15

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

Carbon Dioxide Storage Potential of the Broom Creek Formation in North Dakota: A Case Study in Site Characterization for Large-Scale Sequestration

James A. Sorensen, Steven A. Smith, Anastasia A. Dobroskok, and Wesley D. Peck

Energy and Environmental Research Center (EERC), Grand Forks, North Dakota, U.S.A.

Matthew L. Belobraydic, Justin J. Kringstad, and Zheng-Wen Zeng

University of North Dakota Department of Geology and Geological Engineering, Grand Forks, North Dakota, U.S.A.

ABSTRACT

Future fossil-fuel-based energy production facilities may include carbon management strategies as part of their overall operational plans. Geologic formations, such as saline systems, oil fields, and coal seams, appear to have significant capacity to store carbon dioxide (CO_2), provided that they have adequate porosity, permeability, temperature and pressure conditions, and competent seals. As part of the conceptual design phase of a proposed near-zero emission coal-fired power plant in southwestern North Dakota, the Broom Creek Formation was identified as a potential sink for large-scale CO_2 sequestration. The Pennsylvanian–Permian Broom Creek Formation is a laterally extensive sandstone at the top of the Minnelusa saline aquifer system, which is capped by the Opeche Formation, an anhydritic shale. A wide variety of previously generated data, including well logs, core analysis, water analysis, and other published data, were used to conduct a detailed characterization of an area of the Broom Creek Formation in the immediate vicinity of the proposed power plant location. These data were used to estimate injection rates and predict plume size and migration tendencies. The results of the exercise suggest that a minimum of 50 mmt of CO_2 could be stored in an area no larger than 15 mi^2 (2.5 km^2) over an injection period of 30 yr. This case study describes an approach that

DOI:10.1306/13171244St593378

can be applied to conduct reconnaissance-level, site-specific characterizations of geologic formations for the purpose of large-scale CO_2 sequestration.

INTRODUCTION

Because of their relative abundance and low cost, fossil fuels, such as coal, oil, and natural gas, will continue to dominate the United States energy supply in the foreseeable future. To limit potential adverse effects on Earth's climate, the management of most of the CO_2 emissions associated with fossil fuel use may be necessary. In the United States, geologic sinks such as brine formations, oil reservoirs, and coal seams have been estimated to have a capacity to sequester anywhere from 3 to more than 3700 billion metric tonnes of CO_2 (Bradshaw et al., 2006). Characterization of geologic formations with respect to storage capacity, injectivity, and seal competency is critical when large-scale CO_2 injection projects (>1 million tons/year) are considered. Characterization of candidate brine formations is necessary at both the regional and site-specific scales to determine capacities and operational parameters.

In 2003, the U.S. Department of Energy's National Energy Technology Laboratory established seven regional carbon sequestration partnerships to encourage large-scale geologic CO_2 sequestration projects. The Plains CO_2 Reduction (PCOR) Partnership is one of the partnerships created to perform a regional assessment of carbon sequestration opportunities. One of the primary functions of the PCOR Partnership, which spans an area including nine states and four Canadian provinces, is to conduct a reconnaissance-level characterization of geologic sinks in the region, including selected brine formations. The Broom Creek Formation in western North Dakota was one of the brine formations selected for evaluation as a potential sink for CO_2 sequestration. The Broom Creek Formation was selected for detailed examination because the construction of a new 275-MW CO_2-capture-ready coal-fired power plant in southwestern North Dakota has been under consideration by some members of the PCOR Partnership, and those partners were interested in using a brine formation in the vicinity of the proposed location for large-scale CO_2 sequestration. The goal of the partners was to find a location that could support the storage of 50 mmt of CO_2 to be injected over 30 yr.

Within a brine formation, CO_2 can be stored by three mechanisms: (1) trapped in a supercritical state by displacing the water in the pore volume, (2) dissolved in the formation water, and (3) mineralized through chemical reaction (Pruess et al., 2001). For a geologic formation to act as a CO_2 sink, the formation must have adequate porosity and permeability, suitable pressure and temperature conditions, and a competent seal. The capacity and injectivity of the Broom Creek Formation, the competence of the seal, and a variety of other geologic conditions were demonstrated by the evaluations described below using previously generated data from publicly available sources.

Unlike most previously published evaluations of the CO_2 sequestration potential of brine formations, which are typically focused on developing capacities for a formation over a large area, the evaluation of the Broom Creek Formation in North Dakota was focused on determining the capacity and injectivity for a formation at a specific location. To that end, activities were conducted to predict the projected size of the CO_2 plume that would be created by the injection of a set amount of CO_2 over a set period of time. Two distinct approaches were used to develop predictions of injectivity and plume size. The methods and approaches described in this case study do not consider every factor and condition that may affect the suitability and ultimate storage capacity of the saline aquifer formation in the study area. However, they do provide a means by which the potential capacity of a target injection zone within a brine formation at a specific location can be estimated using relatively limited data. As the need for more CO_2 storage locations increases in coming years, these reconnaissance-level evaluation methods can be used as part of the early stages of site selection for future carbon-capture-ready industrial facilities.

SELECTED SITE

The location for the proposed power plant is in the eastern part of Bowman County in the southwestern corner of North Dakota (Figure 1). The site is located in the southern part of the Williston Basin, an intracratonic sedimentary basin with a column of alternating sequences of permeable and nonpermeable rock formations more than 3048 m (10,000 ft) thick (Heck et al., 2005). Several formations in the Williston Basin have been previously identified that may be suitable for large-scale CO_2 sequestration (Smith et al., 2006). Figure 2 shows the stratigraphy of the Williston Basin and identifies several potential CO_2 sequestration target formations. The Broom Creek Formation, a sandstone saline aquifer of the Minnelusa Group, was determined to be the primary target formation for the geologic sequestration of CO_2 from the proposed facility. The Broom Creek Formation was selected because (1) a significant amount of relevant data was available in the form of published dissertations, theses, and well files and (2) initial evaluations of readily available data on brine formations in the study area suggested that the Broom Creek Formation

FIGURE 1. Location map of Bowman County, North Dakota.

would likely have high capacity and multiple overlying sealing formations.

Well data files, well logs, and core data provided by the North Dakota Department of Mineral Resources Oil and Gas Division were combined with measurements reported by Rygh (1990) and Hoda (1977) to generate formation structure, pressure, temperature, and thickness maps for the Broom Creek Formation and its primary seal, the Opeche Formation. Figure 3 shows a part of a well log taken from a well approximately 8 km (5 mi) east of the proposed site that was used as a type log for the Broom Creek Formation and Opeche Formation in the study area. The porosity and permeability values used in the capacity calculations were derived from this type log. Figures 4 and 5 are cross sections showing the relative positions of the two formations in the study area.

INJECTION FORMATION DESCRIPTION

The Broom Creek Formation is part of an upper Pennsylvanian–Lower Permian clastic wedge (primarily sandstones) that extends from the central part of the Williston Basin in North Dakota southwestward into the Wyoming part of the Powder River Basin (Figure 6). The predominant lithology of the Broom Creek Formation is reddish-brown to pink eolian quartzarenite with thin interbeds of dolostone and shale (Ziebarth, 1972; Rygh, 1990). The average porosity for all facies of the Broom Creek as determined by thin-section measurements is about 14%, with a maximum porosity of roughly 20% in the eolian sandstones (Rygh, 1990). The Broom Creek Formation is the uppermost formation of the Minnelusa Group, sometimes referred to as the Minnelusa aquifer system.

The depth to the Broom Creek Formation (Figures 4, 7) in the study area ranges from approximately 1706 to 2010 m (5600 to 6600 ft), with a depth of 1860 m (6100 ft) at the injection site. The formation ranges in thickness from 30 to 51 m (100 to 170 ft). The in-situ hydrostatic pressure and temperature conditions of the Broom Creek Formation (Figures 8, 9, respectively) are above the CO_2 critical point throughout the Williston Basin. In the study area, the Broom Creek Formation hydrostatic pressure ranges from approximately 17.24 MPa (2500 psi) to approximately 20.68 MPa (3000 psi), whereas

