CO₂ storage capacity estimates for stacked brine-saturated formations in the North Dakota portion of the Williston Basin

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Abstract

The CO₂ storage capacity of stacked brine-saturated formations in the North Dakota portion of the Williston Basin in North America was estimated using publicly available well file data. The study area referred to as the Washburn area encompasses 15,900 square km and is underlain by over 3000 m of sedimentary rock representing every period of the Phanerozoic. Reconnaissance-level CO₂ storage capacity estimates for seven formations in four hydrogeologic systems were developed using a map-based approach. Results indicate that brine-saturated formations in the Washburn area of North Dakota have a CO₂ storage capacity greater than 10 billion tons.

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1. Introduction

The Plains CO₂ Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center, is one of seven regional partnerships in the United States funded by the U.S. Department of Energy’s (DOE’s) Regional Carbon Sequestration Partnership (RCSP) Program. As part of its ongoing regional characterization efforts, the PCOR Partnership has conducted a detailed examination of the potential CO₂ storage capacity of several stacked brine-saturated formations in the vicinity of a cluster of six coal-fired power plants and one coal gasification plant in the North Dakota portion of the Williston Basin. The study area, referred to as the Washburn area, encompasses 15,900 km² and is home to six coal-fired power plants and one coal gasification plant which combine for annual emissions of over 32 million tonnes of CO₂. The Washburn area is underlain by over 3000 meters of sedimentary rock representing every period of the Phanerozoic eon. The stratigraphy of the Washburn area includes several thick and laterally continuous formations of brine-saturated clastics and carbonates of moderate to high porosity and...
permeability, many of which are hydrogeologically isolated by extensive, low-permeability shales, evaporites, and tight carbonates. The characterization of the Washburn area included the development of CO$_2$ storage capacity estimates for several formations that were identified as being potential targets for sequestration. From deepest to shallowest, the potential injection target formations include sandstones of the Cambrian–Ordovician Deadwood Formation and Winnipeg Group, carbonates of the Ordovician Red River Formation and the Mississippian Mission Canyon Formation, and sandstones of the Pennsylvanian–Permian Broom Creek Formation and the Cretaceous Dakota Group. Formations that could act as seals, including the shale of the Ordovician Stony Mountain Formation, evaporites of the Mississippian Charles Formation, salts and shales of the Permian Opeche Formation, and shales of the Cretaceous Mowry Formation were also evaluated. Characterization of the sink and seal formations in the Washburn area was accomplished using an approach that integrated well log data from over 100 wells, core analyses, drill stem test data, water analyses, and other published data to construct detailed property maps. Data were obtained from the publicly available well data files of the North Dakota Department of Mineral Resources (NDDMR). Storage capacities for each saline aquifer system were estimated based on each formation’s effective pore volume, the reservoir fluid properties, and reservoir pressure/temperature conditions. Results indicate that brine-saturated formations in the Washburn area of North Dakota have a CO$_2$ storage capacity greater than 10 billion tonnes.

2. Description of Washburn area sink and seal systems

Washburn area sinks and seals include several clastic and carbonate formations. The potential sink formations evaluated in this study include parts of four distinctive regional aquifer systems (AQ1, AQ2, AQ3, and AQ4) as formally classified by the United States Geological Survey (USGS) [1]. The following is a brief description of each saline aquifer system, from shallowest to deepest, of the formations that were evaluated for CO$_2$ storage capacity. The relative stratigraphic position of these formations within the Williston Basin is shown in Figure 1.

The Lower Cretaceous Dakota Group in North Dakota includes two discrete, primarily sandstone, aquifers that extend from Nebraska, USA, to Alberta, Canada. Sometimes referred to as the Dakota Aquifer, these formations are formally classified as the AQ4 hydrogeologic system by USGS. Water quality varies greatly in the system, ranging from saline to fresh, although in the Washburn area, it is saline. The formations that make up the Dakota Group aquifer system are, in descending order, the Newcastle, Skull Creek (shale aquitard), and Inyan Kara in North Dakota [2]. The Inyan Kara is dominated by fine- to coarse-grained sandstones and siltstones, with some laterally discontinuous shale interbeds. Most of the Inyan Kara was deposited in a shallow marine environment, although some upper members were deposited in a fluvio-deltaic environment. The Skull Creek Formation is a shale aquitard in the Washburn area and acts as a primary seal for the underlying Inyan Kara. The Newcastle Formation is primarily a mudstone, although massive beds of fine- to coarse-grained sandstone are also common. The overlying massive shales of the Mowry Formation provide the primary seal for the Newcastle Formation.

