Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

CHARACTERIZATION OF THE PCOR PARTNERSHIP REGION

Plains CO_2 Reduction (PCOR) Partnership Phase III
Value-Added Report

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Plains CO_2 Reduction (PCOR) Partnership

Energy & Environmental Research Center (EERC)

REGIONAL CHARACTERIZATION OF THE PCOR PARTNERSHIP REGION

EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership is a collaborative effort of both public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic carbon dioxide (CO_2) emissions from stationary sources in the central interior of North America. The PCOR Partnership is one of seven regional partnerships initiated in the fall of 2003 under the U.S. Department of Energy's (DOE's) Regional Carbon Sequestration Partnership (RCSP) Program.

The characterization of the region and its resources is vital to understanding the feasibility of moving from research to practice regarding storage of CO_2 in large-scale projects and implementation of practices regionwide. A necessary step toward the deployment of carbon capture and storage (CCS) is the development and understanding of the magnitude, distribution, and variability of the major stationary CO_2 sources and potential CO_2 storage targets. Using potential storage avenues available coupled with the understanding of both the regional significance as well as in-depth knowledge of their availability to test the storage of CO_2 into available resources gives the opportunity to greatly reduce the impact of anthropogenic CO_2 while also being an economically feasible option across the region.

This report details the individual components used to determine the underlying potential for CO_2 storage in the PCOR Partnership region as well as characterization of the region as a whole to better understand what potential steps forward should be taken for commercialization of CCS not only in our region, but worldwide. CCS in geologic media is a technology that 1) is immediately applicable as a result of the experience gained in oil and gas exploration and production, deep waste disposal and groundwater protection; 2) has large capacity, although unevenly distributed, and 3) has retention times of centuries to millions of years (Intergovernmental Panel on Climate Change, 2005). Geologic storage of CO_2 is actively pursued at several locations around the world, including in the PCOR Partnership region.

Geologic media that have been identified as suitable for CO_2 storage are uneconomical coal beds, oil and gas reservoirs, and deep saline aquifers. Storage of CO_2 in coal beds has the smallest potential in terms of storage capacity and is an immature technology that has not yet been proven. Hydrocarbon reservoirs have the advantage of demonstrated storage capacity and confinement properties, but they need to be produced and depleted first (unless CO_2 is being used in enhanced oil recovery [EOR]), and they are penetrated by many wells, which may diminish storage security. Deep saline aquifers have the advantage of being much more widespread, of significantly

larger storage capacity, and generally present less risk of CO_2 leakage along existing wells because they are penetrated by fewer wells than hydrocarbon reservoirs (Intergovernmental Panel on Climate Change, 2005).

Within the region, CO_2 storage resource potential amounts include 368–1220 billion tons in currently evaluated saline formations, 25 billion tons in depleted oil field reservoirs, 8 billion tons in unminable coal, and 1.71–10.26 billion tons in selected oil fields for EOR. Saline formations have the most significant storage potential, and with understanding each individual formation and its particular caveats, we can better understand how to utilize the information and create economically feasible plans for implementation of storage. By using both a broad and focused approach to characterization of these resources, we have the ability to look at the potential through a multistate/multiperspective as well as a site-specific approach.

The PCOR Partnership continues to refine the characterization of sources, geologic and terrestrial sinks, and infrastructure within the region. This continued regional characterization is refining CO_2 storage resource estimates for the project and providing context for extrapolating the results of the large-scale demonstrations.

References

Intergovernmental Panel on Climate Change, 2005, Special report on carbon dioxide capture and storage: Cambridge, United Kingdom, and New York, Cambridge University Press.

REGIONAL CHARACTERIZATION OF THE PCOR PARTNERSHIP REGION

INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership is one of seven regional partnerships established by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) Regional Carbon Sequestration Partnership (RCSP) Program to determine the best geologic storage approaches and apply technologies to safely and permanently store carbon dioxide (CO_2) for its specific region. The PCOR Partnership region covers an area of over 1.4 million square miles in the central interior of North America and includes all or part of nine U.S. states and four Canadian provinces (Figure 1). Its efforts include monitoring, verification, and accounting support at two large-scale depositionally different demonstration sites. The first demonstration involved the injection of CO_2 captured from one of the largest gas-processing plants in North America into a saline formation in northeastern British Columbia, Canada (Sorensen and others, 2014). The second demonstration is injecting CO_2 into the Powder River Basin in southeastern Montana where the PCOR Partnership is both studying and monitoring CO_2 storage associated with a commercial-scale enhanced oil recovery (EOR) project (Hamling and others, 2013; Gorecki and others, 2012). The PCOR Partnership also continues to provide widespread carbon capture and storage (CCS) outreach and education, aids in regulatory development, and continues to collaboratively undertake regional characterization efforts, including the basal Cambrian (Deadwood) Formation lying in the United States and Canada (Peck and others, 2014; Glazewski and others, 2013).

Within the PCOR Partnership region are eight sedimentary basins and the Midcontinent Rift System (Figure 2), which provide a rich set of options for safe, long-term geologic storage of CO_2. Sedimentary basins are large regional depressions in the Earth's crust which can accumulate a considerable thickness of sediment that can cause further subsidence and allow for more sediment to accumulate. As the sediments are buried, they are subjected to large amounts of compaction from the increased pressure and begin the process of lithification (changing to rock). The basins vary in configuration from bowl-shaped to elongated troughs. If organic-rich sedimentary rocks occur in combination with the appropriate depth, temperature, and duration of burial, hydrocarbon generation can occur within that particular sedimentary basin. In many instances, the sedimentary basins are used to provide a general location of a more specific geologic occurrence, such as oil fields located within the extent of the Williston Basin or systems found in the Powder River Basin.

The subsurface depth window most likely to be used for CO_2 storage overlaps to varying degrees with other subsurface resources (Figure 3), so CO_2 injection might affect, or be affected

Figure 1. PCOR Partnership region (Peck and others, 2012).

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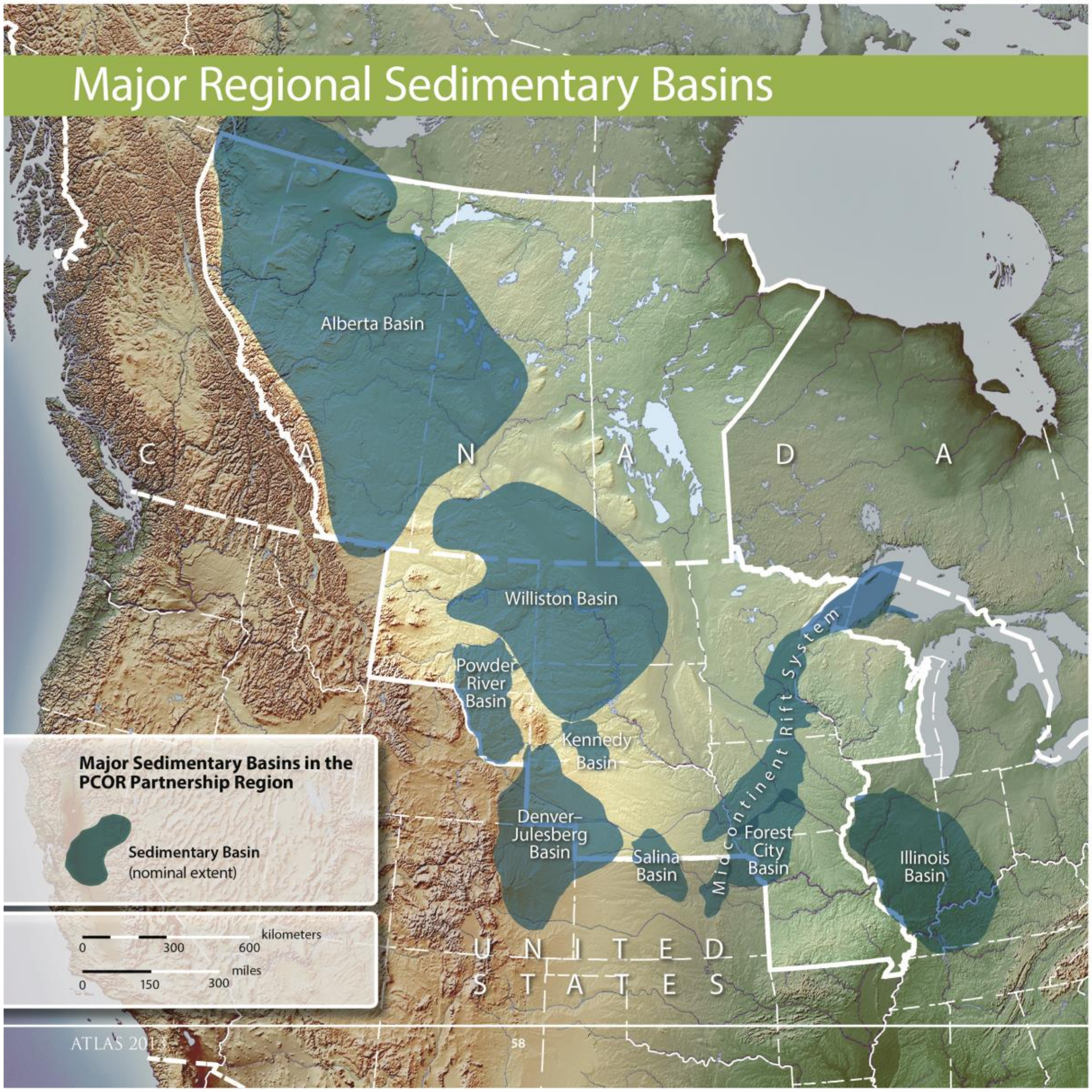

Figure 2. Sedimentary basin regional locations (Peck and others, 2013).

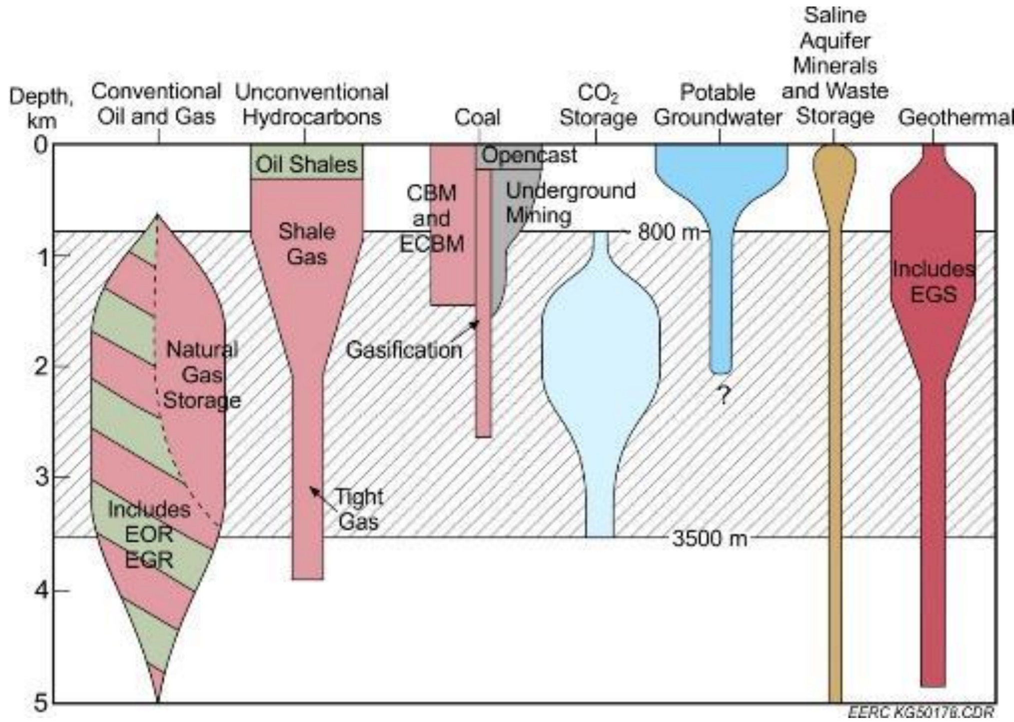

Figure 3. Schematic diagram of the typical depth ranges over which subsurface resources occur, including the use of pore space for CO_2 storage. Variations in the widths of the polygons are conceptually in proportion to the most common depths for the activities (IEA Greenhouse Gas R&D Programme, 2013).

by, several different subsurface operations (IEA Greenhouse Gas R&D Programme [IEAGHG], 2013). The region has stable geologic basins that are ideal storage targets for CCS, and the basins have been well characterized because of the commercial oil and gas activities and have proven to provide a significant avenue for CO_2 storage resources. The geologic characteristics that are necessary for a sink to be considered suitable for storage vary regarding the specific location, but the minimal requirements for consideration are as follows:

- Be capable of holding large volumes of CO_2 in place for a long period of time.
- Be overlain by thick, laterally continuous cap rock that prevents upward migration or by comparable structural traps.
- Be at depths that take advantage of dense-phase CO_2 (typically >2600 feet [800 m]).
- Have formation water salinities greater than 10,000 mg/L.

Under high-temperature and high-pressure conditions, such as those encountered in deep geologic formations (typically greater than 2600 feet [800 m]), CO_2 will exist in a dense phase that is referred to as "supercritical." At this supercritical point, CO_2 has viscosity similar to a gas and the density of a liquid. These properties allow CO_2 to be more efficiently stored deep underground because a given mass of CO_2 occupies a much smaller space in the supercritical state than it does as a gas at the surface (Figure 4).

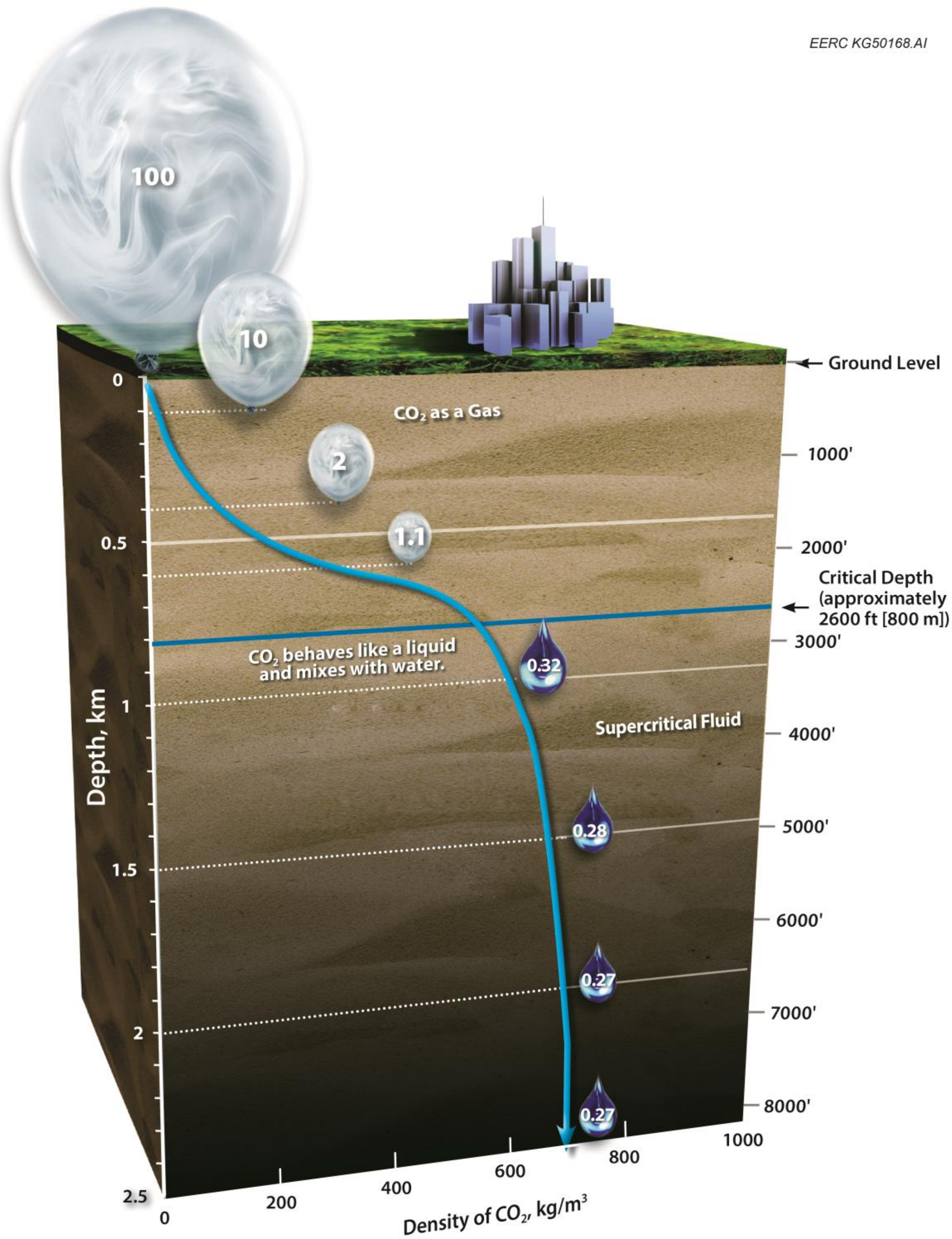

Figure 4. Illustration of the interaction between CO_2 density and depth (Peck and others, 2013).

The mechanisms that function to trap and store CO_2 in these deep geologic media are structural and stratigraphic trapping, residual phase trapping, dissolution trapping, and mineral trapping (Figure 5). As time passes after the injection of CO_2 into a deep geologic environment, the effective trapping mechanism may shift. Storage security increases as the trapping mechanism moves from the physical process of structural and stratigraphic trapping toward geochemically based processes.

- **Structural and stratigraphic trapping** – Because it is less dense than the saline water in the formations, the supercritical CO_2 injected deep (more than 2600 feet [800 m]) underground will rise up through the porous rocks of the target zone until it reaches the top of the formation. Once it reaches the top of the target zone, it will become trapped by a thick, laterally continuous and impermeable layer of cap rock, such as shale. The structural configuration of the containing formation can also act to contain the CO_2. Often these configurations resemble an upside-down bowl.

- **Residual-phase trapping** – At a basic level, reservoir rock acts like a tight, rigid sponge. Prior to injection, the pores of the rocks are filled with saline water and, in

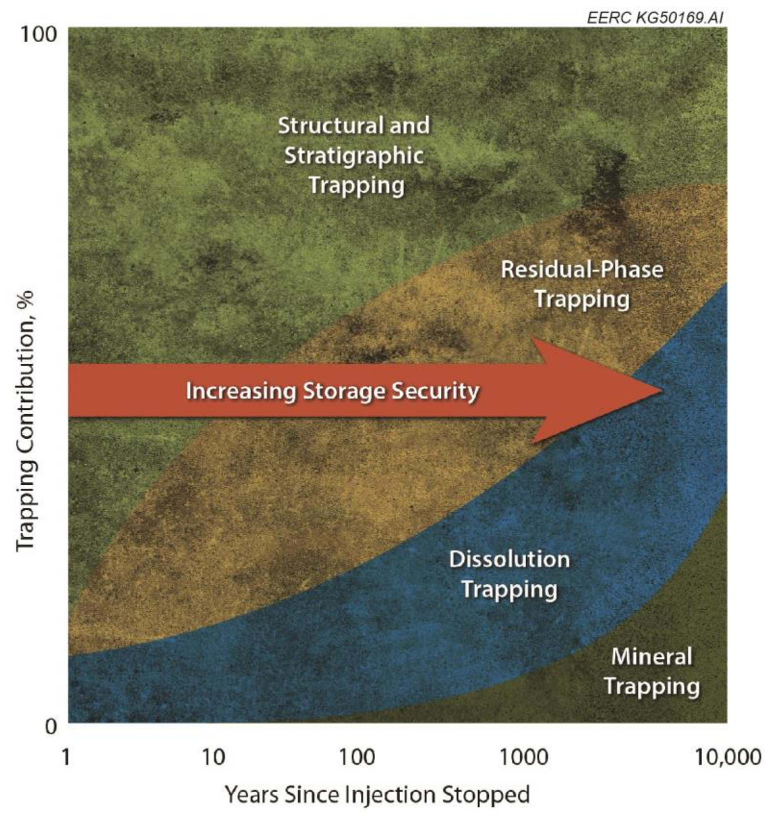

Figure 5. Trapping mechanisms. Image adapted from "Intergovernmental Panel on Climate Change" (2005).

some cases, hydrocarbons. As injected supercritical CO_2 moves through the pores, some of the fluid is left behind as residual droplets in the pore spaces and will be effectively stuck and not able to move, even under high pressure.

- **Dissolution trapping** – Just as sugar dissolves in water, some of the CO_2 will dissolve into saltwater in the pore spaces. Because the water with dissolved CO_2 is denser than the surrounding water, it will sink to the bottom of the formation and be held in place by the less dense fluids above.

- **Mineral trapping** – The last stage of CO_2 trapping involves the chemical reaction between the dissolved CO_2 in the formation fluids with the minerals in the target formation and cap rock to form new solid carbonate minerals, thus effectively locking the CO_2 in place.

REGIONALLY CHARACTERIZED RESOURCES

The PCOR Partnership has identified, quantified, and categorized 890 stationary sources in the region that have an annual output of greater than 15,000 tons (13,600 tonnes) of CO_2. These stationary sources have a combined annual CO_2 output of about 561 million tons (509 tonnes) (Figure 6 and Table 1). Although not a target source of CO_2 for geologic storage, the transportation sector in the U.S. portion of the PCOR Partnership region contributes nearly 188 million additional tons (170 tonnes) of CO_2 to the atmosphere every year. The creation and

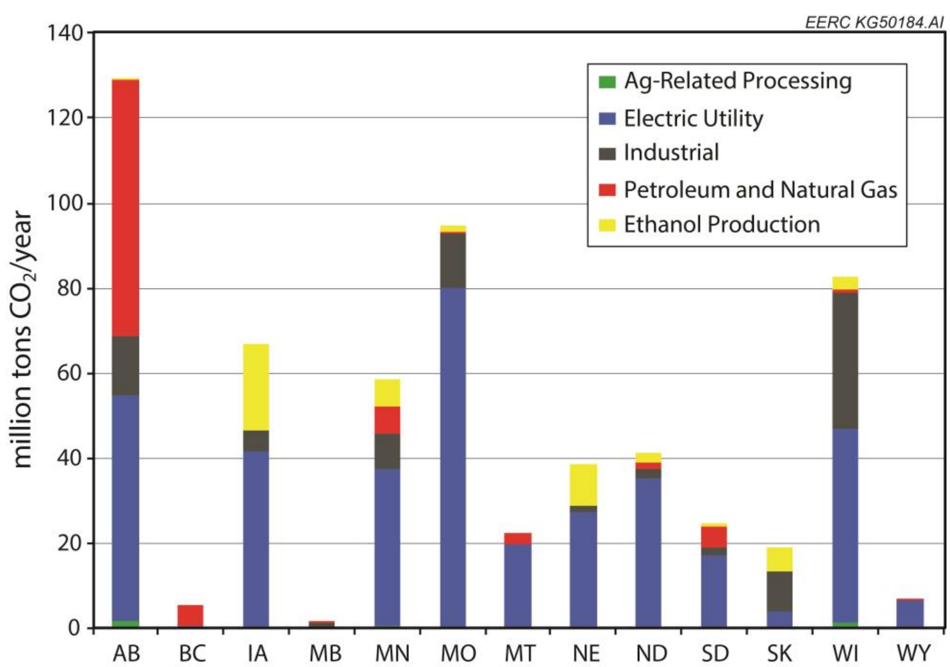

Figure 6. Annual CO_2 emissions by state/province (Peck and others, 2013).

