Plains CO_2 Reduction (PCOR) Partnership

Practical, Environmentally Sound CO_2 Sequestration

GEOLOGIC SEQUESTRATION POTENTIAL OF THE PCOR PARTNERSHIP REGION

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EXECUTIVE SUMMARY

The Plains CO_2 Reduction (PCOR) Partnership region contains vast geologic sinks that can be used to sequester carbon dioxide (CO_2) in a variety of ways. As part of the PCOR Partnership Phase I activities, the CO_2 sequestration capacity of several geologic sinks in the region was estimated. Thousands of oil reservoirs, three major coal fields, and two regional deep brine formations (a.k.a. saline aquifers) were evaluated using readily available characterization data. The characterization data that were available for each sink varied widely and, therefore, all of the values for CO_2 storage capacity that were developed under Phase I should be considered reconnaissance-level estimates; these estimates provide an order-of-magnitude comparison of the potential storage capacities of selected geologic sinks in the region. The estimates indicate that over 240 billion tons of CO_2 could be sequestered in geologic formations in the PCOR Partnership region. Major stationary sources in the PCOR Partnership region produced nearly 590 million tons of CO_2 in 2000. If this rate of CO_2 production were to remain constant, the region's geologic sinks could theoretically sequester all of the CO_2 produced in the region for over 400 years.

One of the primary functions of the PCOR Partnership is to facilitate the implementation of geologic sequestration strategies. As part of that function, identification and characterization of sinks with a value-added component was a critical goal of the PCOR Partnership. With that in mind, major emphasis was placed on evaluation of oil and coal fields in the PCOR Partnership region. The evaluation suggested that over 3.4 billion barrels of incremental oil might be recovered from oil fields in the region through the injection of CO_2, with a vast majority of the oil located in the Alberta and Williston Basins.

Coal seams in the region were also shown to have potential for value-added CO_2 sequestration. Reconnaissance-level estimates indicate that over 17 TCF of methane might be produced from the injection of CO_2 into those coal seams.

The significant gains in incremental oil and methane production projected by the Phase I evaluations, as well as continued high oil and natural gas prices, may provide the incentive needed for stakeholders to invest in the infrastructure and capture technologies needed to make large-scale CO_2 sequestration a reality. CO_2-based enhanced oil recovery (EOR) and enhanced coalbed methane (ECBM) production may provide the economic capital required to develop the infrastructure needed for future large-scale injection of CO_2 into sinks that do not have a value-added component, such as brine formations.

Establishing carbon credit markets for geological sequestration will improve the economics of CO_2-based EOR and ECBM projects and is essential to the implementation of sequestration projects that target brine formations. The development of carbon credit markets for CO_2 sequestered in geological formations will require proper accounting of injected CO_2, which will be facilitated by a streamlined process that takes technical, economic, and regulatory conditions and issues into account. Such a system has already been established in the unitization process under which the U.S. petroleum industry currently operates.

In order to facilitate the implementation of geologic sequestration projects, the PCOR Partnership proposes that target sites for geologic storage of CO_2 be referred to collectively as “geological sequestration units” (GSUs). GSUs may be established in petroleum reservoirs, saline formations, and coal seams. Unit boundaries have already been established for hundreds of oil fields as part of the field operational and regulatory processes.

The establishment of a GSU within a geologic setting that does not produce hydrocarbons, such as a saline formations, will still require the same detailed documentation that demonstrates to the appropriate regulatory agency that the operator of the project 1) adequately understands the geology and hydrodynamics of the proposed GSU and 2) has an appropriate monitoring, mitigation, and verification plan in place to keep track of the injected CO_2. Unitization will facilitate monetization by establishing a technical and legal framework by which CO_2 injection can be implemented. The value of these credits will be largely based on the ability to quantify and verify the amount of CO_2 in a given geological target. The physical and legal boundaries of that target must be established as part of the monetization process.

Areas to be established as GSUs will be those that have been proven to have an effective seal and known fluid migration properties. The first candidates for GSUs will be those geologic features that have already been thoroughly characterized, many of which have been identified during Phase I. Since most detailed characterization of the deep subsurface has been conducted as part of hydrocarbon exploration and production activities, it is likely the first GSUs will be oil fields that are currently in production, depleted oil and gas fields, and other characterized structures that are known to have effective trapping mechanisms (e.g., previously explored anticlines, pinnacle reefs, and other structures that do not have economical reserves of petroleum).

Like oil field units, a GSU should only be established across an area where the geologic and hydrodynamic characteristics have been demonstrated to be thoroughly documented and well understood. With this in mind, it will not likely be possible to declare entire regional formations or aquifer systems (e.g., the Mississippian Madison Formation or the Lower Cretaceous aquifer system) to be single GSUs. Geologic formations and aquifer systems are typically too heterogeneous and lacking in characterization data to adequately model large regions to the precision required for unitization. Rather, it will be necessary to identify localized areas within a formation or aquifer system that have specific characteristics, particularly with respect to competent seals, that allow for the secure long-term storage of CO_2.

The establishment of GSUs within a geological formation will facilitate monetization by providing a technical and legal framework by which CO_2 injection can be implemented. The value of carbon credits associated with sequestration in the oil fields, coal seams, and brine formations of the PCOR Partnership region will be largely based on the ability to quantify and verify the amount of CO_2 in a given GSU.

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BACKGROUND/INTRODUCTION

The Plains CO_2 Reduction (PCOR) Partnership region contains numerous oil reservoirs, coal deposits, and deep sedimentary rock formations saturated with salt water (brine formations, sometimes referred to in the literature as saline aquifers). Under certain conditions, these geological features can be capable of providing secure, long-term storage for large volumes of carbon dioxide (CO_2). They generally occur in geological settings known as sedimentary basins, which in the PCOR Partnership region underlie nearly 40% of the geographical area. Specifically, the Phase I PCOR Partnership region included all of the Williston, Powder River, and Kennedy Basins, a vast majority of the Alberta Basin, and large portions of the Denver-Julesberg, Salina, and Forest City Basins (Figure 1).

As part of the PCOR Partnership Phase I activities, several potential geologic sinks in the region's basins were characterized using readily available literature and data sets. The characterization data were used to develop reconnaissance-level estimates of CO_2 storage capacity for over 1900 sink locations that were previously undetermined, including over 1900 oil fields, three coal seams, and two brine formations. These potential sinks, the methods used to evaluate their sequestration potential, and their estimated CO_2 storage capacities, have been described in detail in other documents (Nelson et al., 2005a,b; Smith et al., 2005; Fischer et al., 2005; Sorensen et al., 2005; Bachu and Adams, 2003; Bachu, 2005).

