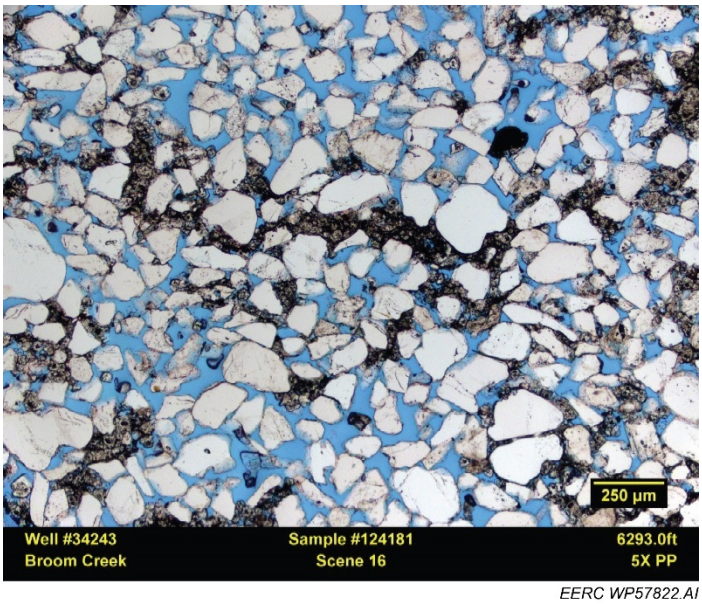


Figure A-11. Dolomite cemented quartz grains at 6293 ft in the Flemmer-1 core.

uppermost sandstone horizon that occurred near the uppermost dolomite bed before a transition into the Opeche occurred. The Opeche (6241 to 6271 ft) consisted of a quartz-rich siltstone with abundant clay, feldspar, dolomite, and some anhydrite.

The XRD data from 25 samples of the BNI-1 core supported facies interpretations from core descriptions and thin-section analysis. Near the base of the Broom Creek section of the BNI-1 core (5137 to 5140 ft), anhydrite occurred as a cement in sandstone near the Amsden–Broom Creek transition, followed by a transgressive marine dolomite (5132.75 ft), and then a regressive anhydrite unit that is interpreted as a sahbka environment deposit (5130.25 ft). A sequence of dolomitic sandstone (5123.5 ft), overlain by sandstone (5096.5 to 5114 ft), overlain by dolomitic shale, overlain by dolomite (5054 to 5061 ft) is interpreted as a small transgression–regression–major transgression sequence. The BNI-1 core had lithology at sample depths of 5061 to 5096.5 ft in the sequence interpreted as a minor transgression that are clay-rich. This could represent near-shore environment representative of meteoric water influence. A thick sequence of sandstone (4977.5 to 5049 ft) follows and was quartz-dominated (~57% to 95%), with potassium feldspars (~3% to ~14%) accounting for the other major siliciclastic phase. The dolomite-rich deposit (78.5%) with quartz grains (14.3%) and clay deposits (7.3%) that overlays the thick sequence of sandstone indicated another transgressive event. Overlaying quartz-rich (71%–81%) sandstone (4925 to 4931.5 ft) with dolomitic cement (4%–78%) was interpreted to represent another regression in the Broom Creek prior to deposition of the overlying siltstone, which marked the transition to the next formation.

3.2.3 XRF Analysis

The bulk chemical data distribution across the cores indicated there were multiple areas from each core that contained carbonate-rich material (CaO, MnO, and light elements) demonstrated to

be dolomite by XRD analysis. Interstitial episodes of silicate-rich material (SiO_2) were present in samples from both cores as well, demonstrated to be quartz-rich sandstone by XRD analysis. Elemental occurrence of CaO, SO_3, and other light elements also points to the possibility of anhydrite associated with the dolomite (confirmed by XRD analysis). Distinguishing dolomite-rich horizons from anhydrite-rich horizons was possible by comparing XRF and XRD data, which coincided with other evidence, especially the XRD data. Both data sets also demonstrate differences in major and minor transgression–regression events based on the chemical compositions consistent with mineral compositions defining depositional environments.

Figure A-12 (Flemmer-1 core data) and Figure A-13 (BNI-1 core data) represent the data in a stratigraphic context with relationships of mineral and geochemical data shown side by side. The elemental data when plotted against sample depth concurrent with mineralogical data plotted in the same manner showed evidence of transgressions and regressions well. Dolomitic intervals were interpreted to represent a transgressive portion of a sequence of events where the clastic influx is minimal and carbonate deposition in a marine environment is dominant. As the seas regressed, the dolomites became sandier (increasing SiO_2) and in several instances in the lower portions of both cores were capped with anhydrite. Minor transgressions and regressions can be recognized in the lower portions of the core, with relatively major transgressions and regressions in the upper portions of the core. Anhydrite was rare in the upper portions of the core, and deposits attributed to eolian sandstones were slightly more common than marine sandstone. The eolian sandstone beds tended to have the greatest porosity, with very little cementation holding grains together. Eolian sandstones were not identified by XRF methods, but samples tended to have a greater amount of SiO_2 and fewer minor elements that would be present in clays such as Al and Mg. Clay minerals were rarely detected in the deposits studied via XRD and thin-section analysis. Thus evidence points to the inference that clay minerals were removed in the eolian dune-forming processes. There was also a lack of material to form diagenetic clays in the deposits.

3.2.4 Electrical Resistivity

Electrical resistivity data are collected by measuring the electrical response of the core plug to formation brine as the saturation profile of the plug changes. By providing the laboratory data to create direct correlations between laboratory and field measurements, these tests assisted in the interpretation of wireline resistivity log data that were collected in the field.

Prior to testing, selected characteristics of the fluid and core plug (e.g., brine conductivity; core plug pore volume, dimensions, and mass) are determined. The sample is then loaded into the apparatus represented by Figure A-14, where the confining volume is filled with distilled water and pressurized before a vacuum is pulled on the sample. The sample is filled from the bottom with brine injected from a 50-cm^3 syringe until water begins to collect in the vacuum trap. Nitrogen pressure is slowly applied to the top of the sample, draining fluid from the bottom of the sample onto a balance. The resistance and brine mass are logged by a computer during the draining process. At the conclusion of the test, the sample is removed, and the final mass is measured to determine the final water saturation. The raw data are then evaluated to determine the formation factor, cementation exponent, saturation exponent, tortuosity, resistance, and resistivity of the core plug.

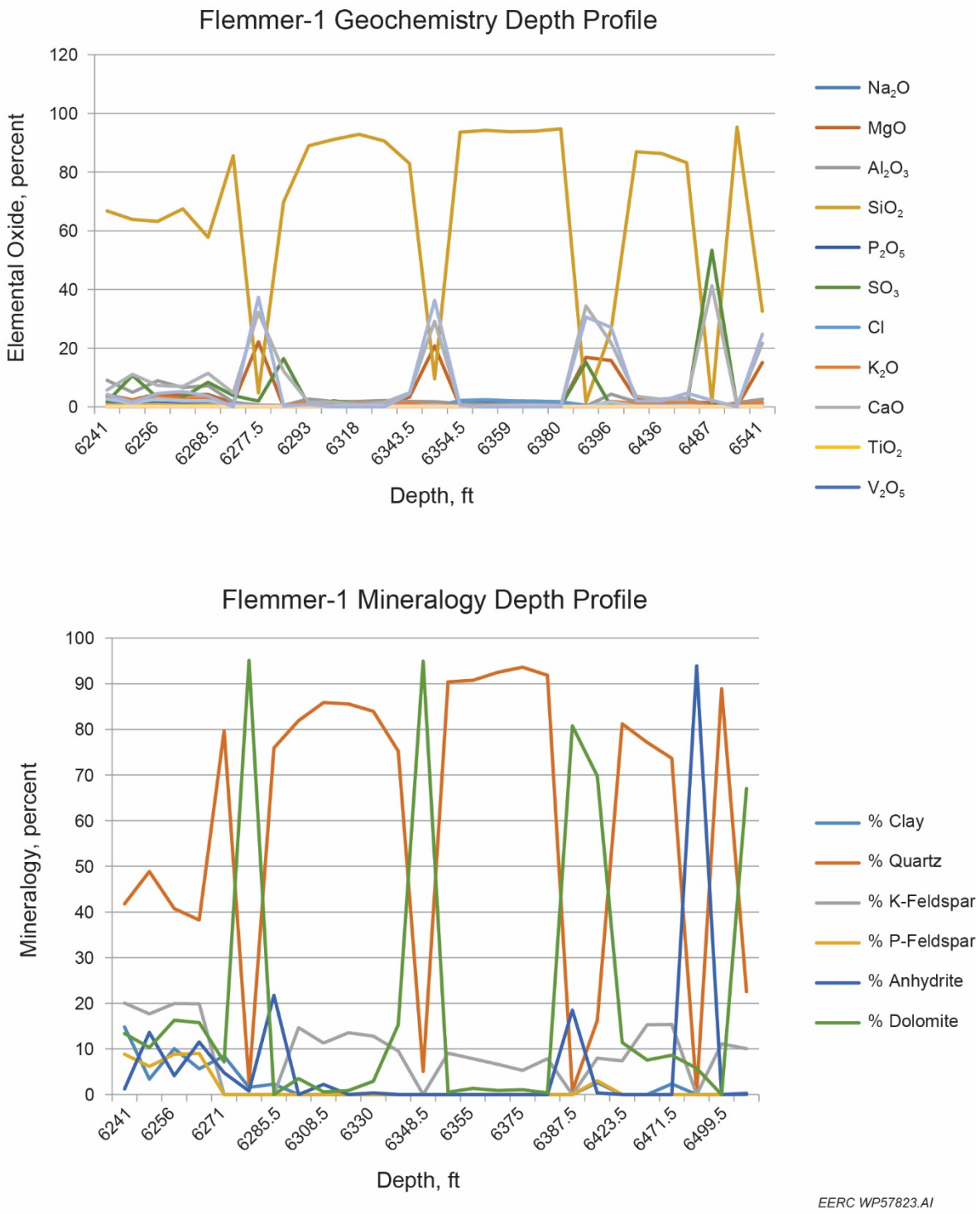


Figure A-12. Elemental and mineralogical data demonstrate trend agreement in relation to interpreted facies progression as seen in the Flemmer-1 core.

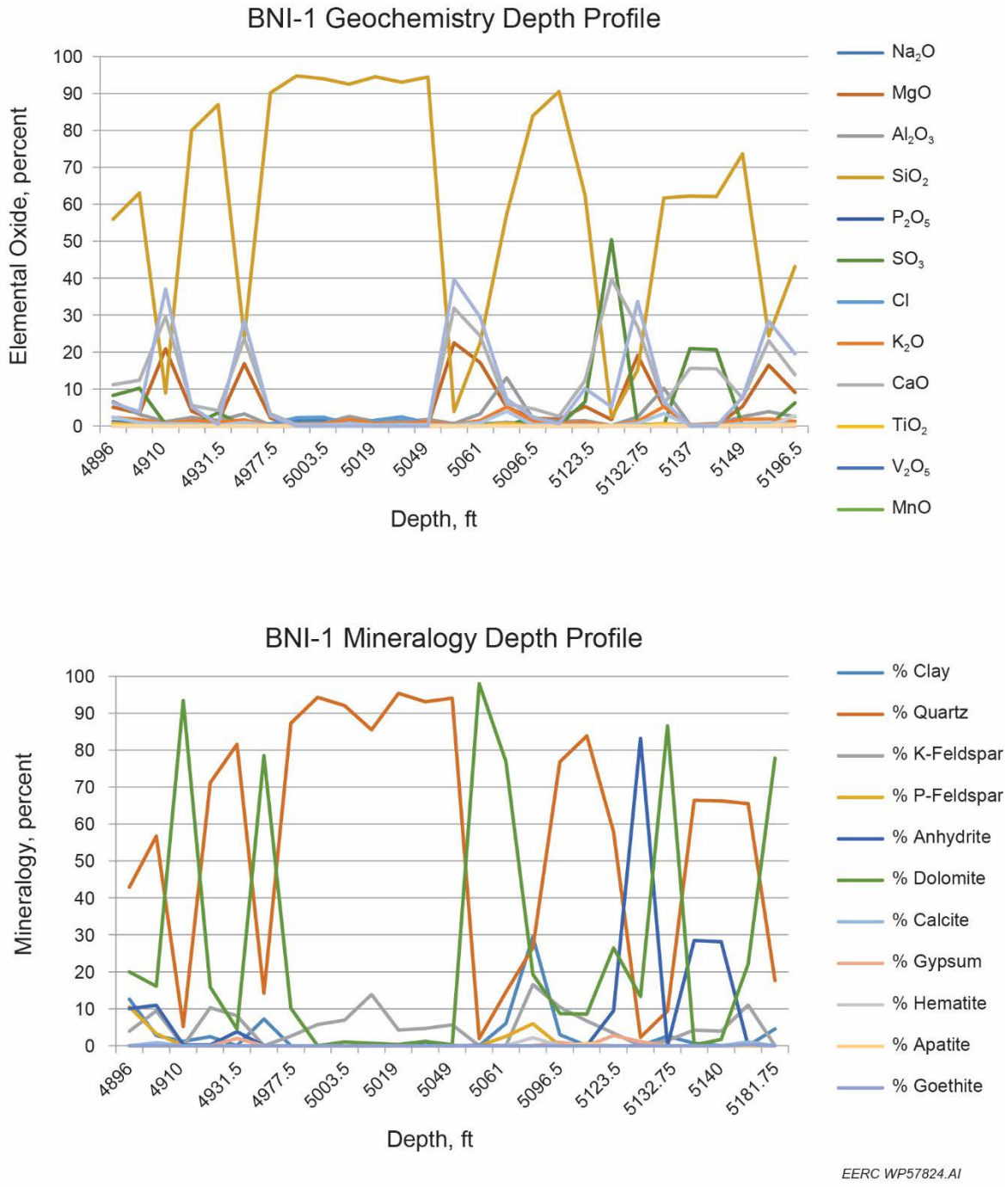


Figure A-13. Elemental and mineralogical data demonstrate trend agreement in relation to interpreted facies progression as seen in the BNI-1 core.

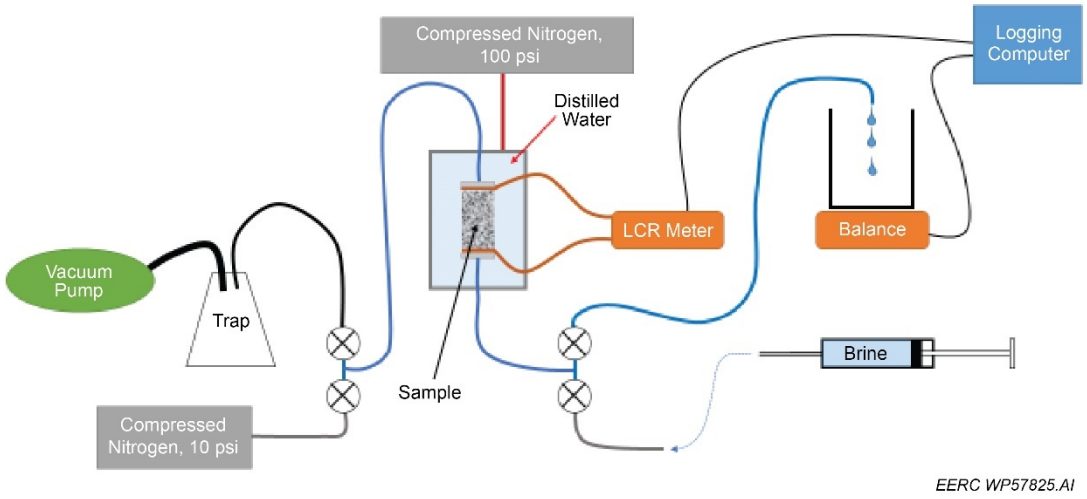


Figure A-14. Electrical resistivity experimental setup.

Electrical resistivity was evaluated for a total of four samples from the Broom Creek Formation: two samples from BNI-1 at depths of 4970 and 5114 ft and two samples from Flemmer-1 at depths of 6462 and 6481 ft (Table A-7). The characteristics of the brine used in these tests are shown in Table in Table A-8, and the test results are provided in Table A-9.

TableA-7. Characteristics of Core Plugs Subjected to Electrical Resistivity Test

Sample	Well	Formation	Depth, ft	Unstressed Porosity	Average Kair, mD	Length, mm	Diameter, mm	Pore Volume, mL
124364	BNI-1	Broom Creek	4970	23%	944.9	46.38	30.20	6.91
124382	BNI-1	Broom Creek	5114	17%	70.80	46.79	28.90	4.60
124204b	Flemmer-1	Broom Creek	6462	21%	125.7	46.17	29.90	6.16
124206b	Flemmer-1	Broom Creek	6481	18%	144.3	47.07	29.95	5.41

Table A-8. Brine Characteristics of Electrical Resistivity Test

Brine Parameter	Value	Unit
TDS	65,000	ppm
Density	1.053	g/mL
Conductivity	94.8	mS/cm
Resistivity	0.1055	ohms*m

Table A-9. Electrical Resistivity Testing Resistance and Resistivity Results

Sample	Final Water Saturation Sw	Formation Factor F	Cementation Exponent m	Saturation Exponent n	Tortuosity Tau	Resistance Rho, Ω Sw=1	Resistivity R, Ω*m Sw=1
124364	12%	14.802	1.854	2.383	3.459	97.830	1.561
124382	32%	21.766	1.761	1.664	3.785	163.768	2.296
124204b	39%	11.615	1.577	1.156	2.453	80.564	1.225
124206b	23%	23.624	1.837	1.539	4.225	165.943	2.492

3.2.5 High-Pressure, High-Temperature Relative Permeability

The high pressure, high temperature flow through system shown in Figure A-15 is designed to determine the relative permeability of a core plug. Relative permeability is the ratio of the effective permeability of an injected fluid to the absolute permeability of the rock. Liquid phases are loaded into transfer vessels inside an oven. High precision syringe pumps are used to control fluid injection rates and a dome backpressure regulator (BPR) is used to control the system pressure.

Fluid is produced out of the BPR into the gas separator with an integrated capacitive level sensor. Gas produced from the separator is passed through a dryer/filter before being measured using a thermal mass flow meter. After testing, the fluid is transferred from the capacitive level sensor to the balance to provide a posttest capacitive level/volume calibration. The produced liquid levels are compared with the system and sample volumes to estimate core saturations.

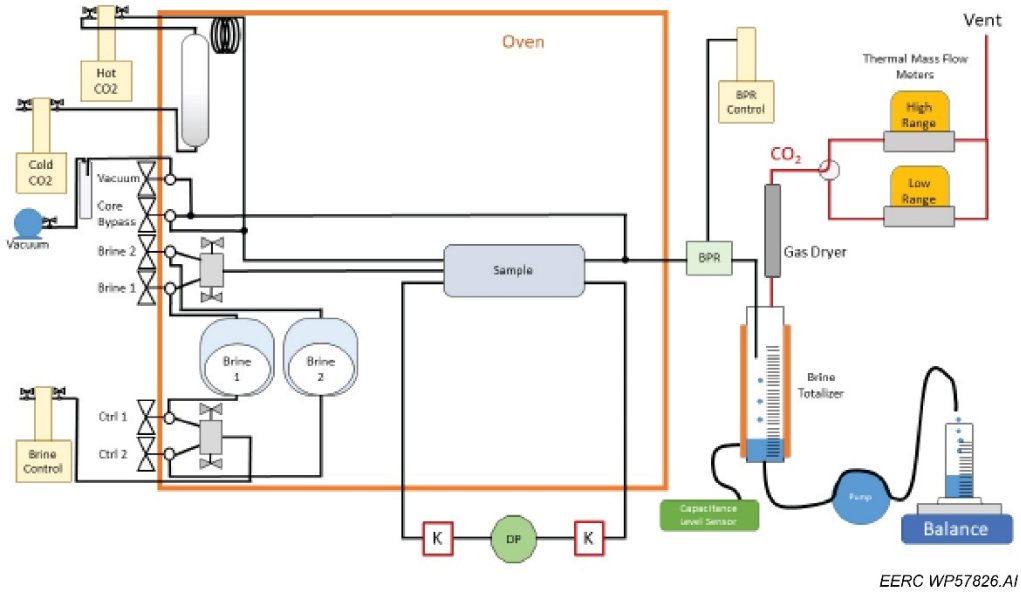


Figure A-15. Experimental setup to conduct relative permeability testing on a core plug.

Data regarding the relative permeability of CO_2 and brine in the subsurface are required to test brine-CO_2 hysteresis. Specifically, a test sequence comprised of steps that provide data regarding CO_2 permeability, brine permeability, CO_2/brine hysteresis, CO_2 permeability at irreducible water saturation, and brine permeability at irreducible CO_2 saturation are completed using the test apparatus in Figure A-16. Each of these steps in the test sequence is briefly described in the remainder of this section.

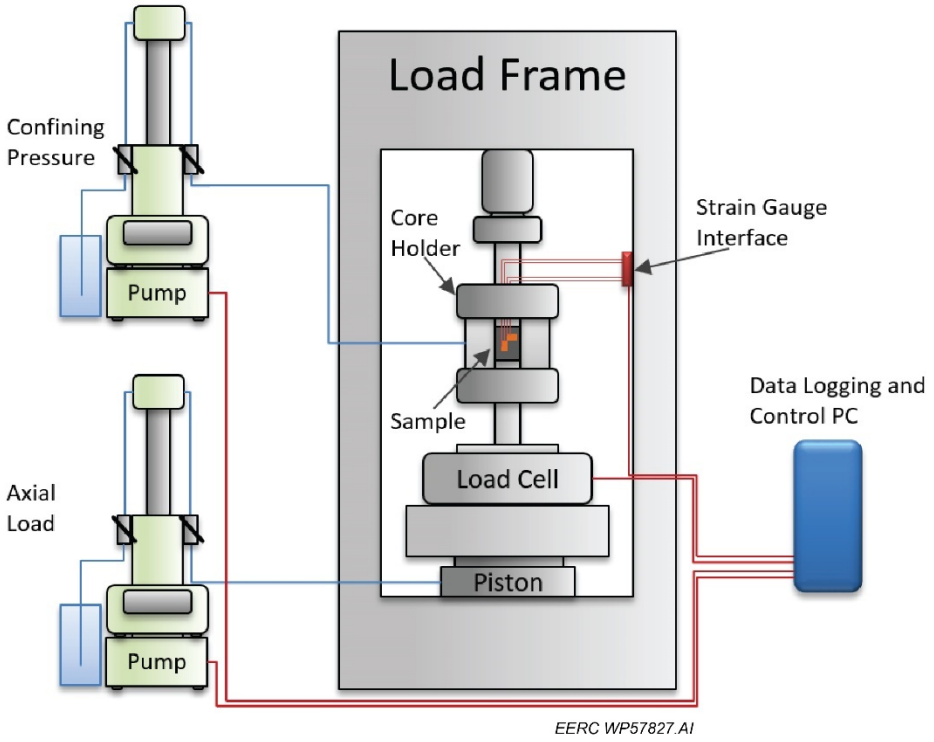


Figure A-16. Diagram of the triaxial test apparatus.

CO_2 Permeability

After the core plug is loaded into the system and the confining pressure is applied to the core holder, a vacuum is pulled to evacuate gas from the sample for up to 24 hours, depending on sample porosity. The core bypass is then opened and the system is pressurized to the test pressure with CO_2. The core bypass is then closed and the system is monitored until the temperature is stabilized and there is confirmation of no leaks in the system. The pressure is then adjusted on the BPR to maintain the desired backpressure before starting injection. CO_2 is then injected into the sample at a constant flow rate for high flow samples or at a constant pressure for low flow samples. The differential pressure is monitored and data are collected for several flow conditions. At least 3 conditions are tested and the permeability vs flow rate for the sample are plotted and compared using a linear regression to verify that testing is being performed within the Darcy flow regime. An observation of nonlinear indicates that flow rates exceeded stable Darcy flow. Permeability calculations are performed according to API RP-40 (American Petroleum Institute, 1998b).

Brine Permeability

The core plug is slowly depressurized and a vacuum is again pulled on the system to prepare for the brine saturation and permeability tests. Following adequate evacuation, brine is injected into the system, raising the system pressure to test conditions. The core bypass is then closed and the BPR is set to maintain the desired backpressure. Testing is started by injecting freshwater into the bottom of the selected bladder accumulator. This displaces synthetic brine, which flows from the top of the accumulator into the core plug at an equivalent rate. The rate is set based on the sample permeability and multiple conditions are tested to verify stable Darcy flow. Steady-state brine permeability is calculated according to API RP-40 “Horizontal Flow of Liquids” (American Petroleum Institute, 1998c). The injected fluid is produced from the core plug through the BPR into the capacitive level sensor/separator. The level data are correlated to the injection data as a calibration check. Collected data are used to calculate the permeability of the core plug to brine. At the conclusion of the test, the sample is maintained at pressure for hysteresis testing.

CO_2/Brine Hysteresis

During hysteresis testing, CO_2 and brine are individually flushed through the sample while pressures, flow rates and fluid volumes are monitored. Following multiple fluid injection cycles, the amount of trapped gas is expected to increase causing higher irreducible CO_2 saturations and detrimentally affecting permeability. The remainder of this section describes the process used to determine the permeabilities of CO_2 and brine when the other phase is present at irreducible saturations.

CO_2 Permeability at Irreducible Water Saturation

With the core plug saturated with brine, the CO_2 injection pump is pressure matched to the system conditions and the injection valve is opened. CO_2 injection is started at a constant flow rate; fluid production and gas flow are monitored. The test is allowed to run until the collected brine, the differential pressure and the CO_2 production all stabilize, indicating that a steady state condition has been reached. These steady-state flow data are used to calculate CO_2 permeability at irreducible water saturation for the first injection cycle. The CO_2 injection valve is then closed and the brine Injection pump is pressure matched to the system.

Brine Permeability at Irreducible CO_2 Saturation

With the brine injection pump pressure matched to the system, the brine injection valve is opened and the system is allowed to come to equilibrium. Brine injection is then started at a constant flow rate based on the sample permeability and produced fluids are collected from the backpressure regulator. The CO_2 and brine flow are monitored in the separator; brine is injected until stable flow conditions are observed. These steady-state flow data are then used to calculate the brine permeability at irreducible CO_2 saturation.

This CO_2 and brine injections are continued for several additional cycles to examine the hysteresis effects of sample permeability. During testing many of the samples produced significant amounts of fines and debris through the system which is indicative of induced damage. The

extremely friable nature of many of these samples made testing extremely difficult and resulted in clogging in various parts of the system.

3.2.6 Geomechanical Testing

Triaxial Compressive Strength

A combination of nondestructive rebound tests and the destructive ISRM (International Society of Rock Mechanics) Type 2 test were performed to provide the Young's modulus, Poison's ratio, the ultimate compressive strength, and residual strength of the core subsamples at a multitude of conditions. Multiple core plugs were prepared with strain gauges and tested for triaxial compressive strength according to the ISRM type 2 multi-failure point testing procedure (International Society of Rock Mechanics, 2007) using the triaxial testing system shown in Figure A-16. These tests provide the maximum amount of data per sample. The testing procedures are described in more detail in the remainder of this section.

Stress Rebound Tests

Stress rebound tests are used to evaluate the sample properties at confining pressures of 75%, 100% and 125% of expected reservoir stress. The sample is initially loaded to less than 50% of failure stress but at a load sufficient to collect a linear set of data to establish Young's modulus and Poisson's ratio. The loading stages for a rebound test is shown in Figure A-17. After a rebound test is completed for each confining pressure, the sample is unloaded and the strain gauge output is checked to verify proper operation before the destructive ISRM Type 2 multifailure point test is performed.

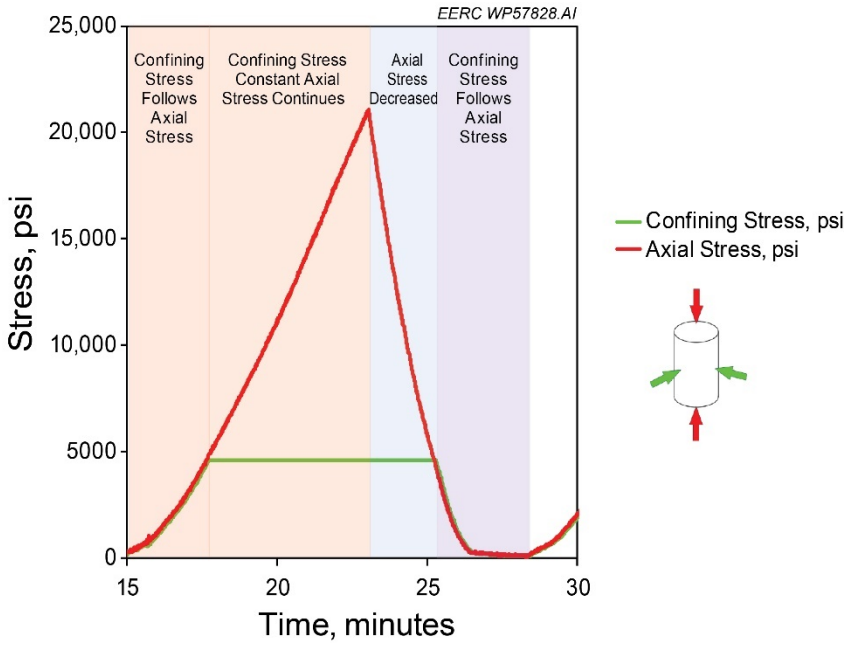


Figure A-17. Example of rebound test illustrating changes in confining and axial stress during testing.

ISRM Type 2 Multifailure Point Test

Figure A-18 shows the loading process for the ISRM Type 2 test. The procedure involves increasing the pressure on the sample until the initial failure of the sample is observed at a "Stage 1" confining condition of 75% of reservoir stress. Once a decrease in the stress strain curve slope is realized, the confining pressure is increased to the next confining condition, i.e., "Stage 2," and again until the next failure is observed, i.e., "Stage 3." The sample is finally loaded until complete failure is observed and a residual strength is measured.

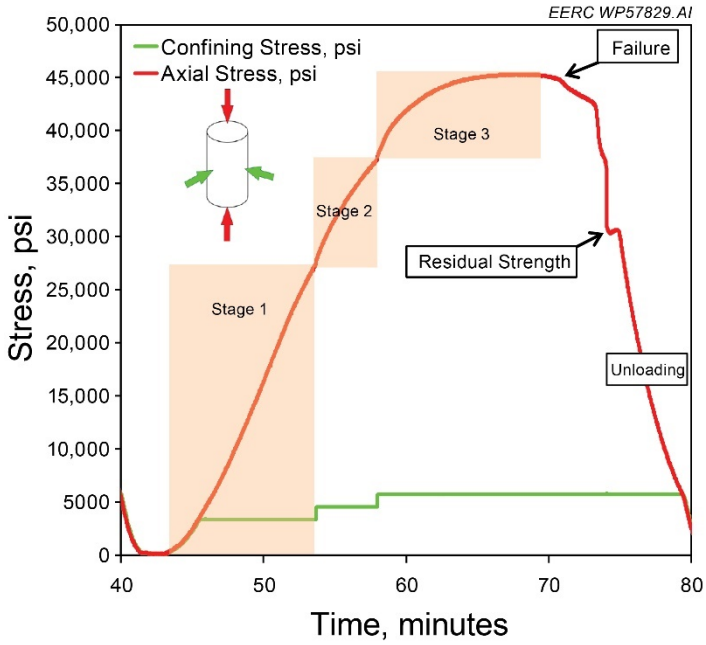


Figure A-18. Example of multifailure point test, illustrating test stages.

REFERENCES

American Petroleum Institute, 1998b, Recommended practices for core analysis, Section 6.2.1 Steady-state permeability equations for gases [2d Ed.]: Exploration and Production Department, American Petroleum Institute, Feb.

American Petroleum Institute, 1998c. Recommended practices for core analysis, Section 6.2.2 Special cases for steady-state flow of incompressible liquids [2d Ed.]: Exploration and Production Department, American Petroleum Institute, Feb.

American Petroleum Institute,1998a, Recommended practices for core analysis, Section 5.3.2.1.1 Boyle's law double-cell (matrix cup) method for grain volume [2d Ed.]: Exploration and Production Department, American Petroleum Institute, Feb.

ASTM International, 1990, Standard test method for permeability of rocks by flowing air: ASTM D4525-90 (reapproved 2001).

ASTM International, 2008, Standard practices for preparing rock core as cylindrical test specimens and verifying conformance to dimensional and shape tolerances: ASTM D4543-08.

Bluemle, J.P., Anderson, S.B., Andrew, J.A., Fischer, D.W., and LeFever, J.A., 1986, North Dakota Stratigraphic Column MS 66: North Dakota Geological Survey.

Fischer, D.W., LeFever, J.A., LeFever, R.D., Helms, L.D., Sorensen, J.A., Smith, S.A., Steadman, E.N., and Harju, J.A., 2008, Broom Creek Formation outline: Plains CO_2 Reduction (PCOR) Partnership, March.

Hoda, B., 1977, Feasibility of subsurface waste disposal in the Newcastle Formation, Lower Dakota Group (Cret.), and Minnelusa Formation (Penn.), western North Dakota: M.S. thesis, Wayne State University, Detroit, Michigan, 79 p.

International Society of Rock Mechanics, 2007, Suggested methods for determining the strength of rock materials in triaxial compression – revised version, suggested methods for triaxial testing: p. 159–164.

Murphy, E.C., Nordeng, S.H., Juenker, B.G., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey.

North Dakota Industrial Commission, 2019, Completed geophysical exploration permit: Five maps and fact sheet, www.dmr.nd.gov/oilgas/seismic/permitfiles/970290.pdf (accessed 2019).

Rasband, W.S., 2016, ImageJ: U.S. National Institutes of Health, Bethesda, Maryland, https://imagej.nih.gov/ij/ (accessed 2020).

Rygh, M.E., 1990, The Broom Creek Formation (Permian) in southwestern North Dakota—depositional environments and nitrogen occurrence" Theses and Dissertations, 254.

Sommer, C., Strähle, C., Köthe, U., and Hamprecht, F.A., 2011, Ilastik—interactive learning and segmentation toolkit, *in* 8th IEEE International Symposium on Biomedical Imaging (ISBI): Proceedings, p. 230–233.

Sorensen, J.A., Smith, S.A., Dobroskok, A.A., Peck, W.D., Belobraydic, M.L., Kringstad, J.J., and Zeng, Z.-W., 2009, Carbon dioxide storage potential of the Broom Creek Formation in North Dakota—a case study in site characterization for large-scale sequestration, *in* Grobe, M., Pashin, J.C., and Dodge, R.L., eds., Carbon dioxide sequestration in geological media—state of the science: AAPG Studies in Geology, v. 59, p. 279–296.

Willis, R.P., 1959, Upper Mississippian-Lower Pennsylvanian stratigraphy of central Montana and Williston Basin: American Association of Petroleum Geologist Bulletin, v. 43, no. 8, p. 1940–1966.

Ziebarth, H.C., 1972, Stratigraphy and hydrocarbon potential of Minnelusa Group, western North Dakota [abs.]: American Association of Petroleum Geologists Bulletin, v. 55, no. 3, p. 544–545.

APPENDIX B

GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

GEOLOGIC MODEL CONSTRUCTION AND NUMERICAL SIMULATION OF CO_2 INJECTION

1.0 INTRODUCTION

Geologic models were built for use in numerical simulation of carbon dioxide (CO_2) injection to evaluate the potential of storing 50 million tonnes (Mt) of CO_2 over a 25-year time frame. The geologic models were constructed over a 5544-mi^2 (77 miles by 72 miles) study area that included three North Dakota coal-based energy generation facilities: Basin Electric Power Cooperative's (BEPC's) Antelope Valley Station (AVS), Dakota Gasification Company's Great Plains Synfuels Plant (GPSP), and Minnkota Power Cooperative's Milton R. Young Station (MRYS) in central Oliver County (Figure B-1). Model construction and numerical simulation efforts focused on three zones of interest: 1) the Permian Broom Creek Formation (primary injection target) and overlying seals of the Opeche, Minnekahta, Spearfish, and Piper Formations, 2) the Cretaceous Inyan Kara Formation and overlying Skull Creek Formation seal, and 3) the Cambrian–Ordovician Deadwood and Black Island Formations and overlying Icebox Formation seal (Figure B-2). The Cretaceous Inyan Kara Formation and Cambrian–Ordovician Deadwood Formation (Figure B-2) were also investigated as potential injection targets to determine their feasibility as stacked storage intervals to augment Broom Creek Formation storage or as alternate primary storage targets. Numerical simulations of CO_2 injection were conducted to evaluate the feasibility of CO_2 storage at GPSP and MRYS, using the geologic models of the Broom Creek, Inyan Kara, and Black Island–Deadwood Formations. Multiple injection scenarios were evaluated including single formation scenarios as well as stacked storage scenarios using multiple formations. Additionally, geochemical simulation investigated CO_2-trapping mechanisms within the Broom Creek Formation following 100 years after the cessation of CO_2 injection.

2.0 GEOLOGIC MODEL CONSTRUCTION

Geologic models were constructed with data acquired as part of this feasibility study and with publicly available data using Schlumberger's Petrel software (Schlumberger, 2016). Data acquired during this project included stratigraphic test well data (Flemmer-1 and BNI-1), a 10-mi^2 3-D surface seismic survey, and 28 miles of 2-D seismic lines (Figure B-1). The two stratigraphic test wells provided formation top depths; modern well log data; 645 feet of core samples (325 feet from Flemmer-1 and 315 feet from BNI-1) from the Amsden, Broom Creek, Opeche, and Spearfish–Piper Formations; fluid samples; and pressure measurements. The 2-D and 3-D seismic surveys provided structural control and increased the understanding of interwell heterogeneity. Publicly available data were acquired from the North Dakota Industrial Commission (NDIC) and the North Dakota Department of Health (NDDH) databases. These data included well datum values (i.e., kelly bushing [KB]), well logs, formation top depths, and core sample descriptions and analyses.

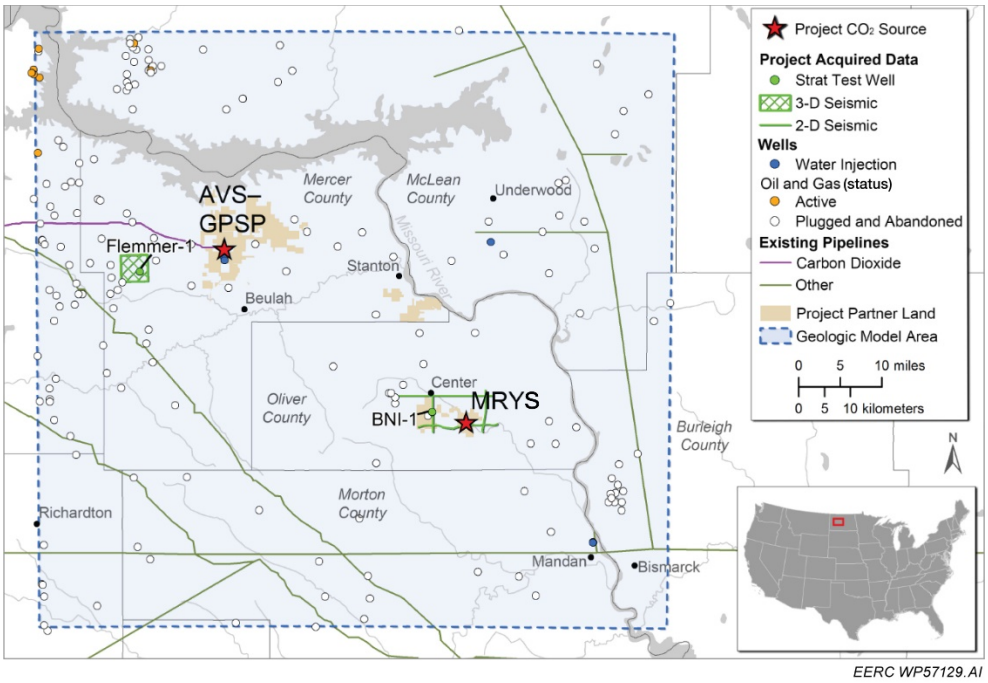


Figure B-1. Map showing the North Dakota CarbonSAFE study area, which includes two North Dakota energy complexes: AVS–GPSP in northwestern Mercer County and MRYS in central Oliver County. The extent of the geologic model created for this study is also depicted by a blue rectangle that encompasses an area of 5544 mi^2.

2.1 Broom Creek Formation

An initial Broom Creek model was constructed during the early stages of the project with formation top depths, well logs, and 2-D and 3-D seismic horizons. The model was used during preliminary simulation scenarios and for an independent evaluation of the National Risk Assessment Partnership (NRAP) tools, which is also being performed as part of the U.S. Department of Energy (DOE) CarbonSAFE projects. The model was later updated to include core analysis results and 3-D seismic interpretations. The final updated model was used for all reported simulation results, including the history-match of two existing Broom Creek water disposal wells (ANG #1 and ANG #2) near GPSP.

2.1.1 Structural Framework

The Broom Creek structural model was composed of the Amsden, Broom Creek, Opeche, Minnekahta, Spearfish–Piper Formations. Formation top depths were picked from well log interpretation of existing wellbores, the two stratigraphic test wells, structural interpretations of the 2-D and 3-D seismic data, and published formation extents from Carlson (1993), Dow (1964), and Rygh (1990). The 2-D and 3-D seismic surveys provided structural control where available, helping reduce the structural uncertainty in those areas (Figure B-1). Figure B-3 shows a typical well log display of the Broom Creek Formation in the study area.

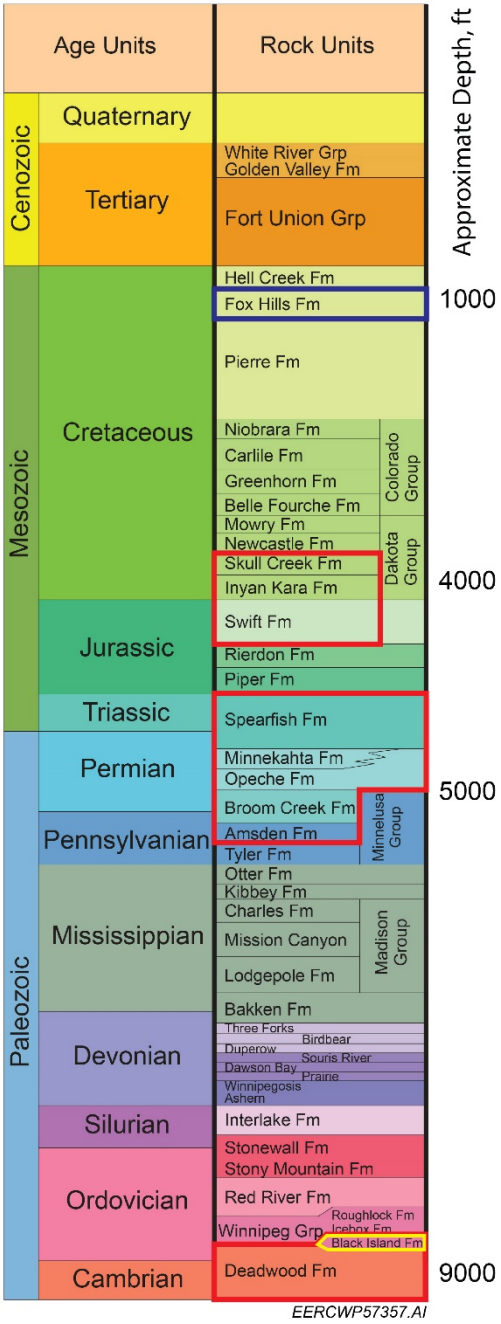


Figure B-2. Williston Basin stratigraphic column (modified from Murphy and others, 2009). Intervals investigated in this work are highlighted in red, including the Inyan Kara, Broom Creek, Black Island, and Deadwood Formations.

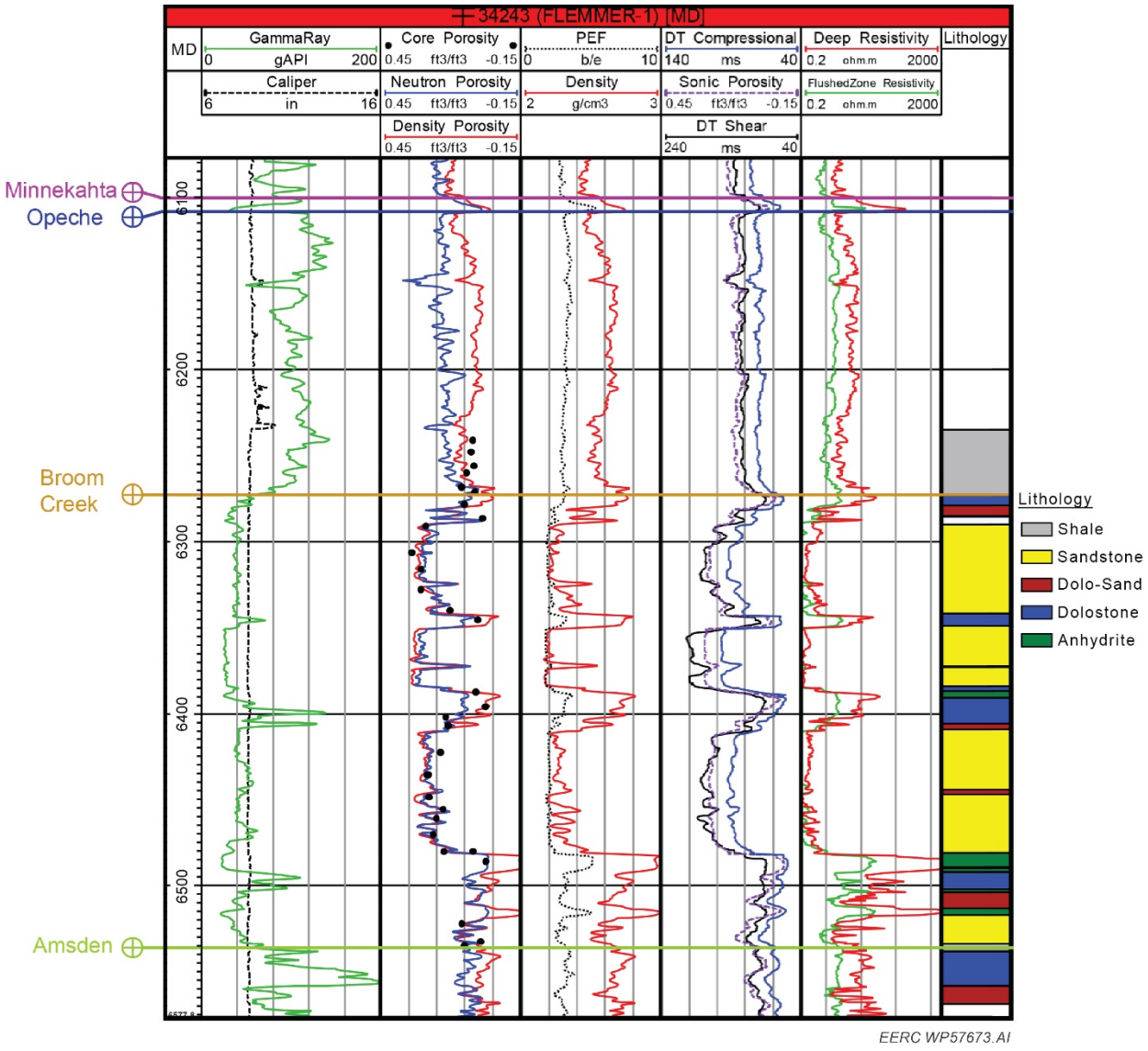


Figure B-3. Typical log of the Broom Creek Formation near GPSP (NDIC #34243, API [American Petroleum Institute] 3305700390000). Curves shown are (from left to right): 1) caliper and gamma ray (GR); 2) core, neutron, and density porosity; 3) photoelectric factor (PEF) and density; 4) compressional sonic travel time (DT compressional), sonic porosity, and shear sonic travel time (DT shear); 5) deep resistivity and flushed zone resistivity; and 6) lithology.

Structural inputs were interpolated across the study area, creating structural surfaces for each formation. The Broom Creek Formation averages 5400 feet below the land surface and 220 feet thick and pinches out (is absent) toward the east–northeast of the study area (Figure B-4). Table B-1 provides average depths and thicknesses within the study area for each formation in the Broom Creek model, along with expected depth and thickness at each CO_2 source.

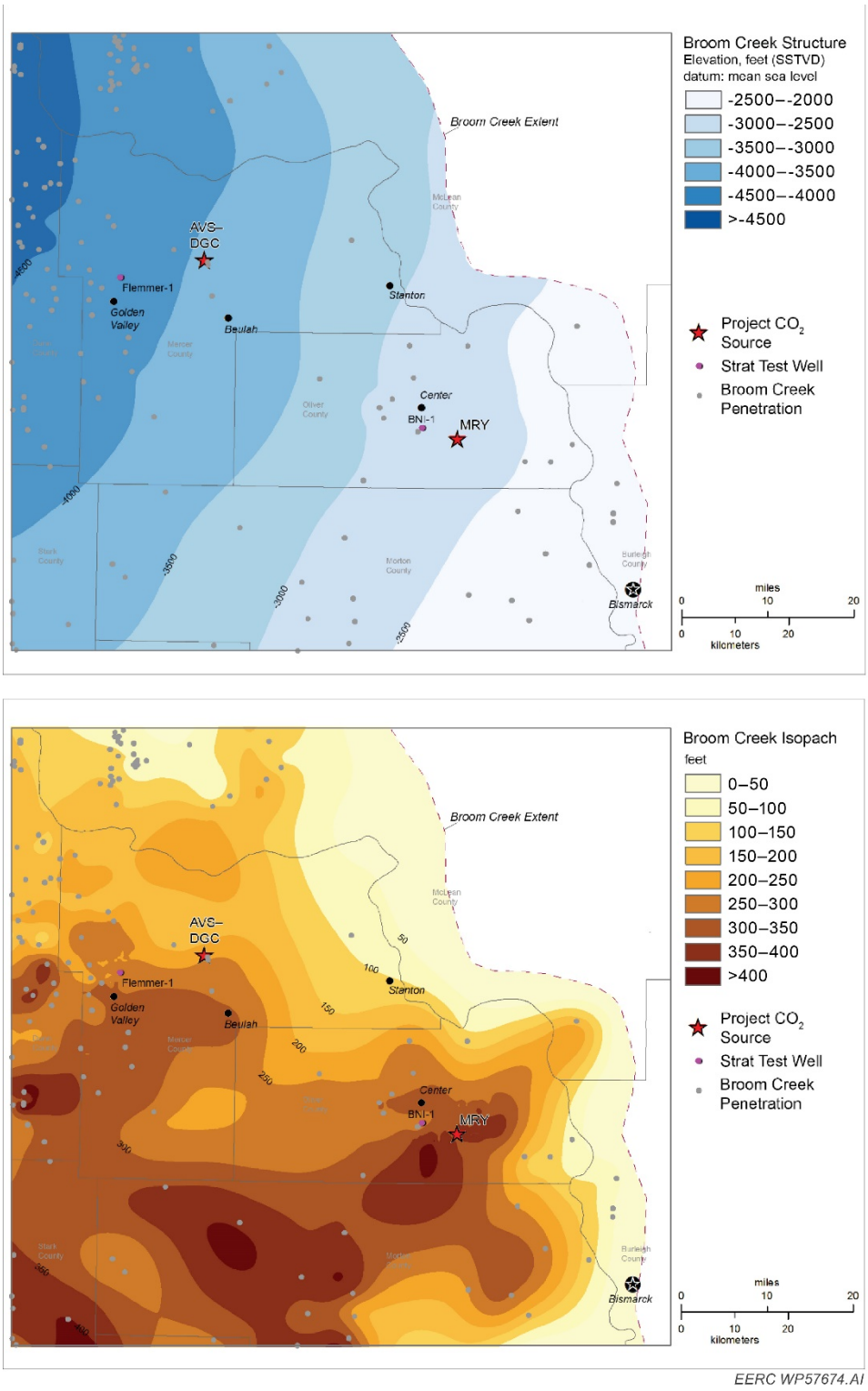


Figure B-4. Top: structure contour map of the top of the Broom Creek Formation (datum – mean sea level). Bottom: isopach map of the Broom Creek Formation.

Table B-1. Depth and Thickness of Formations of Interest in the Broom Creek Model

	Model Area		GPSP		MRYS	
Formation	Average Measured Depth, ft	Average Thickness, ft	Expected Depth, ft	Expected Thickness, ft	Expected Depth, ft	Expected Thickness, ft
Piper–Spearfish	4829	338	5312	345	4346	276
Minnekahta	5920	36	5652	5	N/A[1]	N/A
Opeche	5840	134	5657	173	N/A	N/A
Broom Creek	5400	220	5830	238	4622	348
Amsden	5416	260	6068	338	4970	142

[1] Not applicable.

2.1.2 Lithofacies Distribution

The interpreted depositional environment of the Broom Creek Formation is eolian and nearshore marine sandstone–carbonate cycles (Willis, 1959). The Broom Creek lithofacies model was developed to capture the lithofacies relationships and geometry of the interpreted depositional environment. Lithofacies modeling used core sample descriptions and analyses, well log data, and seismic data interpretations, along with insights from previously completed studies of the Broom Creek Formation (Rygh, 1990; Sorensen and others 2009; Peck and others, 2014).

Core sample and well log data collected from both Phase II stratigraphic test wells (Flemmer-1 and BNI-1) and existing Broom Creek cores (NDIC #90383, 658, ANG #1) were analyzed to better understand the lithologies and lithofacies relationships of the Broom Creek Formation (Figure B-3). The lithofacies and well log associations were then used to create lithofacies logs in wells across the study area. Within the study area, the Broom Creek interval was assigned five lithofacies: sandstone, lower sandstone, dolomitic sandstone, dolostone, and anhydrite. The sandstone, lower sandstone, and dolomitic sandstone lithofacies represent the reservoir lithologies within the Broom Creek Formation because they have the best reservoir properties relative to CO_2 storage. The nonreservoir dolostone and anhydrite lithofacies represent poor reservoir properties, thus creating internal baffles within the Broom Creek.

Lithofacies logs were then upscaled into the structural model and used as control points for lithofacies distributions. Multipoint statistics (MPS) were used to distribute the upscaled lithofacies logs between the control points. A training image used with MPS was generated from the interpreted depositional environment of Ziebarth (1972) and Rygh (1990), along with lithofacies relationships found in the Flemmer-1 and BNI-1 wells and interpreted 3-D seismic data (Livers-Douglas and others, 2019).

Southwest-to-northeast-trending ovular features were identified in the 3-D seismic data using seismic attribute analysis. Core analysis and well log correlations coupled with synthetic modeling suggested these ovular features represent thin interdunal carbonate deposits. Interpreted geobodies including elongate eolian sand dunes (reservoir) and ovular interdune carbonate

(nonreservoir) beds were incorporated into the model by using the dimensions of the interpreted reservoir and nonreservoir lithologies within the formation (Figure B-5). The interpreted geobodies suggest a southwest-to-northeast depositional trend that was used to orient the training image for lithofacies modeling.

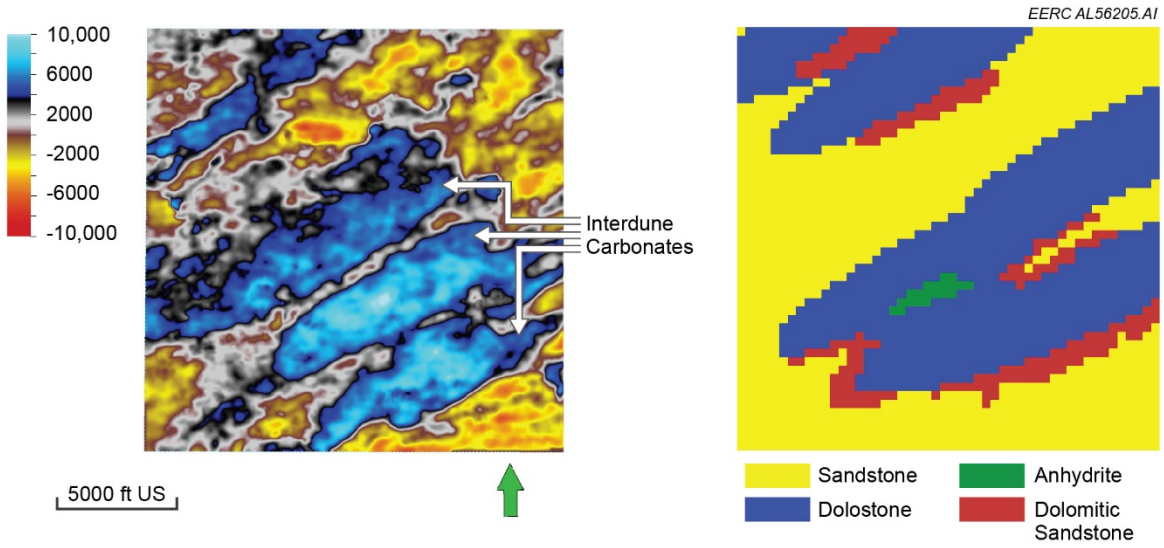


Figure B-5. Left: Map view of seismic amplitude time slice through the Broom Creek Formation with interpreted geobodies. High-amplitude values (blue) caused by thin-bed tuning indicate the presence of interdunal carbonates. Right: Training image grid used in MPS lithofacies distributions.

The training image was created for use in MPS with dimensions of the 3-D seismic geobody interpretations and lithofacies log associations. The completed training image is shown in Figure B-5. The training image was then used to distribute lithofacies between lithofacies log control points. The final Broom Creek lithofacies model was composed of 44% sandstone, 35% dolostone, 12% dolomitic sandstone, 6% lower sandstone, and 3% anhydrite.

Based on the 3-D seismic interpretation, core description, and well log correlation, the Broom Creek is interpreted to be a very heterogeneous formation. Lithofacies uncertainty was addressed because of the heterogeneity of the Broom Creek and the impact on reservoir connectivity.

A lithofacies uncertainty analysis was conducted to provide multiple lithofacies realizations, enabling numerical simulations of CO_2 injection to be conducted with differing ratios of lithofacies and connectivity of reservoir-quality lithofacies. Three lithofacies distributions with varying proportions of sandstone (low, mid, high) were created. A lithofacies distribution based on the upscaled lithofacies logs resulted in the “mid” lithofacies model. Lithofacies uncertainty was achieved by varying the lithofacies proportions of the “mid” case by ±10% (Figure B-6). Table B-2 shows the final lithofacies proportions for the low, mid, and high Broom Creek lithofacies models.

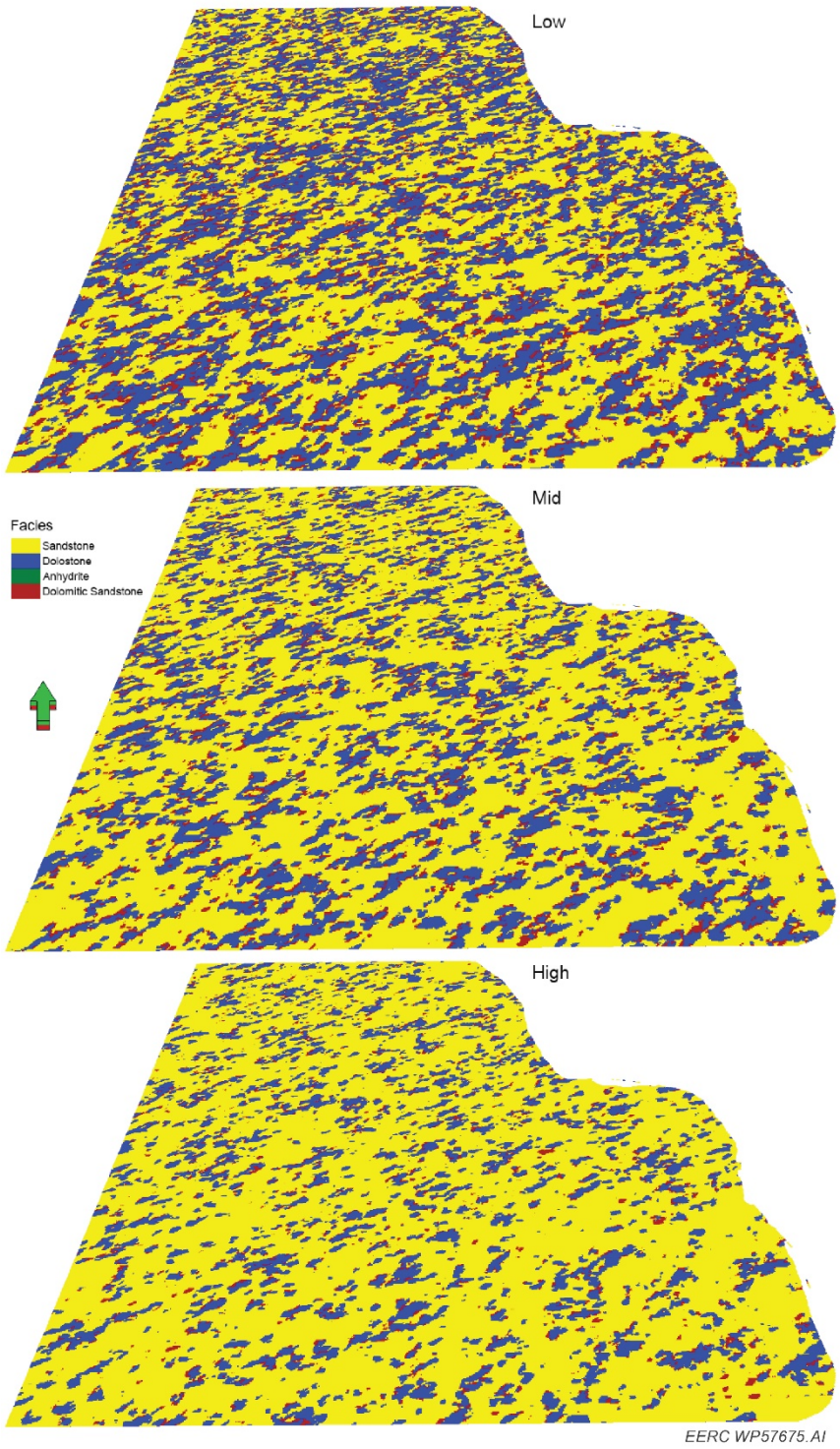


Figure B-6. Lithofacies model depth slice, representing the low, mid, and high cases (top to bottom, respectively).

Table B-2. Lithofacies Proportions from Uncertainty Analysis

	Proportion/Connectivity		
Lithofacies	**Low Case**	**Mid Case**	**High Case**
Sandstone	34.3	44.0	53.5
Dolostone	43.2	34.5	27.3
Anhydrite	2.2	3.4	2.0
Dolomitic Sandstone	15.2	12.3	8.2
Lower Sandstone	5.1	5.8	9.0

2.1.3 Petrophysical Property Distributions

Petrophysical properties (porosity and permeability) were derived from core analysis data and well logs. Broom Creek porosity and permeability from core analysis were acquired from the two stratigraphic test wells along with three existing wells in North Dakota that contain Broom Creek core (Table B-3). Additionally, well logs collected during the stratigraphic test well efforts included derived elemental log analysis (ELAN) porosity and permeability that were also used in petrophysical modeling efforts.

Table B-3. Wells with Available Broom Creek Formation Core Analyses

Well Name (NDIC #)
Flemmer-1 (34243)
BNI-1 (34244)
ANG-1 (N/A)
Herman May Unit #2 (658)
BEST-I1 (90383)

The core and well log-derived porosity and permeability values were categorized based on their lithofacies association within the Broom Creek Formation, which allowed for the creation of porosity–permeability crossplots for each lithofacies (Figure B-7). Porosity and permeability ranges for each Broom Creek lithofacies within the model are shown in Table B-4. Petrophysical properties were conditioned to the previously created lithofacies model using the porosity–permeability crossplot and statistics derived for each lithofacies. Porosity was distributed first using a variogram-based geostatistical method; subsequently, permeability was distributed using bivariate relationships associated with each lithofacies porosity and permeability crossplot. Variogram ranges used to distribute these properties represent general eolian depositional environments documented in Deutsch (2008), with a major variogram range of 1735.6 feet, a minor variogram range of 472.4 feet, and a vertical variogram range of 6.6 feet. Variograms were oriented with the major axis southwest-to-northeast, the same general direction of geobody orientation from 3-D seismic interpretation.

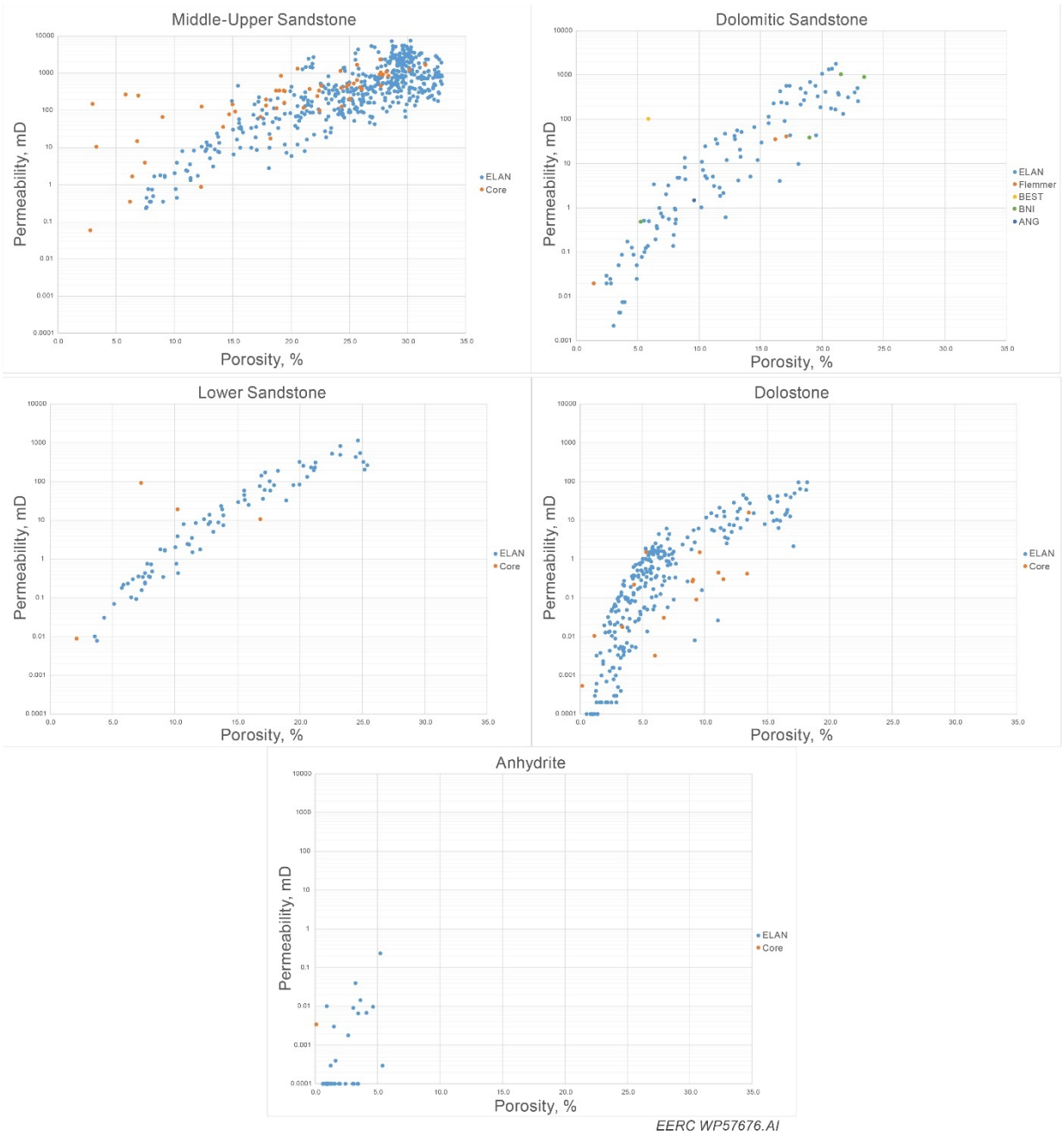


Figure B-7. Broom Creek Formation lithofacies porosity–permeability crossplots, ELAN, and core sample measurements.

A small number of core exists from the Broom Creek Formation in North Dakota, even with the addition of core samples acquired from the two stratigraphic test wells constructed in this study. To address the uncertainty related to petrophysical properties, three petrophysical property distributions (P_{10}, P_{50}, P_{90}) were created to assess a range of realizations. The conservative case

Table B-4. Petrophysical Property Statistics for Each Broom Creek Lithofacies

	Porosity, %		Permeability, mD	
Lithofacies	**Range**	**Mean**	**Range**	**Geometric Mean**
Sandstone	3.0–33.0	27.0	0.01–8000	315
Lower Sandstone	2.0–25.0	13.0	0.01–1200	7.4
Dolomitic Sandstone	1.0–23.0	11.0	0.001–1800	6.5
Dolostone	0.1–18.0	5.0	0.0001–100	0.2
Anhydrite	0.1–5.0	1.0	0.0001–0.3	0.0002

(P_{10}) represented a 10% chance that the actual values were lower. The median case (P_{50}) represented a "most likely" probable case, and the P_{90} case represented a 10% chance that the actual values were higher. Core-measured porosity values were used to determine the P_{10}, P_{50}, and P_{90} values used in petrophysical modeling (Table B-5).

Two existing Broom Creek Formation water injection wells within the study area were history-matched to validate the final model. History match efforts determined that the P_{50} property distribution best represented the petrophysical properties of the Broom Creek Formation in the study area. Because of the history match results indicating the P_{50} petrophysical properties were a good match, only the Broom Creek P_{50} realization was used in numerical simulation of CO_2 injection.

Table B-5. Broom Creek Model Porosity Distribution Characteristics from Uncertainty Analysis

Uncertainty Case	Porosity Range, %	Average Porosity, %
P_{10}	1.0–46.0	11.2
P_{50}	1.0–46.0	16.6
P_{90}	1.0–46.0	21.9

2.1.4 Reservoir Temperature and Pressure

Reservoir temperature and pressure were modeled throughout the area for use in dynamic simulation. The reservoir temperature and pressure of the Broom Creek Formation were also measured in each stratigraphic test well (Flemmer-1 and BNI-1) using Schlumberger's Modular Formation Dynamics Tester (MDT) and Saturn Probe. Temperature and pressure gradients used in modeling efforts can be found in Table B-6. Both stratigraphic test wells showed evidence of overpressured conditions in the Broom Creek Formation. These gradients created a modeled temperature range of 103° to 159°F and a pressure range of 1843 to 3550 psi.

Table B-6. Pressure and Temperature Gradients for the Broom Creek Formation at Each Stratigraphic Test Well

Well Name (NDIC #)	Temperature Gradient, °F/ft	Pressure Gradient, psi/ft
Flemmer-1 (34243)	0.016	0.488
BNI-1 (34244)	0.016	0.487

2.2 Inyan Kara Formation

The Inyan Kara Formation is a Cretaceous clastic formation (Figure B-2) that could provide a viable target for CO_2 sequestration (Fischer and others, 2005). The Inyan Kara Formation is the primary disposal formation for produced water from oil and gas activities in the Williston Basin. Produced water disposal in the Inyan Kara Formation has shown the injectivity and storage potential of the formation.