Table 1. CO_2 Source Output in the PCOR Partnership, short tons

State/Province	Ag Processing	Cement Plant	Electricity	Ethanol	Fertilizer	Industrial	Petroleum/ Natural Gas	Refineries/ Chemical	Total Production	Facility Count
Alberta	65,960	1,928,641	51,057,345	63,159	1,799,501	3,853,772	66,105,011	10,185,921	135,059,309	191
British Columbia*			735,707			283,165	5,593,386		6,612,258	35
Iowa	1,863,007	1,234,524	39,263,703	25,753,089		3,640,463	522,654	727,367	73,004,808	122
Manitoba		155,978	89,958	212,128		306,969	92,756	670,787	1,528,577	11
Minnesota	1,844,451		30,716,906	5,479,861		9,576,166	2,948,071		50,565,456	113
Missouri	162,451	6,769,925	78,919,794	1,115,966		6,508,800	437,862	843,229	94,758,027	83
Montana*	208,397		17,969,345				2,224,832		20,402,574	16
Nebraska	1,078,399	885,486	28,584,987	8,823,876		1,034,441	333,853	45,259	40,786,302	58
North Dakota	1,253,144		33,261,597	1,242,727		167,647	2,095,903	1,840,275	39,861,294	46
Saskatchewan			16,279,347	317,131		529,916	4,856,954	1,888,143	23,871,491	36
South Dakota	109,803	477,064	3,292,312	4,202,133		466,339	386,856		8,934,507	28
Wisconsin	105,693		43,513,391	2,102,310		9,719,496	257,806		55,698,697	111
Wyoming*			7,713,404				2,452,343		10,165,747	40
Total Production	10,930,514	14,955,461	293,887,461	68,783,224	1,990,294	107,413,080	113,748,875	23,128,469	**561,249,044**	
Facility Count	64	12	186	126	1	203	264	34		**890**

* PCOR Partnership region only.

updating of this database is key in the development of CO_2 capture–transportation–storage scenarios that have the potential to reduce greenhouse gas emissions in the PCOR Partnership region. To maintain a reasonably current status, the data set undergoes an annual review during which new or missing sources are identified and added, CO_2 emission rates are updated, and facility locations are verified.

The annual output from the various large stationary sources ranges from under 100,000 tons for industrial and agricultural processing facilities that make up the majority of the sources in the region to nearly 18 million tons for the largest coal-fired electric generation facility. Fortunately, many of the large point sources are located in areas that are favorable for CO_2 storage because of their concurrence with deep sedimentary basins, such as those areas in Alberta, Saskatchewan, North Dakota, Montana, and Wyoming. Actual emission measurements are used whenever possible, but measured data are not always available for each of the sources. In cases where measured data are unavailable, emissions are estimated using the methodologies developed for the DOE NETL RCSP Capture and Transportation Working Group (U.S. Department of Energy National Energy Technology Laboratory, 2010b). Web searches are used to acquire updated information regarding fuel type, heat content, and usage rate and/or product slate and quantities; these values are used to estimate CO_2 emission rates.

There are four primary data sets used to update the CO_2 emission database:

- Environment Canada (2013a) Reported Facility Greenhouse Gas Data and online greenhouse gas search engine.

- Environment Canada (2013b) National Pollutant Release Inventory online data search engine for emission data for criteria pollutants such as SO_x and NO_x.

- U.S. Environmental Protection Agency (EPA) (2013a) Air Markets Program Data online emission search engine.

- EPA (2013b) Greenhouse Gas Reporting Program Data for Calendar Year 2011.

Emission data obtained using the EPA Greenhouse Gas Reporting Program are easily incorporated into the data set, with the exception of the inclusion of ethanol plants. The PCOR Partnership tracks combustion- and process-related CO_2 emissions separately for potential carbon utilization purposes. The EPA site breaks down the emissions as either combustion-related or biogenic CO_2, which is CO_2 that is formed by combustion of a biomass source. Hence, a methodology was developed to estimate the CO_2 formed during the fermentation step of ethanol production. This methodology is based on one developed by the RCSP Capture and Transportation Working Group (U.S. Department of Energy National Energy Technology Laboratory, 2008b). An extended explanation of the precise calculations can be found in Appendix A.

With such socioeconomic diversity in the PCOR Partnership region, there was a need to create categories for the stationary sources based on their specific industries. The main categories are ag-related processing, electrical utility, industrial, petroleum and natural gas, and ethanol. One of the main objectives in classification of these sources is to give a visual representation of where certain industries are more prevalent across a large area in order to better understand the feasibility of transporting captured CO_2 emissions from the source to the resource destination. When reporting annual stationary source outputs and locations to NATCARB (National Carbon Sequestration Database and Geographic Information System), categories are further broken down to ethanol plants, cement plants, ag processing, electric utility, fertilizer, industrial, petroleum and natural gas, and refineries/chemical (Figure 7).

The majority of the region's emissions from these stationary sources come from just a few of the source types. About two-thirds of the CO_2 is emitted during electricity generation. Additional significant emissions come from industrial sources, petroleum refining and natural gas processing, ethanol production, and agricultural processing. While the CO_2 emissions from the individual PCOR Partnership point sources are no different from similar sources located around North America, the wide range of source types within the PCOR Partnership region offers the opportunity to evaluate the capture, transport, and storage of CO_2 in many different scenarios.

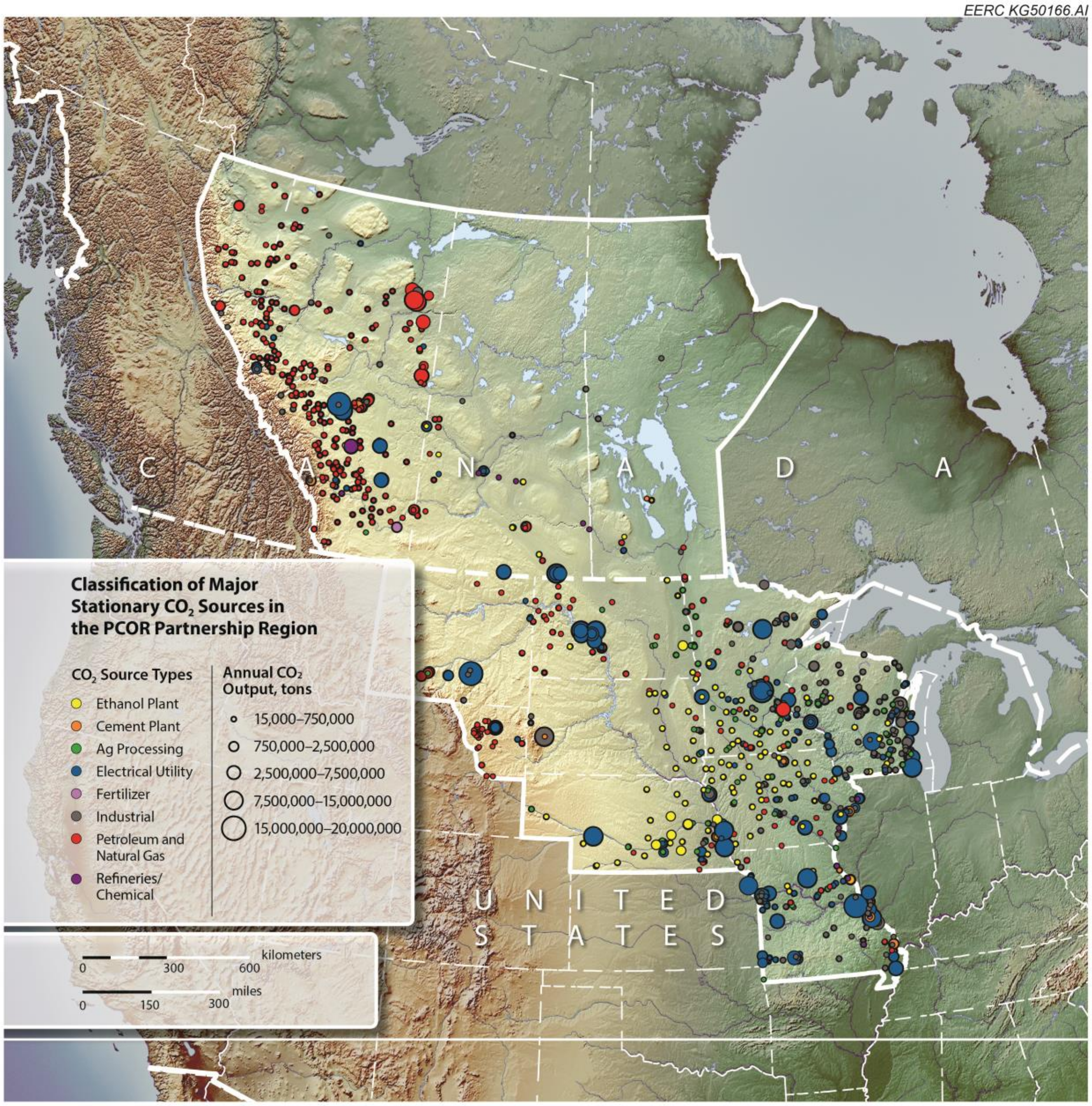

Figure 7. Location of large stationary sources and their annual emissions of CO_2 in the PCOR Partnership region (Peck and others, 2013).

CHARACTERIZATION OF OIL AND GAS FIELDS

As part of the RCSP Program, the PCOR Partnership is tasked with providing a high-level, quantitative estimation of CO_2 storage resource potential for oil and natural gas reservoirs within the PCOR Partnership region (Figure 8). Estimation of CO_2 storage potential is necessary to assess the potential contribution of CCS technologies toward EOR and the reduction of CO_2 emissions. In order to accomplish this task, a comprehensive data set is needed that depicts the characteristics of oil and gas fields and their associated reservoirs.

Estimation of the CO_2 storage potential in oil and gas reservoirs is a relatively straightforward process in comparison to the other two geologic media. Unlike saline formations and coal areas, oil and gas reservoirs are better known and characterized as a result of exploration for and production of hydrocarbons. Oil and gas reservoirs are often discrete rather than continuous, unlike coal beds and saline aquifers, such that the resource potential for CO_2 storage can be calculated on the basis of reservoir properties such as pay thickness, porosity, oil saturation, and oil formation volume factor.

EOR provides a more economical alternative to straight CO_2 storage in oil and gas reservoirs. Provided that there is affordable CO_2 available within a reasonable distance to the oil field, the EOR processes help to offset the costs in acquiring, compressing, transporting, and injecting CO_2 into the target formation. Oil recovery from CO_2 flooding can be 10%–15% of the original oil in place (OOIP) (Stevens and others, 1999), and the CO_2 can potentially be stored for thousands of years in the oil and gas reservoir. Oil and gas reservoirs that are targeted typically have large CO_2 storage potential and large incremental oil recovery amounts in order to make the economic investment of CO_2 EOR injection worthwhile.

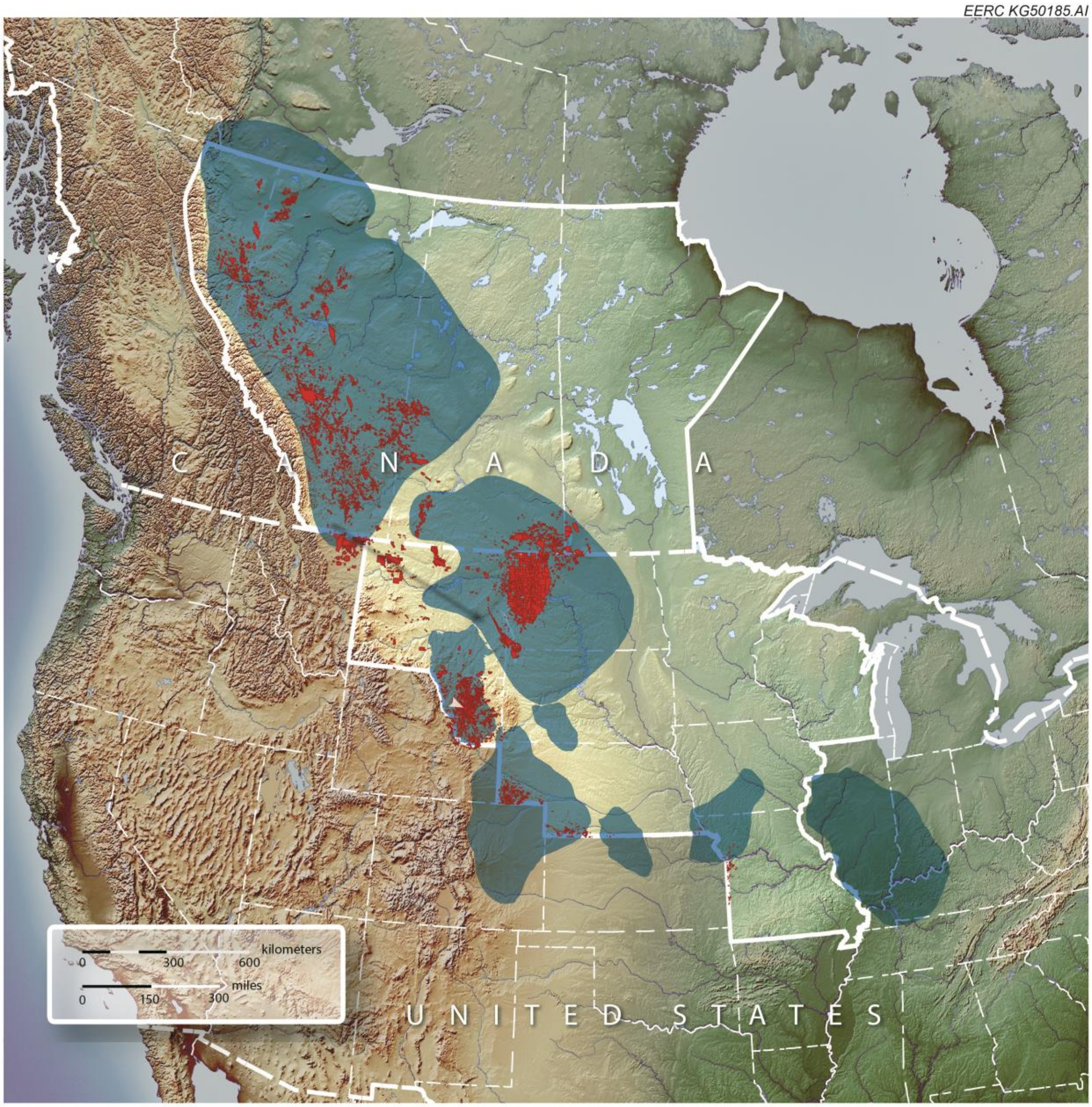

Figure 8. PCOR Partnership oil fields and sedimentary basins (Peck and others, 2013).

Oil and Gas Reservoirs

Oil and gas reservoirs are oil-bearing subsurface geologic formations typically spread across large areas. These reservoirs may be divided into legally defined oil and gas fields that will contain multiple oil wells. These legal boundaries are typically determined by the oil company/regulatory agency for developed fields. While these oilfield boundaries are useful for accounting purposes, this does not mean that the subsurface formation containing the oil or gas follows these boundaries. Within the oil and gas fields, there may be multiple reservoirs that will occur at different depths and contain oil and/or natural gas.

Oil and Gas Data Management

The PCOR Partnership manages oil and gas data through different software programs: ESRI's ArcGIS, Microsoft SQL (MSSQL) server, and IHS's Petra. ArcGIS is capable of managing spatial databases while displaying spatial data. The geographic information system (GIS) is used to display oil and gas field outlines or oil and gas well locations. The MSSQL server is used to manage database tables containing various oil and gas reservoir characteristic data. Petra is used primarily to manage oil and gas wellbore data. All three of the systems are able to provide outputs that are capable of being used between the three programs.

GIS–Oil and Gas Fields

Oil and gas field boundaries are outlined in a GIS feature class across the entire PCOR Partnership region. This feature class contains 3890 oil and natural gas field polygons that are collected from each state or province (Figure 8). In most cases, the field boundaries are housed by each individual state or province's oil and gas regulatory agency.

MSSQL Server–Oil and Gas Reservoirs

The PCOR Partnership compiled a MSSQL server database of oil and natural gas reservoirs in an effort to discover suitable reservoirs for EOR and the storage of CO_2. Where available, the reservoir characteristic data for oil and natural gas fields within the PCOR Partnership are collected or calculated and include parameters such as depth, temperature, pressure, porosity, permeability, initial water saturation, cumulative oil production, estimated CO_2 storage capacity, and OOIP. There are over 16,000 records for oil and natural gas reservoirs in the MSSQL database.

Petra Database–Oil and Gas Wells

Petra software is used to manage oil and gas well information across the PCOR Partnership. There are over 450,000 wells available, with data including API number; depths; formation tops; oil, gas, and water production; and geophysical logs. Information on the Petra well database is shown in Table 2. The well data have been used for a variety of purposes including geologic modeling efforts described later in this report. Well information can include pertinent information such as formation tops and LAS (log ASCII standard) files that can be incorporated into the geologic model. The well information is critical as it provides formational data that can help provide input data for the geologic models or conversely the well data can help verify model outputs.

Table 2. Oil and Gas Well Data Contained in the Petra Database

State/Province	No. of Wells	General Update Frequency	Source of Data
Alberta	0	–	No online source
British Columbia	30,269	–	British Columbia Oil and Gas Commission
Colorado	104,085	4–6 months	Colorado Oil and Gas Conservation Commission
Manitoba	9714	3 months	Manitoba government Web site
Missouri	11,112	Not updated	–
Montana	44,202	Weekly	Montana Board of Oil and Gas (MBOG)
Nebraska	21,820	3–4 months	Colorado Oil and Gas Conservation Commission
North Dakota	27,959	Weekly	North Dakota Industrial Commission (NDIC)
Saskatchewan	120,685	Upon request	Saskatchewan Oil and Gas Wells Web site
South Dakota	2075	3–4 months	South Dakota Department of Environment and Natural Resources (DENR)
Wyoming	116,359	Upon request	Wyoming Oil and Gas Conservation Commission (WOGCC)

Oil and Gas Data Collection by State/Province

Each state or province has its own method and requirements for collecting and managing oil and gas field/reservoir data. For example, Montana, before 1986, and Wyoming, before 1978, each required oil and gas companies to report oil/gas production at the field level. If an oil field was producing from multiple reservoirs or formations, the values were summarized to one field level value. This commingled reporting in these two states makes it impossible to accurately calculate production at the reservoir level for oil fields that have multiple reservoirs before the aforementioned years. The commingled reporting affected OOIP and CO_2 storage calculations in 1117 reservoirs (59.0%) in Wyoming and 882 reservoirs (61.6%) in Montana (Table 3). However, reservoirs with the commingled reporting may not have calculations affected if OOIP was calculated based on reservoir characteristics rather than a production-based estimation or if the reservoir fell within an oil field that only had that one reservoir.

Currently, states/provinces require oil companies to report production at the reservoir level within each field, in other words, there needs to be production values for each producing formation within the oil field. Each state or province data collection source/method is described below.

Table 3. Wyoming and Montana Production Reporting

State	No. of Oil Fields	No. of Oil Reservoirs	No. of Reservoirs with Preproduction*	Percentage of Reservoirs with Preproduction*	No. of Reservoirs Affected by Commingled Reporting	Percentage of Reservoirs Affected by Commingled Reporting
Montana	386	1431	1003	70.1	882	61.6
Wyoming	684	1894	1260	66.5	1117	59.0

*Preproduction refers to pre-1986 oil production for Montana and pre-1978 oil production for Wyoming.

Alberta

Alberta Energy and Utilities Board (EUB) provided oil and gas data for the province of Alberta in late 2005. EUB provided digital GIS files of oil and gas fields and reservoirs along with a spreadsheet of reservoir characteristics that were used for CO_2 storage calculations.

British Columbia

The Government of British Columbia Oil and Gas Commission Engineering and Geology Branch provided oil and gas data for the portion of the province of British Columbia that falls within the PCOR Partnership. These oil and gas field records included data up to August of 2007.

Manitoba

Oil and gas data for the province of Manitoba were taken from a document entitled "Designated Fields and Pools 2004" from the Manitoba Industry, Economic Development, and Mines Petroleum Branch Web site: www.gov.mb.ca/itm/mrd/index.html. Oil and gas reservoir outlines were assumed to be coincident with the field boundaries. Individual reservoir characteristics were provided in May 2004 by the Manitoba Industry, Economic Development, and Mines Petroleum Branch. Cumulative oil production is through December 2002.

Oil and gas well location data and field boundaries were provided by the Manitoba Department of Industry, Economic Development and Mines Web site: www.gov.mb.ca/itm/petroleum/gis/index.html.

Montana

Montana reservoir and well data were obtained from MBOG. Production data for Montana are treated differently than most states/provinces. Prior to 1986, Montana records show cumulative production for each oil and gas field. Records for each reservoir within a specific oil and gas field were summarized to one cumulative value. Therefore, it is impossible to break out individual reservoir values before 1986 in fields with multiple reservoirs. In 1986, the state of Montana required the oil and gas industry to report oil production at the reservoir level. As a result, the reservoir data the PCOR Partnership collected are separated into two values: pre-1986 field production and post-1986 reservoir production.

An effort was made to add Montana abandoned oil fields that were not provided by MTBOG. The methodology for producing those oilfield boundaries is described in Appendix B.

Nebraska

Nebraska's reservoir characteristic data were updated using two different sources: the Rocky Mountain Association of Geologists Oil and Gas Fields of Colorado–Nebraska and Adjacent Areas (1982) and the Rocky Mountain Association of Geologists Oil and Gas Field Volume, Colorado–Nebraska (1961). In the case of overlapping and contradicting data, the data from the Rocky Mountain Association of Geologists Oil and Gas Fields of Colorado–Nebraska and Adjacent Areas (1982) were used.

Monthly lease production data were obtained from the Nebraska Oil and Gas Conservation Commission (NOGCC). In Nebraska, oil and gas production is recorded by lease. Each lease corresponds to a specific formation within a specific oil and gas field. There can be multiple leases associated with one reservoir in one oil and gas field. To calculate cumulative reservoir production, all monthly lease production data are combined. Then cumulative lease production from leases in the same formation of the same oil and gas field is combined to get cumulative reservoir production.

North Dakota

North Dakota reservoir and well data were obtained from the NDIC Department of Mineral Resources. These data contained reservoir characteristics and cumulative oil and gas production for every field and reservoir in North Dakota. The data were matched with a feature class for all the oil fields and unitized fields in North Dakota, which was obtained from the NDIC Web site.

Saskatchewan

Saskatchewan Industry and Resources provided oil and gas data for the province of Saskatchewan. The GIS feature classes representing oil fields were modified to allow them to be represented in a manner consistent with the rest of the PCOR Partnership. Reservoir outlines were assumed to be coincident with field boundaries. Well depth values were assigned to the total depth column and converted from meters to feet in order to be consistent with the rest of the PCOR Partnership data. Cumulative production data were taken from the Saskatchewan 2002 Reservoir Annual, and production estimates are through December 2002.

South Dakota

South Dakota reservoir data were obtained through the Department of Environmental and Natural Resources (DENR) Mineral and Mining Program. Cumulative oil and gas production data for every field and reservoir were downloaded from the DENR Web site.

Wyoming

Wyoming reservoir data were obtained from multiple sources. In some cases, these sources contained overlapping and contradicting data. In these cases, the sources were ranked as to which ones were believed to be most reliable (Table 4). Well data, including cumulative oil production, were acquired from the WOGCC Web site. Similar to Montana, prior to 1978, Wyoming records show cumulative production for each oil and gas field. Records for each reservoir within a specific oil and gas field were summarized to one cumulative value. Therefore, it is impossible to break out individual reservoir values before 1978 in fields with multiple reservoirs. In 1978, the state of Wyoming required the oil and gas industry to report oil production at the reservoir level. As a result, the reservoir data are separated into two values: pre-1978 field production and post-1978 reservoir production.

Another challenge with Wyoming oil and gas wells is in determining a reliable way to spatially represent the oil and gas fields. The most reliable source for oil and gas fields was the Energy Information Administration (EIA). EIA wrote a script that, when used in ArcGIS, creates a buffer around wells, merges the buffered areas of wells from the same oil and gas field, and then smoothes the edges of the merged zones to create field boundaries around wells for a specified field.