The results of the Phase I evaluation indicate that the most appropriate and likely targets for large-scale geologic sequestration are in the Alberta, Williston, Powder River, and Denver–Julesberg Basins. This report summarizes the many geologic sequestration opportunities available in the PCOR Partnership region.

THE CONCEPT OF GEOLOGICAL SEQUESTRATION UNITS

A precise and descriptive vocabulary is needed to adequately describe and discuss the sequestration of CO_2 in geological formations. In the petroleum industry, a rock layer that contains fluid or gas is referred to as a reservoir. A rock layer that oil or gas cannot flow through is referred to as a trap or a cap. In hydrogeology, a rock layer that contains water is referred to as an aquifer. A rock layer that contains water with dissolved solids concentrations that are above drinking water standards is commonly known as a saline aquifer or brine formation. A rock layer that water cannot flow through is referred to as an aquitard or a confining bed. This report focuses on the sequestration of CO_2 in coal seams, petroleum reservoirs, and brine formations, which the PCOR Partnership refers to collectively as geological sequestration units.

The term "geological sequestration unit" was chosen to acknowledge the legal and regulatory process that will be necessary to inject large volumes of CO_2 across areas consisting of numerous mineral ownership tracts; it was not chosen to represent a physical geologic unit or formation. The concept is to apply the process by which petroleum fields become unitized for the development of geological sequestration projects.

In modern hydrocarbon production field practices, prior to initiation of subsurface activities that will affect the fluid distribution and production within an area, mineral ownership tracts may be legally combined to form a larger working area. The process of combining individual tracts is referred to as "unitization," and the working area created by this process is referred to as a "unit." The effective result

Figure 1. Phase I PCOR Partnership region, which includes all of the Williston, Powder River, and Kennedy Basins, a vast majority of the Alberta Basin, and large portions of the Denver–Julesberg, Salina, and Forest City Basins.

of unitization is the protection of correlative rights of all mineral owners within the designated area and coordinated injection and reservoir management practices that improve the efficiency of petroleum extraction. It is anticipated that a similar unitization process will need to be developed prior to large-scale injection of CO_2 for sequestration in geological formations.

A geologic sequestration unit (GSU) may be established in petroleum reservoirs, saline formations, and coal fields. In the case of many of the oil and coal fields in the region that have been considered for CO_2 sequestration, unit boundaries have already been established as part of the field operational and regulatory processes. The establishment of a GSU within a geologic setting that does not produce hydrocarbons, such as a saline formations, will still require the same detailed documentation that demonstrates to the appropriate regulatory agency that the operator of the project 1) adequately understands the geology and hydrodynamics of the proposed GSU and 2) has an appropriate monitoring, mitigation, and verification plan in place to keep track of the injected CO_2.

Using unitized oil fields as a model, GSUs could vary in size from as small as a few acres to as large as hundreds of square miles. The size of a GSU is directly dependent on the geologic and hydrodynamic characteristics of the area being considered as a target for CO_2 injection. Like oil field units, a GSU should only be established across an area where those characteristics have been demonstrated to be thoroughly documented and well understood. With this in mind, it will not likely be possible to declare entire regional formations or aquifer systems (e.g., the Mississippian Madison Formation or the Lower Cretaceous aquifer system) to be single GSUs. Geologic formations and aquifer systems are typically too heterogeneous (especially with respect to porosity and permeability) and lacking in characterization data to adequately model large regions to the precision required for unitization. Rather, it will be necessary to identify localized areas within a formation or aquifer system that have specific features (e.g., structural or hydrodynamic traps, desirable geochemical characteristics, etc.) that will allow for the secure long-term storage of CO_2.

The first step in establishing a GSU is to identify target formations and features that have the potential to safely and effectively store large volumes of CO_2. The geological characterization activities conducted under Phase I of the PCOR Partnership may be considered to be an example of that first step. The results of those activities, as described below, may provide the basis for initiating the establishment of GSUs in selected oil fields, coal seams, and, ultimately, specific portions of brine formations within the PCOR Partnership region.

ESTIMATES OF CO_2 STORAGE CAPACITY IN OIL FIELDS OF THE PCOR PARTNERSHIP REGION

Under the current market system, which does not include non-market-based incentives, CO_2 sequestration in many geologic sinks is typically not economically viable. Enhanced oil recovery (EOR) through CO_2 miscible flooding, however, is a proven, economically-viable technology that could also result in cost-effective CO_2 sequestration. For example, a portion of the revenue generated by CO_2 EOR activities could be used to pay for the infrastructure necessary for future geologic sequestration in brine formations.

Carbon sequestration through EOR is one of the first mechanisms to be used as a long-term strategy for reducing anthropogenic CO_2 from greenhouse gas emissions. The oil and gas industry has been involved in EOR through miscible CO_2 flooding for over 30 years. This knowledge has direct application to CO_2 sequestration. Based on rock and fluid properties, it has been estimated that about 80% of the oil reservoirs worldwide would be candidates for CO_2 injection (Kovscek, 2002). In response to this, the PCOR Partnership felt it was crucial to consider this aspect of carbon sequestration a priority. As part of Phase I, the PCOR Partnership gathered readily available oil production and reservoir characterization data for oil fields in the states of North Dakota, South Dakota, Montana, Wyoming, and Nebraska and the provinces of Manitoba, Saskatchewan, and Alberta. Only minor oil production has occurred in Missouri, and the oil-bearing formation is too shallow to allow supercritical injection of CO_2. Minnesota, Iowa, and Wisconsin have no reported oil production and, therefore, have no EOR-related sinks for CO_2.

Sequestration in Oil Fields

Oil fields have many characteristics that make them excellent target locations for geologic storage of CO_2. Oil reservoirs are locations within a rock formation where hydrocarbon fluids have accumulated over millions of years because of the presence of at least one trapping mechanism. In fields that are sealed by structural or stratigraphic traps, the fact that oil has accumulated into a reservoir strongly suggests that the same trapping mechanism may be used to sequester CO_2.

A single oil field can have multiple zones of accumulation which are commonly referred to as pools, although specific legal definitions of fields, pools, and reservoirs vary for each state or province. Once injected into an oil field, CO_2 may be sequestered in a pool through dissolution into the formation fluids (oil and/or water), as a buoyant supercritical-phase CO_2 plume at the top of the reservoir (depending on location of the injection zone within the reservoir), and/or through geochemical reactions between the CO_2 and formation rock matrix. From a project planning and regulatory standpoint, mature oil fields that are undergoing secondary recovery operations can make for good targets for CO_2 sequestration because they have already gone through the unitization process, which should make their designation as GSUs less complicated.