2.2.1 Structural Framework

The Inyan Kara model encompasses the top of the Inyan Kara Formation to the top of the underlying Swift Formation. Quality-checked formation tops from existing wells, combined with interpreted horizons from 3-D seismic data (where applicable), were used to correlate formation structure. Figure B-8 shows a typical well log display in the Inyan Kara Formation within the study area. Figure B-9 shows structure and isopach maps for the Inyan Kara Formation within the geologic model. Depths and thicknesses of the formations of interest in the Inyan Kara model along with expected depth and thickness at each CO_2 source can be found in Table B-7.

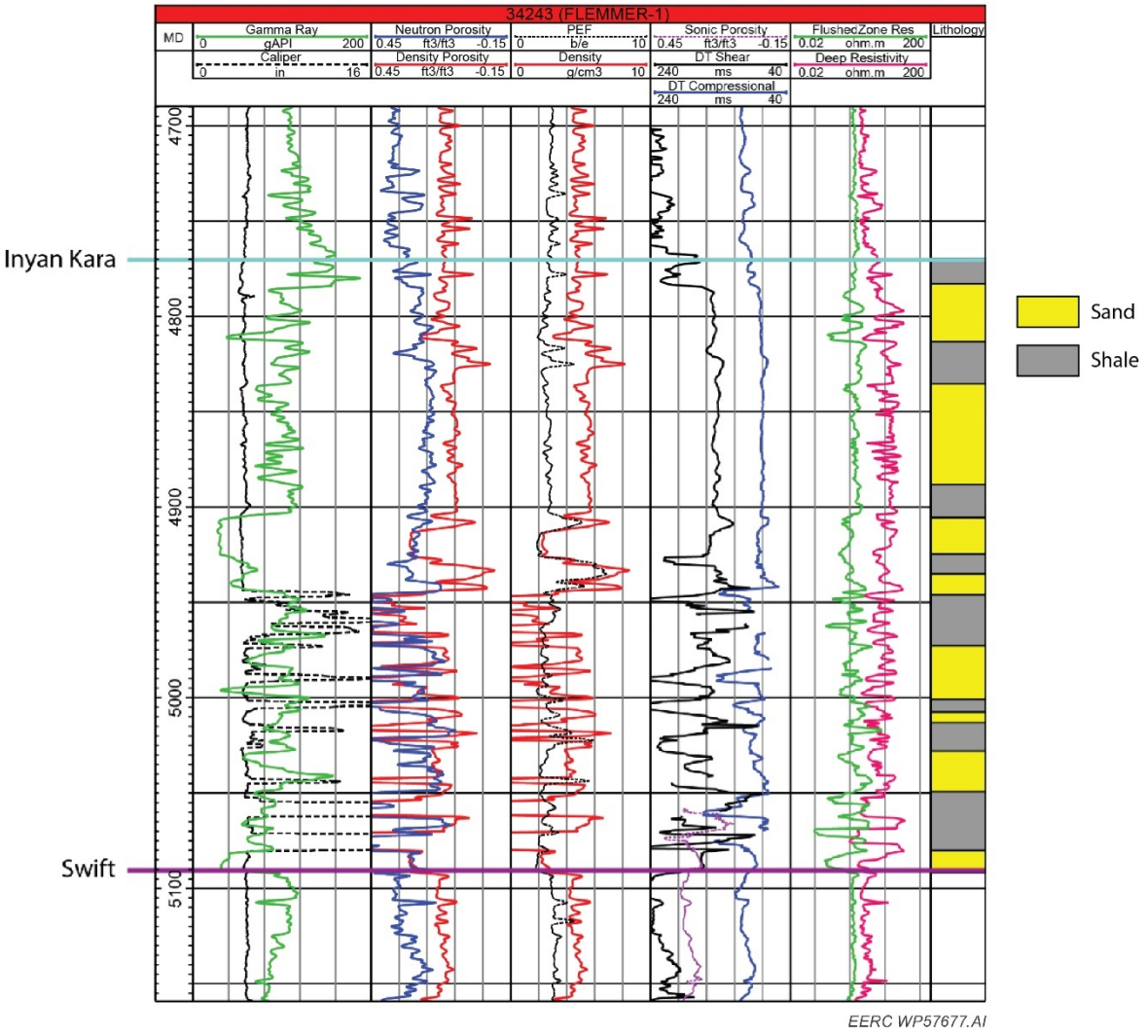


Figure B-8. Type log of the Inyan Kara Formation in the modeled area (NDIC #34243, API 3305700390000). Curves shown are (from left to right): 1) caliper and GR; 2) core, neutron, and density porosity; 3) PEF and density; 4) compressional sonic travel time (DT compressional), sonic porosity, and shear sonic travel time (DT shear); 5) deep resistivity and flushed zone resistivity; and 6) lithology.

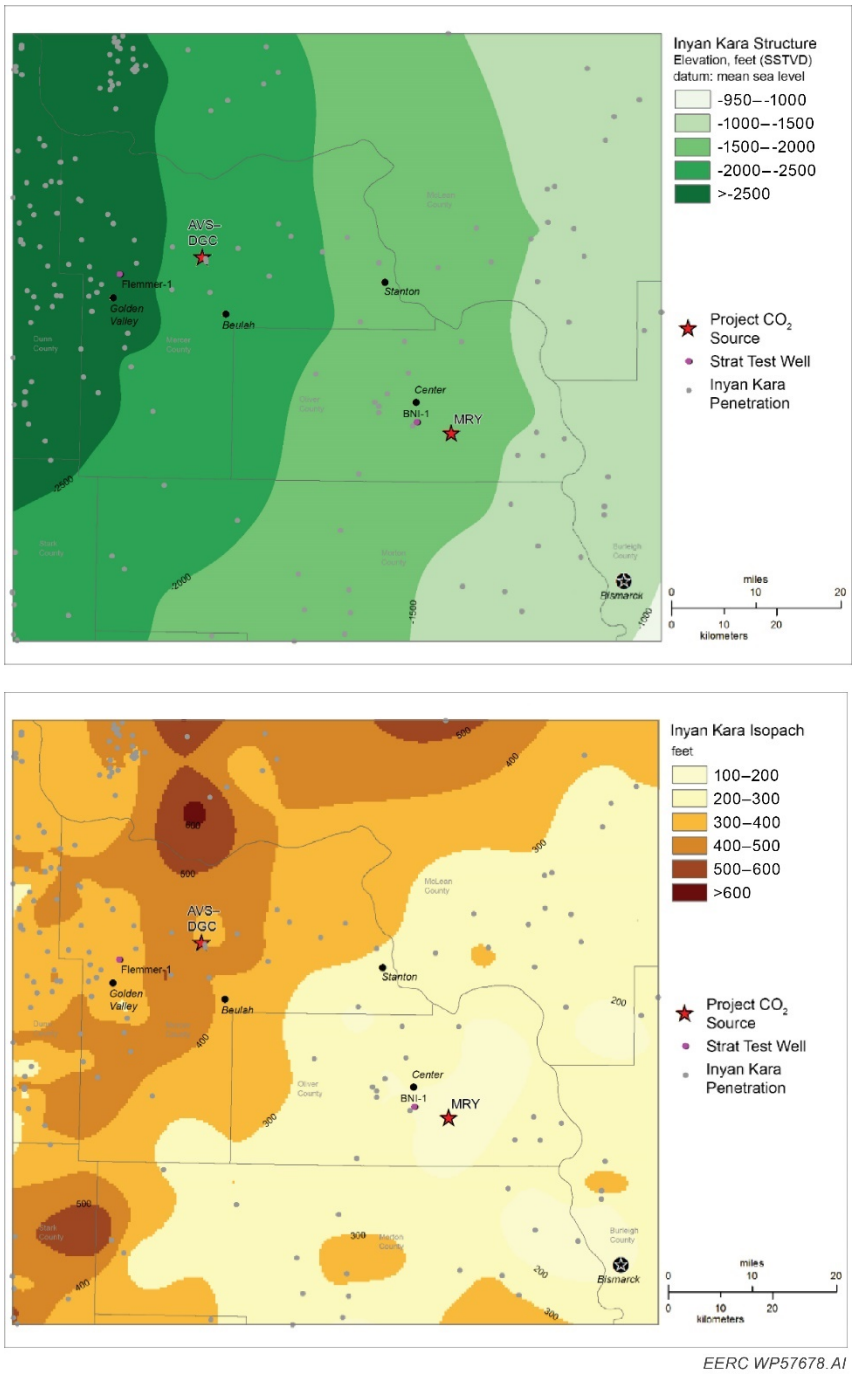


Figure B-9. Top: structure contour map of the top of the Inyan Kara Formation (datum – mean sea level). Bottom: isopach map of the Inyan Kara Formation.

Table B-7. Depth and Thickness of Formations of Interest

	Model Area		GPSP		MRYS	
Formation	Average Measured Depth, ft	Average Thickness, ft	Expected Depth, ft	Expected Thickness, ft	Expected Depth, ft	Expected Thickness, ft
Inyan Kara	3924	321	4286	398	3614	156
Swift	4245	395	4684	414	3770	444

2.2.2 Lithofacies Distribution

The Lower Cretaceous Inyan Kara Formation in the Williston Basin has previously been divided into three members: the lowermost "A," a thick sand deposited in a fluvio-deltaic environment; the middle "B," consisting of varying grain-sized sandstones, siltstones, and shales; and the upper "C," a continuous unit of finer-grained siltstones and clay (Wartman, 1982).

The Inyan Kara model was divided into two main lithofacies: sand and shale. Lithology logs were generated from well logs using cutoffs applied to GR well logs. The threshold values were chosen after comparing core sample analyses with well logs, including elemental log analysis results and GR logs (Figure B-8).

A training image was constructed for an MPS approach to achieve lithofacies distributions throughout the model area. The training image was built using interpretations of the 3-D surface seismic data set collected near the Flemmer-1 wellsite. A channel feature observed in the 3-D seismic data set was used as the template for the training image for the fluvio-deltaic A member. A third lithofacies representing levee characteristics along channel pathways was added to the training image (Figure B-10).

Multiple property realizations were generated to address uncertainty in the petrophysical property distributions. The percentage of cells containing sand–lithofacies cells resulting from distributing the lithofacies via MPS was varied by ~10% in each realization to achieve low, mid, and high cases (Table B-8).

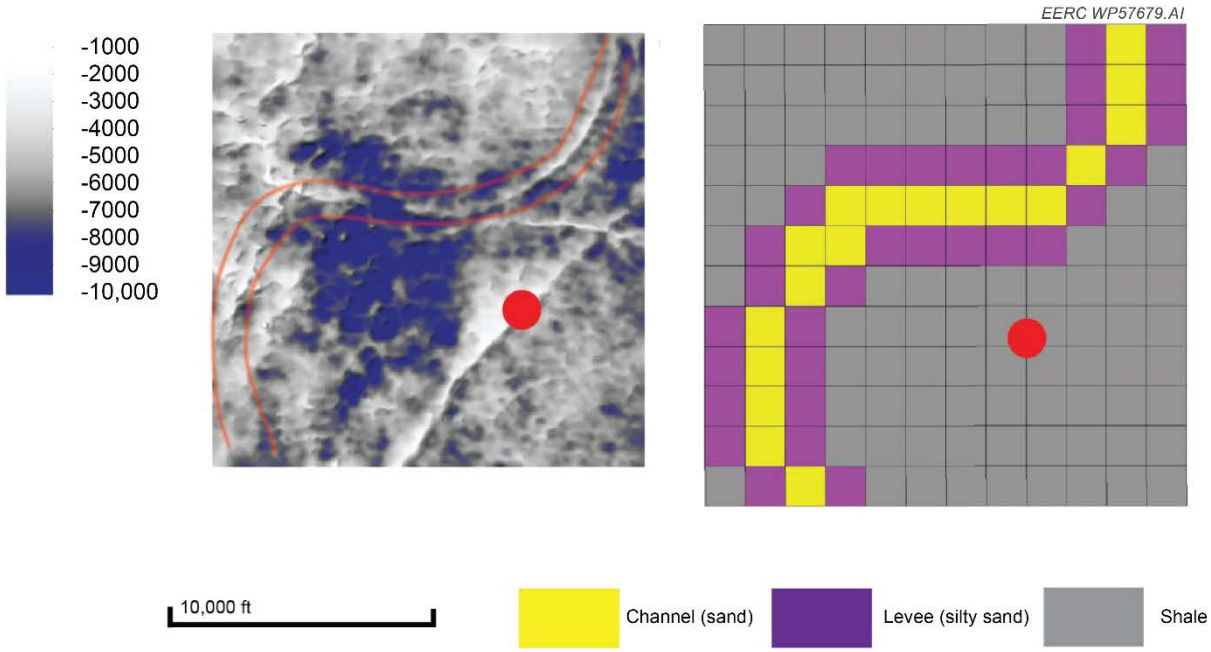


Figure B-10. Left: Map view of seismic amplitude time slice through the Inyan Kara Formation with interpreted channel feature. Right: Training image. The Flemmer-1 wellsite location is represented by a red dot.

Table B-8. Percentages of Each Lithofacies for Low, Mid, and High Cases

Case	Sand, %	Silty Sand, %	Shale, %
Low	15.27	21.90	62.83
Mid	25.35	28.34	46.31
High	35.09	30.50	34.41

2.2.3 Petrophysical Property Distributions

Porosity and permeability from Inyan Kara samples collected throughout the Williston Basin were used to characterize the petrophysical properties of the model. Porosity and permeability distributions were generated by using a variogram- and bivariate-based approach and constrained to lithofacies categories (sand–channel, levee–silty sand, and shale). Variogram ranges were based on depositional environment and channel characteristics, which were interpreted from 3-D seismic data. Porosity and permeability ranges for Inyan Kara lithofacies within the model are shown in Table B-9. A crossplot of the porosity versus permeability for Inyan Kara Formation lithofacies is presented in Figure B-11.

Table B-9. Petrophysical Property Statistics for Each Inyan Kara Lithofacies

	Porosity, %		Permeability, mD	
Lithofacies	**Range**	**Mean**	**Range**	**Geometric Mean**
Sandstone–Channel	4.0–30.0	20.0	0.01–10,000	61.0
Levee–Silty Sand	2.0–20.0	10.0	0.01–1000	1.6
Shale	1.0–10.0	5.0	0.01–10.0	0.1

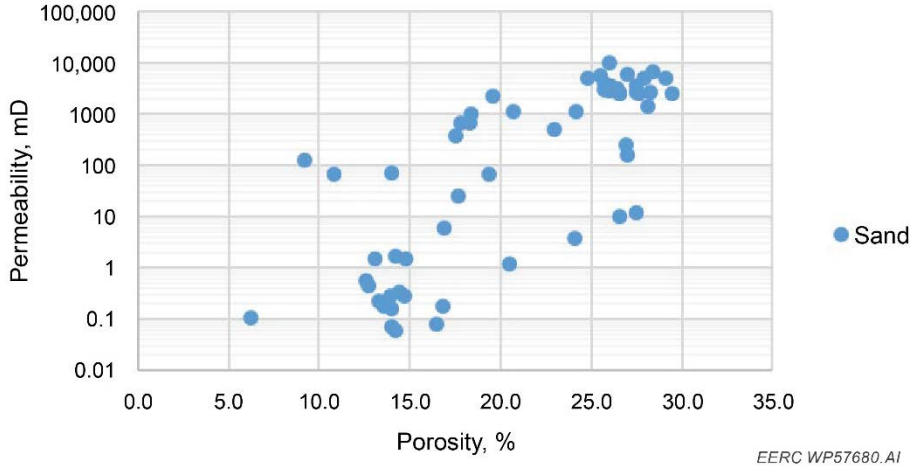


Figure B-11. Inyan Kara Formation lithofacies porosity–permeability crossplots.

2.2.4 Reservoir Temperature and Pressure

Measurements taken from the Inyan Kara Formation with MDT and Saturn Probe wireline tools at both the Flemmer and BNI wellsites were evaluated to estimate temperature and pressure throughout the modeled area (see Table B-10). A calculated temperature gradient of 0.019°F/ft and a pressure gradient of 0.41 psi/ft were ultimately employed in the geologic models.

Table B-10. Pressure and Temperature Gradients for the Inyan Kara Formation at Each Stratigraphic Test Well

Well Name (NDIC #)	Tool	Measured Depth	Temperature Gradient, °F/ft	Pressure Gradient, psi/ft
Flemmer-1 (34243)	MDT	4915	0.019	0.426
BNI-1 (34244)	Saturn Probe	3996	0.021	0.410
BNI-1 (34244)	Saturn Probe	4030	0.021	0.410

2.3 Black Island and Deadwood Formation

The Deadwood Formation is a Cambrian–Ordovician-aged clastic formation that was deposited in a marine to shallow marine environment in the Williston Basin (Fischer and others, 2008). The sandstones of the Deadwood Formation and the overlying Black Island Formation of the Winnipeg Group comprise the lowest potential CO_2 storage target in the Williston Basin (Figure B-2). The Deadwood and Black Island Formations have proven to be a viable target for CO_2 storage in the Williston Basin in Canada at Aquistore (Dalkhaa and others, 2017). Previous investigation of the Deadwood Formation in the Williston Basin show the formation could be used for CO_2 storage within the study area (Liu and others, 2013). To better understand the potential of the Black Island–Deadwood Formation within the study area, a geologic model was constructed over the same extent as that of the previous geocellular models (see Figure B-1).

2.3.1 Structural Framework

The geocellular model for the Deadwood Formation included the Black Island and Deadwood Formation. The structural framework for the model was built using interpreted formation tops from well logs available in the NDIC database. Formation tops for the Black Island Formation of the Winnipeg Group, the Deadwood Formation, and the Precambrian were interpreted from available GR, density, porosity, and sonic logs based on the log responses described by LeFever (LeFever and others, 1987). Figure B-12 shows a typical well log display of the Black Island and Deadwood Formations within the study area. Figure B-13 shows structure and isopach maps for the Black Island and Deadwood Formations within the geologic model. Depths and thicknesses of the formations of interest in the model along with expected depth and thickness at each CO_2 source can be found in Table B-11.

2.3.2 Lithofacies Distribution

Geologic lithofacies were created based on well log interpretations. The interpreted lithofacies in the Deadwood include sandstone, carbonate, shale, and siltstone. These four lithofacies were distributed in the model as laterally continuous layers in lieu of stochastic distribution, or other methods, because of the limited number of wells that penetrated through the Black Island or Deadwood Formation in the model area. Table B-12 shows the percentage distribution of each of the lithofacies for the model.

2.3.3 Petrophysical Property Distributions

The petrophysical properties for the Black Island–Deadwood model were acquired from publicly available core data from Montana, North Dakota, South Dakota, and the Canadian Provinces of Alberta, Manitoba, and Saskatchewan. The petrophysical properties were distributed throughout the model using a variogram-based geostatistical method, conditioned to the lithofacies model. The variogram parameters used for these distributions were adapted from generalized variogram ranges of differing depositional environments as described by Gorecki and others (2009). The mean, minimum, and maximum values from the porosity were calculated and used for

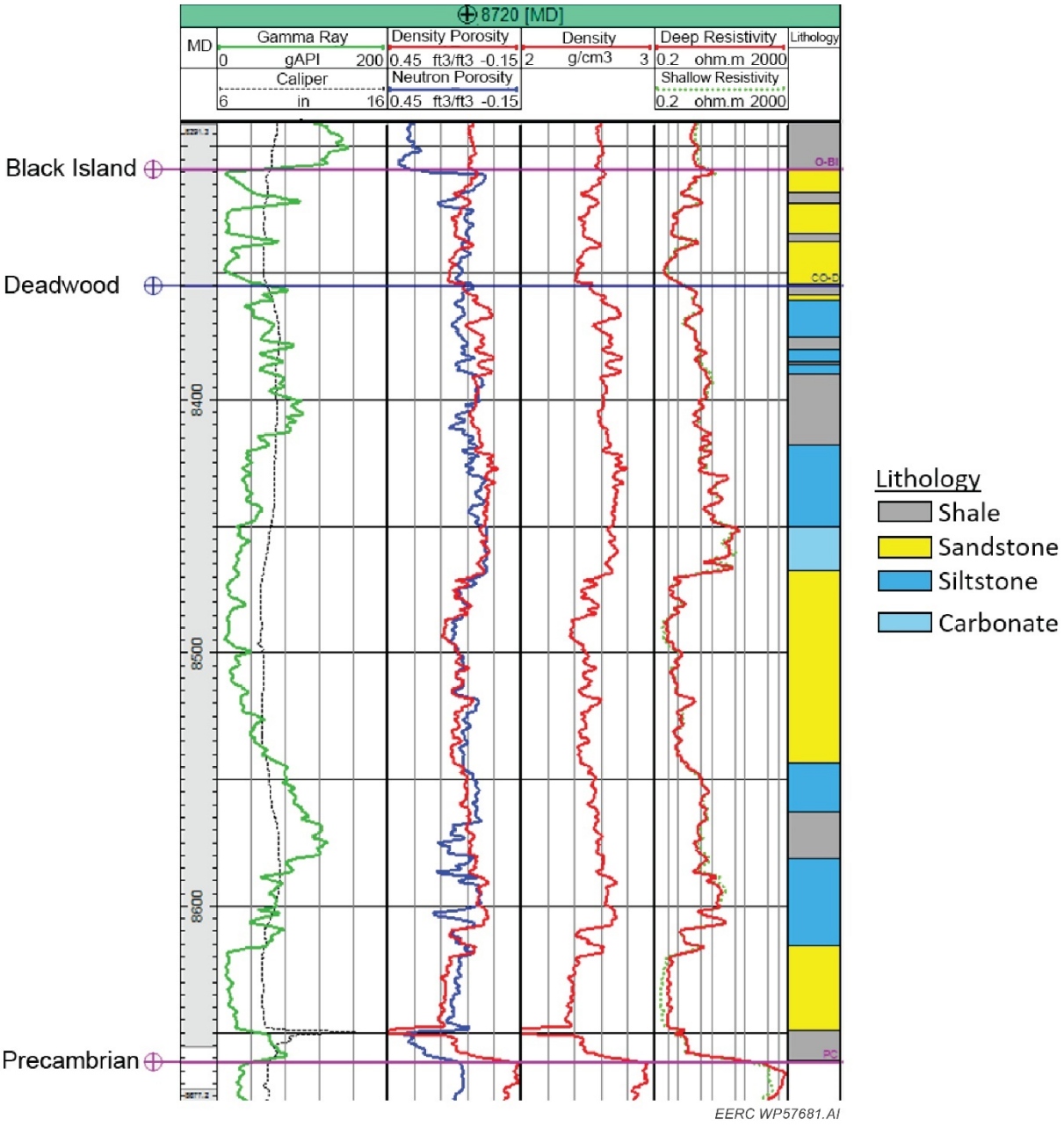


Figure B-12. Typical log of the Black Island and Deadwood Formation in the modeled area (NDIC #8720, API 33055000350000). Curves shown are (from left to right): 1) caliper and GR; 2) core, neutron, and density porosity; 3) density; 4) deep resistivity and shallow resistivity; and 5) lithology.

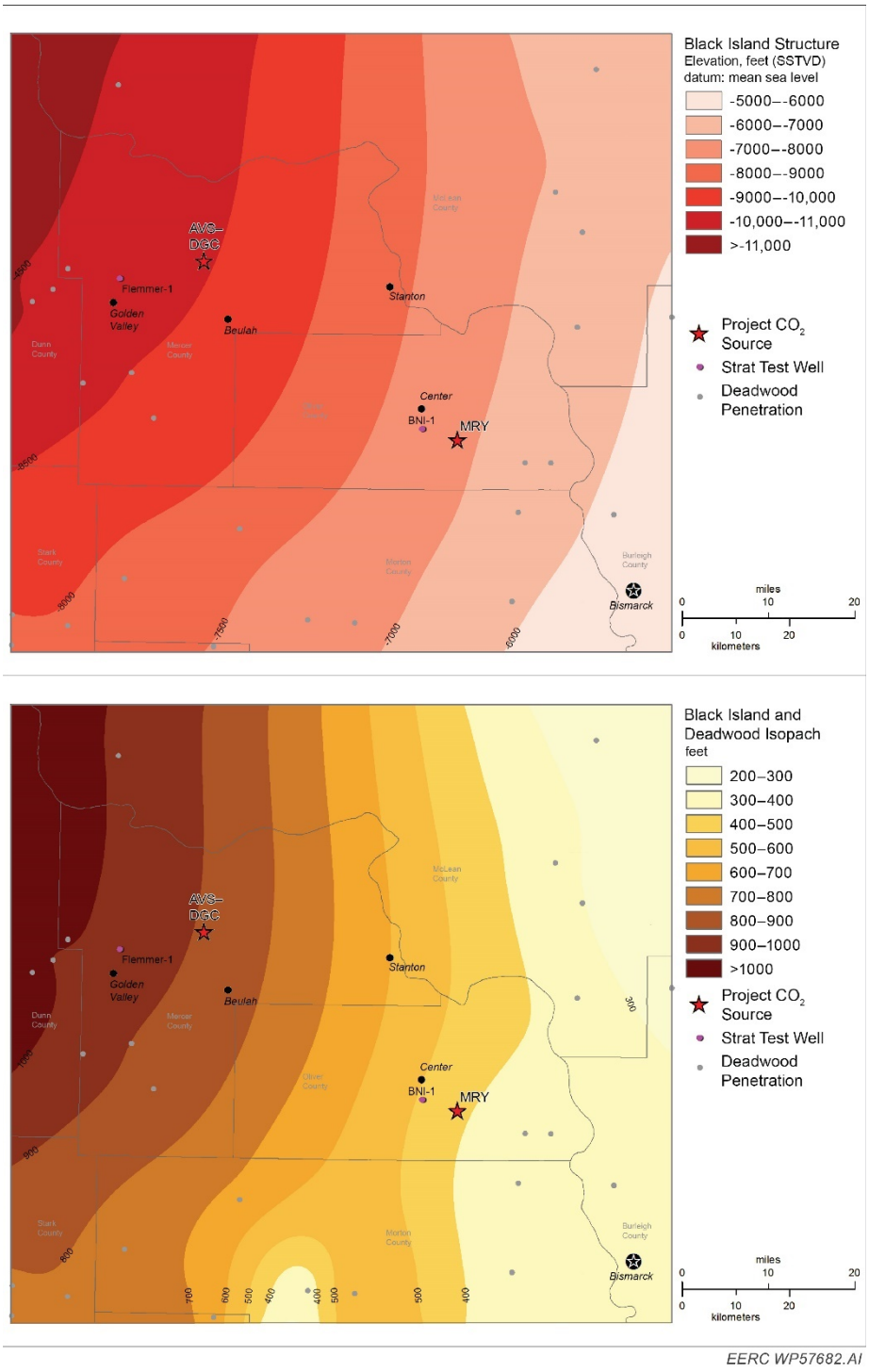


Figure B-13. Top: Structure contour map of the top of the Black Island Formation (datum – mean sea level). Bottom: Isopach map of the Black Island and Deadwood Formations.

Table B-11. Depth and Thickness of Formations of Interest

	Model Area		GPSP		MRYS	
Formation	Average Measured Depth, ft	Average Thickness, ft	Expected Depth, ft	Expected Thickness, ft	Expected Depth, ft	Expected Thickness, ft
Black Island	10,314	56	12,070	72	9055	25
Deadwood	10,370	563	12,150	810	9090	400
Precambrian	10,933	N/A	12,950	N/A	9470	N/A

Table B-12. Percentages of Each Lithofacies

Lithology	%
Sandstone	65.4
Carbonate	3.8
Shale	11.5
Siltstone	19.2

defining the distribution of the porosity property and constrained by lithofacies. Permeability was distributed from a bivariate relationship derived from a porosity–permeability crossplot (Figure B-14) for all of the lithofacies. Table B-13 contains the mean and standard distribution of the petrophysical properties under the P_{50} probability distribution.

Few wellbores penetrate the Black Island or Deadwood Formation in the study area, and few core exist for the formation in the Williston Basin. To address the uncertainty related to petrophysical properties, multiple petrophysical property distributions were created. Petrophysical property distributions that represent P_{10}, P_{50}, and P_{90} values were created to test sensitivity of simulations (Table B-14).

2.3.4 Reservoir Temperature and Pressure

Temperature and pressure properties were also created for use in dynamic simulation. The temperature property was created by calculating a temperature gradient of 0.019°F/ft from bottomhole temperatures in well logs, giving a modeled temperature range of 127° to 261°F. The pressure gradient was calculated based on available drillstem tests taken from two wells on the western edge of the study area. The estimated gradient was 0.465 psi/ft, with a modeled pressure range of 3164 to 6298 psi throughout the modeled volume.

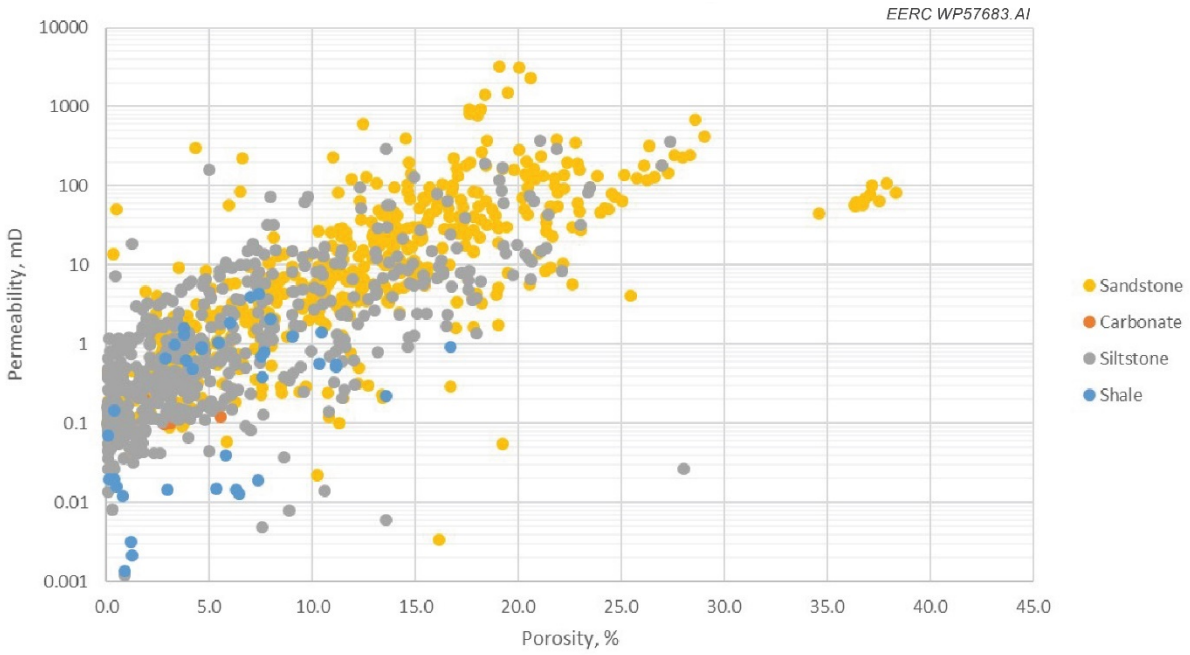


Figure B-14. Black Island and Deadwood Formation lithofacies porosity–permeability crossplots.

Table B-13. Porosity and Permeability Ranges for the P_{50} Distribution of Petrophysical Properties

	Porosity		Permeability	
Lithofacies	Mean, %	Standard Deviation, %	Mean, mD	Standard Deviation, mD
Sandstone	11.0	7.7	70.12	271.53
Siltstone	3.7	5.9	6.93	24.81
Carbonate	1.8	1.9	0.14	0.09
Shale	5.3	3.9	0.88	0.98

Table B-14. Black Island–Deadwood Model Porosity Distribution Characteristics from Uncertainty Analysis

Case	Average Porosity, %	Standard Deviation, %
P_{10}	2.3	6.9
P_{50}	10.1	6.9
P_{90}	17.9	9.0

3.0 NUMERICAL SIMULATION OF CO_2 INJECTION

Numerical simulations of CO_2 injection were conducted to evaluate the feasibility of CO_2 storage at the AVS and MRYS sites, using the geologic models described in the previous sections. Simulations were completed using Computer Modelling Group Ltd.'s (CMG's) GEM software (Computer Modelling Group Ltd, 2018). Optimizing the potential well locations and the number of wells required to meet the storage target was accomplished using CMG-CMOST software. Additionally, geochemical simulation investigated CO_2-trapping mechanisms following 100 years after the cessation of CO_2 injection at MRYS.

Injection scenarios were designed to investigate the feasibility to reach a cumulative CO_2 injection target of up to 50 Mt at GPSP and up to 100 Mt at MRYS over 25 years of CO_2 injection. The feasibility study involves 1) optimization of potential well locations and number of wells required to reach the storage target and 2) estimation of the extent of CO_2 plumes as a result of over 25 years of CO_2 injection.

The CO_2 was injected at a constant rate of 2.0 Mt/year at GPSP and at 2 Mt/year and 4 Mt/year per year at MRYS. Simulated CO_2 injection was evaluated over a 25-year time period followed by a postinjection period of 25 years.

Simulated injection wells were placed on land owned by project partners in an effort to maximize pore space. Additionally, wells were placed at optimal petrophysical property locations within the project partner lands. Scenarios included Broom Creek Formation cases as well as stacked storage cases with multiple formations (Broom Creek, Inyan Kara, Black Island, and Black Island–Deadwood) using vertical and horizontal wells. Stacked storage cases were assessed to minimize the CO_2 plume size within or near the partner land.

The assumptions and parameters for the simulation cases are summarized in Tables B-15 and B-16. The primary parameters to consider for potential CO_2 storage in a formation include an areal extent of the reservoir, thickness, porosity, permeability, and lithology. Other information such as salinity and distributions of porosity–permeability will also influence the CO_2 storage estimate (Bennion and Bachu, 2005). Some representative formation properties (initial pressure and temperature) were specified in the numerical model. Water saturation was set to 100% in each formation model. Based on laboratory analyses of formation brines, a different salinity value was used for each of the formations in the reservoir model. Table B-15 summarizes model properties used in the simulation efforts. The rock compressibility was estimated by Hall's correlation ("Drilling Formulas", n.d.). Figure B-15 shows the 3-D reservoir numerical model for each formation displaying the initial pressure property.

For the numerical simulation models, an open-boundary condition was assumed for allowing lateral fluid movement by specifying an aquifer boundary type to the edge of the reservoir. The formations underlying and overlying the reservoir model were considered as closed boundaries.

Table B-15. Numerical Simulation Model Properties

Reservoir Property	Broom Creek	Inyan Kara	Deadwood
Reservoir Salinity, ppm	65,000	19,800	100,000
Rock Compressibility, 1/psi	4.90E-06	4.50E-06	4.90E-06
Formation Fluid Compressibility, 1/psi	3.00E-06	3.00E-06	3.00E-06
Water Saturation	1.0	1.0	1.0
Grid Cell Dimensions, ft	1500 × 1500	1500 × 1500	1500 × 1500
Grid Cell Thickness, ft	0.92–9.05 (5.03)	3.54–19.15 (9.79)	5.78–57.05 (24.5)
Total Cells	4,330,000	2,170,000	1,769,000

Table B-16. Numerical Simulation Model Assumptions/Constraints

Simulation Assumptions/Constraints	2.0 Mt/year	4.0 Mt/year
Maximum Bottomhole Pressure (BHP), ft/psi	0.625	0.625
Tubing Radio, ft	0.1875	0.1875
CO_2 Injection Target Rate, ft^3/day	1.05×10^8	2.10×10^8
CO_2 Gas Injection Constraint	Group target	Group target
CO_2 Injection Time, years	25	25
CO_2 Postinjection Time, years	25	25

The wells in the models were constrained using maximum BHP, and the group of injection wells was constrained by a maximum CO_2 gas injection rate (STG) in the simulation model (Table B-16). The maximum BHP for the injector well was calculated at the top measured depth (MD) of the perforation using a gradient pressure of 0.625 psi/ft., which is below the fracture gradient of 0.8 psi/ft.

Relative permeability data were obtained from Bennion and Bachu (2005, 2007), with each set of curves representing individual rock type from the lithofacies distribution in the models. Data from these relative permeability curves are from formations representative of the pressure, salinity, porosity, and permeability characteristics of deep saline aquifers in on-shore North American sedimentary basins. Figure B-16 shows the relative permeability curve for a sandstone rock type used in the models. Similarly, representative relative permeability curves were used according to the rock type, for example carbonate and shale. The group of relative permeability curves was used in all three formations under evaluation.

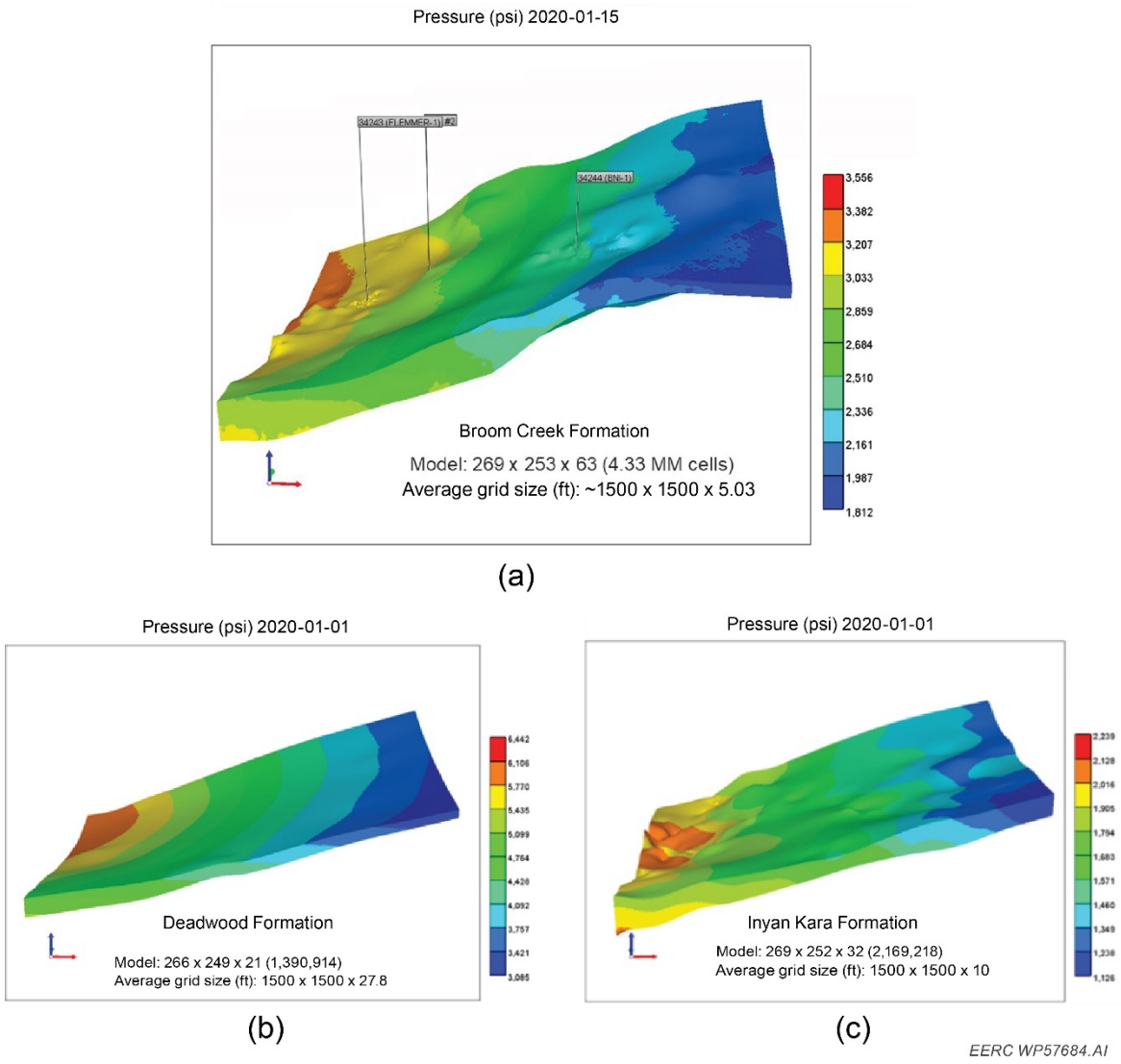


Figure B-15. 3-D reservoir numerical models for a) Broom Creek Formation, b) Black Island–Deadwood Formation, and c) Inyan Kara Formation, showing pressure property distribution in the models

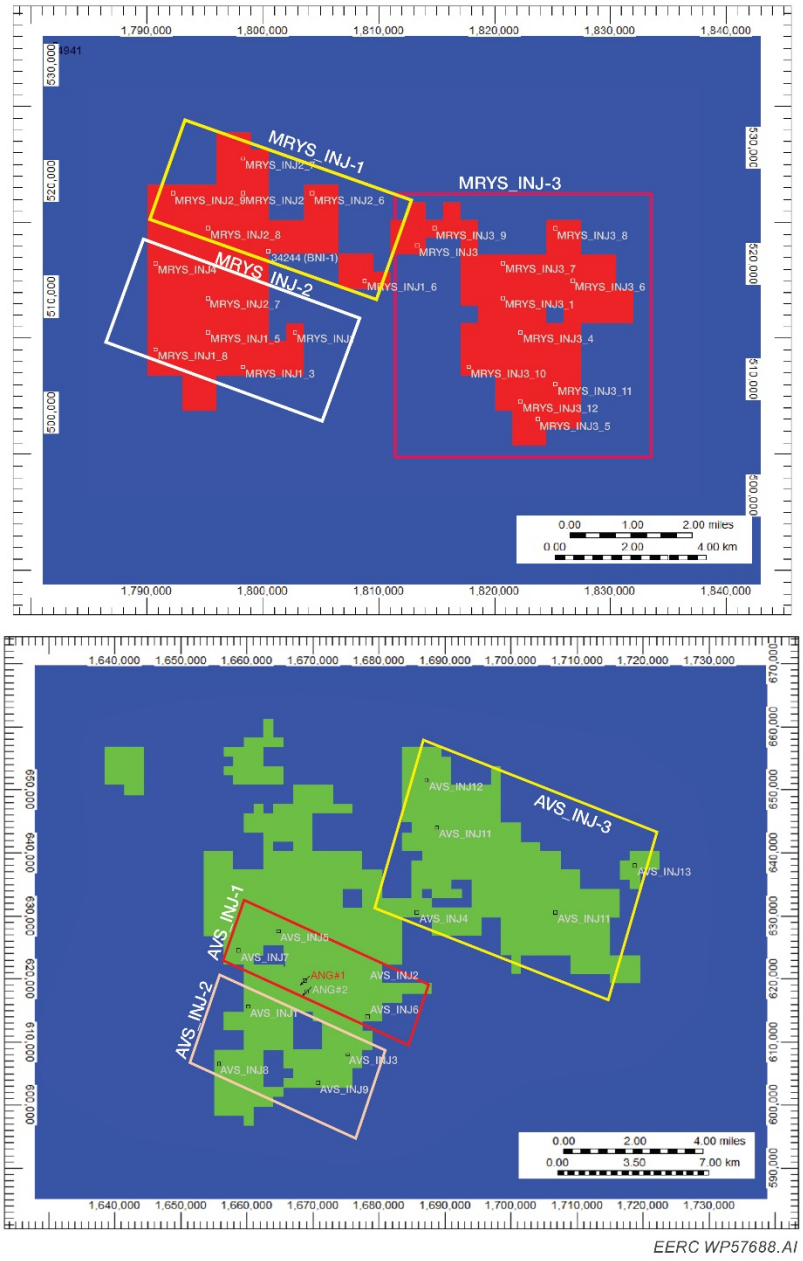


Figure B-16. Relative permeability curves for sandstone used for numerical simulation.

3.1 Broom Creek History Match

The history matching was conducted to verify or calibrate the simulation model using the historical injection data from the two saltwater disposal (SWD) wells, ANG #1 and ANG #2, at the GPSP site. The history match was carried out using the final P_{50} geologic model version of the Broom Creek Formation. The history match allows for the adjustment and validation of the reservoir numerical model by matching model results with the field historic data while taking into consideration geological uncertainties and static/dynamic data quality.

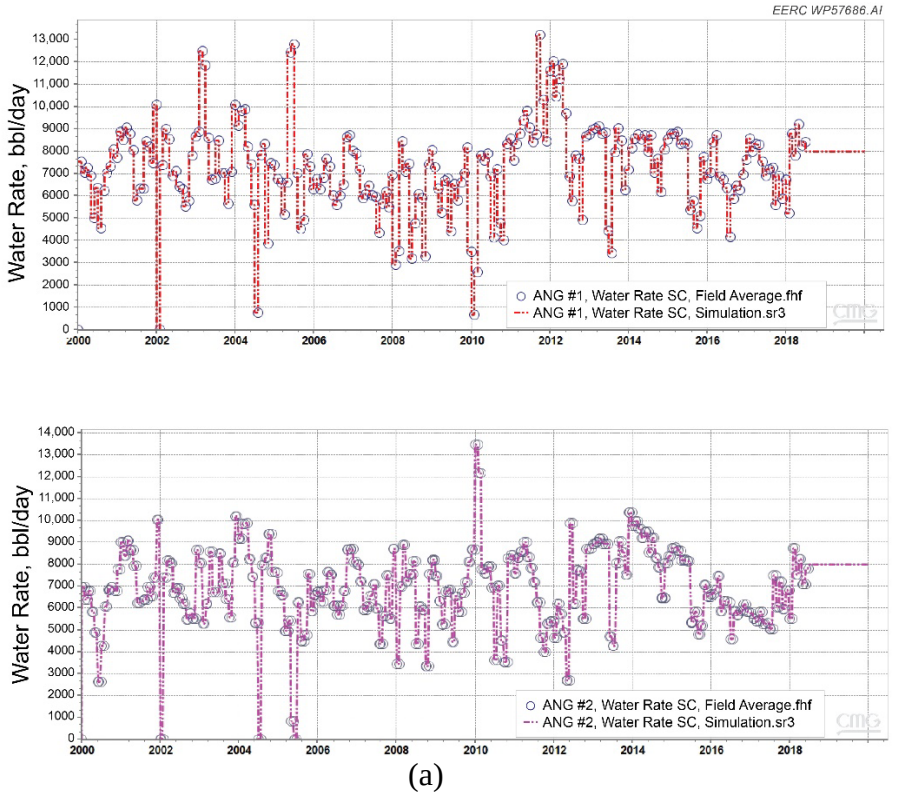
Historical water injection rates and wellhead pressure data for the (SWD) injection wells located in the GPSP area were used for the history match of the model. Since BHP field data are not specified for the disposal wells, the average wellhead pressure (WHP) was used to match the model (Figure B-17b). The historic average monthly injection rates (Figure B-17a) were also matched with the historical field data. The numerical model shows a satisfactory history match for WHP for wells ANG #1 and ANG #2. The calibrated model was used during the evaluation of the different scenarios and predictions to achieve the storage capacity.

3.2 Broom Creek Well Location Optimization

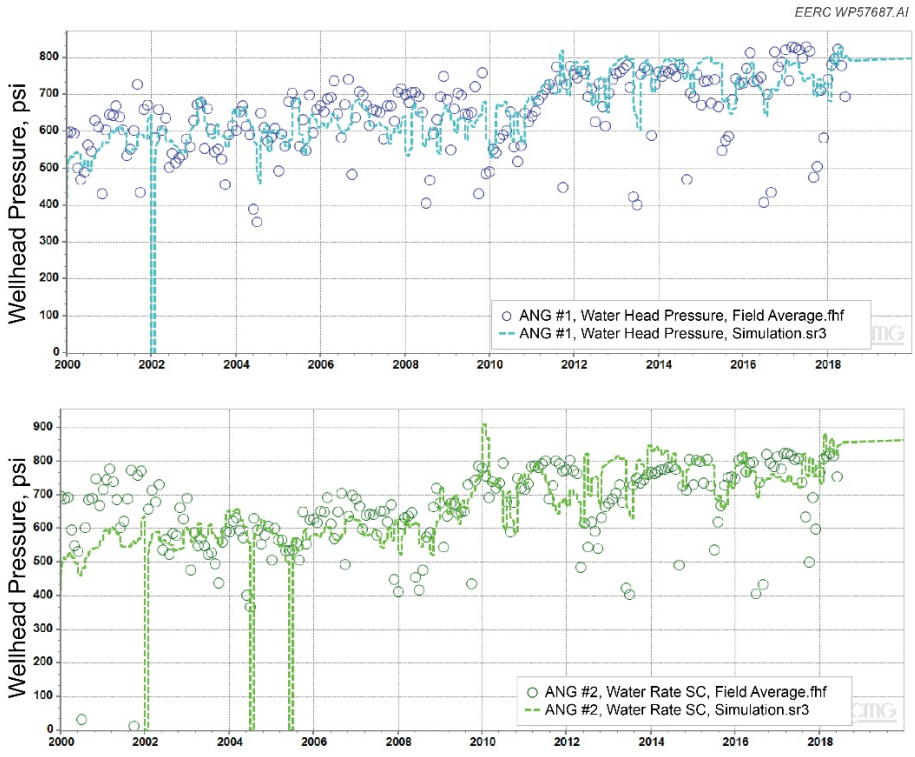
In the case of the Broom Creek model, vertical well orientation was used and wells were placed in areas with good permeability and thickness within or near the partner land to reach the injection target rate and volume. The wells were attached in a group identification structure to control and reach the CO_2 injection target. The injection rate constraint set for a group is a target to be met by the group.

After a base case simulation with three potential vertical wells per site, an optimization study for the well locations was performed to reach the CO_2 injection target for the GPSP and MRYS sites. For this study, CMOST-CMG was used to optimize the three well locations for the AVS and MRYS sites in the Broom Creek Formation. The model was divided into three areas (shown in rectangles in Figure B-18) within or near the partner land, and several potential wells were placed within these areas, designated INJ-1 to INJ-3. The potential wells were placed within the area based on good permeability and thickness values. Then the perforated potential wells were entered in the model as an input parameter to optimize their location, and the maximum cumulative CO_2 mass injection was defined as the output objective function to be maximized for CMOST-CMG software.

Figure B-19 shows the results from CMOST-CMG for the well location optimization study for the GPSP and MRYS sites. CMOST shows the optimal solution and well placement configuration represented by the red dot in the figure for a maximum CO_2 cumulative gas mass injection. Each blue data point represents one experiment or run, and more data points are added as the run progresses.

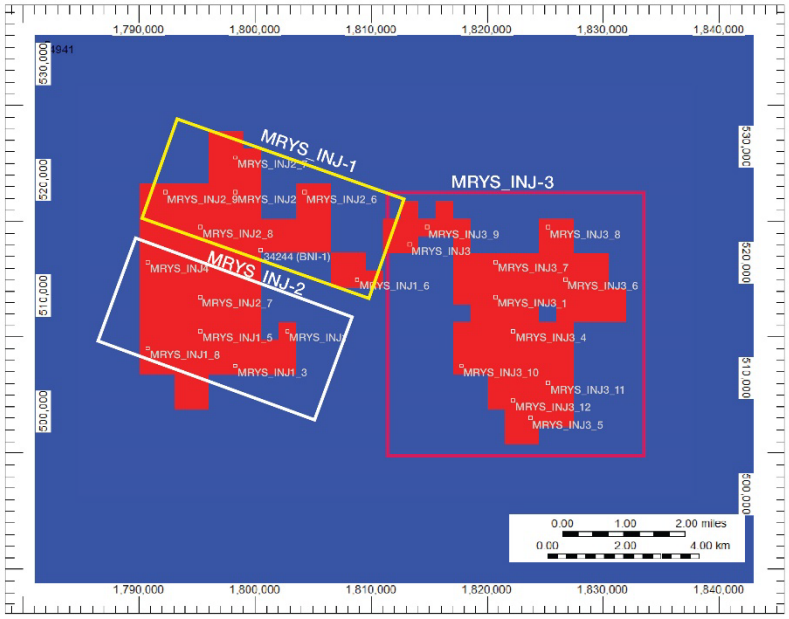


(a)

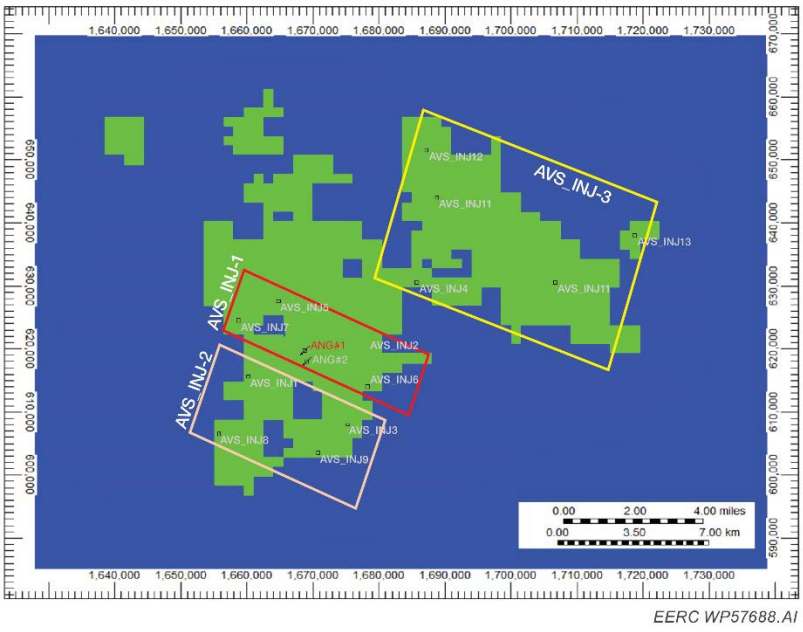


(b)

Figure B-17. a) history-matched water rate data for the disposal wells, ANG #1 and ANG #2, and b) history-matched wellhead pressure data for the disposal wells, ANG #1 and ANG #2.

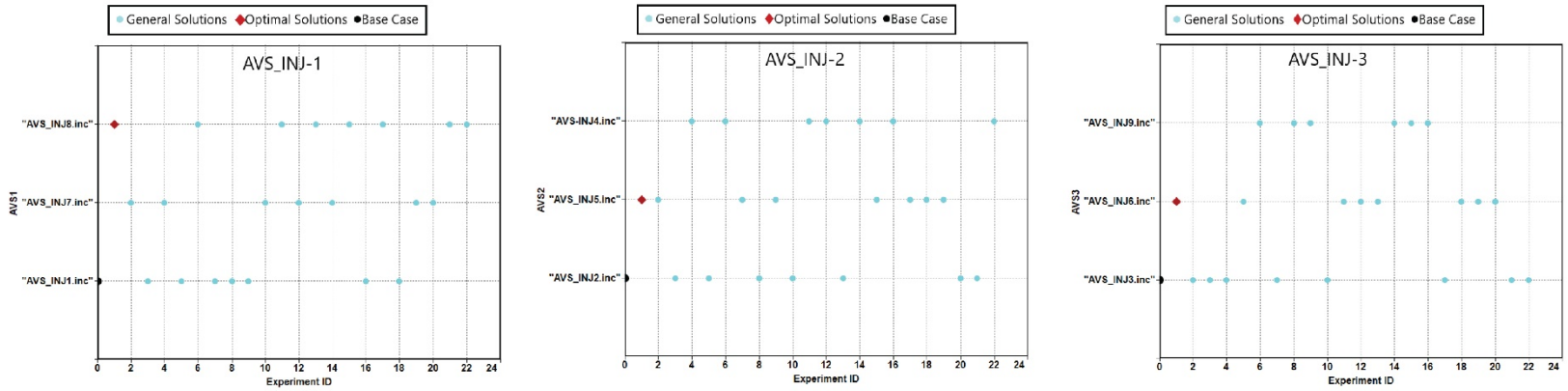


(a)

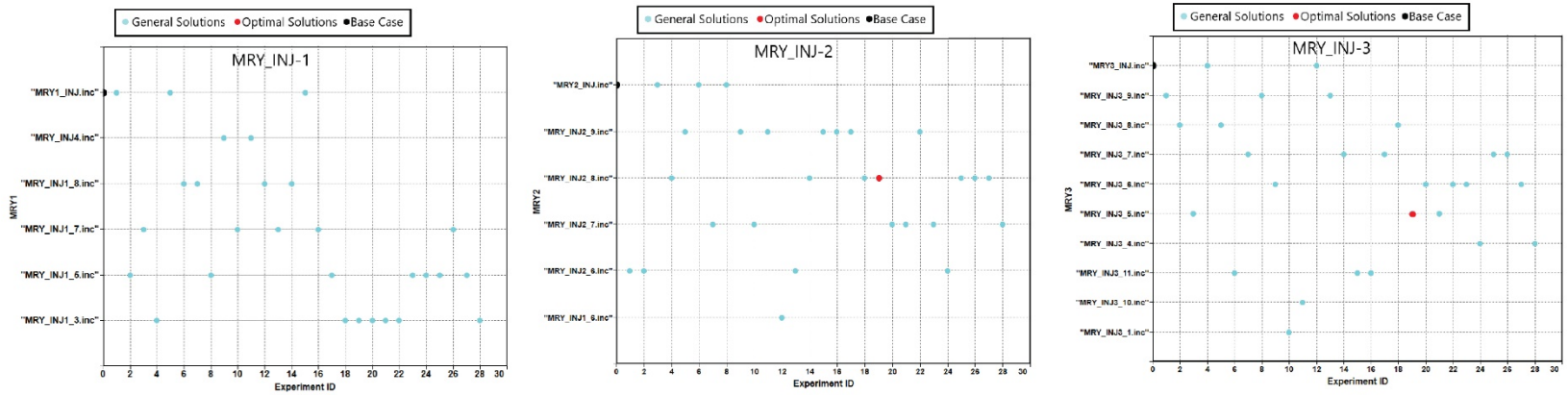


(b)

Figure B-18. Simulation model: a) MRYS (landowner area in red color) and b) GPSP (landowner area in green color) well location areas in rectangles for optimization studies using CMOST-CMG.



(a) GPSP



(b) MRYS

Figure B-19. CMOST-CMG results for well location optimization. Optimal well location configuration represented by red dot. Simulation experiment runs represented by blue dot.

3.3 Results of Numerical Simulations of CO_2 Injection

Several simulation scenarios were conducted in this study to evaluate the feasibility of CO_2 storage and meet the storage target near each coal-fired power plant. While multiple geologic uncertainty models were simulated during the project, only results for the P_{50} geologic models are reported. These cases minimized the CO_2 plume size within or near the partner-owned land. The simulation results of four CO_2 injection scenarios, one for the GPSP and three for the MRYS sites, are discussed in the following sections.

3.3.1 Scenario 1 – GPSP Injection into Broom Creek Formation

The injection feasibility at GPSP was focused on the Broom Creek Formation as the injection target, with the goal of storing up to 50 Mt of CO_2 over 25 years. The CMOST-CMG software was used to optimize the well locations at the GPSP site and to maximize the cumulative CO_2 gas mass (as discussed in Section B.3.2).

The CMOST optimization study indicated that with two vertical injection wells (AVS_INJ1 and INJ2), the injection target of 50 Mt over 25 years could be achieved. Figure B-20 shows the simulated cumulative injected CO_2 (tonnes) and injection rate at 2.0 Mt/year at the GPSP site.

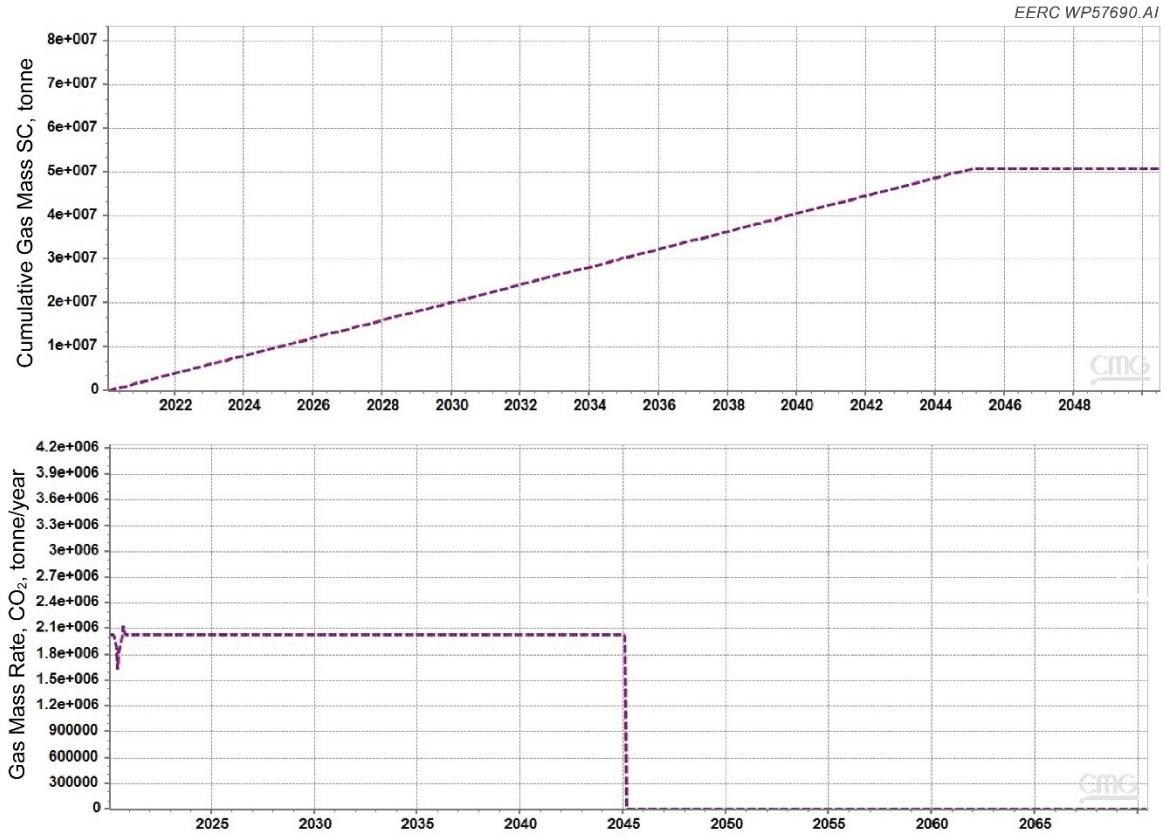


Figure B-20. Cumulative gas mass and gas mass rate for GPSP for reaching CO_2 gas injection of 2.0 Mt/year.

The optimum well locations for these two vertical wells are shown in Figure B-21. The optimum locations for these two wells required a considerable distance between them and the disposal water wells, but still within the partner land, to minimize any pressure and/or injectivity effect of the CO_2 injector wells on the ANG #1 and ANG #2 wells.

The simulation results showed that the total CO_2 plume would cover an area of 14 mi^2 for two injector wells for the GPSP site (light blue shaded area in Figure B-21).

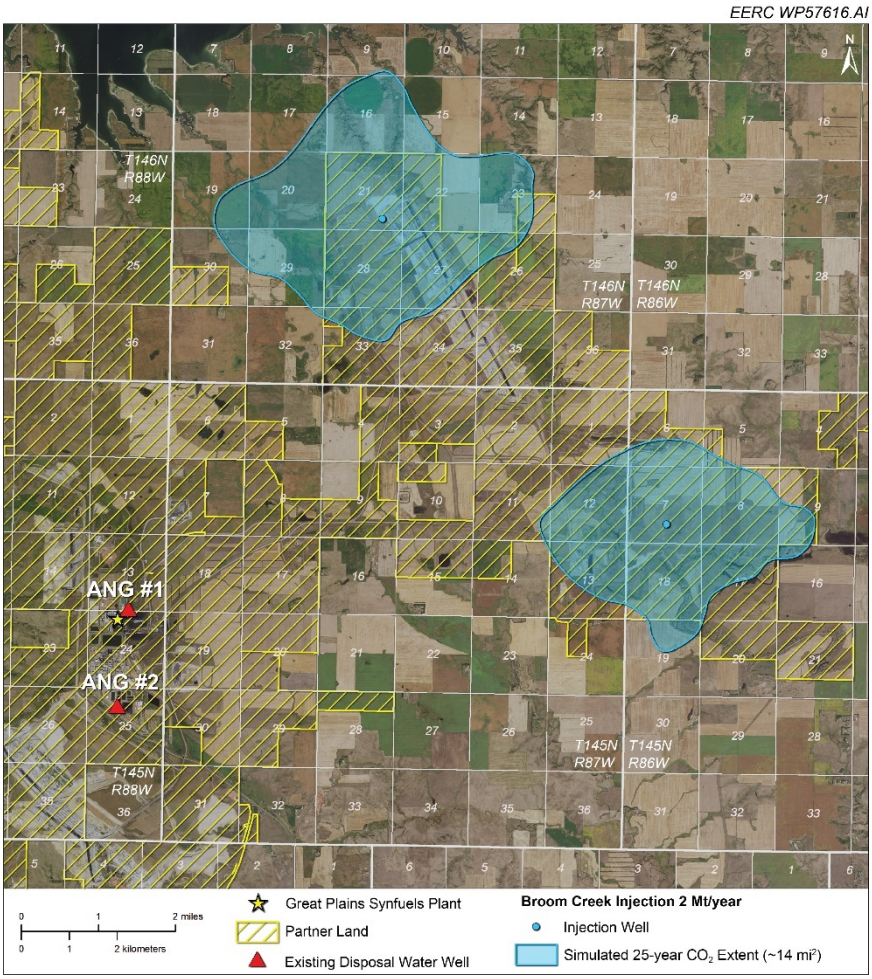


Figure B-21. Scenario 1 – CO_2 plume map for two potential vertical wells for the GPSP site in the Broom Creek Formation after the injection of 25 Mt/year of CO_2 for a period of 25 years.

3.3.2 Scenario 2 – MRYS Injection into Broom Creek Formation

Several numerical simulation studies performed for the MRYS site in the Broom Creek Formation showed that at least four vertical wells would be needed to reach the CO_2 injection target of 100 Mt over 25 years (i.e., injection at a rate of 4 Mt/year). However, not all well locations or well combinations were able to reach the target.

Similar to the injection optimization study of the GPSP site, the CMOST-CMG program was used to optimize the well locations for the MRYS site. Several wells were placed within and near the partner land based on the most favorable permeability values, while keeping a considerable distance between wells to avoid pressure interference during injection. Then the partner land on the MRYS site was divided in four areas, MRYS_INJ-1 through MRYS_INJ-4 (illustrated by different polygons), as shown in Figure B-22. The potential wells per area were used as well parameter input into the program.

More than 60 simulation sensitivity evaluations were run using the maximum cumulative CO_2 mass injection as the objective function in the program to reach the injection target rate of 4 Mt/year.

During the optimization evaluations, it was determined that four potential vertical wells in an optimum location could reach the CO_2 storage and injectivity target. Figure B-23 shows the CO_2 injection target of 4.0 Mt/year and a cumulative gas mass of 100 Mt over 25 years of injection that resulted from the optimal location of four vertical wells on land owned by project partners.

This result showed that controlling the injectivity with a group identification structure in the simulation for well rates, the rate and cumulative are summed into a field cumulative output. This condition allows control and adjusts the CO_2 injection rates in the wells connected to the created group. With this simulation condition, the maximum CO_2 injection rate constraint is a target to be met by the group.

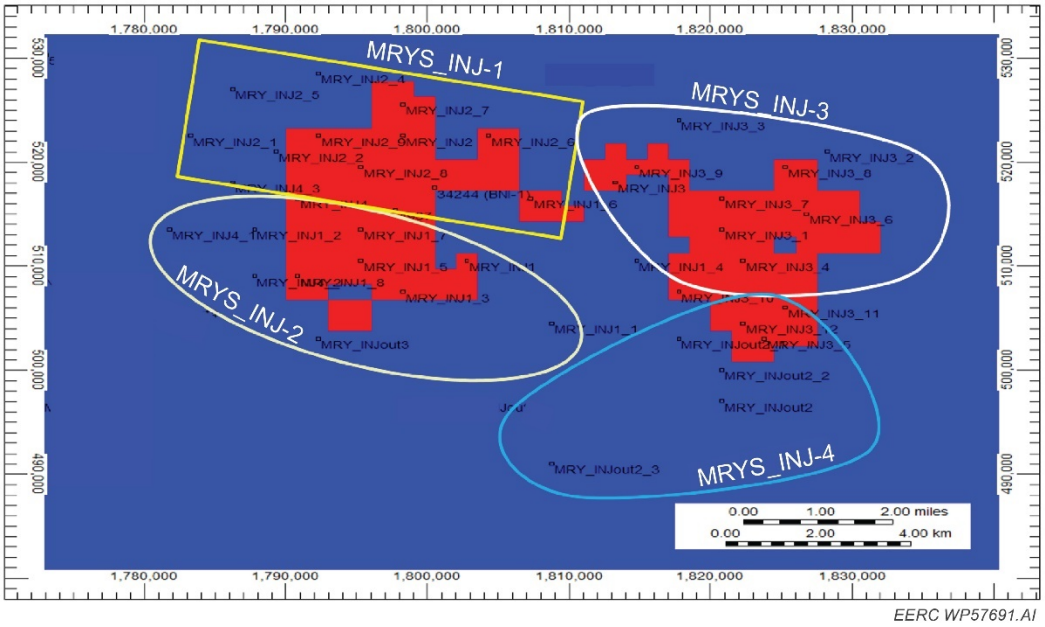


Figure B-22. MRYS site injection into the Broom Creek Formation. Partner land was divided into four areas to optimize the vertical well locations in CMOST-CMG.

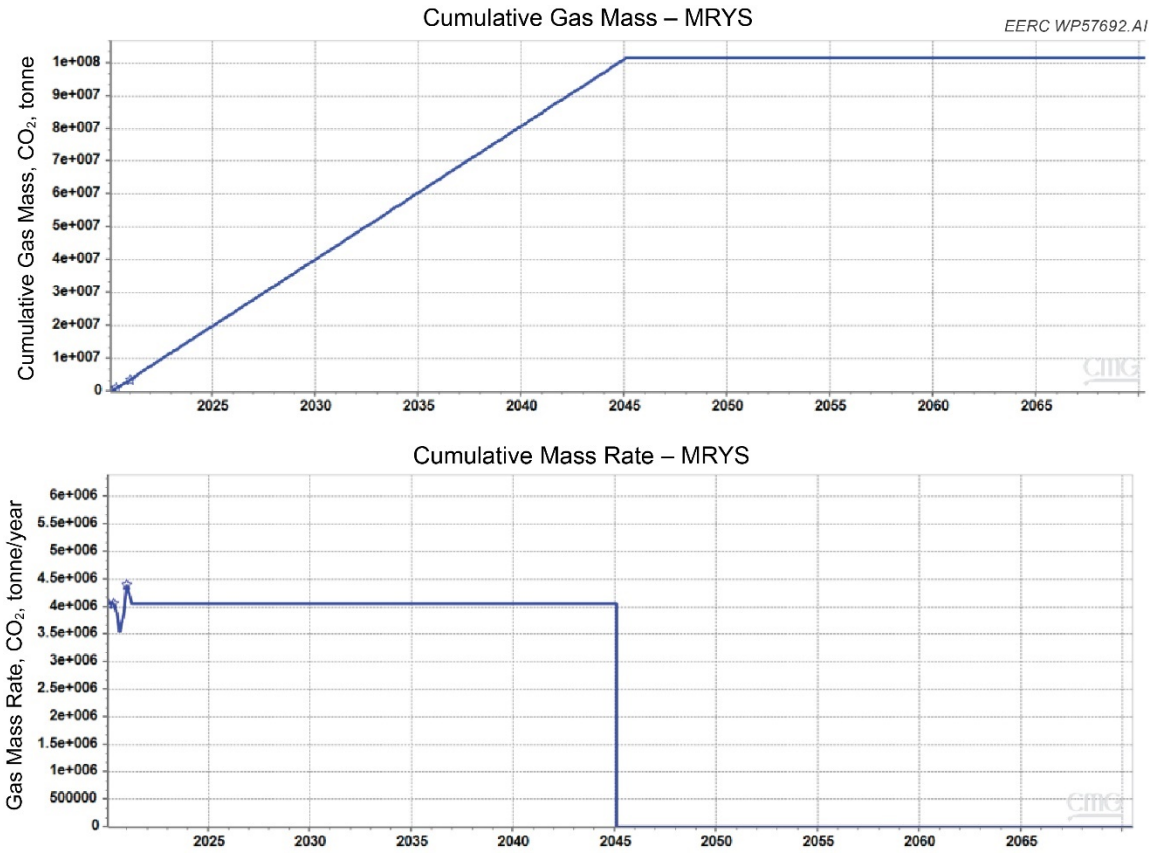


Figure B-23. Cumulative gas mass and gas mass rate for four vertical wells injecting CO_2 into the Broom Creek Formation at the MRYS site.