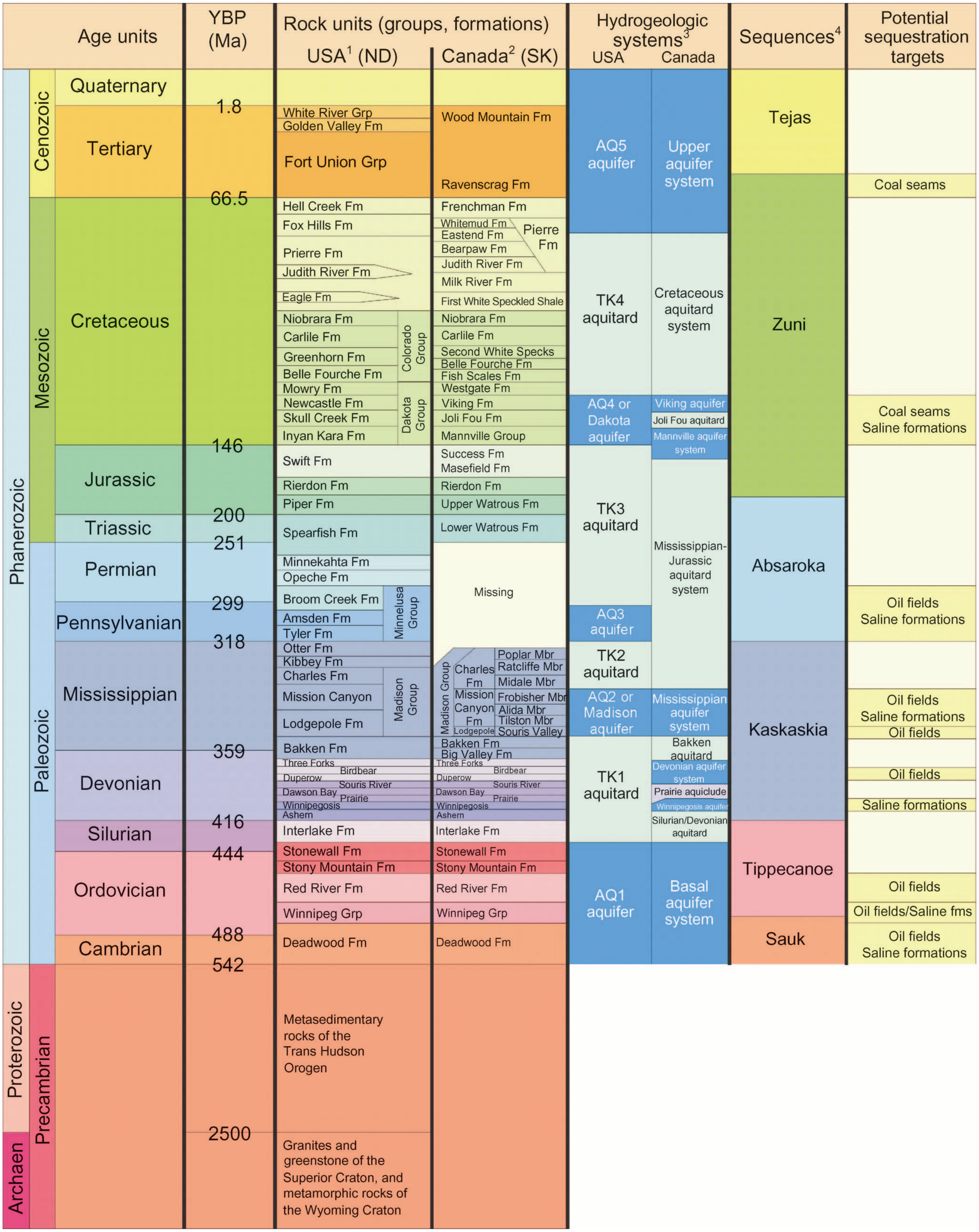

FIGURE 2. Stratigraphic column (nomenclature and relative position) for rock formations in the Williston Basin (Fowler and Nisbet, 1985; Bluemle et al., 1986; Bachu and Hitchon, 1996; Saskatchewan Industry and Resources, 2003). FM = Formation; Grp = Group; YBP = years before present; ND = North Dakota; SK = Saskatchewan; Mbr = Member.

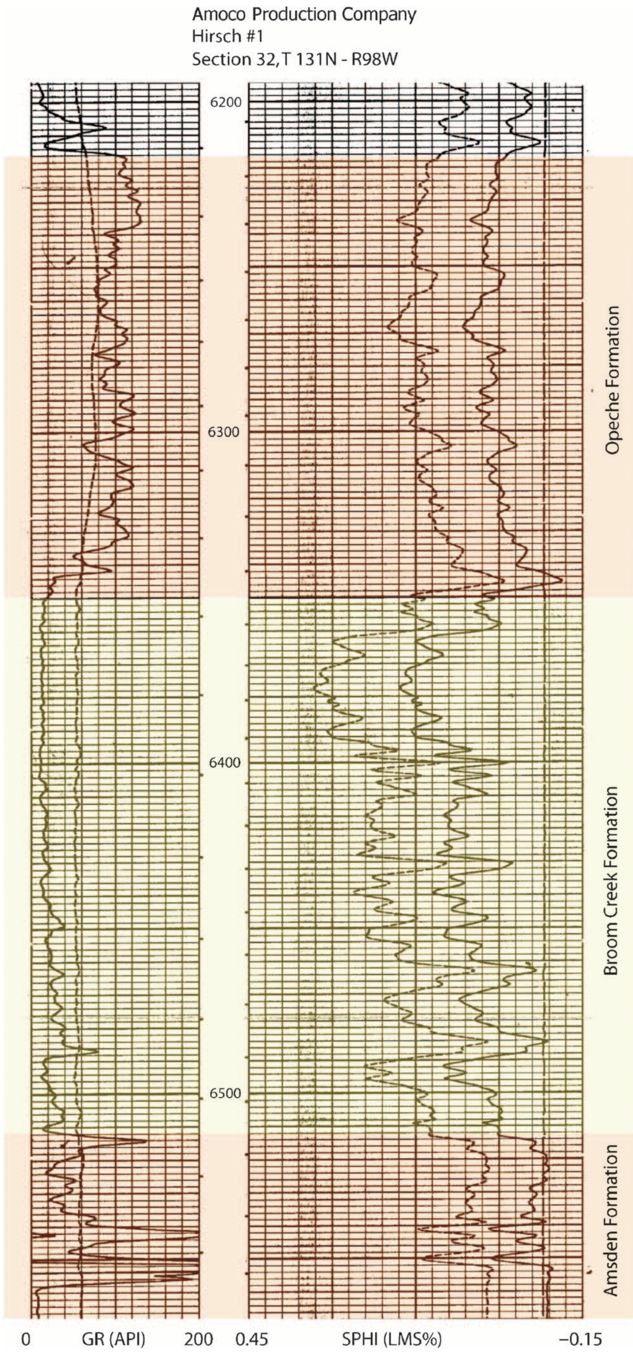

FIGURE 3. Well log (gamma ray and sonic porosity) of the Broom Creek and Opeche formations serving as a type-log for the injection zone and overlying seal at the Bowman County, North Dakota site. GR = gamma ray; SPHI = sonic porosity; LMS = limestone.

temperature ranges from approximately 65 to 80°C (150 to 176°F). The bottom-hole pressure and temperature conditions of the Broom Creek Formation directly underlying the proposed plant site, where the injection would be conducted, are estimated to be approximately 18.96 MPa (2750 psi) and 77°C (170°F), respectively (Rygh, 1990).

With respect to the water quality in the Broom Creek Formation, formation waters have not been directly sampled in Bowman County, but data presented in Hoda (1977) allow for estimation of salinity. The salinity of the Broom Creek Formation was estimated to range from 10,000 to 15,000 ppm in the study area.

Specific measurements of Broom Creek Formation permeability in the study area were not available. Therefore, permeability was estimated using data gathered from a saltwater disposal well located 27 km (17 mi) east of the proposed plant site. Although very few wells in the area have been completed in the Broom Creek Formation, one well reportedly drilled into the undifferentiated Minnelusa Group in the Teepee Butte field was completed with a step-rate test for saltwater disposal. The Broom Creek Formation is the most porous and permeable of the formations in the Minnelusa Group.

Although the geologic report in the well file names the undifferentiated Minnelusa Group as being the injection zone, the Broom Creek sands can be clearly identified on the well logs as shown in Figure 3, and it is those sands into which salt water was injected (North Dakota, 2006). The results of the step-rate test have been used to estimate permeability. The test injected 4.5 bbl water/min at a pressure of 3.45 MPa (500 psi) surface pressure. In the area, the potentiometric surface of the Broom Creek is 914 m (3000 ft) from ground surface (Hoda, 1977). If the well is 1981 m (6500 ft) deep, the reservoir pressure, assuming a pressure gradient of 0.01 MPa/m (0.46 psi/ft) for salt water with total dissolved solids of 100,000 ppm, is 11.03 MPa (1600 psi). Permeability can be estimated using the above data, and the equation for radial flow in a porous reservoir is as follows:

$$k = \frac{qB_{\mathrm{w}}u}{0.00708h} \times \ln\frac{r}{r_{\mathrm{w}}} \times \frac{1}{P_1 - P_2} \tag{1}$$

where q is the flow rate in barrels per day (4.5 bbl/min = 6480 bbl/day); B_{w} is the formation volume factor, approximately 1 $\frac{\text{reservoir barrel}}{\text{stock tank barrel}}$ (RB/STB); u is the viscosity, approximately 1; r is the radius to the unaffected reservoir assumed to be 1000 ft (305 m); r_{w} is the radius of the wellbore assumed to be 4 in. (10 cm); P_1 is the bottom-hole pressure at the injection well (22.72 MPa [3295 psi]); and P_2 is the reservoir pressure (11.06 MPa [1600 psi]). Using the step-rate test data and equation 1 resulted in an estimated permeability of 32 md in the study area.