Table 4. Ranking of Wyoming Reservoir Data

Source Name
1. Enhanced Oil Recovery Institutes database www.uwyo.edu/eori/areas_of_focus/data_generation.html (accessed May 2012)
2. Wyoming Oil and Gas Fields Symposium Powder River Basin, Volumes 1–2, 2000 (DVD)
3. The Economics of Enhanced Oil Recovery: Estimating Incremental Oil Supply and CO_2 Demand in the Powder River Basin (Veld and Phillips, 2010)
4. Comparison of Shoreline Barrier Island Deposits from Wyoming, California, and Texas (Rawn-Schatzinger and Lawson, 1994)

Estimation of CO_2 Storage Capacity for EOR

There are different methods for calculating an estimated CO_2 storage capacity for EOR operations within a reservoir. Static methods used for calculations are based on volumetric- and compressibility-based models. Volumetric (or production-based) methods are applied when it is assumed that the formation is open and the oil and gas are displaced by CO_2 from the formation or managed by production. The PCOR Partnership has selected an incidental CO_2 storage, volumetric-based methodology for CO_2 storage calculations (U.S. Department of Energy National Energy Technology Laboratory, 2010a; Goodman and others, 2011). This methodology may involve two calculations. OOIP, if not provided, is calculated or estimated based on the available reservoir data. Once OOIP is determined, then an estimated CO_2 storage capacity can be calculated. Since the CO_2 storage capacity is dependent on OOIP, the quality of OOIP will have a direct impact on the quality of the CO_2 storage value. These two calculations are discussed below.

OOIP

In order to calculate the estimated CO_2 storage capacity for EOR operations, OOIP needs to be known for each reservoir. Ideally, OOIP would be provided in the data acquired for each individual oil reservoir; however, this is frequently not the case. When data are available for the OOIP calculation, it is derived using the following method:

$$OOIP = (7758*A*h*\Phi*S_{oi})/FVF \qquad \text{[Eq. 1]}$$

Where:

A is field surface area, acres.
H is average pay thickness, feet.
Φ is average porosity, %.
S_{oi} is oil saturation, %.
OOIP is original oil in place in stock tank barrels (stb).
FVF is oil formation volume factor (initial), rb/stb.

7758 is a conversion factor relating acres to barrels. 7758 bbl/ac-ft = (43,560 ft^2/acre) × (.1781 bbl/ft^3).

In the event that the data are not available to calculate OOIP with the equation above, OOIP is estimated from the cumulative production of the reservoir and a chosen recovery factor. OOIP is calculated by:

$$\text{OOIP} = \text{cumulative production/RF} \qquad \text{[Eq. 2]}$$

Where:

* RF = recovery factor

A RF of 0.36 was used, which is an average value after primary and secondary recovery methods (Mast and Howard, 1991) were completed. While it is acknowledged that oil fields/reservoirs throughout the PCOR Partnership region are at different stages of development and/or production, the RF value was selected because typically CO_2 EOR activities would take place after primary and secondary recovery methods have been completed for an oil reservoir. Reservoirs that are at the beginning of their life cycles, which would have low cumulative production numbers to date, will have low calculated OOIP values from this method of OOIP estimation. These reservoirs would be omitted when finding CO_2 EOR target reservoirs because the small storage size would limit the economic feasibility of EOR operations. There were 2579 reservoirs that used this OOIP-estimating equation (15.9% of the reservoirs). Oilfield total OOIP values by state are shown in Table 5.

Table 5. Oil and Gas Information for the PCOR Partnership

State/Province*	No. of Oil Fields	No. of Oil Reservoirs	OOIP, stb
Alberta	579	9227	47,119,831,151
Manitoba	8	37	859,118,946
Montana	386	1431	11,985,499,969
Nebraska	739	760	918,510,866
North Dakota	685	1493	28,918,272,736
Saskatchewan	423	762	30,453,851,917
South Dakota	22	22	137,304,097
Wyoming	684	1894	2,451,838,608
Total	3526	15,626	122,844,228,290

* British Columbia data are currently being evaluated.

Estimated CO_2 Capacity

The estimation of CO_2 storage in the PCOR Partnership region is an incidental CO_2 storage, volumetric-based approach that applies to oil and gas reservoirs that are viewed as possible EOR targets. The equation is:

$$M_{CO2} = \text{OOIP} * \rho_{CO2STD} * \text{RF} * \text{UF} \qquad \text{[Eq. 3]}$$

Where:

M_{CO2} is the CO_2 storage resource mass estimate for geologic storage in oil and gas reservoirs in pounds.
OOIP is the original oil in place in stb.
ρ_{CO2STD} is the density of CO_2 at industrial standard conditions.
RF is the recovery factor in percent.
UF is the net utilization factor in scf of CO_2/barrel of oil recovered.

This equation calculates an associated CO_2 storage value. The amount of CO_2 stored in the reservoir is dependent on how much oil is removed from the reservoir as a result of CO_2 injection. The OOIP describes how much oil is present in the reservoir based on the reservoir characteristics before any oil has been removed in production. Before CO_2 injection occurs, the oil field will have undergone primary and secondary production efforts. RF refers to the amount of oil that is expected to be produced as a result of CO_2 injection, also known as incidental oil production. UF determines how much CO_2 is necessary to produce a barrel of oil. When OOIP, RF, and UF are multiplied together, the result is the amount of CO_2 injected into the formation to produce the oil during the process. To put it another way, the CO_2 is replacing the oil that is recovered during the injection process. The density of CO_2 is included in the calculation in order to convert the CO_2 from a volume (cubic feet) to a mass (pounds). The density of CO_2 can vary depending on the assumed conditions of temperature and pressure. This equation assumed industrial standard conditions with a temperature of 60°F and pressure of 1 atmosphere. The resulting value will show how much CO_2 produced at the surface (i.e., CO_2 emissions from a coal-fired power plant) can be injected into the target formation.

A matrix of RF and UF values was based upon literature to give a range of estimated CO_2 storage values. Brock and Bryan (1989) analyzed data for miscible and immiscible EOR field-scale and pilot-scale reservoirs and found CO_2 injection yielded an incremental oil production of 7% to 22% of OOIP, while Goodyear and others (2003) found between 4% and 20%. Holt and others (1995) found the average incremental recovery of oil in their case studies was 13.2% of OOIP. More recent studies such as Sandhu (2012) found average incremental oil recovery was 10%–12%, and Clark (2012) stated the Rangley Weber sand unit in Colorado yielded an incremental recovery of 4.8%. Based on the literature, RF values for the matrix are 8%, 12%, and 18%.

Brock and Bryan (1989) found net utilization values ranging from 2.4 to 13 Mcf per barrel of oil recovered in their study's oil fields. Goodyear and others (2003) found that the majority of projects have net gas utilizations of less than 8 Mcf/stb, and several reservoirs are less than 6 Mcf/stb. Clark (2012) stated that the net utilization value was 4.9 Mcf/stb for the Rangely Weber unit. Based on the literature, net UF values used in this study's calculations are 3000, 5000, and 8000 ft^3 of CO_2 per barrel of oil recovered.

The matrix of three RF and three UF values will yield a range of nine estimated CO_2 storage values for each targeted oil and gas reservoir (as shown in Table 6). This range of values will allow an end user to select a RF and UF that more closely represent the conditions of their specific oil field/reservoir.

Table 6. Range of CO_2 Storage Volumes by State/Province, storage tons

State/ Province*	RF 8% UF 3000 ft^3	RF 8% UF 5000 ft^3	RF 8% UF 8000 ft^3	RF 12% UF 3000 ft^3	RF 12% UF 5000 ft^3	RF 12% UF 8000 ft^3	RF 18% UF 3000 ft^3	RF 18% UF 5000 ft^3	RF 18% UF 8000 ft^3
Alberta	655,908,050	1,093,180,083	1,749,088,133	983,862,074	1,639,770,124	2,623,632,198	1,475,793,111	2,459,655,186	3,935,448,298
Manitoba	11,958,936	19,931,560	31,890,495	17,938,404	29,897,339	47,835,743	26,907,605	44,846,009	71,753,614
Montana	166,838,160	278,063,599	444,901,759	250,257,239	417,095,399	667,352,638	375,385,859	625,643,098	1,001,028,957
Nebraska	12,785,671	21,309,452	34,095,123	19,178,507	31,964,178	51,142,685	28,767,760	47,946,267	76,714,028
North Dakota	402,542,357	670,903,928	1,073,446,284	603,813,535	1,006,355,891	1,610,169,426	905,721,046	1,509,535,077	2,415,256,123
Saskatchewan	423,917,619	706,529,364	1,130,446,983	635,876,428	1,059,794,047	1,695,670,475	953,814,642	1,589,691,070	2,543,505,712
South Dakota	1,911,273	3,185,455	5,096,728	2,866,910	4,778,183	7,645,092	4,300,364	7,167,274	11,467,638
Wyoming	34,129,593	56,882,656	91,012,249	51,194,390	85,323,984	136,518,374	76,791,585	127,985,976	204,777,561
Total	1,709,991,658	2,849,986,097	4,559,977,755	2,564,987,486	4,274,979,145	6,839,966,631	3,847,481,972	6,412,469,957	10,259,951,931

* British Columbia data are currently being evaluated.

Oil and Gas CO_2 Storage Statistics

The data compiled and used for OOIP and CO_2 storage calculations yielded an extensive amount of data across the PCOR Partnership. Out of 16,194 oil and gas reservoirs, 12,604 reservoirs had OOIP values available for CO_2 storage estimates. OOIP values for 10,025 reservoirs had data available or were calculated using the volumetric equation previously described. OOIP values were estimated based on oil production, as previously described, for 2579 reservoirs, including 18 reservoirs that had unrealistic OOIP values when compared to cumulative production. These 18 reservoirs had OOIP and production data that indicated recovery rates of over 78%, with 11 reservoirs having oil production exceeding OOIP; in other words, recovery rates exceeded 100%, which illustrated the necessity to recalculate OOIP. The calculations to derive OOIP from oil production are assuming that primary and secondary oil recovery have been completed.

For all 12,604 reservoirs where OOIP was provided or calculated, the CO_2 storage values were derived from the previously discussed equation. The matrix of three RF and three UF values yielded a range between 1.71 and 10.62 billion tons of CO_2 storage (Table 6). These estimates of CO_2 storage are based upon the best available data and methods previously described. This dynamic value will change in the future as more data become available, more oil fields are developed, and potential new methodologies are formulated.

One benefit to CO_2 storage in oil and gas reservoirs is the recovery of oil, termed incremental oil recovery. Based on the OOIP values, an estimated incremental oil recovery value can be derived from the same recover factors that were used in the CO_2 storage estimate. As seen in Table 7, the amount of oil recovered in CO_2 EOR operations could range from 9 billion to 22 billion barrels of oil across the PCOR Partnership.

The data presented represent the CO_2 storage potential assessed at the time of data collection based upon the best available data. The storage potential values will change in the future with updated production values, new oil fields, new OOIP calculations, updated methods, and enhancements in CO_2 EOR storage techniques that allow for more efficient recovery factors and net utilization factors. As additional data and information become available, PCOR Partnership databases will be updated and CO_2 storage volumes recalculated utilizing the best available methods and data.

Table 7. Incremental Oil Recovery as a Result of CO_2 Injection, stb

State/Province*	OOIP	Incremental Oil at 8% RF	Incremental Oil at 12% RF	Incremental Oil at 18% RF
Alberta	47,119,831,151	3,769,586,492	5,654,379,738	8,481,569,607
Manitoba	859,118,946	68,729,516	103,094,274	154,641,410
Montana	11,985,499,969	958,839,998	1,438,259,996	2,157,389,994
Nebraska	918,510,866	73,480,869	110,221,304	165,331,956
North Dakota	28,918,272,736	2,313,461,819	3,470,192,728	5,205,289,092
Saskatchewan	30,453,851,917	2,436,308,153	3,654,462,230	5,481,693,345
South Dakota	137,304,097	10,984,328	16,476,492	24,714,737
Wyoming	2,451,838,608	196,147,089	294,220,633	441,330,949
Total	122,844,228,290	9,827,538,263	14,741,307,395	22,111,961,092

* British Columbia data are currently being evaluated.

CHARACTERIZED SALINE FORMATIONS

Sedimentary basins exist around the world and consist of thick successional geologic formations, often consisting of deep saline formations (DSFs). These DSFs offer the greatest potential for storage of anthropogenic CO_2 because of their large pore volume and spatial distribution. DSFs 1) exist at a depth where CO_2 will reside in a dense, supercritical phase, typically at depths greater than 2600 feet (800 meters); 2) contain formation fluids with total dissolved solids (TDS) in excess of 10,000 ppm; and 3) are overlain by a thick, laterally continuous sealing formation with properties that preclude vertical migration of the injected CO_2.

Geologic storage of CO_2 is accomplished through injection into permeable formations and is subsequently trapped by several physical and geochemical processes (Intergovernmental Panel on Climate Change, 2005). When CO_2 is injected it can be physically trapped in structural or stratigraphic closures or as residual gas because of relative permeability hysteresis. Geochemically, CO_2 can be trapped by adsorption onto organic material or through dissolution into the formation brine (solubility trapping), where it can interact with the rock matrix and eventually precipitate into stable carbonate minerals (mineral trapping). Injected CO_2 can also be trapped through hydrodynamic trapping which is a complex combination of the previously mentioned trapping mechanisms (Intergovernmental Panel on Climate Change, 2005). When considering the storage resource potential of a geologic storage target, each of the trapping mechanisms have a differing levels of importance on different time scales. Figure 9 illustrates the relative importance of each trapping mechanism over time.

On the timescales that are being considered for geologic CO_2 storage, it is likely that the most important trapping mechanisms for storing CO_2 in saline formations will be physical and hydrodynamic trapping and, to a lesser extent, solubility trapping.

CO_2 Storage Classification

The classification of CO_2 storage and the terminology that has evolved is intended to provide a comparable basis for assessing CO_2 storage potential from regulatory and business perspectives. The definitions of the terms are meant to convey varying degrees of confidence in the storage assessment values that are generated.

A hierarchy of classification terminology has been developed over the past decade that leverages increasing confidence with increasing data and a smaller geographic area of interest. These relationships were first illustrated by the techno-economic resource–reserve pyramid defined by the Carbon Sequestration Leadership Forum (CSLF) (2007). This graphical representation of terms shows the trend from broad-based resource estimations to small-scale, site-specific characterizations (Figure 10), each with differing degrees of certainty. Moving up the pyramid requires more detailed data in a more focused geographic extent along with the application of increasing constraints such as technical, geological, and economic to the CO_2 storage capacity defined by CSLF.

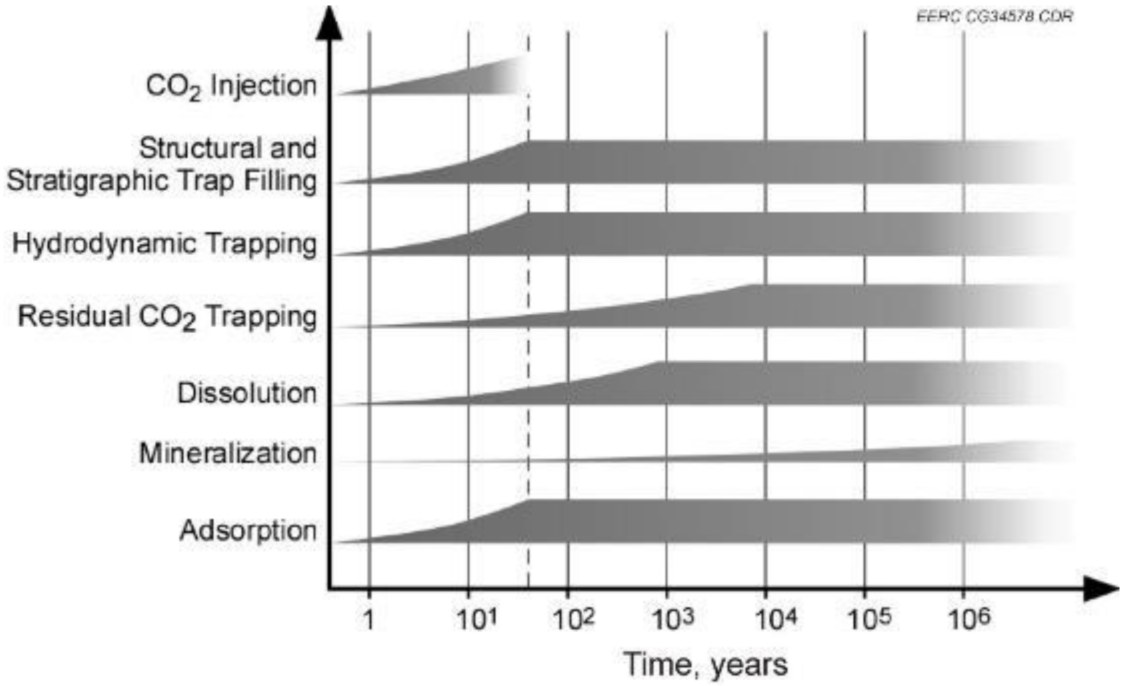

Figure 9. Over the course of a CO_2 storage project, the physical and geochemical processes and the relative importance of each change over time (Intergovernmental Panel on Climate Change, 2005).

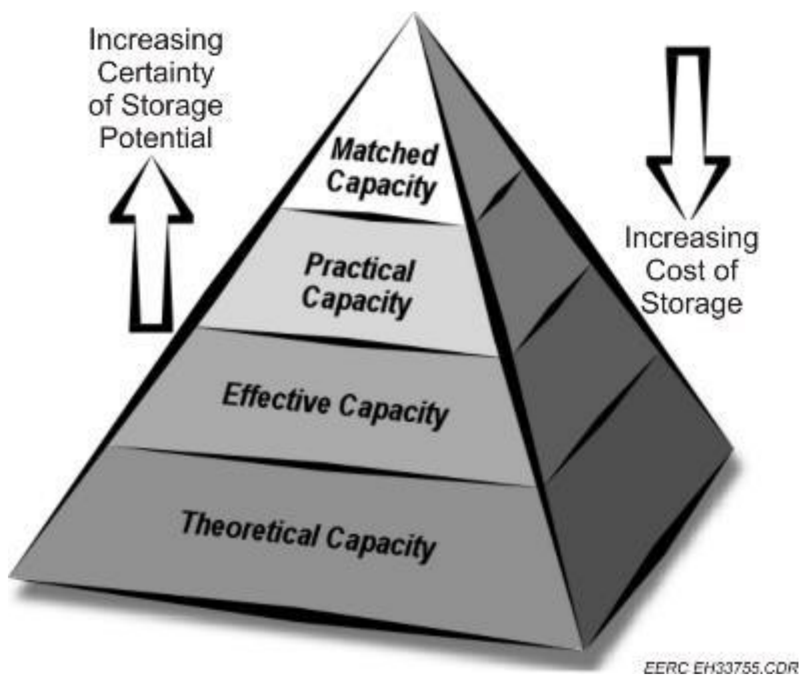

Figure 10. CSLF techno-economic resource–reserve pyramid (Carbon Sequestration Leadership Forum, 2007).

Gorecki and others (2009) proposed a refined classification incorporating terms defined by DOE (U.S. Department of Energy National Energy Technology Laboratory, 2008) that distinguish between storage estimates defined by physical and chemical constraints (resource) and those with added economic and regulatory constraints (capacity) (Figure 11). The first two divisions within this proposed classification framework, theoretical and characterized storage resource, are equivalent to the theoretical capacity of the CSLF pyramid. The effective storage resource refines the broader-level estimates by integrating geologic and engineering limitations. This level is equivalent to CSLF's definition of effective storage capacity, although here it is defined as a resource since economic considerations have not been implemented.

As mentioned earlier, the approach to estimating the CO_2 storage volume, as well as the required level of detail for the required data, will vary depending on the geographic scale of the assessment effort. In its Phase 2 final report, CSLF (2007) presented five terms representing scales of geographic extent for the assessment of CO_2 storage. These terms, in order of decreasing area, are country, basin, region, local, and site. Confidence in the calculated storage potential increases as the geographic scale decreases. Gorecki and others (2009) augment this geographic hierarchy by incorporating a level of spatial scale as defined by political subdivisions (Figure 12).

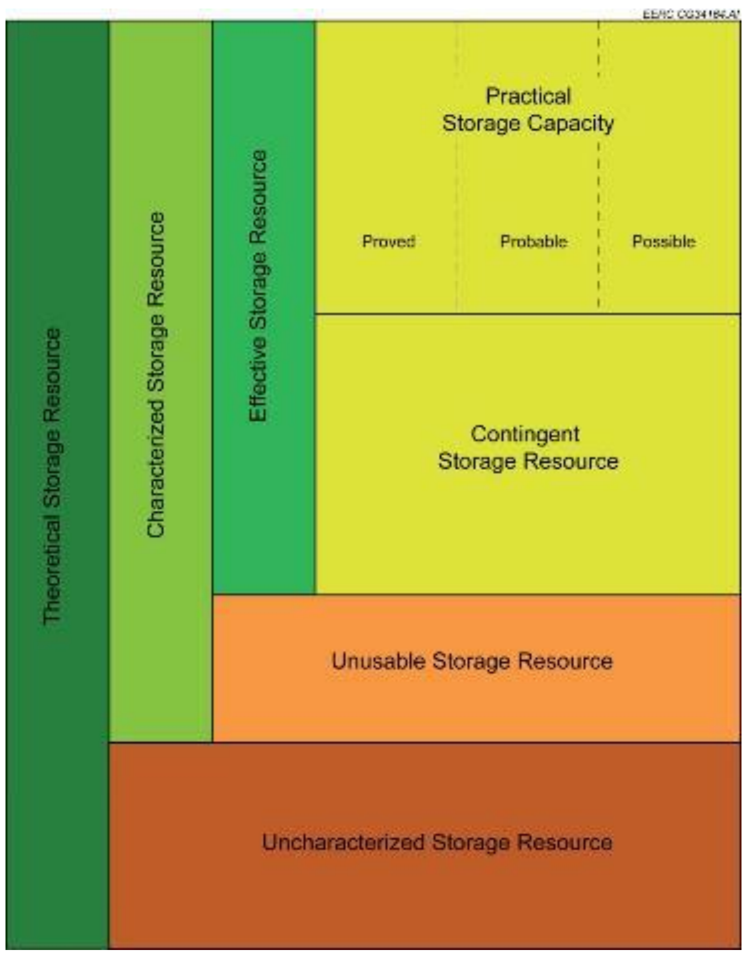

Figure 11. CO_2 storage classification framework (Gorecki and others, 2009).

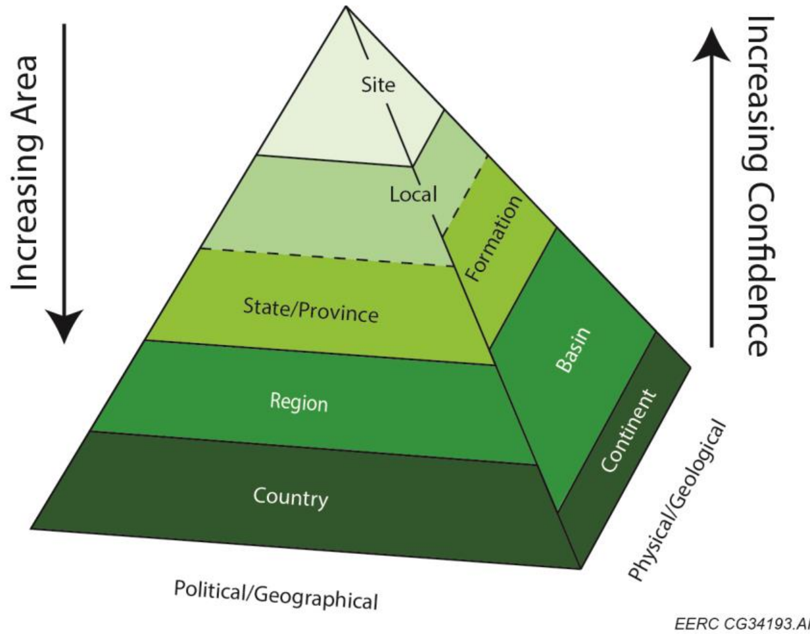

Figure 12. Political–geographic, physical–geologic pyramid of assessment area types and scales (Gorecki and others, 2009).