Figure B-24 shows the optimal configuration of four vertical wells as determined during the optimization study. Also shown is the extent of the CO_2 plume following injection of 4 Mt/year of CO_2 over a period of 25 years (light blue shaded area). The area of the total CO_2 plume is approximately 19.9 mi^2 for the storage of a total gas mass of 100 Mt.

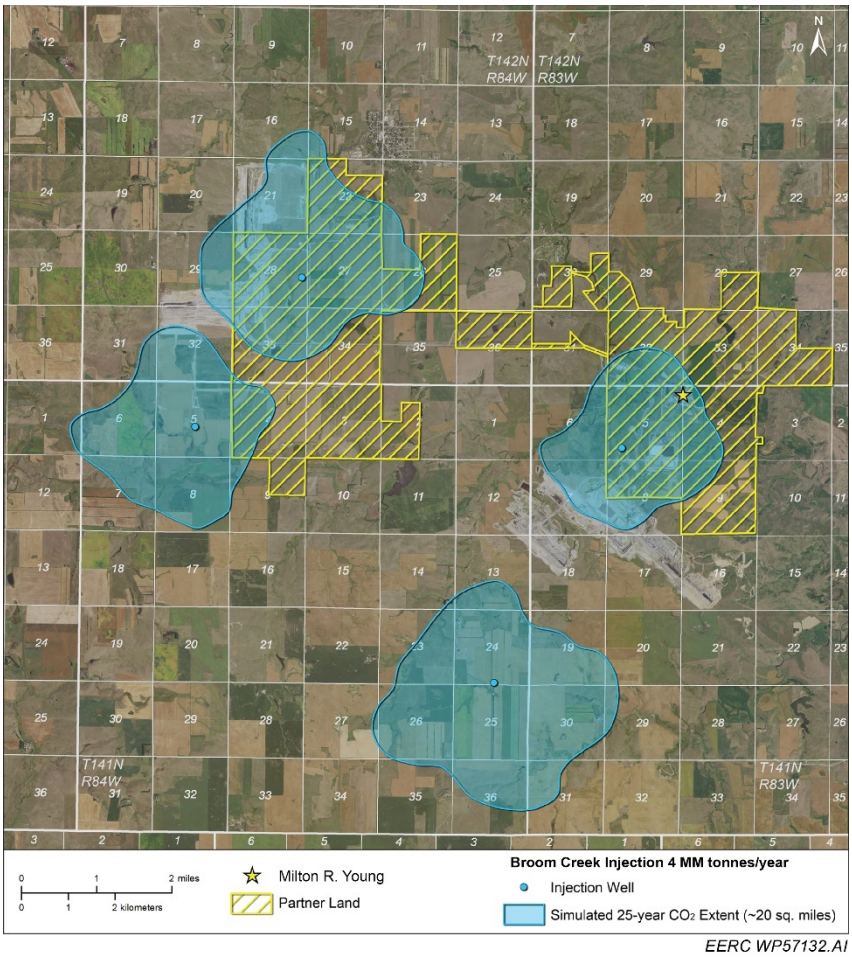


Figure B-24. Scenario 2 – CO_2 plume from simulation results at the end of 25 years of CO_2 injection for four vertical wells at the MRYS site in the Broom Creek Formation.

3.3.3 Scenario 3 – MRYS Injection into the Inyan Kara, Broom Creek, and Deadwood Formations (Stacked Storage Concept 1)

The option of stacked storage to augment storage in the Broom Creek Formation was also evaluated to meet the 25-year CO_2 injection target of 100 Mt at the MRYS site. The primary objective of investigating stacked storage is to minimize areal extent of the CO_2 plume, keeping as much of it as possible within partner-owned land as compared to the CO_2 plume that is created when injecting only into the Broom Creek Formation. Figure B-25 represents the general well configuration that is being investigated for stacked storage, i.e., injection via horizontal wells into either the Inyan Kara or Deadwood Formations, or both, and injection into the Broom Creek Formation via vertical wells. All the CO_2 injection strategy cases referred to in this document are derived from general well arrangements unless noted otherwise.

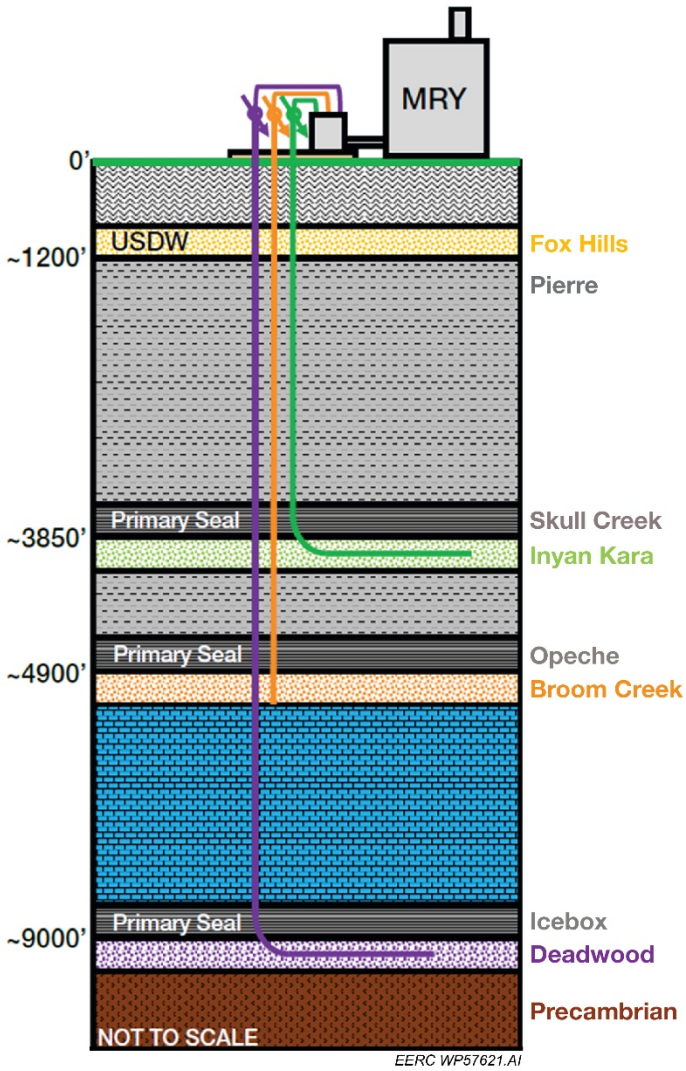


Figure B-25. Generalized well configuration under investigation for the stacked storage of CO_2 in the Inyan Kara, Broom Creek, and Deadwood Formations at the MRYS site.

This scenario evaluated the stacked storage potential of the Inyan Kara, Broom Creek, and Deadwood Formation, which comprise two well pads, one that contains a vertical injection well into the Broom Creek Formation, two horizontal injection wells into the Inyan Kara Formation, and one horizontal well into the Deadwood Formation and the other a vertical injection well into the Broom Creek Formation combined with a horizontal injection well into the Deadwood Formation.

Figures B-26–B-28 show the cumulative rate and gas mass rate of CO_2 per formation (i.e., Broom Creek, Inyan Kara, and Deadwood Formations, respectively) for a total cumulative CO_2 mass of 100 Mt over 25 years. In this scenario, the total gas mass rate of 4.0 Mt/year is distributed among the three target reservoirs as follows: 2.0 Mt/year of CO_2 is injected into the Broom Creek Formation (1 Mt/year per vertical injection well), while the remaining 2 Mt/year of CO_2 is injected into the Inyan Kara and Deadwood Formations at 1 Mt/year per each target reservoir.

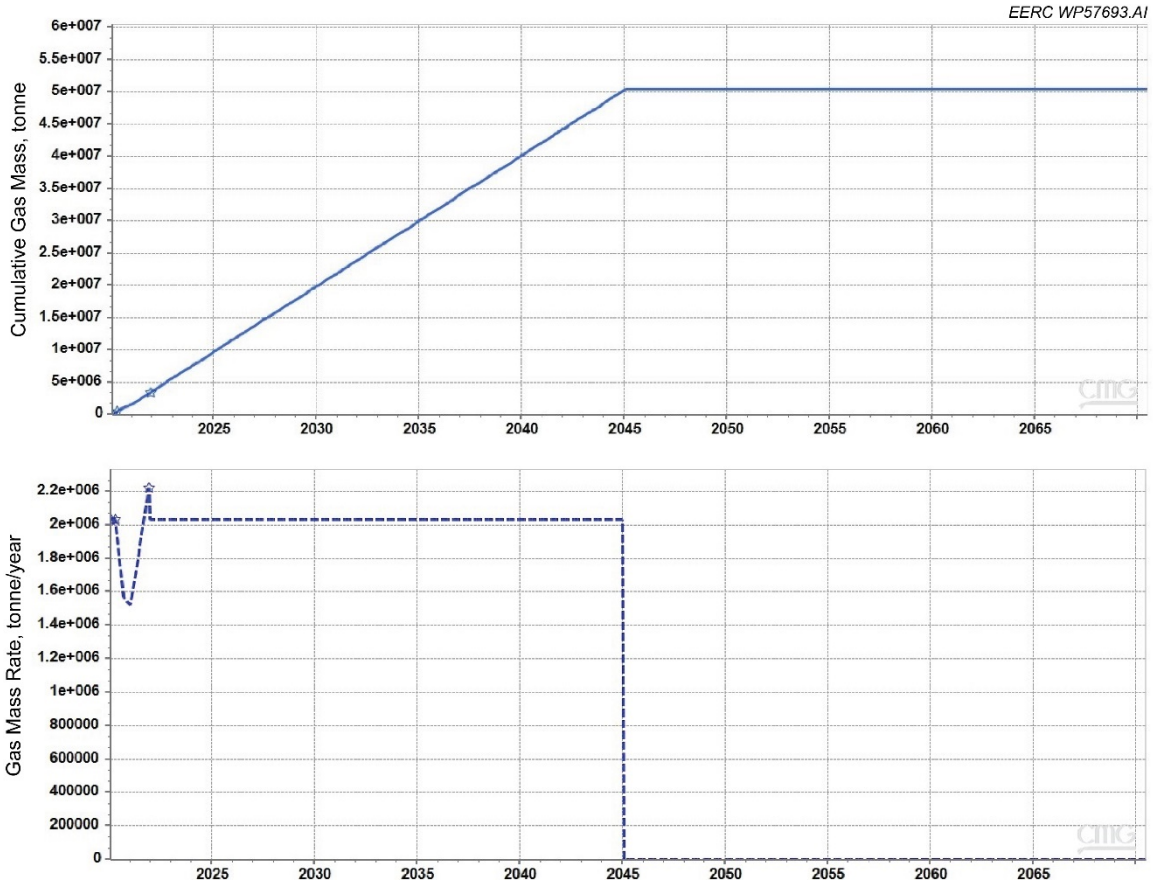


Figure B-26. Broom Creek Formation – two vertical wells: Cumulative gas (CO_2) mass of 50 Mt (left) and CO_2 mass rate of 2.0 Mt/year (right) over 25 years of injection.

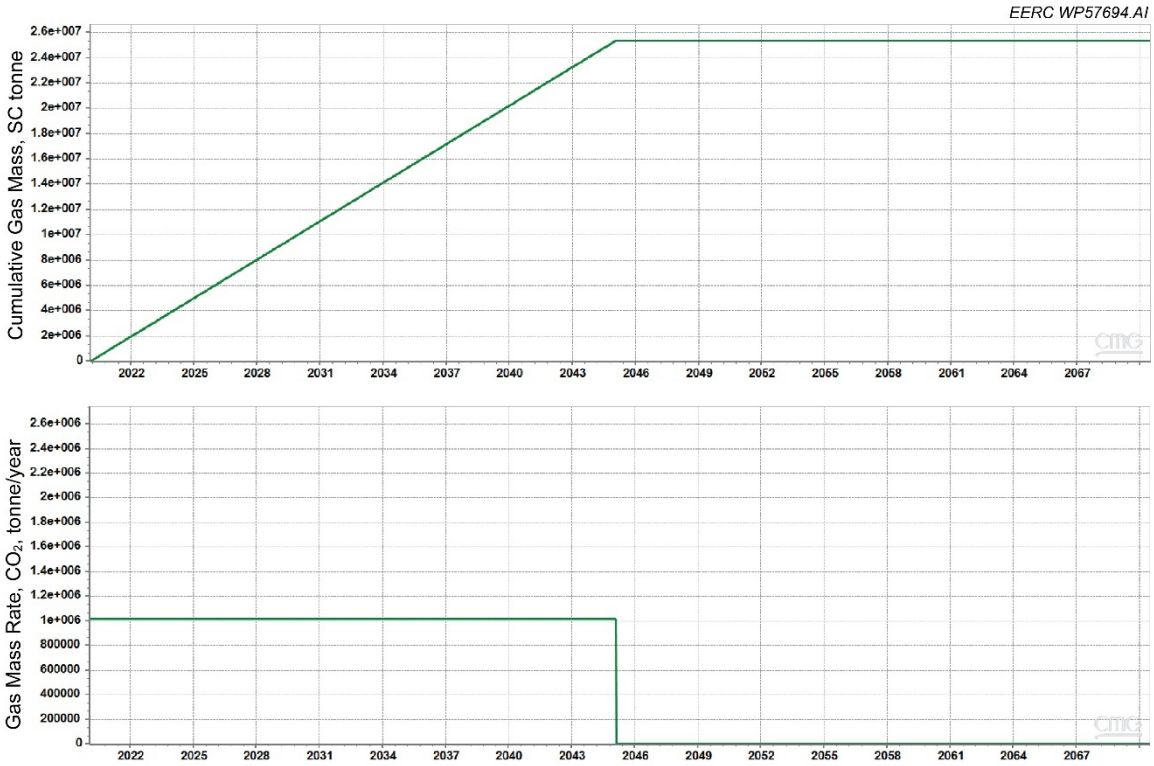


Figure B-27. Inyan Kara Formation – one horizontal well: Cumulative gas (CO_2) mass of 25 Mt (left) and CO_2 mass rate of 1.0 Mt/year (right) over 25 years of injection.

Figure B-29 shows the CO_2 plume map for this well configuration for the stacked model for a total CO_2 mass injection rate of 4.0 Mt/year at the end of the gas injection (i.e., 25 years of injection and a total storage of 100 Mt of CO_2). The green, blue, and red shading represents the areal extent of the CO_2 plume in the Inyan Kara Formation, the Broom Creek Formation, and the Black Island–Deadwood Formation, respectively. The total CO_2 plume area for this well configuration and injection strategy is approximately 22.6 mi^2 for a cumulative CO_2 mass of 25 Mt in the Inyan Kara, 50 Mt in the Broom Creek, and 25 Mt in the Deadwood Formation.

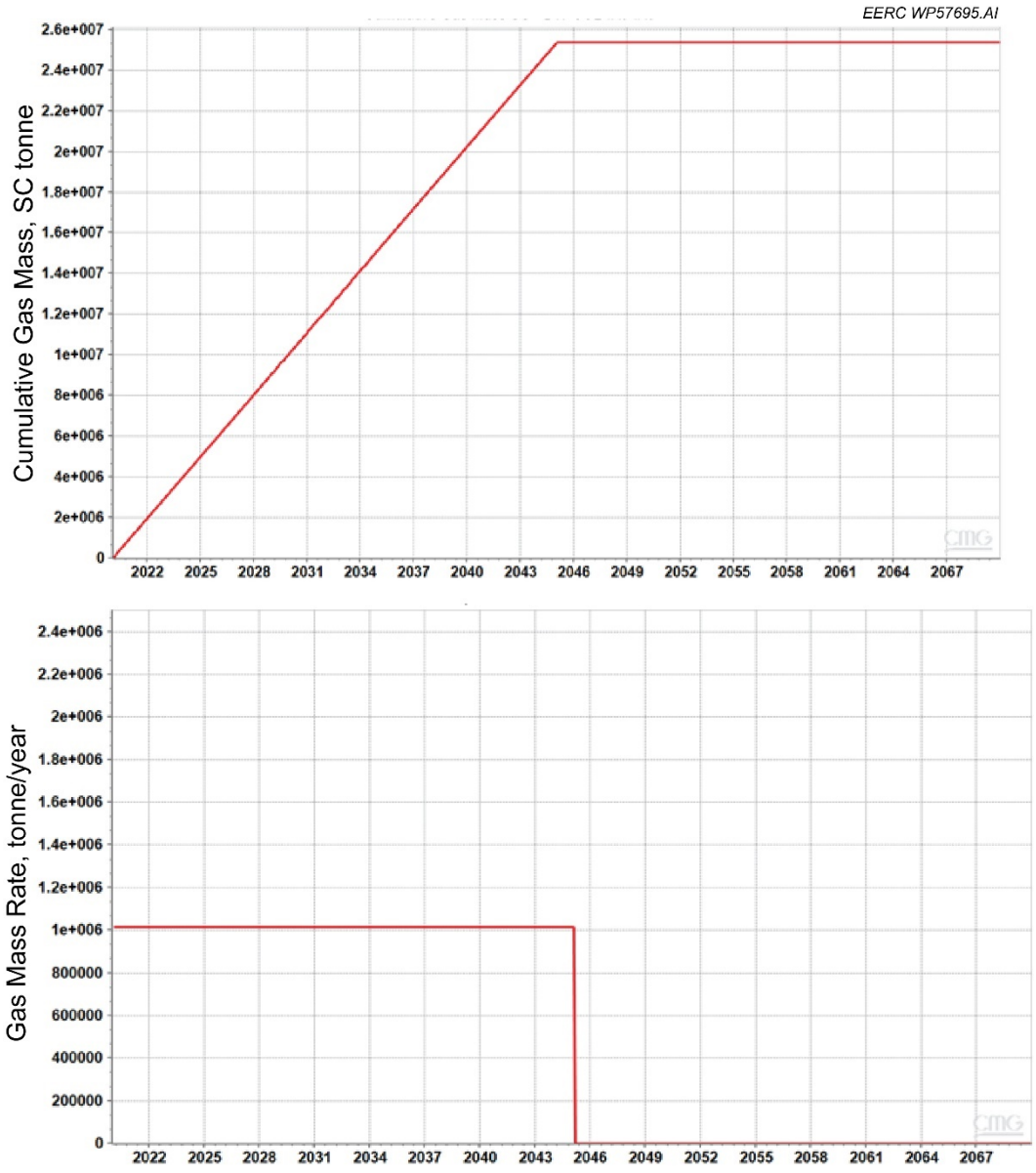


Figure B-28. Deadwood Formation – one horizontal well: Cumulative gas (CO_2) mass of 25 Mt (left) and CO_2 mass rate of 1.0 Mt/year (right) over 25 years of injection as part of the stacked model.

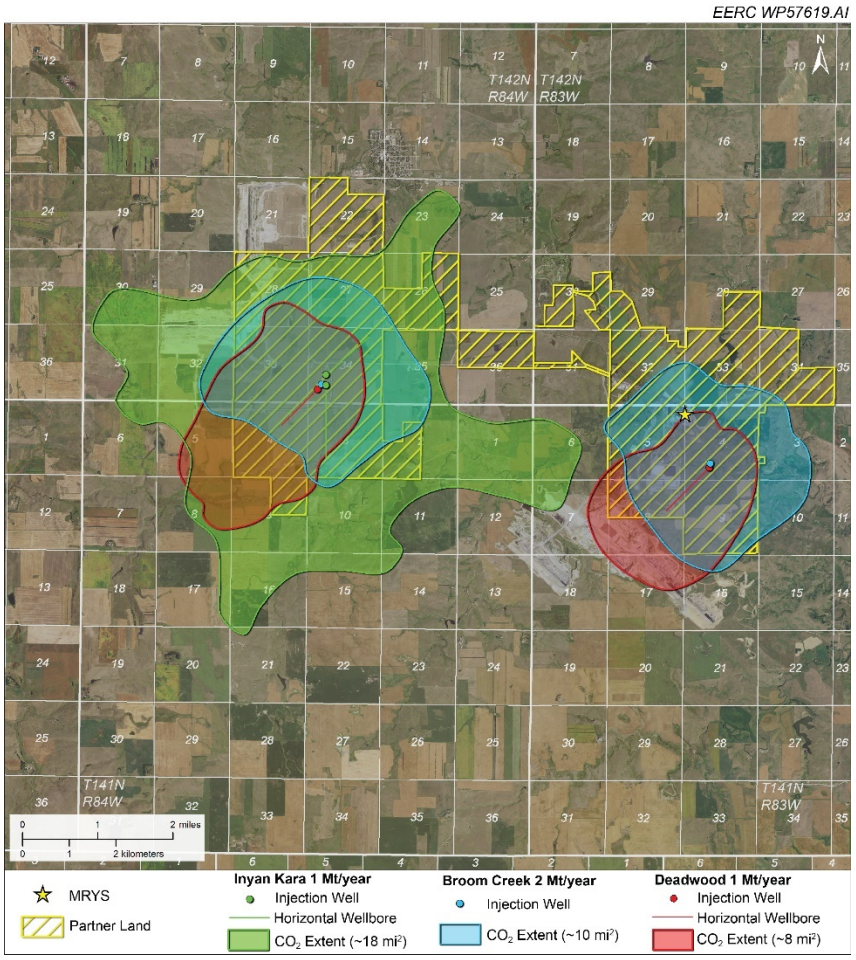


Figure B-29. Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt into the Broom Creek Formation and 25 Mt of CO_2 into each of the Inyan Kara and Deadwood Formations.

3.3.4 Scenario 4 – MRYS Injection into the Broom Creek and Deadwood Formations (Stacked Storage Concept 2)

A second stacked storage scenario was evaluated at the MRYS site which comprised two wells pads, each of which had a vertical injection well into the Broom Creek Formation and a horizontal injection well into the Deadwood Formation. The Inyan Kara Formation was not considered as a viable a storage target as part of this scenario because of the large areal extent of the CO_2 plume that was observed in that formation during the investigation of the previous stacked storage scenario (see Figure B-29).

Figures B-30 and B-31 show the simulated cumulative CO_2 mass and CO_2 mass rate for the Broom Creek and Deadwood Formations, respectively, for this stacked storage scenario. The total CO_2 injection target of 4.0 Mt/year was achieved by injecting 2.0 Mt/year into the Broom Creek Formation and 2.0 Mt/year into the Deadwood Formation. This yielded a total cumulative CO_2 mass stored of 100 Mt over the 25 years of CO_2 injection.

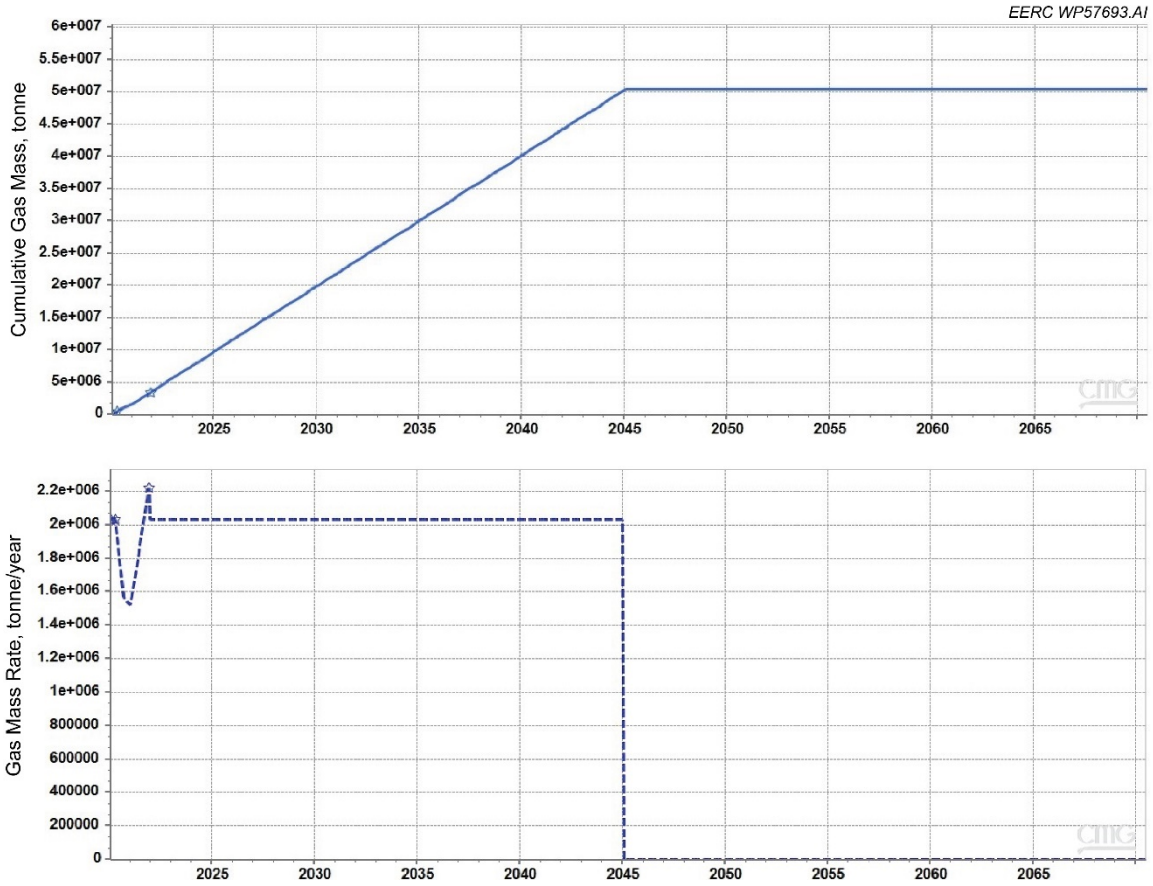


Figure B-30. Broom Creek Formation – two vertical wells: Cumulative CO_2 mass of 50 Mt (left) and CO_2 mass rate of 2.0 Mt/year (right) over 25 years of injection.

The CO_2 plume map for this stacked storage scenario involving the Broom Creek and Deadwood Formations is shown in Figure B-32. The blue shaded area corresponds to areal extent of the CO_2 plume in the Broom Creek Formation; the red shaded area corresponds to the plume in the Deadwood Formation. The total areal extent of the CO_2 plume for this injection strategy is approximately 17.2 mi^2, which is smaller than the other scenarios (injection into the Broom Creek Formation only or into a combination of the Broom Creek, Inyan Kara, and Deadwood Formations) evaluated for the MRYS site for the storage of 100 Mt of CO_2 over a 25-year period.

Based on these results, maximizing the pore space beneath the partner-owned land involves targeting both the Broom Creek and Deadwood Formations for CO_2 storage. To move forward with this storage strategy will require the acquisition of new core from the Deadwood Formation as well as the collection of additional 3-D seismic data in this region, which will greatly reduce the uncertainties in defining the optimal number and configuration of injection wells that are needed.

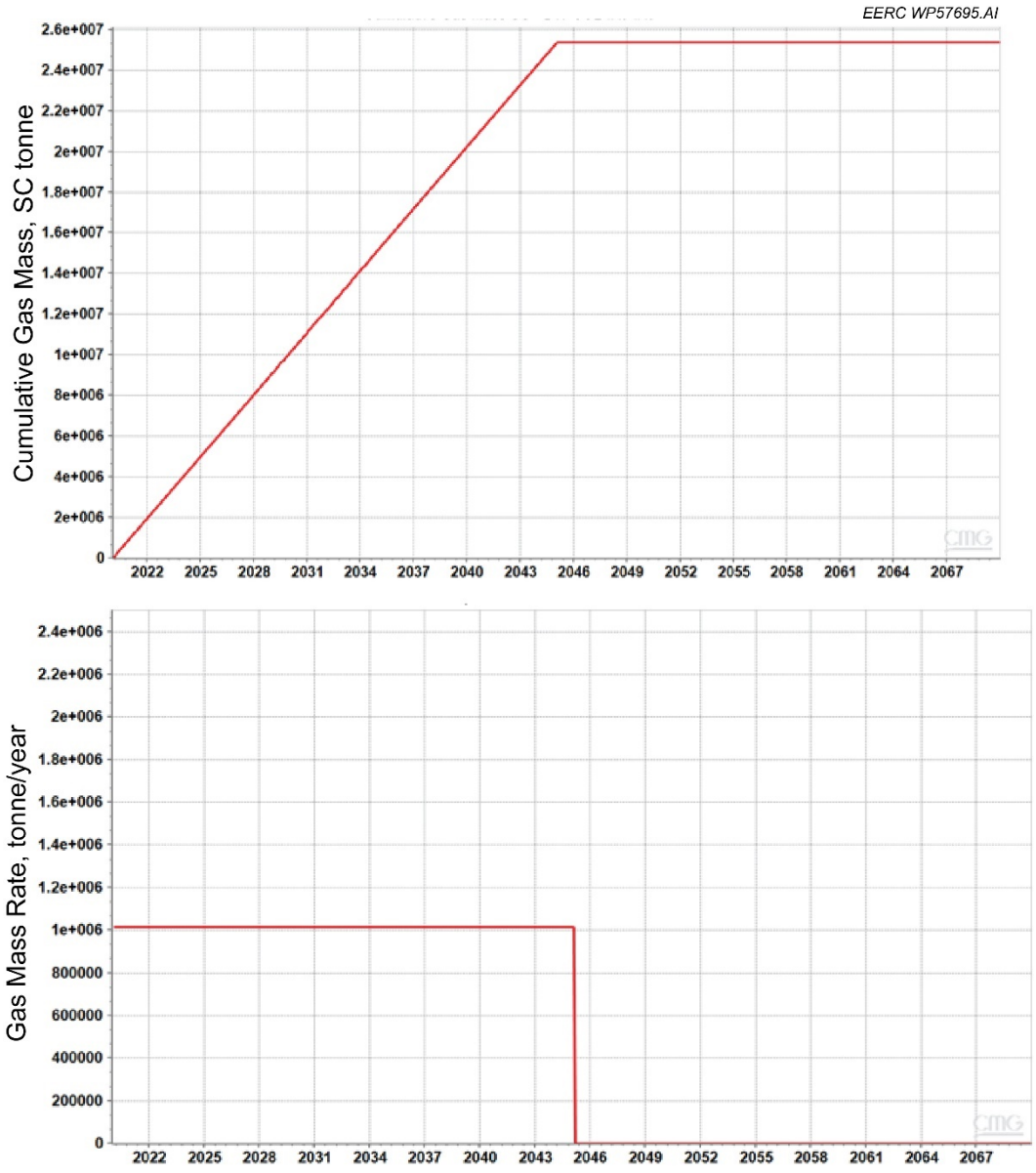


Figure B-31. Deadwood Formation – two horizontal wells: Cumulative CO_2 mass of 50 Mt (left) and CO_2 mass rate of 2.0 Mt/year (right) over 25 years of injection.

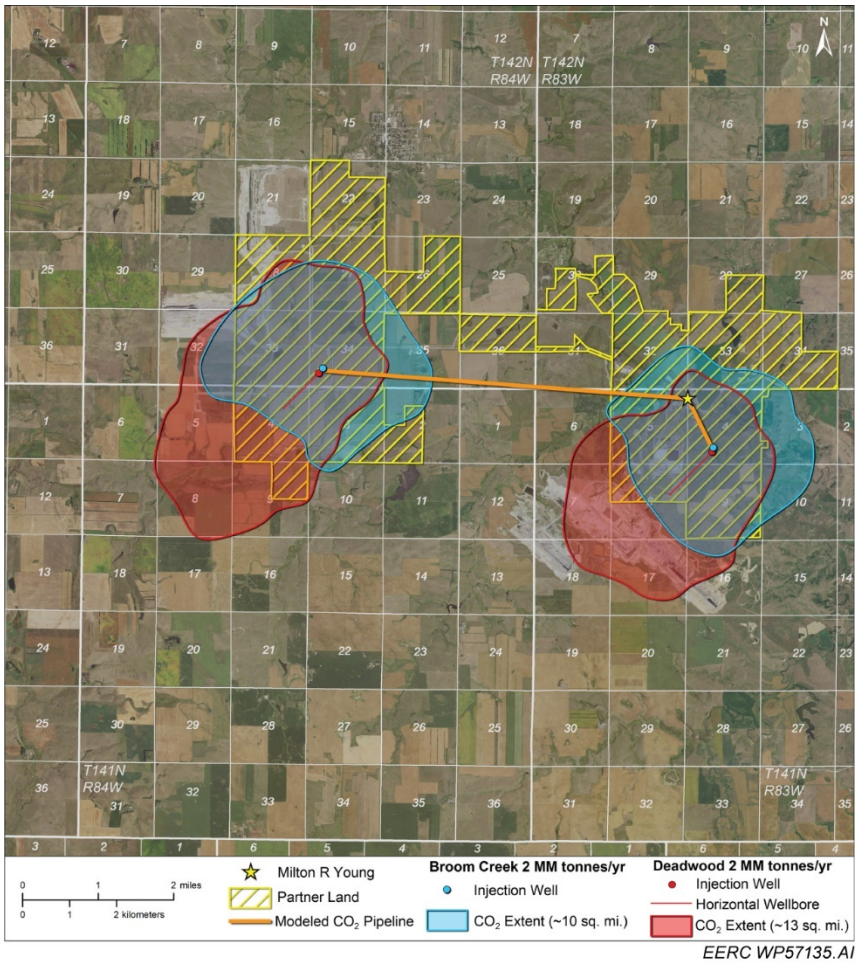


Figure B-32. Extent of CO_2 plume for a total injection of 100 Mt of CO_2 at the MRYS site: 50 Mt each into the Broom Creek and Deadwood Formations.

3.4 Simulation of Geochemical Effects in the Broom Creek Formation

CO_2 injected into a subsurface saline formation can be trapped by four mechanisms (Figure B-33): 1) structure and stratigraphic trapping; 2) residual trapping resulting from the effects of relative permeability hysteresis; 3) solubility trapping; and 4) mineralization through chemical reactions (Xu and others, 2004; Juanes and others, 2006; Ajayi and others, 2019). A good understanding and quantification of the contribution of each individual trapping mechanism are necessary to determine the prospects of sustainable, secure CO_2 storage in the target formation.

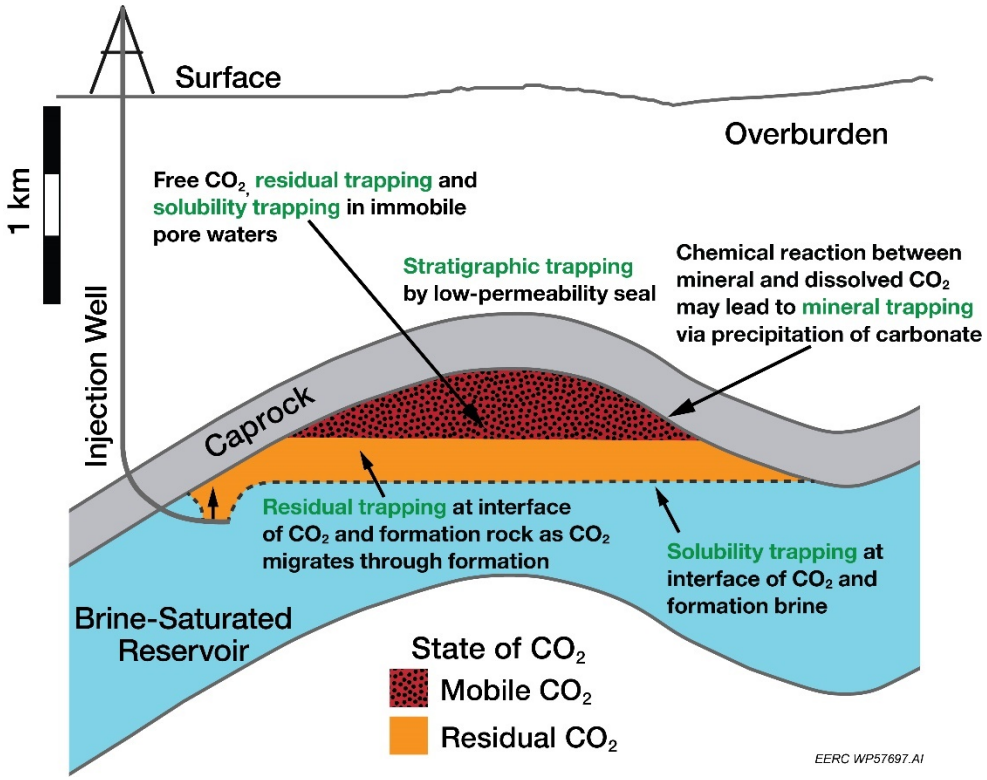


Figure B-33. Schematic of the four primary trapping mechanisms during the subsurface storage of CO_2 in a saline aquifer (University of Edinburgh School of GeoSciences, 2012).

An examination of these trapping mechanisms was conducted for the North Dakota CarbonSAFE project using a reactive transport model, which was applied to the subsurface injection of CO_2 presented in Scenario 3 (see Section B.3.3.3). The model was used to predict the impact of induced geochemical reactions in the sandstone of the Broom Creek Formation, near the MRYS site, on the fate of the injected CO_2.

Equilibrium aqueous reactions (Equations 1 and 2) and rate-dependent mineral reactions (Equations 3 through 7) were incorporated into the model to account for the reactivity of the injected CO_2 with formation brine and rock:

Equilibrium Aqueous Reactions

$$CO_2 + H_2O \rightleftarrows H^+ + HCO_3^- \quad \text{[Eq. 1]}$$

$$H_2O \rightleftarrows H^+ + OH^- \quad \text{[Eq. 2]}$$

Rate-Dependent Mineral Reactions

$$CaCO_3\,(Calcite) + H^+ \rightleftarrows Ca^{2+} + HCO_3^- \quad \text{[Eq. 3]}$$

$$CaMg(CO_3)_2\ (Dolomite) + 2H^+ \rightleftarrows Ca^{2+} + Mg^{2+} + 2HCO_3{}^- \quad \text{[Eq. 4]}$$

$$CaSO_4\ (Anhydrite)\ \rightleftarrows Ca^{2+} + SO_4{}^{2-} \quad \text{[Eq. 5]}$$

$$SiO_2\ (Quartz) \rightleftarrows SiO_{2\ (aq)} \quad \text{[Eq. 6]}$$

$$Ca(Al_2Si_2O_8)\ (Anorthite) + 8H^+ \rightleftarrows Ca^{2+} + 2Al^{3+} + 2SiO_{2\ (aq)} + 4H_2O \quad \text{[Eq. 7]}$$

Inputs to the geochemical model included brine and mineral volume compositions, which were obtained from the fluid and core samples, respectively, of nearby wells (Table B-17) and the relative proportion of minerals, such as quartz, anorthite, calcite, dolomite, and anhydrite, which were found in relative proportion based on x-ray diffraction (XRD) analysis of cores from wells that penetrated the Broom Creek Formation.

Other model inputs included surface area of minerals and thermodynamic equilibrium constants, activation energies, and kinetic rate constants of mineral reactions (Equations 3–7). Since there was no Brunauer–Emmett–Teller (BET) surface area analysis available for each mineral, the surface area was calculated using grain volume, grain surface area, mineral molar volume, and mineral molecular weight, as listed in Table B-17. Meanwhile, the calculation of grain volumes and surface areas assumed that mineral grains are spherical, with an average grain diameter range of 2500 – 5000 μm. The thermodynamic equilibrium constants for the aqueous and mineral reactions were taken from PHREEQC databases (U.S. Geological Survey(s)?).

Table B-17. Brine and Mineral Composition of Broom Creek Formation

Brine, mol/L	Na^+	Ca^{2+}	Mg^{2+}	$SO_4{}^{2-}$	$HCO_3{}^-$	Cl^-	K^+	pH	Salinity, ppm	Ionic Strength
Formation Brine	0.939	0.072	0.018	0.036	0.002	0.038	0.012	6.09	62,775	2.12

	Mineral Volume Fraction					
Mineral	**Quartz**	**Anorthite**	**Calcite**	**Dolomite**	**Anhydrite**	**Average Porosity**
Volume Fraction	0.449	0.019	0.008	0.205	0.129	0.103
Surface Area, m^2/m^3	1200	1200	1200	2390	2400	
Activation Energy, J/mol,	47,830	27,830	14,393	40,000	14,300	
Rate Constant, mol/m^2s	−13.39	−12.12	−11.18	−13.5	−11.45	

The rate constant for each mineral is also presented in Table B-17. Although kinetic rates and activation energy are available from several literature sources (Xu and others, 2004; Kharaka and others, 1989; Nghiem and others, 2004; White and others, 2005), adopting these values generated a serious numerical convergence problem for the model. It appears that these values are so large that mineral volume changes due to dissolution/precipitation occur rapidly, leading to radical changes in pressure and aqueous composition, which results in convergence failure. Coupling the issue of rapid pressure and aqueous molar composition with the heterogeneous model and high CO_2 injection target resulted in an uncontrollable modeling problem. For this reason, the kinetic rates and activation energies presented in Table B-17 represent modifications to literature reported values. However, no attempt was made as part of this project to investigate the uncertainty

associated with the model results that were introduced by modifying the values that are reported in the literature.

3.4.1 Impacts of Geochemical Activity on CO_2 Injection

A comparison of the CO_2 injection simulation results for Scenario 3, with and without the integration of geochemical reactions, is shown in Figure B-34. This figure suggests that there is minimal effect of mineral dissolution and precipitation on the injectivity of the formation. Both the CO_2 injection rate and cumulative injected amount of CO_2, with and without geochemistry, match reasonably well. This observation could be attributed to the small amount of carbonate minerals that are present in the Broom Creek sandstone formation.

A brief discussion of the geochemical activity that is taking place during the injection of CO_2, as interpreted from the modeling results, is provided in the remainder of this section. During the injection period, CO_2 saturation increases near the two injection wells by migrating either vertically through buoyancy-driven effects or horizontally through preferential flow pathways. The dissolution of CO_2 (Equation 1) in the brine during this period lowers the pH of brine, as shown in Figure B-35), and induces changes in mineral composition.

At the same time, calcite and dolomite were observed to dissolve during CO_2 injection, releasing Ca^{2+} and Mg^{2+} ions into brine solution, where the Ca^{2+} ions in the brine are consumed by the precipitation of anhydrite (Figure B-36). The geochemical model results also reveal how much of the CO_2 is spatially stored as diverse mineral phases. Over the 25-year injection period, it is projected that very small amounts of calcite (~2.5 tonnes) and dolomite (~14.5 tonnes) will be dissolved uniformly within the CO_2 plumes.

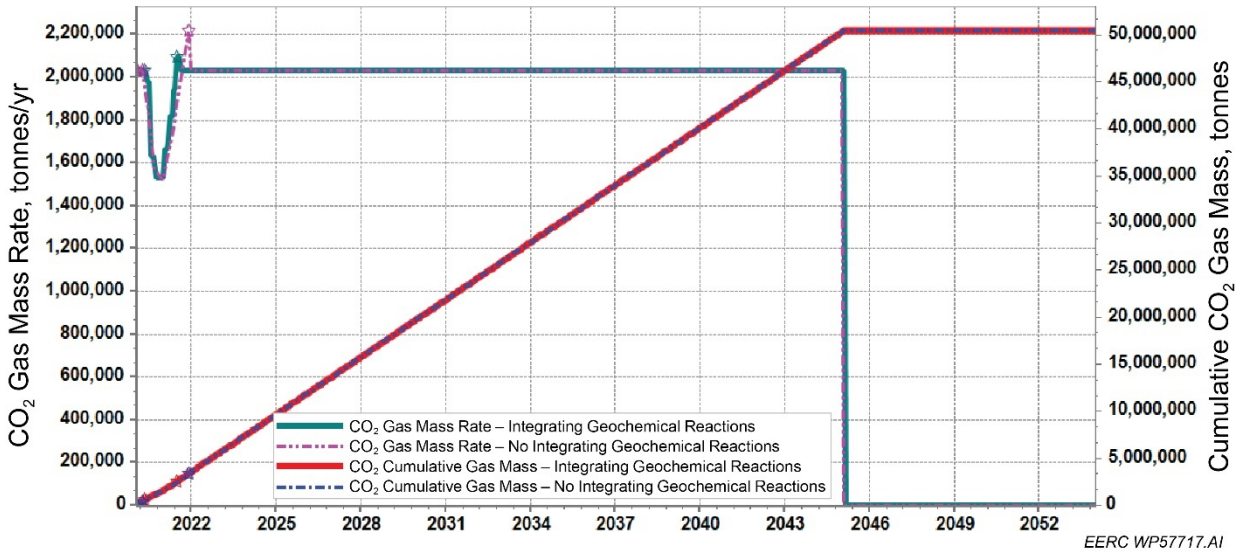


Figure B-34. Comparison of simulated daily CO_2 gas mass rate and cumulative injected CO_2 between model with and without integration of geochemical reactions.

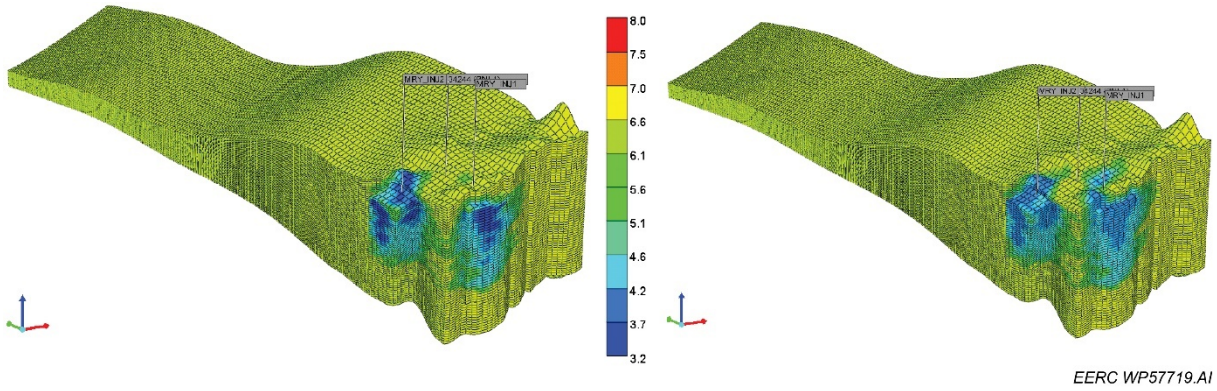


Figure B-35. Effect of CO_2 injection on pH of brine in the vicinity of the CO_2 at the end of 25 years of injection (left) and 100 years following the cessation of CO_2 injection (right).

The simulated mineral changes that result from dissolution and precipitation cause changes in porosity. The altered porosity is shown in Figure B-37, indicating that the projected changes to porosity after 25 years of injection will be relatively insignificant and will not result in any significant changes in permeability. However, 100 years after the cessation of CO_2 injection, mineral precipitation due to CO_2 sequestration is predicted to result in a reduction of porosity by ~0.18%, which has the potential to result in a reduction of formation permeability (Figure B-37).

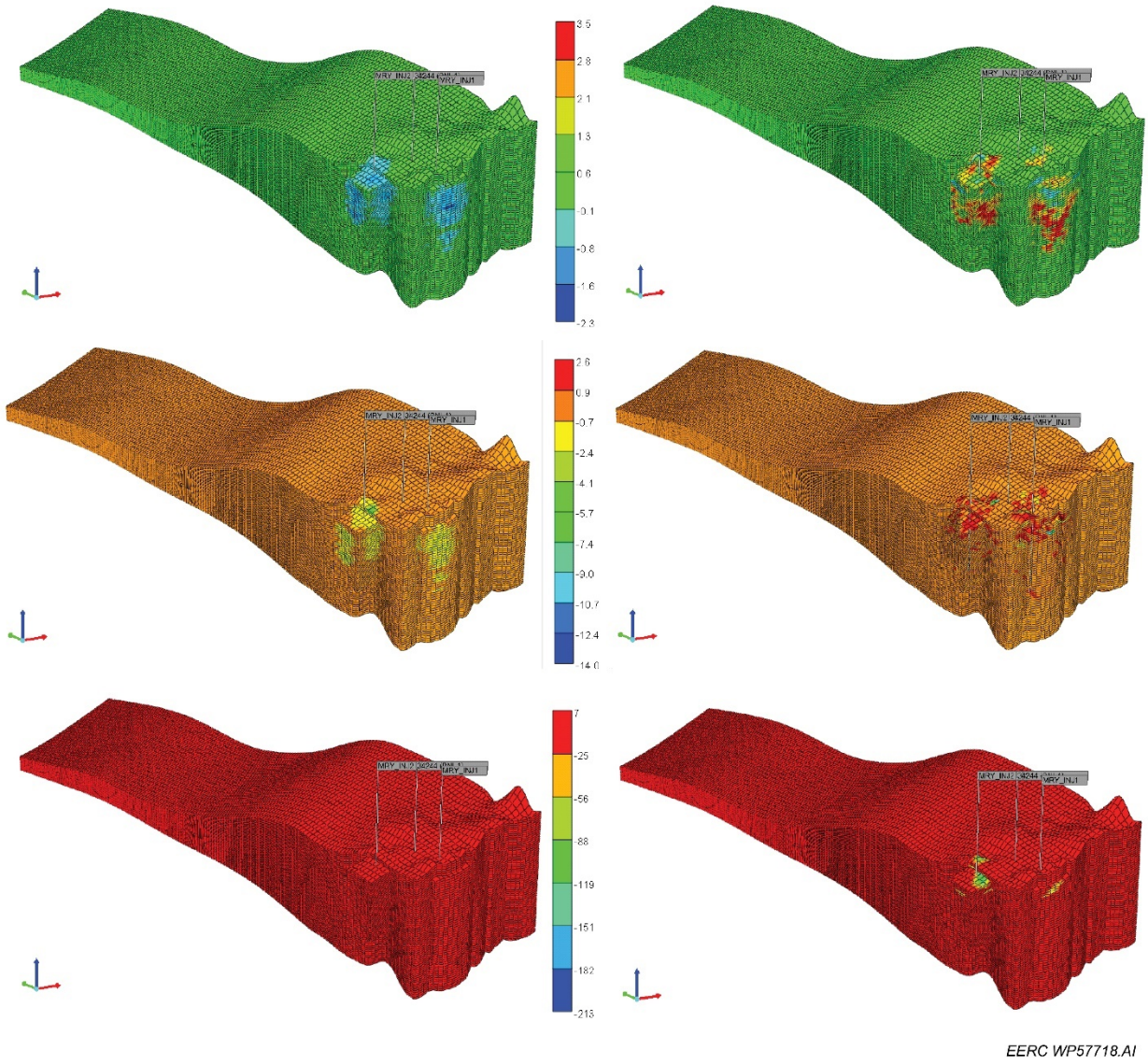


Figure B-36. 3-D cross-sectional views of changes, in tonnes, in calcite (top), dolomite (middle), and anhydrite (bottom) around the CO_2 injection wells at the end of 25 years of CO_2 injection (left) and 100 years following the cessation of CO_2 injection (right).

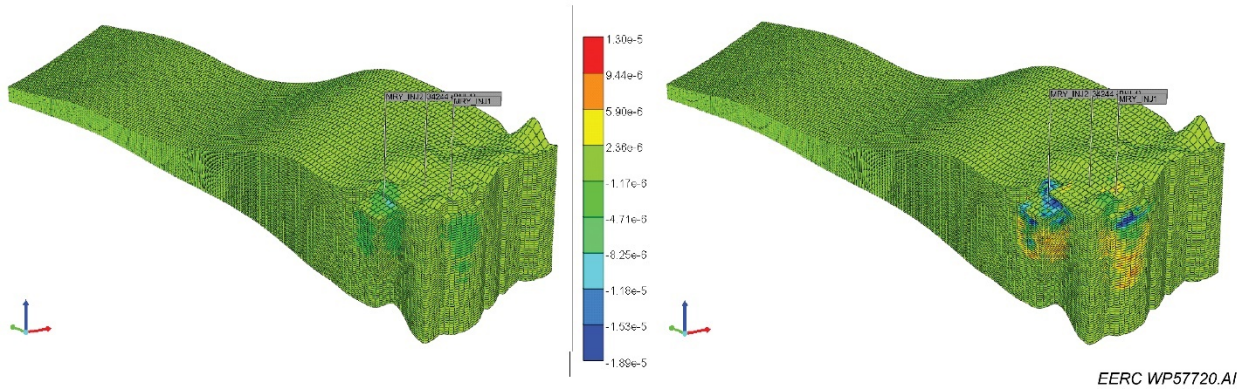


Figure B-37. Comparison of porosity changes around the CO_2 injection wells after 25 years of CO_2 injection (left) and 100 years following the cessation of CO_2 injection (right).

3.4.2 Review CO_2-Trapping Mechanisms

Figure B-38 shows the distribution of CO_2 stored by the different trapping mechanisms. There are two main stages of trapping that can be identified over the course of a CO_2 storage project. Stage 1 is represented by the active injection period, where the hydrostratigraphic trapping is dominant as the CO_2 migrates either vertically or horizontally in the subsurface. During this stage, CO_2 also dissolves in the brine as it encounters fresh brine solution.

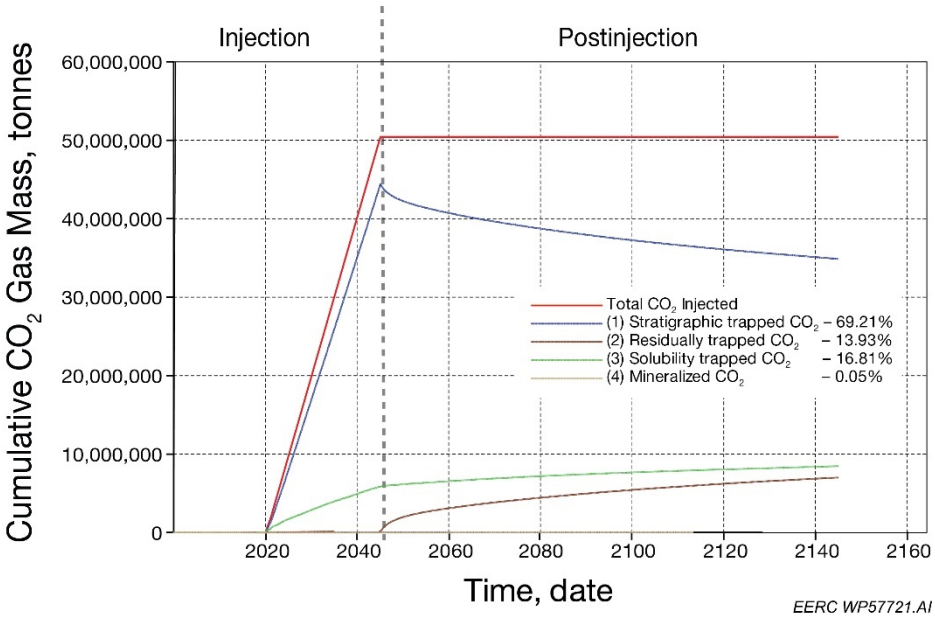


Figure B-38. CO_2 stored, in tonnes, by different trapping mechanisms.

Stage 2 commences after injection is halted, at which time residual trapping becomes dominant. As CO_2 migrates, some of the mobile CO_2 becomes trapped in pores because of the imbibition process that occurs at the tail of the CO_2 plume, where reservoir brine displaces CO_2. At this stage, the mobile CO_2 cumulative mass dramatically decreases, while the quantity of residual CO_2 increases. In addition, the dissolved CO_2 mass continues to increase but at a slower rate than Stage 1 because the injection-triggered partial pressure of CO_2 decreases after injection ends.

The precipitation of CO_2 as minerals is also observed during Stage 2; however, this trapping mechanism is only projected to account for about 0.05% of total CO_2 stored after 100 years. Based on previous studies, mineral trapping is expected to increase and become greater than any other mechanisms only after several thousands of years (Nghiem and others, 2004; White and others, 2005; Han and others, 2010).

Figure B-39 shows the changes in the distribution of mineral mass that is projected to occur over time. For most minerals, 100 years is insufficient time for them to reach equilibrium with reservoir fluids; hence, after 100 years, all minerals are still dissolving or precipitating. For example, it is projected that the rate of dissolution of CO_2 will be reduced 30 years after injection is halted as the solution pH buffers and calcite and dolomite begin to precipitate.

The precipitation of calcite and dolomite are accompanied by dissolution of anhydrite and anorthite. After 100 years following the injection of the CO_2, it is projected that about 41,000 tonnes of dolomite, 4000 tonnes of calcite, and 29,000 tonnes of quartz will have precipitated, while 22,000 tonnes of anhydrite and 70,000 tonnes of anorthite will have dissolved.

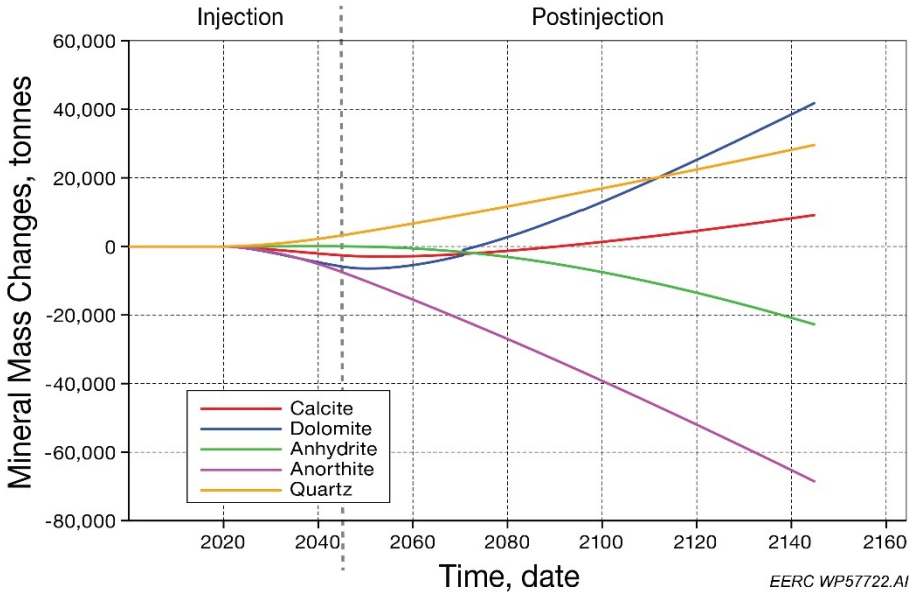


Figure B-39. Evolution of changes of mineral mass, in tonnes, over time.

4.0 CONCLUSIONS

4.1 CO_2 Injection and Pore Space Optimization

The numerical simulation efforts have shown that the storage resource of the different formations targeted by the North Dakota CarbonSAFE project are more than adequate to accept between 50 Mt and 100 Mt of CO_2 over a 25-year period (i.e., CO_2 injection rates of 2 to 4 Mt/year). Among the potential CO_2 injection strategies, four were identified for investigation: 1) Scenario 1 – two vertical wells injecting into the Broom Creek Formation for the GPSP site; 2) Scenario 2 – four vertical wells injecting into the Broom Creek Formation for the MRYS site; 3) Scenario 3 – two vertical wells injecting into the Broom Creek Formation and two horizontal wells, one each, injecting into the Inyan Kara and Deadwood Formations at the MRYS site; and 4) Scenario 4 – two vertical wells injecting into the Broom Creek Formation and two horizontal wells injecting into the Deadwood Formation at the MRYS site. The investigation revealed that Scenario 1 provided a satisfactory approach for the GPSP site and Scenario 4, using stacked storage in the Broom Creek and Deadwood Formations, provided an optimal approach for the MRYS site, i.e., achieved the required storage capacity and injectivity while at the same time time maximizing the amount of pore space that was associated with partner-owned land. Tables B-18 and B-19 provide a summary of the injection scenarios that were investigated in this study and the key injection parameters for each scenario, respectively. The WHP values reported in Table B-19 correspond to simulation results for the specified injection scenario and formation that were evaluated.

In summary, the study demonstrated that all four scenarios were more than adequate to store between 50 Mt (GPSP and MRYS sites) and 100 Mt (MRYS site) of CO_2 over 25 years of injection. The results also show that using stacked storage involving the Broom Creek and Deadwood Formations at the MRYS site (Scenario 4) maximizes the use of pore space of partner-owned land, thereby facilitating the permitting process for the storage operations.

Table B-18. Summary of Scenarios

Scenario	Formation	Site	No. Wells and Configuration	CO_2 Stored, Mt	CO_2 Plume Area, mi^2
1	Broom Creek	GPSP	Two verticals	50	12.2
2	Broom Creek	MRYS	Four verticals	101	19.9
3	Inyan Kara	MRYS	Two horizontals	25	22.8
	Broom Creek		Two verticals	50	
	Deadwood		Two horizontals	25	
4	Broom Creek	MRYS	Two verticals	50	17.2
	Deadwood		Two horizontals	50	

Table B-19. Summary of CO_2 Injection Schemes and Critical Formation Characteristics per Scenario

Scenario	Formation	No. Wells and Configuration	Porosity, %	Permeability, mD	Tubing size o.d., in.	Maximum WHP*, psi
1	Broom Creek	Two verticals	10.3	81	4.5	1570
2	Broom Creek	Four verticals	10.3	81	4.5	1600
3	Inyan Kara	Two horizontals	9.8	384	4.5	1150
	Broom Creek	Two verticals	10.3	81		1500
	Deadwood	Two horizontals	10.1	55		1723
4	Broom Creek	Two verticals	10.3	81	4.5	1500
	Deadwood	Two horizontals	10.1	55		2392

* WHP value corresponds to simulated results by well configuration/formation.

4.2 Geochemical Effects on CO_2 Storage

The geochemical simulations showed that induced mineral changes will have a negligible impact on injectivity during the 25-year injection period. This minimal impact is not surprising for sandstone formations that contain small amounts of carbonate minerals. The major CO_2-trapping mechanisms during the injection and postinjection periods are projected to be hydrostratigraphic, residual, and solubility trapping. However, the dominant CO_2-trapping mechanisms will vary between the injection and postinjection periods. During CO_2 injection, the model results indicate that CO_2 trapping will be dominated by hydrostratigraphic trapping, while following the cessation of injection, the dominant trapping mechanism will be residual trapping. Mineral trapping will not occur until many years after the cessation of CO_2 injection and is projected to account for only 0.05% of total CO_2 stored after 100 years of postinjection.

The geochemical simulation predicts that most of the mineralogical changes in the formations, which are predicted to occur during the postinjection period, will involve the storage of CO_2 in the form of several different minerals. Anorthite and anydrite will be the predominant minerals dissolved in the formations, while calcite, dolomite, and quartz will be the major minerals precipitated.

5.0 REFERENCES

Ajayi, T., Awolayo, A., Gomes, J.S., Parra, H., and Hu, J., 2019, Large-scale modeling and assessment of the feasibility of CO_2 storage onshore Abu Dhabi: Energy, v. 185, p. 653–670.

Bennion B., and S. Bachu, 2005, Relative permeability characteristics for supercritical CO_2 displacing water in a variety of potential sequestration zones in the Western Canada Sedimentary Basin: Presented at the 2005 Society of Petroleum Engineers Annual Technical Conference & Exhibition, Dallas, Texas, October 9–12, SPE 95547.

Bennion, B., and Bachu, S., 2007, Permeability and relative permeability measurements at reservoir conditions for CO_2-water systems in ultralow-permeability confining caprocks: Society of Petroleum Engineers Europec at 69th European Association of Geoscientists and Engineers Conference & Exhibition, London, United Kingdom, June 11–14, SPE 106995.

Carlson, C.G., 1993, Permian to Jurassic Redbeds of the Williston Basin: North Dakota Geological Survey Miscellaneous Series, no. 78, p. 20.

Computer Modelling Group, 2018, GEM user guide.

Dalkhaa, C., Pekot, L.J., Jiang, T., Oster., B.S., Bosshart, N.W., Sorensen, J.A., Gorecki, C.D., 2017, Aquistore CO_2 storage project—numerical modeling and simulation update: Plains CO_2 Reduction (PCOR) Partnership Task 1 – Deliverable D93, Update 3, technical report to U.S. Department of Energy National Energy Technology Laboratory, September.

Deutsch, C.V., 2008, Fundamentals of geostatistics—principles and hands-on practice (2008 ed.).

Dow, W.G., 1964, The Spearfish Formation in the Williston Basin of western North Dakota: Master's Thesis, University of North Dakota, Grand Forks, North Dakota, p. 127.

Drilling Formulas (n.d.), 2016, Retrieved from www.drillingformulas.com/rock-compressibility (accessed February 2020).

Fischer, D.W., Sorensen, J.A., Smith, S.A., L.D., Steadman, E.N., and Harju, J.A., 2005, Inyan Kara Formation outline: Plains CO_2 Reduction (PCOR) Partnership value-added topical report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, September.

Fischer, D.W., Sorensen, J.A., Smith, S.A., L.D., Steadman, E.N., and Harju, J.A., 2008, Deadwood Formation outline: Plains CO_2 Reduction (PCOR) Partnership value-added topical report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, March.

Gorecki, C., Sorensen, J., Bremer, J., Ayash, S., Knudsen, D., Holubnyak, Y., Smith, S., Steadman, E., and Harju, J., 2009, Development of storage coefficients for CO_2 storage in deep saline formations: IEA Greenhouse Gas R&D Programme (IEAGHG) 2009/13.

Han, W.S., McPherson, B.J., Lichtner, P.C., and Wang, F.P., 2010, Evaluation of trapping mechanisms in geologic CO_2 sequestration—case study of SACROC northern platform, a 35-year CO_2 injection site: American Journal of Science, v. 310, no. 4, p. 282–324.

Juanes, R., Spiteri, E.J., Orr Jr, F.M., and Blunt, M.J., 2006, Impact of relative permeability hysteresis on geological CO_2 storage: Water Resources Research, v. 42, p. 12.

Kharaka, Y.K., Gunter, W.D., Aggarwal, P.K., Perkins, E., and Debraal, J.D., 1989, SOLMINEQ.88—a computer program for geochemical modeling of water rock reactions: U.S. Geological Survey Water-Resources Investigations Report 88-4227.

LeFever, R.D., Thompson, S.C., and Anderson, D.B., 1987, Earliest Paleozoic history of the Williston Basin in North Dakota: Fifth International Williston Basin Symposium, p. 22–36.

Livers-Douglas, A.J., Burton-Kelly, M.E., Oster, B.S., Peck, W.D., and Bosshart, N.W., 2019, Geostatistical analysis of seismic data for regional modeling of the Broom Creek Formation,

North Dakota, USA [abs.]: EAGE Petroleum Geostatistics 2019, Florence, Italy, September 2–6, 2019.

Liu, G., Peck, W.D., Gorecki, C.D., Steadman, E.N., Harju, J.A., 2013, Basal Cambrian dynamic capacity estimation completed: Plains CO_2 Reduction (PCOR) Partnership Phase III, Task 16 – Milestone M35 for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement, No. DE-FC26-05NT42592, Grand Forks, North Dakota, Energy & Environmental Research Center, April.

Murphy, E.C., Nordeng, S.H., Juenker, B.G., and Hoganson, J.W., 2009, North Dakota stratigraphic column: North Dakota Geological Survey.

Nghiem, L., Sammon, P., Grabenstetter, J., and Ohkuma, H., 2004, Modeling CO_2 storage in aquifers with a fully coupled geochemical EOS compositional simulator: Society of Petroleum Engineers Journal SPE-89474.

Peck, W.D., Glazewski, K.A., Braunberger, J.R., Grove, M.M., Bailey, T.P., Bremer, J.M., Gorz, A.J., Sorensen, J.A., Gorecki, C.D., and Steadman, E.N., 2014, Broom Creek Formation outline: Plains CO_2 Reduction (PCOR) Partnership Phase III value-added report for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FC26-05NT42592, EERC Publication 2014-EERC-09-09, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

Rygh, M.E., 1990, The Broom Creek Formation (Permian) in southwestern North Dakota: Master's thesis, University of North Dakota, Grand Forks, North Dakota, p. 189.

Schlumberger, 2016, Petrel 2016: Petrel E&P Software Platform.

Sorensen, J.A., Bailey, T.P., Dobroskok, A.A., Gorecki, C.D., Smith, S.A., Fisher, D.W., Peck, W.D., Steadman, E.N., and Harju, J.A., 2009, Characterization and modeling of the Broom Creek Formation for potential storage of CO_2 from coal-fired power plants in North Dakota: Search and Discovery Article 80046.

University of Edinburgh School of geoSciences, 2012, Retrieved from www.geos.ed.ac.uk/ukccsrc/what-is-ccs/storage.html (accessed February 2020).

Wartman, B.L., 1982, Geology and hydrology of the Inyan Kara Formation (Lower Cretaceous), North Dakota, *in* Jorgensen, D.G., and Signor, D.C., eds., Geohydrology of the Dakota Aquifer Symposium, October 5–6, 1982, National Water Well Association, Lincoln, Nebraska, Proceedings: p. 22–26.

White, S.P., Allis, R.G., Moore, J., Chidsey, T., Morgan, C., Gwynn, W., and Adams, M., 2005, Simulation of reactive transport of injected CO_2 on the Colorado Plateau, Utah, USA: Chemical Geology, v. 217, p. 387–405.

Willis, R.P., 1959, Upper Mississippian–Lower Pennsylvanian stratigraphy of central Montana and Williston Basin: American Association of Petroleum Geologist Bulletin, v. 43, no. 8, p. 1940–1966.

Xu, T., Apps, J.A., Pruess, K., 2004, Numerical simulation of CO_2 disposal by mineral trapping in deep aquifers: Applied Geochemistry, v. 19, p. 917–936.

Ziebarth, H.C., 1972, The stratigraphy and economic potential of Permo-Pennsylvanian strata (Minnelusa Group) in southwestern North Dakota: Ph.D. dissertation, University of North Dakota, Grand Forks, North Dakota, p. 414.

APPENDIX C

NORTH DAKOTA CARBON DIOXIDE STORAGE FACILITY AND INJECTION WELL PERMIT APPLICATIONS CHECKLIST

(North Dakota Century Code Chapter 38-22; North Dakota Administrative Code Chapter 43-05-01)

NORTH DAKOTA CARBON DIOXIDE STORAGE FACILITY AND INJECTION WELL PERMIT APPLICATIONS CHECKLIST

(North Dakota Century Code Chapter 38-22; North Dakota Administrative Code Chapter 43-05-01)

C.1 Definitions

- "Storage Facility" or "Facility Area" means the subsurface areal extent of the storage reservoir; this is not in reference to surface facilities.