Although site-specific injectivity data were also not available, relevant data from the same saltwater disposal well in the Teepee Buttes oil field that was used to determine permeability were used to estimate the injectivity of the Broom Creek Formation in the study area. Data from the saltwater disposal well showed that the well injected more than 1.7 million bbl of water with no noticeable increase in pressure. The salt water

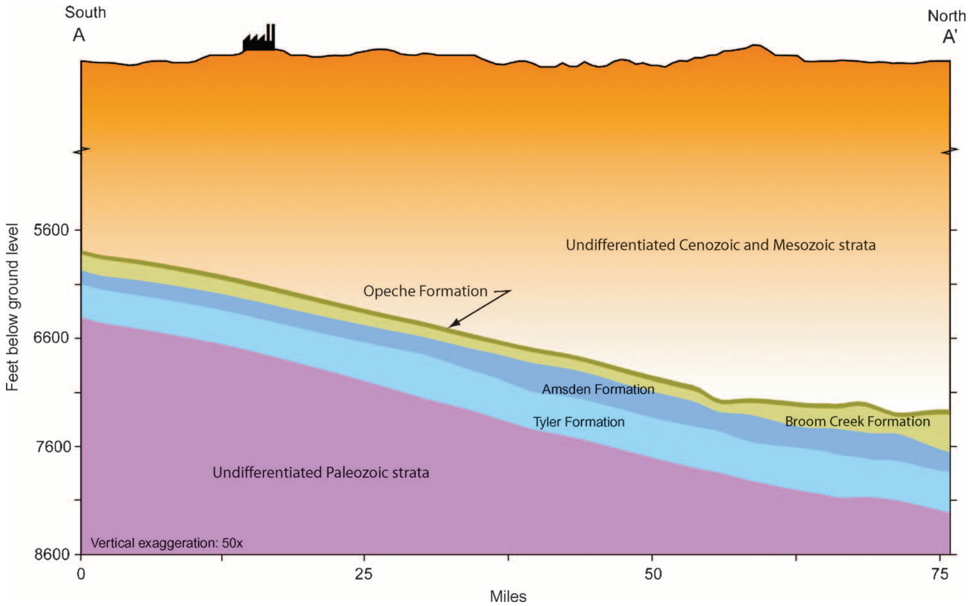

FIGURE 4. Generalized cross sectional view of the relative stratigraphic location and depth of the Broom Creek and the primary seal formation, Opeche Formation, in the vicinity of the proposed new plant site in Bowman County, North Dakota.

was injected over the course of approximately 18 yr, but injection rates over the life of the well were widely variable. The maximum injection rate for the well was 1745 bbl of water per day in January 1984 at approximately 0.69 MPa (100 psi) wellhead pressure. In February 2002, the well was injecting 818 bbl of water per day with no wellhead pressure. Based on the regulations set by the North Dakota Department of Mineral Resources Oil and Gas Division, the fracture gradients in the area are not to exceed 0.02 MPa/m (0.7 psi/ft). With the gradient of 0.02 MPa/m (0.7 psi/ft) at the formation depth (h) of 1981 m (6500 ft), the limit on pore pressure would be 31.37 MPa (4550 psi). This is the product of the fracture gradient and depth to the Broom Creek Formation. Naturally occurring formation pressure at this depth is estimated to be 18.62 MPa (2700 psi). The maximum injection pressure at the wellhead can be estimated by subtracting the formation pressure from the maximum injection pressure.

$$\begin{aligned} p_{\max} &= 4550 - 2700 \\ p_{\max} &= 1850 \text{ psi} \end{aligned} \tag{2}$$

With the information from the saltwater disposal well, the injectivity for the Broom Creek Formation would be 0.0573 psi/bbl injected per day. So the maximum volumetric injectivity (Q_v) would be determined using the following equation:

$$\begin{aligned} Q_v &= \frac{1850 \text{ psi}}{0.0573 \text{ psi/bbl}} \\ Q_v &= 32{,}286 \text{ bbl/day} \end{aligned} \tag{3}$$

or CO_2 mass injectivity is equal to

$$\begin{aligned} Q_M &= \rho_{CO_2} \times Q_v \\ Q_M &= 37.374 \text{ lb/ft}^3 \times 32{,}286 \text{ bbl/day} \\ &\quad \times 5.615 \text{ ft}^3\text{/bbl} \\ Q_M &= \frac{(6{,}775{,}379 \text{ lb/day} \times 365 \text{ days/year})}{(2200 \text{ lb/t})} \\ Q_M &= 1{,}124{,}097 \text{ t/year} \end{aligned} \tag{4}$$

where $\rho_{CO_2} = 602$ kg/m^3 (37.374 lb/ft^3) is the CO_2 density under reservoir conditions (pressure = 2750 psi [18.96 MPa], temperature = 167°F [75°C]).

Using this approach, the injectivity of the Broom Creek Formation has been estimated to be approximately 3000 t/day (3307 tons/day) per well or 1.2 million tons/year per injection well.

SEALING FORMATION

To ensure the safe and effective storage of CO_2 in the subsurface, it must be proven that a competent seal exists to act as a trapping mechanism to the vertical migration of injected fluids. To determine the effectiveness of the Opeche Formation as a seal, a reconnaissance-level evaluation of the capillary entry pressures, stress regimes, lateral continuity, and hydrodynamic characteristics was conducted.

The nature of the stratigraphic sequence at the proposed Bowman County site is ideal for the long-term

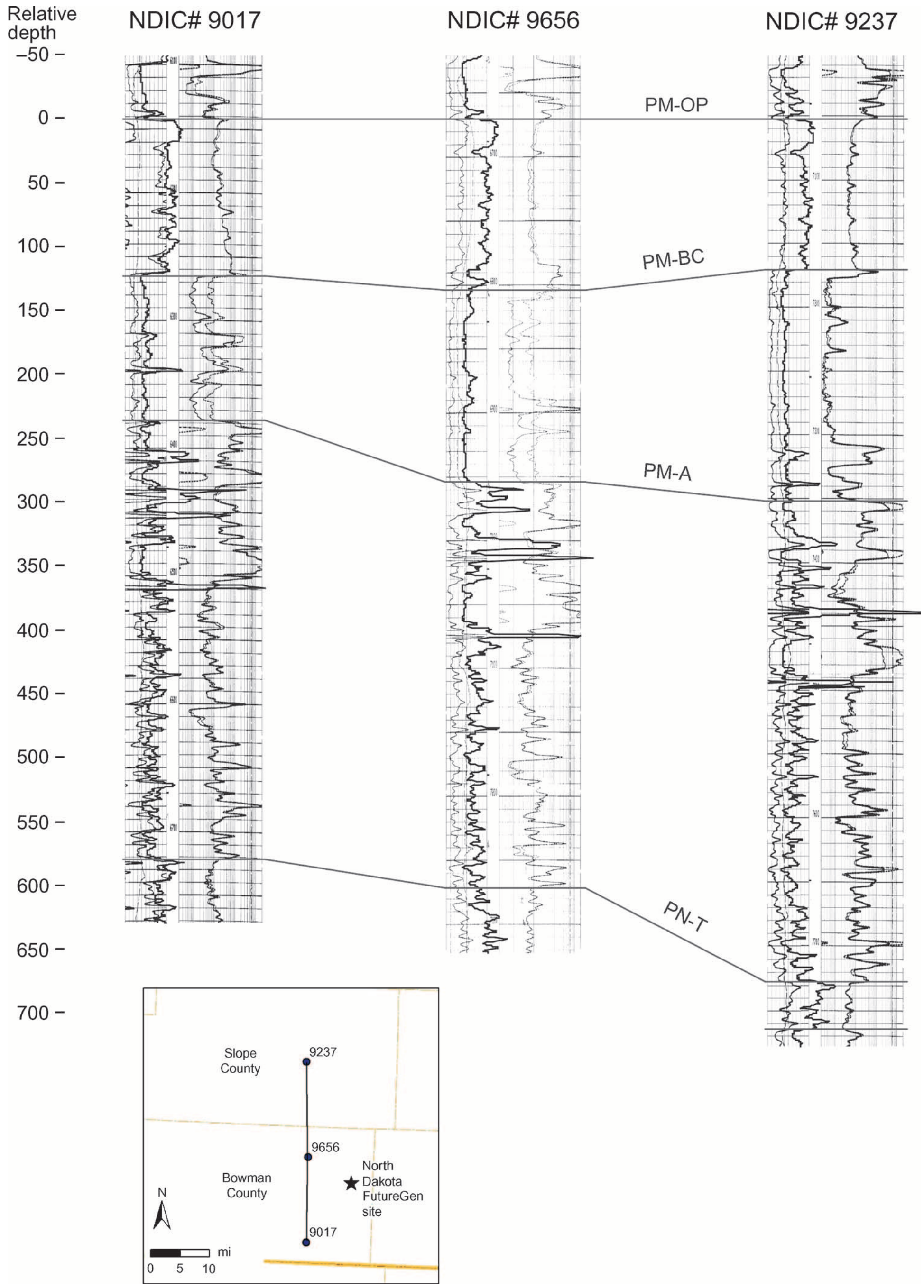

FIGURE 5. Well-log cross section of the Opeche Formation (PM-OP), Broom Creek Formation (PM-BC), Amsden Formation (PM-A), and Tyler Formation (PN-T) in the vicinity of the Bowman County, North Dakota site. NDIC = North Dakota Industrial Commission.

confinement of CO_2 because multiple zones of low-permeability rock lie above the primary injection target formation. Of these zones, the primary sealing formation for the Broom Creek Formation will be the Opeche Formation. The Opeche Formation directly and unconformably overlies the Broom Creek Formation and is made up primarily of shale with thin (less than 5 m [16.5 ft]), discontinuous interbedded evaporites, including a thin anhydrite at its base in the study area. The Opeche Formation occurs extensively throughout the Williston Basin and underlies the entire study area, where it has an average thickness of approximately 34 m (113 ft) (Ziebarth, 1972; Rygh, 1990; Benison and Goldstein, 2000) (Figure 10).