Methodology

The methodology used by the PCOR Partnership follows the approach described by DOE (U.S. Department of Energy National Energy Technology Laboratory, 2010a), which builds on the IEAGHG work of Gorecki and others (2009). It is based on the volumetric approach for estimating CO_2 storage resource potential for saline formations. The volumetric equation to calculate the CO_2 storage resource mass estimate for geologic storage in saline formations is:

$$M_{CO_2e} = A \times h \times \varphi \times \rho_{CO_2} \times E \qquad \text{[Eq. 3]}$$

The total area (A), gross formation thickness (h), and total porosity (φ) terms account for the total bulk volume of pore space available. The value for CO_2 density (ρ) converts the reservoir volume of CO_2 to mass. The storage efficiency factor (E) reflects the fraction of the total pore volume that will be occupied by the injected CO_2. For saline formations, the CO_2 storage efficiency factor is a function of geologic parameters, such as area, gross thickness, and total porosity, that reflect the percentage of volume amenable to CO_2 sequestration and displacement efficiency components that reflect different physical barriers inhibiting CO_2 from contacting 100% of the pore volume of a given basin or region. Volumetric methods are applied when it is generally assumed that the formation is open and that formation fluids are displaced from the formation or managed via production. The DSFs in the PCOR Partnership region are assumed to be an open system. A comprehensive discussion of the derivation of the methodology and the efficiency factor is presented in Gorecki and others (2009), U.S. Department of Energy National Energy Technology Laboratory (2010a), and Goodman and others (2011).

This storage amount calculated excludes areas where the saline system is unconfined and where the TDS is <10,000 mg/L. These areas are excluded because injection will not occur because of leakage and regulations regarding the injection of CO_2 into potable water used for residential, agricultural, or industrial use. Other areas excluded are depths <2500 ft (MD), where CO_2 is not considered to be a supercritical fluid.

CO_2 density was calculated based on the relationship of pressure, temperature, and density defined by the National Institute of Standards and Technology (2003). Temperatures and pressures were exported from the working Petrel project into a look-up function where CO_2 density is calculated. CO_2 density is then interpolated across the saline system using a kriging algorithm.

After calculating CO_2 density, Equation 3 was applied to determine the overall storage capacity of CO_2. The overall storage capacity utilized saline efficiency coefficients for a clastic depositional system from the DOE NETL Atlas III and IV (2010a, 2012). These coefficients were used because the net-to-total area, net-to-total gross thickness, and effective-to-total porosity are known from the characterization activities above.

Geologic Modeling

The PCOR Partnership has employed two different modeling efforts over the course of the regional characterization of DSFs. Initially, a 2-D static model created in ESRI's ArcGIS was used to arrive at a CO_2 storage value. The 2-D model averaged the DSF parameters into a flat layer where CO_2 storage values were calculated. Formations that were modeled in this manner initially included the Maha, Madison (now known as Mission Canyon), Inyan Kara, Red River, Broom Creek, and Viking Formations.

More recent efforts have used a static 3-D geocellular model that takes into account the internal heterogeneity of complex facies relationships that exist vertically and laterally throughout the formations. Formations that have been modeled with the 3-D model include the basal Cambrian, Broom Creek, Minnelusa, and Mission Canyon Formations.

The goal of the modeling activities is to assess the volumetric CO_2 storage of the system based on its geometry, internal architecture, lithology, permeability and porosity, and temperature and pressure distributions (Peck and others, 2014).

Western Canadian Sedimentary Basins

In addition to the formations that were modeled by the PCOR Partnership, CO_2 storage data were provided by the Geological Survey of Canada for five Western Canadian Sedimentary Basins. These DSFs included the Beaverhill Lake Group, Elk Point Group, Rundle Group, Winterburn Group, and Woodbend Group. The area of each formation was determined by a combination of factors, including extent of available porosity data, distribution of producing regions within the formation, and relative lithofacies boundaries of known porous strata. The PCOR Partnership was provided with GIS shapefiles for the formations as well as CO_2 storage capacity values at the P_{10}, P_{50}, and P_{90} levels. However, it is currently unknown what the exact methodology was for arriving at those values. At the current time, these are the best available data for the formations.

PCOR Partnership Region Deep Saline Formations

Within the PCOR Partnership region, there are 13 deep saline formations (Figure 13) that have been investigated to varying degrees (Table 8). These 13 formations are listed in Table 9 along with a range of storage volumes.

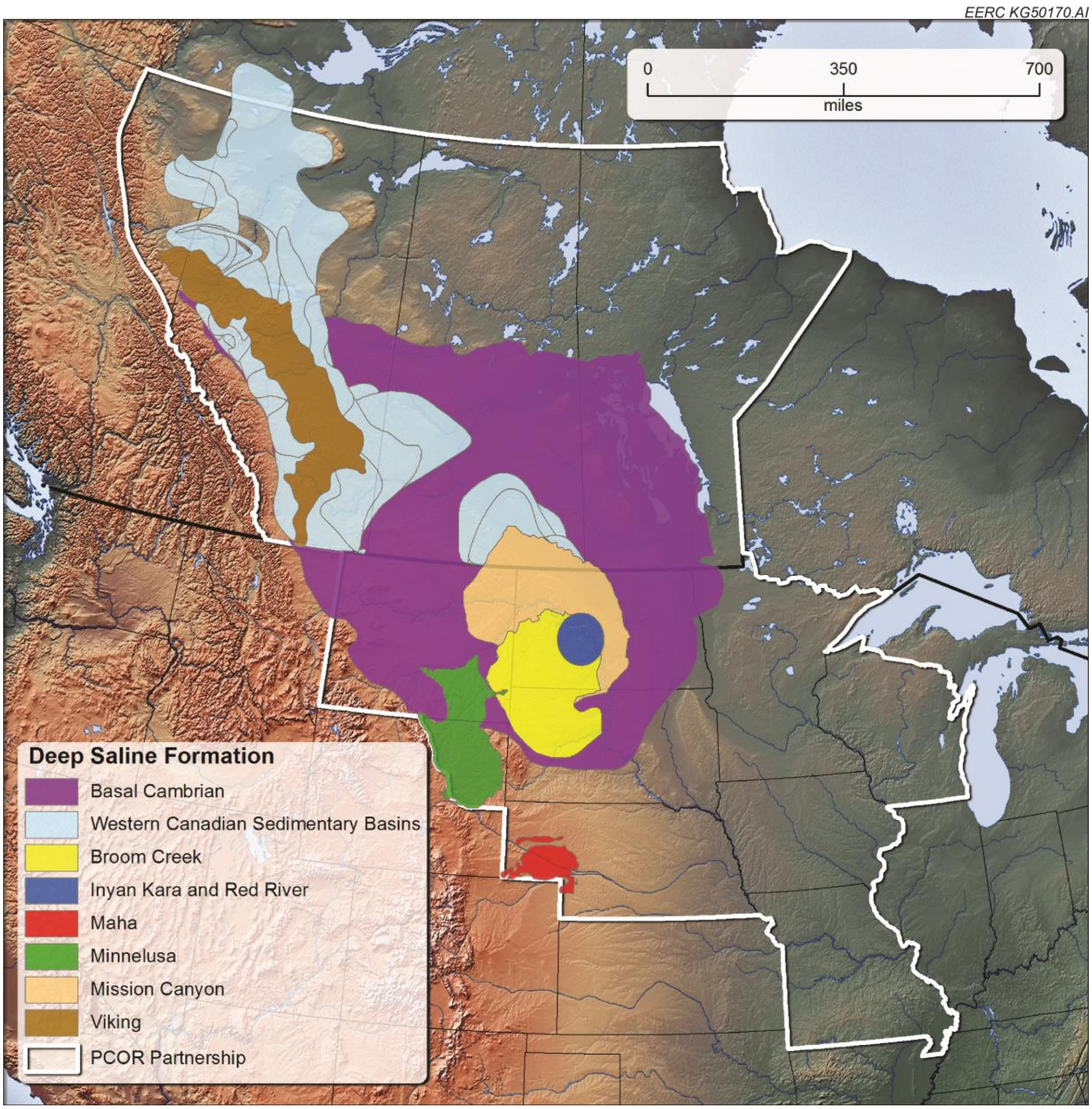

Figure 13. Deep saline formations within the PCOR Partnership region.

Table 8. Summary of DSF Formation Methodology

DSF	Summary of Methodology
Basal Cambrian	3-D geocellular model
Beaverhill Lake Group*	Provided by Geological Survey of Canada
Broom Creek	3-D geocellular model
Elk Point Group*	Provided by Geological Survey of Canada
Inyan Kara	2-D model of the Washburn study area**
Maha	2-D model
Minnelusa (Wyoming-Powder River Basin)	3-D geocellular model
Mission Canyon	3-D geocellular model
Red River	2-D model of the Washburn study area**
Rundle Group*	Provided by Geological Survey of Canada
Viking	2-D model
Winterburn Group*	Provided by Geological Survey of Canada
Woodbend Group*	Provided by Geological Survey of Canada

* Formations are part of the Western Canadian Sedimentary Basins.

** The Washburn study area is an approximately 90-mile-diameter circular formational subset that was studied in west-central North Dakota. Formations studied as part of the Washburn study area included the Red River, Inyan Kara, and Broom Creek Formations.

Table 9. CO_2 Storage in Saline Formations

Saline Formation	CO_2 Storage Low Volume*	CO_2 Storage Medium Volume*	CO_2 Storage High Volume*
Basal Cambrian	222.2	420.3	720.5
Beaverhill Lake Group	0.5	2	5.4
Broom Creek	13.1	24.9	42.6
Elk Point Group	1.3	4.7	12
Inyankara	10.9	20.5	35.2
Maha	20.9	39.5	67.7
Minnelusa	10.9	20.6	35.2
Mission Canyon	64.9	122.8	210.5
Red River	1.9	3.5	6.1
Rundle Group	0.8	3	7.9
Viking	20	37.8	64.8
Winterburn Group	0.6	2.2	5.8
Woodbend Group	0.6	2.3	6.2
Total	368.6	704.1	1219.9

* Billion tons.

BASAL CAMBRIAN

A binational effort, between the United States and Canada, characterized the lowermost saline system in the Williston and Alberta Basins of the northern Great Plains–Prairie region. This 3-year project was conducted with the goal of determining the potential for geologic storage of CO_2 in rock formations of the ~509,000 mi^2 Cambro-Ordovician Saline System (COSS) (Figure 14). To our knowledge, no other studies have attempted to characterize the storage potential of large, deep saline systems that span the U.S.–Canada international border. This multiprovince/multistate, multiorganizational, and multidisciplinary project was led on the U.S. side by the PCOR Partnership and on the Canadian side by Alberta Innovates – Technology Futures (AITF). The project objective was to characterize the basal saline system in the northern Great Plains–Prairie region of North America and to evaluate its storage potential by creating a heterogeneous 3-D model and determining the effects of CO_2 storage in this system using dynamic simulation.

The central interior portion of North America covered in this report encompasses the northern Great Plains–Prairie region of the United States and the southern Interior Plains of Canada. This region of North America is generally characterized by broad expanses of relatively flat land covered by prairie, steppe, and grassland and is bounded by the Canadian Shield to the northeast, the Rocky Mountains to the west, and the central lowlands of Minnesota and Iowa to the southeast. In addition to the strong agricultural focus, this region is also home to a robust energy industry that includes coal, oil, and gas development. The abundant energy resources of this area have resulted in the establishment of many large-scale CO_2 sources such as coal-fired power plants and refineries.

Similar to the Mt. Simon Formation that overlies the Precambrian crystalline basement in the U.S. Midwest (Leetaru and McBride, 2009; Barnes and others, 2009), COSS overlies the Precambrian basement in the northern Great Plains–Prairie region, extending from north of Edmonton, Alberta, to South Dakota and covering a combined area of ~509,000 mi^2 (~1.3 million km^2). The Canadian part of the saline system covers 313,285 mi^2 (811,345 km^2), and the U.S. part covers ~195,814 mi^2 (507,155 km^2). Given its reservoir characteristics and extent, this basal saline system should be considered as a prime target for the storage of CO_2 from large stationary sources in the northern Great Plains and Prairie region. In addition, most of the Cambrian to Silurian strata at the base of the sedimentary succession in the Williston and Alberta Basins (Figure 15) does not contain fossil fuels and also has limited prospects for unconventional oil or gas production, and as such, little of the prospective storage space is leased.

The vast extent and thickness of the model contributes to the large effort to characterize the DSF because of changes in nomenclature and the sparse data available from the absence of oil and gas development compared to other stratigraphically oil bearing zones in this region. The nomenclature for these alternating beds of fine siliciclastics and carbonates varies throughout the study area. In parts of Montana and Wyoming, they are referred to as the Gros Ventre and Gallatin Groups and are equivalent to parts of the Emerson Formation in the Little Rocky Mountains area of Montana and the Deadwood Formation in North and South Dakota. The

Figure 14. Location of basal Cambrian system (Glazewski and others, 2013).

Gros Ventre Group is made up of the Wolsey Shale, the Meagher Limestone, and the Park Shale. The Gallatin Group consists of the Pilgrim Limestone, the Snowy Range Formation (which consists of the Dry Creek Shale and the Sage Pebble Conglomerate), and the Grove Creek Limestone (which is sometimes included within the Snowy Range Formation) (Macke, 1993) (Figure 16).

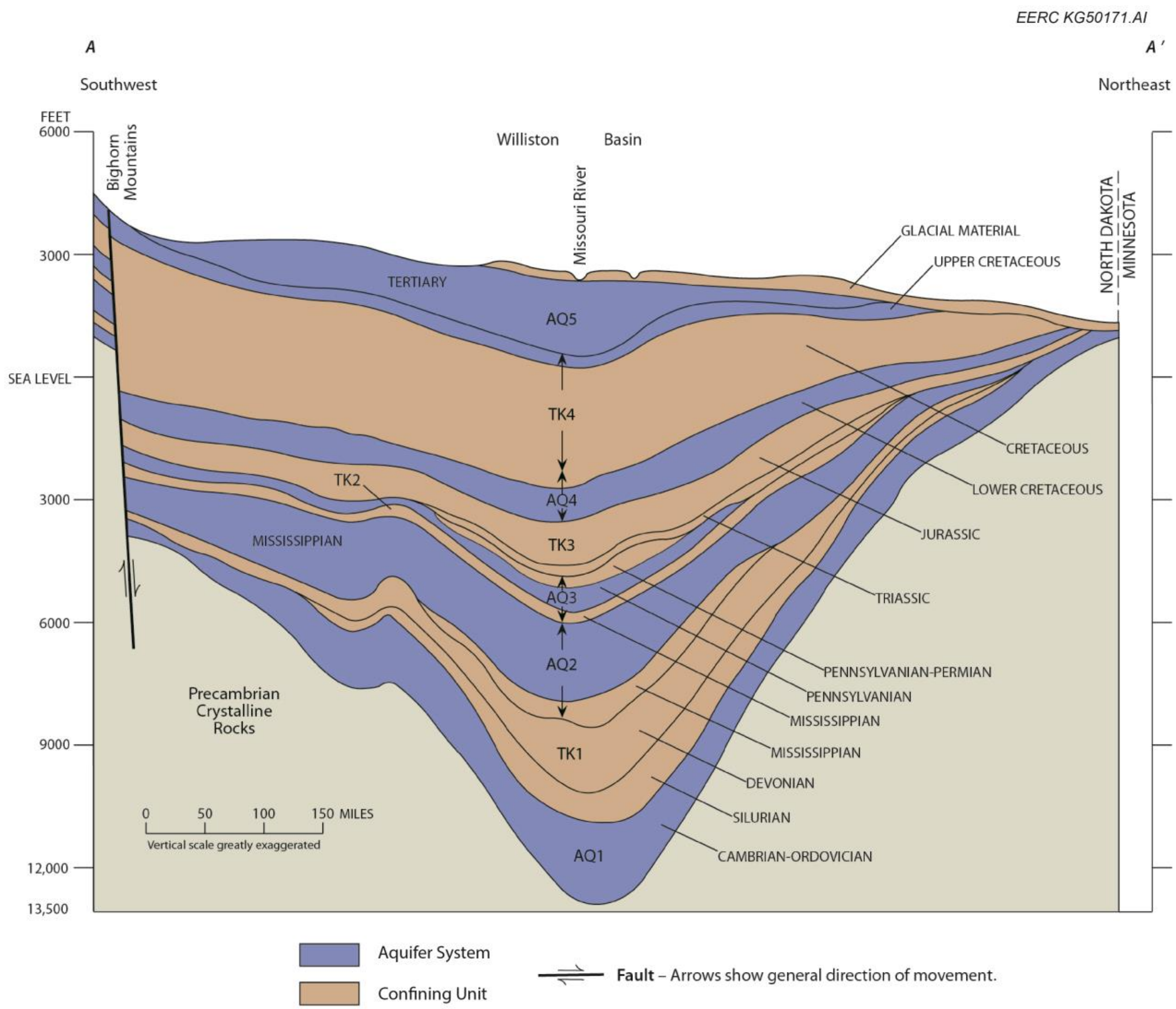

Figure 15. Geologic cross section of the Williston Basin (Peck and others, 2014).

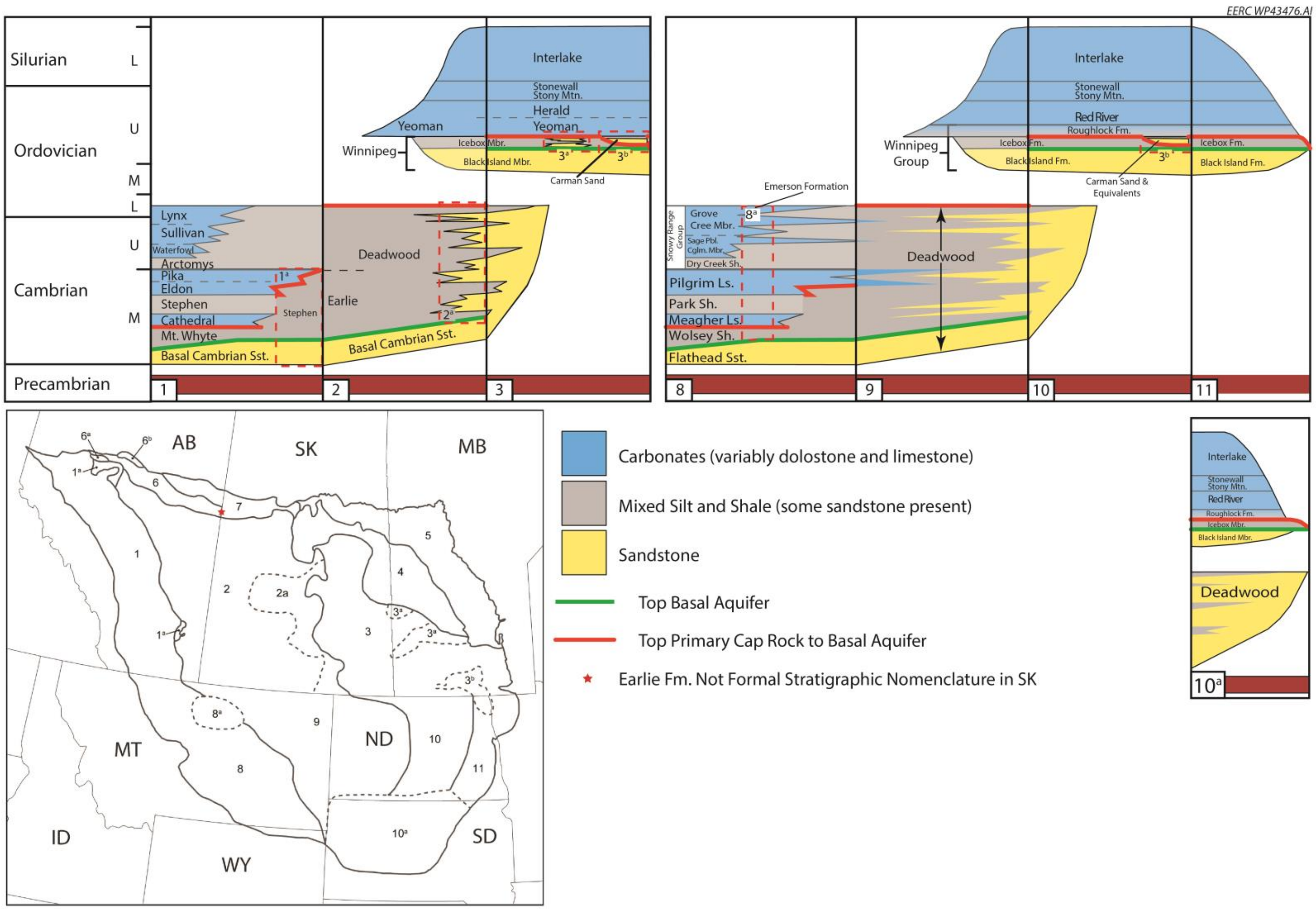

Figure 16. Stratigraphic correlation chart comparing the U.S. portion of the study region with the adjacent Canadian portion (modified from Bachu and others [2011]). The numbers on each stratigraphic column correlate to a region on the map. Nomenclature changes across the U.S.–Canadian border. Region 8a signifies a change in nomenclature, not lithology, in the Little Rocky Mountains area (Peck and others, 2014).

Formation tops of these stratigraphic sections were imported from state databases for Montana, North Dakota, and South Dakota, while tops in Canada were previously picked by Bachu and coworkers (2011) in collaboration with our efforts. After import, the tops went through a quality control (QC) process to adjust the aquifer top or Precambrian top if needed based on available digital well logs. A uniform aquifer top was established throughout the area to comprise the units described above prior to structural modeling.

Static Model

Different than the 2-D model completed in Phase II, the 3-D geocellular model takes into account the internal heterogeneity of complex facies relationships that exist vertically and laterally throughout COSS. The goal of the modeling activities is to assess the volumetric CO_2 storage of the system based on its geometry, internal architecture, lithology, permeability and porosity, and temperature and pressure distributions. In addition, the static model is also used for the dynamic simulation portion to determine dynamic storage and the effects of reservoir pressure buildup.

The complexity of the reservoir was characterized from numerous sources of data. Well data used in the development of the 3-D model across the U.S. portion of the basal saline system were obtained from NDIC and MBOG online databases. Data were also obtained from the Montana Geological Society and the South Dakota Geologic Survey. Data from these organizations included formation tops, well files, which included core measurements, wireline logs in raster and, in many cases, LAS format. Other forms of data were included from Bachu and others (2011) who went through a similar process to characterize the basal saline system in Canada.

Dynamic Simulation Efforts

To further evaluate this extensive saline system, and thus its viability as a potential storage sink, the 3-D geocellular model was used as the framework for an assessment of the dynamic storage capacity of the basal saline system with respect to the large CO_2 sources in the region. Static storage resource calculations do not consider the effect of dynamic factors such as injection rate, injection pattern, timing of injection, and pressure interference between injection locations. Numerical simulation is a method that can be used to validate the estimate of the effective storage resource potential of deep saline formations by addressing the effects of multiple large-scale CO_2 injections. The main goal of this effort is to compare volumetric storage resource estimates with dynamic storage potential for the large-scale sources in the study region.

Through the dynamic simulation effort, two main objectives were addressed: 1) assess the dynamic storage capacity of the saline system, assuming the 16 aggregated major large CO_2 sources located above or in close vicinity to this saline system and 2) assess the effect of pressure-related changes induced by the injection of large volumes of CO_2. To address these objectives, two dynamic injection scenarios were designed based on the base case static model. The two scenarios determine the injectivity of the saline system through the simulated injection of ~104 Mt/yr of CO_2 from the 16 aggregated sources.