The Pennsylvanian–Permian age Broom Creek Formation contains the thickest beds of high porosity and permeability sandstone in the Washburn area. This formation is part of the AQ3 hydrogeologic system, sometimes referred to as the Minnelusa Aquifer. Rygh [3] recognizes three separate lithofacies in the Broom Creek: 1) eolian sandstone, 2) nearshore marine sandstone, and 3) shallow marine carbonate. The Broom Creek Formation is composed of interbedded fine- to medium-grained, locally dolomitic sandstone with poor to good porosity and microcrystalline, locally anhydritic dolomite that is generally nonporous. Locally, interbeds of shale and earthy, textured dolomite are present [4]. The shales and interbedded evaporites of the overlying Permian Opeche Formation provide the primary seal for the Broom Creek Formation.

The Mississippian Mission Canyon Formation is the uppermost formation within the AQ2 hydrogeologic system, also known as the Madison Aquifer. The Mission Canyon Formation is dominated by carbonates and evaporites representing a variety of marine lithofacies. Deposition occurred in environments that ranged from open marine to coastal sabkha or salina and recorded a major regressive sequence [5, 6]. The Mission Canyon Formation
has been subdivided into at least eleven informally named intervals, each representing a different part of the sequence. Porosity and permeability in the intervals of the Mission Canyon Formation is determined in part by depositional facies [5, 7], with some intervals having the characteristics of a potential sink while others may serve as competent localized seals. In the Washburn area, four intervals were identified as having the potential to serve as sinks. In order of descending depth, the Mission Canyon Formation intervals that were evaluated in the study are the Midale, State “A,” Frobisher, and Tilston. The salts and anhydrites of the overlying Charles Formation provide an excellent primary seal for the Mission Canyon Formation as a whole.

The Ordovician Red River Formation is part of the AQ1 hydrogeologic system. It is primarily composed of carbonates (with dolomites dominating the most porous and permeable beds) and widespread intervals of anhydrites. These rocks were deposited in marine to shallow marine to sabkha environments. Like the Mission Canyon Formation, the Red River Formation has been subdivided into a series of informally named intervals [2]. Two of those intervals, the Red River “B” and the Red River “C,” were evaluated in the Washburn area. The shales and low-permeability carbonates of the overlying Ordovician Stony Mountain Formation provide the primary seal for the Red River Formation. The Ordovician Black Island Formation, also part of the AQ1 hydrogeologic system, is a clastic rock unit dominated by quartz arenite sandstones with basal silts and shales [2]. The Black Island Formation was deposited in a marine to shallow marine environment [2]. It is overlain by shales of the Ordovician Icebox Formation. Both the Black Island and Icebox Formations are members of the Winnipeg Group.

The lowermost rock unit in the AQ1 hydrogeologic system is the Cambrian–Ordovician age Deadwood Formation. Clastic sediments, primarily fine- to coarse-grained sandstones with some interbedded siltstones and
shales, were deposited in a marine to shallow marine environment [2]. The basal shales of the Black Island Formation provide an overlying seal for the Deadwood Formation.

3. Methodology – the “map-based” approach

The CO₂ storage capacity estimates for each of the saline aquifer systems in the Washburn area described above were developed using what is referred to as the “map-based” approach. Using the NDDMR well data, maps of the key parameters required to estimate CO₂ storage capacity in saline aquifers were created. Maps generated using the NDDMR data sets include depth to top of formation, porosity, thickness, water salinity, pressure, temperature, and irreducible water saturation, although not all of these were used for the final calculations of capacity estimates. With respect to the most critical parameter, PhiH, the map-based approach was coupled with Monte Carlo uncertainty analysis to determine probabilistic distribution of pore volumes. Using this approach, total effective pore volumes were estimated for each saline aquifer. The maps were then combined mathematically to generate a map of CO₂ capacity distribution in tonnes per square kilometer and determine low-, mid-, and high-case estimates for total storage capacity for each saline aquifer system within the Washburn Study Area.