A basinwide evaluation of the hydrogeologic characteristics of the Williston Basin indicates that the sealing formations existing between the Broom Creek Formation and overlying aquifer systems are competent aquitards. Hoda (1977) and Downey (1986) presented evidence based on hydraulic head data for the Minnelusa aquifer system and overlying Lower Cretaceous aquifer systems, which demonstrates uniform head distribution in all of the aquifers without any sudden changes that would

FIGURE 6. Map showing the extent of the Broom Creek Formation in western North Dakota. The inset map shows a regional extent.

indicate transmissivity between the aquifers. Analysis of the salinity distribution in the aquifers (Hoda, 1977; Downey, 1986) also supports the conclusion that no fluid exchange between deeper and shallower aquifers occurs, which suggests that the formations between the Minnelusa aquifer system and overlying Lower Cretaceous aquifers provide competent seals between the two aquifer systems.

Thorough numerical modeling by Downey (1986) of the aquifer system in southwestern North Dakota and adjoining areas has shown very slow rates of vertical migration (approximately 1.5×10^{-7} m/day [5×10^{-7} ft/day]) corresponding to a permeability of 0.12×10^{-3} md in the Opeche Formation. The numerical simulations did not reveal any zones of increased permeability within the Opeche Formation, which would correspond to the location of fracture networks. An analysis of total dissolved solids distribution in shallower aquifers also does not reveal any anomalies (Croft, 1974), which indicates that no leakage from deep saline aquifers into much shallower potable groundwater occurs. Thus, the Opeche Formation has been demonstrated to be a competent seal to the underlying Broom Creek Formation.

Capillary entry pressure is the measure of the liquid's ability to enter conductive channels within rock. A series of photomicrographs of red-bed siltstones of the Opeche Formation by Benison and Goldstein (2000) provide insight regarding the characteristic size of the

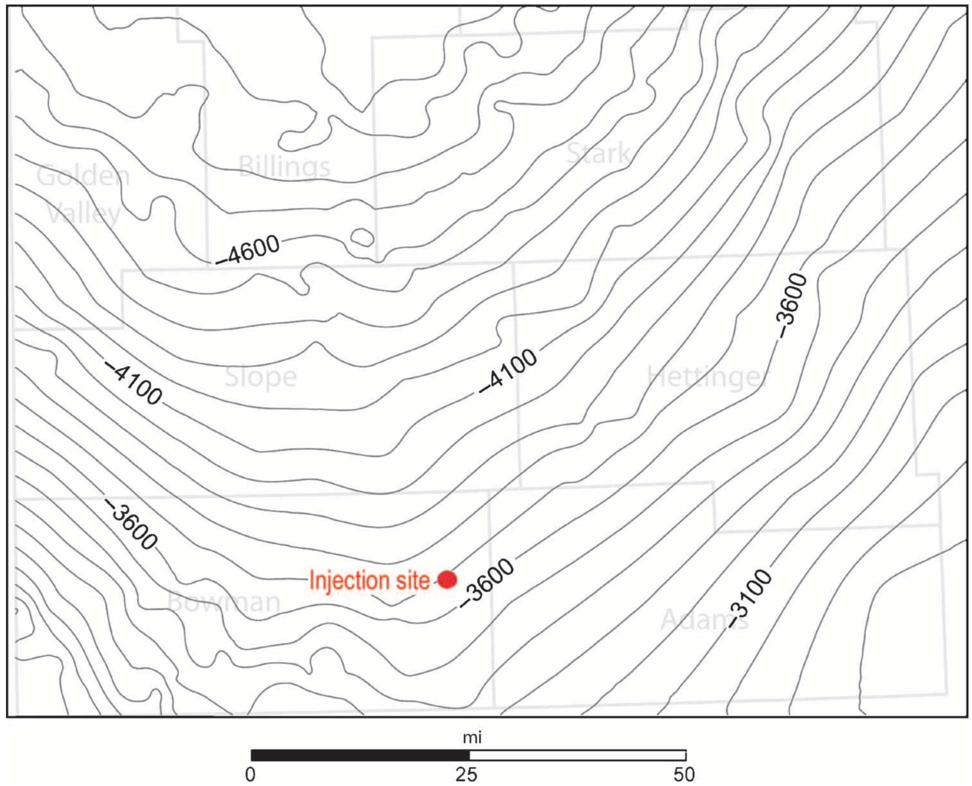

FIGURE 7. Broom Creek Formation structure map, feet below mean sea level.

openings in the formation (Figure 11). The cracks appear to be completely cemented with halite and, therefore, are not conductive channels. The only openings detectable in the photomicrograph are those in the upper right corner of the image and do not appear to be representative of fluid pathways because of their

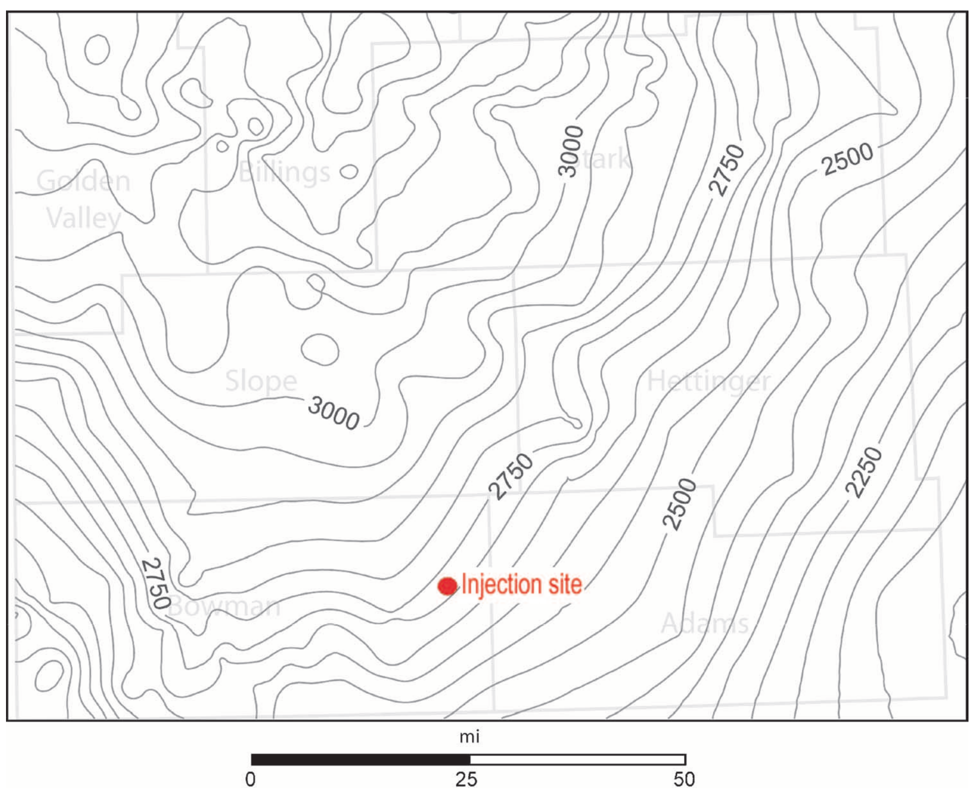

FIGURE 8. Hydrostatic pressure (psi) of the Broom Creek Formation.