The PCOR Partnership region includes many thousands of pools in thousands of oil fields, many of which are already unitized, scattered across portions of four sedimentary basins; the Williston, Powder River, Denver–Julesberg, and Alberta Basins (shown in Figure 2).

Developing estimates of their potential capacity for CO_2 sequestration was one of the primary goals of Phase I. The estimates were developed using reservoir production and characterization data obtained from the petroleum regulatory agencies and/or geological surveys from the states and provinces. A detailed description and discussion of the methodologies and reservoir characterization data used to develop oil field-related CO_2 sequestration capacities and potential incremental oil production for all of the states and provinces in the Williston Basin are available in a PCOR Partnership topical report by Smith et al. (2005). The results of those efforts are summarized below.

Potential CO_2 sequestration capacities and incremental oil production from CO_2-based EOR in selected oil fields in the Williston Basin, Powder River Basin, and part of the Denver–Julesberg Basin were estimated as part of Phase I of the PCOR Partnership regional characterization. These basins include portions of North Dakota, South Dakota, Montana, Wyoming, Nebraska, Saskatchewan, and Manitoba. Smith et al.

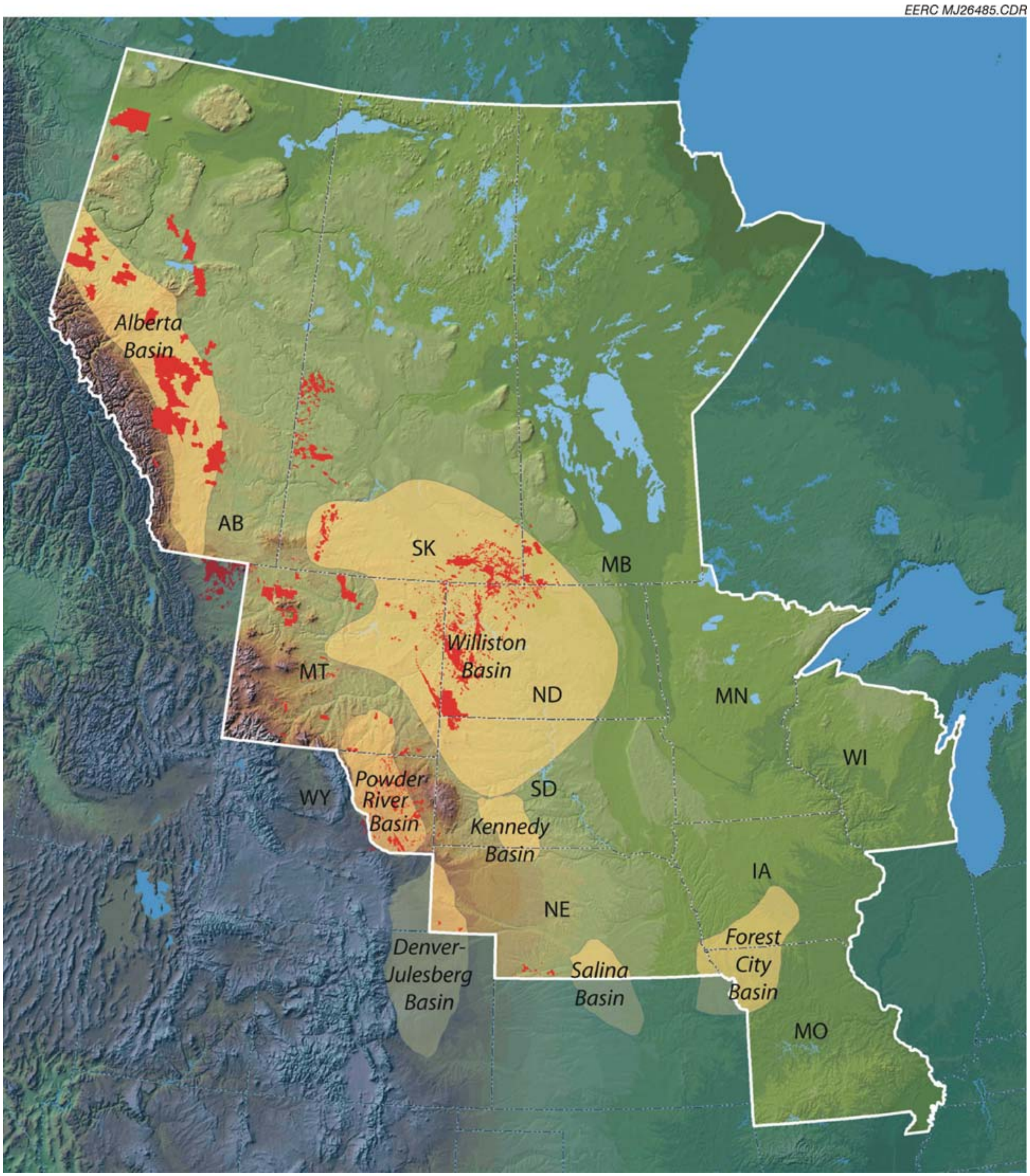

Figure 2. Oil fields of the PCOR Partnership region. The Alberta portion of the map shows only those fields considered to be appropriate for CO_2 EOR activities by Bachu and Shaw (2004). All oil fields are displayed for each of the other states and provinces.

(2005) calculated reconnaissance-level sequestration capacities for oil fields in these basins using two methods. It is important to note that the nature and availability of reservoir characteristic data varied, sometimes significantly, between each state and province. For many of the fields in the region, only one method could be applied, depending on the nature of the available reservoir characterization data for the given field.

Both methods used for estimating the CO_2 sequestration capacity of oil fields in the Williston, Powder River, and Denver–Julesberg Basins are described in detail in the PCOR topical report by Smith et al. (2005). The first method, referred to as the volumetric method, used field area, thickness of the oil-producing interval, average reservoir porosity, properties of CO_2 under reservoir temperature/pressure conditions, and water saturation to develop estimates of the maximum storage potential for 1901 pools. The results generated by the volumetric method, summarized in Table 1, indicate that there may be over 10 billion tons of CO_2 storage capacity in the oil fields of those three basins.

The other method used by Smith et al. (2005), referred to as the EOR method, employed a two-step approach to develop estimates of 1) the amount of CO_2 that could theoretically be sequestered and 2) the volume of incremental oil that could be produced as a result of CO_2 flood EOR activities at selected fields in the region. In the first step of the EOR method, candidate fields were selected from among the total set of fields in the Williston, Powder River, and Denver–Julesberg Basins. The EOR candidate fields were chosen by considering guidelines established by Bachu et al. (2004) for screening reservoirs for CO_2 flood EOR, including overall field production history, secondary recovery performance, depth to production, rock properties, formation fluid properties, and reservoir temperature and pressure.