The map-based approach is used in the oil industry for reserve estimation and well placement in newly discovered fields where subsurface data are relatively scarce, which was considered to be a reasonable analog for reconnaissance-level estimates of capacity within saline aquifer systems. While a modeling approach based on geostatistical techniques could also be applied for estimating the capacity of saline aquifers, such models are typically not constructed unless more data are available, such as in the case of oil fields that are being evaluated for or are currently undergoing secondary or tertiary recovery operations. Industry experience with oil field modeling, as well as the results of limited comparisons using a geostatistical technique conducted as part of this study suggest that pore volumes calculated using a map-based approach can be expected to compare closely (+/- 10%) with those based on geostatistical models.

The effective low-, mid-, and high-case pore volumes for each formation were developed by first selecting the rock units that have reservoir properties that make them amenable to CO₂ storage. Formation tops were then correlated from well logs, and structure maps of each formation were generated using the available well control. Porosity values were assigned using porosity log curves and validated using quality control (QC) techniques based on other geophysical curve data, core data, and well file data for individual wells. For instance, sonic logs can sometimes overestimate porosity values, and core analysis data can be used to correct for porosity overestimations (Figure 2).

A series of maps (Figure 3) were then made for each zone of interest using the log, core, and well file data. A low-, mid-, and high-case was created for three map-based properties: net to gross ratio (NTG), porosity, and interval thickness. NTG is the thickness of an interval that meets a specific cutoff criteria for volume of shale (Vsh) and/or porosity (Φ) divided by the total interval thickness. For example, a midcase, or “base-case,” NTG could equal thickness with a porosity greater than 6% and/or Vsh less than 40%, divided by the total interval thickness. A NTG value allows the modeler to account for poor quality rock that, because of high clay content and/or low porosity, has low permeability and would not contribute to CO₂ storage capacity. The porosity values for each map are determined for intervals which meet the low-, mid-, and high-case NTG criteria. This way, only the porosity values in the portions of the interval that meet the cutoff criteria are considered. Interval thickness maps were created based on the well control, with the midcase, or “base-case,” extrapolated out based purely on the well control and the low- and high-case allowed to vary by up to 10% when the distance from the nearest well is greater than 5000 meters. Low-, mid-, and high-case effective porosity thickness maps (PhiH) were created by multiplying the low-, mid-, and high-case NTG, porosity, and interval thickness maps together. From the PhiH maps, low-, mid-, and high-case effective pore volumes and subsequent storage capacities (Figure 4) for each formation were calculated.
Figure 2. Illustration of how a comparison of core porosity data versus log porosity data was used to develop realistic porosity values for the Broom Creek Formation.

Figure 3. Examples of Broom Creek Formation structure and base-case NTG, porosity, and thickness maps that were used to generate a base-case PhiH map for the Broom Creek Formation.
4. Calculation of storage capacity estimates for Washburn Study Area

The storage capacity of each formation was calculated using a modified version of the DOE methodology, which is:

\[ G_{\text{CO}_2} = \left( \text{pore volume} \right) \times \rho_{\text{CO}_2} \times E \times \frac{1}{1000} \text{[kg/tonnes]} \]

Where:
- \( G_{\text{CO}_2} \) = Total mass of the \( \text{CO}_2 \) that could potentially be stored (tonnes)
- Pore Volume = Total effective pore space in each formation (m\(^3\))
- \( \rho_{\text{CO}_2} \) = density of \( \text{CO}_2 \) under reservoir temperature and pressure (kg/m\(^3\))
- \( E \) = the storage capacity coefficient, which represents the fractional amount of the pore space that can be contacted by injected \( \text{CO}_2 \) (range 0.04–0.01)