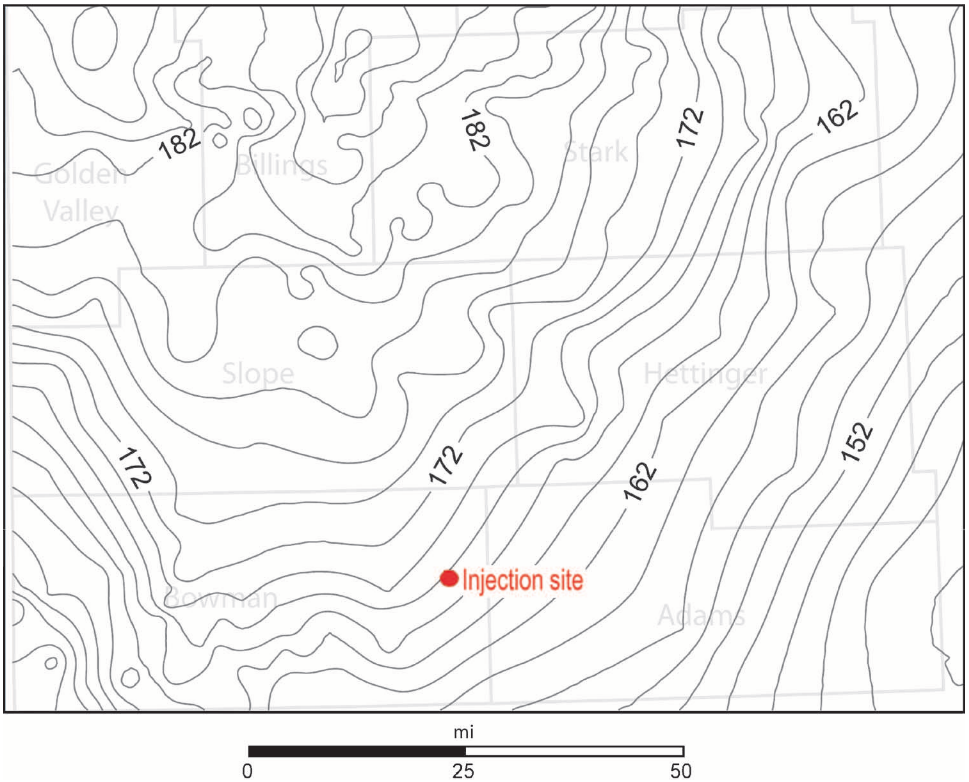

FIGURE 9. Broom Creek Formation temperature (°F) distribution.

isolation. The photomicrograph suggests that the characteristic size of the conductive channels is on the order of nanometers to tens of nanometers. This characteristic size can be used to estimate the order of capillary entry pressure. The pressure P_{ce} needed to push liquid into an opening is shown to be proportional to the liquid

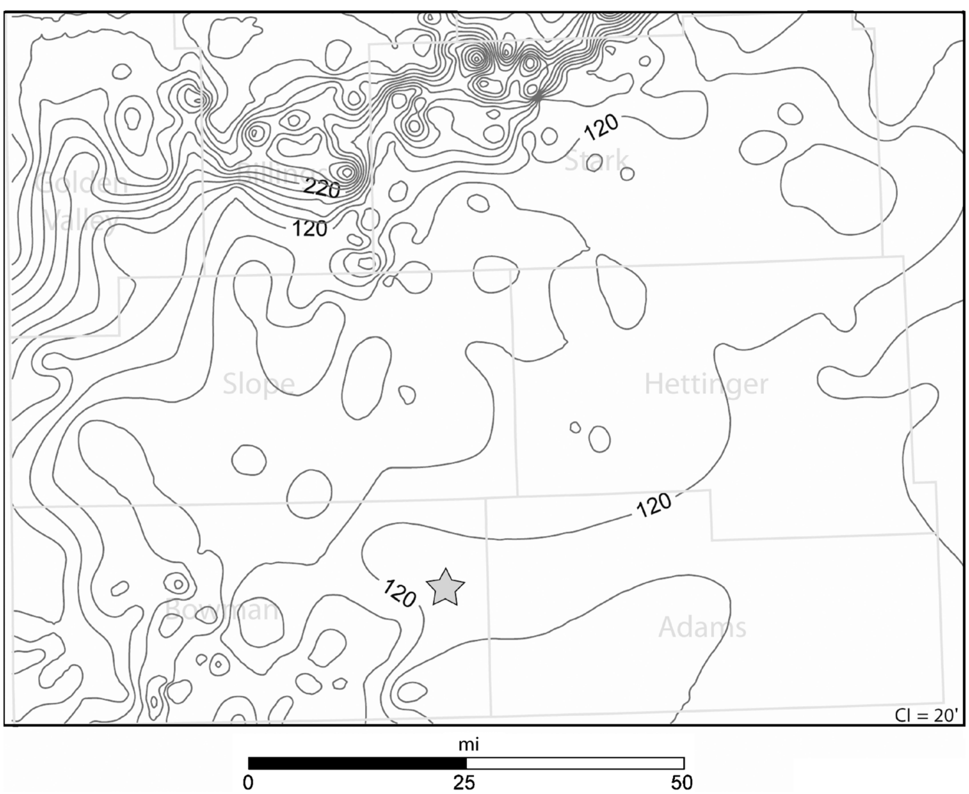

FIGURE 10. Thickness (ft) of the Opeche Formation in southwestern North Dakota.

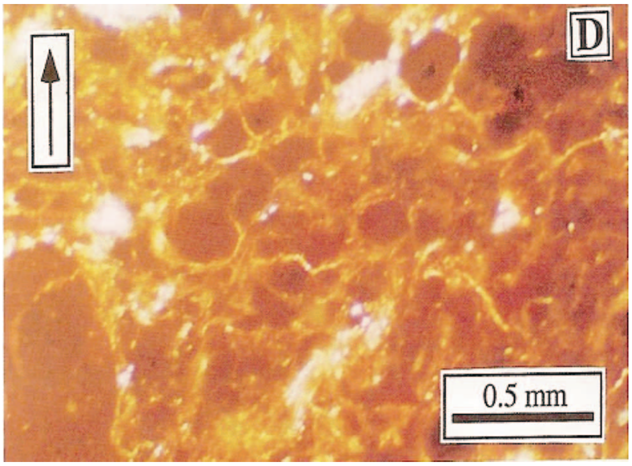

FIGURE 11. Photomicrograph of the red-bed Opeche siltstone (from Benison and Goldstein, 2000; reprinted with permission).

surface tension γ_t, 50 dyn/cm or 0.05 N/m, and to the reciprocal of the opening characteristic size D, 10 nm:

$$P_{ce} = \frac{4\gamma_t}{D} \tag{5}$$

Then, the capillary entry pressure for the Opeche Formation is at least 20.68 MPa (3000 psi). This result is consistent with experimental results for a similar type of rock reported by Davison et al. (1999), where capillary entry pressure for the anhydritic Muskeg Formation (Alberta, Canada) is estimated to be 22.06 MPa (3200 psi). Because the maximum bottom-hole pressure is not expected to exceed 20.68 MPa (3000 psi), the capillary entry pressure of the Opeche should be adequate for the prevention of CO_2 permeation under high injection pressure.

An evaluation of available fracture-related data related to the primary sealing formation suggests that the rupture of the Opeche Formation through overpressurization is not a significant risk. The lithological description of the Opeche Formation by Benison and Goldstein (2000) indicates that the Broom Creek Formation is overlain by anhydrite beds. An analysis of the failure envelope (Figure 12), reconstructed from the halite properties (Kirby and McCormick, 1989), has shown that fracture occurs if the differential stress $\sigma_1 - \sigma_3$ is not less than 172.4 MPa (25,000 psi). This implies a fracture gradient of 0.091 MPa/m (4.03 psi/ft) at a depth of 1890 m (6200 ft). One can suppose that horizontal stresses and, thus, differential pressure are of the order of the vertical stress, which is about 18.62 MPa (2700 psi). The expected maximum bottom-hole pressure is not more than 20.68 MPa (3000 psi), which makes the operations very safe from the point of view of cap-rock strength. Additional evidence of the cap-rock strength is the fact that high pore pressures in the areas of natural nitrogen accumulations do not cause fracturing (Rygh, 1990).

STORAGE CAPACITY USING FUTUREGEN CALCULATOR

To facilitate direct and consistent comparisons of the many sites from around the country that would be proposed as host locations for the FutureGen near-zero-emission coal-fired power plant, the FutureGen Industrial Alliance provided a spreadsheet-based calculator to estimate CO_2 storage capacity and plume size (FutureGen Industrial Alliance, 2006a). The FutureGen Industrial Alliance calculator, which was made available through the Internet (FutureGen Industrial Alliance, 2006b), generated estimates of supercritical and dissolved-phase CO_2 capacity within the injection formation. Table 1 shows the formation parameters and the Broom Creek Formation values used by the calculator and the results obtained in the calculation. The results suggest that the Broom Creek Formation has tremendous capacity for the geologic storage of CO_2. For example, the calculator provided by the FutureGen Industrial Alliance estimates that 220 million tons can be stored in the pore space and waters of the Broom Creek Formation within an 8-km (5-mi) radius of the injection location. The results of the calculation indicate that the supercritical CO_2 capacity of the Broom Creek Formation in the study area is approximately 25.48 kg/m^3 (1.59 lb/ft^3) of formation, whereas the dissolved CO_2 capacity is approximately 5.37 kg/m^3 (0.335 lb/ft^3) of formation.

Plume size was also calculated using the data presented in Table 2. For the test injection phase, 4 mmt is to be injected over the course of 4 yr. With a total capacity of 30.85 kg/m^3 (1.93 lb/ft^3) of formation, the plume is anticipated to reside in an area of approximately 2.88 km^2 (1.11 mi^2) (a circular plume radius of 0.95 km [0.59 mi]). Over the life of the project, a total of 50 mmt is to be injected, which will extend the areal plume extent to approximately 36 km^2 (13.9 mi^2) (a circular plume radius of 3.36 km [2.09 mi]).