Once the EOR fields had been selected, estimates of both potential CO_2 sequestration capacity and incremental oil production were made using a simple equation that was based on an approach used by Nelms and Burke (2004). The EOR method employed by Smith et al. (2005) for estimating potential CO_2 sequestration capacity and incremental oil production assumed for each selected field that 1) 12% of the original oil in place would be produced as a result of CO_2 flood EOR, 2) 8 thousand cubic feet of CO_2 would be required to produce each barrel of incremental oil, and 3) 100% of the CO_2 injected for EOR would remain in the reservoir. While both methods described above are relatively simplistic, they do provide at least order-of-magnitude-level CO_2 capacity estimates for over 1000 geologic sink locations in the region that were previously unavailable. The results of the EOR-based evaluations for the Williston, Powder River, and Denver–Julesberg Basins, shown in Table 1, suggest that over 700 million tons of CO_2 could be sequestered, possibly resulting in over 1.4 billion barrels of incremental oil production.

Sequestration capacities for 4371 pools in Alberta suitable for CO_2 flood EOR were estimated by Bachu and Shaw (2004). The approach employed by Bachu and Shaw (2004) to generate the CO_2 flood-related oil field sequestration capacities took advantage of a more detailed reservoir characterization data set and a rigorous methodology that accounted for not only the parameters considered by Smith et al. (2005) as described above, but also the presence and effects of underlying aquifers on reservoir hydrodynamics, reservoir heterogeneity, and suitability for CO_2 flood EOR. The paper by Bachu and Shaw (2004) presents CO_2 storage capacity estimates for Alberta fields under several

Table 1. Potential CO_2 Sequestration Capacities and Incremental Oil Production for Selected Oil Fields in the PCOR Partnership Region

Basin	Number of Pools Evaluated	Sequestration Capacity – Volume Method, million tons CO_2	Sequestration Capacity – EOR Method, million tons CO_2	Potential Incremental Oil Recovery, million stock tank barrels
Williston	845	>9000	502	1023
Powder River	225	>1000	187	381
Denver–Julesberg	21	14	12	25
Alberta	4371	NC[a]	545[b]	>2000[b]

[a] Value not calculated for the Alberta Basin.
[b] Values for the Alberta Basin were determined using a different methodology than the other basins and, therefore, may not be directly comparable to the other estimates. They are included in the table to provide insight regarding the general magnitude of CO_2 flood-related sequestration capacity and potential incremental oil production in Alberta.

different operational systems (i.e., primary recovery, water flood, gas flood). They also report estimated storage capacity in CO_2 flood EOR at 50% of the hydrocarbon pore volume (HCPV), which generates results that are most comparable to those generated using the methods of Smith et al. (2005). With that in mind, Table 1 includes the CO_2 storage capacity estimated by Bachu and Shaw (2004) for Alberta pools in CO_2 flood EOR at 50% HCPV. Those results indicated that 545 million tons of CO_2 may be stored in Alberta oil pools. Bachu and Shaw (2004) report that over 2.5 billion barrels of incremental oil could be produced as a result of CO_2 injection into 50% HCPV into 4748 pools in western Canada. They do not specify how much of that volume of oil could come from Alberta, but do state that over 90% of Canadian oil production comes from Alberta, so it is likely safe to assume that over 2 billion barrels of incremental oil can be produced from CO_2 flood EOR activities in Alberta.

The CO_2 capacity and incremental oil production estimates generated during Phase I provide the PCOR Partnership with an effective, semiquantitative basis for identifying CO_2 source–sink matches that can take advantage of incremental oil recovery as an economic driver for potential sequestration projects.

ESTIMATES OF CO_2 STORAGE CAPACITY IN SOME OF THE PCOR PARTNERSHIP REGION'S COAL BEDS

Numerous laboratory- and field-based studies have shown that coal beds can have significant capacities for sequestering CO_2 (Nelson et al., 2005a). Coal can physically adsorb many gases and has a higher affinity for CO_2 than for methane (Chikatamarla and Bustin, 2003). Gaseous CO_2 injected into a coal seam will flow through the cleat system and become adsorbed onto the coal surface, effectively replacing and releasing gases with lower affinity for coal (i.e., methane). Through this phenomena, the injection of gaseous CO_2 into a coal seam can result in simultaneous sequestration of CO_2 and enhanced coalbed methane (ECBM) production.

Phase I of the PCOR Partnership examined the potential to sequester CO_2 in coal seams in three basins of the region. The coals, and their respective basins, for which reconnaissance-level evaluations were performed include 1) the Wyodak–Anderson coal zone of the Powder River Basin, 2) the Harmon–Hansen coal seams of the Williston Basin, and 3) the Ardley coals of the Alberta Basin. Data on coal fields in Iowa, Missouri, and Saskatchewan were also collected, but the coal seams in those fields are too shallow and/or too thin to be considered as targets for geologic CO_2 sequestration.

Sequestration Potential of the Harmon–Hansen Coal Seam in the Williston Basin

The Williston Basin contains the second largest deposit of coal resources of any basin in the continental United States. The basin is shown in Figure 3. A geologic model was constructed and used to evaluate the CO_2 sequestration potential of the areas underlain by lignite deposits that are not surface-minable. Areas were determined to be suitable for CO_2 storage if the overburden was at least 500 ft thick. CO_2 sequestration potential for these areas was calculated using the procedure described in detail in the report "Geologic CO_2 Sequestration Potential of Lignite Coal in the U.S. Portion of the Williston Basin" (Nelson et al., 2005b). In summary, the CO_2 sequestration potential was calculated using deposit area, net coal thickness, and in situ lignite density.

The gas storage capacity calculations were made using the Langmuir isotherm model, a numerical model that describes the relationship between the gas storage capacity and pressure. It is the most commonly used isotherm model for coal (Mavor and Nelson, 1997). The Langmuir

Figure 3. Map showing the extent of coal resources in the region. The three coal seams that were evaluated for CO_2 sequestration are highlighted and labeled.

volume and pressure values were experimentally determined for lignite from the Williston Basin.