- "Storage Reservoir" means the total pore space occupied by carbon dioxide during all phases of the project with one-half-mile buffer around its delineated extent.

- "Storage Formation" means the target formation(s) that carbon dioxide will be injected into.

- "Pressure Front" means the zone of elevated pressure and displaced fluids created by the injection of carbon dioxide into the subsurface. The pressure front of a carbon dioxide plume refers to a zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into underground sources of drinking water.

C.2 Scope

- The following guidelines pertain to the geologic storage of carbon dioxide. This guideline does not apply to applications filed with the Commission proposing to use carbon dioxide for an enhanced oil or gas recovery project. Applications filed with the Commission proposing enhanced oil or gas recovery will be processed under North Dakota Century Code (NDCC) Chapter 38-08 and North Dakota Administrative Code (NDAC) Chapter 43-02-05.

C.3 Application of Rules

- In addition to the provisions outlined herein, injection wells utilized for geologic storage are subject to the provisions of NDAC Chapters 43-02-03 and 43-02-05 when applicable.

- Note: A storage facility bond will be required and bond amount determined by hearing. The bond must account for the area of review, regardless of whether or not corrective action in the area of review is phased in accordance with 43-05-01-05.1.

- A processing fee will be billed based on actual processing costs, including computer data-processing costs, incurred by the Commission. After the Commission's work on the application has concluded, a final statement will be sent. The applicant must pay the processing fee regardless of whether a permit is issued, denied, or withdrawn. The Commission has one year from the date an application is deemed complete to issue a final decision.

C.4 Storage Facility Permit

- Pore Space – Applicant must address pore space by filing the following:

  a. An affidavit of mailing certifying that all pore space owners and lessees within the storage reservoir area and within one-half mile outside of its boundary have been notified of the proposed carbon dioxide storage project.

  b. A map showing the extent of the pore space that will be occupied by the injection and geologic storage of carbon dioxide over the life of the project.

  c. A map showing the storage reservoir boundary and one-half mile outside of its boundary, with a pore space ownership description.

  d. A map showing the storage reservoir boundary and one-half mile outside of its boundary, with a description of each operator of mineral extraction activities.

  e. A map showing the storage reservoir boundary and one-half mile outside of its boundary, with a description of each mineral lessee of record.

  f. A map showing the storage reservoir boundary and one-half mile outside of its boundary, with a description of each surface owner of record.

  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.

- Geologic Exhibits – Applicant must include the following geologic exhibits:

  a. The name, description, and average depth of the storage reservoir.

  b. A description of the storage reservoir's mechanisms of geologic confinement, including rock properties, regional pressure gradients, and adsorption characteristics with regard to preventing migration of carbon dioxide beyond the proposed storage reservoir.

  c. Any regional or local faulting.

  d. An isopach map of the storage reservoirs.

  e. An isopach map of the primary and secondary containment barrier for the storage reservoir.

  f. A structure map of the top and base of the storage formation.

  g. Identification of all structural spill points or stratigraphic discontinuities controlling the isolation of stored carbon dioxide and associated fluids within the storage reservoir.

h. Evaluation of the pressure front and the potential impact on underground sources of drinking water, if any.

i. Structural and stratigraphic cross sections that describe the geologic conditions at the storage reservoir.

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.

k. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone, including facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, zone names, and lithologic descriptions.

l. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressure 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.

m. Information on any regional tectonic activity, and the seismic history, including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment.

n. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the storage reservoir area.

o. Identify and characterize additional strata overlying the storage reservoir that will prevent vertical fluid movement, are void of transmissive faults or fractures, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

- Area of Review Determination – The carbon dioxide storage reservoir area of review includes the areal extent of the storage reservoir and one mile outside of its boundary, plus the maximum extent of the pressure front caused by injection activities. The area of review delineation must include the following:

  a. A map showing the boundaries of the storage reservoir and the location of all proposed wells and proposed cathodic protection boreholes within the carbon dioxide storage reservoir area, and any existing or proposed surface facilities.

  b. A method for delineating the area of review, including the computational model to be used, assumptions that will be made, and the site characterization data on which the model will be based.

c. A description of:

   i. The reevaluation date, not to exceed five years, at which time the storage operator shall reevaluate the area of review.

   ii. The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation date.

   iii. How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation.

   iv. How corrective action will be conducted if necessary, including what corrective action will be performed prior to injection, and how corrective action will be adjusted if there are changes in the area of review.

d. A map of all wells, including water, oil, and natural gas exploration and development wells, and other manmade subsurface structures and activities, including coal mines, within the storage reservoir area and within one mile outside of its boundary.

e. An areal map depicting 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.

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.

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. A review of these wells must include the following:

   i. 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 the storage formation.

   ii. A description of each well's type, construction, date drilled, location, depth, record of plugging, and completion.

   iii. A map and cross sections of the area of review.

   iv. 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.

v. A list of contacts, submitted to the Commission when the area of review extends across state jurisdiction boundary lines.

h. Maps and stratigraphic cross sections of all underground sources of drinking water within the area of review indicating their general vertical and lateral limits, water wells, and springs within the area of review; their positions relative to the injection zone; and the direction of water movement, where known.

i. Baseline geochemical data on subsurface formations, including all underground sources of drinking water in the area of review.

- Plans – The following items must accompany the application:

a. The proposed calculated average and maximum daily injection rates, daily volume, and the total anticipated volume of the carbon dioxide to be stored.

b. The proposed average and maximum bottomhole and surface injection pressures to be utilized.

c. The proposed preoperational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone.

d. The proposed stimulation program, a description of stimulation fluids to be used, and a determination that stimulation will not interfere with containment.

e. The proposed procedure to outline steps necessary to conduct injection operations.

f. An emergency and remedial response plan.

g. A detailed worker safety plan that addresses carbon dioxide safety training and safe working procedures at the storage facility.

h. A corrosion monitoring and prevention plan for all wells and surface facilities.

i. A leak detection and monitoring plan for all wells and surface facilities pursuant to NDAC Section 43-05-01-14.

j. 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 groundwater, 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.

k. The proposed well casing and cementing program.

l. A testing and monitoring plan pursuant to NDAC Section 43-05-01-11.4.

m. A plugging plan.

n. A postinjection site care and facility closure plan.

- Any additional information the Commission may require.

C.5 Draft Permit

- When a storage facility permit application is complete, the Commission shall either prepare a draft permit or deny the application. Before preparing the draft permit, the Commission shall consult the State Department of Health.

C.6 Storage Facility Permit Hearing

- The Commission shall hold a public hearing before issuing a storage facility permit. Such application is subject to the following and requires the following attachments:

  a. Notification – At least forty-five days prior to the scheduled hearing, the applicant shall give notice of the hearing to the following:

     i. Each operator of mineral extraction activities within the storage reservoir and within one-half mile outside of its boundary.

     ii. Each mineral lessee of record within the storage reservoir area and within one-half mile outside of its boundary.

     iii. Each owner of record of the surface within the storage reservoir area and one-half mile outside of its boundary.

     iv. Each owner of record of minerals within the storage reservoir area and within one-half mile outside of its boundary.

     v. Each owner and each lessee of record of the pore space within the storage reservoir and within one-half mile of the reservoir's boundary.

     vi. Any other persons as required by the Commission.

  b. Notice – The notice given by the applicant must contain:

     i. A legal description of the land within the storage reservoir area.

     ii. The date, time, and place that the Commission will hold a hearing on the permit application.

     iii. A statement that a copy of the permit application and draft permit may be obtained from the Commission.

iv. A statement that all comments regarding the storage facility permit application must be in writing and submitted to the Commission prior to the hearing or presented at the hearing.

v. A statement that amalgamation of the storage reservoir pore space is required to operate the storage facility, that the Commission may require that the pore space owned by nonconsenting owners be included in the storage facility and subject to geologic storage, and the amalgamation of pore space will be considered at the hearing.

c. Commission gives public notices as outlined in NDAC Section 43-05-01-08.

d. Hearing before the Commission at which time the merits of the application and draft permit will be considered.

e. Commission consideration of all comments with responses made publicly available.

f. Final storage facility permit approval.

C.7 Individual Well Permit Application

- Applicants shall provide the following information to the Commission:

  a. The activities conducted by the applicant which require it to obtain a storage facility permit or other federal, state, or local permits.

  b. Name, mailing address, and location of the storage facility for which the application is submitted.

  c. Up to four standard industrial classification codes which best reflect the principal products or services provided by the facility.

  d. The storage operator's name, address, telephone number, ownership status, and status as federal, state, private, public, or other entity.

  e. Whether the storage facility is located on Indian lands, historic, or archaeological sites.

  f. A listing of all environmental permits, construction approvals, or any other relevant permit received or applied for from the Commission or any other federal, state, or local regulatory agency.

- Drill and complete well:

  a. Form 1 – Application for permit to drill, deepen, convert, or reenter:

     i. Commission issues permit to drill and complete well.

b. Form 25 – Application for carbon dioxide storage:

   i. Operator – Logging, sampling, and testing prior to commencement of injection.

   ii. Operator – Formation and injectivity testing.

c. Permit application to operate injection well:

   i. Application to begin injection operations – within thirty days of well bore completion.

   ii Commission approval based on preoperational formation testing and sampling.

APPENDIX D

COST MODEL FOR ESTIMATING INCREMENTAL COSTS FOR DEDICATED GEOLOGIC STORAGE OF CARBON DIOXIDE IN NORTH DAKOTA

COST MODEL FOR ESTIMATING INCREMENTAL COSTS FOR DEDICATED GEOLOGIC STORAGE OF CARBON DIOXIDE IN NORTH DAKOTA

1.0 OVERVIEW

This document provides a modeling framework for estimating storage-related costs associated with implementing a commercial-scale carbon dioxide (CO_2) geologic storage project in accordance with the North Dakota statute and regulations (North Dakota Century Code [NDCC] Chapter 38-22; North Dakota Administrative Code [NDAC] Chapter 43-05-01: Geologic Storage of Carbon Dioxide). The design basis for this modeling framework assumes that CO_2 is captured at a coal-fired (lignite) power plant located in North Dakota and that the geologic storage of the captured CO_2 occurs via injection into deep saline formations (hereafter "dedicated storage"). For the purposes of this document, "commercial-scale" denotes a CO_2 capture rate of nominally 2 million tonnes (Mt) per year over an operational lifetime of at least 25 years, which is consistent with the injection goals of the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative. The modeling framework used in this study does not include the capital or operating costs associated with the CO_2 capture system and focuses solely on the incremental costs for 1) constructing and operating pipeline transport of the CO_2 to the dedicated storage site and 2) the associated activities involved with permitting, operating, and closing a CO_2 geologic storage site under North Dakota CO_2 geologic storage regulations.

2.0 TECHNICAL APPROACH

2.1 Generic Project Time Line

As part of the North Dakota CarbonSAFE project, a generic project time line was developed for implementing a commercial CO_2 geologic storage site in North Dakota. This time line comprises four distinct periods that encompass the entire life cycle of a CO_2 geologic storage project, i.e., project planning through construction, operation, closure, and transfer of liability to the state:

- Project planning and preparation: Years 1–5 (calendar years 2020 through 2024.
- CO_2 injection operations: Years 6–30 (calendar years 2025 through 2049).
- Postinjection site care (PISC) and closure: Years 31–40 (calendar years 2050 through 2059).
- Certification of compliance: Year 41 (calendar year 2060).

Figure D-1 illustrates the technical activities that are currently included within each period and the approximate years during which each activity will be performed.[1] The model estimates the

[1] The duration of CO_2 injection operations (i.e., 25 years) was dictated by the storage goal of the North Dakota CarbonSAFE project, which was 50 Mt of CO_2 over a 25-year period, i.e., 2 Mt of CO_2 injected into the subsurface per year over a period of 25 years. The PISC and closure and certification of compliance periods of 10 years and 1 year, respectively, represent reasonable estimates of the amount of time required for each effort based on the current regulations of the state of North Dakota. The actual time required for site care and closure will depend on the ability of the storage operator to demonstrate the stability of the subsurface plume of CO_2.

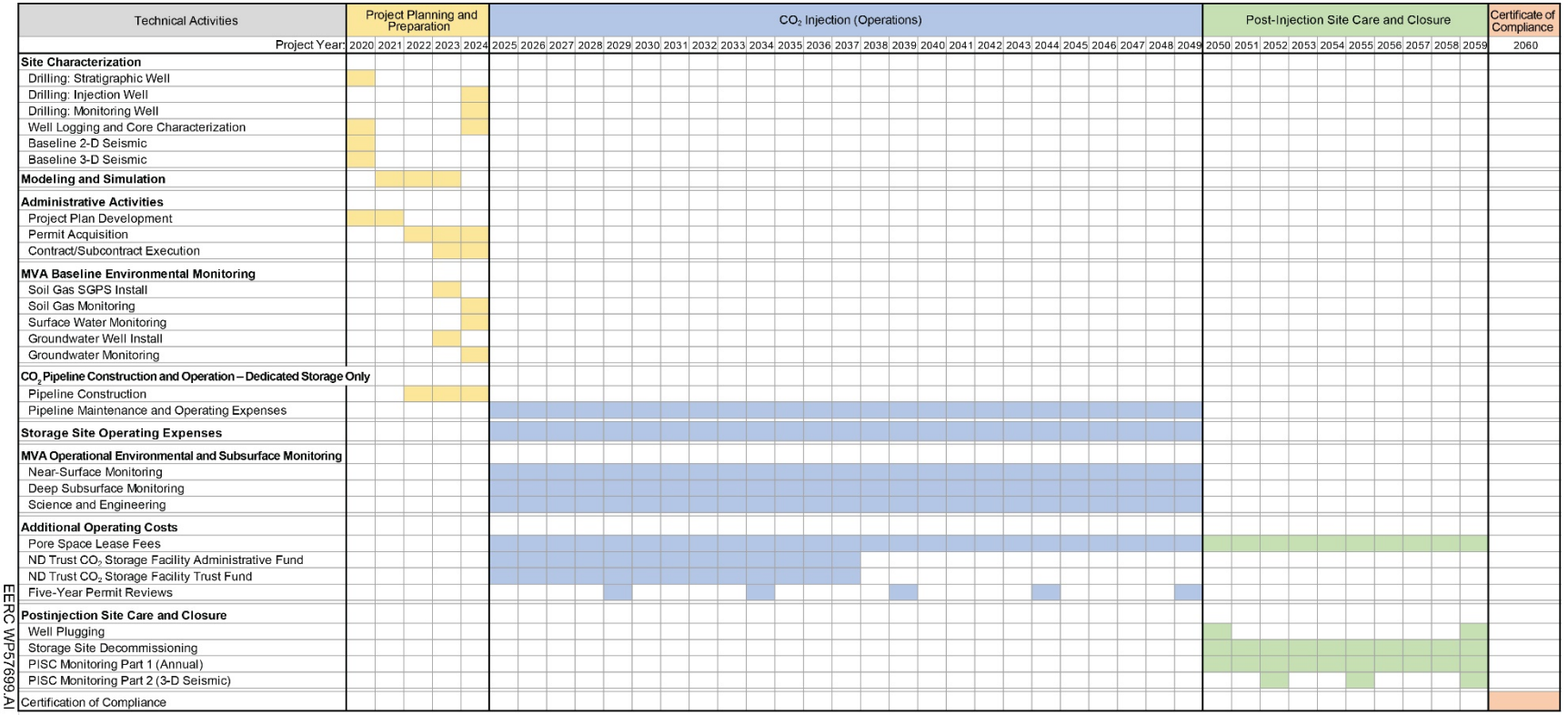


Figure D-1. Generic project time line for a commercial-scale CO_2 geologic storage project developed in accordance with the goals of the North Dakota CarbonSAFE project. This time line shows the technical activities that are included within each of four distinct project periods (1] project planning and preparation, 2] CO_2 injection (operations), 3] PISC and closure, and 4] certification of compliance) and the approximate years during which each activity will be performed.

costs of implementing these activities and maps those costs onto the time line to derive a total cost by year.

2.2 Present Value

The costs for each year are expressed as a present value (PV) using a discount rate of 10% per year and Year 1 as the reference year, according to Equation D-1:[2]

$$PV10 = \frac{R_t}{(1+i)^t} \quad \text{[Eq. D-1]}$$

Where:

R_t = total cost during a single period t.
i = discount rate, assumed to be 10% for the current work.
t = number of time periods, years in the current work.

This study uses "PV10" to denote the fact that a 10% discount rate is used in the analysis. The cumulative PV10 for the project is determined by summing the PV10s for each year of the project over the entire project lifetime (Eq. D-2):

$$PV10_{cumulative} = \sum_{t=1}^{n} \frac{R_t}{(1+i)^t} \quad \text{[Eq. D-2]}$$

Where n represents the number of years included in the summation, which can range from $t = 1$ to $t = 41$ years. Note that economic models typically express the results as "net present value," or NPV10, which sums the PV of cash inflows and the PV of cash outflows over a period of time. Since this study focuses solely on incremental costs (PV of cash outflows), the term "PV10" is used throughout the document. However, this quantity would be analogous to NPV10 and, therefore, consistent with other economic models.

2.3 Model Cost Elements

The individual cost elements that are included in the model correspond to the technical activities within each period of the generic time line. These cost elements include:

- Site Characterization
  - Drilling one or more stratigraphic wells
  - Drilling one or more injection wells
  - Drilling one or more monitoring wells
  - Logging and core characterization of wells
  - Baseline two-dimensional (2-D) seismic acquisition and processing
  - Baseline three-dimensional (3-D) seismic acquisition and processing

[2] A discount rate of 10% was chosen as a reasonable discount rate based on a review of literature sources (IHS Energy, 2016; U.S. Department of Energy, 2017),

- Modeling and Simulation
  - This activity includes the labor and software licensing costs required to construct and populate a geologic model (geomodel) for the site, to calibrate numerical reservoir simulations using an equation-of-state (EOS) simulator, and to generate forecasts of the separate-phase CO_2 plume and pressure plume in the subsurface that can be used for site planning purposes.

- Administrative Activities
  - Project plan development
  - Permit acquisition
  - Contract/subcontract execution

- MVA (monitoring, verification, and accounting) Baseline Environmental Monitoring (prior to injection)
  - Soil gas profiling station (SGPS) installation
  - Soil gas monitoring
  - Surface water monitoring
  - Groundwater well installation
  - Groundwater monitoring

- CO_2 Pipeline Construction and Maintenance (dedicated storage, only)
  - Pipeline construction
  - Pipeline maintenance

- Storage Site Operating Expenses

- MVA Operational Environmental and Subsurface Monitoring
  - Near-surface monitoring (soil gas, surface water, groundwater)
  - Subsurface monitoring (time-lapse 3-D seismic [4-D seismic] and wellbore logging)
  - Science and engineering (continued modeling and simulation, adaptive management)

- Additional Operating Costs
  - Pore space lease fees
  - ND Trust CO_2 Storage Facility Administrative Fund at $0.01 per ton CO_2
  - ND Trust CO_2 Storage Facility Trust Fund at $0.07 per ton CO_2
  - Five-year permit reviews

- PISC and Closure
  - Well plugging
  - Storage site decommissioning
  - PISC monitoring

- Certification of Compliance

The remainder of this document provides a summary of the cost model structure and results using default assumptions about the cost elements.

3.0 ESTIMATED COSTS

The estimated costs for the individual project activities that are embodied within each of the four project periods were developed based on several different sources of information: 1) literature values and cost estimating algorithms for similar projects that were developed by other organizations such as the DOE NETL (U.S. Department of Energy, 2014; U.S. Department of Energy, 2018); 2) extrapolation of cost estimates that had been developed as part of other, similar Energy & Environmental Research Center (EERC) projects; and 3) project-specific cost estimates that were developed based on the preliminary designs of plans for the proposed North Dakota CarbonSAFE projects combined with recent federal/state regulatory developments. Using these sources, a three-point estimation technique was used to generate an estimated value for costs given inputs of a minimum, most likely, and maximum value for each cost element:

$$E = \frac{a+4m+b}{6} \quad \text{[Eq. D-3]}$$

Where:

a = minimum cost estimate.
b = maximum cost estimate.
m = most likely cost estimate.

3.1 Project Planning and Preparation: 2020–2024

Project planning and preparation will occur during the 5-year period from 2020 through 2024. The major project activities performed during this period will include the following:

- Site characterization.
- Modeling and simulation.
- Administrative activities, i.e., project plan development, permit acquisition, and contract execution.
- Collection of baseline MVA data, i.e., soil gas and surface water and groundwater sampling and analysis.

The development of the cost estimates for each of these activities is provided below.

3.1.1 Site Characterization

Site characterization activities are performed to collect site-specific information about the storage unit, seal formation(s), and other geologic aspects of the storage site. This information informs the modeling and simulation efforts, which in turn are used to predict the CO_2 storage capacity and injectivity of the candidate storage unit as well as the extent of the subsurface CO_2 plume and pressure front over time. Site characterization activities include the drilling, well logging, and core characterization of one or more wells, in addition to baseline 2-D and 3-D seismic acquisition, processing, and interpretation.

This feasibility study cost model assumes that the three wells (i.e., one exploratory stratigraphic well, which will be later converted into a Class VI injection well, one other Class VI

injection well, and one monitoring well) will be drilled and characterized during the project planning and preparation period. These generic inputs are consistent with the work currently being anticipated for Milton R. Young Station (MRYS) (i.e., Project Tundra). In mapping these site characterization costs to the generic time line, this cost model assumes that all of these wells will be drilled within the project planning and preparation period. However, it may be possible to stagger the drilling of these injection wells to spread these costs over time. These construction-phasing considerations will be part of the future economic assessments that will be performed for the project as it progresses beyond the feasibility stage.

3.1.1.1 Well Drilling and Construction Costs

Cost ranges and average values for drilling and construction of a stratigraphic well, Class VI injection well, and a Class VI-compliant monitoring well were estimated as follows (Table D-1):

- Stratigraphic well: $2.3MM–$2.8MM ($2.5MM)
- Class VI injection well: $4.0MM–$5.5MM ($4.2MM)
- Monitoring well (built to Class VI specifications): $4.2MM–$5.5MM ($5.0MM)

These costs were developed based on a combination of the following: 1) well drilling and construction cost estimates that were prepared for a commercial storage project that is being implemented at an ethanol plant in Richardton, North Dakota (Leroux and others, 2017); 2) the actual costs of the stratigraphic wells that were drilled as part of Phase 2 of the North Dakota CarbonSAFE project, i.e., Flemmer-1 and BNI-1 wells; and 3) cost estimates prepared by Schlumberger for the Nebraska CarbonSAFE project (Wildgust and others, 2018).[3]

3.1.1.2 Well Logging and Core Characterization Costs

The well logging and core characterization costs were also developed based on previous cost estimates prepared for the North Dakota ethanol project of Red Trail Energy (Leroux and others, 2017) as well as preliminary cost estimates prepared for a potential next phase of the MRYS and GPSP (Great Plains Synfuels Plant) projects. These cost estimates are presented in Table D-2 and briefly discussed below.

In general, multiple openhole (i.e., no casing) wireline runs are used to collect data on each stratigraphic test well. Geophysical data that are collected include gamma ray (total and spectral), caliper, density, porosity (neutron, density, and sonic), spontaneous potential, resistivity, sonic (compressional and shear), and lithoscanner. Core characterization activities typically include x-ray diffraction, x-ray fluorescence, scanning electron microscope morphology, thin section, porosity/permeability testing, and geochemical/geomechanical testing. As shown in Table D-2, the estimated cost per well ranges from $525,000 to $700,000 for well logging and from $550,000 to $825,000 for core characterization. Considering a total cost for these combined activities for the

[3] The cost model assumes a conventional drilling sequence for the wells, e.g., the stratigraphic well is drilled and then plugged and abandoned after which injection wells and monitoring wells are drilled. However, a reduction of these costs may be achievable if it is possible to modify the drilling sequence of the wells at a specific site; e.g., the stratigraphic well could be converted to an injection well rather than plugged and abandoned.

Table D-1. Cost Estimates for Well Drilling and Construction

Type of Well	Cost Estimate	Source
Stratigraphic Wells	• Average cost of $2,500,000 with a cost range of $2,300,000 to $2,800,000 – Capital cost estimates were based on the actual costs of the two stratigraphic test wells that were drilled as part of Phase 2 of the North Dakota CarbonSAFE project: Flemmer-1 (GPSP Project) – $2,300,000 and BNI-1 (MRYS project) – $2,800,000	• Actual project costs from Phase 2 of the North Dakota CarbonSAFE project.
Injection Wells	• Estimated cost of $4,200,000 with a cost range of $4,000,000 to $5,500,000 (2017 estimate): Casing, casing accessories, tubing, surface and subsurface well equipment, site surveys, wellsite and access road preparation, drilling operations, formation evaluation, completion, etc. Range based on potential ~30% increase in construction costs. • Estimated cost of $4,000,000 – derived from Schlumberger cost estimate from Nebraska CarbonSAFE project of $0.32 per tonne of CO_2 stored – assumes 50 Mt of CO_2 stored using four Class VI injection wells.	• Leroux and others (2017) (Appendix J) • Wildgust and others (2018)
Monitoring Wells	• Estimated cost of $5,000,000 with a cost range of $4,200,000 to $5,500,000 (2017 estimate): Casing, casing accessories, tubing, surface and subsurface well equipment, site surveys, wellsite and access road preparation, drilling operations, formation evaluation, completion, etc. Range based on potential ~30% increase in construction costs. • Estimated cost of $5,000,000 – derived from Schlumberger cost estimate from Nebraska CarbonSAFE project of $0.10 per tonne of CO_2 stored – assumes 50 Mt of CO_2 stored	• Leroux and others (2017) (Appendix J) • Wildgust and others (2018)

Table D-2. Estimated Costs of Well Logging and Core Analysis /Testing

Storage Site	Estimated Costs (per well[4])		Total Cost Estimate
	Well Logging	Core Analysis and Testing	
Red Trail Energy[a]			900,000
MRYS	700,000	825,000	1,525,000[b]
GPSP	525,000	550,000	1,075,000[c]

[a] Leroux and others (2017).

[b] Well drilled to Deadwood Formation with the acquisition of three 350-foot cores, one each from the Broom Creek, Inyan Kara, and Deadwood Formations.

[c] Well drilled to Broom Creek Formation with acquisition of two 350-foot cores, one each from the Broom Creek and Inyan Kara Formations.

Red Trail Energy project of $900,000, the range of costs for these activities presented in Table D-2 is $0.9MM to $1.5MM for wells drilled into the storage reservoirs of interest to the North Dakota CarbonSAFE project. For the purposes of this feasibility study, the expected value was assumed to be the midpoint of the range, or $1.2MM.

3.1.1.3 Baseline Seismic Data Collection and Processing

Both 2-D and 3-D seismic data will likely be required as part of the initial site characterization activities to serve as a baseline for comparison with future surveys to assess the presence and movement of CO_2 in the subsurface. This feasibility study estimates that approximately 50 miles of 2-D and 25 mi^2 of 3-D seismic data will be collected during the project planning and preparation period. The 25 mi^2 of 3-D seismic is based on the approximate areal extent of the separate-phase CO_2 plume following 25 years of injection into a single storage reservoir at a rate of 2 Mt per year. The actual areal extent of the separate-phase CO_2 plume will be site-specific and dependent upon the injection rates, the final well configurations, and the properties of the storage reservoir. The unit cost range and average cost for collecting and processing 2-D seismic data were estimated to be $31,500 to $38,500 ($35,000) per mile; the unit cost for collecting a baseline 3-D seismic survey was estimated to range from $75,000 to $78,000 per mi^2, with an expected value of ($76,500) per mi^2 . These unit costs for the 3-D seismic survey were based on bids using vibroseis trucks as the seismic source; however, a seismic source test was completed in the fall of 2019 near the MRYS site to assess the feasibility of acquiring 3-D seismic data over reclaimed mine land and to determine what type of seismic source (i.e., vibroseis truck or dynamite shots) is needed to do so. The results of this source test showed that the signal from dynamite shots at depths of 20 feet or more below the reclaimed interval were less affected by the reclaimed interval than the signals from shallower dynamite shots and from the vibroseis trucks. These field results also documented the feasibility of using dynamite shots to produce sufficient signals to image the Deadwood Formation at approximately 9600 feet. Given this finding, the unit cost for the collection of 3-D seismic data was increased to $100,000 per mi^2. Based on the 50-mile and 25-mi^2 inputs and unit cost estimates of $35,000 per mile for 2-D seismic

[4] These costs will vary based on the depth of the well and the length of core that is acquired for testing. For the purposes of this feasibility study economic evaluation, the costs have been developed based on well depths and core lengths required to assess CO_2 injection into either the Broom Creek Formation or into a stacked storage configuration involving the Broom Creek, Inyan Kara, and Deadwood Formations.

and $100,000 per mi^2 for 3-D seismic, the total cost for these initial seismic surveys is projected to range from approximately $3.825MM to $4.675MM, with an expected value of $4.250MM.

The cost model assigns these initial, preinjection 2-D and 3-D seismic costs to site characterization and applies these costs to the first year of the project. However, all subsequent costs associated with the collection and processing of seismic data during and after CO_2 injection are included as part of the costs for the MVA programs that will be implemented during those project periods (see Sections G.3.2 and G.3.3).

3.1.2 Modeling and Simulation

Modeling and simulation of pressure buildup as a function of CO_2 injection and the spatial distribution of the separate-phase CO_2 plume within the storage unit will be required to predict the performance of the storage site. These predictions will be required to secure the permits for the storage operation and to provide the foundation for the design of a site-monitoring program that is compliant with federal and state regulatory requirements. Lastly, they will also be needed to receive a Certification of Compliance for closure of the operations by demonstrating the long-term stability of the CO_2 plume.

The cost estimates for modeling and simulation were developed based on previous experience with two projects in North Dakota: 1) the Red Trail Energy (RTE) Project (Leroux and others, 2017) and 2) the Basin Electric Power Cooperative (BEPC) Carbon Capture and Storage Project (Steadman and others, 2010). The estimated modeling and simulation costs for these projects suggest a cost range of $250,000 to $600,000, with an expected value of $425,000. From the generic time line shown in Figure D-1, the cost model allocates these modeling and simulation costs over a 3-year period (2021 through 2023), assuming equal expenditures in each year.

3.1.3 Administrative Activities

3.1.3.1 Project Plan Development

Several project plans will be required to initiate the storage project. Among these are the drilling, characterization, pipeline and injection, and MVA plans. A cost estimate of $950,000 was reported for the development of these plans for the BEPC project (Steadman and others, 2010). A breakdown of the $950,000 cost estimate for the BEPC Project noted that $600,000 was attributed to the development of drilling, characterization, and pipeline and injection plans and $350,000 for the development of an MVA plan. Based on this previous cost estimate, the range of costs inserted into the cost model for the development of project plans is $855,000 to $1,045,000, with an expected value of $950,000. As shown in Figure D-1, the cost model allocates these project plan development costs over a 2-year period (2020 through 2021), assuming equal expenditures in each year.

3.1.3.2 Permit Acquisition

The state of North Dakota recently obtained primacy from the U.S. Environmental Protection Agency (EPA) for the permitting of a underground injection control (UIC) Class VI

injection well (U.S. Environmental Protection Agency, 2018). In general, the North Dakota UIC Class VI Program requires all applicants applying for an injection permit for the geologic storage of CO_2 to obtain a storage facility permit, a permit to drill an injection well, and a permit to operate an injection well prior to commencement of injection activities.

A detailed listing of the storage facility permitting requirements is provided in Appendix C of this report. Among the permitting requirements is a geotechnical evaluation that presents the following information:

- Extent of pore space requirements
- Delineation of the area of review (AOR)
- Characteristics and properties of the injection and confining zones (e.g., permeability and porosity)
- Parameters for CO_2 injection
- An evaluation of the CO_2 plume and pressure front and their potential impacts on underground sources of drinking water
- The geomechanical properties of the confining zone and geochemical compositions and potential interactions of subsurface formation and underground sources of drinking water.

In addition, several plans and programs must also be submitted as part of the permit package, including a corrective action plan, an emergency and remedial response plan, a proposed casing and cementing program, a testing and monitoring plan, a well-plugging plan, a PISC and facility closure plan, and a financial responsibility plan.

The cost for the preparation of a CO_2 Storage Facility Permit application was estimated to be $470,000 for the GPSP Project and $585,000 for the MRYS project (Project Tundra).[5] Note that these cost estimates are only for the preparation of the permit applications and do not include the costs of gathering the necessary data for the permits (these costs are embedded in other elements of the cost model), presubmission reviews and discussions of the application with the state regulators, preparation of permit iterations based on comments from the regulators and third parties, and an outreach effort to facilitate the public understanding of the project. Preliminary estimates of the costs of these additional items indicate that they have the potential to be significant (e.g., approximately $1.5MM [Leroux and others, 2017]); however, they are very project-specific and are difficult to estimate at the feasibility stage of a project. Nevertheless, to be conservative, a portion of these additional costs (i.e., $750,000) has been added to the permit preparation costs to yield a cost range for permit acquisition of $1,220,000 to $1,335,000, with an expected value of $1,277,500, and allocates them over a 3-year period (2022 through 2024) as shown in Figure D-1, assuming equal expenditures in each year.

[5] Depending upon the CO_2 injection strategies that are pursued at each site, multiple storage facility permits may be required. At this time, it is anticipated that as many as four permits may be required for the MRYS project and two permits required for the GPSP project.

3.1.3.3 Contract/Subcontract Execution

An administrative cost is associated with the execution of the numerous contracts and subcontracts that are required for the completion of these projects. Little economic data associated with putting these contracts and subcontracts in place have been reported in the literature. For the purposes of this economic assessment, the range of costs associated with contract/subcontract execution has been estimated to be $50,000 to $150,000, with an average cost of $100,000. This cost model allocates these contract/subcontract execution costs over a 2-year period, assuming equal expenditures in each year.

3.1.4 MVA Baseline Environmental Monitoring

The long-term monitoring of an operational CO_2 storage site requires the generation of a baseline monitoring data set which represents the conditions of the storage site prior to any CO_2 injection. This baseline data set will provide a snapshot of preinjection conditions, which can be used as a basis of comparison for monitoring data that are collected during and after CO_2 injection. These comparisons allow the operator to determine if there has been a change from baseline conditions during the injection or postinjection phases of the project. To be useful, the baseline monitoring program should mirror the operational monitoring program, which must satisfy the facility permitting requirements, to permit a comparison with the pre- and postinjection conditions.

For this feasibility assessment, a generic baseline monitoring program comprising soil gas, surface water, and shallow groundwater monitoring was developed based on experience from other monitoring programs conducted within the PCOR Partnership Region. The details for each of the individual components of the baseline monitoring are provided below.

- **Soil gas monitoring:** Three SGPSs will be installed at the site. Each station will be sampled every month over the course of one calendar year to capture the seasonal cycles in soil gas concentrations. The estimated cost of installation for each SGPS is $5000 ($4500 to $5500), and the estimated cost of each of the 12 sampling events and associated sample analyses per station is $6300 ($5670 to $6930). Using these installation and sampling/analysis costs, the cost range for soil gas monitoring is estimated to be $81,540 to $99,660, with an expected value of $90,600.

- **Groundwater monitoring:** The baseline groundwater monitoring program will consist of the sampling of three groundwater wells that are installed into the Fox Hills aquifer, which is the lowermost underground source of drinking water (USDW). The estimated cost for permitting and drilling a groundwater sampling well into the Fox Hills aquifer is $41,500 ($1500 for permitting and $40,000 for drilling). One groundwater sample will be taken from each well during each quarter over the course one calendar year, i.e., four samples per well for a total of 12 samples. The estimated cost for a single groundwater sampling event, i.e., sample acquisition and analysis, is ~$4400. Given these costs for drilling and sample acquisition/analysis, the baseline cost for groundwater monitoring is projected to be ~$177,300 at each site.

- **Surface water monitoring:** A total of ten surface water samples will be acquired and characterized every quarter, yielding a total of 40 samples. At an acquisition and characterization cost of $1800 per sample, the total baseline monitoring cost for surface waters is projected to be $72,000 for both sites.

In total, the estimated cost for baseline monitoring at the North Dakota CarbonSAFE projects is projected to be approximately $339,000, with a range extending from $330,840 to $348,960. The estimated costs for the collection for MVA data during the injection and postinjection phases of the project are presented in Sections G.3.2 and G.3.3.

A second point of reference for baseline monitoring costs for geologic storage units in North Dakota is provided by the baseline monitoring costs that were recently estimated for the RTE Project in Richardton, North Dakota (Leroux and others, 2017). The cost estimates for baseline environmental monitoring for the RTE Project ranged from $100,000 to $200,000, with an average cost of $150,000. This baseline monitoring effort included sampling and analyses for up to 20 regional groundwater wells and two surface waters; installation, permitting and sampling of one aquifer monitoring well; and the installation and sampling of three SGPSs. The cost range reflected the costing of three to six sampling events over the duration of the baseline sampling period.

As previously noted, this cost model does not assign the costs of the preinjection 2-D and 3-D seismic surveys costs to the baseline monitoring program. Rather, these costs are allocated to the site characterization effort since the resulting data are being generated to primarily inform the initial development of the site geologic model. However, subsequent costs associated with seismic data collection during the injection or postinjection phases are assigned to the MVA program. Seismic data collected over time during the injection or postinjection phases, while continuing to support the modeling and simulation activities, are primarily focused on providing information about the movement of the CO_2 plume in the subsurface during and after CO_2 injection.

3.1.5 CO_2 Pipeline Construction

CO_2 pipelines will be required to move the CO_2 from the source of capture to both the dedicated and associated geologic storage sites. This cost model only includes the construction costs of the pipelines to dedicated storage as the pipeline to associated storage is either already in place (i.e., the GPSP Project) or the project developer is not willing to move forward with such a pipeline without commitments of financial participation from the state and/or federal governments or commercial entities with an investment interest in the project. The procedures for estimating the capital costs for the construction of the dedicated storage pipelines are discussed in the remainder of this section.

3.1.5.1 CO_2 Pipeline Characteristics

The size and length of the CO_2 pipelines required to move the captured CO_2 to the dedicated storage sites of the North Dakota CarbonSAFE project are presented in Sections 2.2 and 3.2 of this site development plan and summarized here:

- **MRYS:** Two high-pressure 8-inch-diameter, Schedule 80 pipelines, one with a length of 4.5 miles and the other a length of 0.2 miles. Each pipeline is capable of transporting nominally 1,800,000 tonnes of CO_2 to a single well pad for dedicated storage in a combination of the Broom Creek and Deadwood Formations.[6]

- **GPSP:** Two high-pressure, 8-inch-diameter, Schedule 40 pipelines, each with a length of 20 miles. Each pipeline is capable of transporting 1,250,000 tonnes of CO_2 per year to an injection well pad for dedicated storage into the Broom Creek Formation.

Detailed calculations for the sizing of these pipeline are provided in the site development plan (Peck, 2019). For the purposes of this feasibility study, the shorter pipeline distance of 5 miles was used to estimate the pipeline construction cost for a generic CO_2 storage project. The actual number of pipelines as well as the pipeline distances will be site-specific and will depend upon such factors as the quantity of CO_2 targeted for storage as well as the possible pipeline routes between the CO_2 source and the storage unit injection well pad or pads.

3.1.5.2 Unit Cost Factor for Pipeline Construction

Over the last two decades, numerous unit cost factors have been developed to estimate the capital costs for the construction of high-pressure pipelines. The unit cost factors are expressed as \$/diameter inch-miles. A representative sample of these estimates is provided in Table D-3.

Table D-3. Selected Estimates of Capital Cost Unit Factors for CO_2 Pipelines

Source of Information	Year	Unit Cost (\$/diameter inches-miles)
Dakota Gasification[a]	2000	37,300
Hall-Gurney (KS)[b]	2001	22,000
Regression Analysis of FERC Data[c]	2003	33,800
Coffeyville Resources/DOE[d,e]	2007; 2009	52,100–83,300
Oil and Gas Journal – Average of Natural Gas Pipelines[f]	2008	65,100
Green Pipeline – Denbury Resources[g]	2009	93,570
BEPC[h]	2010	\$107,670
DOE[i]	2014	50,000–85,000

[a] J.E., Sinor and Associates (2000).
[b] Willhite (2001).
[c] Heddle and others (2003).
[d] U.S. Department of Energy (2008)
[e] ICF International (2009).
[f] Oil and Gas Journal (2008).
[g] Perilloux (2009).
[h] Steadman and others (2010).
[i] U.S. Department of Energy (2014).

[6] To meet the storage goal of the North Dakota CarbonSAFE project of 2 Mt of CO_2 per year (i.e., Mt per year per well pad), the required pipelines are as follows: 1) one high-pressure, 6-inch, Schedule 80 pipeline with a length of 4.5 miles and 2) one high-pressure 5-inch-diameter pipeline with a length of 0.2 miles.

For the purposes of this feasibility study, a plausible range of estimates for this unit cost factor was determined to be $50,000 to $85,000/inch (diameter)-mile, which was provided by NETL (U.S. Department of Energy, 2014). This range represents a set of values developed using algorithms developed by three different researchers (Parker, 2004; McCoy and Rubin, 2008; Rui and others, 2011). Furthermore, it not only represents the most recent cost estimate presented in Table D-3 but also encompasses most of the values presented in the table.

This range of pipeline unit costs was used in the cost model, with an expected value of $67,500/inch-mile. Moving forward, a more project-specific unit cost factor will be developed using the construction capital cost models adopted by the more recent publication of NETL (U.S. Department of Energy, 2018) in combination with information from the advanced stages of the project design.

The pipeline construction is assumed to occur over a 3-year period (see Figure D-1), which will complete the pipeline prior to the CO_2 injection phase of the project. These costs assume equal expenditures in each of the 3 years.

3.2 CO_2 Injection: 2025–2049

As part of the 25-year CO_2 injection period, 2025 through 2049, a number of cost items must be estimated to determine the present value of the storage costs. These include the CO_2 pipeline operating expenses, the storage site operating expenses, the MVA monitoring expenses, pore space lease fees, North Dakota administrative and trust fees, and the costs associated with the conduct of the required 5-year permit reviews. Each of these cost items are discussed in more detail in the remainder of this section.

3.2.1 CO_2 Pipeline Operating and Maintenance Expenses

The operations and maintenance of CO_2 pipelines to ensure that they are operating safely comprise several activities. Based on the maintenance schedule for the existing Dakota Gasification Company (DGC) CO_2 pipeline (Steadman and others, 2010), a list of typical activities, including their frequency, includes the following:

- Aerial patrols (26 times per year)
- Population density surveys (one per year)
- Right-of-way inspections (26 times per year)
- Valve maintenance and inspection (twice per year)
- Overpressure safety device inspection and maintenance (once per year)
- Rectifier maintenance (six times per year)
- Cathodic protection survey (once per year)
- Internal inspection using electronic tool (once every 5 years)
- Public awareness and damage prevention program (once per year)

DOE (2014) estimated the annual operating and maintenance cost for CO_2 pipelines at $5000/mi-yr in 1999 dollars (approximately $7700/mi-year today assuming an average inflation rate of 2.20% per year).

The pipeline operating costs were estimated by applying this operating and maintenance unit cost to the dedicated storage CO_2 pipeline, which results in approximately $1MM per year in operating and maintenance costs.

3.2.2 Storage Site Operating Expenses

The storage site operating costs will enter into the present value analysis of the CarbonSAFE project only for dedicated storage operations, since the storage operating costs for associated storage will be borne by the CO_2 EOR operator as part of its routine facility operations, regardless of the source of the CO_2. Stated differently, the cost of injecting the CO_2 for enhanced oil recovery will not be a cost to the CO_2 storage project since the captured CO_2 will be purchased by the CO_2 EOR operator and the cost of its injection into the subsurface will be the responsibility of the EOR operator who will incorporate it into the overall economics of the EOR operations.

On the other hand, current business models assume that the CO_2 generators, i.e., the power plant, will be the owner of the dedicated storage site and will be responsible for their operating expenses. At this time, based on the recommendation of Jablonowski and Singh (2010; 2014), the cost model assumes that the operating expenses for CO_2 injection at saline storage sites would be comparable to the operating and maintenance costs for CO_2 injection wells at CO_2 EOR as given by the following equation for the Rocky Mountain Region:

$$\text{Well O\&M Costs} = 38{,}080 + 4.48 \times (\text{well depth, feet}) \qquad \text{[Eq. D-4]}$$

Estimates of the annual operating and maintenance costs for the dedicated storage scenarios for the GPSP and MRYS projects were based on applying Eq. D-4 to the following sets of inputs:

- GPSP Project – Dedicated storage assuming two injection wells into the Broom Creek Formation at a depth of 5800 feet.

- MRYS Project – Dedicated storage assuming two injection wells into the Broom Creek Formation at 4600 feet and two injection wells into the Deadwood Formation at a depth of 9100 feet.

As noted above, no such operating costs will be incurred as part of the associated storage scenarios. For this generic cost model, the storage site operating expenses assume two injection wells into the Broom Creek Formation at an average depth of 5200 feet, which results in approximately $122,750 in operating expenses per year.

3.2.3 MVA Operational Environmental and Subsurface Monitoring

The MVA monitoring programs for the North Dakota CarbonSAFE project will be dictated by the requirements of the Storage Facility permit combined with the results of site-specific risk assessments. The permit requirements are embodied in the recent North Dakota laws and regulations that were put in place following approval by EPA of a state application for primacy over a comprehensive set of carbon storage regulations for all aspects of CO_2 injection and geologic storage operations within a UIC Class VI Program. EPA signed North Dakota's primacy

application on April 10, 2018, and published the final rule in the *Federal Register* (U.S. Environmental Protection Agency, 2018). The North Dakota Industrial Commission (NDIC) is now the permitting authority for Class VI wells in North Dakota, formally recognizing the North Dakota UIC Class VI Program. Beyond the permit requirements, additional risk-based monitoring needs were also defined through the conduct of site-specific risk assessments, which were conducted on the dedicated storage facilities and operations of both the MRYS and the GPSP projects.

3.2.3.1 Permit Requirements of North Dakota

Since the state of North Dakota only recently received approval of its primacy application, there is no history of previously approved permits to rely upon to guide the development of an MVA program for the North Dakota CarbonSAFE projects. However, during the primacy application process, the EERC did assist RTE, an ethanol producer, in conducting an economic and technical feasibility study for integrating carbon capture and storage (CCS) with the production of ethanol fuel. As part of that feasibility study, the components of a permitting plan were identified and described (Leroux and others, 2017; 2018). This permitting review included an in-depth review of the procedures and requirements embodied in the North Dakota Class VI permitting regulations for the commercial, dedicated geologic storage of CO_2 in North Dakota. The MVA monitoring program prepared for RTE was designed to comply with the Class VI permit requirements of North Dakota and represent the best effort to date of what such a program might look like in North Dakota at this time. However, there still remain some site-specific requirements for the RTE case study that require clarification, e.g., definitions of CO_2 stability, baseline monitoring requirements, pore space amalgamation rules, and options for permitting a stratigraphic test with the intention of completing it as a monitoring well, to name a few. This is not uncommon when first implementing new regulations and will be resolved over time as the permitting of additional facilities moves forward in the state.

The risk-based, site-specific MVA program for the proposed RTE project meets all applicable regulations in the state of North Dakota, which require monitoring of 1) all aspects of CO_2 injection operations, 2) the local groundwater system, 3) the subsurface environment, and 4) engineered systems for competency. The North Dakota regulations also require a regular assessment of the MVA program (minimum of every 5 years as part of a required permit review process) to ensure that the monitoring systems remain appropriate for the site and are effectively tracking the fate of the stored CO_2 in the subsurface environment. Table D-4 provides an overview of the preliminary MVA program that was designed for the geologic storage of CO_2 at the RTE site near Richardton, North Dakota; a more detailed discussion of the components of this MVA plan are provided elsewhere (Leroux and others, 2017; 2018).

Table D-4. Overview of the Initial MVA Program for the Geologic Storage of CO_2 at the RTE Site

Monitoring Type	RTE Program Plan	Region Monitored
Analysis of Injected CO_2	Annual sampling and compositional analysis of the injected CO_2 stream	Surface and storage reservoir
Continuous Recording of Injection Pressure, Rate, and Volume	Instrumentation for continuous wellhead monitoring	Surface-to-reservoir
Near-Surface Monitoring	Groundwater sampling and analyses (existing groundwater wells in the AOR and dedicated water well)	Near surface; USDWs
Direct Reservoir Monitoring	Sampling, logging, and pressure/temperature measurements via a reservoir monitoring well	Storage reservoir and primary sealing formation
Indirect Reservoir Monitoring	3-D seismic surveys, passive seismic measurements	Entire storage complex
Well Annulus Pressure Between Tubing and Casing	Instrumentation for continuous annulus monitoring	Surface-to-reservoir
Mechanical Integrity Testing and Pressure Fall-Off Testing	Well testing every 1 and 5 years, respectively, as required	Well infrastructure
Corrosion Monitoring	Well material corrosion well logging	Well infrastructure

3.2.3.2 Site-Specific Risk Assessment Results

The site-specific risk assessments for North Dakota CarbonSAFE identified six groups of technical risk categories for investigation:

- CO_2 injectivity
- Storage capacity
- Containment – lateral migration of CO_2
- Containment – lateral pressure propagation
- Containment – vertical migration of CO_2 or formation brine
- Induced seismicity

The risk assessments did not identify any risks that required immediate remedial action; rather, it was determined that all of the technical (and nontechnical) risks either required no action or were recommended for continued monitoring to ensure that they remained at acceptable levels (Peck [2019] site development plan). As such, the development of a risk-based MVA program is being planned to monitor these risks over time to determine whether any of them require the application of mitigation strategies over the course of the project lifetime. The monitoring of these

risks has been incorporated into the operational MVA program, which will be implemented at the sites over the lifetime of the subsurface injection of CO_2.

3.2.3.3 Cost Estimates for MVA Monitoring at Dedicated Storage Sites

The MVA plan for the RTE Project was used as a framework to prepare a first-order estimate of the costs for an MVA program for the dedicated storage sites at MRYS and the GPSP Projects. The estimated costs for the primary components of the plan that were developed for the RTE project are provided below and provide a starting point for estimating the costs that might be expected for the dedicated storage sites of the North Dakota CarbonSAFE Project, recognizing that there are site-specific differences that will eventually need to be taken into account as more detailed site information becomes available. These RTE cost estimates are summarized as follows:

- **Near-surface monitoring** (cost range of $100,000 to $200,000 per year with an annual estimated cost of $150,000): Operational sampling and analysis for up to 20 regional groundwater wells; permitting, installation, and monitoring of one monitoring well in the Fox Hills Formation (i.e., the lowermost USDW); and sampling and analysis of two surface waters and three SGPSs.

- **Subsurface monitoring** (average annual cost of $200,000 [assumes repeat seismic survey every 5 years] to $500,000 [assumes repeat seismic surveys every 2 years]): Design of a 4-D repeat seismic survey over an area of 10.5 mi^2 along with recurring fees for induced seismic monitoring and third-party consultant interpretation of the seismic data. Should a repeat 3-D seismic survey be required every 2 years, the average annual cost of subsurface monitoring would increase to $500,000.

- **Science and engineering** ($200,000 to $300,000 per year): Includes data processing and assessment and management of monitoring data to document compliance based on updated models/simulations following repeat seismic survey events.

The above framework was slightly modified to incorporate the monitoring requirements and/or mitigation actions that might be required based on the site-specific factors for the MRYS and GPSP projects. Based on the site-specific risk assessments that were performed for both these dedicated storage sites, it was determined that the MVA plans, which were developed based on the RTE MVA plan, were sufficient to monitor all of the site risks that were identified; however, as part of the risk analysis of the dedicated storage at MRYS, three legacy wells were identified as potential leakage pathways near the point of CO_2 injection that might require remediation, either prior to, or soon after, the initiation of CO_2 injection. Cost estimates for remediating these three wells within the first 5 years of CO_2 injection range from $300,000 to $500,000 per well.

For the purposes of this current cost analysis, the MVA costs for the operational (injection) phase include $150,000 per year (range of $100,000 to $200,000 per year) for near-surface monitoring, $350,000 per year (range of $200,000 to $500,000) for subsurface monitoring, and $250,000 per year ($200,000 to $300,000 per year) for science and engineering. While no costs have been allocated for legacy well remediation for the generic storage site addressed in this appendix, site-specific assessments of all candidate storage sites will require a detailed evaluation

of those legacy wells that have the potential to come into contact with the subsurface CO_2 plume. Based on those evaluations, it will be determined if, and to what extent, remediation action will be required prior to or during CO_2 injection. It has been estimated that the remediation of legacy wells will lie between $300,000 to $500,000 per well. These costs would have to be included in the economic assessment in the appropriate year of the project time line.

3.2.4 Additional Operating Costs

3.2.4.1 Pore Space Lease Fees

The commercial-scale geologic storage of CO_2 in deep saline formations has resulted in discussions of pore space ownership and approaches for amalgamating the pore space required to contain the injected mass of CO_2. In anticipation of the long-term geologic storage of CO_2 in North Dakota, the state legislature amended NDCC in 2009 to clarify that pore space ownership is tied to, and cannot be severed from, surface ownership. Specific to the geologic storage of CO_2, NDCC §38-22 states:

> "It is in the public interest to promote the geologic storage of carbon dioxide. Doing so will benefit the state and the global environment by reducing greenhouse gas emissions. Doing so will help ensure the viability of the state's coal and power industries, to the economic benefit of North Dakota and its citizens. 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. Geologic storage, however, to be practical and effective requires cooperative use of surface and subsurface property interests and the collaboration of property owners. Obtaining consent from all owners may not be feasible, requiring procedures that promote, in a manner fair to all interests, cooperative management, thereby ensuring the maximum use of natural resources."

With regard to pore space amalgamation and landowner compensation associated with CO_2 storage sites, NDCC will follow the approach that has been used for unitization for oil and gas operations. More specifically, when at least 60% of landowners within the extent of the CO_2 plume agree to pore space leasing agreements, the state can compel the remaining 40% of landowners to agree to terms. Importantly, NDCC requires pore space leasing agreements be "equitable" among landowners but does not establish any financial guidelines regarding specific compensation amounts. That said, the staged acquisition of pore space over time as the injected CO_2 migrates through the storage reservoir is not supported; rather, all of the pore space required to accommodate the total mass of CO_2 targeted for storage should be secured at the time of project initiation.

Several approaches for handling pore space economics for CO_2 storage have been considered, resulting in a wide range of potential cost estimates. For example, it is possible that the minimum compensation for pore space could be defined as equivalent to the sum of the trust and administrative fees that are levied on the project developer by the state of North Dakota, which, as presented later in this section, is equivalent to $0.08 per each short ton of stored CO_2. On the other hand, some commercial companies (e.g., Willow Grove Carbon Solutions) assigned a value

to pore space of $50/acre/year based on a planned royalty payment of 8% of the income that the company was expecting to make from revenues associated with the handling of the CO_2 for a generator and its subsequent sale to CO_2 EOR operators (Bismarck Tribune, 2010; Endres, 2011). Since there is no precedence in the state for estimating compensation for pore space, an initial estimate of $0.08 per short ton of CO_2 has been used as a placeholder in the cost model at this time, and variations in this cost will be investigated to provide an assessment of the sensitivity of the incremental cost of storage to this particular input.[7] If relevant cost data do become publicly available, these cost estimates will be updated accordingly.

3.2.4.2 North Dakota Administrative Trust Fees

The state of North Dakota has established two storage facility fees that must be paid by the operator of dedicated storage facility.[8] These storage facility fees are codified in NDAC 43-05-01-17 (Storage Facility Fees) as follows:

- The storage operator shall pay the commission a fee of 1 cent ($0.01) on each short ton of carbon dioxide injected for storage. The fee must be deposited in the carbon dioxide storage facility administrative fund.

- The storage operator shall pay the commission a fee of 8 cents ($0.08) on each short ton of carbon dioxide injected for storage. The fee must be deposited in the carbon dioxide storage facility trust fund.

Money from the carbon dioxide storage facility trust fund, including accumulated interest, may be relied upon to satisfy the financial assurance requirements for the postclosure period (NDAC 43-05-01-09.1 – Financial Responsibility). If sufficient money is not available in the carbon dioxide storage facility trust fund at the end of the closure period, then the storage operator shall make additional payments into the trust fund to ensure that sufficient funds are available to carry out the required activities on the date at which they may occur. The commission shall take into account project-specific risk assessments, projected timing of activities (e.g., PISC), and interest accumulation in determining whether sufficient funds are available to carry out the required activities.

These fees will be paid by the storage operator at the end of each calendar year during the CO_2 injection period. For the purposes of the cost model, which assumes 2 Mt per year of CO_2 injection (2.2 million short tons), the annual fees collected for the North Dakota Administrative Fund and North Dakota Trust Fund are $19,842 and $138,891, respectively (~ $158,730 total).

3.2.4.3 5-year Permit Reviews

NDAC mandates periodic review of injection well permits (NDAC 43-05-01-10 – Injection Well Permit) and the testing and monitoring plan (NDAC 43-05-01-11.4 – Testing and Monitoring

[7] Analogous to the state fees, the current pore space cost calculations have assumed that the costs for each year are based on the tons of CO_2 stored during that year and not on the cumulative tons of CO_2 stored in the subsurface from the onset of injection.

[8] These fees are not required for the associated storage of CO_2 as occurs during CO_2 EOR.

Requirements) to verify the geologic sequestration project is operating as permitted and is not endangering underground sources of drinking water. Specifically, these reviews are required every 5 years and require the storage operator to incorporate all monitoring and operating data into a reevaluation of the AOR to 1) determine whether the injection well permit should be modified or revoked and 2) support either an amendment to the testing and monitoring plan or a demonstration that no amendment is necessary.

The cost of performing these permit reviews was estimated for the RTE Project considering the compilation of additional monitoring and operating data, the updating of the project geologic models, and the analysis of the dynamic simulations of the CO_2 injection. These cost estimates ranged from $325,000 to $650,000, with an expected value of $487,500. As part of this economic analysis, it was projected that these costs would be incurred during the CO_2 injection period at 5, 10, 15, 20, and 25 years following the initiation of injection, i.e., at the end of calendar years 2029, 2034, 2039, 2044, and 2049.

3.2.5 PISC and Closure: 2050–2059

Following 25 years of CO_2 injection into the dedicated storage facility, the storage operation must be subjected to a period of PISC and undergo formal regulatory closure. The PISC period comprises well plugging, pipeline and storage site decommissioning, and a surface/subsurface monitoring program. Based on the results of the monitoring of the site during this period, a formal certification of compliance is requested from the state of North Dakota. This certification documents that the storage site is in compliance with the applicable state laws and regulations and grants the storage operator the ability to transfer the future liability for the stored CO_2 to the state of North Dakota. The current cost model assumes a PISC of 10 years; however, the actual duration of the PISC period for a dedicated storage site will be site-specific.[9]

These PISC and closure requirements do not apply to the associated storage of CO_2 since the injection of CO_2 at the CO_2 EOR operations will continue after the delivery of the captured CO_2 from the CarbonSAFE project has ceased, with this supply of CO_2 being replaced by other sources of CO_2. The continuation of CO_2 injection and EOR operation at the site eliminates the need for both postinjection and closure activities. Based on this assessment, the cost items discussed in the remainder of this section apply solely to the dedicated storage sites.

[9] Ten years is the minimum time period required by the state before a storage operator can receive approval of a Certificate of Completion from NDIC (NDCC Section 38-22-17). To receive this approval, the storage operator must demonstrate that the CO_2 in the storage reservoir is stable, i.e., is essentially stationary, or if it is migrating or may migrate, that any migration will be unlikely to cross the storage reservoir boundary. Based on the predictive simulations performed to date on the ND CarbonSAFE project, it has been assumed that the demonstration of a stable CO_2 plume should be achievable following the minimum period of 10 years at a dedicated storage site in North Dakota. Should this not be the case, the PISC period would be extended to 50 years or until such time that this demonstration could be made (NDAC 43-05-01-19; Subsections 8 and 9).

3.2.6 Well Plugging

The CO_2 injection wells at the dedicated storage sites will be plugged as soon as possible following the cessation of injection operations, i.e., the first year of the PISC and closure period. However, monitoring wells will not be plugged until the last year of that period following the completion of the PISC monitoring program and the receipt of an approved certification of compliance.

The current cost model assumes a cost range of $35,000 to $60,000, with an expected value of $40,000 for the plugging of a well. It is assumed that the two injection wells will be plugged at different times, one in the first year of the PISC (2050) and one in the last year of the PISC (2059). The plugging of the monitoring well will be done at the discretion of NDIC depending upon its desire to maintain it for post-PISC monitoring that would be conducted by the state. The cost of plugging this well is currently not included in the cost model.

3.2.7 Pipeline Decommissioning

The decommissioning of the pipelines put in place to transport the captured CO_2 to the dedicated storage is not likely to take place within the lifetime of the CarbonSAFE or any other commercial storage project. This is due largely to the expense associated with their installation as well as the fact that there is likely to be additional storage capacity available at the dedicated storage site at the end of the project, which may have some potential future value. Currently, no costs associated with the decommissioning or continued maintenance of the CO_2 pipelines are included in this storage cost estimate.

3.2.8 Storage Site Decommissioning

The decommissioning of the dedicated storage site includes a number of miscellaneous closure activities and periodic reports. A cost estimate for these activities of $100,000 was generated using the IECM model of the DOE (Integrated Environmental Control Model (www.cmu.edu/epp/iecm/iecm_dl.html). For the purposes of this regulatory–economic analysis, it is assumed that these costs are evenly distributed over the entire 10-year PISC at $10,000 per year.

3.2.9 PISC Monitoring

Monitoring of the subsurface of the dedicated storage site is required as part of the PISC. The purpose of this monitoring is to demonstrate that the injected CO_2 is stable and is not migrating beyond the storage reservoir boundary. This monitoring is required for a minimum of 10 years, although it could be extended to as many as 50 years if it is not possible to demonstrate to the state that the CO_2 plume is stable using the monitoring data that are available at any given time.

The components of the PISC monitoring program will be a streamlined version of the operational MVA monitoring program that was previously presented as part of this storage cost model. For this cost model, the primary components of the PISC monitoring program consist of the following:

- **Environmental monitoring:** An environmental monitoring program will be implemented over the entire PISC period. This annual monitoring effort will comprise sampling and analysis of surface waters, shallow groundwater, a deep aquifer, and the soil gas in the vadose zone. Based on the previous estimates for the RTE MVA project, an annual cost of $100,000 to $200,000, with an expected value of $150,000 is estimated to implement this monitoring program (Leroux and others, 2017).

- **Repeat 3-D seismic surveys:** Similar to the constraints for the baseline 3-D seismic survey, the repeat 3-D seismic surveys will be performed over the estimated areal extent of the separate-phase CO_2 plume, which is assumed to be approximately 25 mi^2 for this cost model. Three repeat 3-D seismic surveys have been included at PISC years 3, 6, and 10 (i.e., calendar years 2052, 2055, and 2059). The range of unit costs per survey is estimated to be $90,000 to $110,000 per mi^2, with an average of $100,000 per mi^2, yielding a total cost of approximately $2.5MM per survey or $7.5MM total.

- **Pulsed-neutron and ultrasonic logs:** Time-lapsed PNLs and ultrasonic imaging logs will be conducted in the monitoring wells. The estimate cost for these wellbore logs is $40,000 per year and is assumed to occur on the same acquisition schedule as the repeat 3-D seismic surveys in PISC years 3, 6, and 10 (i.e., calendar years 2052, 2055, and 2059).

This storage cost estimate assumes that these PISC monitoring efforts will be required for a 10-year PISC and closure period, even though this time period could be extended should it not be possible to demonstrate that the CO_2 plume is stable and that all USDWs are no longer endangered using the monitoring data available at any given time (NDAC 43-05-01-19).

3.3 Compliance Certification (2060)

Following a demonstration that the CO_2 plume is stable, that all underground sources of drinking water are no longer endangered, and upon full compliance with NDCC section 38-22-17, the storage operator may apply to NDIC for a certificate of project completion. More specifically, the storage operator must provide a final assessment of the location, characteristics, and future movement of the stored CO_2 within the storage reservoir. The storage operator shall submit the final assessment to the NDIC within 90 days of completing all PISC and closure requirements. The cost for preparing and applying for a certificate of project completion has been estimated to be on the order of $250,000.

4.0 ESTIMATES OF INCREMENTAL COST FOR DEDICATED STORAGE

4.1 Cumulative PV10 of Incremental Dedicated Storage Costs

The cumulative present value (PV10) of the estimated incremental costs for the dedicated geologic storage of CO_2 in North Dakota is presented in Figure D-2. These costs reflect the generic time line of 5 years of project planning and preparations (yellow), 25 years of CO_2 injection (blue), 10 years of PISC (green), and 1 year for compliance certification (red). As shown in the figure, the

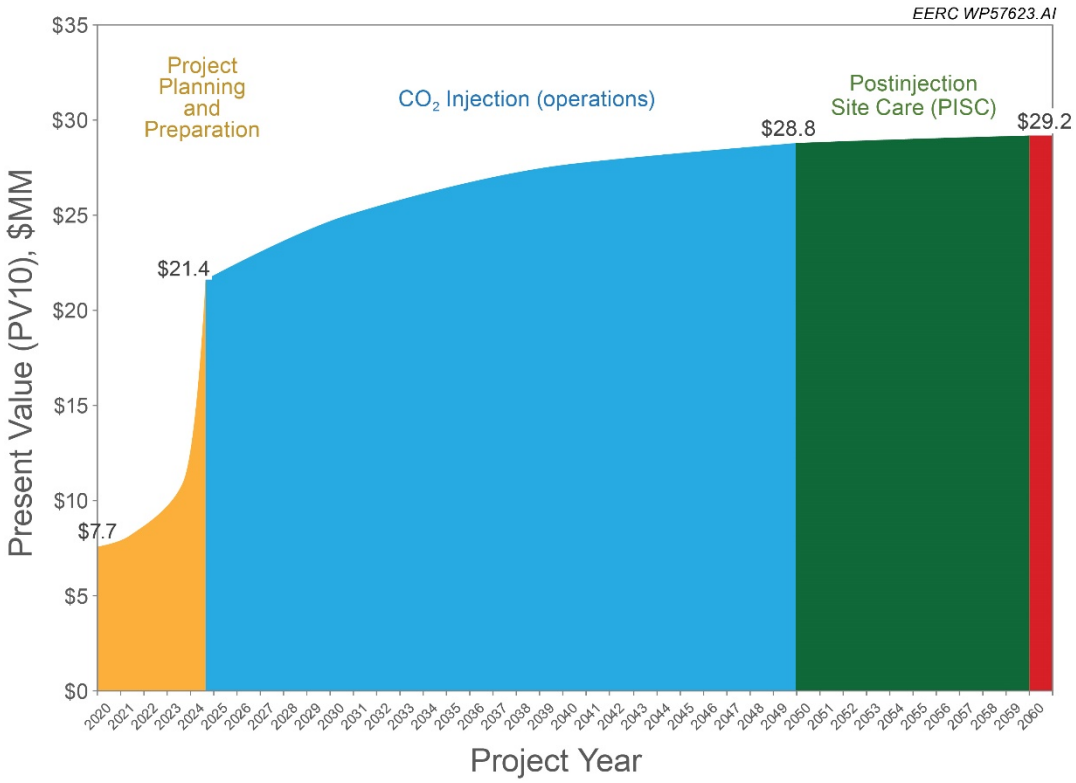


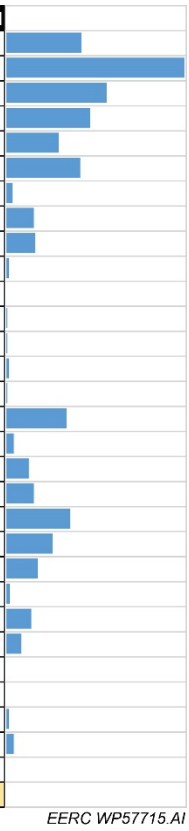
Figure D-2. Cumulative present value (PV10) of the estimated costs for a generic geologic storage project injecting 2 Mt per year and comprising project planning and preparation (5 years – yellow), CO_2 injection (25 years – blue), PISC (10 years – green), and compliance certification (1 year – red).

PV10 of the storage costs rises steeply from $7.7MM to $21.4MM during the project planning and preparation period (i.e., 2020 to 2024), with the dominant costs attributable to the characterization of the site and the drilling of a combination of wells, including a stratigraphic test well, two CO_2 injection wells, and a monitoring well. Following the initiation of CO_2 injection (2025), the PV10 of the costs continues to rise, but at a much slower rate, plateauing at $28.8MM at the end of the 25 years of CO_2 injection, i.e., 2049. The primary storage costs during this period are dominated by the leasing of the pore space in combination with the cost of monitoring and the payment of fees to the North Dakota Administrative and Trust Funds. During the PISC phase, the PV10 of the storage costs edges slowly toward $29.2MM, with the primary costs attributable to site monitoring, which is required by the state regulations.

4.2 Relative Magnitude of Individual Cost Elements

Figure D-3 presents an illustrative example of the relative magnitude of the individual cost elements expressed as PV10 rather than nominal costs. From a review of this figure, it is clear that the up-front costs associated with site characterization, notably, the drilling, construction, and logging of the stratigraphic, injection, and monitoring wells, represent the most significant costs. Other storage costs that are potentially significant are the CO_2 pipeline to dedicated storage and

Cost, $	Cost Element	Cost, PV10, $MM
$ 2,287,879	Drilling: Stratigraphic Well	$ 2.3
$ 5,443,410	Drilling: Injection Well	$ 5.4
$ 3,073,561	Drilling: Monitoring Well	$ 3.1
$ 2,581,120	Well Logging and Core Characterization	$ 2.6
$ 1,590,909	Baseline 2-D Seismic	$ 1.6
$ 2,272,727	Baseline 3-D Seismic	$ 2.3
$ 203,197	Modeling and Simulation	$ 0.2
$ 824,380	Project Plan Development	$ 0.8
$ 875,194	Permit Acquisition	$ 0.9
$ 65,197	Contract/Subcontract Execution	$ 0.1
$ 10,245	Soil Gas SGPS Install	$ 0.0
$ 46,942	Soil Gas Monitoring	$ 0.0
$ 44,706	Surface Water Monitoring	$ 0.0
$ 85,035	Groundwater Well Install	$ 0.1
$ 32,785	Groundwater Monitoring	$ 0.0
$ 1,849,725	Pipeline to Dedicated Storage	$ 1.8
$ 216,991	Pipeline Operating Expenses	$ 0.2
$ 691,846	Storage Site Operating Expenses	$ 0.7
$ 845,419	MVA Operational Monitoring Near-Surface	$ 0.8
$ 1,972,645	MVA Operational Monitoring Subsurface	$ 2.0
$ 1,409,032	MVA Operational Monitoring Sci. and Engineering	$ 1.4
$ 950,534	Pore Space Lease Fees	$ 1.0
$ 111,830	ND Trust CO_2 Storage Facility Administrative Fund	$ 0.1
$ 782,809	ND Trust CO_2 Storage Facility Trust Fund	$ 0.8
$ 450,052	Five-Year Permit Reviews	$ 0.5
$ 3,153	Well Plugging	$ 0.0
$ 3,521	Storage Site Decommissioning	$ 0.0
$ 76,296	PISC Monitoring Part 1 (annual)	$ 0.1
$ 243,752	PISC Monitoring Part 2 (3-D seismic)	$ 0.2
$ 5,022	Certification of Compliance	$ 0.0
$ 29,049,913	Total Cost, PV10	$ 29.0



EERC WP57715.AI

Figure D-3. Tabulated breakdown and bar chart of the individual cost elements expressed as PV10.

the MVA activities for near-surface monitoring, subsurface monitoring, and science and engineering. Expressing these costs as PV10, which incorporates the time-value of costs mapped onto the generic time line, provides insights about which particular cost elements drive the total incremental storage costs.