Each of the two dynamic injection scenarios has multiple cases, and each case varied parameters that affected the dynamic simulation in an effort to optimize overall CO_2 injection. The first scenario positioned injection clusters at the locations of the 16 aggregated CO_2 sources. The second scenario partitioned the sources into 25 feeds that were piped to regions with "better" reservoir characteristics (i.e., high permeability of connected volumes) to optimize injection. The varying cases build upon one another with regard to changes, including the vertical-to-horizontal permeability ratio, addition of water extraction wells, relative permeability, rock compressibility, and horizontal injection. All of the dynamic simulations were performed using Computer Modelling Group's (CMG's) software package (www.cmgl.ca/). More details on the scenarios and their associated cases can be found in Peck and others (2014).

The two different scenarios (Figure 17) did not reach the total output of the CO_2 emissions because of the limited number of wells and injection clusters. Problems of injection occur for Scenario 1 because of the location of the initial injection clusters over areas of poor geologic conditions such as areas of low permeability and porosity and disconnected volumes. Scenario 2 increased injectivity after moving the injection clusters to areas of "better" geologic properties and distributed nine more injection clusters based on Scenario 1 that reaches 59.8% of the total CO_2 emissions.

Static Capacity of the Basal Saline System

Utilizing the storage coefficients, a total of ~420 billion tons of CO_2 could theoretically be stored in the P_{50} case for the basal saline system (Figure 18). Table 10 shows the P_{10}, P_{50}, and P_{90} efficiency factors and calculated CO_2 storage capacity volumes.

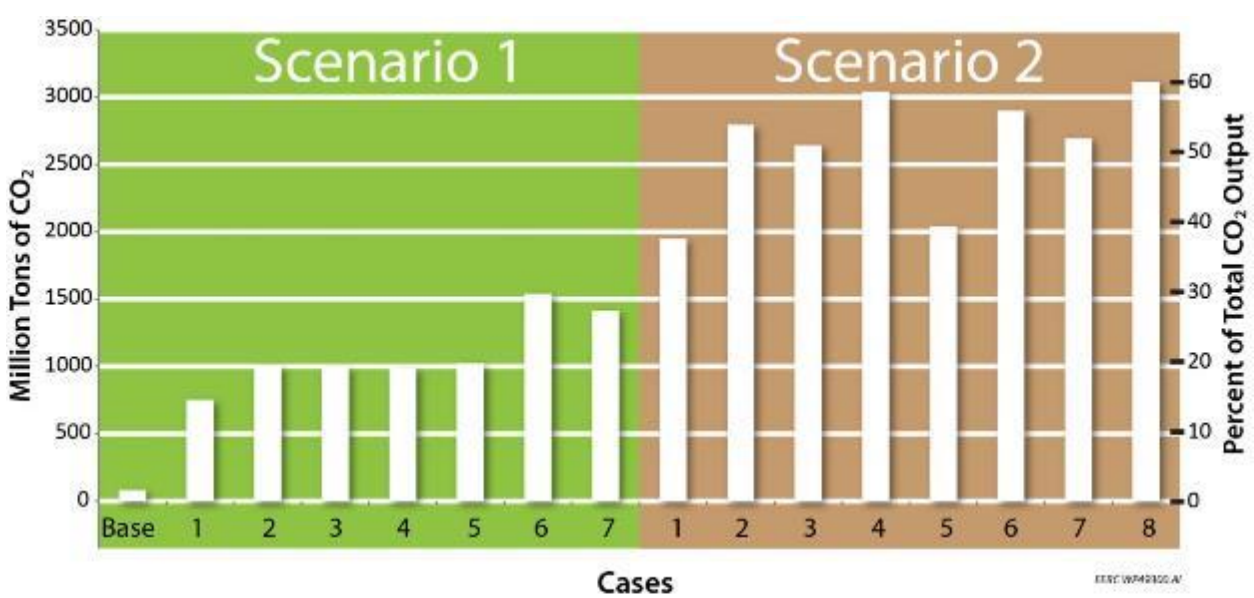

Figure 17. Cases are compared between Scenarios 1 and 2. The best simulation results in this study occurred in Scenario 2, with the inclusion of "better" geology and optimal operations (Peck and others, 2014).

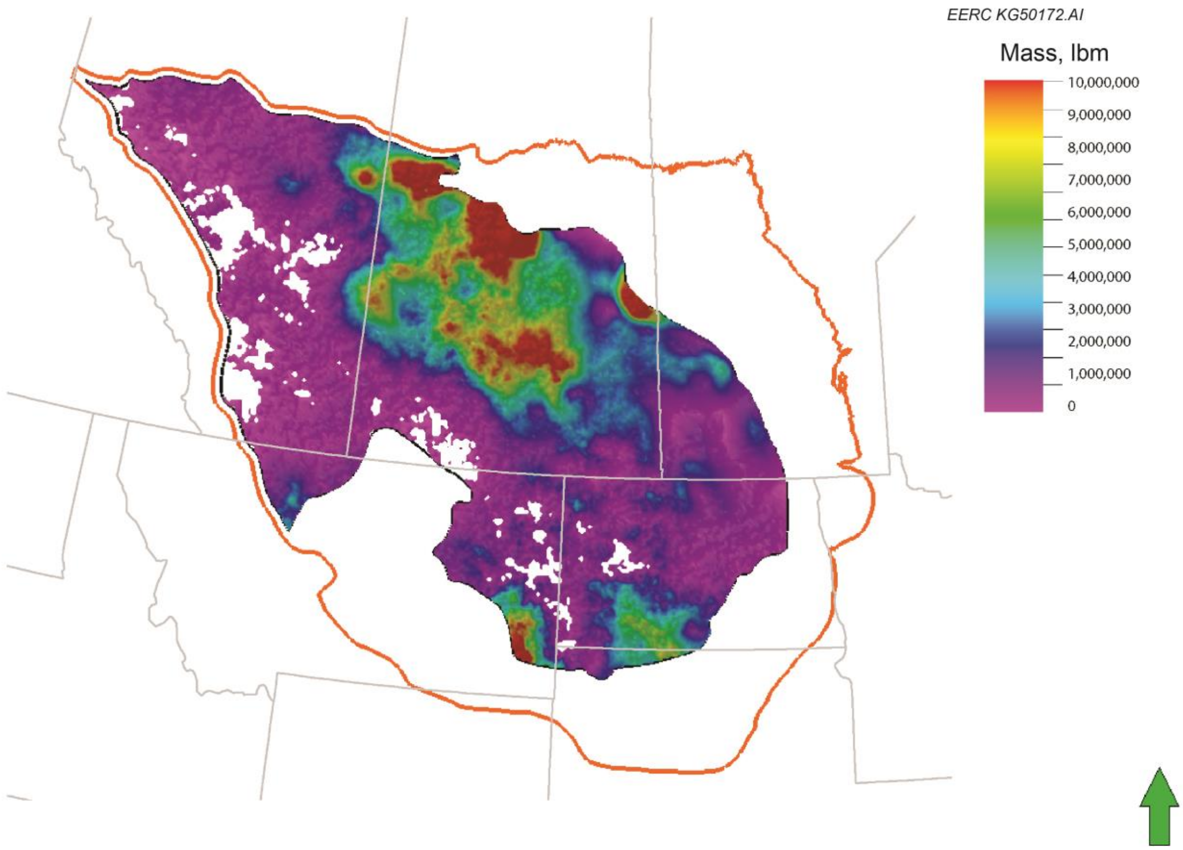

Figure 18. Storage potential (tons) of the basal saline system using a P_{50} efficiency factor of 9.1% (Peck and others, 2014).

Table 10. Storage Coefficients for Saline Formations and Storage Potential for the Basal Saline System

	P_{10}	P_{50}	P_{90}
Efficiency Factor, %	7.4	14	24
CO_2 Storage Capacity, billion tons	223	420	721

BASAL CAMBRIAN WELLBORE EVALUATION

As one of the three geologic media targeted for CO_2 storage, deep saline formations (greater than 2600 feet [800 meters]) are the most widespread and, theoretically, have the largest storage capacities of the three. A potential challenge associated with CO_2 storage is numerous wells drilled that may impact storage security, particularly in oil and gas reservoirs; however, deep saline formations may have fewer wellbore penetrations in areas without oil and gas exploration and production activities.

As part of the basal Cambrian evaluation for CO_2 storage potential, a wellbore evaluation was conducted on wells that penetrate the U.S. side of the formation in North Dakota, South Dakota, and Montana (Figure 14).

Wellbore Integrity

For CCS to be successful, a CO_2 storage formation needs to meet three fundamental conditions: 1) capacity, 2) injectivity, and 3) confinement (Zhang and Bachu, 2011; Bachu, 2003, 2010; Intergovernmental Panel on Climate Change, 2005). The targeted CO_2 storage formations in the basal Cambrian system have demonstrated the capacity and ability to hold materials such as oil, natural gas, or saline water. Wellbore integrity is the ability of a well to maintain isolation of geologic formations and prevent the vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). Wellbore integrity is crucial because any leakage of CO_2 poses a potential risk to surrounding groundwater, vegetation, and wildlife. In addition, it diminishes the quantity of CO_2 for which storage credits can be claimed as part of either monetary agreements or regulatory compliance. For the purposes of this study, leakage will be defined as a loss of CO_2 or other fluid from its intended storage formation and not necessarily losses to the atmosphere.

Wells are one possible pathway for CO_2 to escape the storage formation (Celia and others, 2004) (Figure 19). CO_2 could leak along interfaces between different materials, such as steel casing and cement interface (Figure 19a), cement plug and steel casing interface (Figure 19b), or rock and cement interface (Figure 19f). Leakage could also occur because of casing corrosion and subsequent failure leading to large leakage pathways, with the wellbore as a conduit.

The goal of the wellbore evaluation was to assign a relative risk score for deep and shallow well leakage for wells penetrating the basal Cambrian system on the U.S. side of the U.S.–Canada border as part of DOE efforts to identify potential CO_2 storage sites. It is important to note that the assignment of the relative leak potential scores is solely for purposes of internally comparing and contrasting the different wellbores within this portion of the system. Stated differently, the assignment of individual relative leakage potential scores to the wellbores means that a particular wellbore can be compared to the other wellbores and assigned a priority for further investigation, analysis, and monitoring in areas targeted for CO_2 injection. Site-specific risk analysis within these target areas would trigger a more detailed assessment of those wells identified for further investigation. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies. As such, it is an internal assessment of the potential associated with that wellbore relative to all of the other wellbores and does not represent an absolute assessment of its potential to impact the proposed carbon storage within the basal Cambrian system.

Wellbore Evaluation Methodology

The wellbores across the study area were evaluated through wellbore files obtained from each state's oil and gas regulatory agency. From the well files, information pertinent to identifying the potential for well leakage was extracted. The information included well

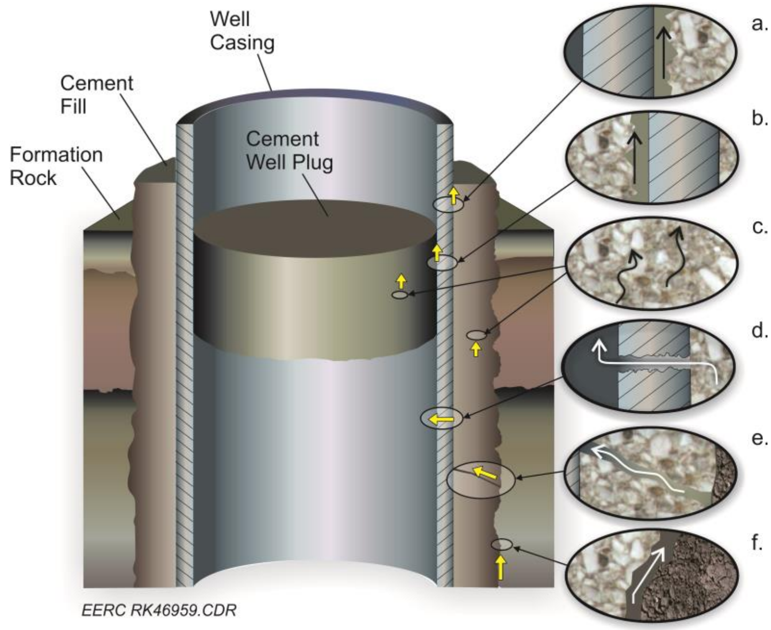

Figure 19. Conceptual illustration of the potential leakage pathways for CO_2 in a well along the casing–cement interface (a and b), within the cement (c), through the casing (d), through fractures (e), and along the cement–formation interface (f) (from Celia and others, 2004) (in Glazewski and others, 2013).

completion dates (drilling and/or abandonment dates), casing depths, casing diameters, cement types, amount of cement used, top of cement (TOC), completions, plugging and abandonment procedures, fracture treatments, acid treatments, and any other relevant information about the well. In addition to this well file information, the physical implementation and accurate reporting of drilling, completion, and workover activities are equally important factors in assessing the integrity of an individual well, albeit they are difficult to quantify. Some of this information is available in the well files in the form of field crew notes; however, data sets are often incomplete, lending difficulties in determining the quality of cement placement during installation.

Despite the challenges in classifying the potential for well leakage based on well files, methodologies have been developed (Watson and Bachu, 2007, 2008; Bachu and others, 2012). These papers outlined an approach that was implemented in the Canadian province of Alberta based on similar well data, and, importantly, surface casing vent flow (SCVF) and gas migration (GM) data beginning in 1995. These data were used to verify the methods developed to evaluate shallow well leakage potential. SCVF is leakage of gas to the surface casing vent valve (always open) on the wellhead, and GM is a measurement of leakage of gas out of the ground around the wellhead (Bachu and others, 2012).

Watson and Bachu (2008) and Bachu and others (2012) attempted to quantitatively classify the potential for shallow and deep wellbore leakage based on risk factors identified from their previous work in Watson and Bachu (2007). Shallow leakage refers to compromised hydraulic well integrity in the upper portion of the well, where shallow gas, if present, may leak upward, along the outside of the casing/wellbore annulus to shallow freshwater aquifers or through a casing leak and along the inside of the production casing to the surface (Bachu and others, 2012). Deep leakage pertains to leakage along the deep part of the well from the CO_2 storage zone to adjacent permeable horizons (Bachu and others, 2012). Bachu and others (2012) provided a numerical score for deep and shallow leakage potential. This score indicates the relative likelihood that any one well may leak based on the factors evaluated; however, the score does not reflect the volume or impact of the leak.

The deep leakage potential risk factors evaluated include fracture treatments, acid treatments, abandonment type, and completions. The shallow leakage potential risk factors evaluated include spud date, well type, total depth, plug near surface, and cement to surface. Each risk factor receives a score, and the scores are multiplied together to arrive at a final deep or shallow leak potential score. The deep and shallow leakage factors are shown in Tables 11 and 12 and are described in more detail in Glazewski and others (2013).

Wellbore Evaluation Results

The basal Cambrian wellbore evaluation revealed that the most susceptible wells to potential leakage, based on the data and methods utilized, fell in the eastern Montana–western North Dakota region for both deep and shallow leakage potential scores (Figures 20 and 21). Fifteen percent of the wells assessed were classified as moderate or higher potential for deep well leakage, and 6.0% of the wells classified the same for shallow well leakage. 3.4% of the wells exhibited moderate or higher potential for shallow and deep leakage. The locations of these wells are known to be an area of intensive oil and gas exploration and production. The practice of producing oil and gas from these wells has increased the well leakage potential (based on the available data and methods utilized) and, in the event of a future CCS project, would require additional screening criteria.

Table 11. Deep Leakage Risk Factors*

Deep Leakage Factor	Criterion	Meets Criterion Value	Default Value
Fracture	Count = 1	1.5	1
Fracture	Count > 1	2	1
Acid	Count = 1	1.1	1
Acid	Count = 2	1.2	1
Acid	Count > 2	1.5	1
Abandonment Type	Bridge plug	3	1
Abandonment Type	Not abandoned	2	1
Abandonment Type	Unknown	2	1
Number of Completions	Count > 1	2	1
Number of Completions	Count = 1	1.5	1

* Modified from Bachu and others, 2012.

Table 12. Shallow Leakage Risk Factors*

Shallow Leakage Factor	Criterion	Meets Criterion Value	Default Value
Spud Date	1974–1986	3	1
Well Type	Drilled and cased	8	1
Well Type	D&A** with casing	3	1
Well Total Depth	8202 ft (>2500 m)	1.5	1
Additional Plug	No	3	1
Additional Plug	Unknown	2	1
Cement to Surface	No	5	1
Cement to Surface	Unknown	3	1

* Modified from Bachu and others, 2012.
** Drilled and abandoned.

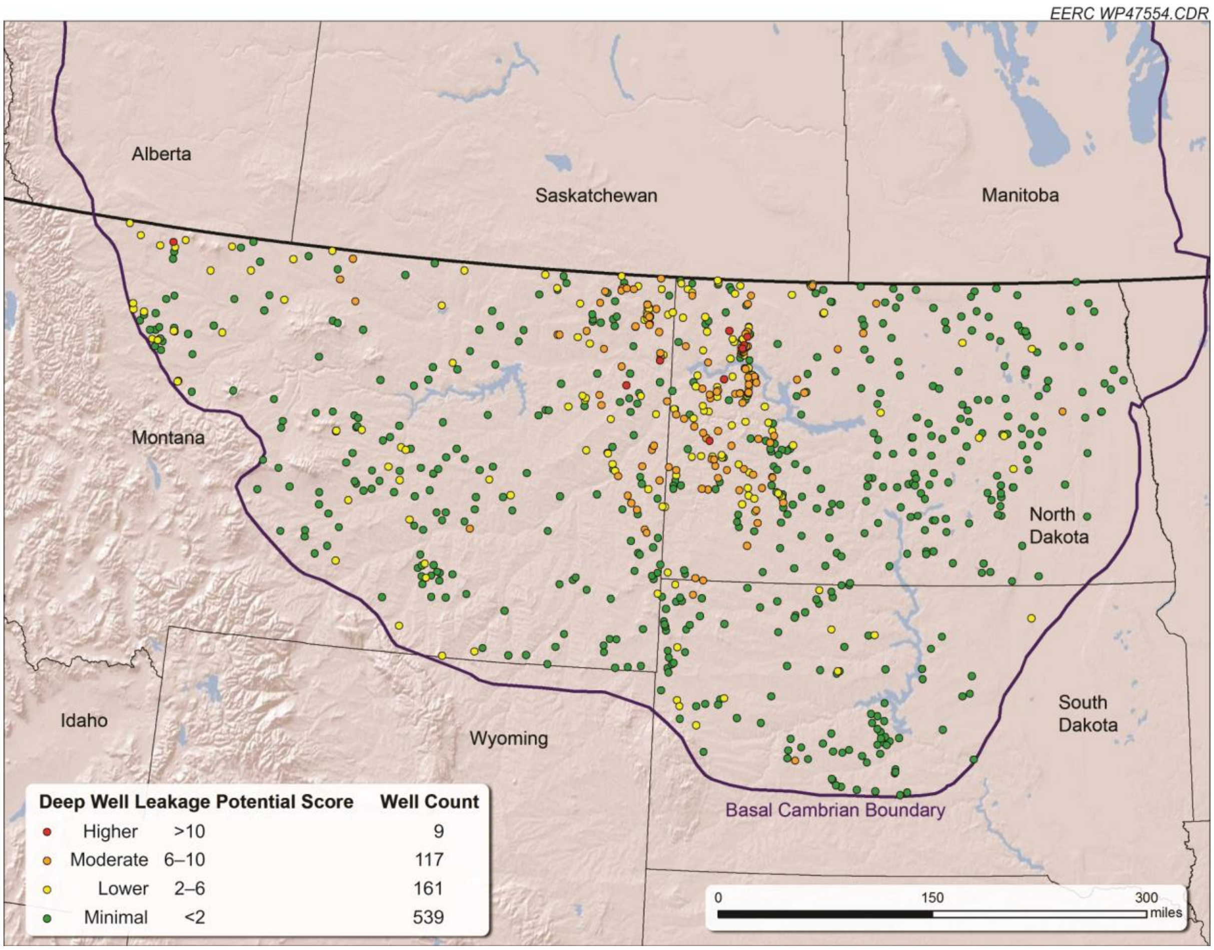

Figure 20. Deep leakage potential score distribution for wells in the study area (Glazewski and others, 2013).

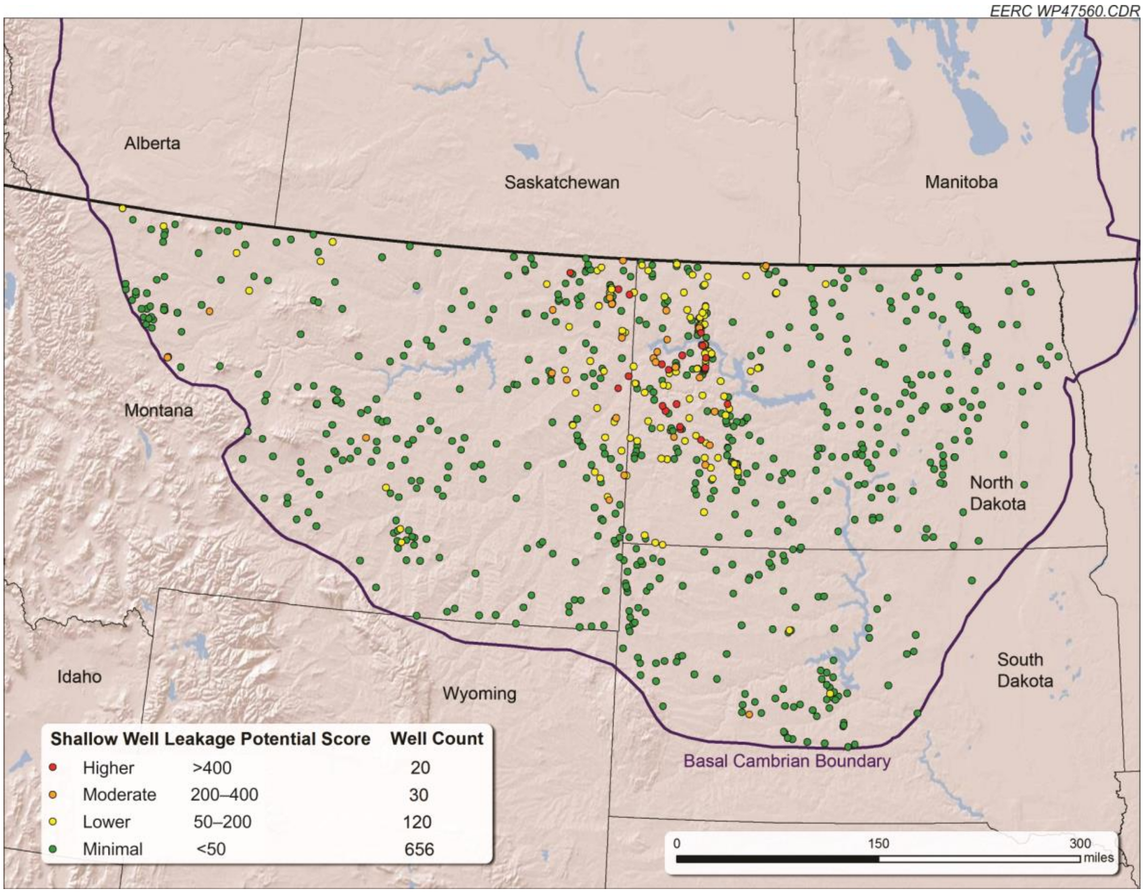

Figure 21. Shallow leakage potential score distribution for wells in the study area (Glazewski and others, 2013).

While these methods indicate a higher relative potential for well leakage, the quality of the drilling, casing, cementing, and completion practices is extremely important in determining the actual potential of a well leaking. The study methods provide a good screening-level assessment to rank wells that may require further investigation as part of a CCS project. The ranking of the relative leakage potential provides a mechanism to screen wells for detailed evaluation in areas being targeted for CO_2 injection. Potentially leaking or high-risk wells could be addressed using established remediation programs employing current well mitigation technologies or appropriate monitoring during CO_2 injection.