The CO_2 sequestration potential for the areas where the coal overburden is thicker than 500 ft was estimated to be 380 million tons. Table 2 summarizes the CO_2 sequestration potential for the Williston Basin lignites. Although there is currently no coalbed methane (CBM) production from seams in the Williston Basin, some exploratory activities for CBM have been conducted in recent years. Very little site-specific data are available, however a methane gas content of 20 standard cubic feet (scf)/ton has been reported from a test hole in the Harmon seam of Slope County in southwestern North Dakota. Assuming an average seam thickness of 15 feet, a coal density of 1750 tons/acre-foot (which is typical of lignite), and an estimated area of 13,000 square miles, if the reported methane gas content of 20 scf/ton were shown to be a common characteristic of the Harmon lignite, then the total CBM gas in place for the Harmon could be calculated to be as high as 4.4 trillion cubic feet (Tcf). Even if only 25% of this total is recoverable, it is conceivable that there may be as much as 1.1 Tcf of recoverable natural gas in the Harmon lignite of North Dakota.

While the nature of the above estimate is speculative and highly debatable, it does speak to the potential size of a gas resource that may provide an economic incentive to sequester CO_2 in Williston Basin coal seams. Detailed laboratory- and field-based data are required to fully determine the potential CBM resources of the Williston Basin and the role that CO_2 injection may play in exploiting any reserves that exist.

Sequestration Potential of the Wyodak–Anderson Coal Zone in the Powder River Basin

The Powder River Basin is the No. 1 coal-producing area and the second most prolific CBM-producing area in the United States. The CO_2 storage potential of the Powder River Basin was calculated using a method similar to that used for the storage potential of the lignite in the Williston Basin. However, the Powder River Basin calculation also took into account the impact of sorbed-phase natural gas and its composition on the total CO_2 storage capacity.

A detailed description of the approach, methodology, and results of the evaluation of the Wyodak–Anderson coal zone are available in the PCOR Partnership topical report by Nelson et al. (2005a).

It is estimated that 16.1 Tcf of coalbed gas could be recovered during CO_2 sequestration in the Wyodak–Anderson coal zone. The calculations show that the Powder River Basin Wyodak–Anderson coal zone could sequester 7.9 billion tons of CO_2 in the areas where the coal overburden is estimated to be thicker than 500 ft.

Sequestration Potential of the Ardley Coal Zone in the Alberta Basin

The Ardley coal zone is the uppermost coal zone in Alberta. The Ardley coal zone includes as many as 34 individual coal seams that vary in thickness from 0.5 to 11.0 m. As part of Phase I of the PCOR Partnership, a portion of the Ardley coal zone was evaluated with respect to CO_2 sequestration. The methodology and results of this evaluation are described in detail in the PCOR Topical Report entitled “Carbon Dioxide Storage Capacity in Upper Cretaceous–Tertiary Ardley Coals in Alberta” by Bachu (2005) and are similar to those used for the Wyodak–Anderson. The region suitable for CO_2 sequestration was defined based on depth (greater than

300 m) and to ensure the protection of potable groundwater resources. The theoretical CO_2 sequestration capacity in the study area was estimated on the basis of CO_2 adsorption isotherms measured on coal samples from eight locations. The results of the evaluation indicate that the Ardley coals within the defined region have an effective sequestration capacity of 2.9 billion tons of CO_2.

Estimates of potential CBM resources within the Ardley coal zone were not developed as part of this study. However, the study did consider economic factors related to infrastructure development. Assuming that it is economical to build the necessary infrastructure only in areas with an effective sequestration capacity greater than 200 kilotons of CO_2/km^2, then the region of the Ardley coals that is practically suitable for CO_2 sequestration will be reduced, with a corresponding reduction in capacity to 836 million tons of CO_2.

Table 2. Reconnaissance-Level Estimates of CO_2 Sequestration Potential in Selected Coal Intervals of the PCOR Partnership Region

Coal Interval (Location)	CO_2 Capacity Range, million tons CO_2	Estimated Potential Recoverable CBM, TCF
Wyodak–Anderson (Wyoming)	6880–7980	16.1
Ardley (Alberta)	836–2900	Not determined
Harmon–Hansen (North Dakota)	380	1.1

ESTIMATES OF CO_2 STORAGE CAPACITY IN BRINE FORMATIONS OF THE PCOR PARTNERSHIP REGION

Deep saline aquifer systems, or brine formations, represent a significant portion by volume of the sedimentary basins in the PCOR Partnership region. These formations can sequester or store CO_2 by three primary mechanisms: 1) solubility trapping through dissolution in the formation water, 2) mineral trapping through geochemical reactions with formation water and rocks, and 3) hydrodynamic trapping of a CO_2 plume. Thus the capacity of a brine formation may be considered in terms of free-phase CO_2 in the rock pore space, dissolved phase CO_2 in the formation water, and CO_2 converted to solid minerals that become part of the rock matrix. The degree to which each mechanism will affect sequestration under the range of geologic, hydrodynamic, and geochemical conditions that can occur in any given field is currently not well understood and difficult to predict. It is possible, and perhaps even likely, that all three mechanisms may occur at any given location, although mineral trapping is the least understood.

Since the focus of Phase I of the PCOR Partnership was to conduct reconnaissance-level evaluations of geologic sinks in the region, capacity estimates for brine formations only considered characteristics that control solubility and hydrodynamic trapping mechanisms. Mineral trapping was not considered, and the effects that it may have on the sequestration of CO_2 in the studied formations, whether they be positive or negative, are unknown.

It is important to keep in mind that a single geologic formation can include many different rock types and can change lithology over distance. For example, in the Williston Basin, the Newcastle Formation is primarily mudstone but also includes sandstones and shale, and the Madison Formation includes both carbonate and evaporite rocks. As lithologies change within a formation, so will the key characteristics that determine the capacity and suitability of a formation for CO_2 sequestration. In particular porosity and permeability, arguably the two most critical characteristics for predicting the success of a CO_2 injection project, are known to be especially variable over distance within many formations.

The inherent heterogeneity found in nearly all geologic formations means that detailed subsurface mapping and characterization must be conducted in any area that is being considered for large-scale injection of CO_2. Maps showing structure, porosity, and permeability within a target formation and other detailed characterization data are essential components for the establishment of GSUs within brine formations.

To calculate the storage potentials of these saline aquifer systems, a model was developed to produce a continuous gridded surface representing the volume of CO_2 that could be sequestered per square mile. The model is based on existing data relating to hydrological studies of regional aquifer systems; oil, gas, water well data; and existing geographic information system (GIS) map data.