4.3 Cumulative PV10 per Ton of CO_2 Stored by Project Year

The cumulative PV10 cost of storage by year, normalized per ton of CO_2, is presented over the project lifetime in Figure D-4. As would be expected, the cumulative PV10 cost per ton is highest at the beginning of the project, as cost outlays are large and storage is nonexistent prior to the CO_2 injection phase. Consequently, the $/ton at the first year of injection is approximately $11.14/ton (2025). As injection continues, the cumulative PV10 per ton of CO_2 stored steadily decreases, approaching a value of approximately $2.47, $1.33, and $0.58 per ton of CO_2 stored at 5, 10, and 25 years into the operations phase, respectively. This decrease reflects that fact the initial, up-front site characterization and well-drilling costs have been replaced with lower annual operating costs, i.e., pore space lease fees and monitoring costs, while the cumulative quantity of CO_2 that is stored continues to increase at the same rate, i.e., 2 MMt per year. The decreasing numerator and increasing denominator, therefore, act to decrease the cost per ton.

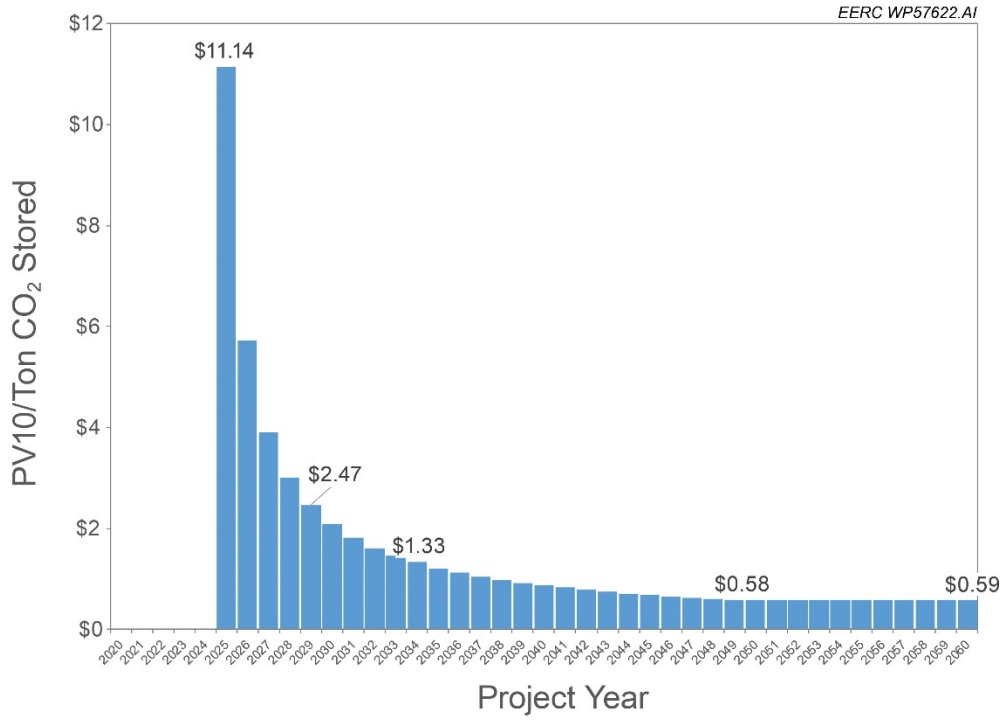


Figure D-4. Cumulative PV10 of storage costs per ton of CO_2 stored per project year.

After injection ceases, the PV10 cost of storage per ton of CO_2 stored is projected to slightly increase as PISC monitoring costs continue to be incurred but with no additional storage of CO_2. However, as shown in Figure D-4, the approximate cost at the end of the project lifetime (2060) is estimated to be \$0.59 per ton of CO_2 stored, which is virtually indistinguishable from the \$0.58 per ton of CO_2 stored at the end of injection. These price per ton of CO_2 stored estimates are dependent upon the individual cost elements and how those cost elements are mapped onto the project time line. Therefore, the estimates shown in Figure D-4 should be considered illustrative and not directly applicable to a particular storage site.

Moving forward, this storage cost model will be populated with improved cost estimates that are generated as the project moves beyond the feasibility stage and toward design. At the same time, it can be used to conduct cost sensitivity analyses in support of commercial cost optimization studies, identifying for future assessment those cost elements that have the greatest potential to impact the estimated cost of CO_2 storage.

5.0 REFERENCES

Donovan, L., 2010, Company wants to lock carbon dioxide in deep formation: Bismarck Tribune. December 16.

Endres, A.B., 2011, Geologic carbon sequestration—balancing efficiency concerns and public interest in property rights allocations: University of Illinois Law Review, p. 623–650.

Heddle, G., Herzog, H., and Klett, M., 2003, The economics of CO_2 storage: Cambridge, Massachusetts, Massachusetts Institute of Technology Laboratory for Energy and the Environment, 106 p.

ICF International, 2009, Developing a pipeline infrastructure for CO_2 capture and storage—issues and challenges: prepared for INGAA Foundation by ICF International.

IHS Energy, 2016, CO_2 EOR potential in North Dakota—challenges, policy solutions, and contribution to economy and environment: IHS Energy, June.

J.E. Sinor and Associates, 2000, Financial future brightens for Dakota Gasification: Sinor Synthetic Fuels Report, v. 7, no. 3, p. 63, http://edj.net/sinor/sfr7-00art6.html (accessed 2020).

Jablonowski, C., and Singh, A., 2010, A survey of CO_2 EOR and CO_2 storage project costs: SPE Paper No. 139669-MS, Presented at the SPE International Conference on CO_2 Capture, Storage, and Utilization, New Orleans, Louisiana, November 10–12.

Jablonowski, C., and Singh, A., 2014, Acquisition and development of selected cost data for saline storage and enhanced oil recovery operations: DOE/NETL 2014/1658, p. 10–14.

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

Leroux, K.M., Klapperich, R.J., Jensen, M.D., Kalenze, N.S., Daly, D.J., Crocker, C.R., Ayash, S.C., Azzolina, N.A., Crossland, J.L., Doll, T.E., Gorecki, C.D., Stevens, B.G., Schlasner, S.M., Botnen, B.W., Foerster, C.L., Hamling, J.A., Nakles, D.V., Peck, W.D., Glazewski, K.A., Harju, J.A., Piggott, B., and Vance, A.E., 2018, Integrated carbon capture and storage for North Dakota ethanol production – Phase II: Final report (November 1, 2017 – July 31, 2018) for North Dakota Industrial Commission and Red Trail Energy, Grand Forks, North Dakota, Energy & Environmental Research Center, July.

McCoy, S., and Rubin, E., 2008, An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage. International Journal of Greenhouse Gas Control,
v. 2, p. 219–229.

Oil and Gas Journal, 2008, Construction, other cost increases hit home: Oil and Gas Journal, v.106, no. 33.

Parker, N., 2004, Using natural gas transmission pipeline costs to estimate hydrogen pipeline costs: UCD-ITS-RR-04-35, Institute of Transportation Studies, University of California at Davis.

Perilloux, G., 2009, Enhanced oil recovery key to $720 million deal, The Advocate, www.2theadvocate,com/news/business/3875982.html (accessed November 2009).

Rui, Z., Metz, P., Reynolds, D., Chen, G., and Zhou, X., 2011, Regression models estimate pipeline construction costs: Oil and Gas Journal, v. 109, no. 27.

Smith, C.E., 2009, Pipeline profits, capacity expansion plans grow despite increased costs: Oil and Gas Journal, v. 107, no. 34, pp. 60–79.

Steadman, E.N., Sorensen, J.A., Gorecki, C.D., Hamling, J.A., Liu, G., Klapperich, R.J., Bailey, T.P., Bremer, J.M., Braunberger, J.R., Smith, S.A., Botnen, L.A., Holubnyak, Y.I., Schmidt, D.D., and Harju, J.A., 2010, The Basin Electric Power Cooperative carbon capture and storage project—a geological characterization report detailing key elements and paths forward for two injection scenarios: Confidential final report for Basin Electric Power Cooperative, EERC Publication 2010-EERC-08-10, Grand Forks, North Dakota, Energy & Environmental Research Center, August.

U.S. Department of Energy, 2008, NETL carbon sequestration newsletter—annual index: National Energy Technology Laboratory, U.S. Department of Energy, September 2007 – August 2008.

U.S. Department of Energy, 2014, FE/NETL CO_2 transport cost model—description and user's manual: National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2014/1660, Pittsburgh, Pennsylvania, July 11.

U.S. Department of Energy, 2017, FE/NETL CO_2 saline storage cost model—User's manual: National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL-2018/1873, Pittsburgh, Pennsylvania, 2017.

U.S. Department of Energy, 2018, FE/NETL CO_2 transport cost model—National Energy Technology Laboratory, U.S. Department of Energy, DOE/NETL 2018-1894.

U.S. Environmental Protection Agency, 2018, Approval and promulgation of state plans for designated facilities and pollutants: Federal Register, v. 83, no. 79, p. 17758–17761, April 24.

Wildgust, N., Leroux, K.M., Botnen, B.W., Daly, D.J., Jensen, M.D., Glazewski, K.A., Kalenze, N.S., Burton-Kelly, M.E., Dalkhaa, C., Torres, J.A., Doll, T.E., Vettleson, H.M., Wilson, W.I., Crocker, C.R., and Gorecki, C.D., 2018, Nebraska integrated carbon capture and storage pre-feasibility study: Final report (Jan 1, 2017 – June 30, 2018) for U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement No. DE-FE0029186, EERC Publication 2018-EERC-06-12, Grand Forks, North Dakota, Energy & Environmental Research Center, June.

Willhite, G.P., 2001, Carbon dioxide flooding in Kansas reservoirs: Presented at 14th Oil Recovery Conference, Wichita, Kansas, March 14–15.

APPENDIX E

OUTREACH

APPENDIX E-1

CCUS PUBLIC PERCEPTIONS STUDY RESULTS

APPENDIX E-2

INFOGRAPHICS

APPENDIX E-1

CCUS PUBLIC PERCEPTIONS STUDY RESULTS

CCUS PUBLIC PERCEPTIONS STUDY RESULTS

The purpose of the public perception study was to better understand public perceptions of carbon capture, utilization, and storage (CCUS) in North Dakota. The study utilized a mixed-method design consisting of both qualitative (focus groups) and quantitative (online survey) market research to explore public perceptions of carbon management strategies as they relate to the North Dakota CarbonSAFE project. Further, the study provided citizens a means (either online or in-person) to share their concerns.

METHOD

Research methodology was approved by the University of North Dakota (UND) Institutional Review Board, with prior acceptance of online survey content by the Outreach Advisory Board (OAB).

Quantitative data were gathered via an online survey hosted by UND on the Qualtrics platform. Launched in June 2019, the online survey ran 90 days and focused on households in Mercer and Oliver Counties. Postcard notification to residents in Mercer and Oliver Counties was deployed using U.S. Postal Service Every Door Direct Mail® (EDDM) delivery service. This eliminated the need to obtain mailing lists, but also eliminated the ability to track who responded to the survey for second and third reminder mailings. Participants were asked to access an online link to complete the survey and given the option to request a mail survey; two participants did so. Postcards (n = 5611) were mailed to nearly all of the households in Oliver and Mercer Counties during summer 2019 to invite them to participate in the survey. Zip codes included in the survey are listed in Table E-1. Additional methods to publicize the survey included project partner e-mails to employees, a letter to the editor of the *Center Republican* encouraging residents to complete the survey, advertising the survey in two local newspapers (*Beulah Beacon* and *Center Republican*) and on Facebook, sharing on EERC and partner Facebook accounts, and sharing the link at the county fairs in both counties. The online survey was the means to populate the focus groups in Oliver and Mercer Counties; respondents were offered the option to express interest in participating in subsequent focus groups at the end of the survey. Through this opinion research, participants were given a voice to share concerns and ask questions.

Qualitative research took place in two stages, with the initial focus group in Grand Forks, followed by two focus groups in the two-county study area.

The Grand Forks focus group provided feedback on materials from the perspective of state residents removed from the site of potential CCUS projects. They reviewed the infographic “North Dakota Is a Great Place for CCUS,” the project fact sheet, the draft project FAQs, and vertical banners used at the initial open house.

Table E-1. U.S. Postal Zip Codes and Routes Receiving EDDM[1] Postcards

Zip Code	City	Routes
58523	Beulah	H003, R001, R002, R003, PBOX
58530	Center	H002, R004, PBOX
58625	Dodge	R001
58541	Golden Valley	H004, PBOX
58545	Hazen	R001, R002, R003, PBOX
58554	Mandan	H005
58563	New Salem	H003, R003
58571	Stanton	R004, PBOX
58580	Zap	R003, PBOX

[1] https://eddm.usps.com/eddm/customer/routeSearch.action (accessed June 20, 2019).

The second set of focus groups, held in Beulah and Center, North Dakota, in September 2019, reviewed the same infographic, revised FAQ, and 8-minute documentary. This qualitative research was exploratory sequential in nature, enabling the research team to gather a deeper understanding of what was learned in previous phases of the public perception research. Thus, after collecting online data, the research team was able to explore the opportunities and concerns identified in the online survey in more depth in the focus groups.

SURVEY PARTICIPANTS

The sample consisted of 163 respondents.

Demographics: Age, Biological Sex, Marital Status, Education, and Income

The mean age of the sample was 49.2 years. The range was 19 to 81 years old. In the sample, 22.7 were over 65 years of age, which is comparable to recent census estimates for Oliver County (22.2%) and Mercer County (19.3%), as shown in Table E-2. Gender was 42.9% female and 57.1% male. North Dakota is less than 50% female; however, the sample slightly underrepresents females (5%). The sample was predominately white (96.9%) as compared to Mercer (94.4%) and Oliver (95.0%) Counties. Most of the sample was married (75.2%), while the remainder endorsed their marital status as single (15.8%), separated or divorced (6.8%), or widowed (2.3%). The average length of time respondents had lived in North Dakota was 41.9 years, with a range of 4 to 80 years.

The educational background of the sample is shown in Table E-3. Based on highest level of education, ~54% of those over 25 years of age had a bachelor's degree or higher. Compared to census estimates shown in Table E-2, the sample represented more with bachelor's degrees or higher compared to the state of North Dakota (28.9%), Mercer County (22.7%), and Oliver County (19.6%). Educated individuals in the sample may be opinion leaders, as they chose to participate in the online survey and share their opinion.

Table E-2. Demographic Characteristics of Survey Sample and Population in Counties and State

Demographic	Survey Sample[1]	Oliver County[2]	Mercer County[2]	North Dakota[2]
Persons 65 years and Over, %	22.7	22.2	19.3	15.3
Female Persons, %	42.9	47.7	48.4	48.8
White Alone, %	96.9	95.0	94.4	87.0
Black or African American Alone, %	0.0	0.4	0.6	3.4
American Indian and Alaska Native Alone, %	1.2	2.8	2.6	5.5
Asian Alone, %	1.2	0.3	0.6	1.8
Native Hawaiian and Other Pacific Islander Alone, %	0.0	0.1	0.1	0.1
Hispanic or Latino, %	0.0	2.0	3.0	3.9
White Alone, Not Hispanic or Latino, %	96.9	93.2	92.4	84.0
Persons Age 25 years+,[3]				
High School Graduate or Higher, %	87.2	88.7	91.0	92.3
Bachelor's Degree or Higher, %	44.8	19.6	22.7	28.9
In Civilian Labor Force, Total, % of Population Age 16 years+[3]	68.2	63.6	65.6	69.5
Median Household Income (in 2017 dollars) [3]	$87,000	$71,500	$80,337	$61,285

[1] 2019 data.
[2] Source: www.census.gov.
[3] 2013–2017.

Table E-3. Educational Background

Highest Level of Education	Percent
High School Diploma or Equivalent	12.7
Vocational Training	2.2
Some College	14.9
Associate's Degree	15.7
Bachelor's Degree	41.8
Graduate or Professional Degree	12.7

n = 134

Reported household income for the sample is shown in Table E-4. The median household income for the sample was $87,000, while the median in Mercer County ($80,337), Oliver ($71,500), and North Dakota ($61,285) is lower (shown in Table E-2). There was no monetary incentive or compensation to complete the survey and may have attracted higher-income individuals.

In terms of generalizability, the survey sample is comparable to both Oliver and Mercer Counties and to the state of North Dakota in terms of age and gender. The sample was higher in education and income than the county averages. Thus the sample represents individuals with similar profiles and may tend to underrepresent lower levels of income and educational attainment.

Table E-4. Household Income

Household Income	Percent
Less than $25,000	3.7
$25,0000 to $49,999	7.4
$50,000 to $74,999	11.0
$75,000 to $99,999	14.1
$100,000 to $149,999	26.4
$150,000 to $199,999	9.8
$200,000 to $249,999	2.5
$250,000 or Over	1.8

n = 125

Employment and Landownership

Of particular value for the North Dakota CarbonSAFE project were the opinions of residents with no direct interest in coal-related industry and agricultural landowners whose livelihood may appear to be impacted by permanent geologic storage projects. Two-thirds of the sample stated they did not work (67.2%) for an organization in the coal or coal-fired electricity industry.

Of respondents completing the survey, 93.9% own their home and 30.7% indicated that someone in their household was a landowner of agricultural land. Further, 16% indicated that someone in the household identified as an agriculture producer or operator. Of the overall sample, 20.9% stated that they had participated in a government conservation program administered by a state or federal entity.

SURVEY RESULTS

Awareness of CCUS Projects and Process

The survey polled familiarity with the North Dakota CarbonSAFE scenario with the statement:

> *The North Dakota CarbonSAFE project is investigating the feasibility of safe, permanent, geologic storage of carbon dioxide deep underground as part of the effort to address CO_2 emissions from large stationary sources like coal-based energy facilities.*

Of the overall sample of 147 participants, nearly half (45.6%) had heard of North Dakota CarbonSAFE, which speaks to the success of the public outreach efforts over nearly 2 years of the project. When asked if they had heard of any other carbon-related projects, 34.4% of respondents had. The top answers were Dakota Gasification (DGC), DGC, Elam [sic: Allam cycle], enhanced oil recovery, Flemmer farm, Great Plains Synfuels, Tundra, Weyburn capture project, and some general awareness of projects in various locations and of work being done with capture carbon.

Participants were asked if, before participating in this survey, they had heard about the "process of capturing carbon dioxide from a power plant and permanently storing it deep underground, a technique known as carbon capture and storage (CCS)." Of the respondents completing the survey, 82.1% indicated yes, while, 17.9% indicated no. CCS was defined for the respondents, so a yes answer indicates that all or part of what they read in that survey item resonated with them. This is a recognition item, meaning that they recognized at least some component of the definition or acronym.

Awareness of Coal Characteristics

Respondents were asked to rank six sources of electricity from most to least affordable (1) to least affordable (6). The results in Table E-5 show belief that coal is the most affordable electricity source (66.4% most or second most affordable) followed by hydroelectric (48.6%) and natural gas (46.4%)

When asked about coal use and electricity generation in North Dakota, the majority of respondents had a good grasp on the role coal plays in electricity generation (70% of respondents estimated coal at 60% to 80% of the primary source of generation) (Figure E-1). In 2018, coal provided 66% of the electricity produced in North Dakota (www.eia.gov/state/?sid=ND), a decline from previous years.

Perceptions of Coal Use and Industry

When asked their opinion on the use of coal to produce electricity, 90.9% favored it (Table E-6), and even more respondents (96.6%) recognized the importance of the coal-based industry to the area's economy (Table E-7). When asked to react to coal-focused messages, the greatest majority of the sample expressed strong agreement on the impact of coal (Figure E-2). Respondents agreed with statements that coal should continue to be mined in North Dakota to produce electricity (97.2%), increases tax revenues that help state and local economies (95.8%). provides this region with affordable energy (92.3%), and creates good-paying jobs (89.6%).

Table E-5. Perceived Affordability of Electricity Generated from Coal and Other Sources

	1	2	3	4	5	6
Coal, %	37.1	29.3	16.4	8.6	5.7	2.9
Water/Hydroelectric, %	33.6	15.0	22.1	22.1	5.7	1.4
Natural Gas, %	15.7	30.7	27.1	15.0	10.0	1.4
Solar, %	6.4	5.0	7.1	12.1	32.9	36.4
Nuclear, %	4.3	8.6	10.7%	23.6	7.1	45.7
Wind, %	2.9	11.4	16.4	18.6	38.6	12.1

1 = most affordable to 6 = least affordable

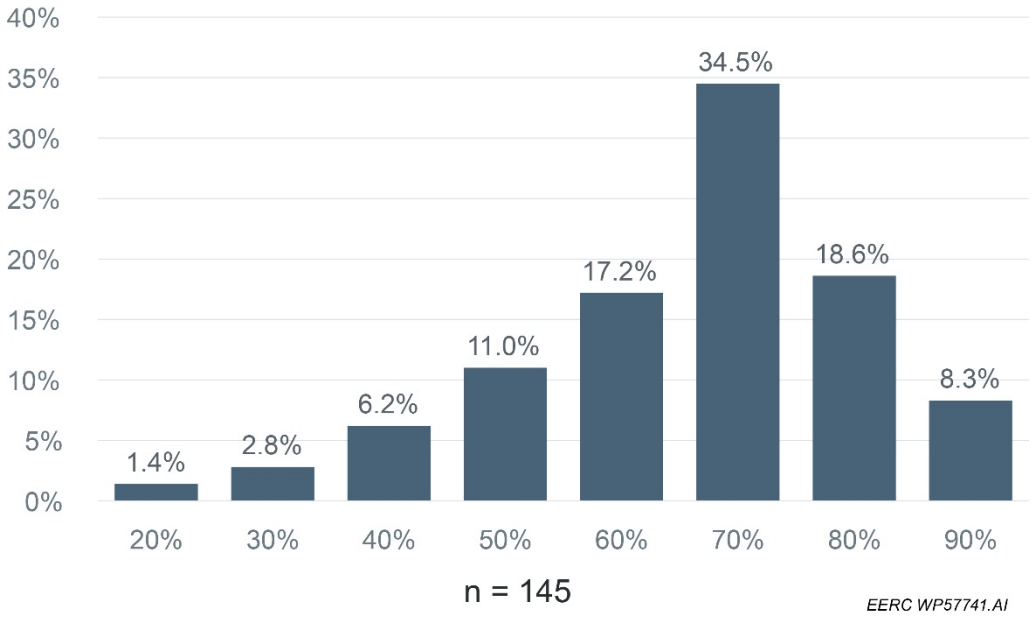


Figure E-1. Public perception of the percent of electricity produced from coal in North Dakota.

Table E-6. Coal Use to Produce Electricity

Opinion	Percent
Strongly Favor	69.9
Somewhat Favor	21.0
Somewhat Oppose	7.0
Strongly Oppose	2.1

Sample size (n) = 146

Table E-7. Importance of the Coal-Based Industry to Area's Economy

Opinion	Percent
Very Important	88.4
Somewhat Important	8.2
Uncertain	2.1
Not Very Important	0.7
Not Important at All	0.7

Sample size (n) = 146

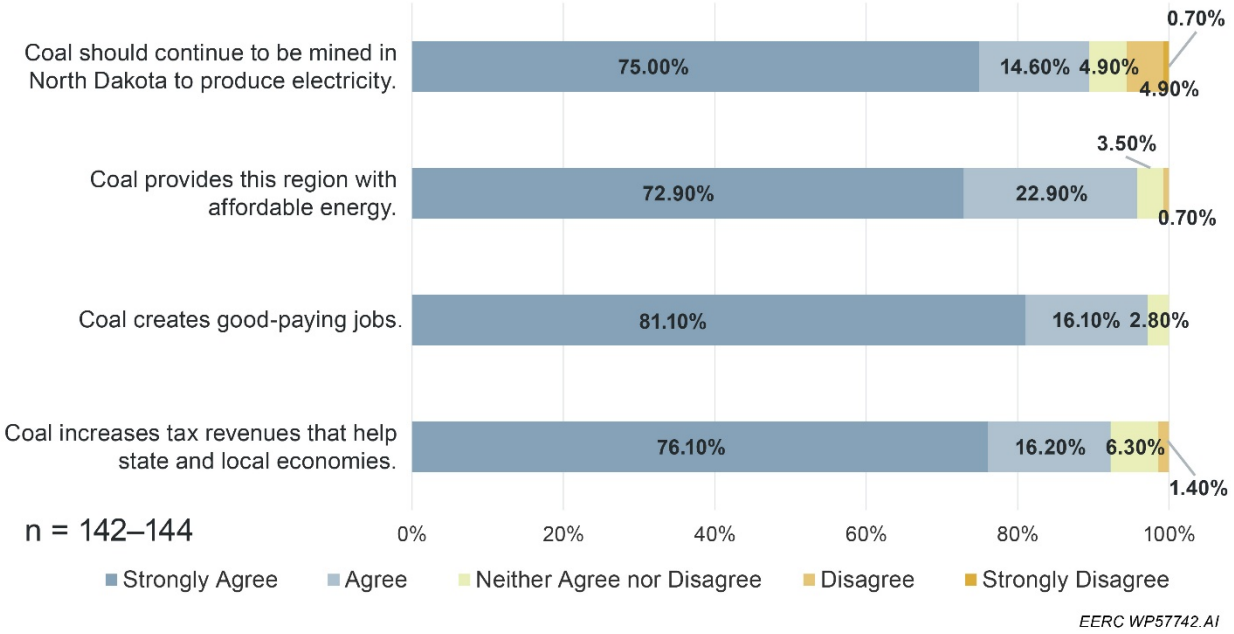


Figure E-2. Opinions on economic impact of coal on the region and North Dakota.

Opinions on Climate Change

When asked about their level of agreement with climate change statements (Figure E-3), the majority of respondents recognized the existence of climate change (77.0%), although fewer acknowledged manmade elements (63.2%). Less than half of the respondents agreed (48.6%) with the statement that evidence shows climate change is occurring because of human activity, and more than a quarter (28.5%) disagreed, which set the tone for subsequent responses related to climate change and reasons to investigate CCUS.

When asked to rate their position on climate change along the continuum of natural phenomenon versus human-invoked, more than half (58.6%) attributed more effect to natural phenomenon and less than a third (30.7%) to human actions (Figure E-4).

When asked to consider opinions about energy and environment issues (Figure E-5), only 18.4% on the sample endorsed concern about fossil fuels running out. Twice as many respondents (36.9%) relayed a sense of urgency that something should be done about climate change now—although slightly more (40.4%) disagreed with taking action. More respondents (43.3%) agreed or strongly agreed that we should promote the use of renewable energy as soon as possible.

Perceptions of CO_2, Its Capture, and Permanent Storage

When asked to provide an opinion on CO_2 using a continuum of adjectives shown in Figure E-6, no discernable pattern of response arose as a strong minority perceived CO_2 to be dangerous (41.0%), whereas nearly as many perceived CO_2 to be clean (40.3%) and positive (37.2%). A majority of respondents perceived CO_2 as useful (59.4%).

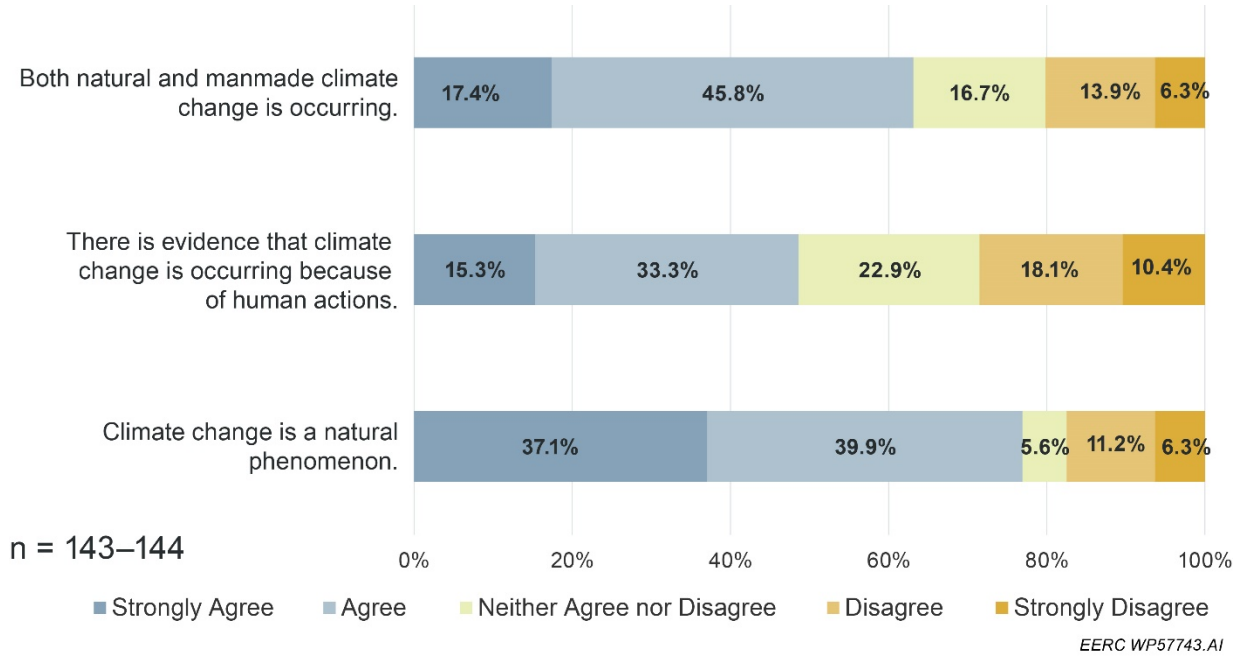


Figure E-3. Perception and causality of climate change.

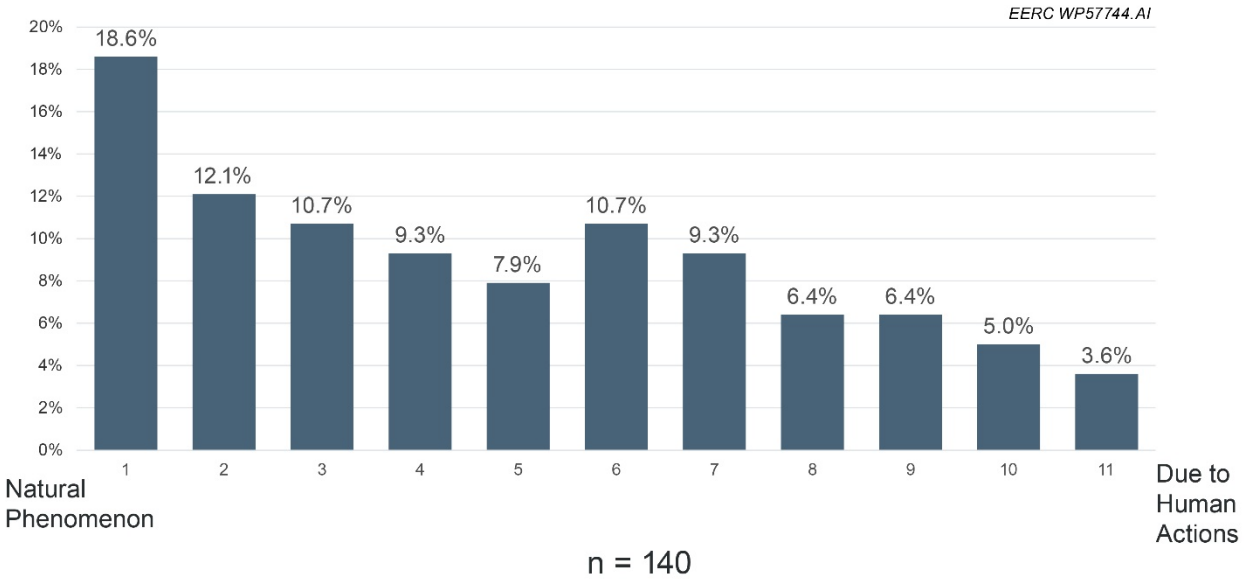


Figure E-4. Perceived status of climate change along the continuum of natural versus human causality.

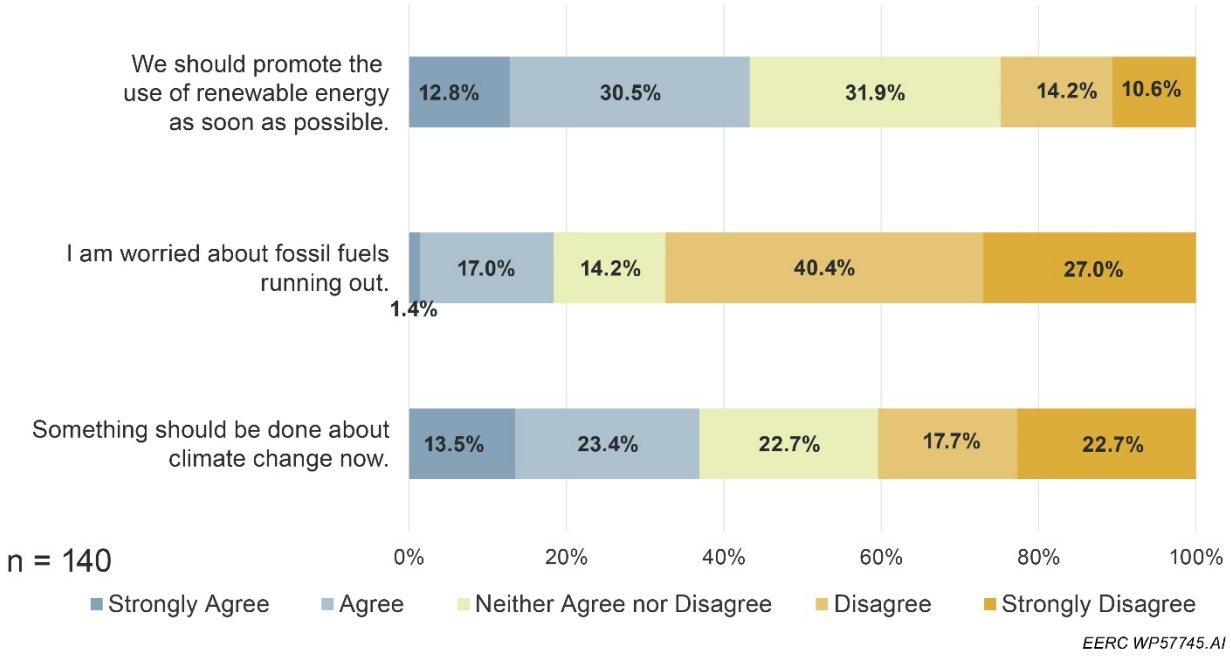


Figure E-5. Opinions about potential actions and concerns.

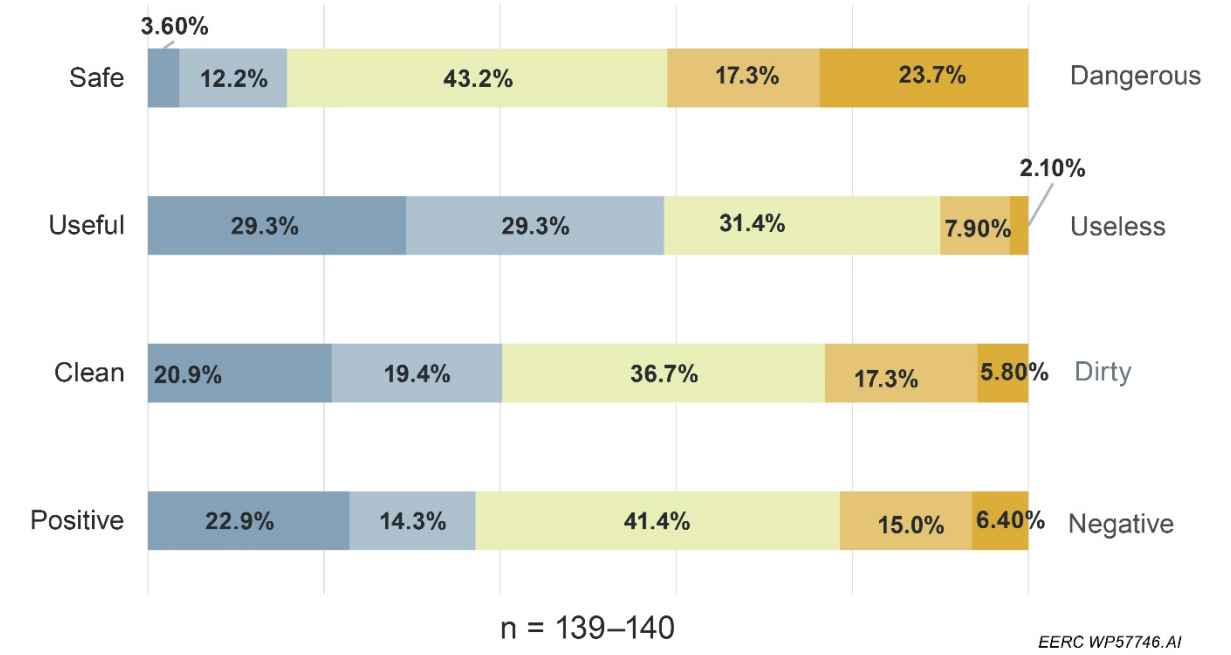


Figure E-6. Perceptions of CO_2 as a continuum of paired adjectives.

When asked to rate CO_2 capture and permanent storage technology on a similar continuum of adjectives with the addition of developing/mature technology (Figure E-7), more than half viewed the technology as useful (52.8%), clean (51.8%), and positive (54.0%). More than half viewed the technology as mature (57.6%) as opposed to developing. However, a smaller proportion viewed the technology as safe or somewhat safe (19.4%). On all of the adjective continua, there was a substantial neutral stance, meaning that at least 30% (and up to 36%) of respondents endorsed the middle between two adjectives (see Figure E-2).

When asked if they favor or oppose using CO_2 to produce additional oil through enhanced oil recovery (EOR) in North Dakota, 90.7% strongly or somewhat favored. Next, when asked if they favored or opposed projects that permanently store CO_2 deep underground in North Dakota, 77% strongly or somewhat favored. Thus there is more support and stronger support for EOR than permanent storage.

Respondents were presented with four reasons to investigate CO_2 capture and permanent storage and to indicate the importance of those reasons (Figure E-9). Ranked in order of collective importance are the percentage of respondents who feel each reason is very or somewhat important: economic value to my region (90.0%), environmental stewardship (87.9%), continued use of fossil fuels to supply energy in our modern lifestyle (87.8%), and management of carbon resources through regulations (60.1%). Thus economic value is of highest importance overall to respondents, but environmental stewardship ranked nearly as strong a driver for investing in CCUS.

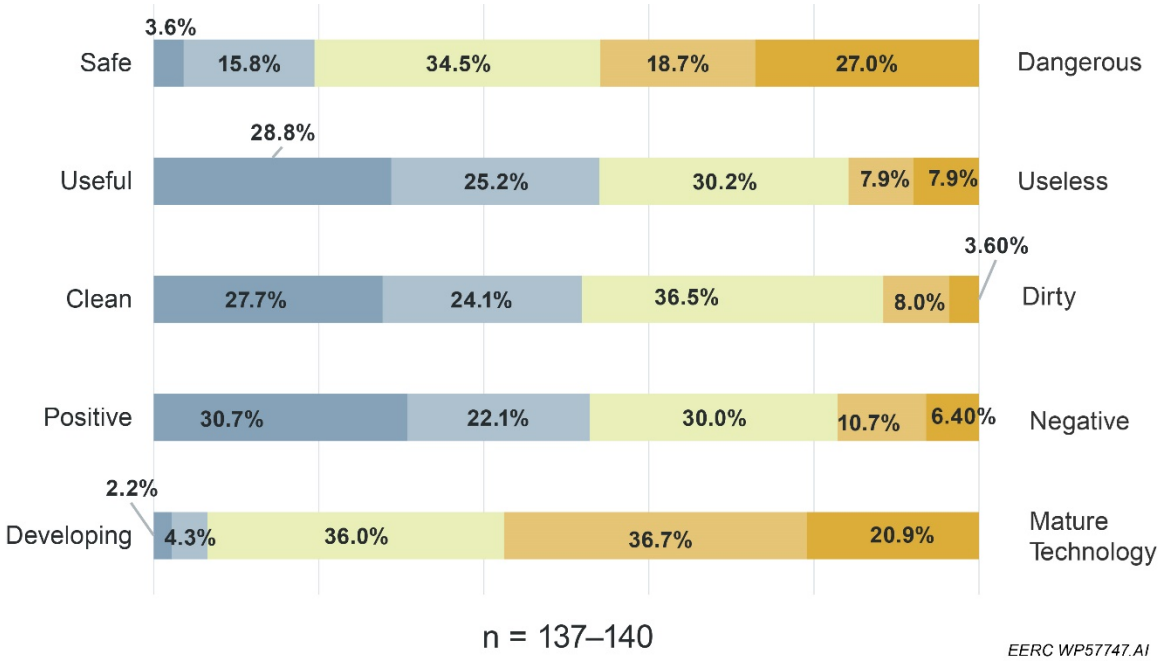


Figure E-7. Perceptions of CO_2 capture and permanent storage as a continuum of paired adjectives.

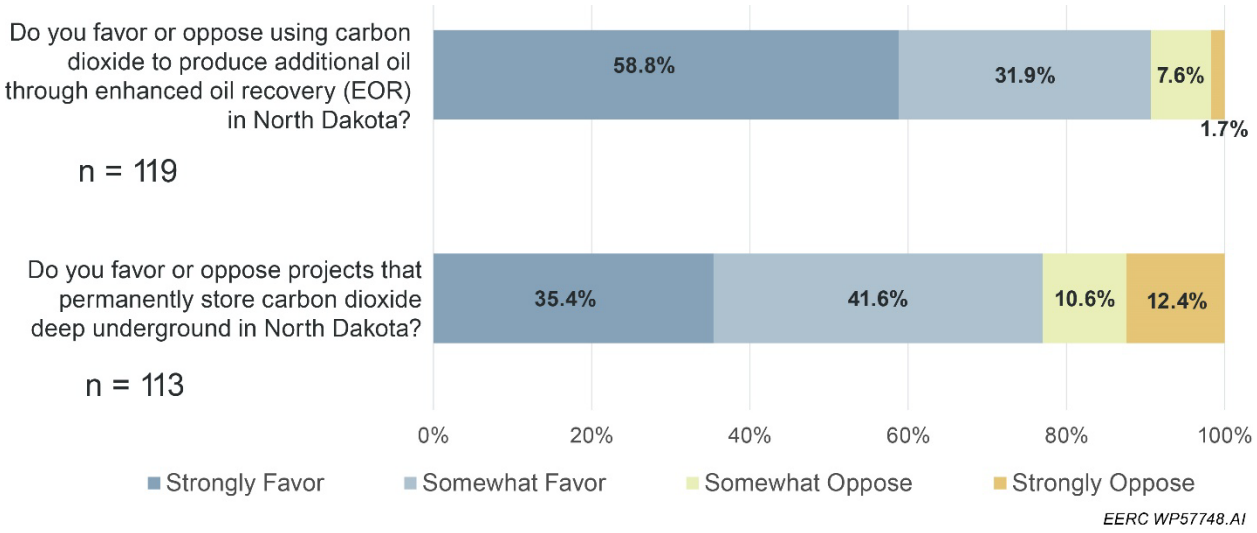


Figure E-8. Opinion on associated and dedicated permanent CO_2 storage in North Dakota.

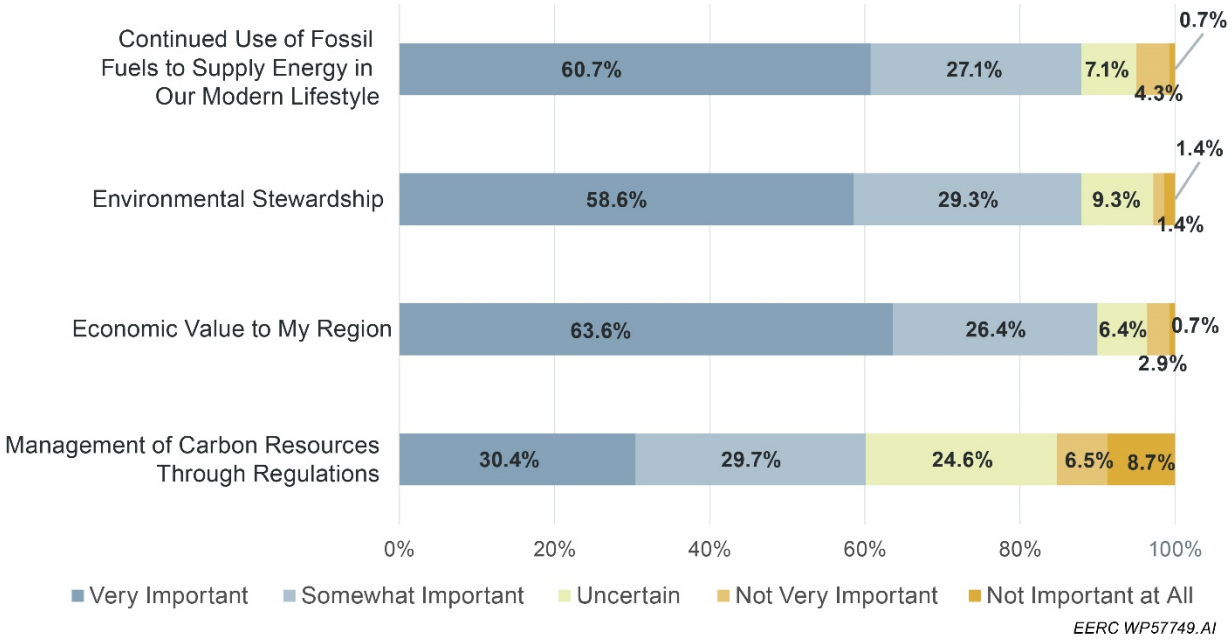


Figure E-9. Importance of various rationale to investigate CO_2 capture and permanent storage.

Respondents were then asked to react to messaging related to CCUS. First were reasons to investigate CO_2 capture and permanent storage based on the importance of fossil fuels to energy and quality of life, shown in Figure E-10. All messages rated well with the majority of the respondents (79.0%–88.4%). Disagreement with the statements ranged from 5.0% to 10.9% of the respondents. The second set of messages focused on what CO_2 capture and permanent storage could do. The results shown Figure E-11 indicate that the sample was less enthusiastic (possibly less comfortable or familiar) with these messages.

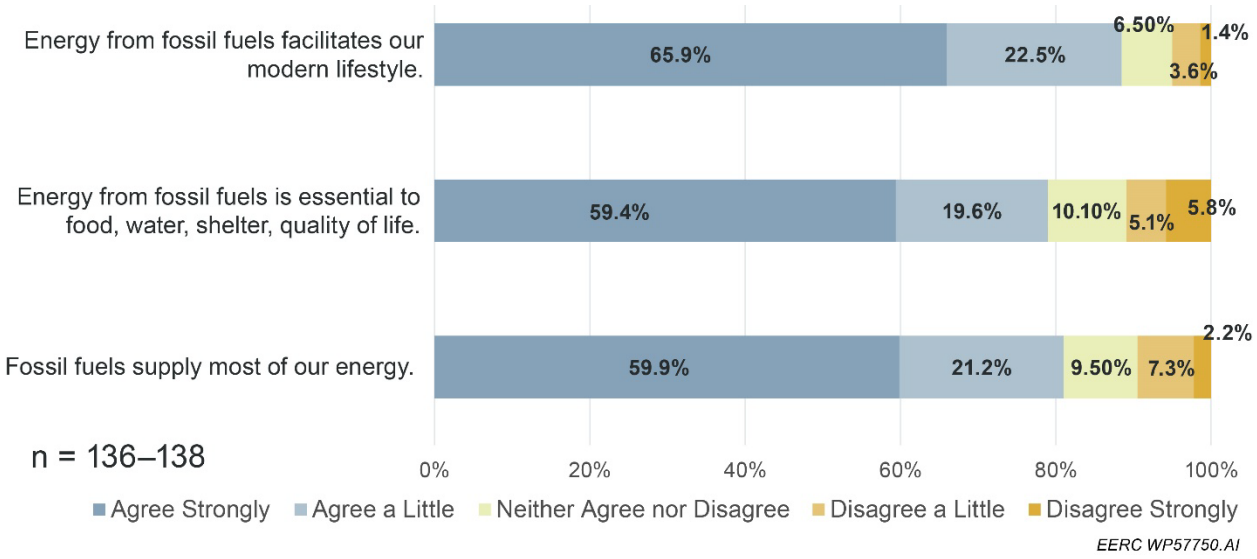


Figure E-10. Opinion of messages justifying investigation of CO_2 capture and permanent storage.

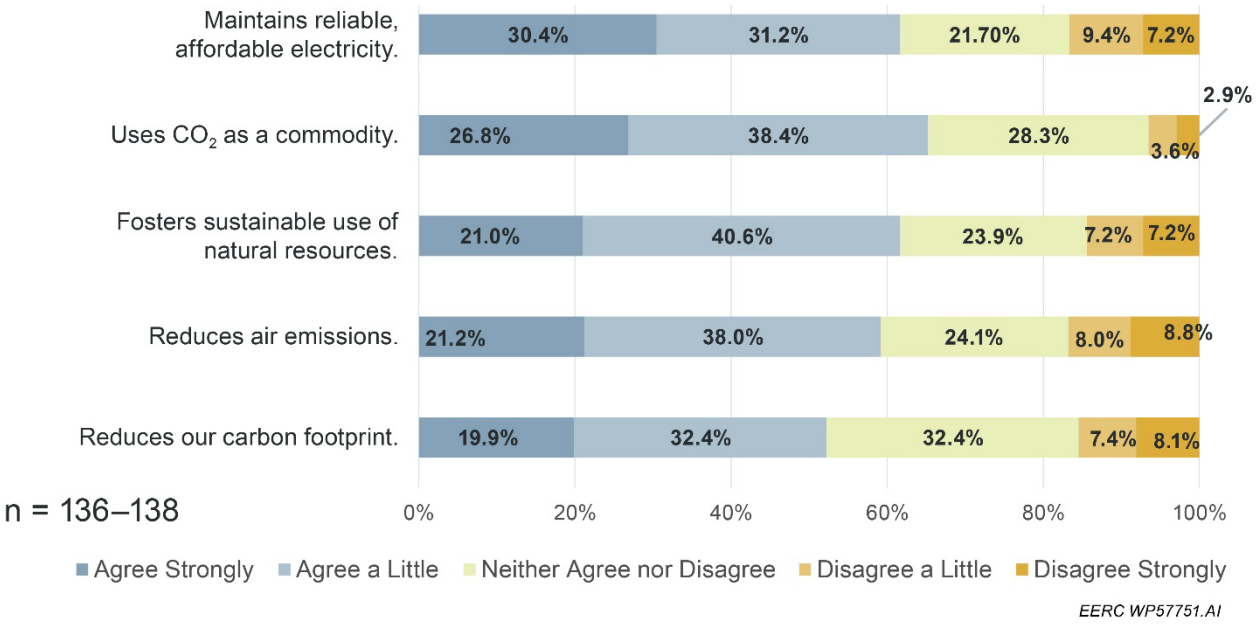


Figure E-11. Opinion of messages completing the sentence "CO_2 capture and permanent storage …."

When asked if they believe CO_2 capture and permanent storage represent an ***opportunity*** for North Dakota, 81.4% agreed (Figure E-12). On the other hand, when asked if they believe CO_2 capture and permanent storage represent an ***area of concern*** for North Dakota, 48.6% agreed. Directly after online survey respondents endorsed their level of agreement with CO_2 capture and permanent storage as an opportunity or area of concern for North Dakota, they were encouraged to add open-ended comments.

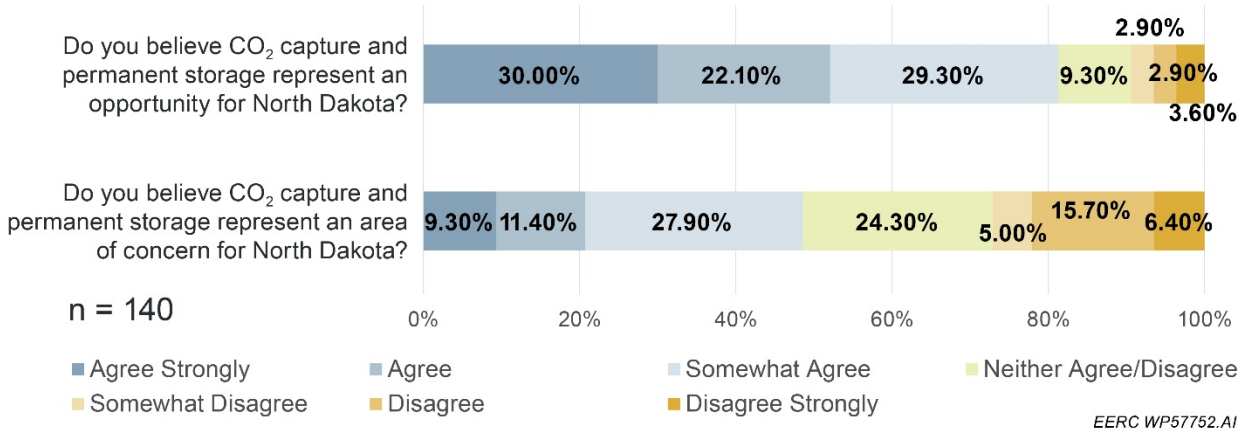


Figure E-12. Public perception of CO_2 capture and permanent storage as opportunity/area of concern.

In the open-ended comments, the areas of opportunity largely focused on the benefits of the geologic storage of CO_2. Areas of concern included risk and safety; pore space management and compensation, overall economic impacts (e.g., cost of electricity, future generation of electricity, etc.), impact of leaks on water quality, potential for induced seismicity, detection of leaks and other risks (e.g., monitoring), and lack of information (e.g., need for more education). Further, at the end of the survey, all online respondents had the chance to state their interest in participating in focus groups to share their opinions in a format where they could converse about survey topics with project staff.

The final questions of the survey were focused on where respondents acquire trustworthy information, both organizations (Table E-8) and media sources (Table E-9). In both cases, the majority of respondents did not recommend any source as "very trustworthy." Proximity appears to be important to establishing trustworthiness, as local sources rated higher than distant or national sources.

Focus Group Participants

A total of 18 people participated in the three groups, with six participants per group. Within the focus group, participants were eight males and ten females. They ranged in age from 22 to 73 years old. In Grand Forks, the participants were a mix of professionals and students. None had ties to the coal industry. In Beulah and Center, participants included retired professionals; business, education, and local government professionals; landowners; and community members. Coal-related industry employees and agricultural producers comprised a minority of the participants. All participants were clearly engaged in the process and the topic.

Table E-8. Trustworthiness of Sources

	Very Trustworthy	Somewhat Trustworthy	No Opinion	Not Very Trustworthy	Not Trustworthy at All
Scientists/Researchers	26.1%	53.7%	9.7%	6.7%	3.7%
Local/Regional Government Agencies/Organizations	21.2%	46.7%	9.5%	16.8%	5.8%
Friends, Neighbors, Family	14.9%	35.8%	34.3%	9.7%	5.2%
Local Civic and/or Community Groups	15.4%	47.8%	22.8%	11.0%	2.9%
Project Developers, Energy Companies	5.9%	48.9%	15.6%	20.7%	8.9%
National Government Agencies/Organizations	6.6%	33.6%	14.6%	32.8%	12.4%
Environmentally-Focused Organizations	5.8%	17.5%	12.4%	24.8%	39.4%
United Nations Organizations	5.9%	14.7%	25.0%	17.6%	36.8%

Table E-9. Trustworthiness of Media

	Very Trustworthy	Somewhat Trustworthy	No Opinion	Not Very Trustworthy	Not Trustworthy at All
Local Newspapers and Television	6.7%	58.5%	14.8%	14.8%	5.2%
National Newspapers	3.7%	26.9%	20.9%	29.1%	19.4%
Web Sites	1.5%	28.1%	28.9%	29.6%	11.9%
National Television Programs	2.2%	28.9%	13.3%	31.9%	23.7%
Social Media	0.0%	7.5%	13.4%	33.6%	45.5%

Focus Group Results

Focus Group Discussion on Risks, Concerns, and Opportunities

The focus groups gave researchers the opportunity to have conversations with participants and gain a deeper understanding of their concerns. Importantly, the final two focus groups were asked to go beyond simply stating their concerns to sharing how they would like their concerns to be addressed, by whom (e.g., scientists, regulators), how best to communicate with citizens and communities (e.g., in-person, social media), and how to tailor messaging to meet the needs of specific communities (e.g., Beulah vs. Center).

Universally expressed among the groups were concerns related to risk to humans and the environment, cost, and time line. Specific example questions show the types and level of information needed to address these concerns:

- More statistics, time line info, and info about direct impacts of CCS would be helpful.
- Is the storage zone being pressurized? If so, is the storage zone likely to puncture and CO_2 more dangerous than compressed air.
- Will the ground get full?
- Is the land safe to use?
- What long-term effects would CCS have?
- What would happen if this goes wrong? What are the possible effects on the geology/groundwater?
- What if it does leak? What would happen?
  - Is it leaking into the atmosphere?
  - Into the drinking water zone?
- The economic value needs to be explained more! How much will it bring in, etc.? Hard numbers, if persuasive, and further information from multiple sources would be great.
- Mentions CO_2 use as a commodity but doesn't explain how.
- How does this play with mineral rights?

Less universally, members of the focus group wanted to tie CCS to broader energy context. Example concerns include:

- How will this affect emissions?
- Why is CCS preferable over entirely renewable energy sources?
- Why is this better than allowing CO_2 emissions into the air?
- Are we going to continue to use fossil fuels?
- My trust/hope for change in North Dakota when it comes to use of fossil fuels is very low, but this has potential to work that edge.
- These [materials] all do have a premise that coal is necessary and will continue for electricity generation. I'm not saying that is wrong but [they] do not clarify how this fits with alternatives.
- Is this a patch or a permanent solution? It is concerning that they want to use it as a permanent thing.
- Rather than feds requiring it, consider "one solution of many."

A combination of CCS in the greater energy context, coal/CCS as part of an all-of-the-above energy strategy, CCS can and would be done safely, cost/benefit explanations, and the long-term plan for monitoring and risk mitigation are key topics for public outreach messaging.

Preferred Messengers

Focus group members preferred multiple sources to one source of information. They expressed concern about the validity of social media outlets. No clear trusted authority was agreed upon in the discussions. Lifelong residents tended to distrust federal authorities as much or more than state authorities; others tended to express a desire for more oversight than the state (U.S. Environmental Protection Agency [EPA], for example). With respect to ensuring drinking water and environmental protection, focus group members were not comforted by authority resting with North Dakota's oil and gas regulators. Suggestions for additional oversight by the North Dakota

Department of Health were met with positive response with the caveat that provisions for and communications regarding real oversight are critical to public acceptance of any plan.

Preferred Messages

The Center focus group was asked to react to several talking points. After review and comment at the end of the focus group, the members were comfortable with the following talking points:

- North Dakota, the only state in the country to receive primary regulatory authority from the EPA, has established laws to regulate CCS to ensure its people, resources, and the environment are protected.
- For CO_2 storage projects, North Dakota law gives pore space ownership to the surface landowner. That ownership cannot (*can never* would be better) be severed, and the landowner must be compensated for permanent CO_2 storage in dedicated storage projects.
- Drinking water will be monitored for changes in quality. In accordance with North Dakota regulations, a groundwater-monitoring well will monitor for potential changes in drinking water quality.
- Injection pressures are regulated by the state of North Dakota and will be kept below levels that could fracture the rock.
- Areas of the country where fluid injection has caused seismic activity have key differences, for example, the presence of active fault systems. These are not relevant factors for the CCS projects being considered in North Dakota. CO_2 injection in North Dakota would not cause seismic activity (earthquakes).

These talking points would be a good starting point for more in-depth conversation.

APPENDIX E-2

INFOGRAPHICS

NORTH DAKOTA IS A GREAT PLACE FOR CCUS

CARBON CAPTURE, UTILIZATION, AND STORAGE (CCUS) ADDRESSES AN ENVIRONMENTAL CHALLENGE, AND NORTH DAKOTA IS A GREAT PLACE TO DO IT.

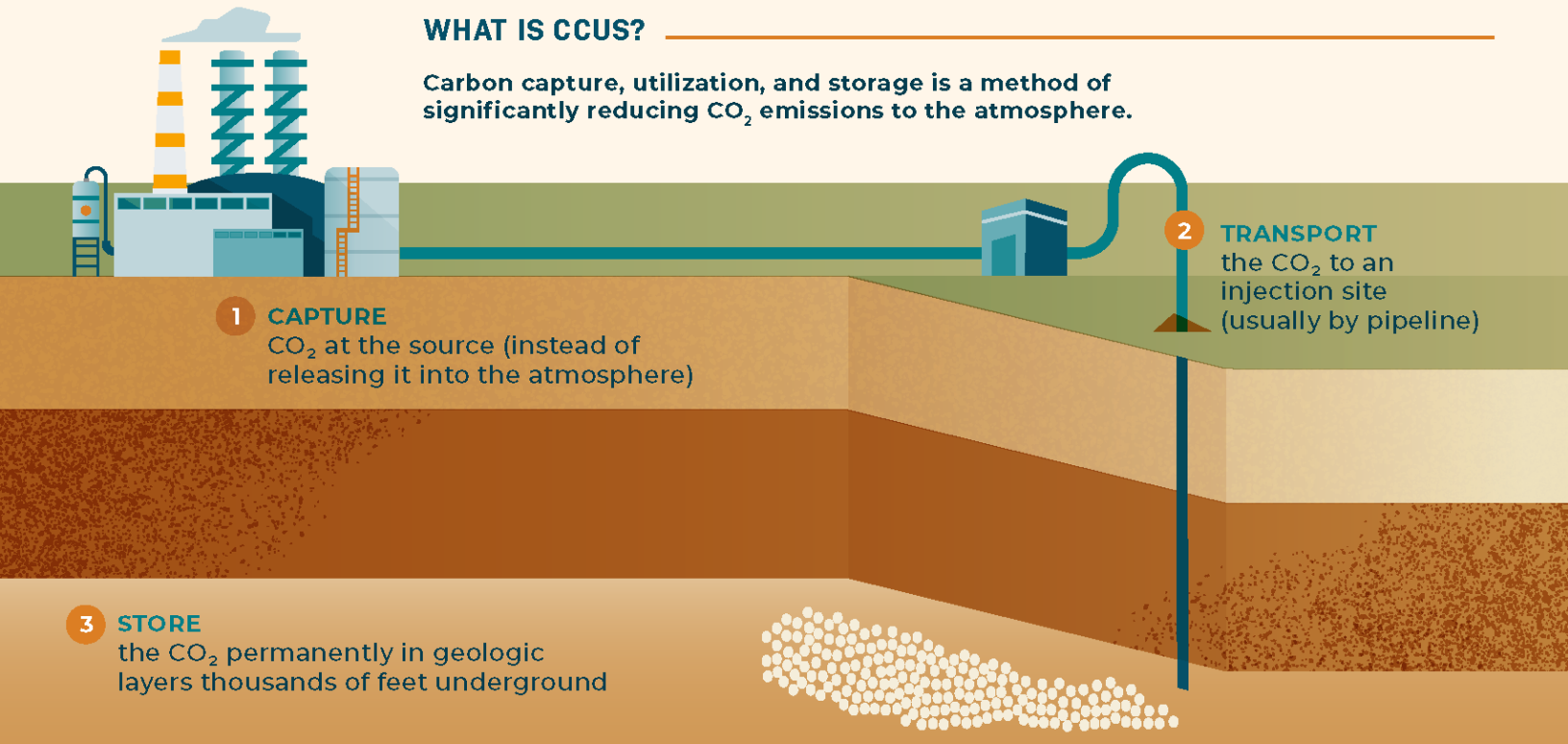
Scientists are concerned that increased greenhouse gases from human activities are contributing to climate change.

Carbon dioxide from North Dakota's energy development and consumption is one of those greenhouse gases.

CCUS reduces CO_2 emissions from large, stationary sources.

WHAT IS CCUS?

Carbon capture, utilization, and storage is a method of significantly reducing CO_2 emissions to the atmosphere.



1 **CAPTURE**
CO_2 at the source (instead of releasing it into the atmosphere)

2 **TRANSPORT**
the CO_2 to an injection site (usually by pipeline)

3 **STORE**
the CO_2 permanently in geologic layers thousands of feet underground

WHY NORTH DAKOTA IS A GREAT PLACE FOR CCUS!

MULTIPLE LARGE SOURCES OF CARBON DIOXIDE EMISSIONS THAT ARE IMPORTANT TO THE ECONOMY AND QUALITY OF LIFE IN A VARIETY OF WAYS

Produce energy

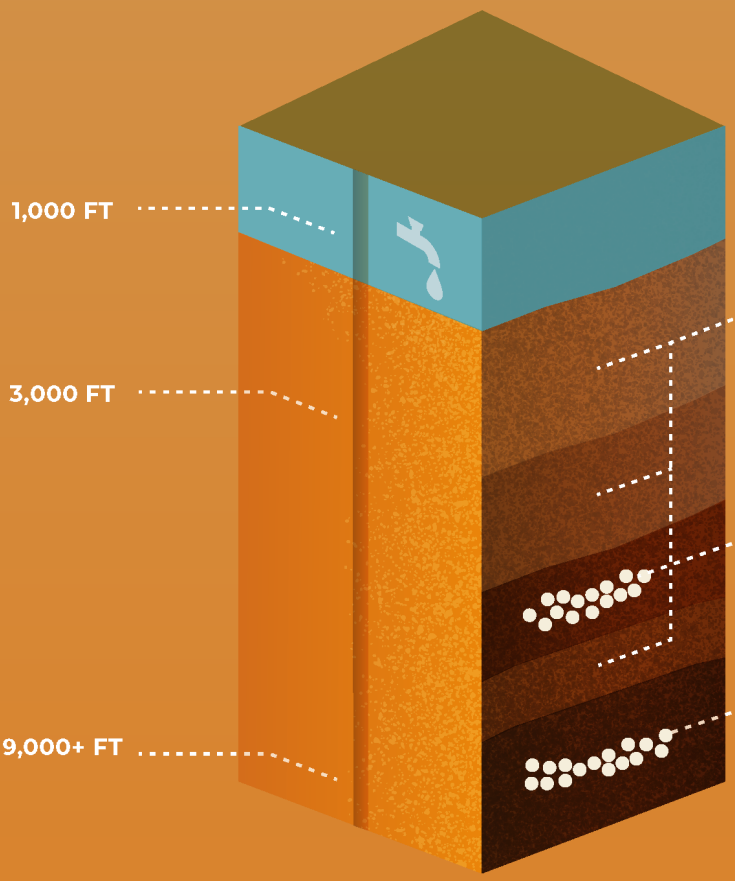
Provide economic benefits like jobs

These CO_2 sources include various industrial plants:

Agricultural processing (ethanol)

Coal-based facilities (electrical generation, gasification)

THE RIGHT GEOLOGY FOR SAFE, PERMANENT STORAGE IN DEEP, DEEP ROCK LAYERS



STABLE GEOLOGY

- Very low risk for seismic events

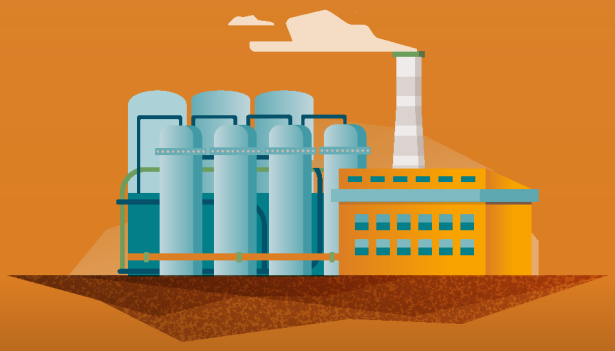
CAP ROCKS

- Impermeable rocks prevent salty water and CO_2 from leaving the injection zone

INJECTION ZONES

- Porous rocks containing salty water
- Older oil fields that might use CO_2 to produce more oil while permanently storing CO_2
- North Dakota's potential injection zones are large enough to hold all the CO_2 from coal-based energy facilities

CO_2 SOURCES LOCATED NEAR POTENTIAL PERMANENT STORAGE SITES



THE RIGHT REGULATORY, INDUSTRY, AND POLICY ENVIRONMENT

- Structure to oversee safe, permanent CO_2 injection and storage
- Authority to regulate CO_2 injection wells
- Long-term liability laws for the permanently stored CO_2
- State regulatory agencies familiar with the state's subsurface geology
- Experience with CO_2 pipelines

SUPPORT THE DEVELOPMENT OF CCUS IN NORTH DAKOTA AS A CLEAN ENERGY STRATEGY.

LEARN MORE AT UNDEERC.ORG

EERC
UNIVERSITY OF NORTH DAKOTA
U.S. DEPARTMENT OF ENERGY | NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

Keeping an Eye on Injected CO_2

CCUS MONITORING

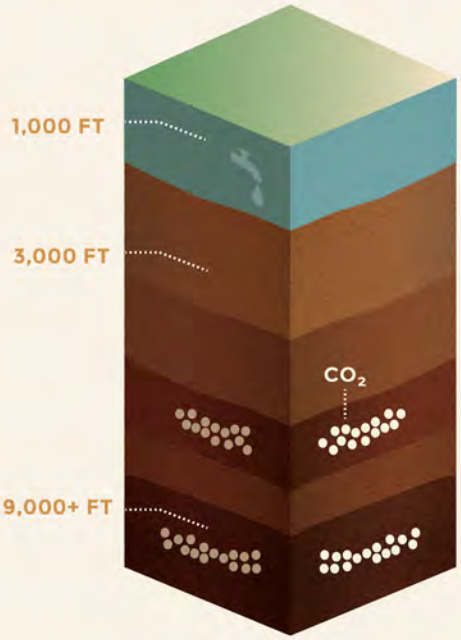
Permanently storing CO_2 captured from industrial sources can help address climate change concerns.

HOW DO WE KNOW THE PROCESS IS SAFE?

CO_2 capture, utilization, and storage (CCUS) projects are designed to be safe for humans and the environment. Plans and operations throughout the CCUS project ensure the CO_2 will stay within the geologic rock layer into which it's injected.

BEFORE THE PROJECT BEGINS:

CCUS professionals select only the best sites for safe, permanent CO_2 storage



CONTAINMENT
Sealed container (sealing or cap rocks above the storage zone)

CAPACITY
More than enough space to hold all the injected CO_2

STABILITY
No geologic faults in the surrounding rock

DEPTH
Ample barriers between the storage zone and sources of drinking water

CHEMISTRY
Rock compatible with CO_2 injection

PRESSURE
Injection pressure won't break rock layers

Predict lateral movement of CO_2 in the storage zone

How far will the CO_2 move over time?

How fast?