COAL ASSESSMENT AREAS

Storage of CO_2 in coal beds has the smallest potential in terms of storage resource and is an immature technique that has not yet been proven commercially viable (Bachu and others, 2012). However, with that said, there can be situations where the circumstances align to make CO_2 storage in coal beds an option. If coal beds underlie or are in close proximity to large CO_2 sources such as coal-fired power plants, it may make sense to store CO_2 in the coal formation. If the coal bed has a large capacity for CO_2 storage, that may also make the investment in CCS worthwhile.

CO_2 sequestration can occur by either a physical or chemical trapping process (White and others, 2003) in coal beds. The gas molecules are immobilized by physical adsorption at near-liquidlike densities on micropore wall surfaces, and the hydrostatic pressure in the formation controls the gas adsorption process (Mavor and Nelson, 1997; Nelson, 1999; Pashin and others, 2001). Because the gas adsorption process is reversible, the hydrostatic pressure must be maintained at or above the gas desorption pressure in order for sorbed-phase gas molecules to remain immobile (Mavor and Nelson, 1997).

Temperature affects the amount of gas that coal can adsorb. Gas sorption capacity decreases as temperature increases (Mavor and Nelson, 1997; Pashin and others, 2001; Pashin and McIntyre, 2003). The phase of CO_2 is a consideration for storage in a coal seam. Supercritical CO_2 (above 88°F and 1074 psi) may interact differently with coal than normal gaseous CO_2. Whether supercritical CO_2 conditions can occur in the target area is important during evaluation for CO_2 sequestration (Pashin and McIntyre, 2003). Overburden thickness is important in evaluating the suitability of coal beds for CO_2 storage. Coal seams need to have an overburden thickness that is too great for economical mining of coal while also allowing for the temperature and phase of the CO_2 to meet the necessary requirements for CO_2 storage.

Benefit to Storage in Coal Seams

Economics associated with geologic CO_2 sequestration are enhanced when there is a product being recovered in the process such as oil or natural gas. A potentially economically viable approach to sequester CO_2 in unminable coal seams is in conjunction with natural gas recovery. The natural gas would provide a revenue stream to partially offset the costs of CO_2 capture and sequestration (Garduno and others, 2003; Pashin and others, 2001; White and others, 2003; Wong and others, 2000).

Natural gas production typically requires that the coal bed is depressurized by pumping water out of the reservoir. Injection of CO_2 into the coal bed can accomplish the same goal when the CO_2 displaces natural gas and remains stored in place. The process for using CO_2 to recover coal bed natural gas still needs to refined, but the technique may be an option in parts of the PCOR Partnership region.

Coal Seams Within the PCOR Partnership Region

The PCOR Partnership region has three coal formations that potentially could be used for CO_2 storage: the Ardley, Harmon–Hanson, and Wyodak–Anderson Formations (Figure 22). The Wyodak–Anderson has the potential to store the largest amount of CO_2, while the Ardley would hold the least amount of CO_2 (Table 13). The number of CO_2 sources located within the Wyodak–Anderson (Figure 23) and Ardley (Figure 24) Formations would mean a supply of CO_2 would be readily available in the region. The number of CO_2 sources located within the Harmon–Hanson area is limited (Figure 25), and a pipeline network transporting CO_2 to the coalfield would be necessary.

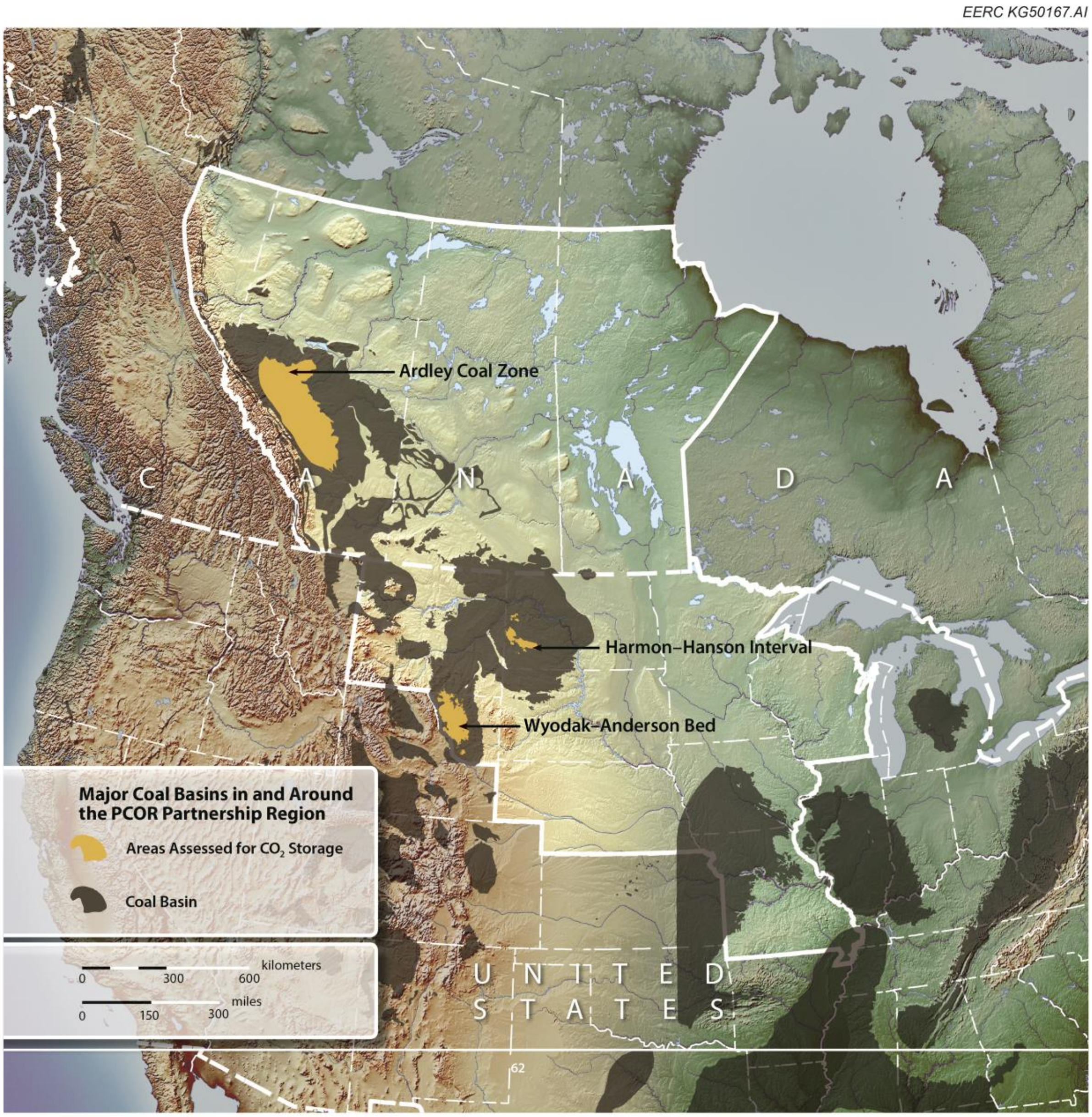

Figure 22. Potential CO_2 storage coal seam locations within the PCOR Partnership region (Peck and others, 2013).

Table 13. Coal Seam CO_2 Storage Estimates

Coal Seam	CO_2 Storage Volume, metric tons	CO_2 Storage Volume, short tons
Ardley	28,864,500	31,817,700
Harmon–Hanson	543,030,800	598,588,800
Wyodak–Anderson	6,242,338,000	6,880,997,900
Total	6,814,233,300	7,511,404,400

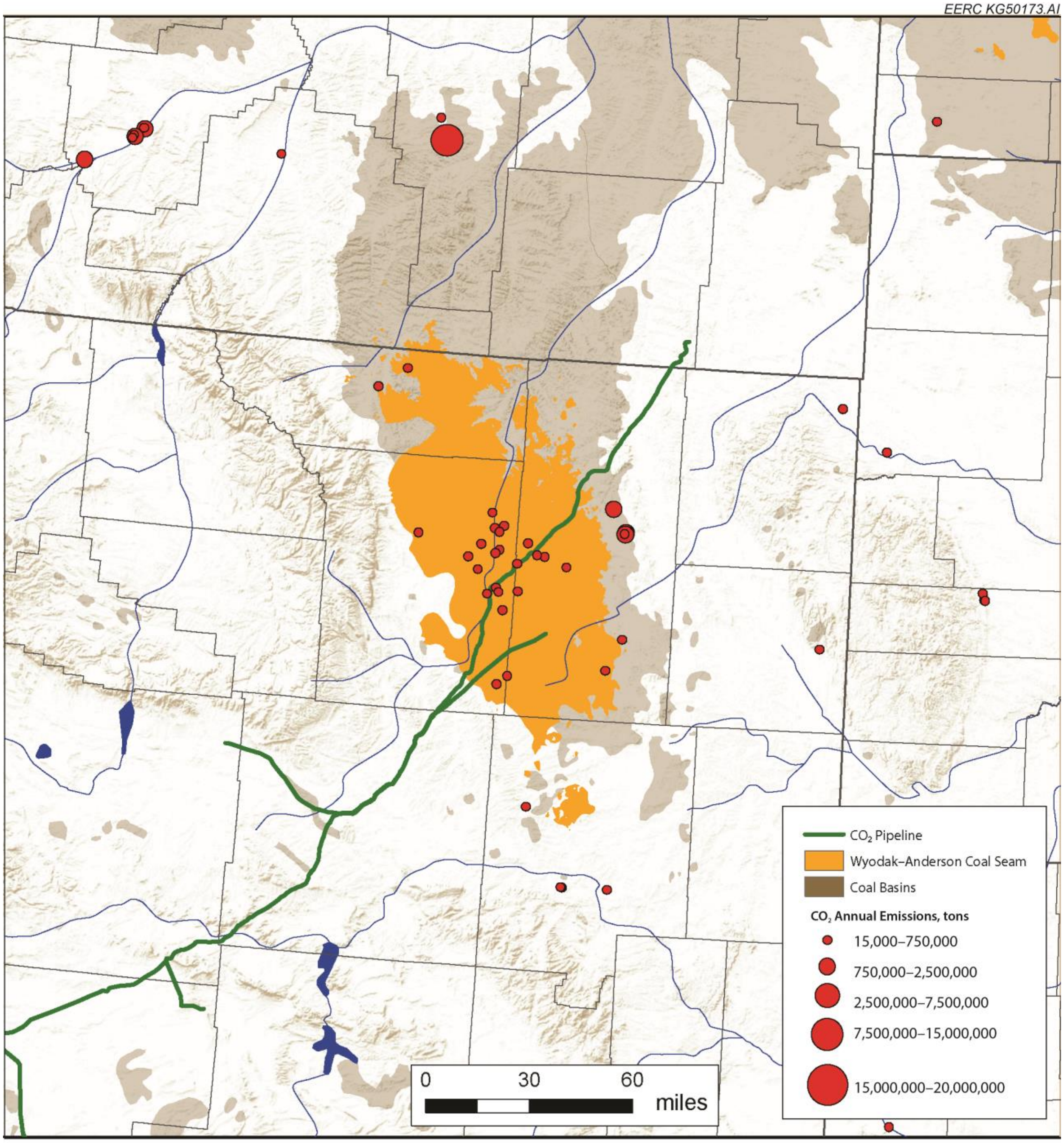

Figure 23. Wyodak–Anderson coal seam with CO_2 sources.

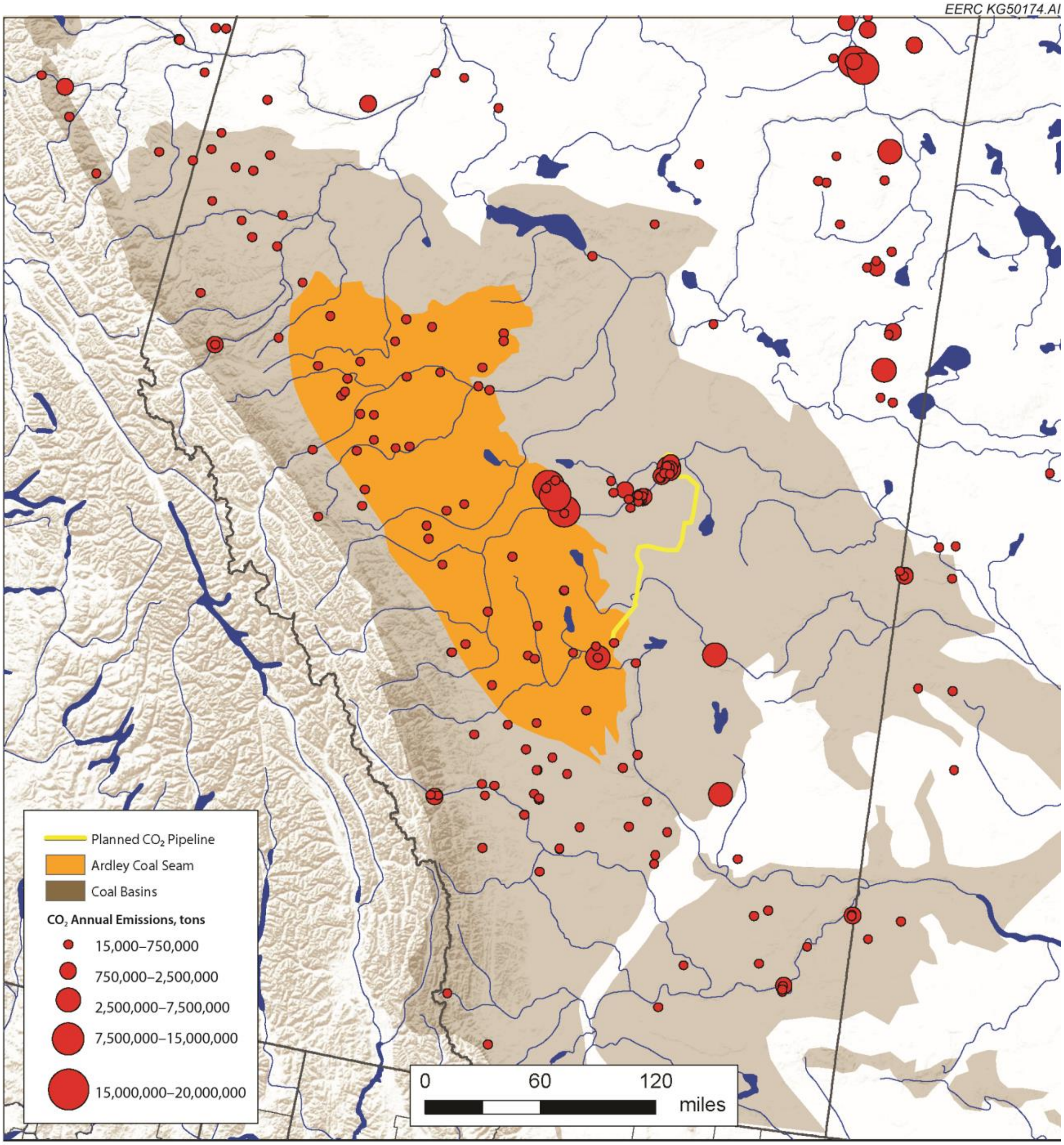

Figure 24. Ardley coal seam with CO_2 sources.

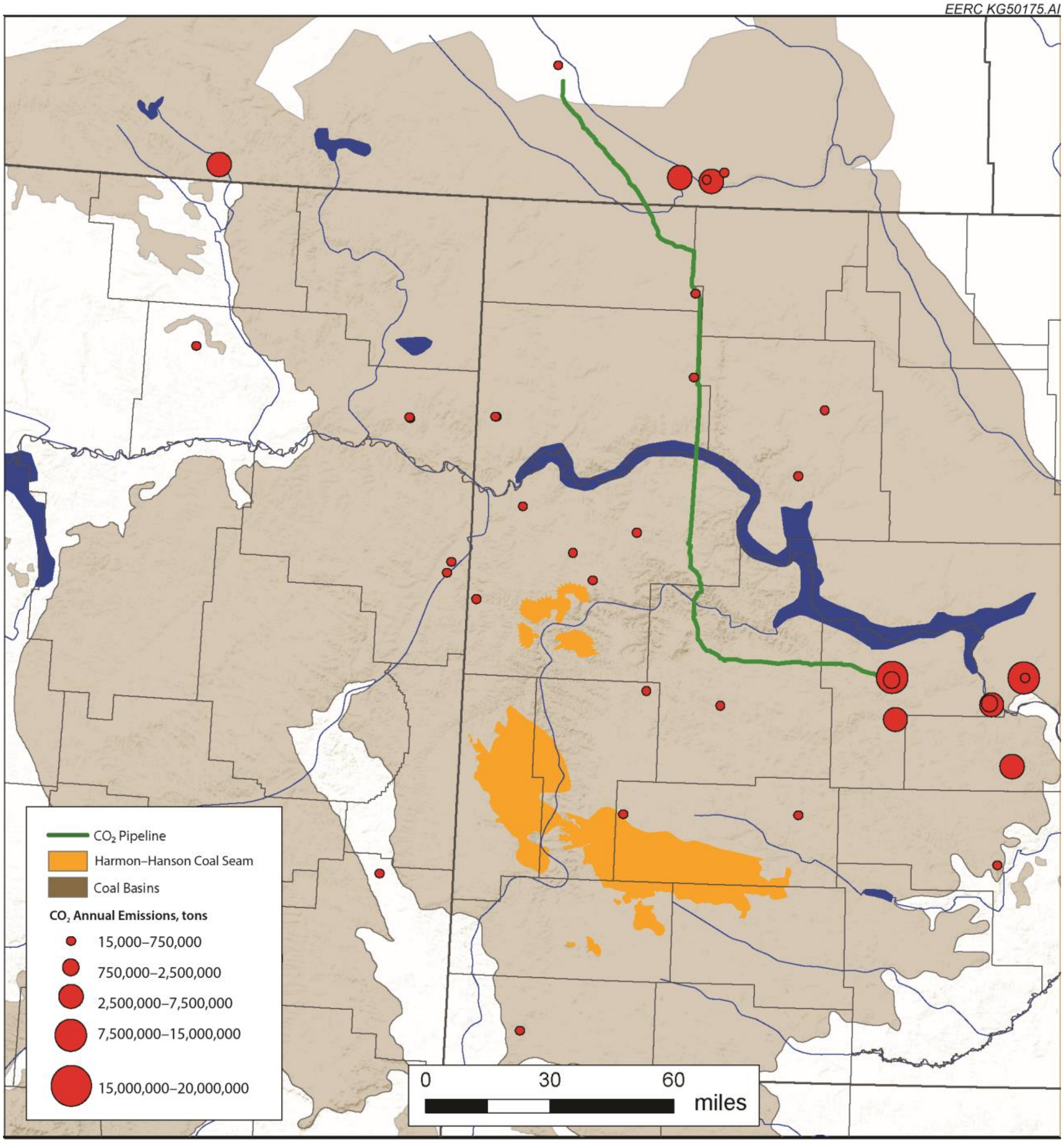

Figure 25. Harmon–Hanson coal seam with CO_2 sources.

Challenges to CO_2 Storage in Coal Seams

While CO_2 storage in coal seams is a potential option, there are challenges associated with the technique. As discussed earlier, the target areas need to meet the geologic and physical characteristics necessary for CO_2 to maintain the correct phase and remain stored in the formation. The economics of CO_2 storage in the coal seams need to be viable for companies to utilize the technique. CO_2 sources and transportation to the target formations need to be present, and a recoverable material such as natural gas would be needed to help offset costs. There are environmental concerns, particularly with potential exposure of CO_2 gases to groundwater sources. EPA has regulations in place that pertain to CO_2 injection, and this includes a new class of wells, Class VI, under the authority of the Safe Drinking Water Act's Underground Injection Control Program. If these challenges can be addressed, there may be a potential market for utilizing coal seams for CO_2 storage.

TRANSPORTING THE CO_2

CO_2 pipeline networks are necessary for delivery of CO_2 from the sources to the storage sites that include EOR reservoirs, enhanced coalbed methane (ECBM) recovery sites, and DSFs. Currently, there is more than 4000 miles of CO_2 pipelines worldwide, most linked to EOR operations in the United States (IEA Greenhouse Gas R&D Programme, 2013). Within the PCOR Partnership region, there is over 400 miles of existing CO_2 pipeline and roughly 200 miles planned or under construction. As the demand for CO_2 for EOR projects grows, the need for more pipelines will continue to grow. Construction of new CO_2 pipelines requires significant capital investment that must be supported by the long-term oil production potential of the target basin and by the expectations of future oil prices. Building a regional CO_2 pipeline network will require careful planning in order to maximize the value and usage of the future network. Pipelines can connect individual CO_2 sources with target basins in a one-at-a-time manner, or they can be a network of pipelines that connect many large CO_2 sources with major geologic sinks.

Pipeline Characteristics

CO_2 pipelines are similar in design to natural gas or crude oil pipelines, although the higher pressures in CO_2 pipelines often require thicker pipe made from carbon steel. Natural gas is typically transported at roughly 300 to 1200 psig, while CO_2 is typically transported as a supercritical fluid at 1200 to 3000 psig. Because supercritical CO_2 behaves as a liquid, pumps are used at booster stations to recompress, usually every 50 to 200 miles, depending on the end-use pressure requirements and topography. Pipeline diameters are rigorously calculated during the design process, but estimations correlating pipeline diameter and CO_2 flow rates can be made (Table 14).

Table 14. Pipeline Characteristic Diameter and Flow Rate

Pipeline Diameter, in.	CO_2 Flow Rate: Lower Bound, Mt/yr	CO_2 Flow Rate: Lower Bound, MMscfd	CO_2 Flow Rate: Upper Bound, Mt/yr	CO_2 Flow Rate: Upper Bound, MMscfd
4	–	–	0.19	10
6	0.19	10	0.54	28
8	0.54	28	1.13	59
12	1.13	59	3.25	169
16	3.25	169	6.86	357
20	6.86	357	12.26	639
24	12.26	639	19.69	1025
30	19.69	1025	35.16	1831
36	35.16	1831	56.46	2945

Massachusetts Institute of Technology Carbon Capture and Sequestration Technologies Program, 2009; Jensen and others, 2011.

Composition of CO_2

The composition of CO_2 streams varies depending on the source. CO_2 quality issues are important when the CO_2 enters a pipeline containing CO_2 from other sources or if the pipeline is delivering to different sinks with other quality requirements.

Several compounds can impact the end use of a CO_2 stream (Table 15). It is important that the nitrogen and methane concentrations in a CO_2 stream be low (generally 5% each; 10% total maximum) so as not to rule out dense-phase operations. Higher concentrations of nitrous oxide or methane render CO_2 unacceptable for use in EOR. Sulfur compounds such as hydrogen sulfide (H_2S) can be hazardous to both humans and wildlife and, therefore, require robust safety strategies. High oxygen content can lead to microbial induced corrosion of iron and steel as well as chemical reactions and/or aerobic bacterial growth within the injection tubular or in the geologic formation. Oil concentrations are usually limited to less than 10–20 ppm. Finally, minimization of water within the CO_2 stream is crucial to avoid corrosion. The typical maximum allowable water vapor concentration is in the range of 20–30 lb/MMcf.

Risk

The technology of transporting CO_2 via pipeline is well understood, and many of the risks of CO_2 transport are being managed. Risks are accounted for either during the planning/design of the pipeline or through monitoring. Corrosion is prevented by dehydrating the CO_2 before transport, making the CO_2 pipelines out of carbon steel of an appropriate gauge, using high-durometer elastomeric seals, and conducting periodic corrosion assessments. Surge capacity is accounted for in the pipeline's design, and fracture arresters are typically employed every 1000 feet to reduce fracture propagation. Monitoring of the pipeline is done by aircraft, satellite, or internal inspections, and cleaning is completed by pipeline "pigs."