The calculation used was a straightforward estimate relating the pore volume in the reservoir (area × thickness × porosity) and the solubility of NaCl in the reservoir water at spatially varying pressures and temperatures. Solubility factors for temperatures and concentrations in excess of 200°F and 200,000 ppm NaCl, respectively, were not readily available at the time of this study (temperatures and concentration values are routinely above these values in the Powder River and Williston Basins). As such, data were extrapolated to above 500°F and 300,000 ppm from tables provided through personal communication with the Indiana Geological Survey in April 2004 in order to attain the necessary solubility correction factors.

The Mississippian Madison Group and the Lower Cretaceous aquifer system within the PCOR Partnership region have the potential to store vast quantities of anthropogenic CO_2. Their unique lateral extent, the current understanding of their storage potential, and their geographic proximity to major CO_2 point sources suggest that they may be suitable CO_2 sinks. Both brine formation systems are capped by competent seals over large portions of the region. Their relative depth within the stratigraphic framework of the region is shown in Figure 4. Figures 5 and 6 show portions of the Lower Cretaceous and Mississippian Madison brine formation systems that were evaluated under Phase I, respectively. Published data were used to evaluate their regional continuity, hydrodynamic characteristics, fluid properties, and ultimate storage capacities.

A regional evaluation of the Mississippian Madison Group was completed for the U.S. portion of the Williston and Powder River Basins and showed that the system has the potential to store over 60 billion tons of CO_2. The regional evaluation of the Lower Cretaceous aquifer system used existing data sets and included the Newcastle, Viking, Maha, Inyan Kara, Dakota, and Skull Creek Formations. Areas of the Lower Cretaceous aquifer system that have been used as sources of water for agricultural, industrial, or residential purposes were not considered to be appropriate targets for CO_2 injection and, thus, were not included in the evaluation. The evaluation showed that the Lower Cretaceous system has the potential to store over 160 billion tons of CO_2 in the Newcastle, Viking, and Maha Formations. A summary of the aquifer system storage capacity is shown in Table 3.

SUMMARY AND CONCLUSIONS

Phase I of the PCOR Partnership included developing estimates of the CO_2 sequestration capacity of the geologic sinks

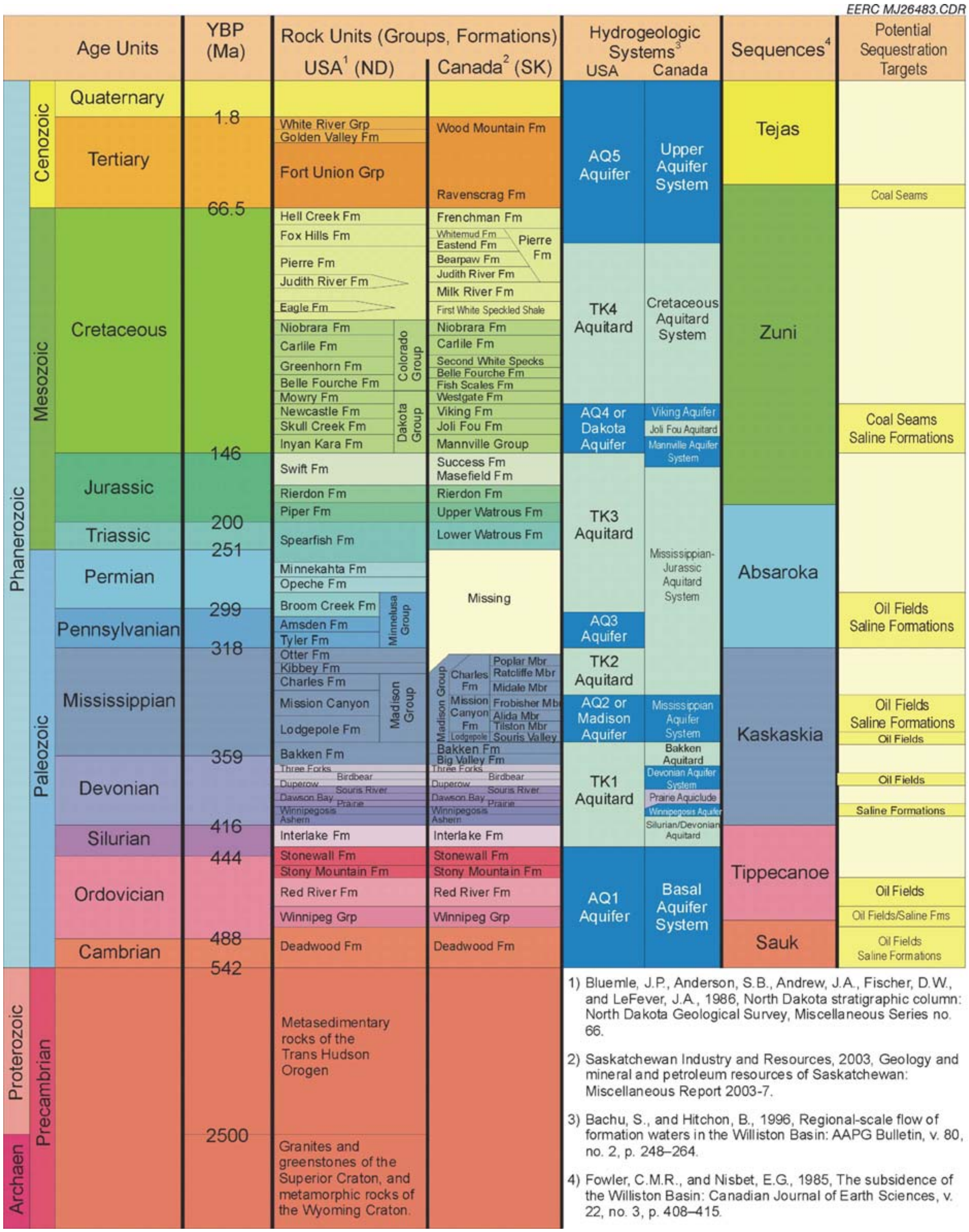

Figure 4. Stratigraphic and hydrogeologic column for the Williston and Powder River Basin portions of the PCOR Partnership region.