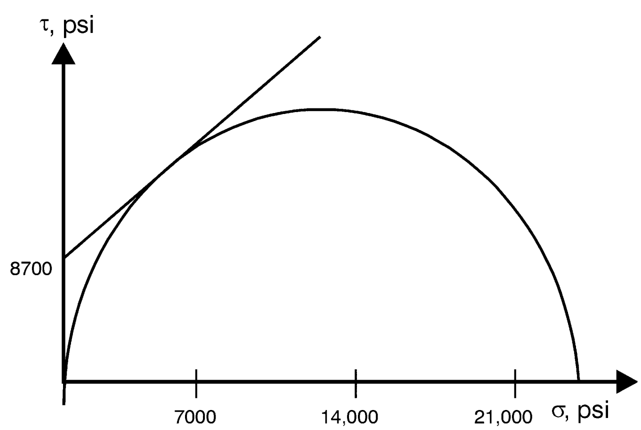

FIGURE 12. Failure envelope and differential pressure for halite.

Table 1. Broom Creek Formation parameters used in FutureGen calculator.

	SI Unit	*English Unit*
Input Parameters		
Formation depth	1981 m	6500 ft
Formation thickness	45 m	148 ft
Effective porosity	14%	14%
Temperature	75°C	167°F
Dissolved NaCl	0.22 molal	0.22 molal
Percentage of injection	100	100
Calculated Parameters		
Formation pressure	19,403 MPa	2814.2 psi
CO_2 density	655 kg/m^3	40.90 lb/ft^3
CO_2 fugacity coefficient	0.51	0.51
CO_2 Henry's constant	705,561,378	NA*
CO_2 aqueous mass fraction	0.03 kg/m^3	1.87 10^{-3} lb/ft^3
Aqueous density	1059.05 kg/m^3	66.13 lb/ft^3
Water content	10%	10%
Fixed Parameter		
Mass of injected CO_2	4 mmt	4.4 million tons
Results		
Formation's supercritical CO_2 capacity	25.48 kg/m^3	1.59 lb/ft^3
Formation's dissolved CO_2 capacity	5.37 kg/m^3	0.335 lb/ft^3
CO_2 plume areal extent	2.88 km^2	1.11 mi^2
CO_2 plume volume	0.13 km^3	0.03 mi^3

**The Henry's constant value is derived from multiple variables and is used as calculated by the FutureGen Alliance CO_2 plume calculator.*

LIMITATIONS OF THE FUTUREGEN CALCULATOR RESULTS

The results of the Broom Creek Formation CO_2 storage capacity evaluation using the FutureGen approach indicate that the location is well suited for large-scale injection of CO_2. However, the evaluation does have some key limitations that must be considered. The plume geometry generated by the FutureGen calculator does not consider the potential effects of natural groundwater flow within the formation. Although the FutureGen Industrial Alliance calculator yielded a circular-shaped plume, the plume is anticipated to migrate, elongate, and disperse within the formation in a northeasterly direction, along the preferred path of fluid migration described by Rygh (1990). Also, because supercritical CO_2 is significantly less dense than saline water, buoyancy effects will likely also cause the plume to have a more funnel or cone-shaped geometry (Benson and Cook, 2005). This geometry will result in a larger plume radius than is predicted by the calculator. The effects of both of these phenomena on the shape, size, and movement of the plume should be rigorously modeled prior to the final site selection and design of an injection scheme. The accuracy of results generated by the FutureGen calculator is limited by the highly simplified nature of the geologic model on which it is based. However, the approach prescribed by the FutureGen Industrial Alliance does yield a useful reconnaissance estimate of plume geometry for sites with limited geologic data.

Table 2. Carbon dioxide PVT data at 2725 psia (19 MPa) and 169°F (76°C).*

Property	*Value in Field Units*	*Value in SI Units*
Density	34.7219 lb/ft^3	0.5562 g/cm^3
Viscosity	0.1338 lb/ft h	0.0553 cp
z factor	0.5119	0.5119

**Average study area conditions.*
PVT = pressure, volume, temperature.

ADDITIONAL ESTIMATION OF STORAGE CAPACITY

Additional efforts were conducted to verify the FutureGen approach results by taking the areal plume extent predicted by the FutureGen calculator and applying principles of reservoir engineering that were not explicitly defined in the methodology prescribed by the FutureGen Industrial Alliance (FutureGen Industrial Alliance, 2006a). In the second evaluation, the trapped and dissolved CO_2 in the Broom Creek Formation was estimated using pore volume; permeability; irreducible water saturation; residual gas saturation; and pressure, volume, and temperature (PVT) data of CO_2 and formation water under reservoir conditions. A primary example of the difference between the FutureGen calculation and the subsequent effort was the inclusion of permeability data in the generation of storage capacity estimates. The verification efforts resulted in the development of a range of theoretical storage capacities for the Broom Creek Formation within the study area.

VERIFICATION METHOD

Potential storage capacity was assessed using calculations from Towler (2002) and Holtz (2002) and using data obtained for the initial evaluation. For this method, the following parameters were estimated: pressure, temperature, porosity, salinity, initial water saturation, and formation thickness. Value ranges were determined from a commercial contour mapping software package (Surfer) using data presented by Rygh (1990) and Hoda (1977). The following values were used in the calculation and represent the average values of the parameters over the study area considered: pressure (p) = 19 MPa (2725 psia), temperature (T) = 76°C (169°F), porosity (ϕ) = 14%, and thickness (h) = 46 m (150 ft). Initial water saturation (S_{wi}) is 100%. The maximum and minimum salinity values (15,000 and 10,000 ppm) are also used to give a range of sequestration capacities at the in-situ aquifer conditions. The sink geometry is assumed to be cylindrical within the horizontal formation.

EFFECTIVE PORE VOLUME

The results derived from the FutureGen calculator predicted that an injected mass of 50 mmt would reside within a 3.5-km (2.2-mi) radius. Because future energy production activities may be larger in scope and require more storage capacity, a second radius of 8 km (5 mi) was included in this second evaluation. The first step in calculating the theoretical storage capacity is estimating the effective pore volume. Effective pore volume, V_{ef}, is equal to the total volume of the formation, V_t, times the porosity, ϕ, reduced by the percentage of irreducible water, S_{wir}, in the pore space:

$$V_{ef} = V_t \times \phi \times (1 - S_{wir}) \tag{6}$$

Because irreducible water has not previously been measured from laboratory experiments, correlation among permeability, k, porosity, ϕ, and irreducible water saturation, S_{wir}, presented by Holtz (2002) is used:

$$S_{wir} = 5.159\left(\frac{\log k}{\phi}\right)^{-1.559} \tag{7}$$

Holtz (2002) also presented a correlation between porosity and permeability:

$$k = 7000 \times 10^7 \times \phi^{9.61} \text{ md} \tag{8}$$

For the porosity of 14% presented by Rygh (1990), permeability is calculated at 435 md using equation 8. This estimate is similar to initial sample tests of a single Broom Creek sandstone core sample from a well located north of the proposed Bowman County plant site in Billings County, North Dakota, which was found to have a permeability of 350 md. The agreement between measured and calculated permeability gives some confidence to the use of the equations provided by Holtz (2002) to be applied to the Broom Creek Formation over the previously presented permeability of 32 md estimated using data from a saltwater disposal well west of the proposed Bowman County site. From the porosity and calculated permeability, irreducible water saturation is calculated as 5.3% using equation 7.

Assuming a 3.5- and 8-km (2.2- and 5-mi) radius from the injection site, the total volumes for these radii are 1.77×10^9 and 9.29×10^9 m^3 (6.27×10^9 and 3.28×10^{11} ft^3), respectively. Applying the above parameters in equation 6, effective pore volumes of 2.36×10^8 and 1.23×10^9 m^3 (8.32×10^9 and 4.35×10^{10} ft^3) are obtained for the 3.5- and 8-km (2.2- and 5-mi) radii, respectively.

PRESSURE, VOLUME, AND TEMPERATURE PROPERTIES

Density, formation volume factor, z factor, and viscosity for the formation water and CO_2 under the given sink conditions are needed to calculate the trapped and dissolved CO_2. The solubility of CO_2 in the saline water must also be estimated. Based on a Peng-Robinson equation of state (EOS) and using PVT data, a commercial simulator was used to develop density, viscosity, and the z factor for CO_2 (Calsep, 2005). Table 2 shows the calculated results.

Carbon dioxide solubility in saline water is calculated using the following equation (Enick and Klara, 1990; Freund et al., 2005):

$$\omega_{CO_2,b} = \omega_{CO_2,w} \times \begin{pmatrix} 1.0 - 4.893414 \times 10^{-2}s \\ + 0.1302838 \times 10^{-2}s^2 \\ - 0.1871199 \times 10^{-4}s^3 \end{pmatrix} \quad (9)$$

where ω_{CO_2} is CO_2 solubility, s is water salinity in weight percent, and the subscripts w and b represent pure and saline water, respectively. At the average pressure and temperature of the Broom Creek in the study area, the CO_2 solubility in pure water, $\omega_{CO_2,w}$, is found to be 5 lb CO_2/100 lb H_2O (Dodds et al., 1956; Stalkup, 1983), which is further confirmed in the work of Kohl and Nielsen (1997). Using salinity of 10,000 ppm, or 1.0 wt.%, equation 9 results in $\omega_{CO_2,b}$ of 4.8 lb CO_2/100 lb H_2O.