Table 15. Pipeline Composition (from Jensen and others, 2011)

Component	Kinder Morgan CO_2 Pipeline Specs[a]	Ethanol Plant[b]	Great Plains Synfuels Plant[c,d]	Gas-Processing Plant[e]	Coffeyville Resources Ammonia-UAN Fertilizer Plant[f]	Food-Grade CO_2 Specs[g]
CO_2	≥95 vol%	≥98 vol%	≥96.8 vol%	≥96 vol%	99.32 vol%	≥99.9 vol%
Water	≤30 lb/MMcf	Dry	<25 ppm	≤12 lb/MMcf	0.68 vol%	≤20 ppmw
H_2S	≤20 ppmw	–	<2 vol%	≤10 ppmw	–	≤0.1 ppmv
Total Sulfur	≤35 ppmw	40 ppmv	<3 vol%	≤10 ppmw	–	≤0.1 ppmv
N_2	≤4 vol%	0.9 vol%	0 ppm		–	None
Hydrocarbons	≤5 vol%	2300 ppmv	1.3 vol%	≤4 vol%	–	CH_4: ≤50 ppmw; others: ≤20 ppmw
O_2	≤10 ppmw	0.3 vol%	0 ppm	≤10 ppmw	–	≤30 ppmw
Other	Glycol: ≤0.3 gal/MMcf	–	0.8 vol%		–	≤330 ppmw
Temperature	≤120°F	120°F	100°F	100°F	100°F	–

[a] Kinder Morgan, 2007; [b] Chen and others, 2004; [c] Perry and Eliason, 2004; [d] Hattenbach, 2009; [e] Tracy, 2009; [f] Kubek, 2009; [g] Logichem Process Engineering, 2009.

Even when appropriate risk management efforts are employed, there are rare problems with CO_2 pipelines. According to the National Response Center's accident database, there were 12 accidents in 3500 miles of CO_2 pipeline between 1986 and 2008. No serious human injuries or fatalities were reported for any of these accidents. By contrast, there were 5610 accidents causing 107 fatalities and 520 injuries related to natural gas and hazardous liquid (excluding CO_2) pipelines during the same period. Although the total length of CO_2 pipelines is far less than that of natural gas and hazardous liquid pipelines, injury and property damage data suggest that CO_2 pipelines are safer than natural gas and hazardous liquid pipelines.

Pipelines in the PCOR Partnership

There are two CO_2 pipelines currently active in the PCOR Partnership region (Table 16 and Figure 26). The Dakota Gasification Company (DGC) pipeline is owned by Souris Valley Pipeline, Ltd., and runs 205 miles from North Dakota to Saskatchewan. The DGC pipeline has a capacity of 3.22 million short tons of CO_2 per year.

Table 16. Pipelines in the PCOR Partnership

Pipeline	Owner	Location	Approximate Length, mi
Alberta Carbon Trunk Line	Enhance Energy Inc.	Alberta, Canada	150
Anadarko*	Howell Petroleum Corporation	Wyoming	125
Dakota Gasification Company	Souris Valley Pipeline, Ltd.	North Dakota to Saskatchewan	205
Greencore Pipeline	Denbury Resources Inc.	Wyoming to Montana	232
Fort Nelson	Spectra Energy	British Columbia	10
Shell Quest	Shell	Alberta	6–37

* While not technically within the boundaries of the PCOR Partnership region, this pipeline is regionally significant.

The second pipeline is the Greencore pipeline that is owned by Denbury Resources Inc. (Denbury). This pipeline runs 232 miles from the Lost Cabin gas-processing facility in Wyoming to the Bell Creek Field in southeastern Montana. The Greencore pipeline has a capacity of 50–60 million cubic feet per day.

Pipeline Data

The PCOR Partnership has typically acquired pipeline data on an annual basis from Pennell. Currently, Pennell is offering a Web service that will allow the PCOR Partnership to access pipeline data for all of North America. While the extent of the data has expanded, we are limited to using the data with Pennell's Web service rather than having GIS files available.

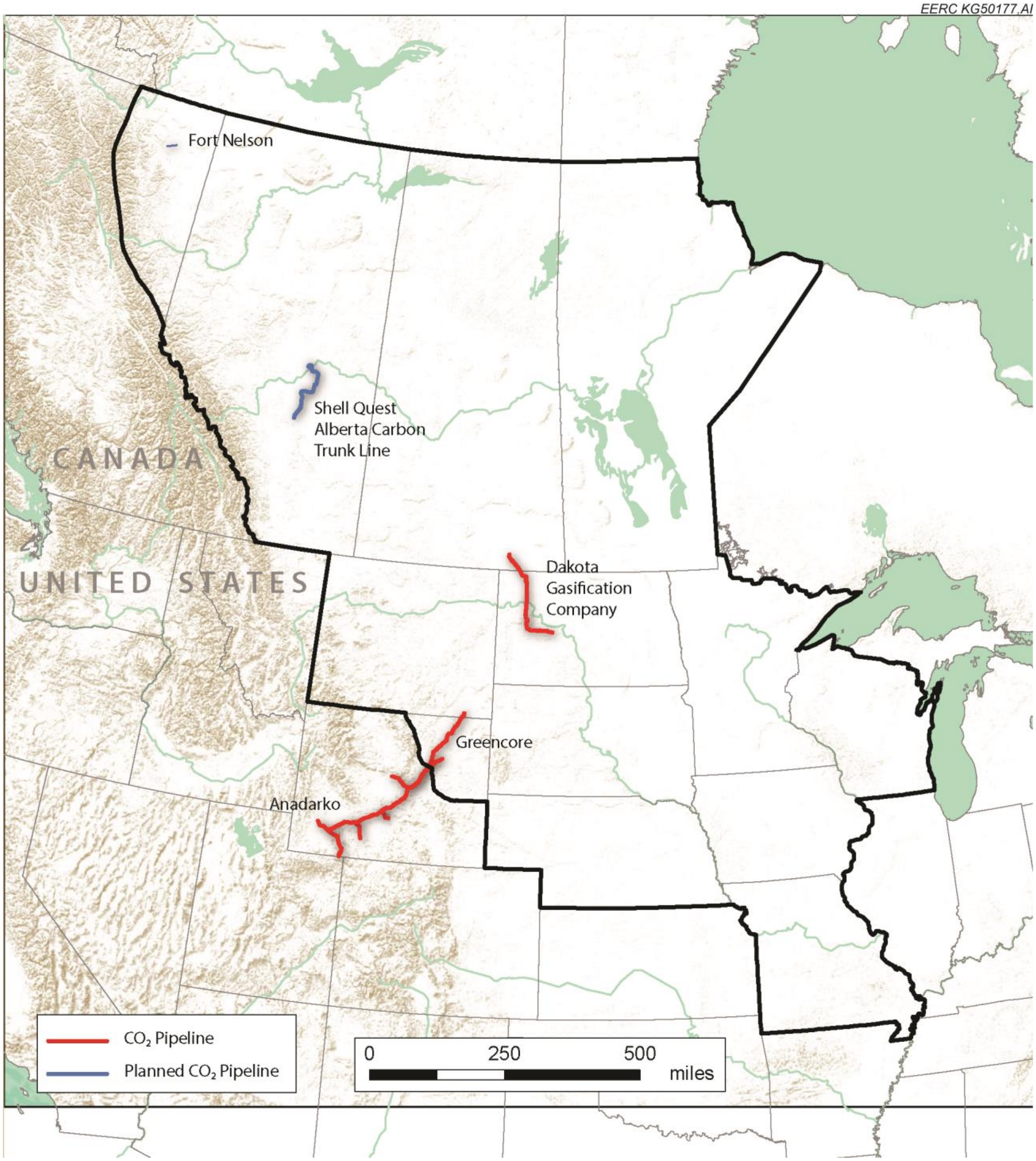

Figure 26. Pipelines in the PCOR Partnership region.

PCOR PARTNERSHIP PRODUCTS

The PCOR Partnership continues to refine the characterization of sources, geologic and terrestrial sinks, and infrastructure within the PCOR Partnership region. The objective is to further refine the assessment of the region's CO_2 production and storage potential in an effort to optimize source–sink opportunities within the region. This continued regional characterization is used to refine capacity estimates that are used in a variety of products.

National Atlas

DOE NETL has published four editions of the *United States Carbon Utilization and Storage Atlas*. Production of the atlas is the result of collaboration among the seven RCSPs and their partners. The atlas provides a coordinated update of carbon capture, utilization, and storage (CCUS) potential across the United States and other portions of North America. The primary purpose of atlas is to update the CO_2 storage potential for the United States and to provide updated information on RCSP field activities and new information on American Recovery and Reinvestment Act of 2009 (ARRA)-funded site characterization projects. In addition, the atlas outlines DOE's Carbon Storage Program and CCUS collaborations, worldwide CCUS projects, and CCUS regulatory issues and presents updated information on the location of CO_2; stationary source emissions and the locations and storage potential of various geologic storage sites; and further information about the commercialization opportunities for CCUS technologies from RCSPs. The PCOR Partnership has contributed material on a biennial basis for NETL's four atlases. Material submitted includes information on CO_2 sources, oil and gas fields, coal seams, saline formations, and field demonstration projects.

PCOR Partnership Atlas

In addition to contributions to the national atlas, the PCOR Partnership has produced four editions of the *PCOR Partnership Regional Atlas*. This atlas provides a visual introduction to the concept of global climate change and a regional profile of CO_2 sources and potential sinks across nearly 1.4 million square miles of the PCOR Partnership region of central North America. The regional atlas includes an overview of the CO_2 challenge, carbon management, a description of the PCOR Partnership, regional characterization, field-based activities, CCS deployment, and a look at the possible future of CCS.

NATCARB

NATCARB is a GIS-based tool developed to provide a view of CCS potential. The interactive, Web-based viewer shows disparate data (CO_2 stationary sources, potential geologic CO_2 storage formations, infrastructure, etc.) and analytical tools (pipeline measurement, storage resource estimation, cost estimation, etc.) required for addressing CCS deployment, providing all stakeholders with improved online tools for the display and analysis of CCS data.

On a yearly basis, the PCOR Partnership provides characterization data for NATCARB. Data submitted include CO_2 sources and storage values in coal seams, deep saline formations, and oil and gas fields. The NATCARB team provides a blank geodatabase that is used by all seven

RCSPs in submission of their data. The feature classes within the geodatabase include sources, coal, coal 10K, saline, saline 10K, and oil and gas. The source layer is a point-based feature class, while the coal, saline, and oil and gas layers are each polygon-based feature classes. The coal 10K and saline 10K layers are ~32,800-feet by 32,800-feet (10,000-meter by 10,000-meter) grid cells that cover the seven RCSP study areas. Coal and saline CO_2 storage data and related information are tabulated within each of these grid cells. The data submitted by the PCOR Partnership and the other RCSPs are compiled and posted to a NATCARB Web site by the NATCARB team.

Decision Support System (DSS)

The PCOR Partnership has accumulated a wealth of data in characterizing the partnership region with respect to CO_2 storage opportunities. Major components of this characterization include creating an inventory of large stationary sources of CO_2 and identifying and mapping geologic and terrestrial sinks for CO_2 storage across the PCOR Partnership region. Knowledge of the character and spatial relationships of sources, sinks, and regional infrastructure is crucial to developing and assessing approaches to economical and environmentally sound CO_2 storage.

The most efficient way to communicate this information to PCOR partners has been through a GIS-enabled Web site. This site is a major component of a larger Web-based DSS that provides the PCOR Partnership with a single point of access to a wide variety of research data for evaluation and the development of potential storage scenarios. This password-protected (members-only), Web-based platform contains the tools and capabilities designed to deliver functional and dynamic access to data acquired through the project. The data are housed in a relational database and accessed through a map-based portion of the Web site. More traditional pages provide access to relatively static data, such as reports, CO_2-related Web sites, terrestrial maps, and snapshots of regional data.

North American Carbon Atlas Partnership (NACAP)

The United States, Canada, and Mexico participate in a joint CO_2-mapping initiative called the North American Carbon Atlas Partnership (NACAP). This initiative serves as an important opportunity to foster collaboration among the three countries in the area of CCS. The goal of NACAP is for each country to identify, gather, and share data for CO_2 stationary sources and potential geologic storage sites. Results of this initiative were published in the North American Carbon Storage Atlas (NACSA). The CO_2 stationary sources and potential geologic storage sites are available through the NACAP map viewer. This GIS-based system supports the Carbon Storage Program, the objectives of the North American Energy Working Group, and current topics being discussed under the Canada–U.S. Clean Energy Dialogue.

The PCOR Partnership provides the same CO_2 source and storage site data to NACSA as is done for the National and Regional Atlas and NATCARB. In fact, PCOR Partnership data are directly provided to NACSA via NATCARB's geodatabase.

Demonstration Project Reporting System (DPRS)

To provide updates to DOE and partners on the progress of the Bell Creek and Fort Nelson projects, approved information (e.g., reports, summaries, tables, maps, etc.) is posted to a DPRS within the password-secured area of the PCOR Partnership's DSS, a database-driven, password-protected Web site containing both traditional static pages and an interactive GIS.

The Bell Creek project involves the injection of CO_2 into the Bell Creek oil field in southeastern Montana for the dual purpose of CO_2 storage and EOR. The Fort Nelson project will involve monitoring, verification, and accounting (MVA) support for the injection of CO_2 into a saline formation in British Columbia, Canada, captured from one of the largest gas-processing plants in North America.

The DPRS navigation structure for the Bell Creek and Fort Nelson demonstration projects is as follows:

- **Scope of work**. This section describes the objectives of the demonstration project and provides basic information about the effort.

- **Benefits to the region**. This section includes materials and discussion on how the individual demonstration projects fit into the broader context of CCS within the PCOR Partnership region.

- **Characterization data**. This section includes subsurface information on geologic characteristics, overlying seal(s) and formations, and formation storage injectivity and capacity.

- **Modeling**. Modeling activities will feed into the MVA and risk management components of project development. Approved results of modeling runs and the input parameters are provided in this section.

- **MVA**. Data in this category include information on the MVA techniques being employed at the sites. As the MVA activities mature, this area will contain summaries of monitoring results and interpretations.

- **Risk Management**. An integrated risk management concept is central to the PCOR Partnership approach to the demonstration projects. Discussion and products related to this concept are housed in this section.

- **Permitting**. This section includes discussions on how regulatory and permitting issues were addressed at the two demonstration sites.

- **Site Operations**. Material pertinent to how the site is operating, including injection rates and cumulative injection data, is included in this section, which also includes information on the transportation of the CO_2 to the site.

- **Products**. Topical reports, final reports, posters, presentations, and fact sheets directly related to the demonstration project are accessible in this portion of the DPRS. Programming allows for a dynamic link to the DSS Products Database, which houses all PCOR Partnership products. At the time of this writing, the Products Database contained 29 and 31 products related to the Bell Creek and Fort Nelson demonstration projects, respectively.

SITE-SPECIFIC INVESTIGATIONS

Aquistore

The PCOR Partnership is providing technical expertise and outreach to the Petroleum Technology Research Centre's (PTRC's) Aquistore Project. The Aquistore Project has targeted the basal Cambrian system, which has the potential to be a major regional resource for storage of CO_2. The Aquistore Project will inject CO_2 into a 300- to 700-foot (90- to 230-meter)-thick section of this system that is predominantly sandstone interbedded with shales and siltstone at a depth of 11,000 feet (3400 meters). The project is located west of Estevan, Saskatchewan (Figure 27). The source of CO_2 is the SaskPower Boundary Dam Integrated Carbon Capture and Storage Demonstration Project—the first-ever commercial scale capture of CO_2 from a coal-fired power plant.

The PCOR Partnership's role in the Aquistore Project consists of four main tasks: 1) perform a mineralogical characterization of representative core samples of the storage zone and the seal formations; 2) work with PTRC and Schlumberger Carbon Services to develop a static geologic model of the injection zone and overlying seal; 3) run a series of dynamic simulations for CO_2 and formation fluid behavior under different injection scenarios; and 4) prepare public outreach materials (i.e., fact sheet and poster) as well as technical reports for the characterization, modeling, and simulation portions of the work.

Rival Field

Site characterization and 3-D geologic modeling were completed for the Rival oil field, Burke County, North Dakota (Figure 27), as part of the PCOR Partnership's advanced characterization efforts targeting oil fields with potential for future CO_2 EOR and long-term CO_2 storage. Predictive static 3-D geologic models were built with the goal of better understanding spatial distribution of reservoir properties across the 100-square-mile study area centered on the Rival Field.

Volumetric EOR and CO_2 required were calculated based on OOIP, industry standard recovery and utilization factors, and a literature-derived formation factor. This resulted in 6.0–9.0 Mbbl of incremental oil from the Rival Field which required 1.5–2.9 Mt of CO_2 that would ultimately be stored.

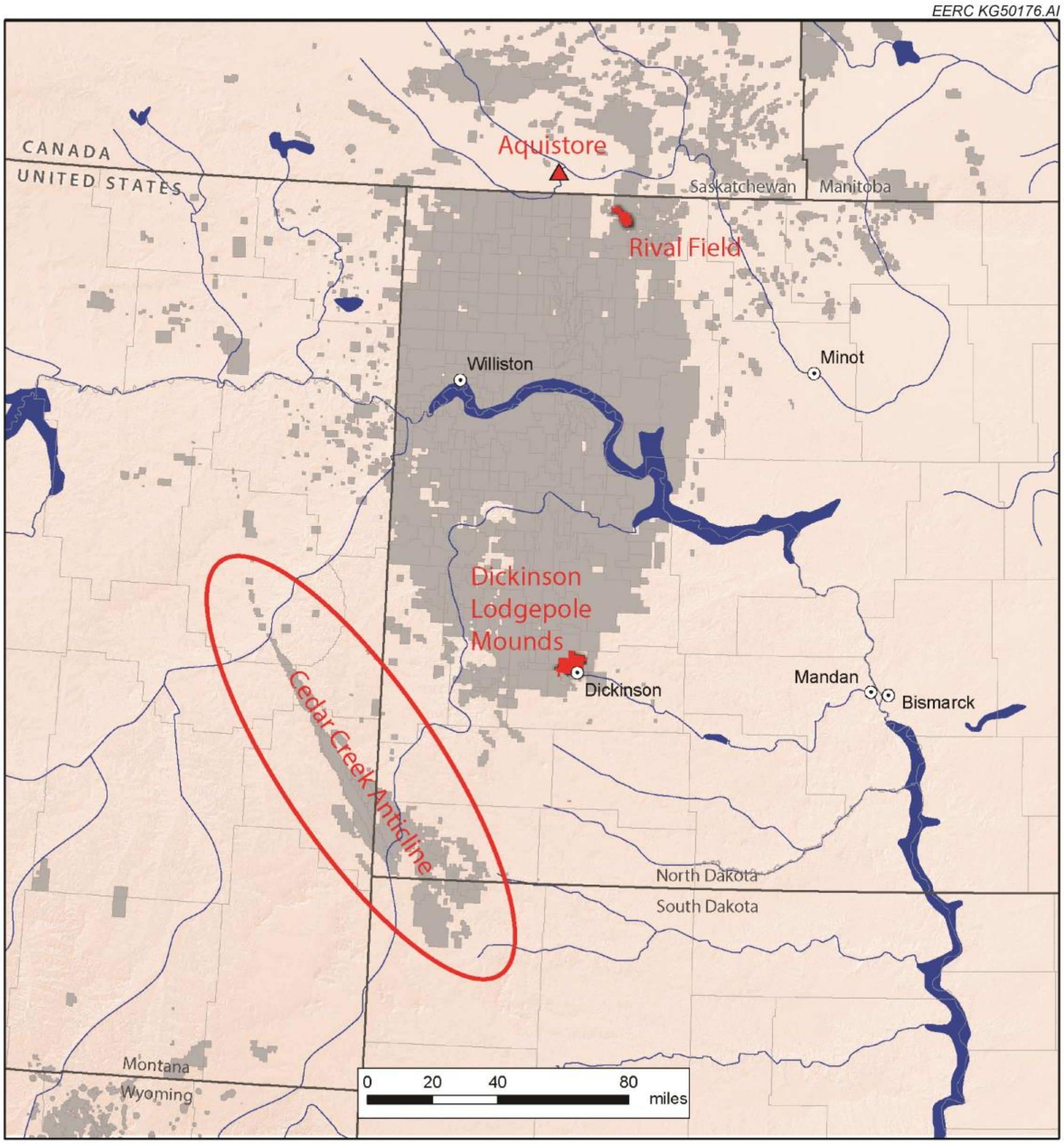

Figure 27. Location of site investigations in the PCOR Partnership region.

Cedar Creek Anticline

The Cedar Creek Anticline (CCA), located in east-central Montana (Figure 27), has potential for CO_2 storage in ten separate operating areas. The PCOR Partnership and Denbury teamed up to assess the potential of Denbury conducting CO_2 EOR operations in the CCA oil fields. The PCOR Partnership developed a technical database of several CCA fields, identified data gaps due to incomplete and missing well records, evaluated subsurface technical issues related to wellbore integrity in select fields, characterized CCA geology, and initiated the development of reservoir models in select fields.

Dickinson Lodgepole Mounds

The Dickinson Lodgepole Mounds (DLM) in southwestern North Dakota (Figure 27) were identified as possible targets for CO_2 storage and CO_2 EOR activities because of the high recovery factor and very successful waterflooding operations (Gorecki and others, 2008). Many of the oil fields that encompass DLM are operated by PCOR Partnership partners, and as a result, the entire mound complex was selected for additional site characterization activities. Characterization of DLM was accomplished using modern stochastic geostatistical techniques to create a model of the features, with the goal of describing DLM to a greater degree, including macrofacies and microfacies analysis. The model was used for calculations of EOR potential and CO_2 storage volume analysis.

DSF Outlines

As discussed earlier, 13 DSFs (Figure 3 and Table 8) were investigated to varying degrees across the PCOR Partnership region. CO_2 storage for each of the formations was estimated in some capacity, either through calculations based on formation characteristics or through a more detailed geologic model. The CO_2 storage results can be seen in Table 9.

SUMMARY

The PCOR Partnership continues to refine the characterization of sources, geologic and terrestrial sinks, and infrastructure within the region. Characterization is key in the development of CO_2 capture–transport–storage scenarios that have the potential to reduce greenhouse gas emissions in the PCOR Partnership region. By having the CO_2 sources and sinks characterized and located, the feasibility of a large-scale CCS project can be investigated.

The PCOR Partnership has identified 890 stationary sources of CO_2 in the region that have an annual output of 15,000 tons (13,600 tonnes) or greater. The combined annual output of CO_2 is about 561 million tons (509 tonnes). This dynamic data set is updated on an annual basis, and source locations may be added or subtracted from the database based on the changing CO_2 emission values of the different facilities.

Within the PCOR Partnership region, CO_2 storage potential includes 368–1220 billion tons in saline formations, approximately 25 billion tons in depleted oil field reservoirs, approximately

8 billion tons in unminable coal, and 1.10–10.22 billion tons in selected oil fields to be used in EOR (which may provide between 9.8 and 22.1 billion stb of incremental oil recovery).

Storage of CO_2 in unminable coal beds has the least potential in terms of storage capacity and is an immature technology that has not yet been proven; however, hydrocarbon reservoirs have the advantage of demonstrated storage capacity and confinement properties. The saline formations have the greatest storage capacity of the geologic media studied; however, CO_2 storage in oil fields is used more frequently in the current landscape. Oil fields are well characterized and, with EOR, offer a greater economic incentive.

In addition to the sources and storage locations relative to each other, CO_2 transport is an important consideration for CCS projects. Existing CO_2 pipelines near target sources and sinks make a potential CO_2 project more economically feasible, whereas a lack of CO_2 pipeline infrastructure requires added financial consideration to a potential CCS project. Additional CO_2 pipelines in the PCOR Partnership are in varying stages of proposal/planning, and the completion of these pipelines will enhance CCS efforts.