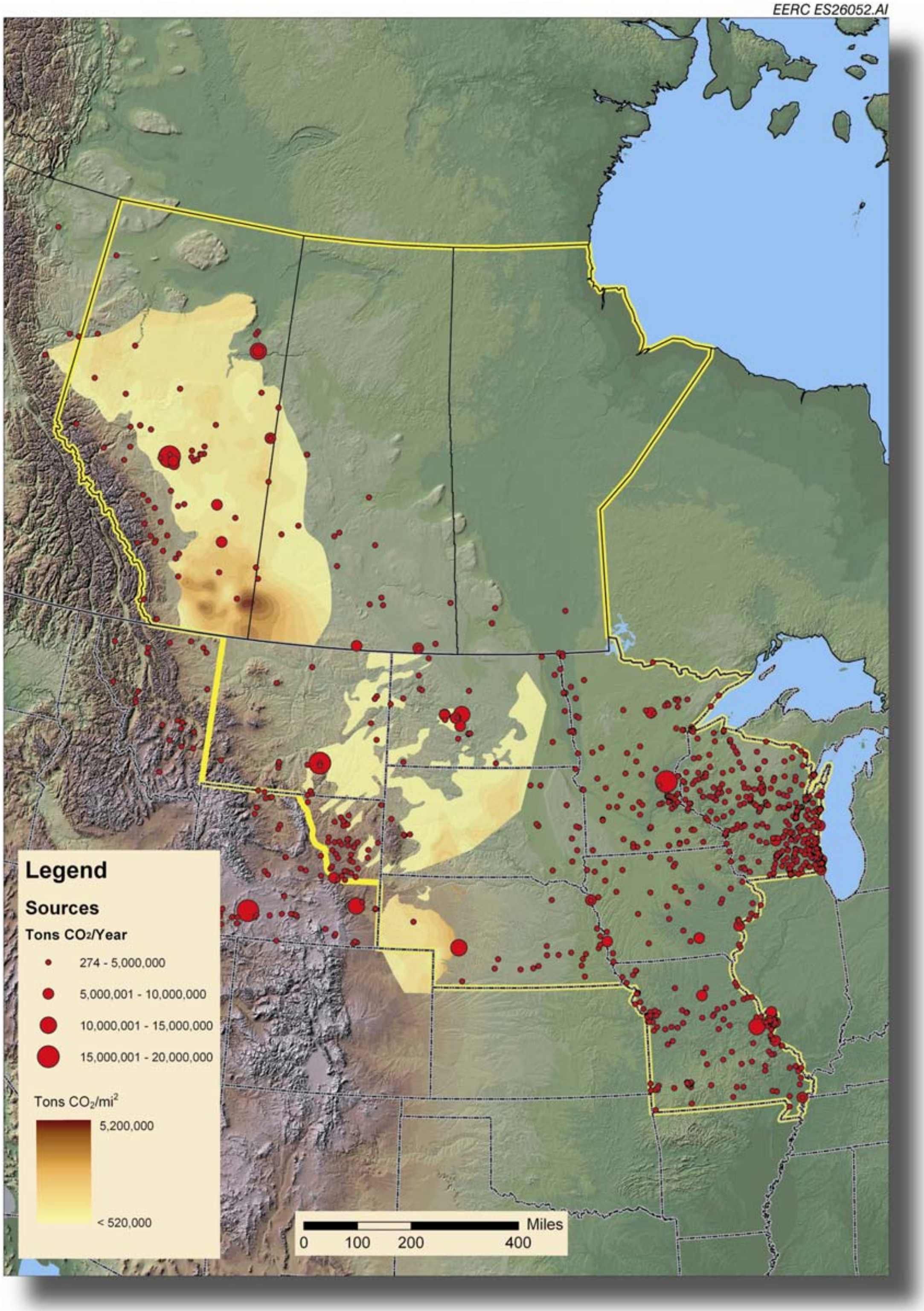

Figure 5. Map showing the portions of Lower Cretaceous saline aquifer system that may be suitable for CO_2 sequestration and major CO_2 point sources in the PCOR Partnership region.

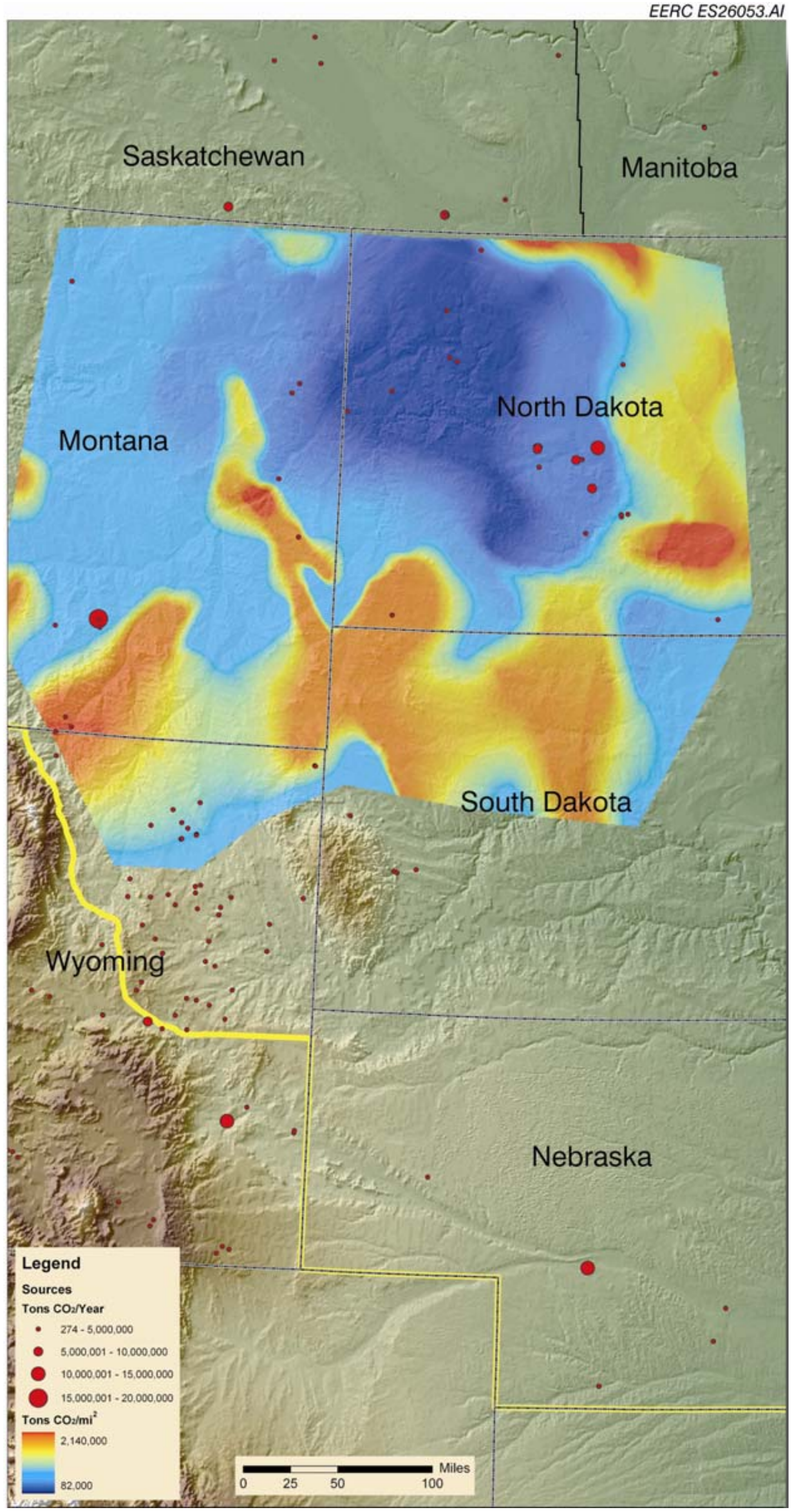

Figure 6. Map showing the Mississippian Madison saline aquifer system and major CO_2 point sources in the PCOR Partnership region.