The formation volume factor of water, B_w, under reservoir conditions can be calculated as follows (McCain, 1991):

$$B_w = \left[1 + \left(-1.0001 \times 10^{-2} + 1.33391 \times 10^{-4}T + 5.50654 \times 10^{-7}T^2\right)\right] \times \left[1 + \begin{pmatrix} -1.95301 \times 10^{-9}pT - 1.72834 \times 10^{-13}p^2T \\ -3.58922 \times 10^{-7}p - 2.25341 \times 10^{-10}p^2 \end{pmatrix}\right] \quad (10)$$

where p and T are reservoir pressure (psia) and temperature (°F). This correlation is valid for pressures up to 34 MPa (5000 psi) and temperatures up to 127°C (260°F). The pressure and temperature of the Broom Creek Formation are in the valid range of this correlation. Inputting the average pressure (2725 psia; 19 MPa) and temperature (169°F; 76°C) of the Broom Creek Formation to equation 10 results in B_w at 1.0244 RB/STB. Assuming that the salinity effect on the formation volume factor of water is negligible, the saline water formation volume factor, B_b, is set equal to B_w as 1.0244 RB/STB.

The Broom Creek saline water density, ρ_{br}, can be calculated from saline water density at standard condition, ρ_{bS}, with corrections for pressure and temperature. According to McCain (1991), saline water density at standard condition, ρ_{bSC}, is related to pure water density, ρ_{wSC}, and salinity, s, as follows:

$$\rho_{bSC} = \rho_{wSC} + 0.438603s + 1.60074 \times 10^{-3}s^2 \quad (11)$$

Table 3. Saline water (10,000 ppm) PVT data at 2725 psia (19 MPa) and 169°F (76°C).

Property	*Value in Field Units*	*Value in SI Units*
Density	61.3125 lb/ft^3	0.9821 g/cm^3
Viscosity	1.0051 lb/ft h	0.4155 cp
Formation volume factor	1.0244 RB/STB	1.0244 RB/STB

PVT = pressure, volume, temperature; RB/STB = reservoir barrel/stock tank barrel.

From the general definition of formation volume factor, the following relation is obtained:

$$\rho_{br} = \frac{\rho_{bSC}}{B_b} \quad (12)$$

Combining equations 11 and 12 results in

$$\rho_{br} = \frac{1}{B_b}\left(\rho_{wSC} + 0.438603s + 1.60074 \times 10^{-3}\ s^2\right) \quad (13)$$

Using the values of ρ_{wSC} at 1000 kg/m^3 (62.368 lb/ft^3), B_b at 1.0244 RB/STB, and s at 1 wt.% in equation 13, the saline water density in the Broom Creek Formation is obtained as ρ_{br} = 0.9821 g/cm^3 (61.3125 lb/ft^3).

The viscosity of saline water in the Broom Creek Formation, μ_{br}, is calculated as follows (McCain, 1991):

$$\begin{cases} \mu_{br} = \mu_{b1atm}\left(0.9994 + 4.0295 \times 10^{-5}p + 3.1062 \times 10^{-9}p^2\right) \\ \text{where} \\ \mu_{b1atm} = AT^{-B} \\ A = 109.574 - 8.40564s + 0.313314s^2 + 8.72213 \times 10^{-3}s^3 \\ B = \begin{pmatrix} 1.12166 - 2.63951 \times 10^{-2}s + 6.79461 \times 10^{-4}s^2 \\ + 5.47119 \times 10^{-5}s^3 - 1.55586 \times 10^{-6}s^4 \end{pmatrix} \end{cases} \quad (14)$$

Inputting

$$\begin{cases} p = 19 \text{ MPa } (2725 \text{ psia}) \\ T = 76°\text{C } (169°\text{F}) \\ s = 1 \text{ wt.\%} \end{cases}$$

into equation 14 gives μ_{br} = 0.4155 cp.

Table 3 summarizes the related PVT data of 10,000-ppm saline water under the average reservoir conditions.

CARBON DIOXIDE STORAGE VOLUME

As CO_2 is injected into a formation, two interactions occur immediately: part of the injected CO_2 displaces the formation water, and the rest dissolves into the formation water. Comparing the PVT data in Tables 2 and 3, we can see that the viscosity and density of CO_2 are much lower than that of water, indicating that the CO_2 will tend to move upward toward the top of the formation after being injected, although vertical permeability and heterogeneity will affect the extent and rate of vertical migration. If the CO_2 is injected into the bottom part of the formation, part of the upward-migrating CO_2 may be trapped in the pore spaces as residual CO_2, which can be described by the residual CO_2 saturation (S_{gr}). To calculate the maximum amount of residual CO_2 in a formation, the linear trend presented by Holtz (2002) is used:

$$S_{gr_{MAX}} = -0.9696\phi + 0.5473 \tag{15}$$

For a porosity of 14%, the maximum residual CO_2 in the pore space is 41.16%. This number indicates an upper limit of residual CO_2 saturation in the Broom Creek Formation. The trapped CO_2 can be calculated by the following equation:

$$\begin{cases} V_{CO_2,\text{Trapped}} = S_{gr} \times V_{ef} \\ M_{CO_2,\text{Trapped}} = \rho_{CO_2,\text{res}} \times V_{CO_2,\text{Trapped}} \end{cases} \tag{16}$$

where $V_{CO_2,\text{Trapped}}$ is the volume of trapped CO_2, V_{ef} is the effective pore volume of the sink, S_{gr} is the residual CO_2 saturation, $M_{CO_2,\text{Trapped}}$ is the mass of the trapped CO_2, and $\rho_{CO_2,\text{res}}$ is the density of CO_2 at aquifer conditions.

As the CO_2 migrates through the formation water, mixing and dissolution of the CO_2 will occur. To calculate the dissolved part of CO_2, the following equations are used:

$$\begin{cases} V_{W,\text{Available}} = (1 - S_{gr}) \times V_{ef} \\ M_{W,\text{Available}} = \rho_{br} \times V_{W,\text{Available}} \\ M_{CO_2,\text{Dissolved}} = \omega_{CO_2 b} \times M_{W,\text{Available}} \end{cases} \tag{17}$$

where $V_{W,\text{Available}}$ is the volume of formation water that is not displaced by CO_2 in the effective pore spaces, V_{ef} is the effective pore volume of the sink, S_{gr} is the residual CO_2 saturation not exceeding $S_{gr_{MAX}}$, $M_{W,\text{Available}}$ is the mass of the water in the pore space, ρ_{br} is the density of the formation water, and $M_{CO_2,\text{Dissolved}}$ is the mass of the CO_2 dissolved in the formation water.

Because of the relatively slow process, this approach ignores the mineralized part of CO_2 in the estimation of the CO_2 storage potential in the Broom Creek Formation. The total storage potential thus equals the sum of the trapped and the dissolved CO_2. Four cases have been assembled to compare different aquifer conditions possible in the Broom Creek Formation. For all cases, pressure, temperature, and formation thickness have been kept constant at p = 19 MPa (2725 psia), T = 76°C (169°F), and h = 46 m (150 ft). Cases 1 and 2 use a radius of 3.5 km (2.19 mi) for the plume extent and vary the residual CO_2 saturation from 0 to 41%. Case 1 uses a formation-water salinity value of 10,000 ppm, whereas case 2 uses 15,000 ppm. Cases 3 and 4 are evaluated using a plume radius of 8 km (5 mi) from the injection site. Table 4 shows the results of cases 1 through 4.

Cases 3 and 4 (8-km [5-mi] radius) demonstrate that the dissolved potential alone results in a storage capacity that approaches a minimum of 60 mmt. If trapped CO_2 is also counted, the theoretical capacity of the study area increases significantly to a value that may range between 60 and 300 mmt or more. For cases 1 and 2 (3.5-km [2.19-mi] radius), the trapped and dissolved CO_2 are both necessary to store the 50 mmt of CO_2 that would be produced by the proposed Bowman County power plant. These results appear to be in close agreement with the results generated by the FutureGen Industrial Alliance calculator.

All cases assume a fixed volume that is fully accessible for CO_2 storage. Although this initial calculation of the CO_2 sequestration potential in the Broom Creek Formation indicates a sufficient sink capacity, further laboratory tests are required to determine some of the values of key parameters for a more accurate calculation. Furthermore, computer modeling is needed to simulate the dynamic processes of the plume.

CONCLUSIONS

Data typically generated by oil and gas exploration and production activities have been used to conduct reconnaissance-level examinations of brine formations for large-scale CO_2 storage. These examinations are a critical part of the site selection process for new energy production facilities that plan to use carbon capture and geologic storage schemes.