Site-specific investigations within the PCOR Partnership have shown the potential for CO_2 storage in different geologic media. These investigations have evaluated the storage potential along with the technical challenges that such projects may face. These projects offer key information on successes and challenges that may be faced by CCS projects in other regions of the country or world. The information from the site-specific investigations and regional characterization efforts can be valuable to PCOR Partnership partners in their pursuit of potential CCS or EOR projects.

The PCOR Partnership will continue to refine the characterization of sources, geologic sinks, and infrastructure within the PCOR Partnership region with the objective to identify the region's CO_2 production and storage potential and optimize source–sink opportunities. This continued regional characterization will be used to refine capacity estimates for DOE NETL's national atlas and to provide context for extrapolating the results of the large-scale demonstrations. By using both a broad and focused approach to characterize these storage resources, we have the ability to look at the storage potential through a multistate/multiperspective as well as a site-specific approach.

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APPENDIX A

CO_2 EMISSION CALCULATIONS

CO_2 EMISSION CALCULATIONS

The first step consists of determining the amount of combustion-related carbon dioxide (CO_2) resulting from the production of 1 gal of ethanol for each of the specific fuel(s) used by the ethanol plant. The fuels and CO_2 produced by each are provided on the searchable U.S. Environmental Protection Agency (EPA) Web site for each CO_2 source. Fuel CO_2 emission factors for a variety of fuels can be obtained online from EPA (U.S. Environmental Protection Agency, 2013).

$$\left(\frac{39{,}000\ Btu}{gal\ ethanol}\right) \times \left(\frac{Fuel\ CO_2\ Emission\ Factor}{10^6\ Btu}\right) = \frac{lb\ combustion\ CO_2}{gal\ ethanol} \qquad \text{[Eq. 1]}$$

During the second step, the resulting quantity of CO_2 produced per gal of ethanol during combustion is then ratioed against the amount of CO_2 produced during the fermentation step (i.e., 6.6 lb), resulting in a multiplier that can be used to estimate the fermentation CO_2 when the combustion CO_2 is known.

$$\left(\frac{\frac{6.6\ lb\ fermentation\ CO_2}{gal\ ethanol}}{\frac{lb\ combustion\ CO_2}{gal\ ethanol}}\right) = multiplier\ for\ combustion\ CO_2\ emission \qquad \text{[Eq. 2]}$$

Finally, the tons of CO_2 produced by the combustion of each fuel are multiplied by each fuel's multiplier value and summed to arrive at the CO_2 produced during fermentation. The total CO_2 for the stationary point source would then be the sum of the combustion CO_2 (from the EPA Web site) and the fermentation CO_2 (estimated using this methodology). The following example illustrates this approach to estimating fermentation CO_2 for a source burning subbituminous coal and natural gas. For natural gas:

$$\left(\frac{39{,}000\ Btu}{gal}\right) \times \frac{117.08\ lb\ CO_2}{10^6\ Btu} = 4.566\ lb\ CO_2 \qquad \text{[Eq. 3]}$$

$$\frac{6.6\ lb\ CO_2}{4.566\ lb\ CO_2} = 1.45 \qquad \text{[Eq. 4]}$$

For subbituminous coal:

$$\left(\frac{39{,}000\ Btu}{gal}\right) \times \frac{212.7\ lb\ CO_2}{10^6\ Btu} = 8.295\ lb\ CO_2 \qquad \text{[Eq. 5]}$$

$$\frac{6.6\ lb\ CO_2}{8.295\ lb\ CO_2} = 0.796 \approx 0.8 \qquad \text{[Eq. 6]}$$

If the CO_2 produced during natural gas combustion totals 100,000 short tons CO_2 and the CO_2 produced during subbituminous coal combustion totals 200,000 short tons CO_2, then the CO_2 produced during fermentation would total:

$$\begin{gathered}(100{,}000\ tons\ \times 1.45) + (200{,}000\ tons\ \times\ 0.8) = \\ (145{,}000 + 160{,}000)\ tons = 305{,}000\ tons\end{gathered} \qquad \text{[Eq. 7]}$$

The total CO_2 emissions for the source would be 100,000 + 200,000 + 305,000 = 605,000 tons.

This approach is probably reasonably accurate as long as the source does not emit combustion CO_2 that is related to another process (such as cogeneration) at the facility. Obviously, if the CO_2 is partly produced by another process, the portion that is not ethanol-related would inflate the estimated fermentation CO_2 quantity.

The EPA searchable database presents a second challenge in that it is difficult to determine the total CO_2 emissions as opposed to the total CO_2-equivalent (CO_2eq) emissions for some of the source types. One example of this is sugar-processing facilities with their inherent lime production. This is not true for all source types.

A final note about the use of the EPA database: the power plants are listed as producing CO_2 from both “stationary combustion” and “electricity generation.” These values must be summed to produce the total CO_2 emissions at such sites.

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APPENDIX B

MONTANA ABANDONED OIL FIELDS

MONTANA ABANDONED OIL FIELDS

In the state of Montana, geographic information system (GIS) shapefiles containing oil and gas field boundaries and well locations are typically acquired through the Montana Board of Oil and Gas (MBOG) Web site (www.bogc.dnrc.mt.gov/WebApps/DataMiner/). However, there are abandoned oil fields where boundaries are not defined within these shapefiles. The Plains CO_2 Reduction (PCOR) Partnership has made an effort to approximate the oilfield boundaries based upon the location of each abandoned field's oil wells. The area investigated covers 36 counties in the eastern part of Montana (Figure B-1).

The identification of Montana's abandoned oil fields within the PCOR Partnership was performed with data from the MBOG Web site. Oilfield boundary and oil well shapefiles were used to identify the abandoned oil fields that were not yet delineated. The process is outlined below:

1) Oil field boundary and oil well data were obtained from MBOG.

2) Oil wells that were associated with an existing oil field were eliminated.

3) Oil wells that were associated with an oil field that had no oil production were eliminated.

4) Oil wells that were part of an active oil field were eliminated.

5) The remaining oil wells were wells that are part of an oil field that is no longer producing, but the oil field does have past production data.

6) 1200-foot buffers were created around each of these remaining oil wells.

7) With each of the oil wells associated with an oil field, the GIS spatial analysis tool called "Minimum Bounding Geometry" was used to create an "envelope" boundary around each set of well buffers with matching oilfield names (Figure B-2).

8) This envelope boundary was completed for each newly created oil field. Cumulative production values were assigned to each oil field.

The methodology resulted in 76 abandoned oil fields across the study area (Figure B-3). A total of 436 abandoned oil wells were used in the creation of these fields. The total cumulative production of these oil fields was 9,299,781 bbl (MBOG). The field-level production ranged from a minimum of 160 bbl to a maximum of 2,030,660 bbl (Figures B-4 and B-5).

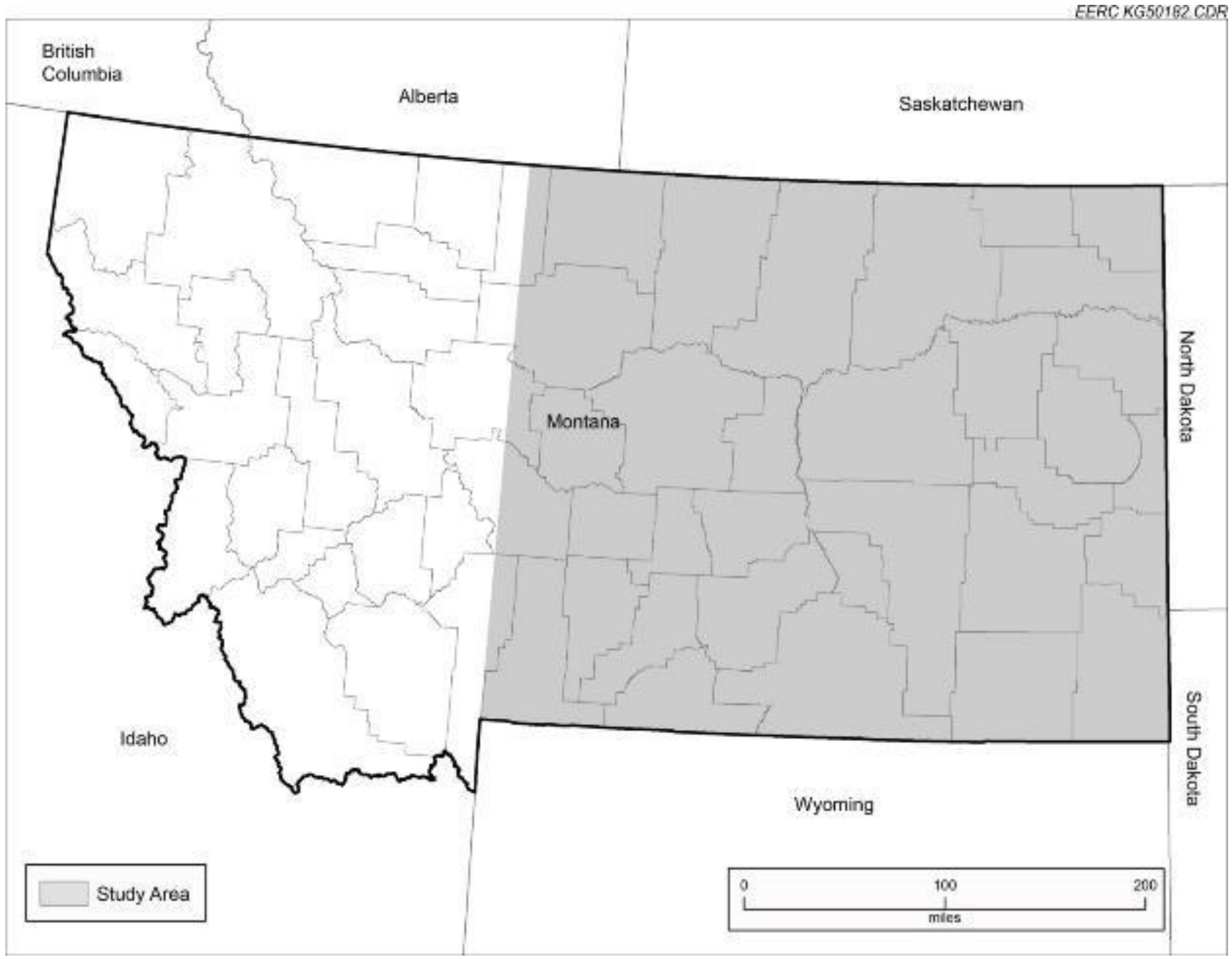

Figure B-1. Study area.

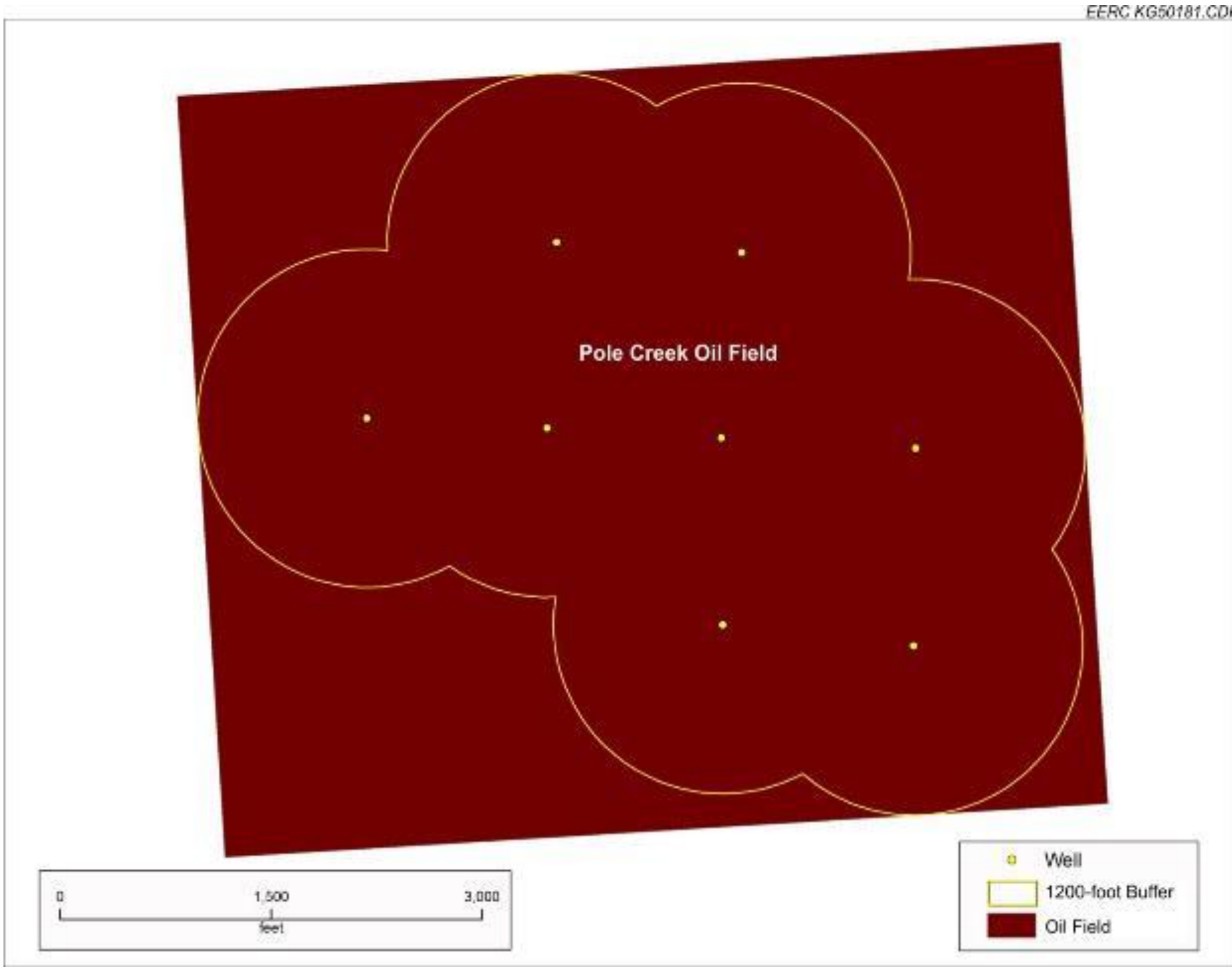

Figure B-2. Creation of Pole Creek oilfield boundary.

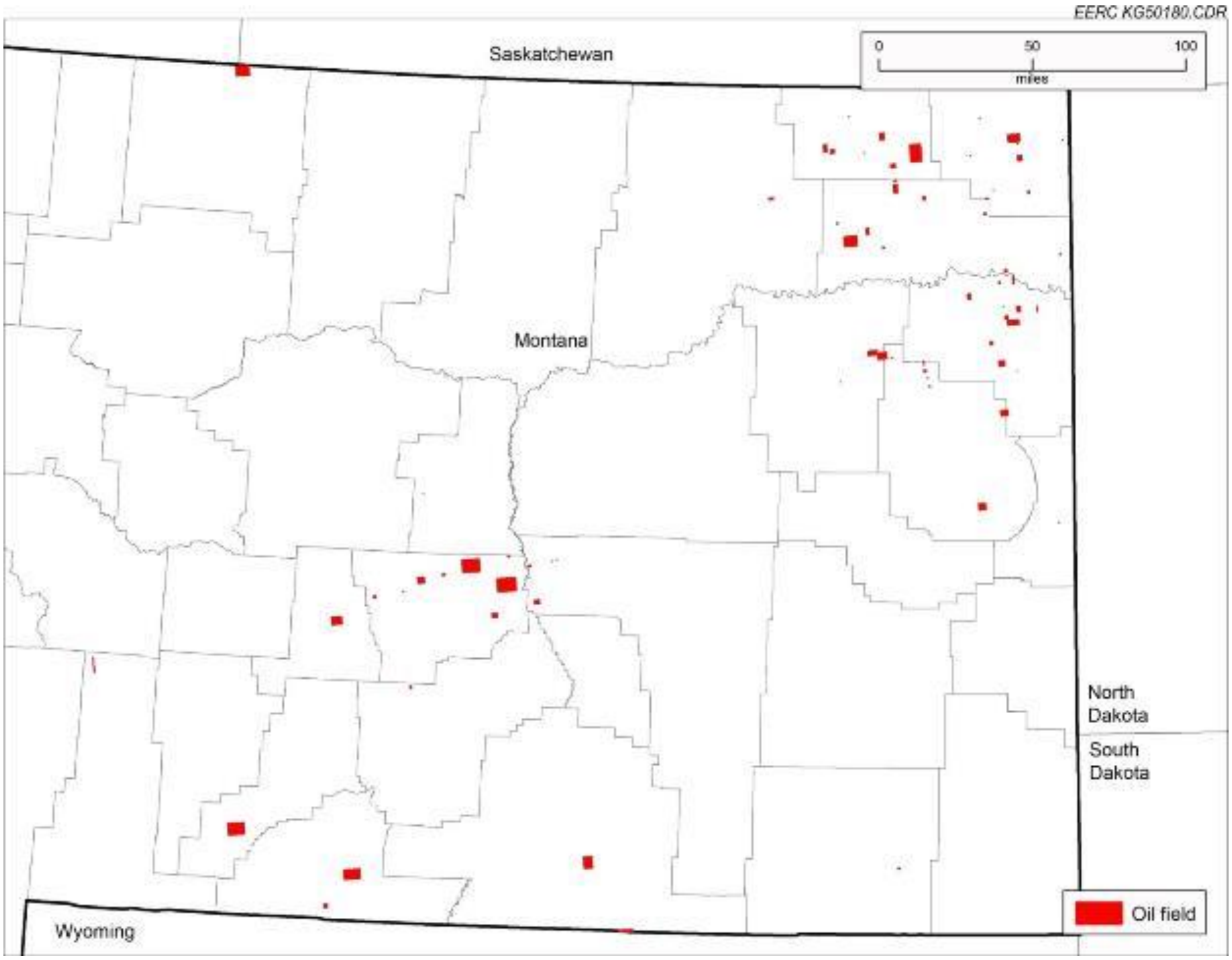

Figure B-3. Abandoned oil fields created for Montana.

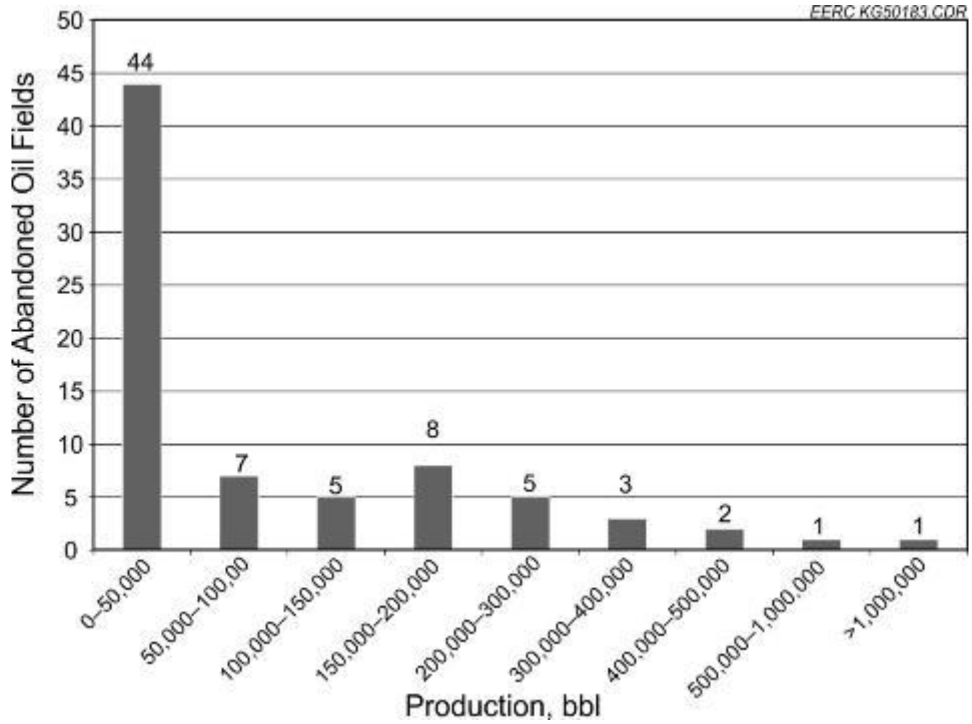

Figure B-4. Histogram showing abandoned oilfield production in bbl.

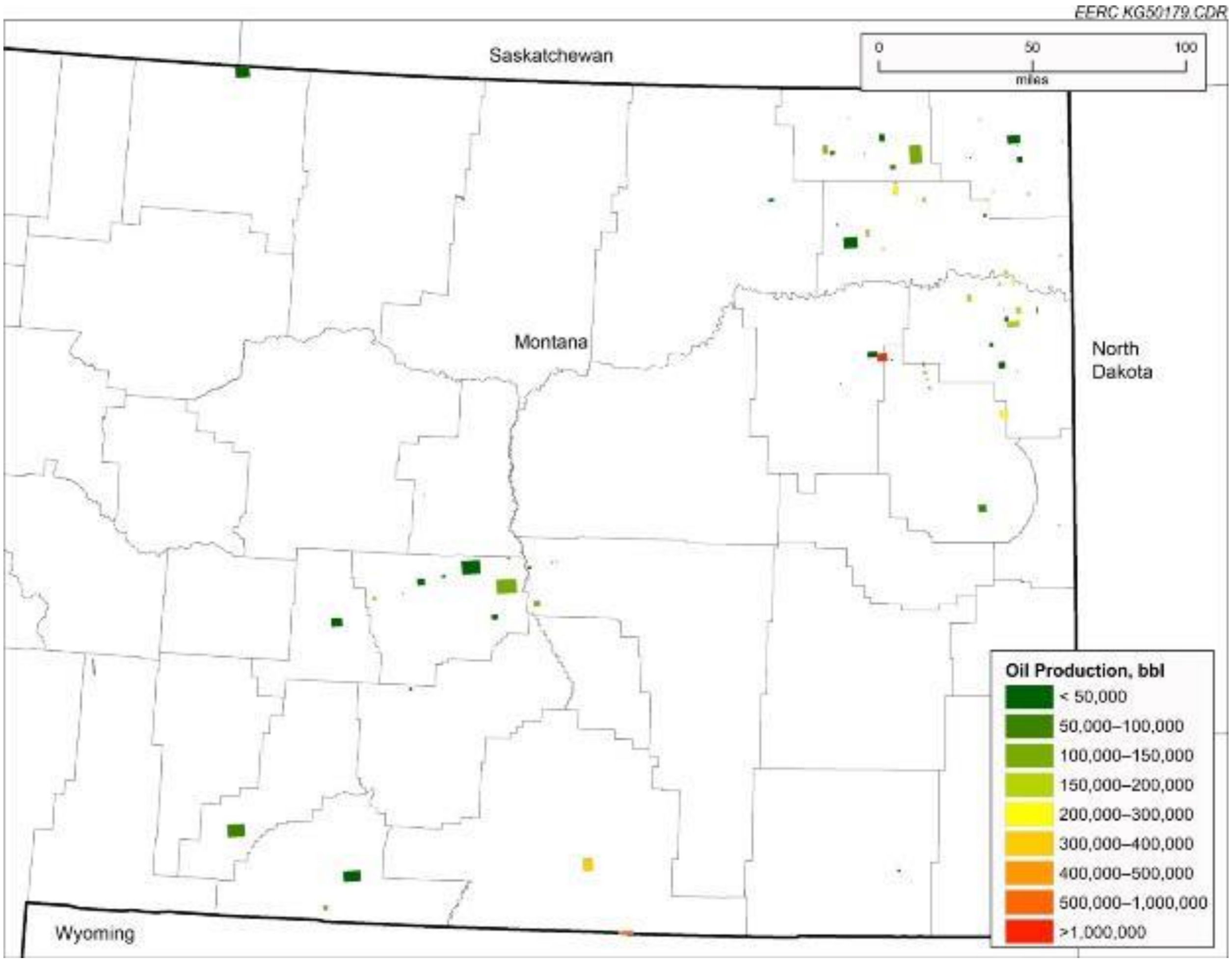

Figure B-5. Abandoned oilfield production.