Table 3. PCOR Partnership Aquifer System Storage Capacity Summary

Aquifer System	Basin	Estimated CO_2 Capacity, billion tons
Lower Cretaceous System		
Newcastle Formation	Williston and Powder River	42
Viking Formation	Alberta	100
Maha Formation	Denver–Julesberg	19
Mississippian System		
Madison Formation	Williston and Powder River	60
Total		221

in the region. To that end, thousands of oil reservoirs, three major coal fields, and two regional deep brine formations were evaluated using readily available characterization data. The nature and quality of characterization data that were available for each sink were found to be widely variable. The methodologies used to estimate CO_2 storage volume for each of the three types of sinks include many assumptions that are based on previously established peer-reviewed literature and industry standards. The variable quality of the data sets from which the estimates are derived, coupled with the uncertainty that must be attached to calculations that are based partially on assumptions, requires that all of the values for CO_2 storage capacity developed under Phase I be considered to be reconnaissance-level estimates. These estimates have been developed to provide an order-of-magnitude comparison of the potential storage capacities of selected geologic sinks in the region so that stakeholders and decision makers can begin to consider CO_2 source-to-sink relationships that may lead to large-scale sequestration projects.

In summary, the total of all of the storage values for the sinks evaluated under Phase I indicate that there is capacity to sequester over 240 billion tons of CO_2 in geologic formations. The major stationary sources in the PCOR Partnership region produced nearly 590 million tons of CO_2 in 2000. If this rate of CO_2 production were to remain constant, the region's geologic sinks could theoretically sequester all of the CO_2 produced in the region for over 400 years.

Absent a robust carbon credit-trading market for CO_2 sequestered in geologic formations, identifying and characterizing sinks that have a value-added component was considered to be a critical goal of the PCOR Partnership. With this in mind, a major emphasis was placed on evaluating oil and coal fields in the PCOR Partnership region. The results of Phase I indicate that there are numerous oil fields in the PCOR Partnership region that may be suitable candidates for CO_2 flood EOR operations. Specifically, the Phase I evaluations suggest that there may be over 3.4 billion barrels of incremental oil to be recovered from oil fields in the region through the injection of CO_2, with a vast majority of the oil being located in the Alberta and Williston Basins.

At an oil price of $60 per barrel (a price that was typically exceeded on the world market during the last 6 months of the Phase I project period), the value of that incremental oil could exceed $180 billion. The history of oil prices indicates that price stability is uncertain at best, so the duration of the $60/bbl price is speculative. But this price scenario provides an idea of the potential magnitude of the economic opportunities that may exist for development of projects that can simultaneously sequester CO_2 and increase oil production.

Phase I results showed that coal seams in the region also have potential to be targets for value-added CO_2 sequestration. Reconnaissance-level estimates indicate that over 17 TCF of methane may be produced from the injection of CO_2 into those coal seams. The significant gains in incremental oil and methane production projected by the Phase I evaluations and continued high oil and natural gas prices may provide the incentive needed for stakeholders to invest in the infrastructure and capture technologies needed to make large-scale CO_2 sequestration a reality.

With respect to CO_2 injection into geologic formations above and beyond that needed for incremental oil and methane production, CO_2-based EOR and ECBM may provide the economic capital needed to conduct future large-scale injection of CO_2 into sinks that do not have a value-added component, such as brine formations. It is also important to note that CO_2 flood EOR and ECBM projects can provide researchers with valuable real-world sites at which economically viable monitoring, mitigation, and verification (MMV) technologies and approaches can be tested. The implementation of accurate, cost-effective MMV technologies is critical to the monetization of carbon credits for the geologic sequestration of CO_2.

The PCOR Partnership recognizes the challenges facing the injection of CO_2 in geological media, especially with respect to monetization of geologic sequestration credits. The development of markets for carbon credits associated with geologic sequestration will require action from several diverse communities. As with many disciplines and technologies, a broadly recognized framework is needed to facilitate effective communication between the scientific, engineering, regulatory, and legal communities. With this in mind, the PCOR Partnership is developing a monetization framework which includes the establishment of GSUs. The development of GSUs will facilitate monetization of carbon credits for geological sequestration by providing a technical and legal framework by which large-scale CO_2 injection can be implemented. The value of these credits will be largely based on the ability to quantify and verify the amount of CO_2 in a given GSU. The physical and legal boundaries of that target must be established as part of the monetization process.

GSUs may be established in petroleum reservoirs, saline aquifers, and coal seams. Unit boundaries have already been established for hundreds of oil fields in the PCOR Partnership region as part of the field operational and regulatory processes. Areas to be established as GSUs will be those that have been proven to provide effective storage and have known fluid migration properties. The first candidates for GSUs will be those geologic features that have already been thoroughly characterized. Since most detailed characterization of the deep subsurface has been conducted as part of hydrocarbon exploration and production activities, it is likely the first GSUs will be oil and gas fields that are currently in production, depleted oil and gas fields, and other characterized structures that are known to have effective trapping mechanisms (e.g., previously explored anticlines, pinnacle reefs, and other structures that do not have economical reserves of petroleum).

Porosity and permeability are the two physical characteristics of a geological formation that most profoundly effect its suitability to accept large volumes of CO_2. The porosity and permeability of most geological formations are often widely and unpredictably variable. The heterogeneity commonly associated with most geological formations and the uncertainty that is inherently associated with heterogeneity will make it difficult, if not impossible, to promote the concept of designating regional-scale brine formations as receptacles for large volumes of CO_2. Only localized areas within a brine formation that have been thoroughly characterized enough to verify the existence of competent seals and conduct robust predictive fluid migration modeling should be considered to be appropriate targets for CO_2 sequestration.

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