Seek project approval from North Dakota regulatory authority to operate storage facilities and inject CO_2

- ✓ Provide proof that the permanent storage container is safe
- ✓ Provide plans for:

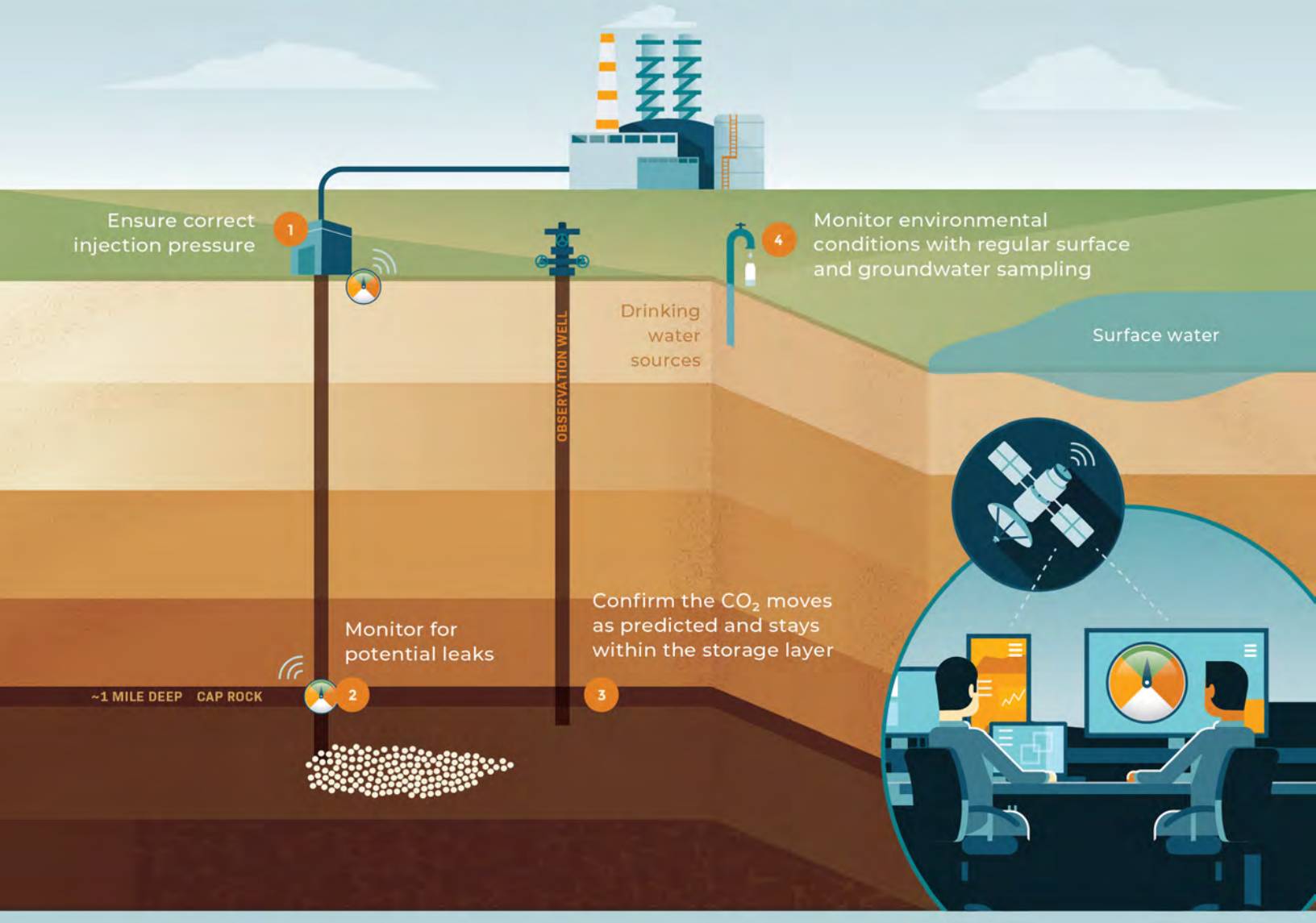
Safe injection and monitoring

Leak detection and reporting

Risk assessment and mitigation

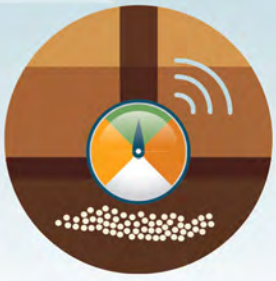
Post-injection site care and closure

DURING THE CO_2 INJECTION PHASE:



AFTER THE CO_2 INJECTION PHASE HAS ENDED:

Continue monitoring according to permit plan until the CO_2 stops moving (at least 10 years)



DEEP UNDERGROUND MONITORING

Monitor to ensure that the CO_2 remains securely stored in the storage zone

AT/NEAR THE SURFACE MONITORING

Monitor environmental conditions to assure no effects from CCUS

Support the development of CCUS in North Dakota as a clean energy strategy.

LEARN MORE AT UNDEERC.ORG

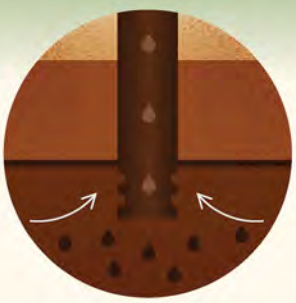
EERC
UND UNIVERSITY OF NORTH DAKOTA
U.S. DEPARTMENT OF ENERGY | NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

CO_2 ENHANCED OIL RECOVERY:
GREENER OIL

As global energy demand continues to increase, energy producers aim to produce more and "greener" oil—that is, oil with a reduced carbon footprint—through a process called CO_2 enhanced oil recovery (EOR).

PRODUCING OIL FROM RESERVOIRS

Stages of oil production



PRIMARY RECOVERY

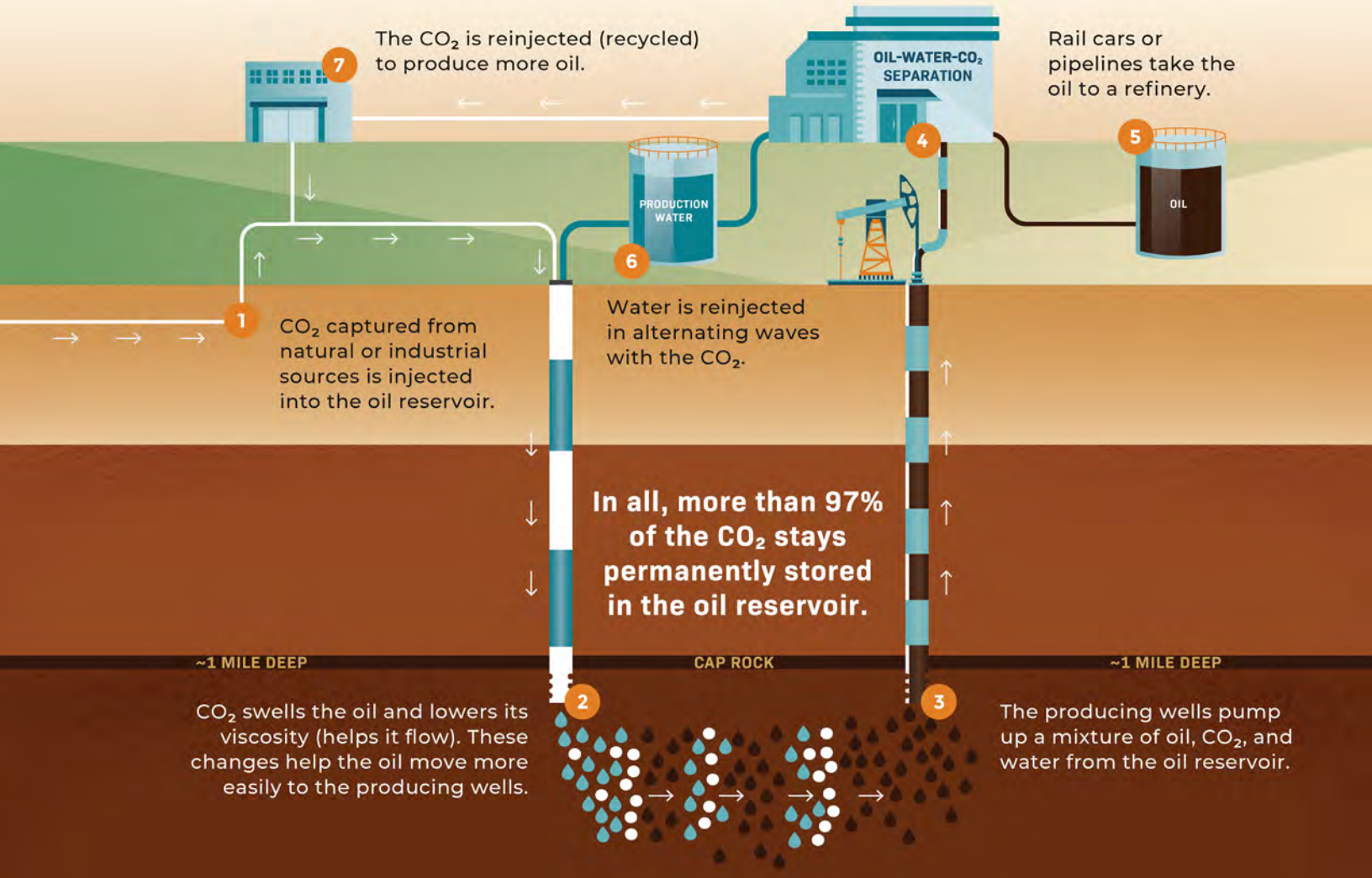
Natural pressure of the reservoir pushes some of the oil to producing wells where pumps bring the oil to the surface.

SECONDARY RECOVERY (WATER FLOODING)

Water injected into the reservoir increases pressure and pushes more oil to producing wells.

TERTIARY RECOVERY (CO_2 EOR)

Injected CO_2 mixes with oil and causes more of the oil to flow to the producing well.



BENEFITS

Using CO_2 captured from industrial sources like power plants, ethanol plants, and gas processing plants for enhanced oil recovery:

- Produces greener oil with a smaller carbon footprint because CO_2 is permanently stored in the process
- Provides economic incentive to capture the industrial CO_2, as the CO_2 is sold to offset the cost of capture
- Enhances energy security with homegrown oil production
- Generates and maintains well-paying jobs, tax base, and viable communities
- Reduces industrial CO_2 emissions to the atmosphere

LOCATION

North Dakota's older (conventional) oil fields

When the market is ready, CO_2 EOR will revitalize older oil fields that are in declining stages of production.

North Dakota's Bakken (unconventional) oil fields

When the technology is ready, CO_2 EOR can be applied to declining Bakken oil wells to improve production.

SAFETY

- Oil reservoirs can hold CO_2 the same way they've been holding oil and gas for millions of years.
- The oil industry has 40+ years of CO_2 EOR experience.
- 4,000+ miles of CO_2 pipelines in North America move CO_2 every day without incident.
- North Dakota's stable geology is ideal for CO_2 EOR.
- Millions of additional barrels of oil have been safely produced (Texas, Saskatchewan, Montana, Mississippi).

Support the development of CCUS and CO_2 EOR in North Dakota as a clean energy strategy.

LEARN MORE AT UNDEERC.ORG

EERC
UND UNIVERSITY OF NORTH DAKOTA
U.S. DEPARTMENT OF ENERGY | NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

APPENDIX F

NATIONAL RISK ASSESSMENT PARTNERSHIP (NRAP) VERIFICATION

NATIONAL RISK ASSESSMENT PARTNERSHIP (NRAP) VERIFICATION

INTRODUCTION

The National Risk Assessment Partnership (NRAP) is a multinational laboratory effort led by the U.S. Department of Energy National Energy Technology Laboratory. The goal of NRAP is to develop quantitative, science-based methods for estimating long-term environmental risks related to potential leakage and induced seismicity regarding the long-term storage of carbon dioxide (CO_2). To address this goal, NRAP has developed a suite of risk assessment tools based on reduced-order modeling (ROM) approaches.

As part of the risk assessment activities of this investigation, the EERC tested several of the NRAP tools with data inputs derived from the GPSP and MRYS sites. The NRAP tools provided assessments of the project storage complex similar to the characterization, modeling, and simulation assessments described earlier in this report. The five NRAP tools tested using project-specific data were the following:

- RROM-Gen (Reservoir Reduced-Order Model – Generator), Version 2017.03-1.2.1
- REV (Reservoir Evaluation and Visualization), Version 2017.03-1.2.1
- WLAT (Wellbore Leakage Analysis Tool), Version 2016.11-1.0.0.3
- GMPIS (Ground Motion Prediction applications to potential Induced Seismicity) Version 2016.11-1.0.0.3
- NRAP-Open-IAM (open-source Integrated Assessment Model [IAM] for Phase II of NRAP)

The remainder of this document provides a brief overview of each NRAP tool, describes the inputs and assumptions that were used to evaluate each tool, and summarizes the results, key findings, and recommendations.

NRAP TOOLS OVERVIEW

RROM-Gen

RROM-Gen is used to convert reservoir simulation results at the reservoir–seal interface layer into a usable input format for Open-IAM. Converting reservoir simulation results into a format acceptable to NRAP-IAM-carbon storage (CS) requires two main steps: 1) the results need to be translated onto an acceptable grid (specifically 100 × 100) and 2) the data on an acceptable grid must be written into the appropriate file format. RROM-Gen automates both of these steps and uses piecewise bilinear interpolation to translate the reservoir simulation data onto an acceptable grid. The new grid data are then output in the format specified by NRAP-IAM-CS. RROM-Gen allows user inputs to define the grid size for conversions and produces a graphical output for review (King, 2016b).

REV

REV is used to transform the outputs of reservoir simulations into three simple metrics for studying reservoir performance as it relates to risk for carbon storage: 1) CO_2 plume size (identified as the CO_2 saturation above a specified threshold), 2) differential pressure plume size (identified as differential pressure above a specified threshold), and 3) pressure profiles at specified locations in the reservoir. REV takes outputs from a three-dimensional (3-D) reservoir simulation model and converts them to a two-dimensional (2-D) view of the CO_2 or pressure plume over each of the specified time steps. Since this tool only explores the behavior of the storage unit and not the overlying formations or leakage pathways, the metrics computed by the tool are not calculations of risk, but rather insights on how the CO_2 or pressure plumes are expected to evolve within the storage unit (King, 2016a).

WLAT

WLAT includes four separate ROMs for estimating CO_2 or brine leakage through a wellbore that penetrates the seal and therefore provides a potential leakage pathway from the storage unit to overlying formations. The four ROMs included in WLAT are 1) cemented wellbore model, 2) multisegmented well model, 3) brine leakage model, and 4) open wellbore model. Each of the ROMs within WLAT can be used to estimate the rates of CO_2 or brine leakage into overlying formations given different input assumptions, well geometries, and leakage scenarios (Huerta and Vasylkivska, 2016).

GMPIS

GMPIS is designed to calculate ground motion predictions and generate ShakeMaps to assess potential risks associated with induced seismicity. GMPIS uses ground motion prediction equations to calculate peak ground acceleration and velocity for earthquakes induced by CO_2 injection or faults that were reactivated by CO_2 injection. The ground motion prediction equations were modified from equations developed using data from active geothermal sites and tectonic earthquakes in the western United States (Bradley and others, 2016).

NRAP-Open-IAM

NRAP-Open-IAM is currently in active development, and its availability is for testing and feedback only (King and others, 2019). This version will replace the previous NRAP-IAM-CS, Version 2016.11-1.1 (Stauffer and others, 2016). Essentially, NRAP-Open-IAM integrates inputs from a reservoir simulation and allows the user to simulate leakage of CO_2 or brine through the storage complex using stochastic simulation within different modules. The value of this stochastic approach is that the results provide a probability distribution of potential impacts rather than discrete point estimates using a fixed set of inputs.

GEOLOGIC MODEL AND RESERVOIR SIMULATIONS

The geologic model and reservoir simulation input for evaluating the NRAP tools was exported from one of the Computer Modelling Group Ltd. Generalized Equation-of-State Model (CMG-GEM) simulations generated for the North Dakota CarbonSAFE project. The CMG-GEM

model represents an areal extent of approximately 25 mi by 20 mi roughly centered on the Milton R. Young Station (MRYS) near Center, North Dakota. The MRYS study area represents one of the two storage complexes that were evaluated under the North Dakota CarbonSAFE project. The other study area was centered around the Basin Electric Power Cooperative (BEPC)-owned Dakota Gasification Company (DGC) Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota, which currently captures, compresses, and transports CO_2 emissions from a coal gasification process. Both study areas were evaluated under similar injectivity constraints of 2 million tonnes (Mt) per year, and both study areas have similar stratigraphy. Thus, in terms of NRAP tools testing, these two study areas were viewed as interchangeable and the MRYS study area was selected for all of the NRAP tools testing.

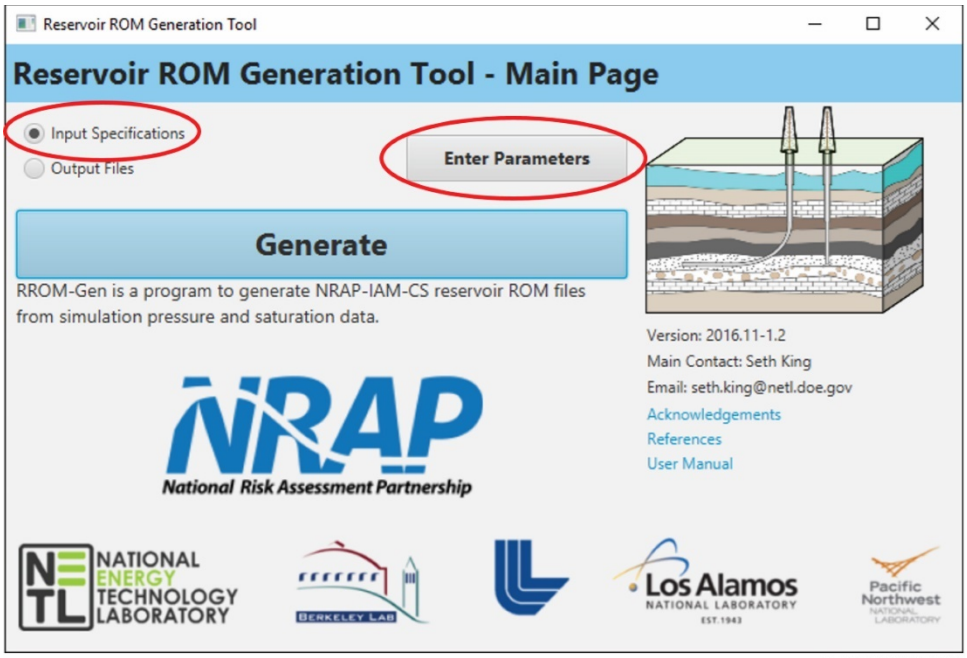
RROM-GEN TESTING SUMMARY

RROM-Gen was used to convert reservoir simulation outputs into usable formats for input into NRAP-Open-IAM. The input for RROM-Gen included pressure and saturation time series output from a reservoir simulator. An assessment of the quality of the conversion was done by visually comparing the output from the CMG-GEM reservoir simulation to the output from RROM-Gen.

Inputs and Assumptions

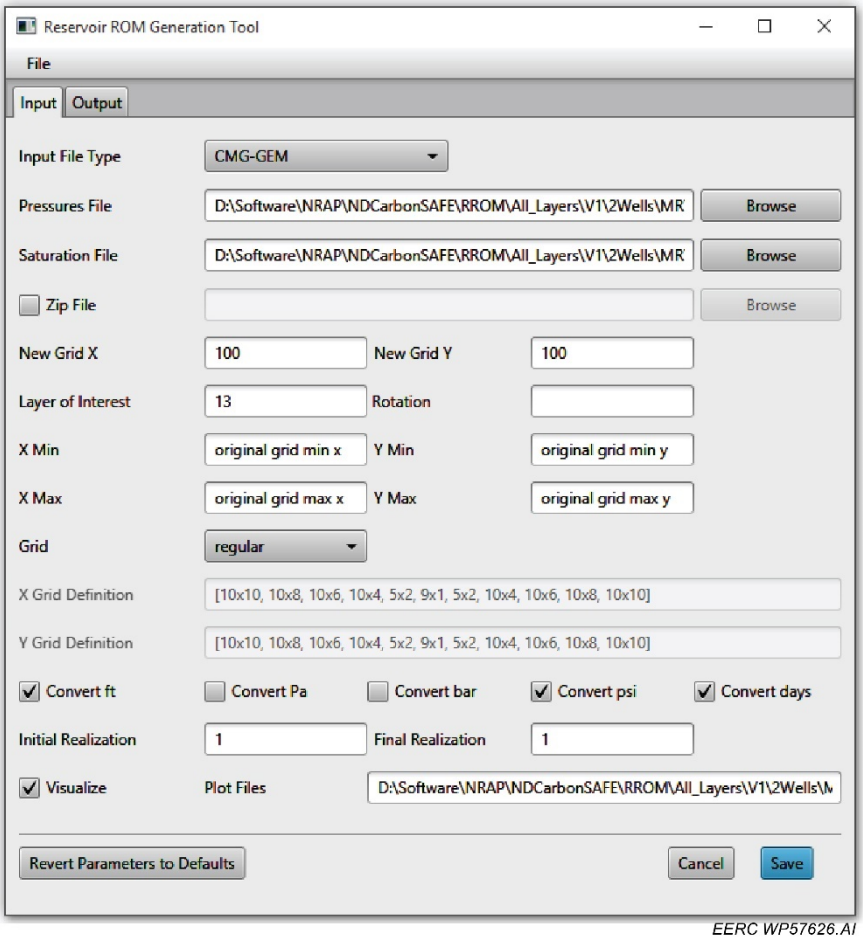
The inputs to RROM-Gen started with launching the tool, opening the main page, selecting the input specifications radio button, and selecting enter parameters, as shown in Figure F-1. This step opened the Input/Output page, as shown in Figure F-2.

The input files for RROM-Gen were simulation results that were exported from CMG-GEM for pressure and gas saturation (CO_2) over the 25-year period of CO_2 injection for the reservoir–seal interface. The Input File Type was therefore set to CMG-GEM (Figure F-2). The process of exporting these files from CMG-GEM included the following sequence of steps.



EERC WP57625.AI

Figure F-1. RROM main page (Source: King, 2016b).



EERC WP57626.AI

Figure F-2. RROM-Gen input/output page.

Step 1 – Layer Selection in CMG-GEM

The input to RROM-Gen requires pressure and gas saturation from the reservoir–seal interface layer of the geologic model. One issue that was encountered was that the Petrel model that was used to generate the geologic model for the CMG-GEM simulations was constructed using proportional gridding. Proportional gridding divides the model into layers of equal thickness based on the desired number of layers. Proportional gridding is the preferred layering method for reservoir simulation because it makes a relatively simple cellular geometry (Shepherd, 2009). Consequently, because proportional gridding was used, the reservoir–seal interface within the model was not designated as a single model layer. Based on NRAP reports from Phase I efforts, the layer representing the uppermost reservoir layer with the highest CO_2 saturation was chosen for regridding with RROM-Gen. This layer of interest was chosen because of its location near the top of the reservoir and the highest CO_2 saturation in order to test a worst-case scenario (Figure F-3).

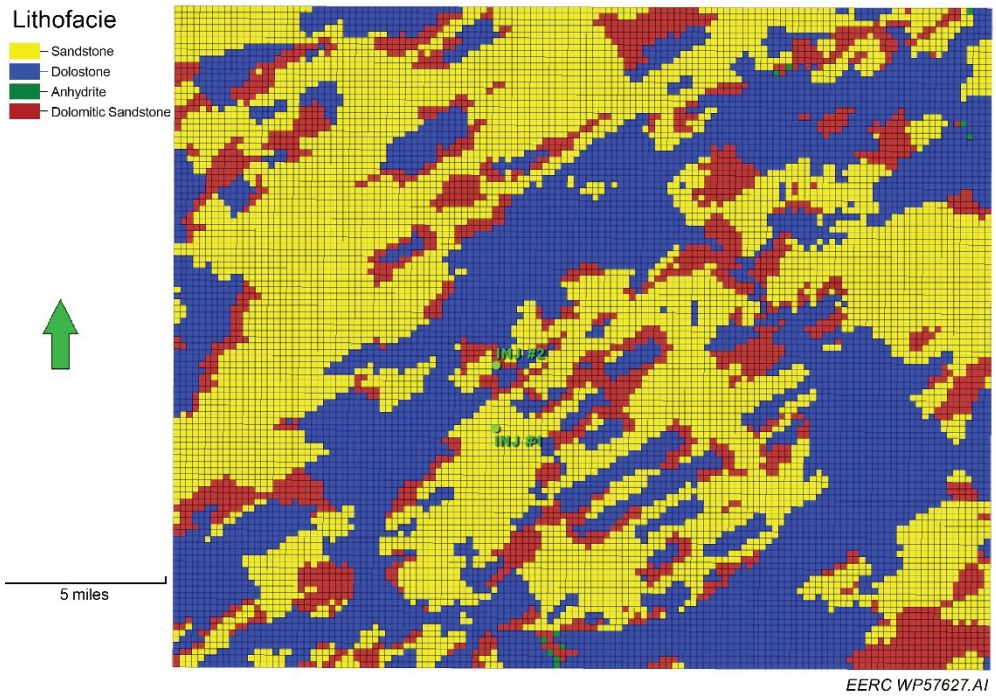


Figure F-3. Petrel model screenshot showing the layer of interest (Layer 14) for the MRYS Version 1 model and the two injection wells (INJ #1 and INJ #2).

One of the findings during the layer selection process was that when using CMG-GEM results with RROM-Gen, care must be taken to ensure that the correct layer of interest is selected. The layer of interest exported from RROM-Gen is actually the CMG-GEM layer plus one. For example, if Layer 14 in the CMG-GEM model is the desired layer, then the user must select Layer 13 as the layer of interest in RROM-Gen.

Step 2 – Data Processing in CMG-GEM

The function model of CMG-GEM was used to set the CO_2 saturation as 0% when the CO_2 saturation in the simulation was less than 0.01%. This preprocessing step in CMG-GEM provided a more consistent output for RROM-Gen. Figure F-4 shows an example screenshot of how the function model statement was used to conduct the truncation to 0.01% saturation.

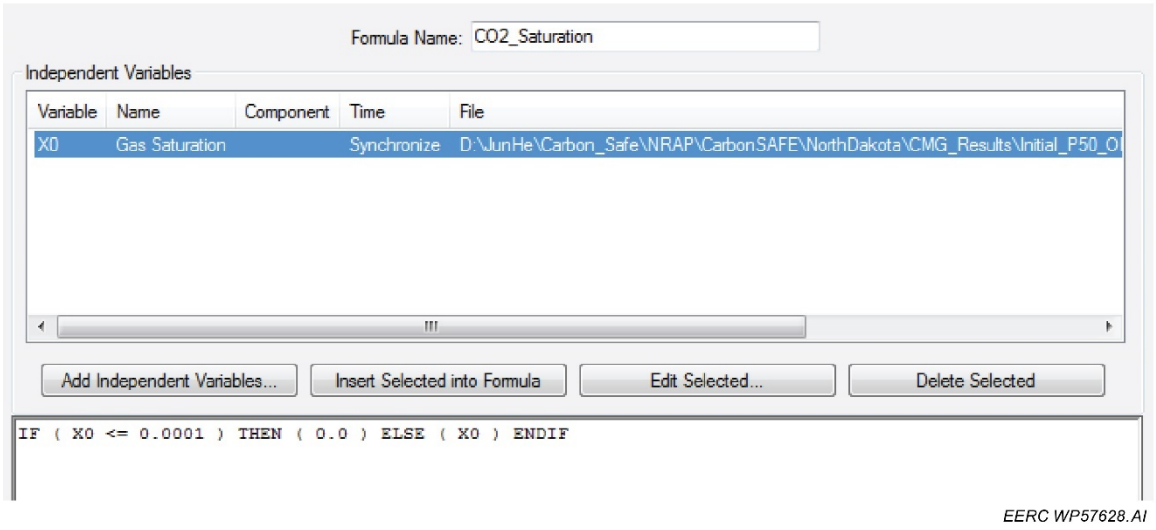
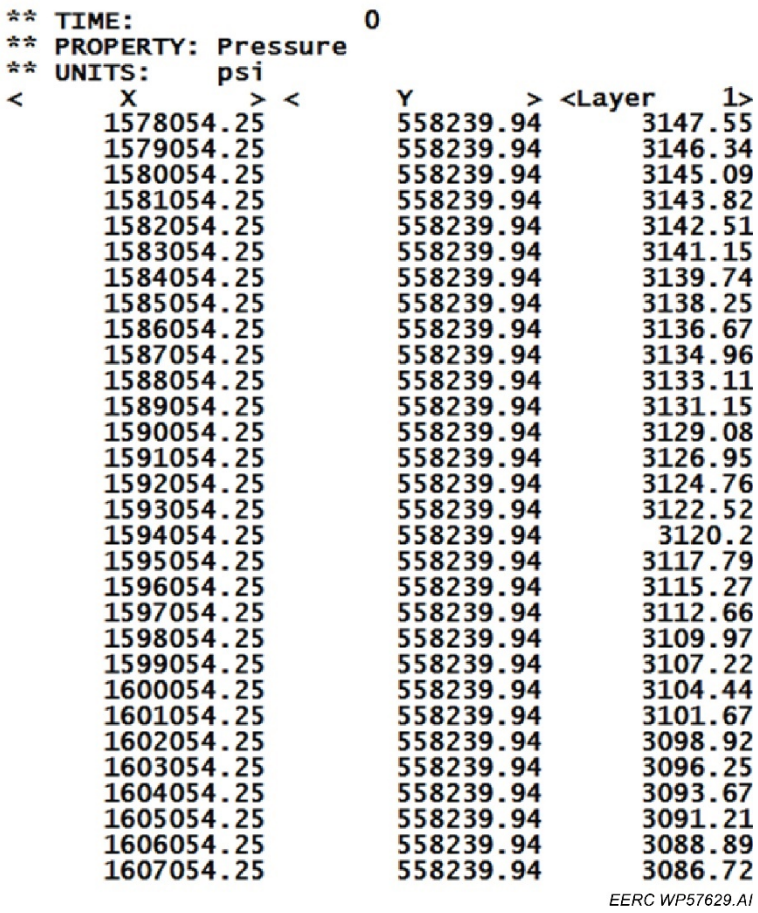


Figure F-4. Screenshot of CMG-GEM's function model showing the process for setting CO_2 saturation as 0% whenever the CO_2 saturation in the simulation was less than 0.01%.

Step 3 – Pressure and Gas Saturation Export from CMG-GEM

Both pressure and CO_2 saturation of all model layers were exported from CMG-GEM with XYZ format. Figure F-5 shows an example pressure output file with the X- and Y-coordinates of the geologic model grid and the pressure in psi for the initial and final time steps.



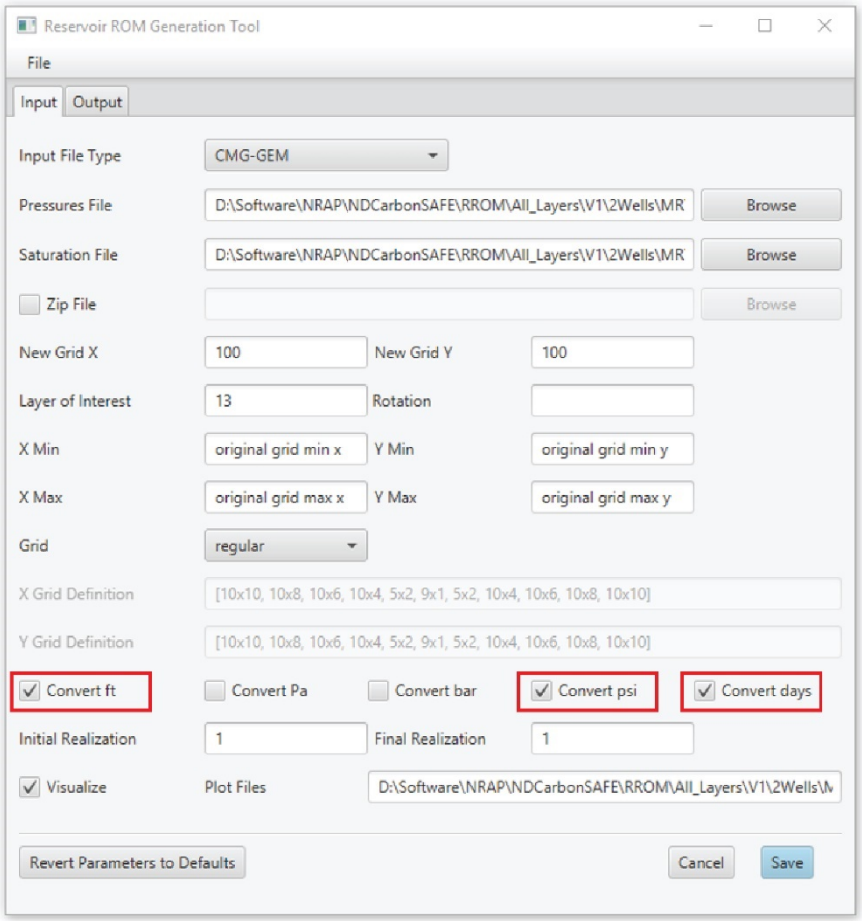
```
** TIME:              0
** PROPERTY: Pressure
** UNITS:    psi
<       X       > <       Y       > <Layer    1>
      1578054.25          558239.94       3147.55
      1579054.25          558239.94       3146.34
      1580054.25          558239.94       3145.09
      1581054.25          558239.94       3143.82
      1582054.25          558239.94       3142.51
      1583054.25          558239.94       3141.15
      1584054.25          558239.94       3139.74
      1585054.25          558239.94       3138.25
      1586054.25          558239.94       3136.67
      1587054.25          558239.94       3134.96
      1588054.25          558239.94       3133.11
      1589054.25          558239.94       3131.15
      1590054.25          558239.94       3129.08
      1591054.25          558239.94       3126.95
      1592054.25          558239.94       3124.76
      1593054.25          558239.94       3122.52
      1594054.25          558239.94        3120.2
      1595054.25          558239.94       3117.79
      1596054.25          558239.94       3115.27
      1597054.25          558239.94       3112.66
      1598054.25          558239.94       3109.97
      1599054.25          558239.94       3107.22
      1600054.25          558239.94       3104.44
      1601054.25          558239.94       3101.67
      1602054.25          558239.94       3098.92
      1603054.25          558239.94       3096.25
      1604054.25          558239.94       3093.67
      1605054.25          558239.94       3091.21
      1606054.25          558239.94       3088.89
      1607054.25          558239.94       3086.72
```

EERC WP57629.AI

Figure F-5. Example pressure output file from CMG-GEM showing the X- and Y-coordinates of the geologic model grid and the simulated pressure in psi.

Step 4 – Unit Conversion

The CMG-GEM simulations were conducted in English units of length in feet, pressure in psi, and time increments of days. NRAP-Open-IAM expects input units of length in meters, pressure in MPa, and time in years. The unit conversions in RROM-Gen were used to convert length, pressure, and time from CMG-GEM to the standard units of meters, MPa, and years (Figure F-6).



EERC WP57630.AI

Figure F-6. Example RROM-Gen input screen showing the unit conversion tools used to convert length (ft), pressure (psi), and time (days) from CMG-GEM to the standard units of meters, MPa, and years.

Step 5 – Finalizing the Inputs

All other inputs were held at their default settings. These include 1) X- and Y-dimensions of the new grid, which were held at 100 × 100; 2) minimum and maximum extents of the X- and Y-dimensions; and 3) assumption of a regular grid.

Figure F-7 provides an example screenshot from RROM-Gen showing the user inputs. The input file type was CMG-GEM for all scenarios. Pressure and gas saturation files were imported from the files that were generated in the previous export steps described above. The layer of interest was Layer 13. The final steps were to select the visualize box and to hit save, which generated image files (portable network graphic [.png] format) of pressure and gas saturation.

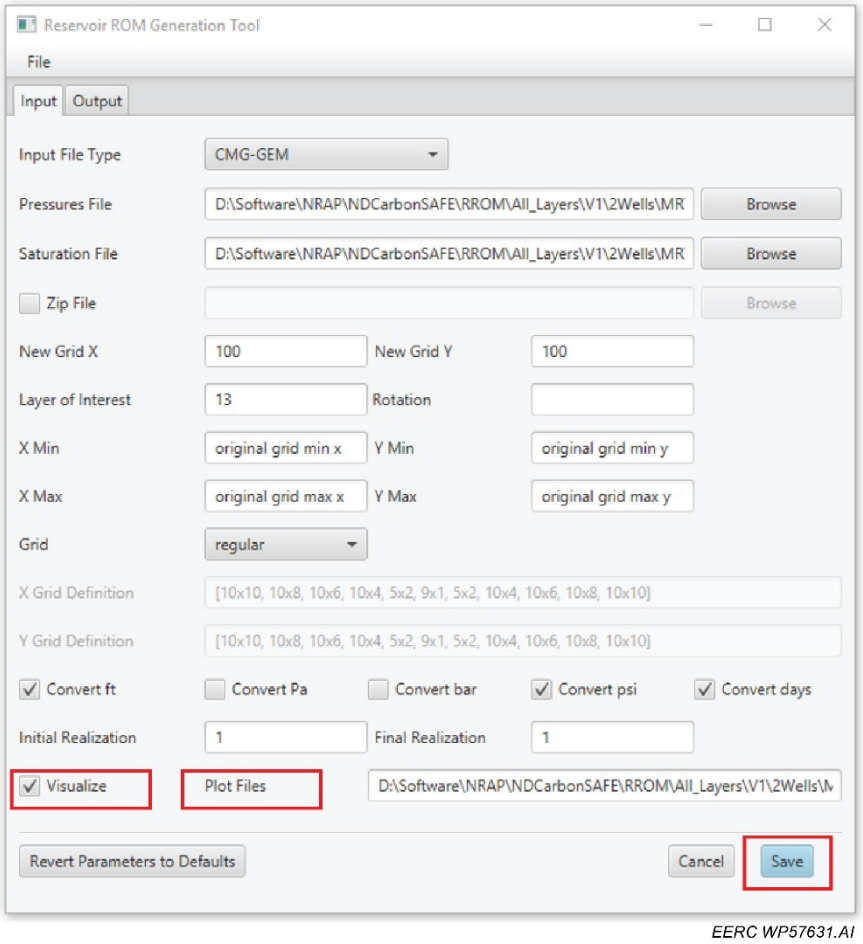


Figure F-7. Example window of RROM-Gen showing the user inputs.

Results

RROM-Gen output consisted of two text files: one for pressure and one for gas saturation. These files are identified in the Output tab, as illustrated in Figure F-8.

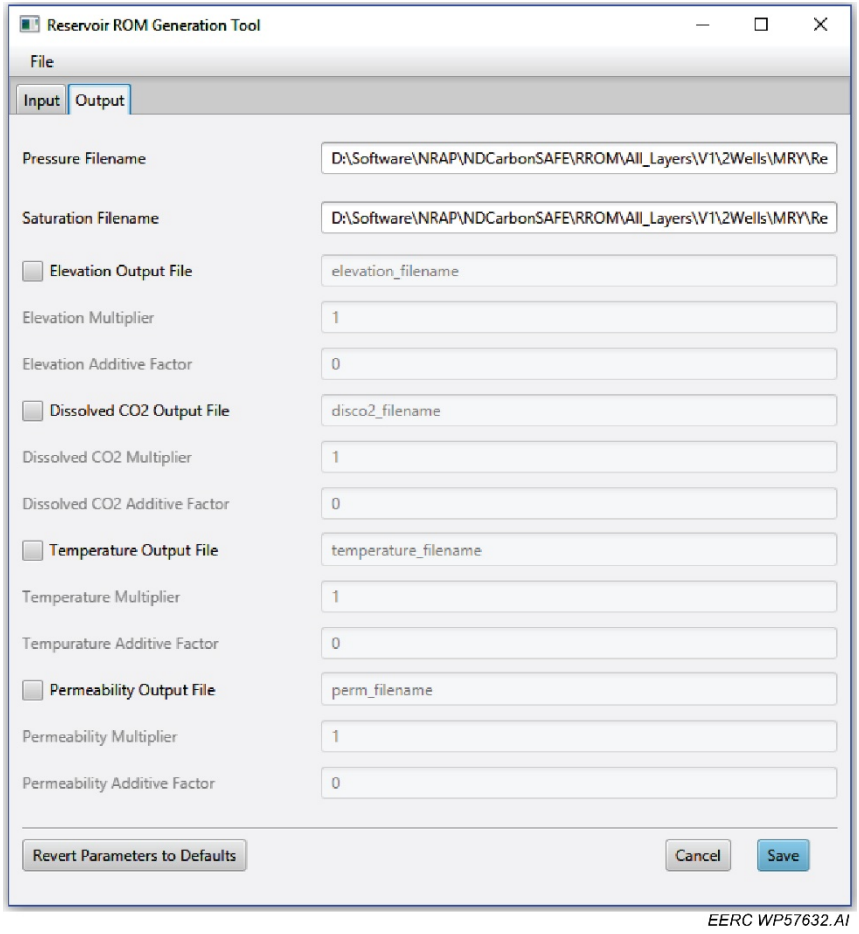


Figure F-8. Example window of RROM-Gen showing the output files.

The pressure and gas saturation output files from RROM-Gen have identical file structure. Figure F-9 provides an example of the pressure output file. This output file contains the following information:

- Line 1 is the size of the file header. The number 3 means that the file header has three lines.
- Line 2 shows the grid size of X (100) and Y (100), and the number of simulation times (301).
- Line 3 is the X-coordinate for each cell in the X-direction; the total number is 100.
- Line 4 is the Y-coordinate for each cell in the Y-direction; the total number is 100.
- Line 5 is the unit of the time for simulation. The letter d means day.
- Line 6 is the time for each simulation. In this case, there are 301 numbers in this line, and the following simulation results will correspond to Day 0, Day 31, Day 59, and so on.
- Line 7 is the beginning of the real value of the simulation result; the total number of each line is 100. Every 100 lines shows the result with the matching simulation time. A total of 30,106 (301 × 100 + 6) lines are in this pressure output file. For this example, the value is pressure. The gas saturation output file would report gas saturation.

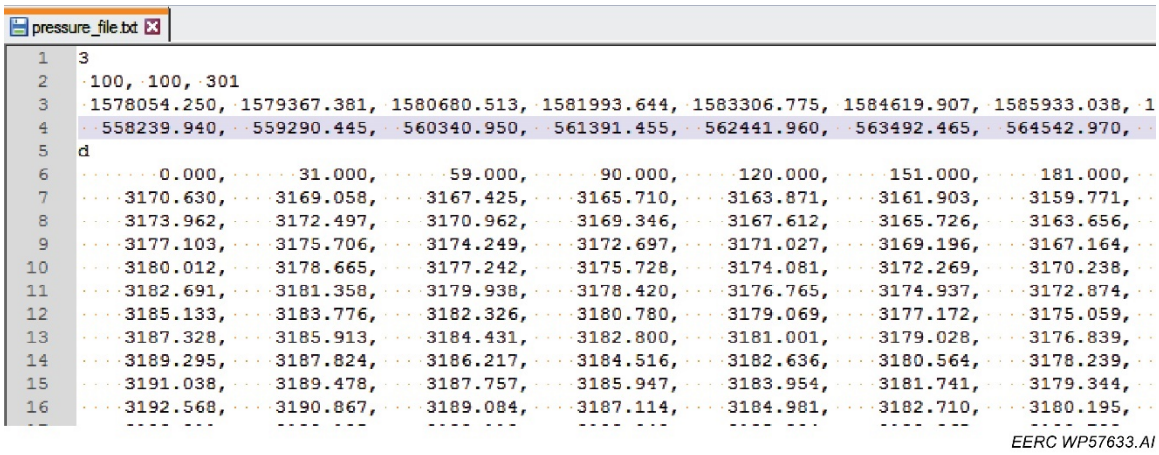


Figure F-9. Example pressure output file from RROM-Gen.

The image file generated by RROM-Gen plots the original data from CMG-GEM and the new data from RROM-Gen side by side to allow visual comparisons between the two products. Figure F-10 shows the results of CMG-GEM outputs and RROM-Gen outputs for the pressure plume (top row) and the CO_2 plume (bottom row) after 25 years of injection. The pressure plume shows a color ramp from higher pressure (red) to lower pressure (blue) in units of MPa. The output generated from RROM-Gen is shown on the right, while the output from CMG-GEM reservoir simulation is shown on the left. The area of highest pressure is located around the injection wells, with a maximum pressure of 18.4 MPa, which decreases toward the baseline (hydrostatic) pressure of 16.9 MPa. A structural feature in the western portion of the model domain results in higher pressure buildup within that portion of the output. While RROM-Gen output captured the overall trends observed in CMG-GEM simulation model, direct visual comparison between these two images was challenging because of perturbations in CMG-GEM output. These perturbations were likely attributable to a lack of graphing capability within RROM-Gen when faced with tight grid data.

The bottom two panels in Figure F-10 show the CO_2 plumes for RROM-Gen output (right) and CMG-GEM reservoir simulation (left). The area of highest gas saturation (highest CO_2 concentration in the subsurface) is located around the injection wells (red) and decreases toward no gas saturation (blue). Similar to the results for the pressure plume, while RROM-Gen output captured the overall trends observed in the CMG-GEM simulation model, direct visual comparison between these two images was challenging because of perturbations in CMG-GEM output.

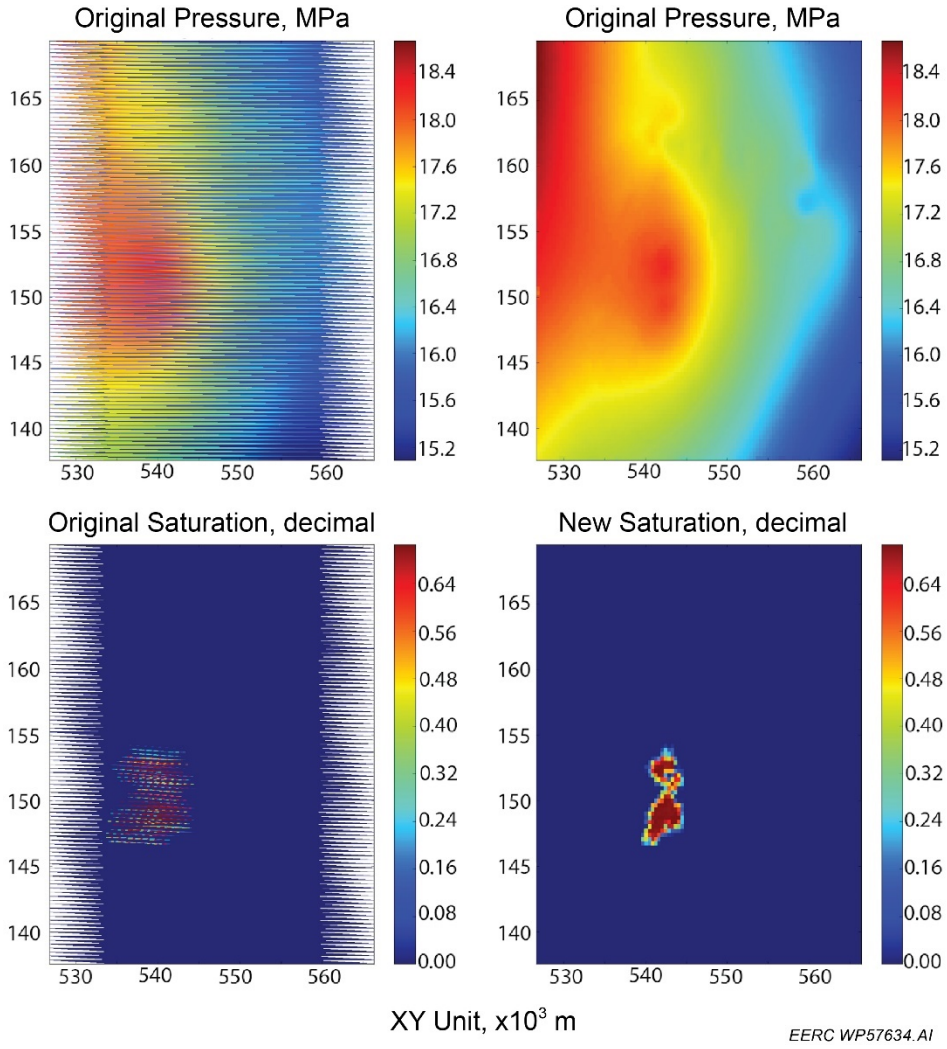


Figure F-10. Comparison of the results from RROM-Gen (right) and CMG-GEM (left) for the pressure plume (top row, MPa) and the CO_2 plume (bottom row, gas saturation) after 25 years of injection.

Key Findings

The process described above for utilizing RROM-Gen resulted in the following key findings:

- **Inputs:** The graphical user interface (GUI) within RROM-Gen for inputting data was functional and allowed for the successful import of CMG-GEM pressure and gas saturation files and unit conversions.

- **Inputs:** Because RROM-Gen extracts data from the reservoir–seal interface layer, that layer must be identified as the layer of interest in the reservoir simulation model. Identifying a single layer of interest that defines the reservoir–seal interface is difficult for geologic models that do not contain a uniform number of cap rock layers.

- **Outputs:** When using CMG-GEM results with RROM-Gen, care must be taken to ensure that the correct layer of interest is selected. The layer of interest exported from RROM-Gen is actually the CMG-GEM layer plus one. For example, if Layer 14 in the CMG-GEM model is the desired layer, then the user must select Layer 13 as the layer of interest in RROM-Gen.

- **Outputs:** RROM-Gen provides a representative visualization of the pressure and CO_2 saturation plumes across the model domain. Visual comparison of RROM-Gen outputs to CMG-GEM reservoir simulation outputs shows that these two outputs are in general agreement. However, the perturbations introduced in RROM-Gen gridding process may affect the subsequent use of RROM-Gen output in downstream NRAP tools like NRAP-Open-IAM.

Recommendations

Consistent with the key findings, the following are two recommendations for improving RROM-Gen:

1. Future release versions of RROM-Gen should allow for inputs from more than one model layer to accommodate geologic models that do not contain a uniform number of cap rock layers (e.g., proportional gridding).

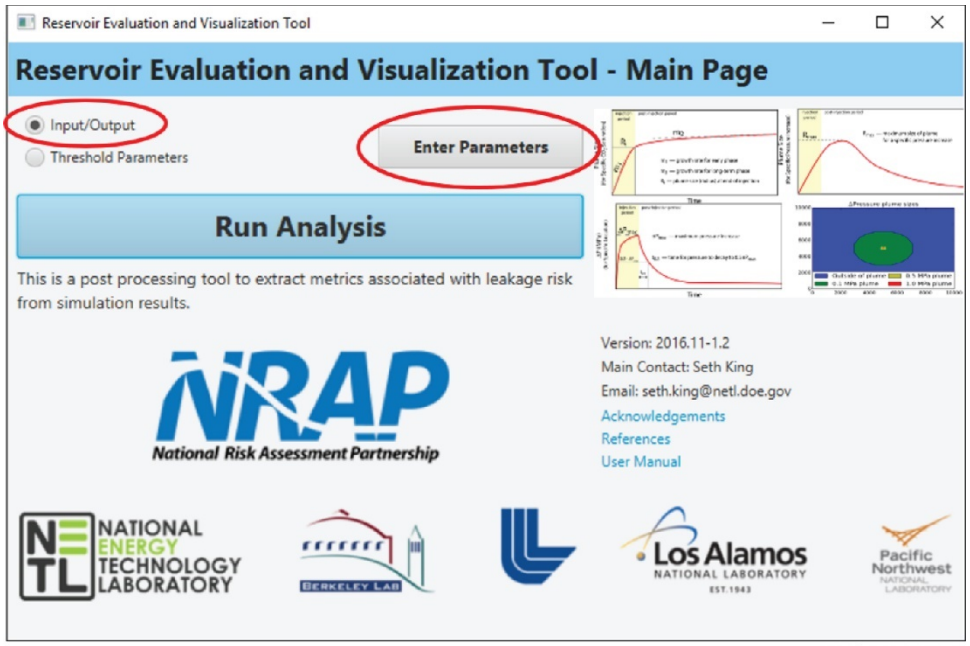
2. Future release versions of RROM-Gen should address the perturbations introduced in the gridding process during conversion from the simulation model grid (e.g., CMG-GEM) to the standardized 100 × 100 grid.

REV TOOL TESTING SUMMARY

REV was used to determine the areal extent of pressure and CO_2 plumes using the CMG-GEM simulation outputs from the MRYS Version 1 model. An assessment of the quality of the conversion was done by visually comparing the output from CMG-GEM reservoir simulation to the output from REV.

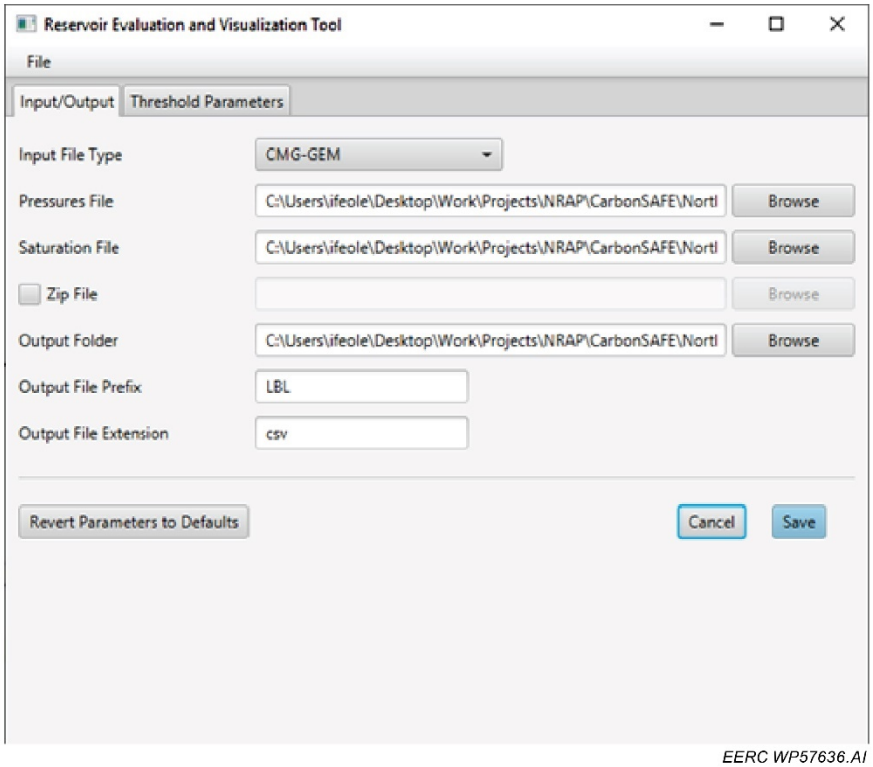
Inputs and Assumptions

The inputs to REV started with launching the tool, opening the main page, selecting the input/output radio button, and selecting enter parameters, as shown in Figure F-11. This step opened the input/output page, as shown in Figure F-12. Similar to RROM-Gen, the input for REV includes pressures and gas saturation time series output from a reservoir simulator. Input CMG-



EERC WP57635.AI

Figure F-11. REV main page (Source: King, 2016a).



EERC WP57636.AI

Figure F-12. REV input/output page.

GEM files for pressure and gas saturation were the same ASCII text files as those used for RROM-Gen testing. The sequence of steps used to generate REV input files is therefore not repeated here.

One difference between the inputs for RROM-Gen and REV is that for REV, specific layers as well as specific time steps can be selected to reduce computing time. For example, the first and final time steps in the CMG-GEM simulation can be exported to show the potential maximum pressure or CO_2 plume extents and significantly reduce REV computing time. The export process for both pressure and gas saturation should use the same number of layers and time steps. After setting the Input File Type to CMG-GEM and selecting the input file and output folder locations, the next step was to set the threshold parameters.

Pressure Threshold Parameters

REV calculates a differential pressure plume size based on a user-specified pressure threshold value. If a grid cell has a pressure value above the specified pressure threshold, then that grid is marked as being inside of the differential pressure plume. Once all of the grid cells are evaluated, the differential pressure plume is then mapped onto the horizontal plane (3-D XYZ domain to 2-D XY domain). This mapping gives an areal extent for the differential pressure plume above the threshold value, and this area is plotted graphically through time and reported quantitatively in the output files (King, 2016a).

As described above, the user must specify the pressure threshold(s). U.S. Environmental Protection Agency (EPA) guidance for area of review (AoR) calculations under the Underground Injection Control (UIC) Program for Class VI wells provides several methods for estimating the critical pressure threshold, which is defined as the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the underground source of drinking water (USDW) through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals (U.S. Environmental Protection Agency, 2013). In the case of the MRYS study area, the injection zone is already overpressurized and thus subject to potential fluid leakage from the injection reservoir to the USDW even prior to the planned storage project. Therefore, the alternative methods provided by EPA for the overpressured case are more applicable.

REV testing used the equations for the hydrostatic case based on displacing fluid initially present in the borehole. The critical pressure threshold may be calculated as:

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

Where ξ is a linear coefficient determined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq. 2]}$$

Where:

ΔP_c is the change in pressure from baseline (hydrostatic) conditions (MPa).
g is the acceleration of gravity (m/s^2).

z_u is the elevation of the base of the lowermost USDW (m).
z_i is the elevation of the top of the injections zone (m).
p_i is the fluid density in the injection zone (kg/m^3).
p_u is the fluid density in the USDW (kg/m^3).

The site-specific inputs for Equations 1 and 2 resulted in an estimated ΔP_c of 0.17 MPa (25 psi), as shown through the series of calculations below:

$$\xi = \frac{1030\,\frac{\text{kg}}{\text{m}^3} - 1000\,\frac{\text{kg}}{\text{m}^3}}{-329\text{ m} - (-1495.7\text{ m})} = 0.0257\,\frac{\text{kg}}{\text{m}^2} \qquad \text{[Eq. 3]}$$

$$\Delta P_c = \frac{1}{2}\left(9.81\,\frac{\text{m}}{\text{s}^2}\right)\left(0.0257\,\frac{\text{kg}}{\text{m}^2}\right)\left(-329\text{ m} - (-1495.7\text{ m})\right)^2 = 0.17\text{ MPa} \qquad \text{[Eq. 4]}$$

In addition to the site-specific estimated ΔP_c of 0.17 MPa, REV testing explored the sensitivity of the differential pressure plume to the threshold value and therefore generated outputs for ΔP_c of 0.13, 0.17, and 0.20 MPa (20, 25, and 30 psi). These inputs are shown in the Δ pressure threshold input line of the threshold parameters page of REV (Figure F-13).

REV includes a built-in utility tool for calculating the pressure threshold using essentially the same approach outlined above in Equations 1 and 2. The user must input the storage reservoir depth, groundwater aquifer depth, brine density, and groundwater density and define the input density units (e.g., kg/m^3) and the desired output units for ΔP_c (e.g., MPa) (Figure F-14). Unfortunately, while using REV it was found that the calculations generated by the tool were not the same as the ones we calculated using the pressure threshold equations (Eqs. 1 and 2). Upon investigation, it was found that the calculator tool was generating pressure threshold values approximately double the value calculated using the pressure threshold equations. It was surmised

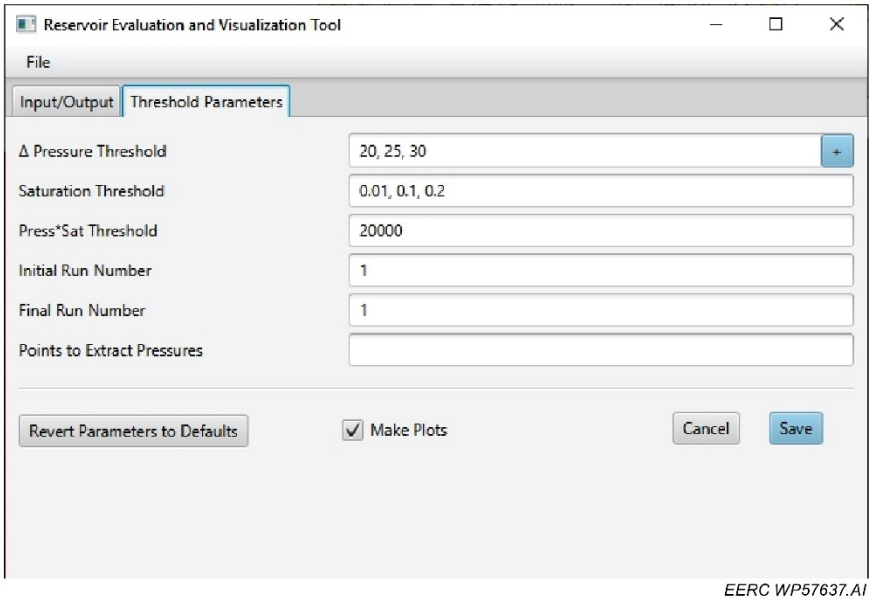


Figure F-13. REV threshold parameters page.

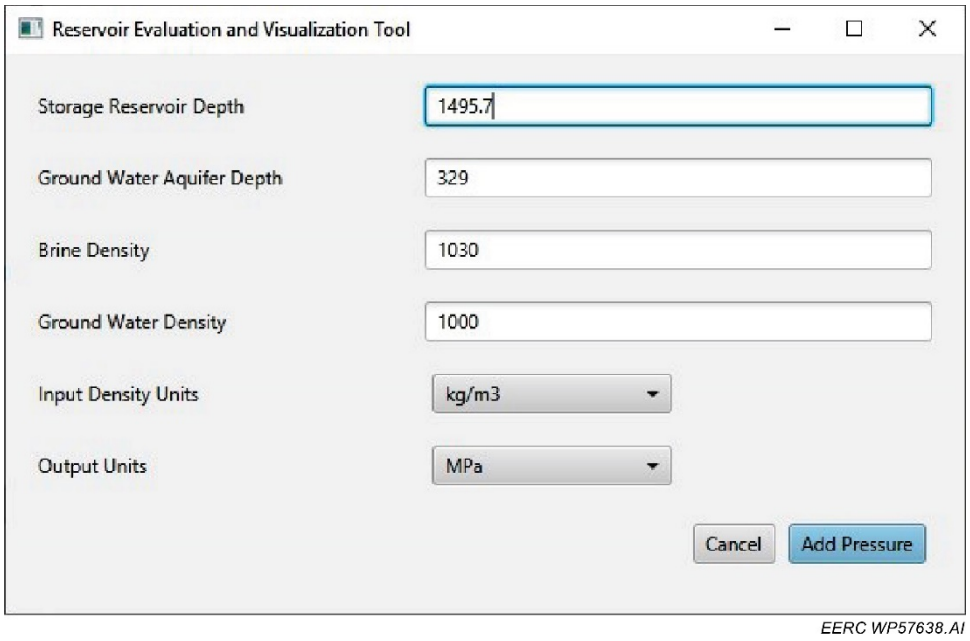


Figure F-14. REV utility for calculating the Δ pressure threshold.

that the discrepancy between the calculator in REV and the calculations we made was that the "½" in Equation 1 was missing from REV. This could account for the REV calculator having double the value of the equation calculation.

CO_2 Saturation Threshold Parameters

Similar to the pressure differential plume, REV calculates a CO_2 plume size based on a user-specified saturation threshold value. If a grid cell has a CO_2 saturation value above the specified saturation threshold, then that grid is marked as being inside of the CO_2 plume. In addition to evaluating a near-maximum areal extent of 1% saturation (saturation threshold = 0.01), REV testing explored the sensitivity of the CO_2 plume to the threshold value and therefore generated outputs for saturation threshold = 0.01, 0.10, and 0.20 (1%, 10%, and 20%, respectively). These inputs are shown in the saturation threshold input line of the threshold parameters page of REV (Figure F-13).

Results

REV provides four different comma-separated values (.csv) file outputs, one for each of the pressure, CO_2, and pressure*saturation thresholds, and one for all of the points to extract pressure. The outputs for pressure, CO_2, and pressure*saturation thresholds give the total area of the pressure or CO_2 plume for each time step. Comparison between the CMG-GEM simulation and REV showed that these area measurements were similar, approximately 1.3E10 ft^2 (466 mi^2) for the differential pressure plume using a threshold ΔP_c value of 0.17 MPa (25 psi).

The .csv file generated for the points to extract pressure gives the pressure at the specified point for each of the time steps in the input file. The four-digit number used by REV for identifying the location of each point to extract pressure uses the first two digits to identify the grid cell X-direction and the second two digits to identify the grid cell Y-direction. However, REV testing was unable to find similar X- and Y-values in the CMG-GEM simulation and could therefore not implement this feature of the tool. This result may have been due to the CMG-GEM simulation having multiple layers of values compared to REV, which only generates one value. Alternatively, this result may have been due to location differences between the plot output in REV and the CMG-GEM simulation. Without a visual aid in REV plots, such an X- and Y-axis, the testing was unable to verify the location of the CMG-GEM point in REV.

REV also provides a graphic, in the form of a .png file, by selecting the make plots option in the threshold parameters page (Figure F-13). However, REV testing found that this graphical tool was limited in its ability to format the graphical display and to compare REV output against the input CMG-GEM reservoir simulations. For example, REV plot output generated an elongated aspect ratio, with a rectangular north–south direction that was longer than the east–west direction. In addition, graphical output for REV does not include X- and Y-coordinates or a scale bar, which limits the direct interpretation of REV outputs with respect to key features of the storage site. In addition, an issue with the REV plot being distorted from banding and feathering limited the utility of REV graphical output for comparisons against CMG-GEM outputs. This banding and feathering issue was rectified by creating an R script that made the input file from CMG-GEM a square instead of its original rectangular form. This correction fixed the banding and feathering issue with the REV plot (Figure F-15).

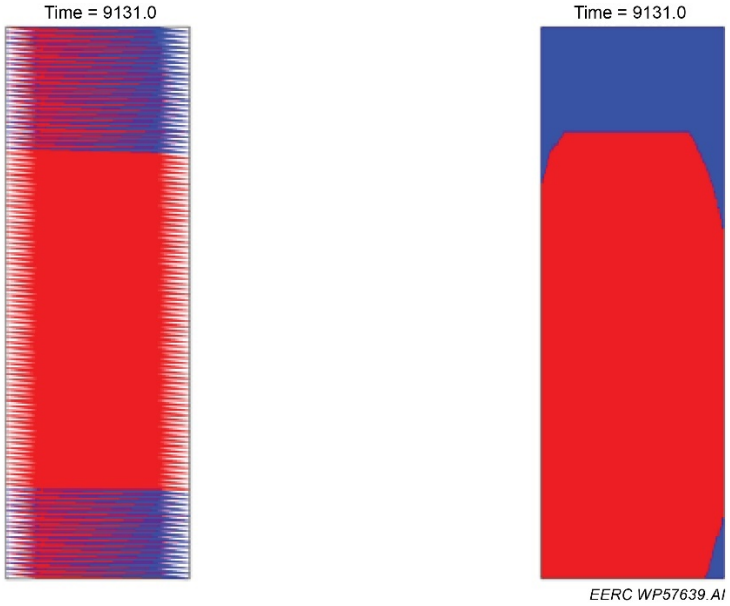


Figure F-15. Plots generated from unaltered inputs from CMG-GEM simulation require modification for distortion correction. Both plots show the REV differential pressure plume using a threshold ΔP_c value of 0.17 MPa (25 psi). The plot on the left side shows the unaltered input into REV, and the plot on the right shows the inputs altered by the R script making the input square.

Figures F-16 and F-17 show the CMG-GEM and REV outputs for the differential pressure plumes and CO_2 plumes, respectively. The differential pressure plumes compare CMG-GEM and REV outputs for a ΔP_c of 0.13, 0.17, and 0.20 MPa (20, 25, and 30 psi), while the CO_2 plumes compare CMG-GEM and REV outputs for saturation thresholds of 1%, 10%, and 20%. These comparisons show that while difficult to directly compare because of the elongated REV plot, the relative plume sizes for pressure and CO_2 look similar between CMG-GEM and REV. This result suggests that REV is generating pressure and CO_2 plume sizes and geometries similar to the CMG-GEM simulation. However, not having the ability to see an X- and Y-axis or scale bar on REV plots limits the ability to directly compare CMG-GEM and REV.

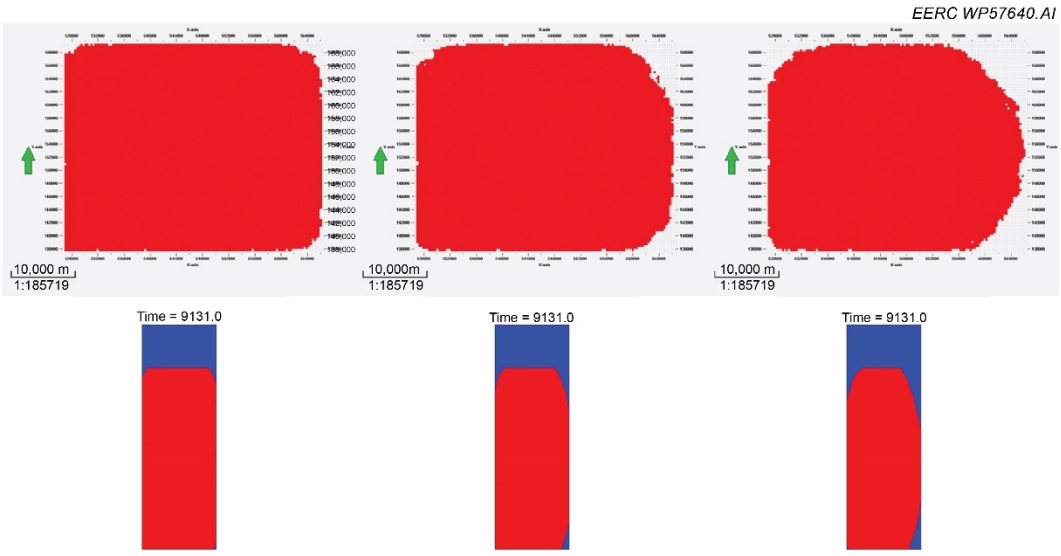


Figure F-16. Comparative assessment of the differential pressure plumes between the CMG-GEM reservoir simulation (top) and REV (bottom). The left, middle, and right columns show the differential pressure plumes assuming ΔP_c 0.13, 0.17, and 0.20 MPa (20, 25, and 30 psi), respectively.

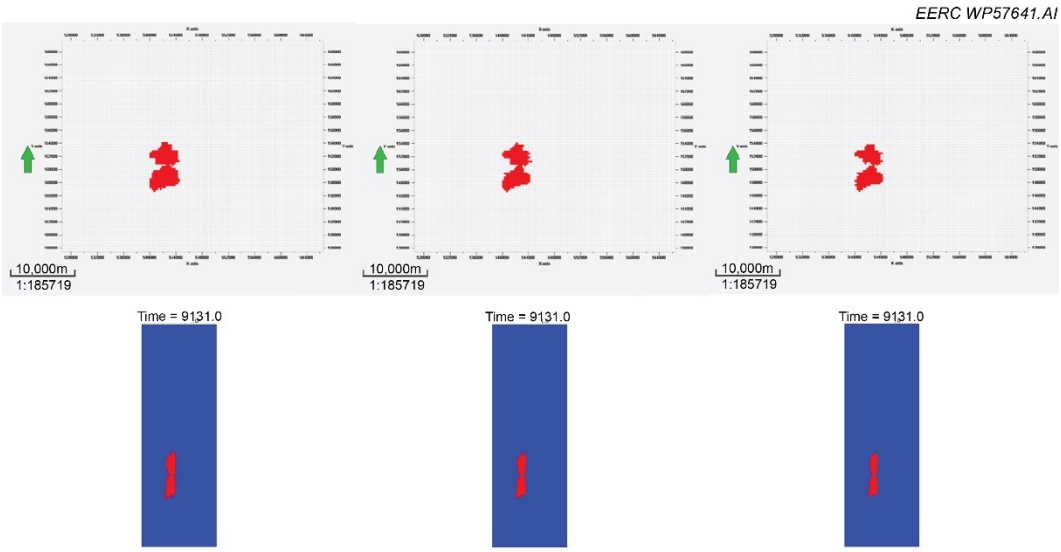


Figure F-17. Comparative assessment of the CO_2 plumes between the CMG-GEM reservoir simulation (top) and REV (bottom). The left, middle, and right columns show the CO_2 plumes assuming saturation thresholds of 1%, 10%, and 20%, respectively.