This case study provides two example approaches in developing reconnaissance-level CO_2 storage capacity estimates for a brine formation at a specific location in Bowman County, North Dakota. The results of both methods were in close agreement and indicate that the storage capacity of the Broom Creek Formation is more than adequate to accept the CO_2 produced by a 275-MW coal-fired power plant over 30 yr of operation. Although these reconnaissance-level estimates are useful in the site selection process, additional detailed examinations,

Table 4. Four cases for the Broom Creek Formation.*

r (mi)	*h (ft)*	*(S_{gr})*	*Trapped (mmt)*	*Dissolved (mmt)*	*Total (mmt)*
Case 1: salinity = 10,000 ppm, radius = 2.19 mi (3.5 km), sink area = 15 mi^2 (2.5 km^2), residual CO_2 saturation = 0–41%					
2.19	150.00	0.00	0.00	11.31	11.31
2.19	150.00	0.05	6.56	10.74	17.3
2.19	150.00	0.10	13.13	10.17	23.3
2.19	150.00	0.15	19.69	9.61	29.3
2.19	150.00	0.20	26.25	9.04	35.29
2.19	150.00	0.25	32.81	8.48	41.29
2.19	150.00	0.30	39.38	7.91	47.29
2.19	150.00	0.35	45.94	7.35	53.29
2.19	150.00	0.41	53.81	6.67	60.48
Case 2: salinity = 15,000 ppm, radius = 2.19 mi (3.5 km), sink area = 15 mi^2 (2.5 km^2), residual CO_2 saturation = 0–41%					
2.19	150.00	0.00	0.00	11.03	11.03
2.19	150.00	0.05	6.56	10.48	17.04
2.19	150.00	0.10	13.13	9.93	23.06
2.19	150.00	0.15	19.69	9.38	29.07
2.19	150.00	0.20	26.25	8.83	35.08
2.19	150.00	0.25	32.81	8.28	41.09
2.19	150.00	0.30	39.38	7.72	47.1
2.19	150.00	0.35	45.94	7.17	53.11
2.19	150.00	0.41	53.81	6.51	60.32
Case 3: salinity = 10,000 ppm, radius = 5 mi (8 km), sink area = 78.5 mi^2(203.3 km^2), residual CO_2 saturation = 0–41%					
5.00	150.00	0.00	0.00	59.2	59.2
5.00	150.00	0.05	34.36	56.24	90.6
5.00	150.00	0.10	68.72	53.28	122
5.00	150.00	0.15	103.09	50.32	153.41
5.00	150.00	0.20	137.45	47.36	184.81
5.00	150.00	0.25	171.81	44.4	216.21
5.00	150.00	0.30	206.17	41.44	247.61
5.00	150.00	0.35	240.53	38.48	279.01
5.00	150.00	0.41	281.77	34.93	316.7
Case 4: salinity = 15,000 ppm, radius = 5 mi (8 km), sink area = 78.5 mi^2 (203.3 km^2), residual CO_2 saturation = 0–41%					
5.00	150.00	0.00	0.00	57.77	57.77
5.00	150.00	0.05	34.36	54.88	89.24
5.00	150.00	0.10	68.72	52	120.72
5.00	150.00	0.15	103.09	49.11	152.2
5.00	150.00	0.20	137.45	46.22	183.67
5.00	150.00	0.25	171.81	43.33	215.14
5.00	150.00	0.30	206.17	40.44	246.61
5.00	150.00	0.35	240.53	37.55	278.08
5.00	150.00	0.41	281.77	34.09	315.86

**For each case, pressure, temperature, and thickness are kept constant (p = 2725 psia [19 MPa]; T = 169°F [76°C]; h = 150 ft [46 m]).*
r = radius; S_{gr} = residual CO_2 saturation.

which include robust reservoir, geochemical, and hydrogeologic modeling of the site, are necessary before large-scale injection of CO_2 is implemented.

ACKNOWLEDGMENTS

This report was prepared with the support of the U.S. Department of Energy National Energy Technology Laboratory Cooperative Agreement DE-FC26-05NT42592. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the authors(s) and do not necessarily reflect the views of the U.S. Department of Energy. This research was also partly supported by the U.S. National Science Foundation through North Dakota EPSCoR (EPS-0447679) and the University of North Dakota. The authors appreciate the generous help from these agencies and organizations.

REFERENCES CITED

Bachu, S., and B. Hitchon, 1996, Regional-scale flow of formation waters in the Williston Basin: AAPG Bulletin, v. 80, no. 2, p. 248–264.

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

Benson, S., and P. Cook, 2005, Underground geological storage: Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage, Section 5: New York, United Nations Secretariat on Climate Change, p. 5-1–5-134.

Bluemle, J. P., S. B. Anderson, J. A. Andrew, D. W. Fisher, and J. A. LeFever, 1986, North Dakota stratigraphic column: North Dakota Geological Survey, Miscellaneous Series 66.

Bradshaw, J., S. Bachu, D. Bonijoy, R. Burruss, S. Holloway, N. P. Christensen, and O. M. Mathaissen, 2006, CO_2 storage capacity estimation: Issues and development of standards: 8th International Conference on Greenhouse Gas Control Technologies, Trondheim, Norway, June 19–22, unpaginated, CD-ROM.

Calsep, 2005, Methodology documentation of PVTsim15: Copenhagen, Denmark, Calsep, p. 1–17.

Croft, M. G., 1974, Ground-water basic data for Adams and Bowman counties, North Dakota: County Ground-Water Studies 22, part II, and Bulletin 65, part II, p. 294.

Davison, R. J., A. Mayder, D. W. Hladiul, and J. Jarrell, 1999, Zama acid gas disposal/miscible flood implementation and results: Journal of Canadian Petroleum Technology, v. 38, p. 45–54.

Dodds, W. S., L. F. Stutzman, and B. J. Sollami, 1956, Carbon dioxide solubility in water: Industrial and Engineering Chemistry Data Series, v. 1, p. 92–95.

Downey, J. S., 1986, Geohydrology of bedrock aquifers in the northern Great Plains in parts of Montana, North Dakota, South Dakota, and Wyoming: U.S. Geological Survey Professional Paper No. 1402-E, p. 88.

Enick, R. M., and S. M. Klara, 1990, CO_2 solubility in water and brine under reservoir conditions: Chemical Engineering Communications, v. 90, p. 23–33.

Fowler, C. M. R., and E. G. Nisbet, 1985, The subsidence of the Williston Basin: Canadian Journal of Earth Sciences, v. 22, no. 3, p. 408–415.

Freund, P., S. Bachu, D. Simbeck, K. Thambimuthu, and M. Gupta, 2005, Annex I: Properties of CO_2 and carbon-based fuels: Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage: New York, IPCC, p. 385–399.

FutureGen Industrial Alliance, Inc., 2006a, Final request for proposals for FutureGen facility host site: Morgantown, West Virginia, U.S. Department of Energy, p. 54.

FutureGen Industrial Alliance, Inc., 2006b, Final site RFP Appendix B: CO_2 plume calculations, Excel spreadsheet calculator: http://www.futuregenalliance.org/solicitations.stm (accessed March 25, 2006).

Heck, T. J., R. D. LeFever, D. W. Fischer, and J. LeFever, 2005, Overview of the petroleum geology of the North Dakota Williston Basin: Modified July 2006: www.state.nd.us/ndgs/resources/wbpetroleum_h.htm (accessed September 10, 2006).

Hoda, B., 1977, Feasibility of subsurface waste disposal in the Newcastle Formation, lower Dakota Group (Cretaceous) and Minnelusa Formation (Pennsylvanian), Western North Dakota: Master's thesis, Wayne State University, Detroit, Michigan, 79 p.

Holtz, M. H., 2002, Residual gas saturation to aquifer influx—A calculation method for 3-D computer reservoir model construction: Calgary, Alberta, Society of Petroleum Engineers, SPE Paper No. 75502, 10 p.

Kirby, S. H., and J. W. McCormick, 1989, Inelastic properties of rocks and minerals: Strength and rheology, *in* R. S. Carmichael, ed., Practical handbook of physical properties of rocks and minerals: Boca Raton, CRC Press, p. 139–280.

Kohl, A. L., and R. B. Nielsen, 1997, Gas purification: Houston, Texas, Gulf Publishing Company, 900 p.

McCain Jr., W. D., 1991, Reservoir fluid property correlations—State of the art: Society of Petroleum Engineers Reservoir Engineering, v. 1, p. 266–272.

North Dakota, 2006, North Dakota well file #7819: www.dmr.nd.gov/oilgas (accessed March 15, 2006), p. 114.

Pruess, K., T. Xu, J. Apps, and J. Garcia, 2001, Numerical modeling of aquifer disposal of CO_2: Society of Petroleum Engineers/U.S. Environmental Protection Agency/U.S. Department of Energy Exploration and Production Environmental Conference, San Antonio, Texas, SPE Paper No. 66537, p. 26–28.

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

Saskatchewan Industry and Resources, 2003, Geology and mineral and petroleum resources of Saskatchewan Miscellaneous Report 2003-7.

Smith, S. A., J. A. Sorensen, D. W. Fischer, E. M. O'Leary, W. D. Peck, E. N. Steadman, and J. A. Harju, 2006, Estimates of CO_2 storage capacity in saline aquifers and oil fields of the PCOR Partnership region: 8th International Conference on Greenhouse Gas Control Technologies (GHGT-8), Trondheim, Norway, June 19–22, unpaginated, CD-ROM.

Stalkup Jr., F. I., 1983, Miscible displacement, monograph series: Richardson, Texas, Society of Petroleum Engineers, p. 35–36.

Towler, B. F., 2002, Fundamental principles of reservoir engineering: Richardson, Texas, Society of Petroleum Engineers, 232 p.

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