An E factor of 3% or 0.03 was used to develop very conservative potential storage capacity estimates. The high-, mid-, and low-case storage capacities presented in Table 1 reflect the high-, mid-, and low-case pore volumes based on variability of the NTG, formation thickness, and porosity. An E factor of 3% is considered to be very conservative in this estimate of storage capacity because the approach takes into consideration only the “effective pore volume” of the formations in the Washburn Study Area that have reservoir characteristics that make them amenable to \( \text{CO}_2 \) storage. In the DOE method for calculating storage capacity, there are seven variables used to calculate storage capacity coefficient. The first three are used to estimate the effective pore volumes of an entire formation in a region or basin. By targeting only the formation intervals within the Washburn Study Area that have the best reservoir properties (equates to net thickness), determining NTG (equates to effective pore volume),
Table 1. High-, mid-, and low-case CO₂ storage capacities calculated using an E = 0.03 and based on high-, mid-, and low-case pore volumes.

<table>
<thead>
<tr>
<th>Group or Formation</th>
<th>Formation or Member</th>
<th>Pore Volume (billion m³)</th>
<th>CO₂ Density (kg/m³)</th>
<th>CO₂ Capacity (Gtonnes)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>High</td>
</tr>
<tr>
<td>New Castle</td>
<td></td>
<td>5.9</td>
<td>2.9</td>
<td>754</td>
</tr>
<tr>
<td>Inyan Kara</td>
<td></td>
<td>222.5</td>
<td>152.9</td>
<td>756</td>
</tr>
<tr>
<td>Dakota Total</td>
<td></td>
<td>228.4</td>
<td>181.2</td>
<td>155.8</td>
</tr>
<tr>
<td>Minnelusa</td>
<td>Broom Creek</td>
<td>124.8</td>
<td>82.4</td>
<td>2.86</td>
</tr>
<tr>
<td></td>
<td>Midale</td>
<td></td>
<td>19.6</td>
<td>769</td>
</tr>
<tr>
<td></td>
<td>State A</td>
<td>5.3</td>
<td>3.4</td>
<td>769</td>
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<td></td>
<td>Frobisher</td>
<td>72.4</td>
<td>48.0</td>
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<td></td>
<td>Tilton</td>
<td>60.0</td>
<td>42.9</td>
<td>0.16</td>
</tr>
<tr>
<td>Mission Canyon</td>
<td>Total Mission Canyon</td>
<td>165.0</td>
<td>113.9</td>
<td>4.02</td>
</tr>
<tr>
<td></td>
<td>Red River B</td>
<td>10.1</td>
<td>2.6</td>
<td>778</td>
</tr>
<tr>
<td></td>
<td>Red River C</td>
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<tr>
<td>Red River</td>
<td>Total Red River</td>
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<td>12.9</td>
<td>1.00</td>
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<tr>
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<td>Black Island</td>
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<td>16.1</td>
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</tr>
<tr>
<td>Deadwood</td>
<td>Deadwood</td>
<td>156.4</td>
<td>64.2</td>
<td>782</td>
</tr>
<tr>
<td>Washburn Total</td>
<td></td>
<td>745.9</td>
<td>445.3</td>
<td>17.4</td>
</tr>
</tbody>
</table>

mapping each interval extent (equates to effective aerial extent), and creating isopach maps, the first three variables in the DOE method are accounted for. The other four variables of the DOE method (areal displacement efficiency, vertical displacement efficiency, gravity, and microscopic displacement efficiency) formed the basis for the E factor used in the Washburn Study Area calculations. These four variables deal with the interaction of CO₂ with the reservoirs and could result in a range of E from 0.03 to 0.34. Thus the application of E = 0.03 will result in the most conservative estimates for regional CO₂ storage capacity in the Washburn Study Area. It may be worth noting that more optimistic estimates for storage capacity in the study area could be as much as an order of magnitude higher. This estimate does not take into consideration the technical or economic feasibility of injecting this quantity of CO₂.

5. Conclusions

By using publicly available well file information, the PCOR Partnership was able to use a map-based approach to develop petrophysical models of several stacked saline aquifer systems in the Washburn area of North Dakota. The petrophysical models provided the basis for estimating CO₂ storage capacity of 11 potential target injection zones (intervals) in seven different formations within four distinct regional aquifer systems as classified by the USGS Groundwater Atlas. The total CO₂ storage capacity in the evaluated formations in the Washburn area has been estimated to range from approximately 10 billion tonnes to nearly 20 billion tonnes.

References