Key Findings

The process described above for utilizing REV resulted in the following key findings:

- **Inputs:** The utility for calculating the pressure threshold within the threshold parameters page of REV generated incorrect values as compared to the EPA-recommended (2013) approach for estimating ΔP_c. These differences were likely attributable to an issue with the equation used to calculate the pressure threshold for REV. This may be due to the equation used in the REV calculator missing the ½ term in Equation 1, as dividing the REV calculator values by two resulted in similar pressure threshold values to those calculated using Equation 1.

- **Inputs:** The graphical output from REV resulted in a banding and feathering along with the elongated aspect ratio, with a rectangular north–south direction that was longer than the east–west direction. The issue with the edge effect was found to be due to a nonsquare model grid size in the CMG-GEM reservoir simulation. To correct the problem, the outputs from the CMG-GEM simulation had to be resized using an R script that was created by EERC staff.

- **Outputs:** REV provides a basic visual output of the pressure and CO_2 plumes across the model domain. The aspect ratio of REV image output makes it difficult to properly compare between the CMG-GEM reservoir simulation outputs and the REV outputs. Therefore, these types of comparisons are currently best handled outside of REV.

- **Output:** The graphical output for REV does not include X- and Y-coordinates or a scale bar, which limits the direct interpretation of the REV outputs with respect to key features of the storage site.

Recommendations

Consistent with the key findings, the following are three recommendations for improving REV:

1. Future versions of REV should rectify the current issues with graphical output, which causes banding and feathering, and an elongated aspect ratio that distorts the shape of the differential pressure or CO_2 plumes when the input grid from the reservoir simulation is not a square model domain. Many storage sites will not build a square model domain; thus the current issues with REV graphical output are a limitation to widespread use of the tool at other storage sites.

2. The utility for calculating the pressure threshold within the threshold parameters page of REV should be modified to agree with the calculations presented in by EPA (2013). In addition, the subsequent user's manual for REV should document the specific equations that are used for calculating ΔP_c.

3. Future versions of REV should include X- and Y-coordinates and a scale bar in the image output, which would allow the user to reference locations within the image relative to key features of the storage site.

WLAT TESTING SUMMARY

WLAT was used to estimate the rates of CO_2 or brine leakage from the storage unit into overlying formations through a wellbore. WLAT testing should be regarded as a theoretical exercise as no evidence exists for the presence of a leaking wellbore in the MRYS study area. WLAT testing used three of the available WLAT ROMs: 1) cemented wellbore model, 2) multisegmented wellbore model, and 3) open wellbore model. The cemented wellbore model estimates the multiphase flow of CO_2 and brine along a cemented wellbore and can treat leakage to a thief zone, an aquifer, or the atmosphere. The multisegmented wellbore model can treat the leakage of CO_2 and brine along wells with multiple thief zones or to the atmosphere. The open wellbore model treats the leakage of CO_2 up an open wellbore or up open (i.e., uncemented) casing/tubing and can treat leakage to an aquifer or the atmosphere (Huerta and Vasylkivska, 2016).

Figure F-18 shows the generalized stratigraphy of the MRYS study area storage complex. The target geologic storage unit is the Broom Creek Formation, a saline formation roughly

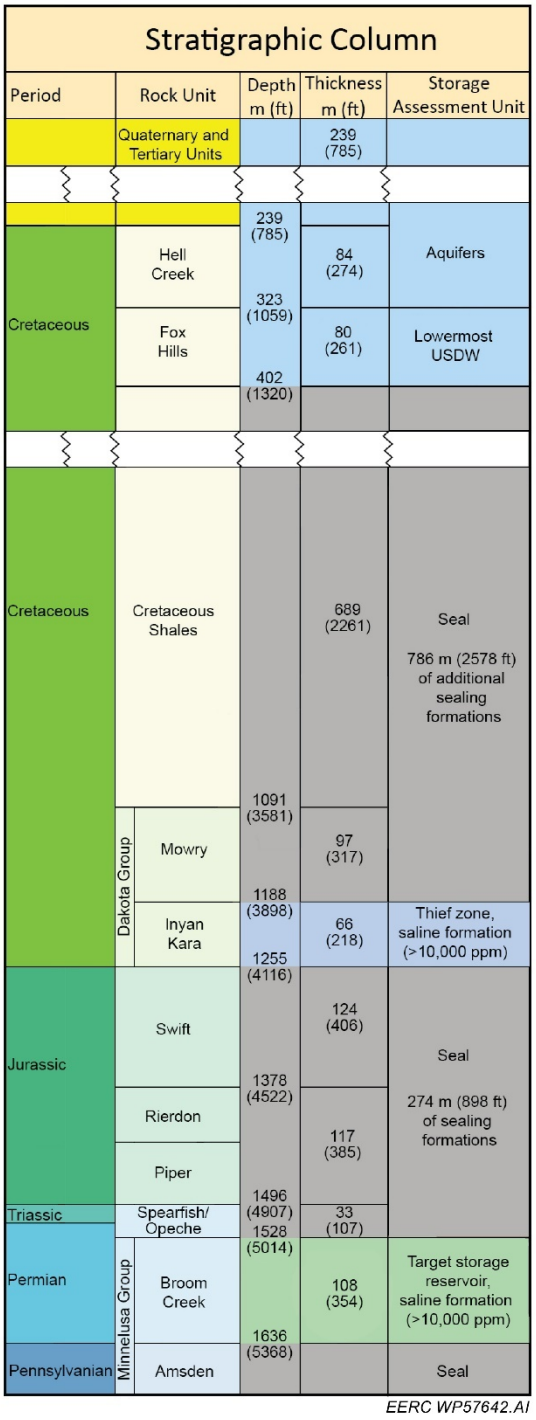
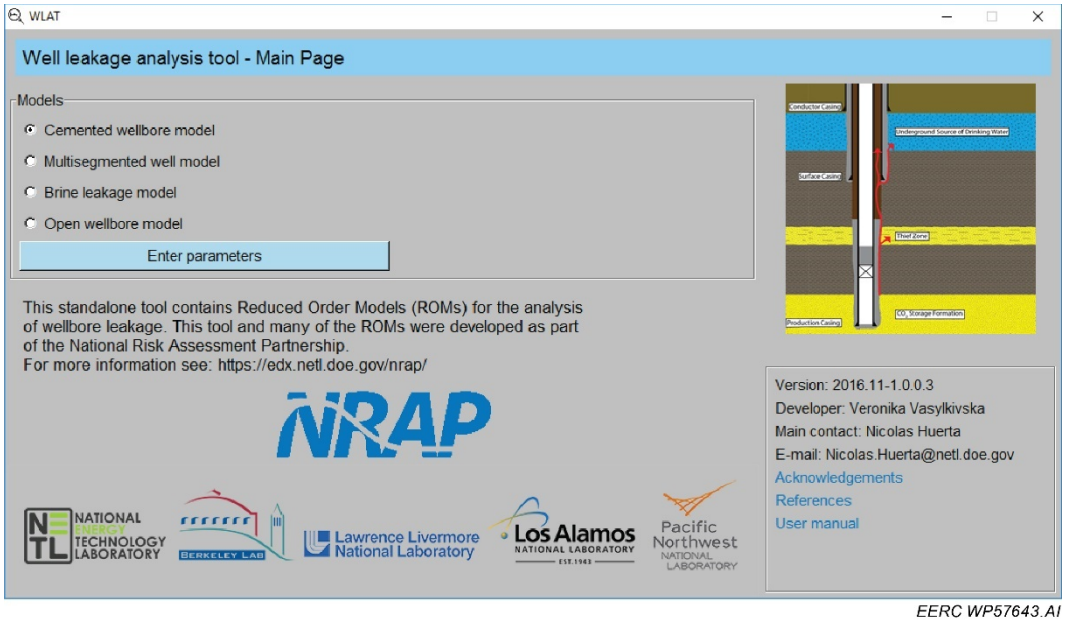


Figure F-18. Generalized stratigraphy used for WLAT testing.

5000 ft deep. Notable features of the storage complex include 1) nearly 900 ft of primary sealing formations between the storage unit and the second saline formation – the Inyan Kara, 2) roughly 220 ft of Inyan Kara saline formation, and 3) an additional 2500 ft of sealing formations between the Inyan Kara and the lowermost USDW – the Fox Hills aquifer. WLAT testing captured these features by modifying the inputs to reflect the stratigraphy shown in Figure F-18. This was not always possible given the constraints of a particular ROM, as described in their respective sections. The conceptual model for wellbore leakage for all of the WLAT testing was a wellbore that penetrated the Broom Creek Formation and provided a migration pathway from the storage unit up to the surface, including, when applicable, the saline aquifer from 3898 to 4116 ft below ground surface (bgs) (the Inyan Kara Formation) and the USDW from 1059 to 1320 ft bgs (the Fox Hills aquifer). In this context, the Inyan Kara is referred to as a thief zone, which is a formation between the storage unit and the USDW with higher permeability that could accept fluids (CO_2 or brine) and thus reduce the flux of fluids to overlying units.

The inputs to WLAT started with launching the tool, opening the main page, selecting the radio button for the specific wellbore leakage model, and selecting enter parameters, as shown in Figure F-19. The specific inputs and assumptions for each model are described in their respective sections.



EERC WP57643.AI

Figure F-19. WLAT main page showing the radio buttons for each of the four leakage models.

Cemented Wellbore Model

Inputs and Assumptions

As described in Huerta and Vasylkivska (2016), the cemented wellbore model does not incorporate time-dependent leakage because of geochemical and geomechanical changes in the medium; CO_2 dissolution in brine and other reactive chemistry; and residual saturations and brine density changes with temperature and pressure. Neglecting dissolution and residual saturations increases the leak flux estimates and is therefore conservative (i.e., overestimation) for risk assessments.

The cemented wellbore model opens with the dashboard shown in Figure F-20. The left-hand side of the screen are the available inputs, some of which the user can manipulate and others that are hard-wired within the model and cannot be changed. The inputs are divided into three major blocks:

- Field properties
- Wellbore properties
- Additional parameters

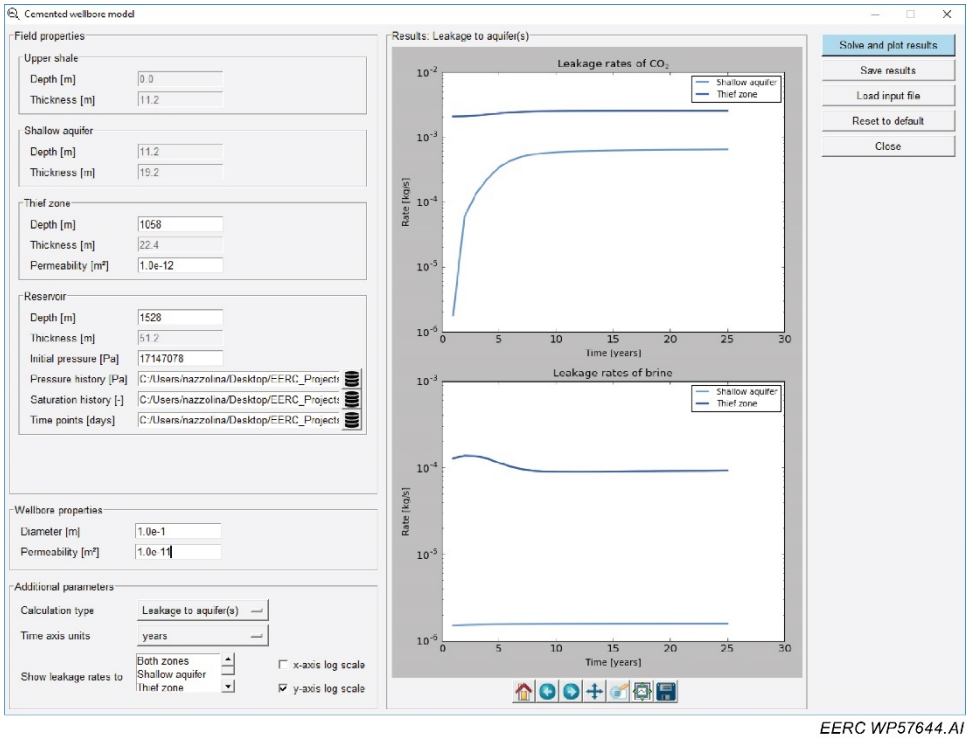


Figure F-20. WLAT cemented wellbore model dashboard showing inputs on the left and results on the right. Note: y-axis is displayed on a $\log_{10}$ scale.

Field Properties

Upper Shale and Shallow Aquifer

The depth and thickness of the upper shale and the depth and thickness of the shallow aquifer cannot be changed in the field properties. The depth and thickness of the upper shale are fixed at 0.0 m and 11.2 m (36.7 ft), respectively, and the depth and thickness of the shallow aquifer are fixed at 11.2 m (36.7 ft) and 19.2 m (63.0 ft), respectively. These depths and thicknesses do not correspond to site-specific stratigraphy, which is a limitation of the cemented wellbore model for evaluating site-specific impacts to the USDW. For example, the site-specific USDW resides at a depth of approximately 323 m (1028 ft) and has a thickness of approximately 80 m (261 ft), which are significantly different from the hard-wired default values within the field properties.

Thief Zone

Field properties will accept several inputs for a site-specific thief zone. However, the thickness of the thief zone cannot be changed in the field properties and is hard-wired at 22.4 m (73.5 ft). This thickness does not correspond to the site-specific stratigraphy, which is a limitation of the cemented wellbore model for evaluating site-specific impacts to the thief zone. For example, the site-specific thief zone of the Inyan Kara has a thickness of approximately 66 m (218 ft), which is thicker than the hard-wired default value within the field properties. The depth of the site-specific thief zone (Inyan Kara) is 1188 m (3898 ft). Because of restrictions with the tool, the actual depth of the thief zone could not be used because it was greater than the maximum depth allowed in relation to the depth of the reservoir (Broom Creek). Because of the depth restriction, the testing set the thief zone depth to 1058 m (3471 ft), which corresponds to the deepest allowable depth by the tool when the reservoir depth is 1528 m (5014 ft). The permeability of the thief zone was set to 1.0E-12 m^2 (1013 millidarcies [mD]), which represents a highly permeable sandstone.

Reservoir

Field properties will accept a site-specific reservoir depth, initial pressure, pressure history, and saturation history, and time points. Pressure history and saturation history are pressure and saturation values from a single location in the reservoir simulation output over a set of user-defined time steps. The reservoir thickness cannot be changed in the field properties and is hard-wired at 51.2 m (168 ft), which does not correspond to the site-specific reservoir thickness of the Broom Creek Formation of approximately 108 m (354 ft). The location chosen from the CMG-GEM simulation for the pressure and saturation time series output was identified through the following series of steps:

- First, the CMG-GEM simulation pressure and saturation results were reviewed in order to identify a cell location (I,J,K coordinate system) for a hypothetical wellbore within the simulated CO_2 plume. Simulation grid cell (I52, J38, K30) was chosen to represent the location of a hypothetical wellbore, because this location was within the CO_2 plume.

- The CMG-GEM simulation pressure and saturation results were then exported using the same series of steps that were previously described in the RROM-Gen section and imported into Schlumberger's Petrel.

- Using Petrel, the simulated pressure was converted from psi to Pa for input into the cemented wellbore model.

- The simulated pressure and saturation were then exported from Petrel as Gslib text format. A Python script was used to select and write the pressure and saturation values from the chosen cell location (I52, J38, K30) for each time step into separate pressure and saturation input file formats for the cemented wellbore model (Figure F-21). Each input file began at the first year of CO_2 saturation, which corresponded to Time Step 365.

- The time series pressure, saturation, and time step files were then imported into the pressure history, saturation history, and time steps fields of field properties.

Wellbore Properties

Wellbore properties accepts inputs for the wellbore diameter and permeability. The testing included a matrix of properties comprised of two different wellbore diameters (0.10 and 0.50 m) and four different wellbore permeability values (1E-11, 1E-12, 1E-13, and 1E-14 m^2), as shown in Table F-1. These combinations of different wellbore diameters and permeability values were used to assess the sensitivity of the modeled leakage rates to these wellbore properties.

Additional Parameters

The calculation type for all testing was set to leakage to aquifer(s) using a time axis unit of years. The show leakage rates to was set to both zones for all testing, which provided leakage rates to both the thief zone and the shallow aquifer (Figure F-20).

Results

Two types of outputs were generated from the cemented wellbore model: graphical results and quantitative outputs. Graphical results were generated by selecting the solve and plot results tab in the dashboard, which generates time series plots of the leakage rates of CO_2 and brine into the thief zone and shallow aquifer, as shown in Figure F-20. However, this graphical output is specific to the set of inputs used for that particular model realization. For assessing the effects of the different wellbore properties on the leakage rates, the results were exported from the cemented wellbore model for each of the Table F-1 wellbore property combinations, and a composite set of figures was generated in Microsoft Excel to compare the different leakage rates.

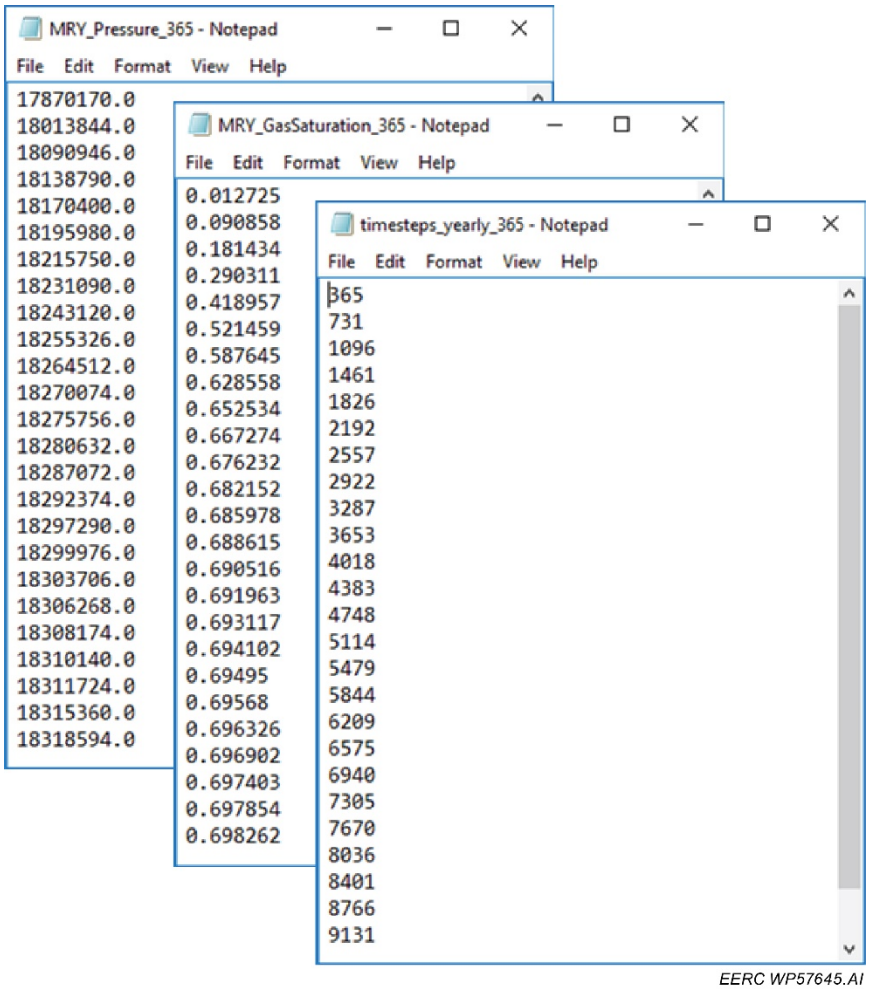


Figure F-21. WLAT cemented wellbore model pressure, saturation, and time step inputs.

Table 1. Wellbore Property Inputs Included in Cemented Wellbore Model Testing

Diameters, m	Permeability, m^2	Permeability, mD
0.10	1E-11	10,133
0.10	1E-12	1013
0.10	1E-13	101
0.10	1E-14	10
0.50	1E-11	10,133
0.50	1E-12	1013
0.50	1E-13	101
0.50	1E-14	10

Figures F-22 and F-23 provide a composite set of figures showing the modeled leakage rates of CO_2 and brine, respectively, into the thief zone (Inyan Kara) and shallow aquifer (USDW) as a function of wellbore diameter and cement permeability. The *y*-axes in all panels are log_{10}-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative leakage rates. As shown in Figure F-22, the cement permeability and wellbore diameter both affected the estimated leakage rates of CO_2 to the thief zone and USDW in the direction that would be expected, i.e., higher cement permeability and larger wellbore diameters both resulted in greater leakage rates. For example, under the scenario with the highest cement permeability of 1E-11 m^2 (blue lines) and the 0.1-m-diameter wellbore, the CO_2 leakage rate to the USDW at 15 years into CO_2 injection was

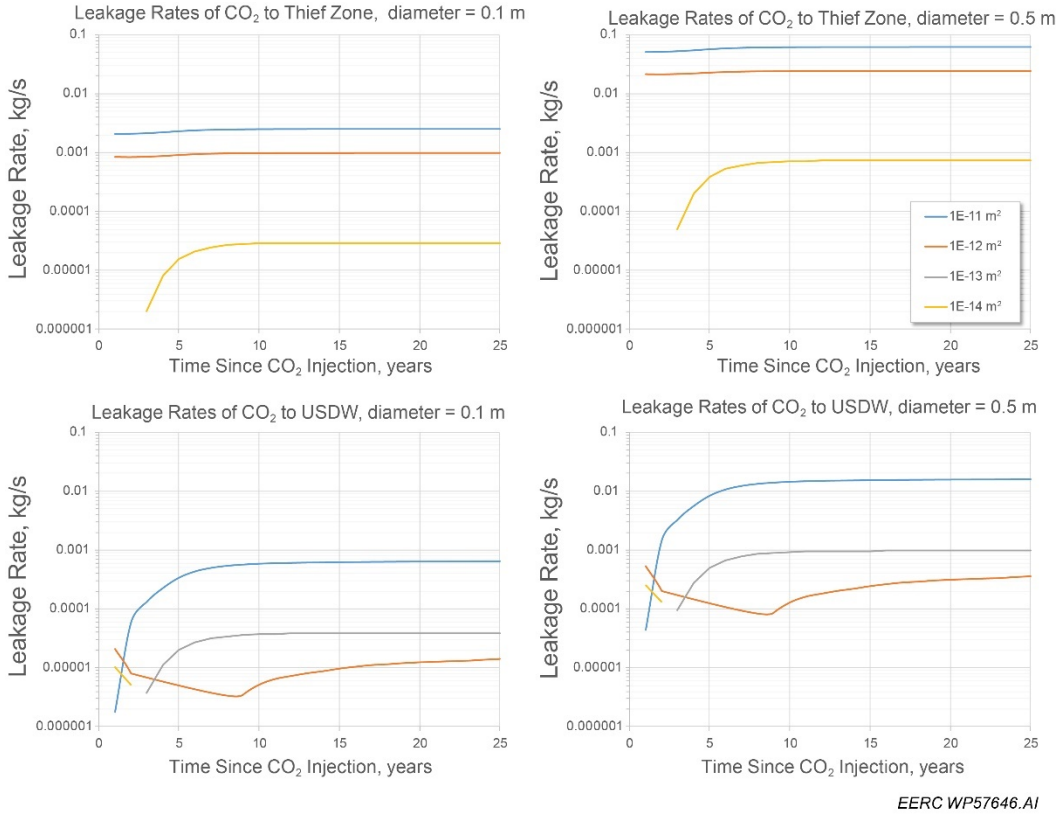


Figure F-22. WLAT cemented wellbore model composite set of figures showing the modeled leakage rates of CO_2 into the thief zone (Inyan Kara, top panels) and shallow aquifer (USDW, bottom panels) as a function of wellbore diameter (0.10 m [left column] and 0.50 m [right column]) and cement permeability (1E-11, 1E-12, 1E-13, and 1E-14 m^2). The *y*-axes in all panels are log_{10}-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative CO_2 leakage rates.

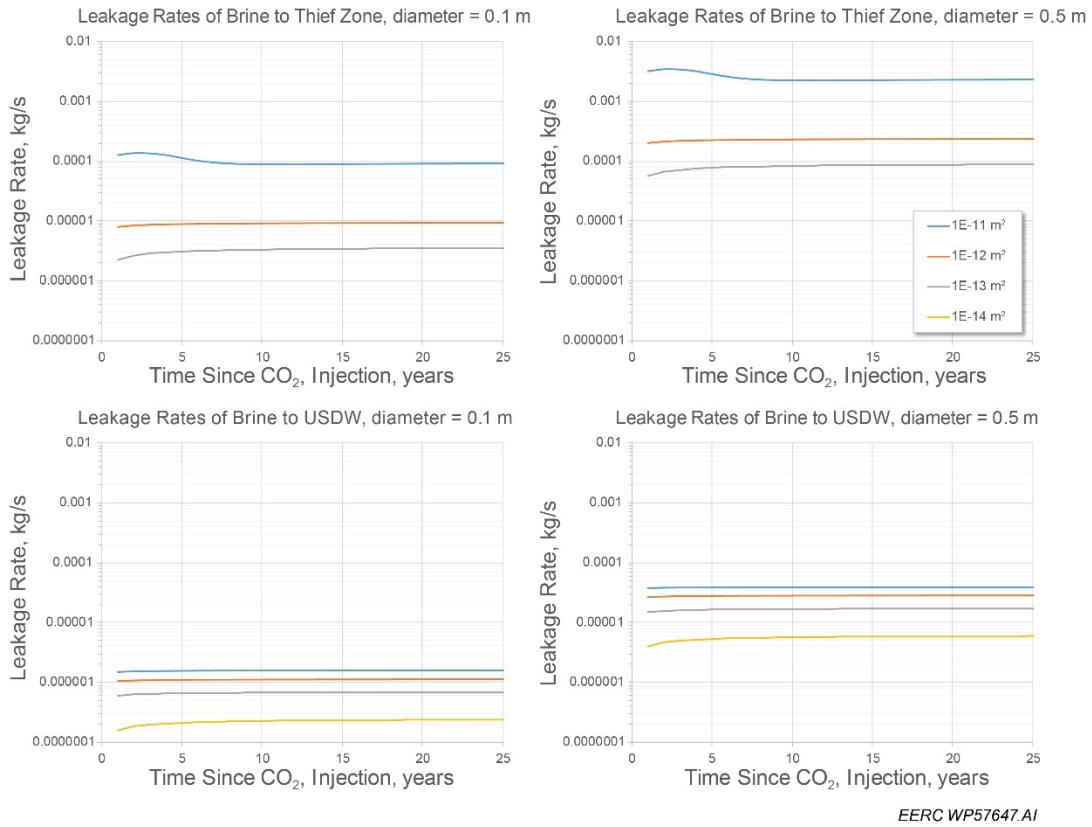


Figure F-23. WLAT cemented wellbore model composite set of figures showing the modeled leakage rates of brine into the thief zone (Inyan Kara, top panels) and shallow aquifer (USDW, bottom panels) as a function of wellbore diameter (0.10 m [left column] and 0.50 m [right column]) and cement permeability (1E-11, 1E-12, 1E-13, and 1E-14 m^2). The *y*-axes in all panels are log_{10}-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative brine leakage rates.

approximately 6.14E-04 kg/s. However, the CO_2 leakage rate to the USDW decreased to 9.75E-06 kg/s when cement permeability was decreased to 1E-12 m^2 (orange lines). Thus a tenfold reduction in cement permeability corresponded to a 60-fold reduction in the CO_2 leakage rate to the USDW. Increasing the wellbore diameter from 0.1 to 0.5 m increased CO_2 leakage rates. For example, under the scenario with the highest cement permeability of 1E-11 m^2 (blue lines) and the 0.5-m-diameter wellbore, the CO_2 leakage rate to the USDW at 15 years into CO_2 injection was approximately 1.53E-02 kg/s. Thus a fivefold increase in the wellbore diameter resulted in a 25-fold increase in the CO_2 leakage rate to the USDW. The CO_2 leakage rates to the thief zone were significantly greater than the CO_2 leakage rates to the USDW for the same set of inputs, which illustrates the effect of a thief zone on reducing CO_2 leakage to overlying units.

The scenarios with cement permeability of 1E-13 m^2 (gray lines) resulted in erroneous outputs, with negative CO_2 leakage rates to the thief zone and commensurately greater CO_2 leakage rates to the USDW than the cement permeability of 1E-12 m^2 scenario. The reason for these erroneous outputs is currently unknown.

As shown in Figure F-23, the cement permeability and wellbore diameter both affected the estimated leakage rates of brine to the thief zone and USDW. However, the effects of cement permeability were much lower than they were for CO_2 leakage. For example, under the scenario with the highest cement permeability of 1E-11 m^2 (blue lines) and the 0.1-m-diameter wellbore, the brine leakage rate to the USDW at 15 years into CO_2 injection was approximately 1.57E-06 kg/s. However, the brine leakage rate to the USDW decreased to 1.12E-06 kg/s when cement permeability was decreased to 1E-12 m^2 (orange lines). Thus a tenfold reduction in cement permeability corresponded to only a 1.4-fold reduction in the leakage rate to the USDW, which was significantly lower than the 60-fold effect on CO_2 leakage rates. Increasing the wellbore diameter from 0.1 to 0.5 m increased brine leakage rates. For example, under the scenario with the highest cement permeability of 1E-11 m^2 (blue lines) and the 0.5-m-diameter wellbore, the brine leakage rate to the USDW at 15 years into CO_2 injection was approximately 3.92E-05 kg/s. Thus a fivefold increase in the wellbore diameter resulted in a 25-fold increase in the brine leakage rate to the USDW, which was identical to the effects for CO_2 leakage rates. The brine leakage rates to the thief zone were significantly greater than the leakage rates to the USDW for the same set of inputs for wellbore diameter and cement permeability. These results illustrate the effect of a thief zone on reducing CO_2 leakage to overlying units. Unlike the CO_2 leakage rates, there were no erroneous outputs for brine leakage rates associated with the cement permeability of 1E-13 m^2, and the brine leakage rates maintained the order of 1E-11 > 1E-12 > 1E-13 m^2. However, the scenarios with cement permeability of 1E-14 m^2 (yellow lines) resulted in erroneous outputs, with negative CO_2 leakage rates to the thief zone and commensurately greater CO_2 leakage rates to the USDW than to the thief zone. The reason for these erroneous outputs is currently unknown.

Key Findings

Cemented wellbore model testing resulted in the following key findings:

- **Inputs:** The cemented wellbore model dashboard provides a compact and easy-to-use interface for entering input values. However, there are constraints for certain inputs that limit the utility of the tool. For example, the input depth for the thief zone is constrained to between 30% and 70% of the reservoir depth. In addition, the depth and thickness of the shallow aquifer are fixed at 11.2 m (36.7 ft) and 19.2 m (63.0 ft), respectively. These constraints did not allow for the use of site-specific depths and thicknesses for the North Dakota CarbonSAFE storage complex and were a limitation of the cemented wellbore model for evaluating site-specific impacts to the USDW.

- **Outputs:** The graphical outputs generated by the cemented wellbore model provide a useful screening tool for quickly evaluating the leakage rates over time of CO_2 and brine to the thief zone, shallow aquifer, and/or atmosphere. However, the graphical output is specific to a single set of inputs, which makes evaluating multiple inputs, such as wellbore properties, challenging to assess within the tool. For comparing the effects of different wellbore properties on leakage rates, the testing required exporting results from the cemented wellbore model into a separate program to generate a series of figures.

- **Outputs:** Some combinations of wellbore diameter and/or permeability resulted in negative leakage rates, which are not physically possible. In addition, some combinations

of wellbore diameter and/or permeability resulted in greater leakage rates to the USDW than to the thief zone, which is also not physically possible.

Recommendations

Consistent with the key findings, the following are four recommendations for improving the WLAT cemented wellbore model:

1. Future versions of the cemented wellbore model should accommodate site-specific depth inputs for the thief zone and shallow aquifer, which would allow for the tool to more closely approximate the site-specific stratigraphy of a storage complex.

2. Future versions of the cemented wellbore model should allow for additional graphical outputs to permit comparisons of leakage rates given variable wellbore properties.

3. Future versions of the cemented wellbore model should allow the initial pressure to be included in the pressure history input file instead of the current input option, which requires the user to manually enter the initial pressure.

4. Future versions of the cemented wellbore model should accommodate zero-saturation in early time steps, as wellbores that are located further away from the injection wells will not have CO_2 saturation near the wellbore during the initial years of injection.

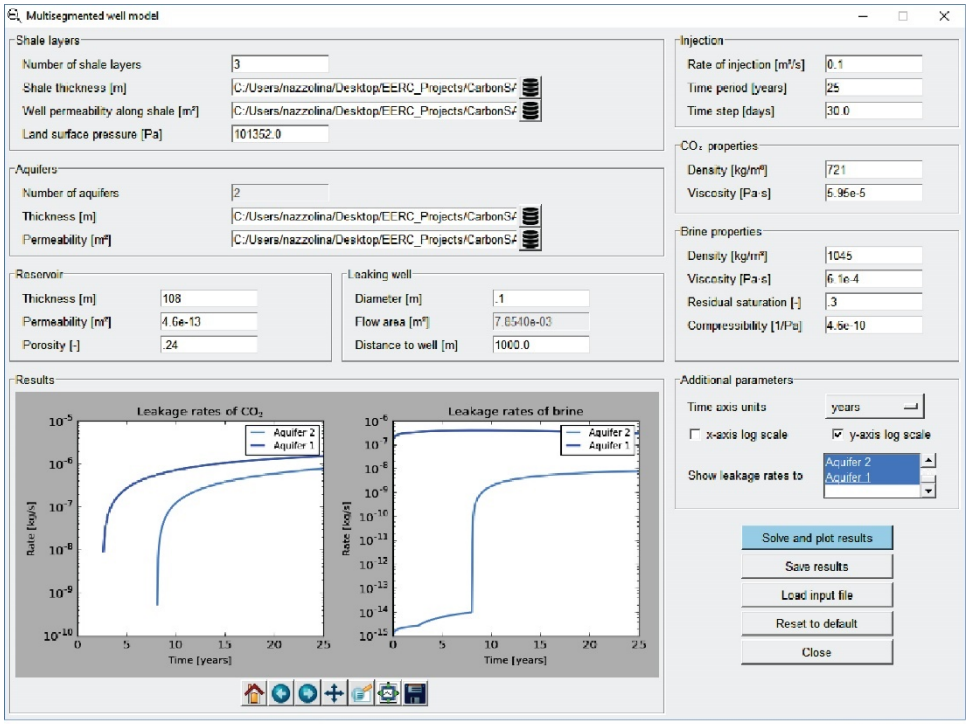
Multisegmented Wellbore Model

Inputs and Assumptions

The primary differences between the multisegmented wellbore model and the previously described cemented wellbore model are that the former 1) allows multiple thief zones, 2) allows for investigation of the effect of distance between the injection well and the leaking well, and 3) does not require simulated saturation and pressure input files. These additional features of the multisegmented wellbore model therefore allow for a more robust representation of the site-specific storage complex. The testing of the multisegmented wellbore model used three shale layers and two aquifers, which more closely approximates the storage site stratigraphy (Figure F-18).

The multisegmented wellbore model opens with the dashboard shown in Figure F-24. The inputs are divided into eight major blocks:

- Shale layers
- Aquifers
- Reservoir
- Leaking well
- Injection
- CO_2 properties
- Brine properties
- Additional parameters



EERC WP57648.AI

Figure F-24.WLAT multisegmented wellbore model dashboard showing inputs and results. Note: y-axis is displayed on a $\log_{10}$ scale.

Shale Layers

The shale layers input block requires inputs for the number of shale layers, shale thickness, well permeability along shale, and land surface. The number of shale layers for the testing was set at three, one for the primary set of sealing units from 1255 to 1528 m (4116 to 4907 ft) (274 m [898 ft] of sealing units), one for the secondary set of sealing units from 402 to 1188 m (1320 to 3898 ft) (786 m [2578 ft] of sealing units), and one for the surface. The shale thickness and well permeability along shale inputs were imported into the multisegmented wellbore model as text files. The well permeability along shale was set to 1E-14 m^2 (10 mD) for all shale–wellbore interfaces. The land surface was set at the default value of 101,352.0 Pa (1.0 atm).

Aquifers

The aquifers input block requires inputs for the number of aquifers, thickness, and permeability. The number of aquifers is automatically calculated as the number of shale layers – 1 and was therefore set at two, one for the Inyan Kara thief zone from 1188 to 1255 m (3898 to 4116 ft) (66 m [218 ft] thick) and one for the Fox Hills aquifer (lowermost USDW) from 323 to 402 m (1059 to 1320 ft) (80 m [400 ft] thick). The thickness and permeability inputs were imported into the multisegmented wellbore model as text files. The permeability for the Inyan Kara was set at 1E-12 m^2 (1013 mD), and the permeability for the Fox Hills aquifer was set to 2.76E-13 m^2 (280 mD), which was the average value from the MRYS Version 1 geologic model.

Reservoir

The reservoir input block requires inputs for thickness, permeability, and porosity, which were set to 108 m (354 ft), 4.6E-13 m^2 (469 mD), and 0.24 (dimensionless), respectively. These inputs represent the average values from the MRYS Version 1 geologic model.

Leaking Well

The leaking well input block requires inputs for the wellbore diameter and distance to well. The diameter was set to either 0.10 or 0.50 m to mirror the wellbore properties used in the cemented wellbore model testing. The distance to well was set at 1000, 2000, 3000, 4000, or 5000 m (1, 2, 3, 4, or 5 km), which represents the ranges of distances from an injection well to the nearest wellbore within the study area. Unlike the cemented wellbore model, there is no input for the wellbore cement permeability.

Injection

The injection input block requires inputs for the rate of injection, timer period, and time step, which were set to 0.1 m^3/s, 25 years, and 30 days, respectively, for all tests. The rate of injection was set based on the annual target injection rate of 2 Mt per year, which results in 50 Mt over the 25-year injection period and is consistent with the CarbonSAFE Initiative definition of a commercial storage site.

CO_2 Properties

The CO_2 properties input block requires inputs for CO_2 density and viscosity. These estimates were obtained from CMG-GEM, which resulted in an estimated density of 721 kg/m^3 (45.0 lb/ft^3) and an estimated viscosity of 5.95E-06 Pa s (0.0595 cP).

Brine Properties

The brine properties input block requires inputs for brine density, viscosity, residual saturation, and compressibility, which were set at 1045 kg/m^3 (65.2 lb/ft^3), 6.1E-4 Pa s (0.61 cP), 0.30 [-], and 4.6E-10 Pa^{-1} (6.67E-14 psi^{-1}), respectively.

Additional Parameters

The additional parameters input block requires inputs for time axis units and show leakage rates, which were set to years and Aquifer 1 and Aquifer 2, respectively. In the multisegmented wellbore model, the aquifers are numbered from lowermost to uppermost, such that Aquifer 1 referred to the Inyan Kara thief zone and Aquifer 2 referred to the USDW.

Results

Two types of outputs were generated from the multisegmented wellbore model: graphical results and quantitative outputs. Graphical results were generated by selecting the solve and plot results tab in the dashboard, which generates time series plots of the leakage rates of CO_2 and brine into Aquifer 1 (Dakota Group thief zone) and Aquifer 2 (USDW), as shown in Figure F-24. However, this graphical output is specific to the set of inputs used for that particular model realization. For assessing the effects of the different wellbore diameters (0.10 and 0.50 m) and distances (1–5 km) on the leakage rates, the results were exported from the multisegmented wellbore model and a composite set of figures was generated in Microsoft Excel to compare the different leakage rates. Figures F-25 and F-26 provide a composite set of figures showing the modeled leakage rates of CO_2 or brine, respectively, into Aquifers 1 and 2 as a function of wellbore diameter and distance to the wellbore. As shown in the figures, the distance between the injection well and the leaking well plays a significant role in the leakage rates to either the USDW or the thief zone, with 1 km > 2 km > 3 km > 4 km > 5 km. Similar to the results from the cemented wellbore model, larger wellbore diameters both resulted in greater leakage rates.

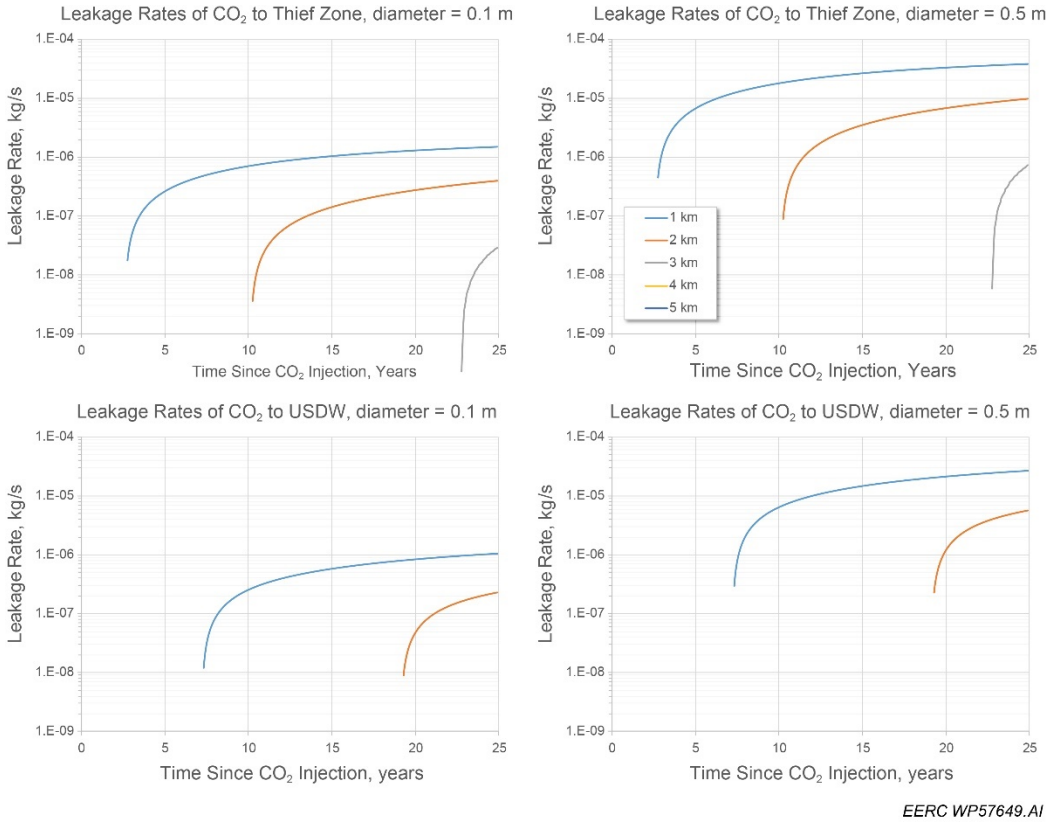


Figure F-25. WLAT multisegmented wellbore model composite set of figures showing the modeled leakage rates of CO_2 into Aquifer 1 (thief zone) (top row) and Aquifer 2 (USDW) (bottom row) as a function of wellbore diameter (0.10 m [left column] and 0.50 m [right column]) and distance from the injection well to the leaking wellbore (1 to 5 km). The *y*-axes in all panels are log_{10}-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative CO_2 leakage rates.

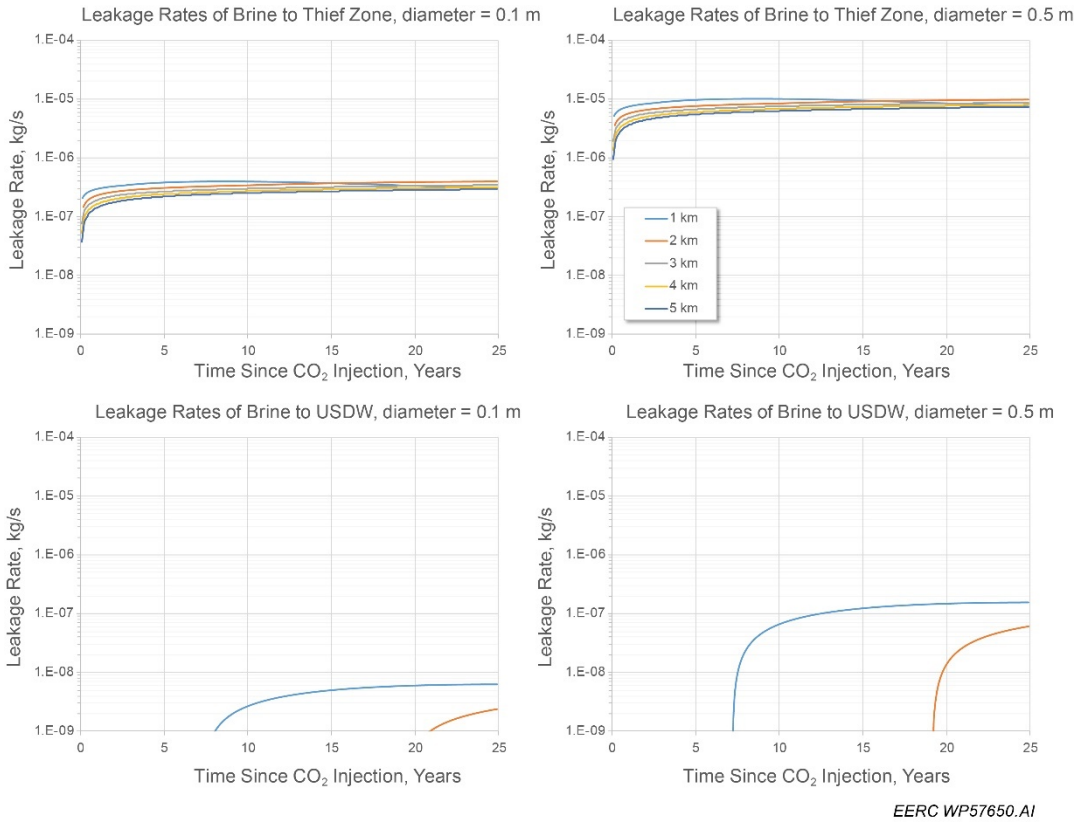


Figure F-26. WLAT multisegmented wellbore model composite set of figures showing the modeled leakage rates of brine into Aquifer 1 (thief zone) (top row) and Aquifer 2 (USDW) (bottom row) as a function of wellbore diameter (0.10 m [left column] and 0.50 m [right column]) and distance from the injection well to the leaking wellbore (1 to 5 km). The *y*-axes in all panels are $\log_{10}$-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative brine leakage rates.

Key Findings

The multisegmented wellbore model testing resulted in the following key findings:

- **Inputs:** The multisegmented wellbore model dashboard provides a compact and easy-to-use interface for entering input values and did not have some of the constraints on aquifer depths and thicknesses that were a limitation of the cemented wellbore model. The additional inputs of CO_2 and brine properties require a simplifying assumption about the reservoir pressure and temperature conditions, which will change over time as a function of CO_2 injection.

- **Outputs:** The graphical outputs generated by the multisegmented wellbore model provide a useful screening tool for quickly evaluating the leakage rates over time of CO_2 and brine to the aquifer(s) and/or atmosphere. However, similar to the cemented wellbore

model, the graphical output of the multisegmented wellbore model is specific to a single set of inputs, which makes evaluating multiple inputs, such as distance from the injection well to the leaky well, challenging to assess within the tool. For comparing the effects of different distances on leakage rates, the testing required exporting results from the multisegmented wellbore model into a separate program to generate a series of figures.

Recommendations

Consistent with the key findings, one recommendation for improving the WLAT multisegmented wellbore model is that future versions should allow for additional graphical outputs to permit comparisons of leakage rates given variable distances between the injection well and the leaky well.

Open Wellbore Model

Inputs and Assumptions

The open wellbore model was the final ROM evaluated as part of WLAT testing. The current version of the open wellbore model does not simulate the coupling of the pressure at the bottom of the leaking well with time-dependent reservoir pressure. Therefore, the open wellbore model provides a reasonable estimate of the leakage rate through an open wellbore only for a short initial transient period (Huerta and Vasylkivska, 2016).

The open wellbore model opens with the dashboard shown in Figure F-27 and includes three different input blocks:

- Field properties
- Wellbore properties
- Additional parameters

Field Properties

Shallow Aquifer

The depth and thickness of the shallow aquifer are fixed at 0 and 500 m (1640 ft), respectively, and cannot be changed. This depth and thickness does not correspond to the site-specific stratigraphy, which is a limitation of the open wellbore model for evaluating site-specific impacts to the USDW. For example, the site-specific USDW resides at a depth of approximately 323 m (1028 ft) and has a thickness of approximately 80 m (261 ft), which are significantly different from the hard-wired default values within the field properties.

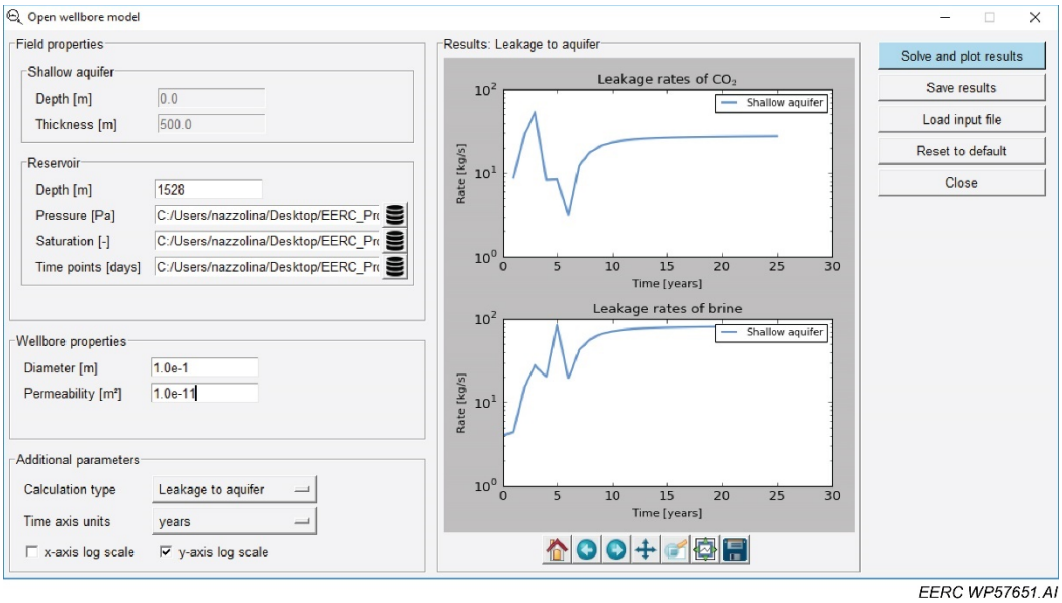


Figure F-27. WLAT open wellbore model dashboard showing inputs and results.

Reservoir

Inputs must be provided for the reservoir depth, pressure, saturation, and time points. The open wellbore model input uses the same information for the reservoir as the cemented wellbore model. The pressure and saturation inputs are pressure and saturation values from a single location in the reservoir simulation output over a set of user-defined time steps. Unlike the cemented wellbore model, reservoir thickness is not an input for the open wellbore model.

Wellbore Properties

Wellbore properties accepts inputs for the wellbore diameter and permeability. The testing for the open wellbore model included the same matrix of wellbore diameters (0.10 and 0.50 m) and wellbore permeability values (1E-11, 1E-12, 1E-13, and 1E-14 m^2) as the testing for the cemented wellbore model (Table F-1). These combinations of different wellbore diameters and permeability values were used to assess the sensitivity of the modeled leakage rates to these wellbore properties.

Additional Parameters

The calculation type for all testing was set to leakage to aquifer using time axis units of years (Figure F-27).

Results

Two types of outputs were generated from the open wellbore model: graphical results and quantitative outputs. Graphical results were generated by selecting the solve and plot results tab in the dashboard, which generates time series plots of the leakage rates of CO_2 and brine into the aquifer, as shown in Figure F-27. However, this graphical output is specific to the set of inputs used for that particular model realization. For assessing the effects of the different wellbore properties on the leakage rates, the results were exported from the open wellbore model for each of the Table F-1 wellbore property combinations and a composite set of figures was generated in Microsoft Excel to compare the different leakage rates. When testing multiple wellbore diameters, diameters greater than 0.1 m would result in an error, even though the user manual states diameter may range from 0.1 to 1 m. Thus only results for the 0.1 m case are presented.

Figure F-28 provides a composite set of figures showing the modeled leakage rates of CO_2 and brine into the aquifer (USDW) as a function of cement permeability. As shown in the figure, the leakage rate results for each cement permeability were virtually indistinguishable, which resulted in nearly identical time series curves. In addition, unlike the cemented wellbore model or the multisegmented model results, the open wellbore model leakage rates over time were not a smooth, continuous function and instead resulted in a peak leakage rate followed by a decreased and then and increased leakage rate. These results may have been attributable to the fact that the open wellbore model provides estimates of the leakage rate through an open wellbore only for a short initial transient period (Huerta and Vasylkivska, 2016).

Key Findings

The open wellbore model testing resulted in the following key findings:

- **Inputs:** The open wellbore model dashboard provides a compact and easy-to-use interface for entering input values. However, the depth and thickness of the aquifer are fixed at 0 and 500 m (1640 ft), respectively, which did not allow for the use of site-specific depths and thicknesses for the North Dakota CarbonSAFE storage complex and were a limitation of the open wellbore model for evaluating site-specific impacts to the USDW.

- **Inputs:** When testing multiple wellbore diameters, diameters greater than 0.1 m resulted in an error, even though the user manual states diameter may range from 0.1 to 1 m.

- **Outputs:** The graphical outputs generated by the open wellbore model provide a useful screening tool for quickly evaluating the leakage rates over time of CO_2 and brine to the aquifer and/or atmosphere. However, the graphical output is specific to a single set of inputs, which makes evaluating multiple inputs, such as wellbore properties, challenging to assess within the tool. For comparing the effects of different wellbore properties on leakage rates, the testing required exporting results from the open wellbore model into a separate program to generate a series of figures.

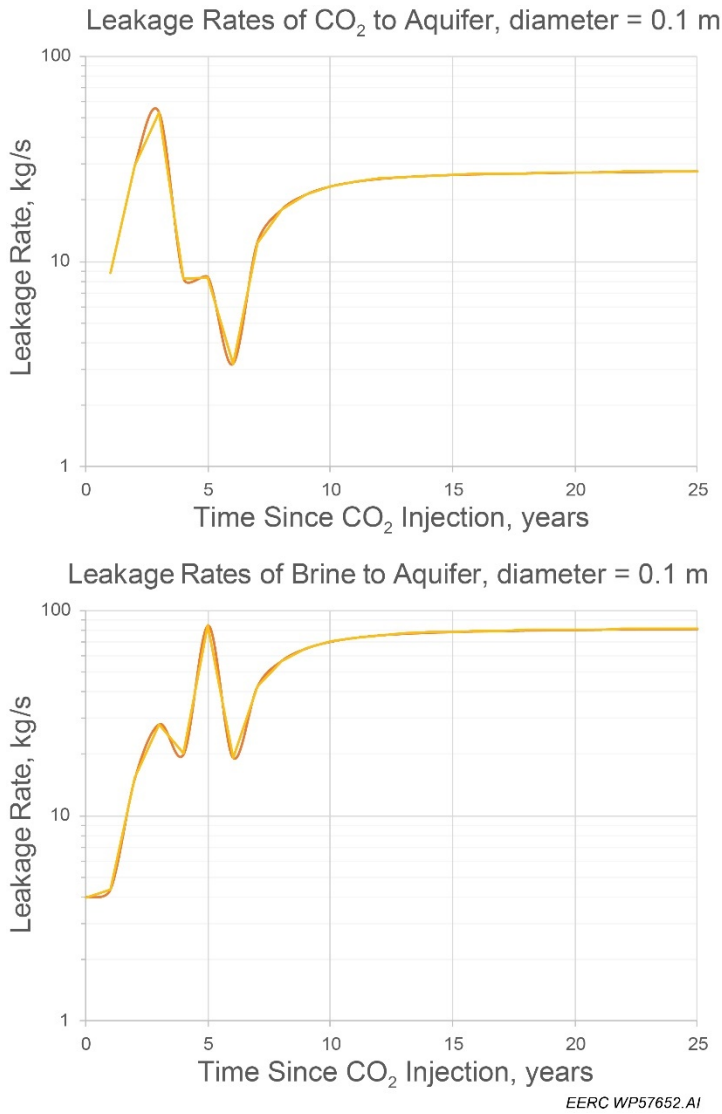


Figure F-28. WLAT open wellbore model composite set of figures showing the modeled leakage rates of CO_2 (top) and brine (bottom) into the aquifer as a function of cement permeability (1E-11, 1E-12, 1E-13, and 1E-14 m^2). The results for each cement permeability were virtually indistinguishable, which is why the curves overlap.

Recommendations

Consistent with the key findings, the following are two recommendations for improving the WLAT open wellbore model:

1. Future versions of the open wellbore model should accommodate site-specific depth inputs for the shallow aquifer, which would allow for the tool to more closely approximate the site-specific stratigraphy of a storage complex.

2. Future versions of the open wellbore model should allow for additional graphical outputs to permit comparisons of leakage rates given variable wellbore properties.

Summary

WLAT testing successfully used the cemented wellbore model, multisegmented wellbore model, and open wellbore model. The key findings across all three models were that the dashboards provided a compact and easy-to-use interface for entering input values. The constraints for aquifer and/or shale depth and thickness inputs to the cemented wellbore model and the open wellbore model limited the utility of these tools for approximating a site-specific storage complex, whereas the multisegmented wellbore model provided greater versatility for adjusting the shale and aquifer layers to approximate the site stratigraphy. Across all three ROMs, the graphical outputs provided a useful screening tool for quickly evaluating the leakage rates over time of CO_2 and brine to the aquifer and/or atmosphere. However, the graphical outputs are specific to a single set of inputs, which makes evaluating multiple inputs, such as wellbore properties or distance between the injection well and the leaky well, challenging to assess within the tools. Subsequent versions of the ROMs should allow for additional graphical outputs to permit comparisons of leakage rates given variable wellbore properties or variable distances.

GMPIS TESTING SUMMARY

GMPIS from the Phase 1 NRAP tool set was tested using both the example San Joaquin Valley data set provided with the tool and data generated as part of the North Dakota CarbonSAFE project. Average seismic shear wave velocity values for the top 30 m of the subsurface, commonly referred to as "Vs 30 data," were input into GMPIS to calculate peak ground acceleration for several hypothetical earthquake events within the project area. Currently, no commercial software packages are available against which to compare GMPIS results, and the testing did not evaluate alternative open-source tools such as the U.S. Geological Survey (USGS) ShakeMap software; however, the testing resulted in meaningful findings related to parameter selection and data input. A list of recommendations to make GMPIS more user friendly was also generated as part of this testing effort.

Inputs and Assumptions

The inputs to GMPIS started with launching the tool, opening the main page, selecting the enter parameters radio button, and selecting enter parameters, as shown in Figure F-29. This step opened the Master page, as shown in Figure F-30.

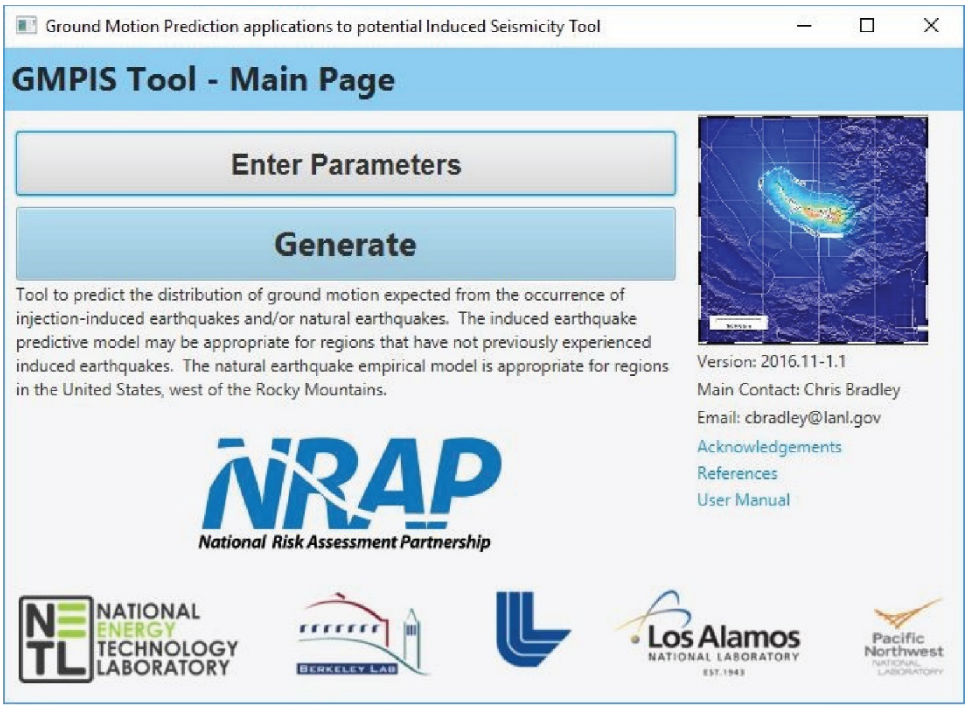


Figure F-29. GMPIS tool main page (Source: Bradley et al., 2016).

The ground motion type drop-down box on the master page allows for the selection of induced or tectonic events (Figure F-30). GMPIS was built with the assumption that site-specific data for induced seismicity are not readily available for most areas of interest. Because of this assumption, the ground motion prediction equation (GMPE) for induced events was developed using global induced seismicity data. These global induced seismicity data consist of only moment magnitude (Mw) 1–4 events, limiting the applicability of the induced GMPE to events of less than Mw 5. Bradley and others (2016) recommend using the tectonic GMPE for events Mw 5 and greater; however, the tectonic GMPE requires detailed information about the fault associated with the tectonic event, including fault type, coordinates, and dip. Only the induced option was selected for testing the North Dakota CarbonSAFE project data as no major faulting exists within the project area.

The detailed output and generate ShakeMap script boxes were checked for testing (Figure F-30).

Vs 30 Grid Output Type

The input file for GMPIS was a grid of Vs 30 data for the North Dakota CarbonSAFE project area. GMPIS uses Vs 30 values to apply site amplification correction to adjust the GMPEs. The Vs 30 grid was generated and input using the following steps.

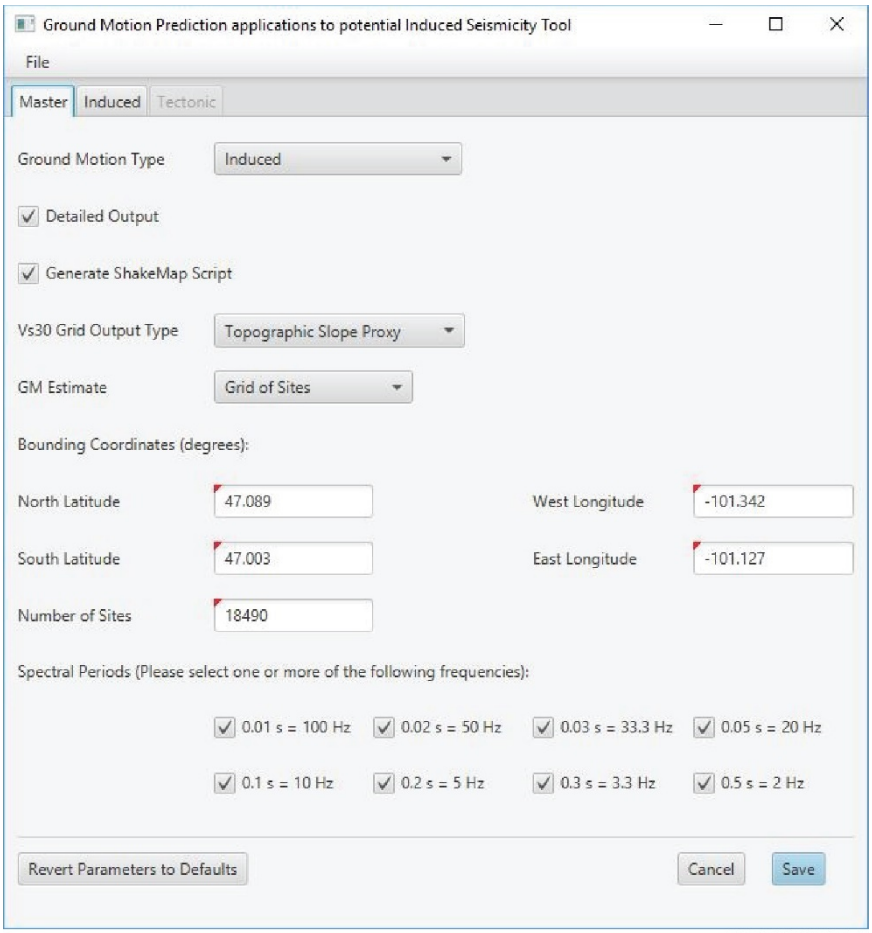


Figure F-30. GMPIS master page showing parameters used for testing site-specific data.

Step 1 – Data Acquisition

The EERC acquired a 5-mile-long 2-D seismic line near MRYS in September 2017. The receiver station spacing for the 2-D lines was 110 ft and the shot station spacing was 220 ft. The seismic source was a trailer-mounted 850-lb Gisco ESS850 accelerated weight drop source towed behind a pickup truck. Receivers were FairfieldNodal Zland nodes with three-component 5-Hz geophones. The final products of data acquisition were raw shot gathers in SEG-D format.

Step 2 – Data Processing and Analysis

The raw SEG-D shot gathers from the 5-mile-long 2-D seismic line were input into the Geogiga Seismic Pro 8.1 Surface software package to perform multichannel analysis of surface waves (MASW). The MASW method uses velocity information from the surface wave data contained in shot gathers to produce shear wave velocity (Vs) profiles for the near surface (Park and others, 1999). Vs profiles were generated for 58 points along the 2-D line and exported from Geogiga in ASCII format. The exported ASCII file contained coordinate information, Vs values,

and corresponding depth values for each point. These data were imported into Excel and used to calculate a Vs 30 value for each of the 58 points. The average of the 58 Vs 30 values was 365 m/s.

Step 3 – Text File Generation

A MatLab script was written to format a Vs 30 input file for GMPIS using a format consistent with the San Joaquin example data set. This script allows the user to input bounding coordinates for the area of interest, site spacing, and average Vs 30 value. Using the bounding coordinates and site spacing, the script creates a grid of sites within the area of interest and generates latitude and longitude coordinates for each site. The script then populates a text file with the number of rows corresponding to the number of sites, latitude and longitude coordinates for each site, and Vs 30 value for each site. The average Vs 30 value calculated in Step 2 was used for each site for this test (Figure F-31).

```
nrow
   18490

-101.3420   47.0890 365.00
-101.3420   47.0880 365.00
-101.3420   47.0870 365.00
-101.3420   47.0860 365.00
-101.3420   47.0850 365.00
-101.3420   47.0840 365.00
-101.3420   47.0830 365.00
-101.3420   47.0820 365.00
-101.3420   47.0810 365.00
```

EERC WP57655.AI

Figure F-31. Screenshot showing the first several rows of the Vs 30 grid text file generated by the MatLab script. The header contains the number of rows. Each row contains the latitude, longitude, and Vs 30 value for each site. Column one is the longitude, column two is latitude, and column three is the Vs 30 value.

Step 4 – Text File Input

GMPIS does not have an option to select an input Vs 30 text file. In order for the tool to read the Vs 30 text file, the file containing the data needs to be placed into the bin folder from which the tool is launched. The text file name must follow a specific naming convention. The required naming convention is Vs 30 grid followed by an abbreviation for the grid type “topo” for topographic slope proxy, “wc” for Wills and Clahan, and “kt” for kriging with trend. The grid type corresponding to the file name must then be selected using the Vs30 grid output type dropdown box on the master page. The text file generated using the MatLab script was renamed VS30gridtopo.txt and placed into the bin file. The topographic slope proxy grid type was selected on the Vs 30 grid output type of the master page (Figure F-30).

Parameter Selection

Several different parameters for number of sites and boundary coordinates on the master page were tested using North Dakota CarbonSAFE project data. GMPIS does not require the coordinates in the Vs 30 text file to fall within the bounding coordinates entered on the master page. The number of sites in the Vs 30 text file must be greater than or equal to the number of sites entered on the master page, and Vs 30 values must be greater than 0. For subsequent parameter testing, the boundary coordinates and number of sites were set to the values used to populate the Vs 30 text file shown in Figure F-30.

Varying combinations of spectral periods found on the master page were tested for induced events of different depths and magnitudes specified using the Induced page (Figure F-32). The latitude and longitude values for the induced events and the site amplification method were kept constant for this testing (Figure F-32).

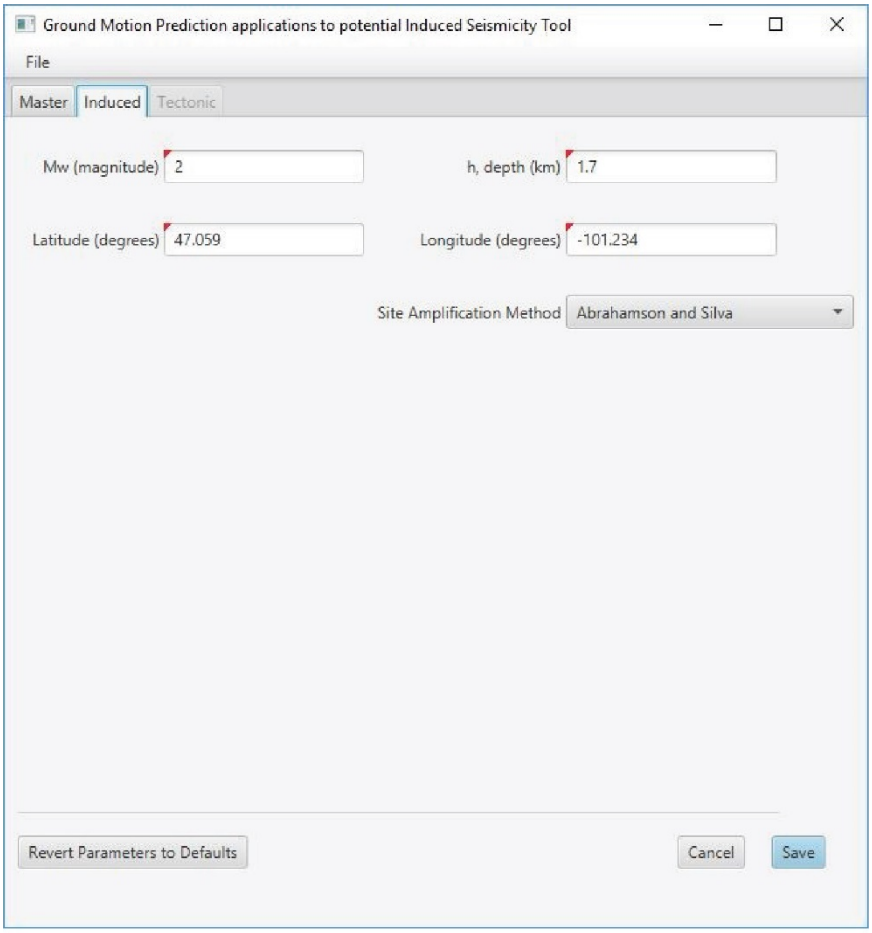


Figure F-32. GMPIS induced page showing latitude and longitude values and site amplification method used for testing site-specific data.

After a set of parameters was entered on the master page and induced page, the save button was selected, which relaunched the main page. The Generate radio button was then selected to run the ground motion prediction calculations (Figure F-30). This process was repeated for each combination of parameters tested.

The example San Joaquin data set provided with GMPIS was also used for testing. This data set and the default parameters containing fault coordinates for the San Joaquin Valley allowed for testing of the tectonic page (Figure F-33).

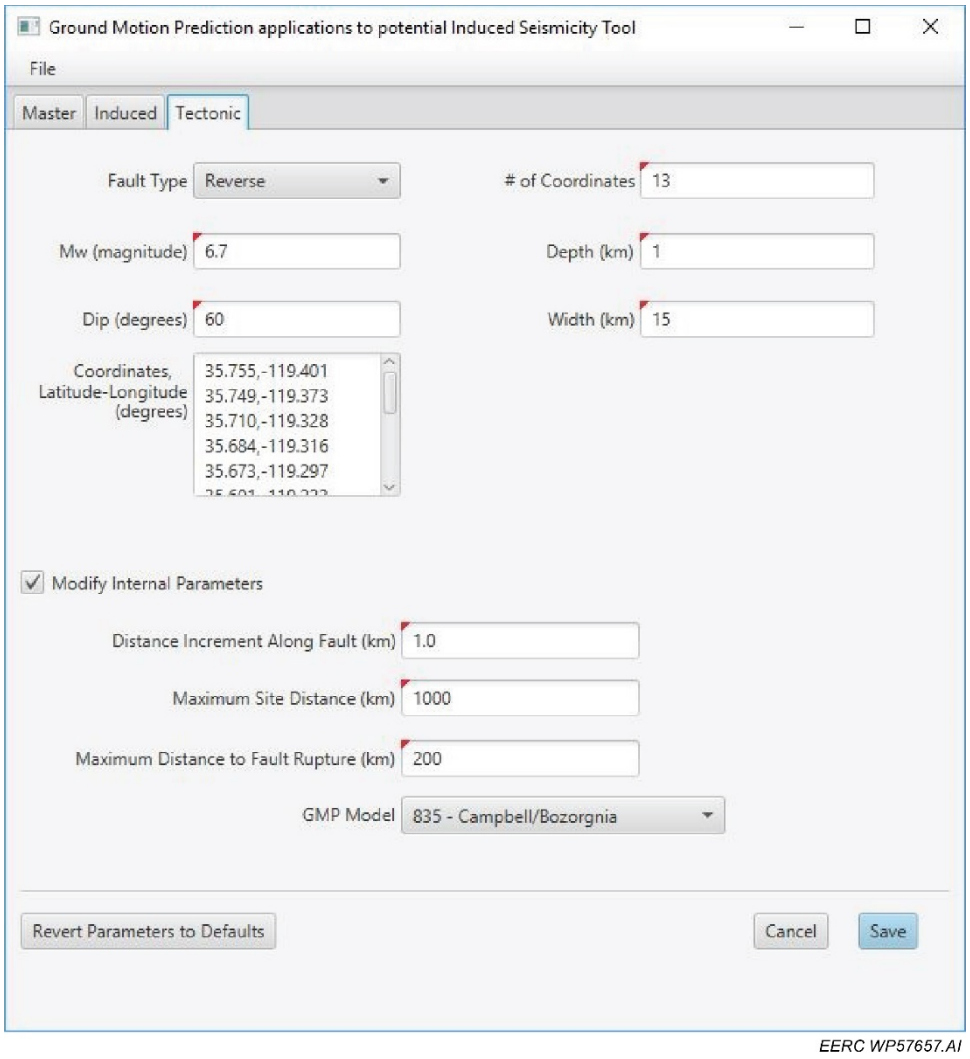


Figure F-33. GMPIS tectonic page showing default parameters (Source: Bradley and others, 2016)

Results

GMPIS generates ASCII files containing calculated peak ground acceleration and spectral acceleration for each site in the Vs 30 grid. Separate sets of ASCII files are generated for induced and tectonic events. The tool also outputs ASCII files needed to generate a ShakeMap using the generic mapping tool (GMT) open source package, including a script and files to plot calculated ground motion values, event epicenter, fault trace, and titles describing the parameters of the selected event.

The commands from the output ShakeMap script were entered into GMT to produce a ShakeMap for the example San Joaquin data set. Some modifications to the script were required because of missing topography files and syntax errors. Figure F-34 shows the ShakeMap generated in GMT using the example data and default parameters.

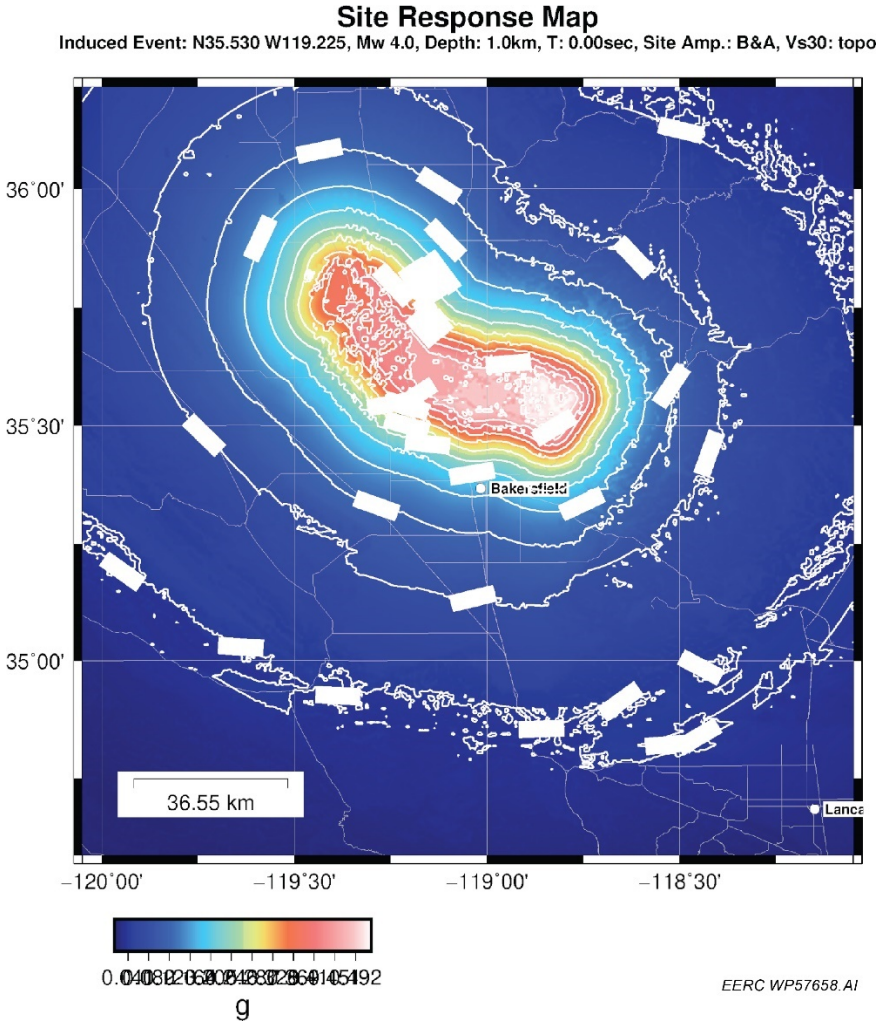


Figure F-34. ShakeMap of the Southern San Joaquin Valley generated in GMT. The map shows the peak ground acceleration values calculated using the San Joaquin example data and GMPIS default parameters.

Peak ground acceleration values calculated with GMPIS for the North Dakota CarbonSAFE data set were mapped using ArcGIS software. Figure F-35 shows one of the ShakeMaps produced using this data set. As shown in the figure, the induced peak ground acceleration would be an order of magnitude less than 0.05% g (the maximum was 0.003 %g), which, according to the scales developed by Worden and others (2012), would not be felt and would result in no potential damage.

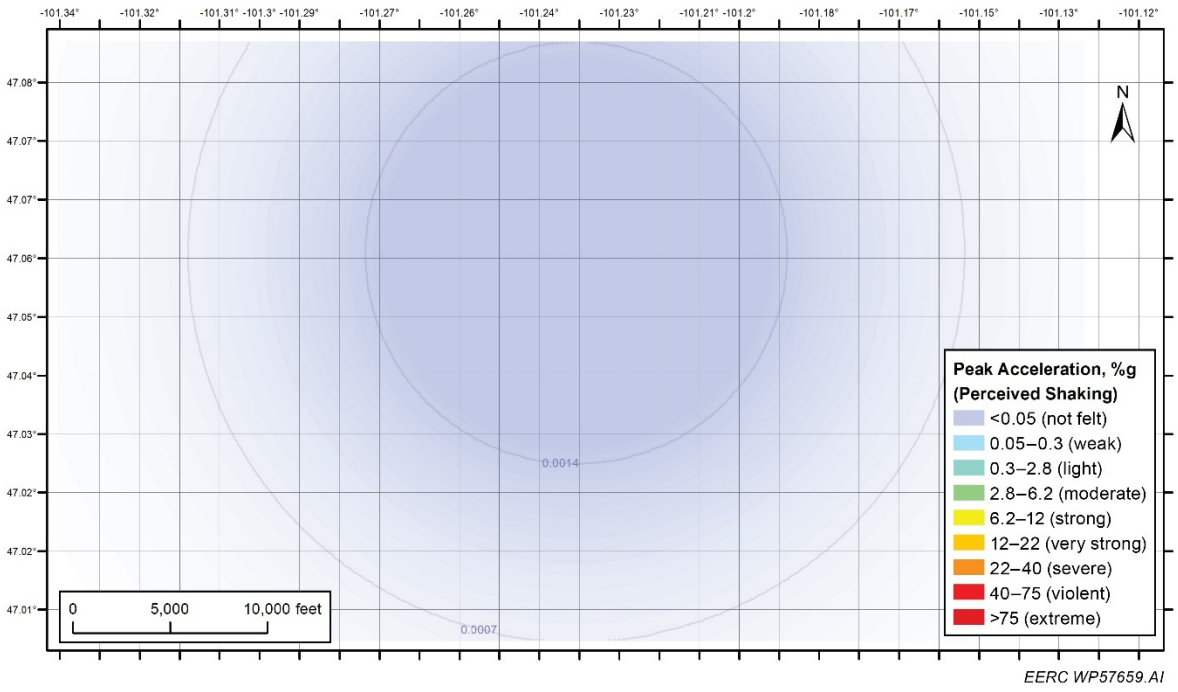


Figure F-35. ShakeMap of the North Dakota CarbonSAFE project area generated in ArcGIS. The map shows the peak ground acceleration values calculated using GMPIS.

Key Findings

The process described above for utilizing GMPIS resulted in the following key findings:

- **Inputs:** The user manual describes options for inputting Vs 30 data that are not available in the version of GMPIS that was tested. Two specific options included in the user manual but not the tool are 1) a box to select if the site is in the Southern San Joaquin Valley and 2) a box to upload a site-specific database if the area of interest is not in the Southern San Joaquin Valley. To use site-specific Vs30 data, the user needs to replace the contents of the VS30gridtopo.txt, VS30gridkt.txt, or VS30gridwc.txt in the bin folder with site-specific data. These site-specific data must be in the appropriate format, and the user must select the corresponding grid type in the Vs30 grid output type dropdown box on the master page in GMPIS.

- **Inputs:** The number of sites entered on the master page needs to be equal to or less than the number of data points in the Vs 30 text file. If the number of sites is greater than the number of data points, then GMPIS gives an error. If the number of sites is less than the number of data points in the Vs 30 text file, then GMPIS only reads in a number of data points equal to the number of sites. GMPIS reads the data point from the text file in sequential order. For example, if the number of sites entered on the master page is ten and the Vs 30 text file contains 20 data points, then the tool only reads the first ten data points. If the user wants to change the number of sites to produce a sparser grid of sites, then the user must modify the Vs 30 text file accordingly.

- **Inputs:** The boundary coordinates entered on the master page do not constrain the ground motion calculations. GMPIS calculates ground motion predictions for sites whose coordinates are in the Vs 30 text file. If the coordinates in the VS 30 text file are outside of the boundary coordinates entered on the master page, then no error is given. Additionally, if the induced event or fault coordinates are outside of the boundary coordinates, then no error is given.

- **Inputs:** No error is given if the number of coordinates specified on the tectonic page does not match the number of coordinates entered in the coordinates, latitude-longitude box.

- **Outputs:** The output ASCII files containing calculated peak ground acceleration and spectral acceleration do not have a header or column labels describing what the data values are or the units for the values. The current version of the user manual does not describe the format of these ASCII files.

- **Outputs:** The output GMT script required modifications to successfully create a ShakeMap using the example data and default parameters. One of the files needed to run the script as it was originally written, the SJVtopo.xyz file, is missing from the example data set. GMT is not commonly used by all tool users. Using GMT to plot site-specific data would require much effort for the user to learn GMT syntax.

Recommendations

Consistent with the key findings, the following are several recommendations for improving GMPIS:

1. The user manual should include more detailed descriptions, including:
   - How the tool reads input files.
   - Minimum and maximum values accepted for each parameter.
   - The input files for the tool and GMT that need to be edited by the user for areas of interest outside the San Joaquin Valley.
   - File formats for input and output data including information about units.
   - Examples of error messages that may be encountered when using the GUI and what is causing them.
   - Steps for how to use the GMT script to produce a ShakeMap, including where to download GMT from, how to call the script, and references to GMT resources.

- References for the different GMP model options on the tectonic page.

2. An option should be added for the user to select a Vs 30 input file from his/her computer.

3. A tool should be provided to the user to populate the Vs 30 input text file, including options to change the number of sites and bounding coordinates.

4. More constraints should be added to input parameter selections such as data validation or error messages.

5. More descriptions should be added to output files, including column labels with units, so it is more straightforward for the user to use the output files with mapping or graphing software.

6. More comments should be added to the GMT script so that the user can better understand how to edit the script for site-specific needs.

NRAP-OPEN-IAM TESTING SUMMARY

The NRAP-Open-IAM (hereafter "Open-IAM") was used to estimate the rates of CO_2 or brine leakage from the storage unit into overlying formations through a set of wellbores located within the study area. Open-IAM testing should be regarded as a theoretical exercise as no evidence exists for the presence of a leaking wellbore in the MRYS study area. Open-IAM testing used two of the available ROMs: 1) open wellbore component and 2) cemented wellbore component. The open wellbore component treats the leakage of CO_2 up an open wellbore or up open (i.e., uncemented) casing/tubing and can treat leakage to an aquifer or to the atmosphere. The cemented wellbore component estimates the multiphase flow of CO_2 and brine along a cemented wellbore and can treat leakage to a thief zone, an aquifer, or the atmosphere (Huerta and Vasylkivska, 2016).

The WLAT testing summary showed the generalized stratigraphy of the MRYS study area storage complex. This figure is repeated below as Figure F-36. The target geologic storage unit is the Broom Creek Formation, a saline formation roughly 5000 ft deep. Notable features of the storage complex include 1) nearly 900 ft of primary sealing formations between the storage unit and the second saline formation – the Inyan Kara, 2) roughly 220 ft of Inyan Kara saline formation, and 3) an additional 2500 ft of sealing formations between the Inyan Kara and the lowermost USDW – the Fox Hills aquifer. These features are identical to those used in previously described WLAT testing. Open-IAM testing captured these features by modifying the inputs to reflect the stratigraphy shown in Figure F-36. This was not always possible given the constraints of a particular ROM, as described below. The conceptual model for wellbore leakage for all Open-IAM testing was a set of eight wellbores that penetrated the Broom Creek Formation and provided a migration pathway from the storage unit up to the surface, including, when applicable, the saline aquifer from 3898 to 4116 ft bgs (the Inyan Kara Formation) and the USDW from 1059 to

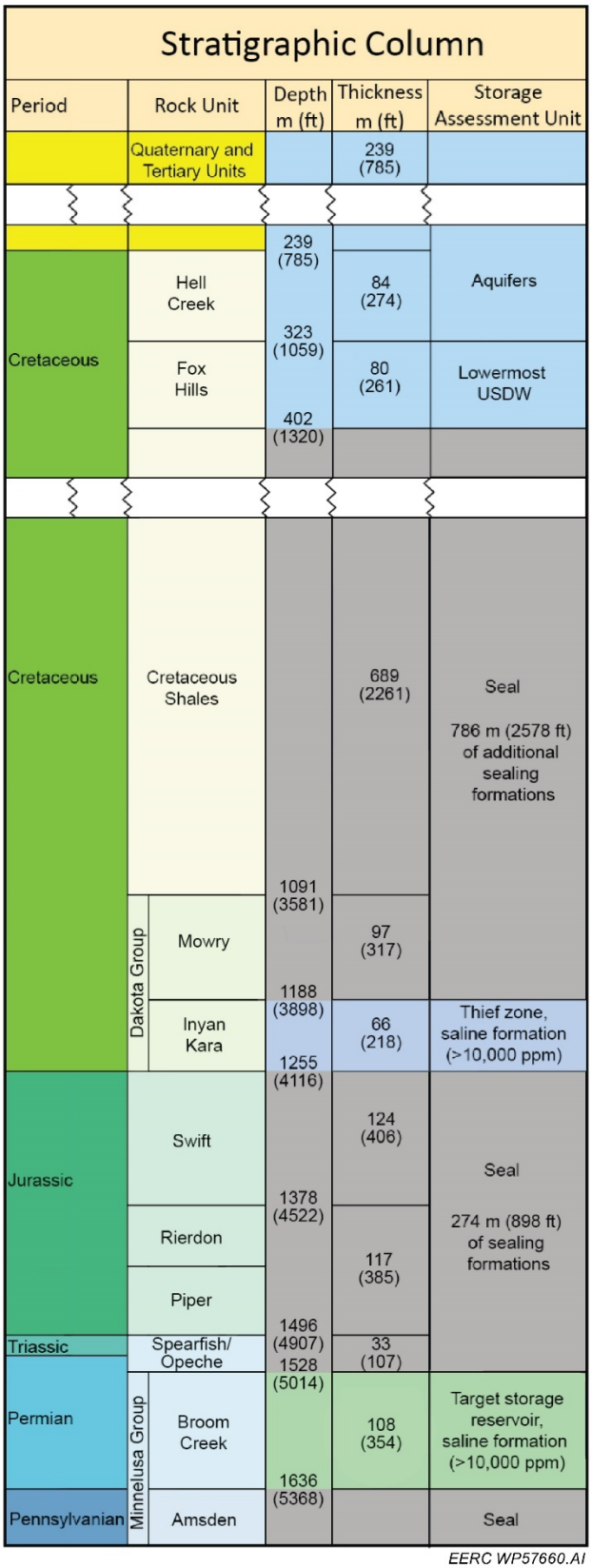


Figure F-36. Generalized stratigraphy used for Open-IAM testing.

1320 ft bgs (the Fox Hills aquifer). In this context, the Inyan Kara is referred to as a thief zone, which is a formation between the storage unit and the USDW with higher permeability that could accept fluids (CO_2 or brine) and thus reduce the flux of fluids to overlying units. Figure F-37 shows a map of the study area with the CMG-GEM simulated CO_2 plume after 25 years of injection and the locations of the eight wellbores included in Open-IAM testing.

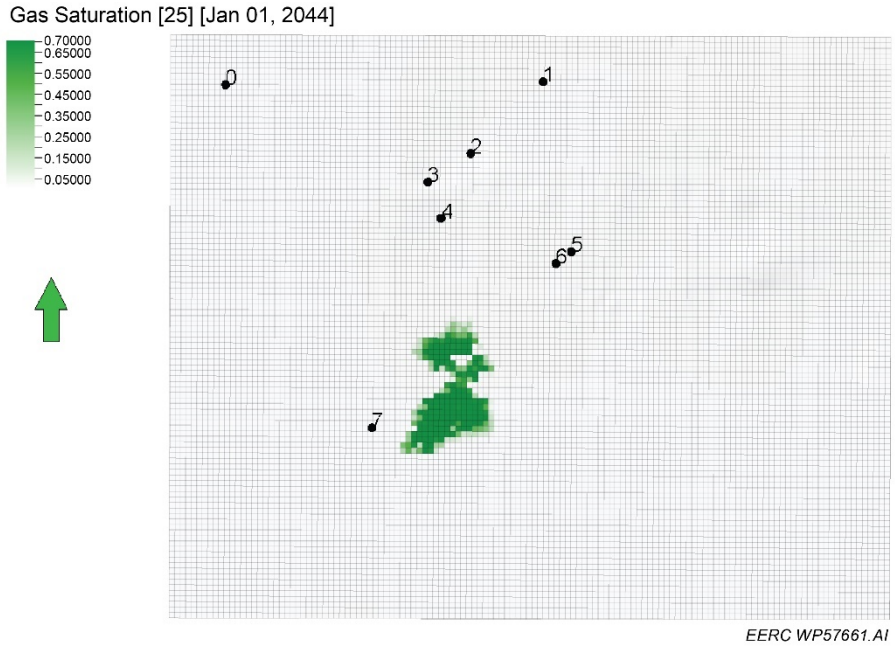


Figure F-37. Map showing the study area with the CMG-GEM simulated CO_2 plume (gas saturation) after 25 years of injection and the locations of the eight wellbores that were included in Open-IAM testing (labeled Wells 0 through 7).

Python Version and Installation

The current version of Open-IAM (release version 1.0.0-19.04.01) requires a Python 3.5 (or greater) installation and depends on a number of additional libraries such as NumPy, SciPy, PyYAML, Matplotlib, pmw, and six. Many of the required libraries are regularly included with scientific-based distributions of Python (such as Anaconda), but they can be installed to existing Python installations with the commonly used pip script and associated commands.

The Open-IAM program that was included in this review was distributed as a .zip file, from which the user could extract the contents of the .zip file to any directory. After Python and Open-IAM's dependencies are installed and the .zip file contents have been extracted, users can access Open-IAM's GUI by using their Python installation to execute the NRAP_OPENIAM.py script (located by default in the *open_iam**source**GUI*\directory).

Inputs and Assumptions

The process of building a model within Open-IAM consists of three primary steps: 1) entering basic model parameters, 2) defining the geologic stratigraphy of the site, and 3) defining a component model for each component of the system to be modeled.

Model Parameters

Open-IAM testing assumed a forward simulation end time of 25 years, in 1-year time step increments. Injection of CO_2 occurred throughout the entire duration of the simulation. Hypothetical leakage from eight wellbores was simulated using either the open wellbore model or the cemented wellbore model. Details about the wellbore properties are entered in subsequent wellbore components; however, the geographic locations of each wellbore are entered in the model parameters. Wellbore locations within Open-IAM may be specified in XY coordinate pairs, according to any coordinate reference system so long as the reservoir properties employ the same system. The eight wellbores shown in Figure F-37 were entered into the model using the X-Coordinates and Y-Coordinates fields located under the wellbore locations input (Figure F-38).

Figure F-38. General model/simulation parameters. Random well-bounding box was not used.

Stratigraphy Component

Similar to WLAT testing, Open-IAM requires stratigraphic thickness inputs for all seals, aquifers, and the reservoir for simulations (Figure F-39). However, Open-IAM allows for more site-specific stratigraphic inputs than WLAT. At a minimum, Open-IAM requires three shale units,

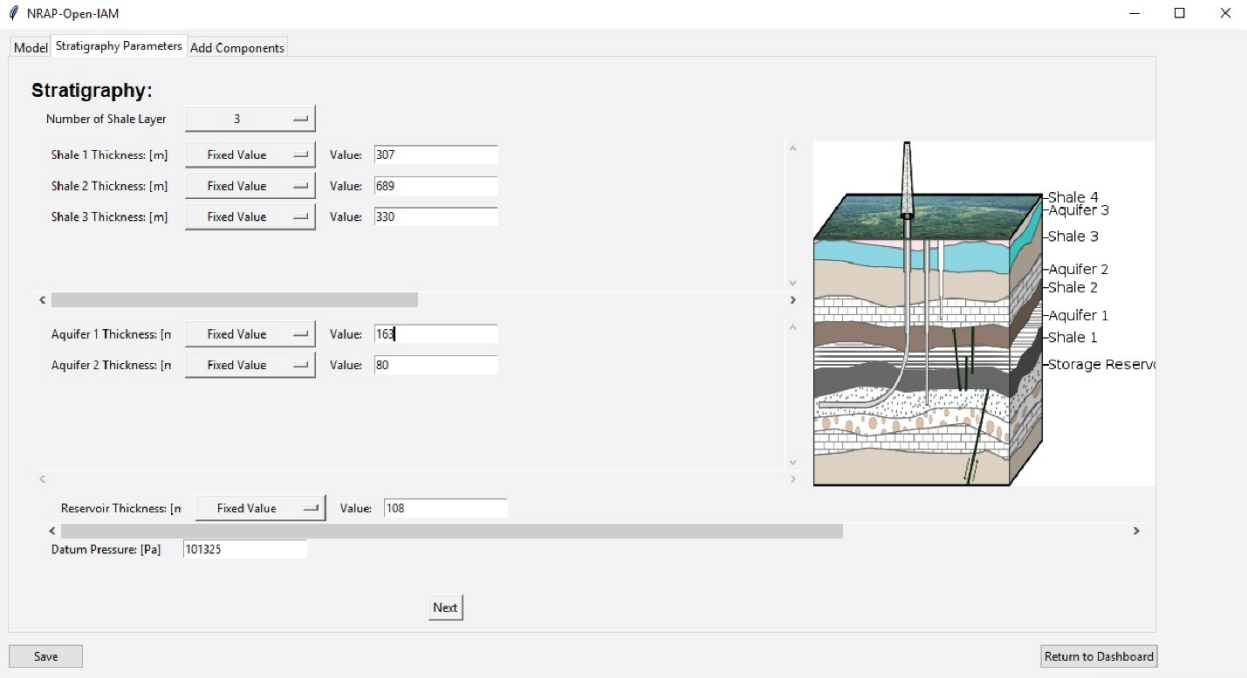


Figure F-39. Input stratigraphy used for the Open-IAM testing. Unit thicknesses and datum pressure are parameterized on the left with an example of the modeled stratigraphic order on the right.

two aquifer units, and a single reservoir unit. The reservoir unit represents the CO_2 storage target. Aquifer 1 represents a high-permeability interval or thief zone, while Aquifer 2 represents a USDW aquifer (the Fox Hills aquifer, in this case). The shale and aquifer units alternate vertically from the storage reservoir up to the ground surface. For example, Shale 1 is the seal (or cap rock) overlaying the storage reservoir. Aquifer 1 overlays Shale 1. Shale 2 overlays Aquifer 1. Aquifer 2 overlays Shale 2. Lastly, Shale 3 overlays Aquifer 2 (Figure F-39). Atmospheric pressure or datum pressure can also be specified, which was left at the default value of 101,325 Pa (1 atmosphere). Table F-2 shows the stratigraphy (units and thicknesses) tested with Open-IAM.

Table 2. Stratigraphic Units and Thicknesses Used in Open-IAM Testing (units are listed in vertical order from the surface [Shale 3] to the storage reservoir)

Unit	Thickness, m
Shale 3	330
Aquifer 2	80
Shale 2	689
Aquifer 1	163
Shale 1	307
Reservoir	108

Lookup Table Reservoir Component

Open-IAM testing used the lookup table reservoir component (lutReservoir tab within Open-IAM), which is a reduced-order model based on interpolation of data from a set of lookup tables (Figure F-40). The lookup tables were derived from CMG-GEM simulation and included gas saturation (CO_2) and pressure outputs within the Broom Creek Formation at each time step and for each model grid cell (X- and Y-coordinates). In previous version of the integrated assessment model NRAP-IAM-CS User's Manual, Version 2016.11-1.1 [Stauffer and others, 2016]), reformatted CMG-GEM simulation files for use as input into IAM could be generated with RROM-Gen. However, RROM-Gen formatted files are currently incompatible with the new Open-IAM and will likely require additional user processing. For Open-IAM testing, a Python script was constructed to reformat the simulation data from CMG-GEM into a format that was appropriate for use in the Open-IAM lookup reservoir component. This lookup table consisted of data from simulation files (e.g., CMG-GEM output) in a comma-delimited format. The table was formatted to contain two columns for X and Y locations and additional columns for properties (e.g., pressure and saturation) for each time step in the simulation (Table F-3).

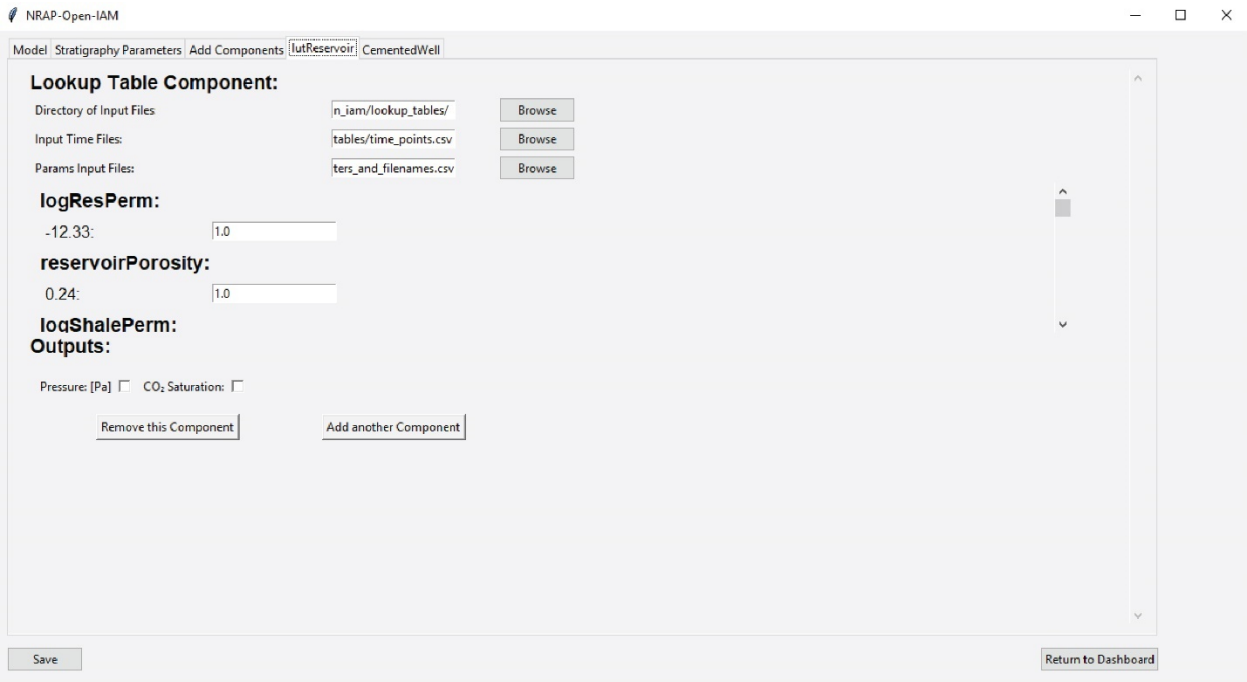


Figure F-40. Parameters used for the lookup table reservoir component. The directory of input files contains the input time files and parameter input files. The input time files contain each time step used for the simulation. The parameter input file contains the general reservoir characteristics (reservoir permeability, reservoir porosity, shale permeability, and file name for the pressure and saturation lookup table).

Table F-3. Example Lookup Table Used in Open-IAM Testing for Reservoir Gas Saturation and Pressure

X	Y	CO_2 Saturation 1	CO_2 Saturation	CO_2 Saturation 25	Pressure 1	Pressure 2	Pressure 25
1728051	451239	0.01	0.01	0.01	17016298	17017726	17053442
1729051	451239	0.01	0.01	0.01	16997208	16998632	17034354
1730051	451239	0.01	0.01	0.06	16977988	16979414	17015132

Three additional parameters are required in the lookup table reservoir component to describe the general petrophysical properties throughout the model: 1) logResPerm, 2) reservoirPorosity, and 3) logShalePerm. The logResPerm is the logarithm of reservoir permeability in units of m^2. The default value is −12 m^2 (1013 mD). A logResPerm of −12.33 $\log_{10}m^2$ (4.6E-13 m^2 or 469 mD) was used in Open-IAM testing. The reservoirPorosity was set to 24%; the default value is 30%. The logShalePerm is the logarithm of shale permeability also in units of m^2. A logShalePerm of −17.96 $\log_{10}m^2$ (1.0E-18 m^2 or 0.001 mD) was used in Open-IAM testing.

Wellbore Properties

Hypothetical leakage from eight wellbores was simulated using either the open wellbore component or the cemented wellbore component. The inputs used for each of these leakage models are described below.

Open Wellbore Component

The open wellbore component (openWell tab within Open-IAM) uses a lookup table ROM based on the drift-flux approach (King and others, 2019). The component considers the wellbore to be open from the ground surface to the depth of the reservoir. The lookup table uses nonisothermal flow of CO_2 and brine up the wellbore and allows for phase transition of the CO_2 from supercritical to gaseous. Implementing the component via the GUI does not allow for definition of a thief zone. The major parameters to define within the open wellbore component are (Figure F-41):

- Normalized wellbore transmissivity ([$\log_{10}$) (−1 to 1): reservoir transmissivity log normalized by depth average transmissivity (default 0.0).
- Brine salinity (−) (0 to 0.2): brine salinity (mass fraction) (default 0.1).
- Radius of the wellbore (m).
- Number of wellbores.
- Leakage to aquifer *n.*

The wellbores used in Open-IAM testing were populated with a normalized wellbore transmissivity of 0 (the default value), brine salinity mass fraction of 0.065, wellbore radius of 0.05 m, eight wellbores, and leakage to Aquifer 2 (the Fox Hills aquifer USDW in this scenario) (Figure F-41).

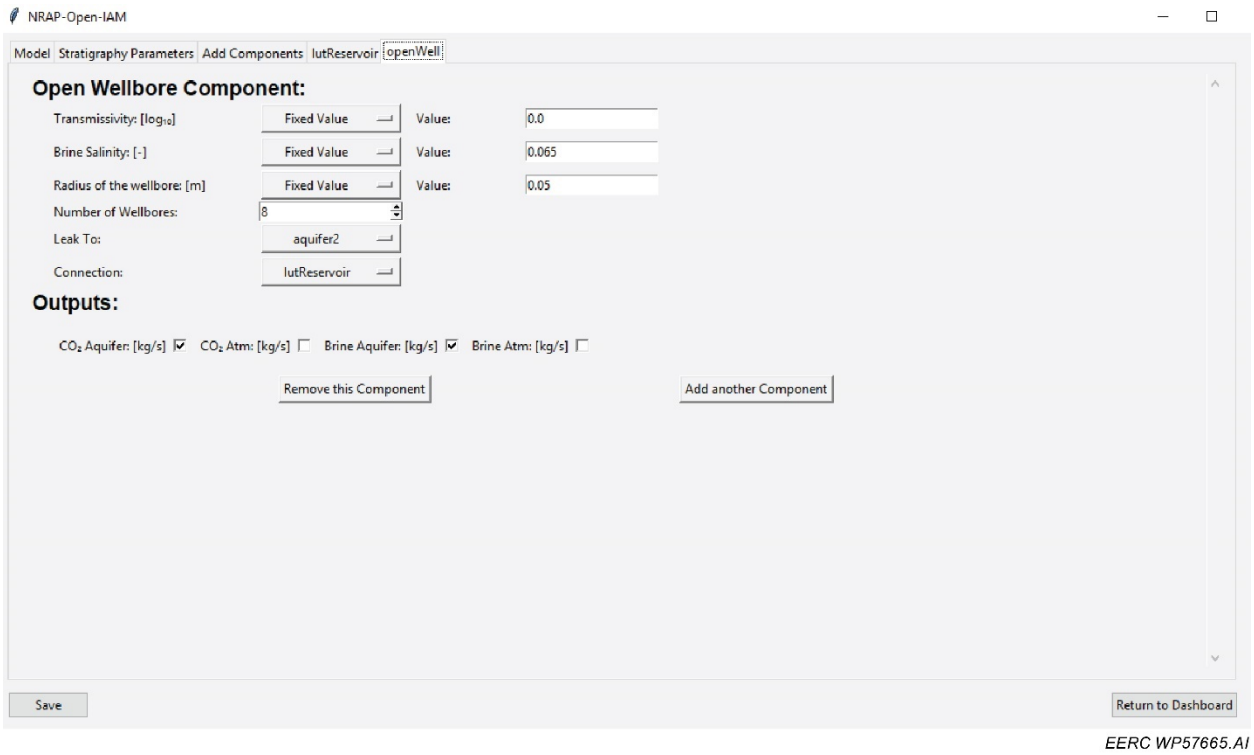


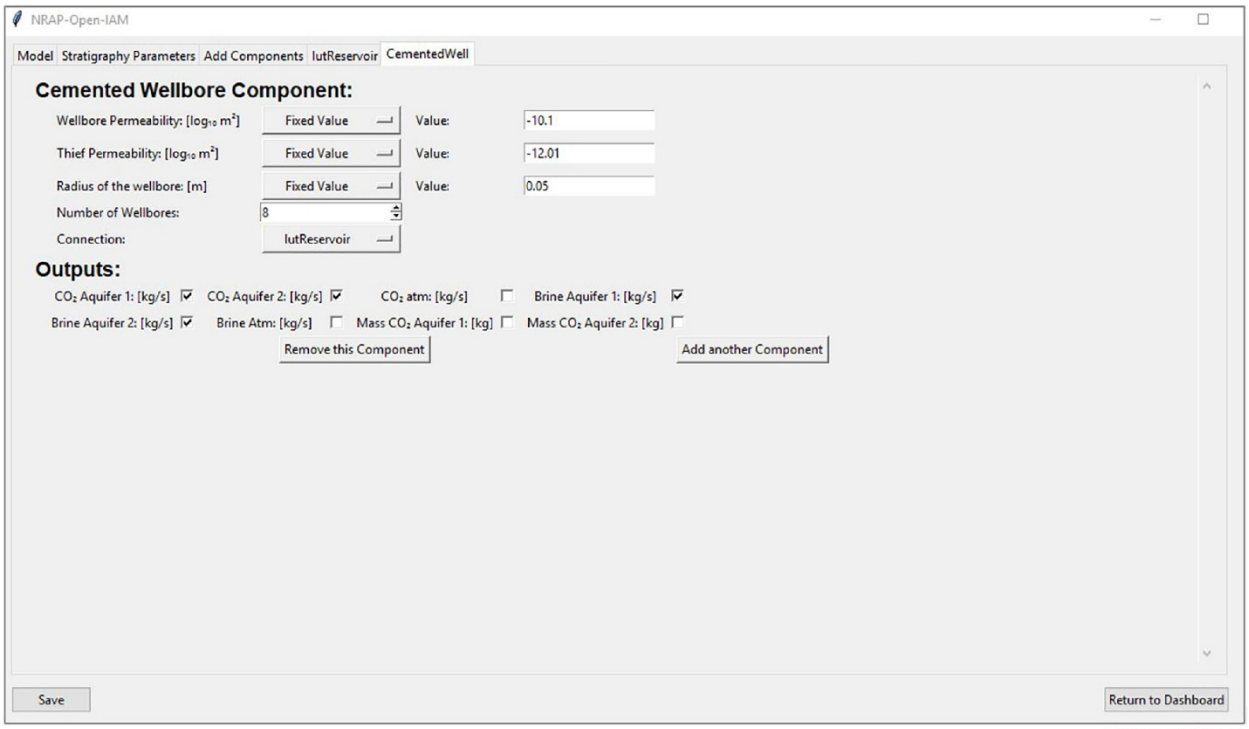
Figure F-41. Open wellbore component parameter input screen for Open-IAM.

Cemented Wellbore Component

The Open-IAM user manual (King and others, 2019) describes the cemented wellbore component as a model built from detailed full-physics finite element head and mass (FEHM) simulations. The FEHM transfer simulations are three-dimensional, multiphase solutions of heat and mass transfer of water and supercritical, liquid, and gas CO_2.

The cemented wellbore component requires the presence of a thief zone. The program assigns Aquifer 1 as the thief zone and Aquifer 2 as the leak to unit, which was left as is for Open-IAM testing. The major parameters to define within the cemented wellbore component are (Figure F-42):

- Wellbore Permeability ($\log_{10}$ m^2) (−13.95 to −10.1): logarithm of wellbore permeability (default is −13).
- Thief Permeability ($\log_{10}$ m^2) (−13.995 to −12): logarithm of thief zone permeability (default is −12).
- Radius of the wellbore (0.05 m).
- Number of wellbores.



EERC WP57851.AI

Figure F-42. Cemented wellbore component parameters for the -10.1 $\log_{10}$ m^2 wellbore permeability case.

For Open-IAM testing, wellbore permeability was varied to assess the sensitivity of the leakage results to this parameter. The wellbore permeability values were decreased from a maximum of −10.1 to a minimum of −13.95 $\log_{10}$ m^2 in five increments (−10.1, −11, −12, −13, and −13.95 $\log_{10}$ m^2). The permeability of the thief zone, wellbore radius, and number of wellbores were held constant at −12.01 $\log_{10}m^2$, 0.05 m, and eight wellbores, respectively (Figure F-42).

Results

The simulated time series leakage rates for CO_2 and brine to Aquifer 2 (USDW) for each of the eight wellbores were exported from Open-IAM into Microsoft Excel for organizing and graphing. As shown in the map in Figure F-37, these wellbores were located at different distances from the simulated CO_2 plume. Wellbore 7 was located closest to the CO_2 plume, while Wellbores 0 and 1 were located furthest from the CO_2 plume. The following set of figures illustrates the effect of distance from the CO_2 plume on Open-IAM results by plotting the simulated time series leakage rate results for Wellbores 7, 4, and 1. These three wellbores provide results corresponding to near, middle, and far wellbores, respectively. Results were generated for the open wellbore component and for five different realizations of the cemented wellbore component, assuming a wellbore permeability of 10.1, −11, −12, −13, and −13.95 $\log_{10}$ m^2 (Figures F-43–48).

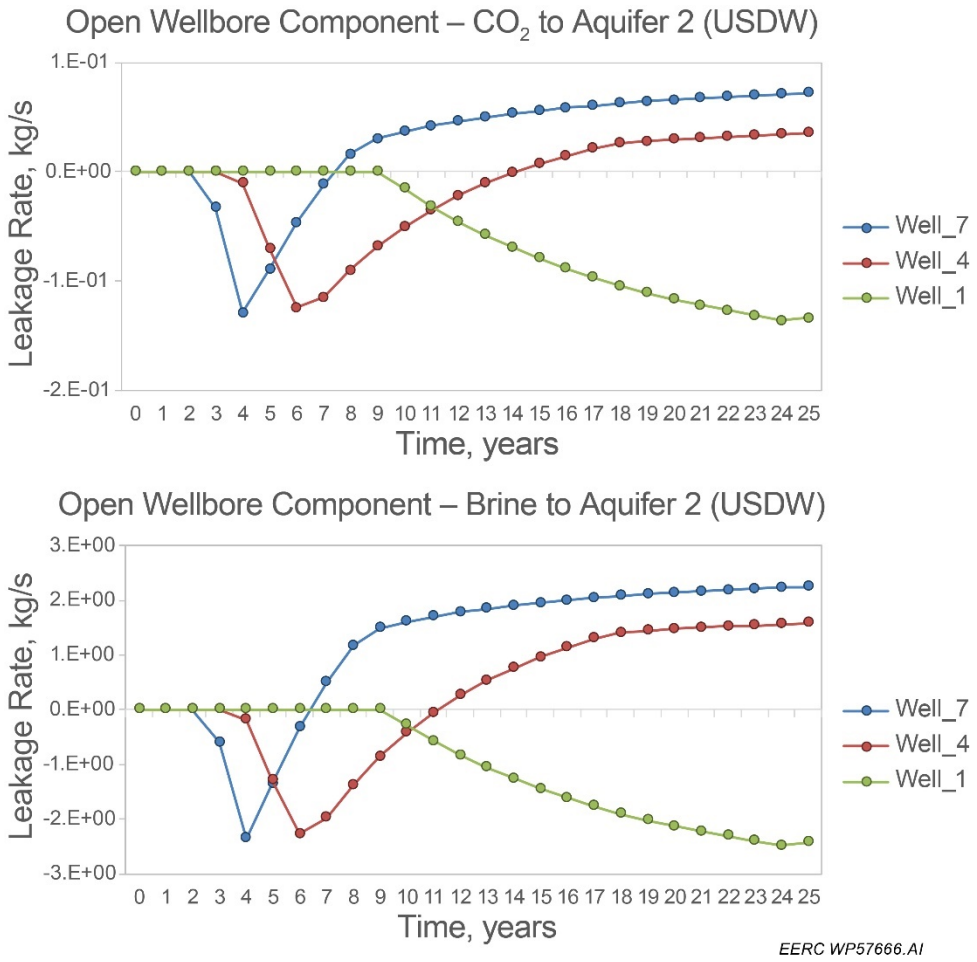


Figure F-43. Open-IAM results for the open wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection.

The results in Figures F-43–48 show somewhat similar trends as those from WLAT testing. For example, the estimated CO_2 and brine leakage rates increased with time and the leakage rates were proportional to cemented wellbore permeability (i.e., higher permeability resulted in greater leakage rates).

One issue that was encountered while testing Open-IAM was CO_2 leakage from wellbores located beyond the separate-phase CO_2 plume. As shown in the map in Figure F-37, Wellbores 0, 1, and 7 were located at different distances from the simulated CO_2 plume. Wellbore 7 was located closest to the CO_2 plume, while Wellbores 0 and 1 were located furthest from the CO_2 plume. Consequently, Wellbores 0 and 1 should not have had CO_2 leakage, as these wellbores were located well beyond the separate-phase CO_2 plume. As described in RROM-Gen testing, the function model of CMG-GEM was used to set the CO_2 saturation as 0% when the CO_2 saturation in the simulation was less than 0.01%. This preprocessing step in CMG-GEM provided

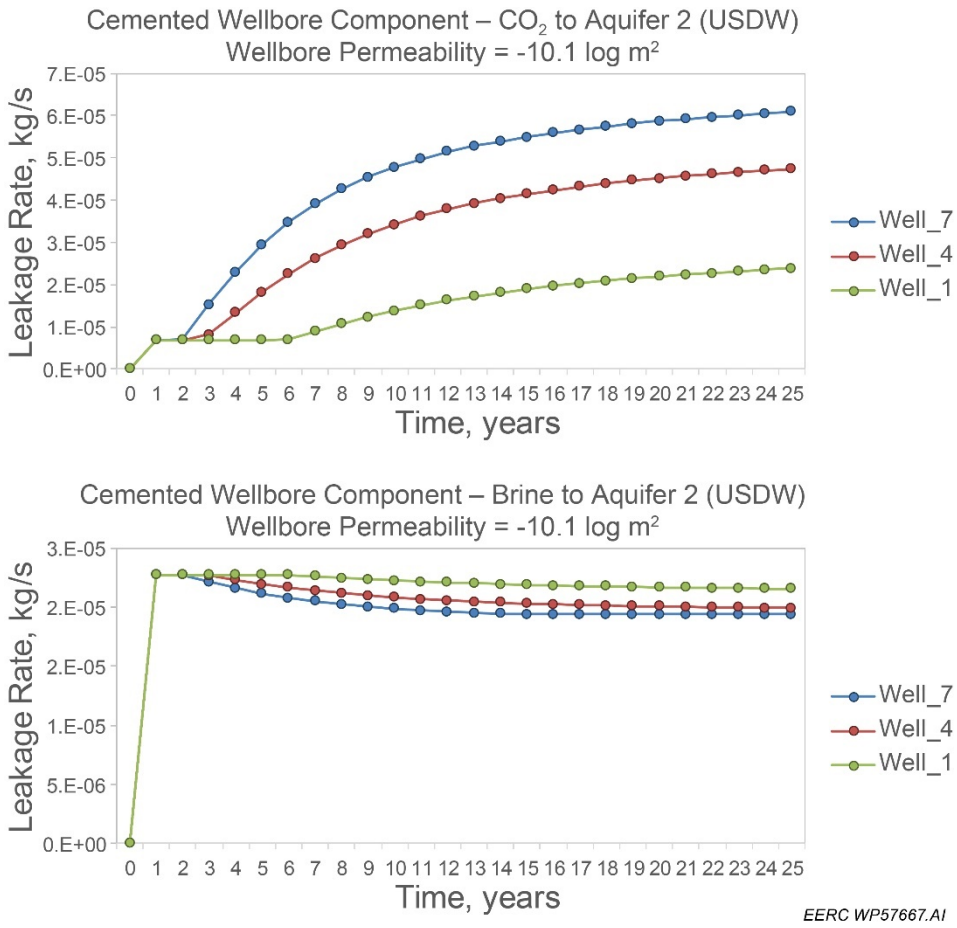


Figure F-44. Open-IAM results for the cemented wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability was -10.1 $\log_{10}m^2$ (the maximum allowable in the cemented wellbore component).

a more consistent output for RROM-Gen. Unfortunately, the testing found that Open-IAM would not run with null cells in the lookup table reservoir component. As a result, the model domain used in the lookup table for Open-IAM testing contained small gas saturation values that generated CO_2 leakage results for all wells, even those outside of the separate-phase CO_2 plume. A second issue encountered while testing Open-IAM was negative leakage rates for some cemented wellbore permeability settings. For example, while cemented wellbore permeability values of -10.1 and -11 log m^2 generated positive CO_2 and brine leakage rates across all time steps, lower permeability values (-12, -13, and -13.95 log m^2) resulted in negative CO_2 and/or brine leakage rates some or all time steps. Similar results were observed during WLAT testing of the cemented wellbore model when the cement permeability was set to -13 log m^2. The reason for these erroneous outputs is currently unknown.

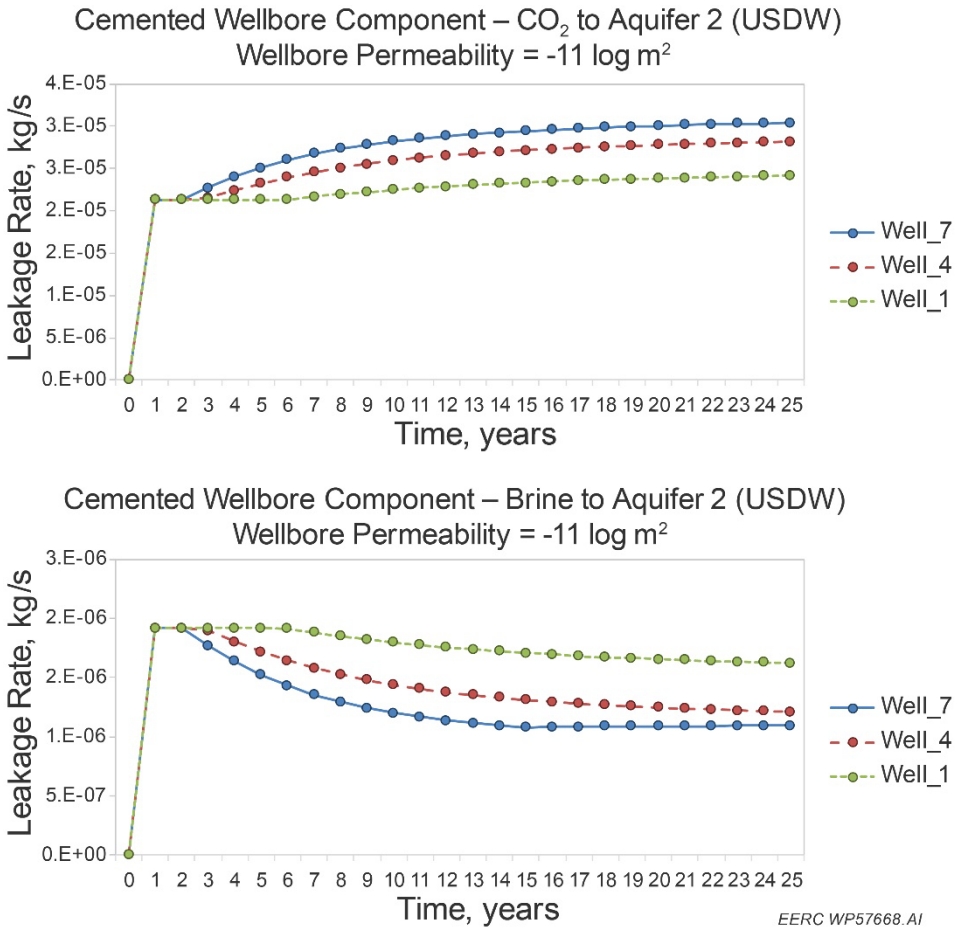


Figure F-45. Open-IAM results for the cemented wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability was -11.0 $\log_{10}m^2$.

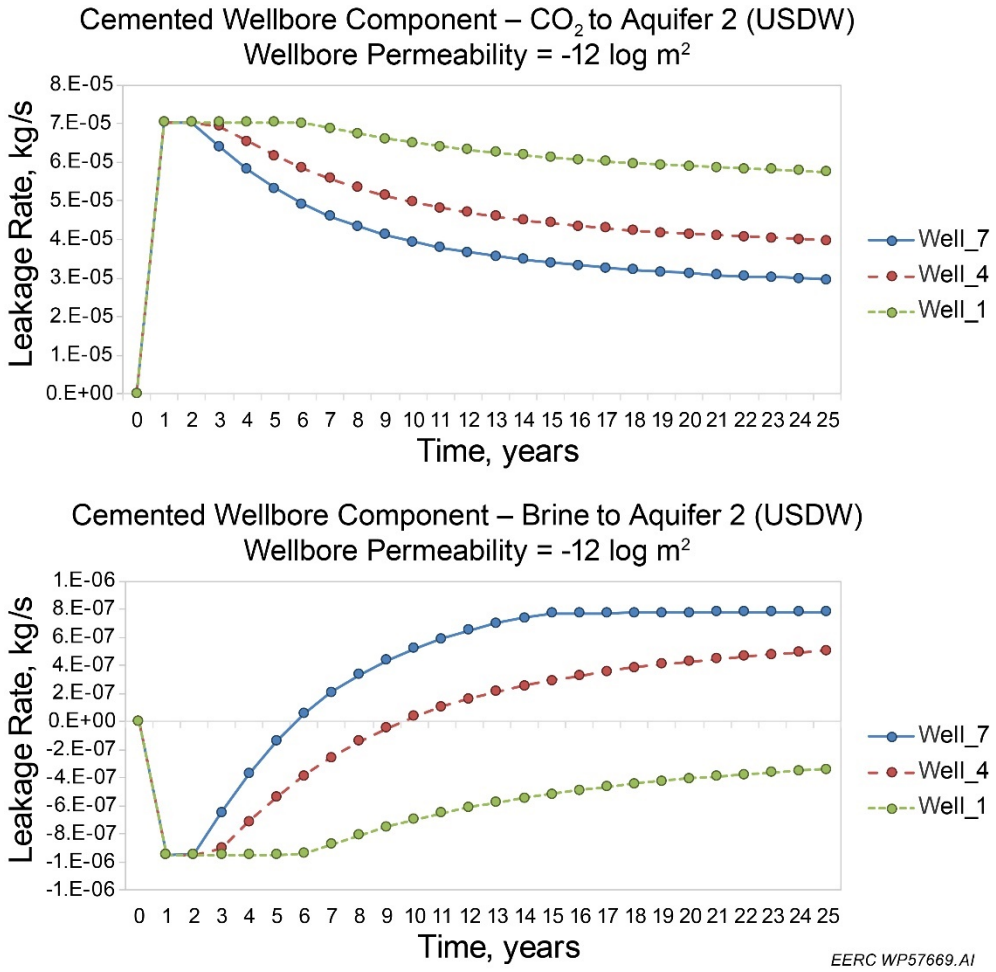


Figure F-46. Open-IAM results for the cemented wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability was -12.0 $\log_{10}m^2$.

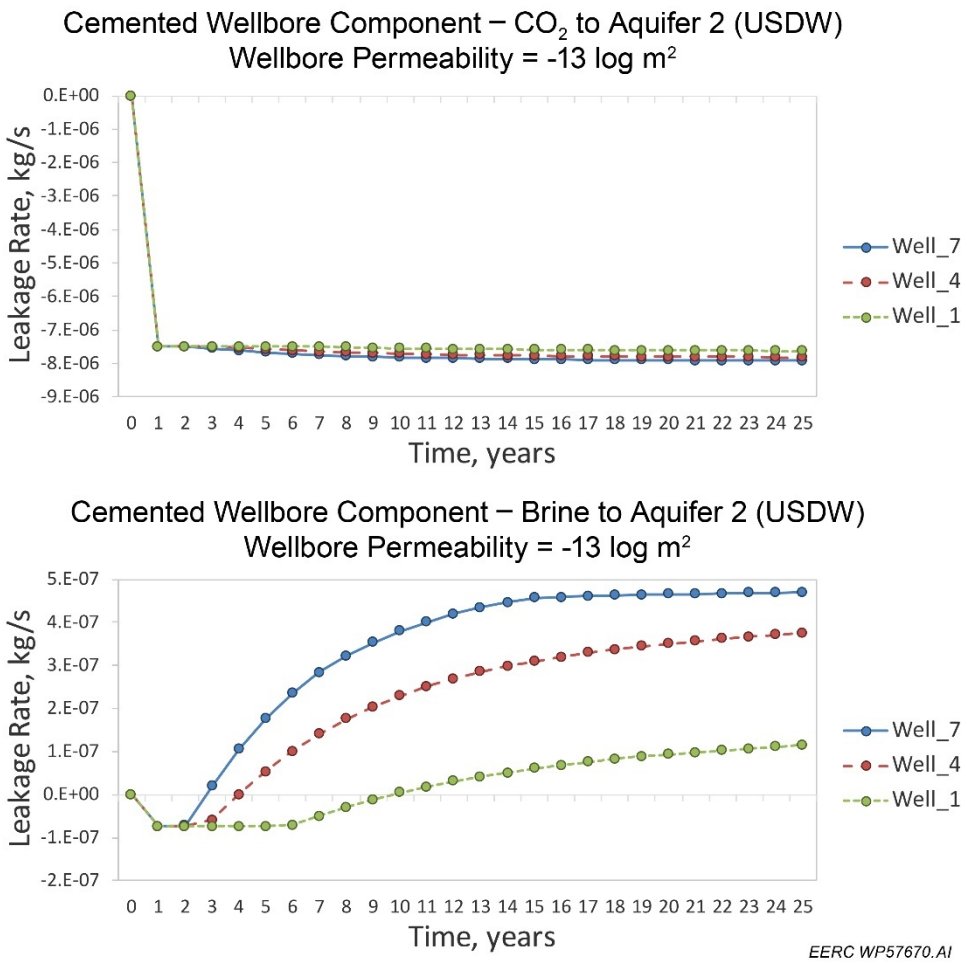


Figure F-47. Open-IAM results for the cemented wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability was -13.0 $\log_{10}m^2$.

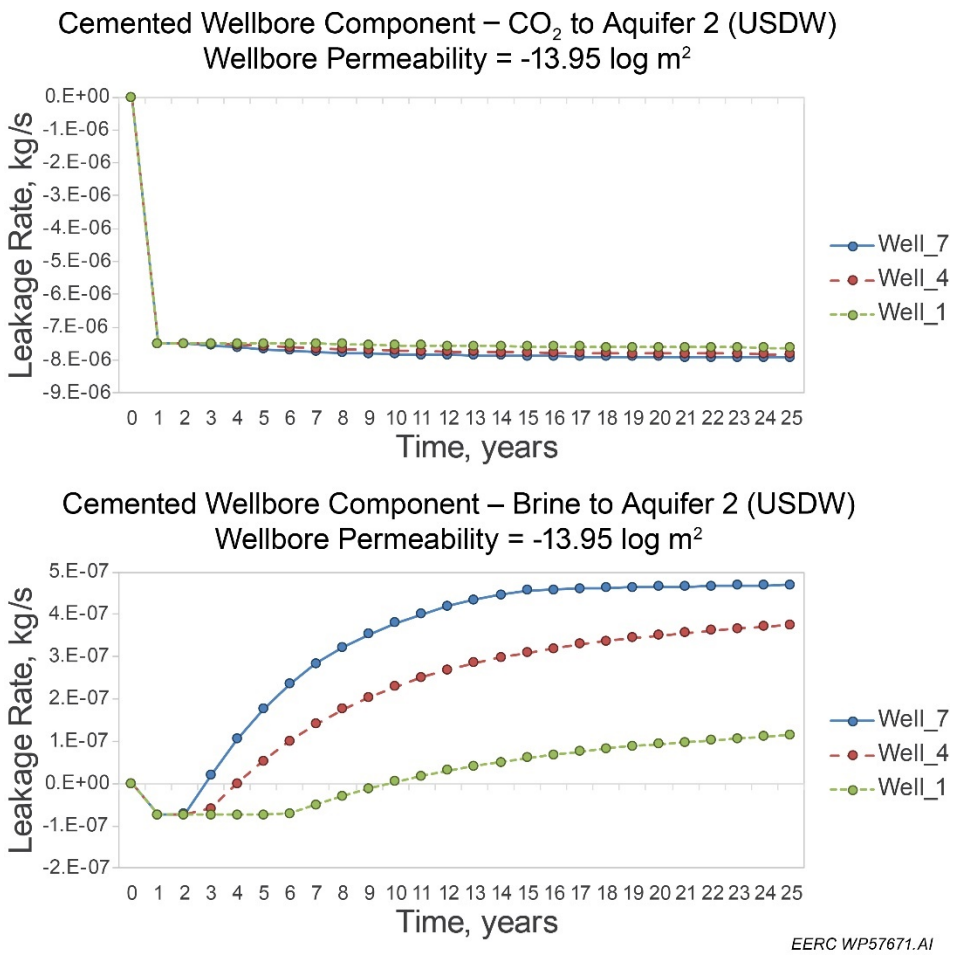


Figure F-48. Open-IAM results for the cemented wellbore component for Wellbores 7, 4, and 1 (near, middle, and far, respectively) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability was -13.95 $\log_{10}m^2$ (the minimum allowable in the cemented wellbore component).

Figure F-49 compares Open-IAM CO_2 and brine leakage rates for Wellbore 7 for each of the six realizations (one open wellbore component and five different realizations of the cemented wellbore component, assuming a wellbore permeability of 10.1, −11, −12, −13, and −13.95 $\log_{10}$ m^2). The *y*-axes in all panels are $\log_{10}$-transformed to aid comparison across scenarios, which results in some cases not appearing in the panels on account of model results of either zero or negative CO_2 leakage rates. As shown in the figure, the open wellbore component is the most conservative assessment, with several orders-of-magnitude greater leakage rates than any of the Cemented Wellbore Component realizations.

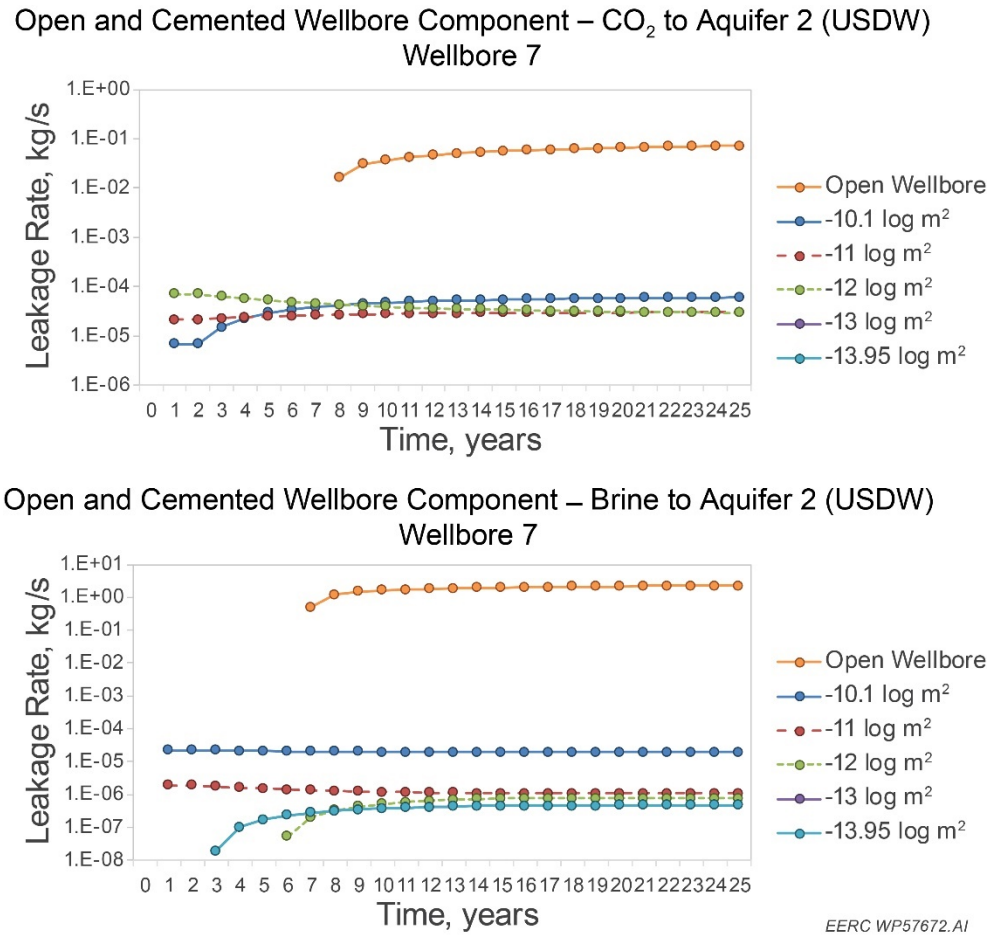


Figure F-49. Open-IAM results for the open and cemented wellbore components for Wellbore 7 (the closest to the injection wells) showing leakage rates of CO_2 (top) and brine (bottom) to Aquifer 2 (USDW) as a function of time in years since CO_2 injection. Wellbore permeability for the cemented wellbore component was varied from -10.1 $\log_{10}m^2$ (the maximum allowable) to -13.95 $\log_{10}m^2$ (the minimum allowable). It should be noted that the y-axis is displayed on a log scale, which does not show zero or negative values; hence, some results are not displayed in this version of the outputs.

Key Findings

Open-IAM testing resulted in the following key findings:

- **Inputs:**
  - To be used as a lookup table, pressure and CO_2 saturation outputs from CMG-GEM needed to be reformatted to a comma-delimited table format (Table F-3). In previous versions of IAM, this lookup table format could be obtained from the IAM RROM-Gen. However, the current version of Open-IAM is not compatible with RROM-Gen output format, which requires the user to reformat the lookup table.

- In order to use the cemented wellbore component, the site-specific stratigraphy needed to be altered from the actual stratigraphy shown in Figure F-36 because the program requires the depth to the center of the thief zone from the top of the reservoir to be within a certain range. The depth is represented, and automatically calculated from the stratigraphy component, by a depth ratio between 0.3 and 0.7.

- Using the GUI, it can become difficult to troubleshoot input errors. Some erroneous inputs (values outside of ranges, incorrect parameter file entries, etc.) cause the console window to close immediately, imparting little feedback to the user.

- Minimum CO_2 saturation values (e.g., locations far away from a plume) must be 1% at a location. If entered as 0%, then the simulation reports no leakage even at wells close to a plume.

- **Outputs:**
  - Outputs from a forward simulation of this type, using fixed values for each realization, can only be plotted as a time series.

  - The Open-IAM program creates a file with leakage rates for each time step for each well. With a large number of wells, a large number of files could potentially be generated, which would make plotting and analyzing the results intractable.

Recommendations

Consistent with the key findings, the following are three recommendations for improving Open-IAM:

1. Future versions should provide more feedback for user-caused errors and warnings, e.g., leave the console window open longer, expand on causes of scaling issues if possible, etc.

2. Documentation accompanying Open-IAM should provide more examples of proper comma-delimited tables for use as lookup tables and a workflow to generate these files from commercial simulation packages like CMG-GEM or future releases of RROM-Gen.

3. Future versions should allow the user to have more control over the depth to aquifer and reservoir units such that the physical system modeled in Open-IAM can more accurately reflect the site-specific stratigraphy. Based on Open-IAM testing, the fraction of well depth to the center of the thief zone from the top of the reservoir must be in the range of 0.3 to 0.7. Allowing the user to manually enter this value, or widening the range, would allow for a more accurate system stratigraphy.

REFERENCES

Bradley, C., Coblentz, D., and Lee, R., 2016, Ground motion prediction applications to potential induced seismicity (GMPIS) tool user's manual, Version 2016.11-1.1; NRAP-TRS-III-018-

2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p. 28.

Huerta, N.J. and Vasylkivska, V.S., 2016, Well leakage analysis tool (WLAT) user's manual, Version: 2016.11-1.0.0.3; NRAP-TRS-III-011-2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Albany, OR, p. 44.

King, S., 2016a, Reservoir evaluation and visualization (REV) tool user'sm, Version: 2016.11-1.2.0; NRAP-TRS-III-013-2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p 20.

King, S., 2016b, Reservoir reduced-order model – generator (RROM-Gen) tool user's manual, version: 2016.11-1.2; NRAP-TRS-III-014-2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p. 16.

King, S., Vasylkivska, V., Bacon, D., Harp, D., Keating, E., Yang, Y., Zhang, Y., Chen, B., and Mansoor, K., 2019, NRAP-Open-IAM user's guide, Release beta 1.0.0-19.04.01; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p. 28.

Park, C.B., Miller, R.D., and Xia, J., 1999, Multichannel analysis of surface waves, Geophysics, v. 64.3, p. 800–808.

Shepherd, M., 2009, 3-D geocellular modeling, in M. Shepherd, Oil Field production geology: AAPG Memior, v. 91, p. 175–188.

Stauffer, P., Chu, S., Tauxe, C., and Pawar, R., 2016, NRAP integrated assessment model-carbon storage (NRAP-IAM-CS) tool user's manual, Version: 2016.11-1.1; NRAP-TRS-III-010-2016; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, p. 64.

U.S. Environmental Protection Agency, 2013, Geologic sequestration of carbon dioxide—Underground Injection Control (UIC) Program Class VI well area of review evaluation and corrective action guidance: Office of Water (4606M), EPA 816-R-13-005, May 2013.

Worden, C.B., Gerstenberger, M.C., Rhoades, D.A., and Wald D.J., 2012, Probabilistic relationships between ground-motion parameters and modified Mercalli intensity in California Bull. Seism. Soc. Am., v. 102, no. 1, p. 204–221, DOI: https://doi.org/10.1785/0120110156.